DECLARATION OF YOLANDA ANDERSEN

I, Yolanda Andersen, declare as follows:

1. I am the Director of Member Services at the Sierra Club. I have had this position for more than 22 years.
2. In that role, I manage all aspects of the Sierra Club's customer service functions related to members, including maintaining an accurate list of members and managing the organization's member databases.
3. The Sierra Club is a non-profit membership organization incorporated under the laws of the State of California.
4. Sierra Club's mission is to explore, enjoy and protect the wild places of the Earth; to practice and promote the responsible use of the Earth's resources and ecosystems; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives.
5. The Sierra Club's Natural Gas Reform campaign is focused on reducing the amount and impacts of natural gas extraction, including preventing the export of unconventional natural gas without a full analysis of the environmental and public interest effects of such export.

6. When an individual becomes a member of the Sierra Club, his or her current residential address is recorded in our membership database. The database entry reflecting the member's residential address is verified or updated as needed.
7. The Sierra Club currently has 601, 141 members in the United States, and 22,089 members in Texas. These members have a strong interest in protecting human health and the environment from the effects of natural gas extraction and export.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed in San Francisco, California on August 1, 2012.

Yolanda Andersen

Yolanda Andersen

The Deputy Secretary of Energy
Washington, DC 20585

December 11, 2012

The Honorable Ron Wyden
United States Senate
Washington, DC 20510-4305

Dear Senator Wyden:

Thank you for your letter of October 23 concerning exports of liquefied natural gas (LNG).

As you noted in your letter, DOE's authority over exports of natural gas, including LNG, arises under section 3 of the Natural Gas Act (NGA), 15 U.S.C. § 717b, as well as under section 301(b) of the DOE Organization Act, 42 U.S.C. § 7151. Under section 3(c) of the NGA, DOE is required to grant applications to export LNG to countries with which the United States has entered into a free trade agreement calling for national treatment for trade in natural gas (FTA nations) without modification or delay. Pursuant to that requirement, DOE has approved 17 long-term applications to export LNG to FTA nations.

NGA section 3(a) requires DOE to conduct a public interest review of non-FTA LNG export applications and to grant the applications unless DOE finds that the proposed exports will not be consistent with the public interest. Under this provision, DOE performs a thorough public interest analysis before acting.

To date, DOE has granted one long-term application to export domestically-produced lower-48 LNG to non-FTA countries. That authorization was issued in *Sabine Pass Liquefaction, LLC*, (*Sabine Pass*) DOE/FE Order Nos. 2961 and 2961-A (May 20, 2011 and August 7, 2012). In the first of the two *Sabine Pass* orders, DOE stated that it will evaluate the cumulative impact of the Sabine Pass authorization and any future authorizations for export authority when considering subsequent applications.

To develop such an analysis, DOE undertook a two-part study to evaluate the cumulative economic impact of LNG exports. The first part of the study was conducted by EIA and looked at the potential impact of additional natural gas exports on domestic energy consumption, production, and prices under several export scenarios. The second part of the study was made available on December 5. Both parts of the study have been placed in all 15 pending dockets. An initial round of comments on the study is due January 24, 2013, and reply comments are due February 25, 2013. DOE will make no final decisions in the 15 pending proceedings until it has evaluated both the study and the comments.

The NGA does not prescribe what factors should go into the public interest analysis. The criteria that DOE uses to make its public interest determinations in its review of non-FTA export applications have evolved from policy guidelines published in 1984 (49 Fed. Reg. 6684), as supplemented and refined by subsequent agency adjudication.

These criteria include the following:

- Domestic need for the natural gas proposed for export;
- Adequacy of domestic natural gas supply;
- U.S. energy security;
- Impact on the U.S. economy (GDP), consumers, and industry, including impact on domestic natural gas prices;
- Job creation;
- U.S. balance of trade;
- International considerations; and
- Environmental considerations.

It is important to emphasize, however, that these criteria are not exclusive. Other issues raised by commenters and/or interveners or by DOE that are relevant to a proceeding may be considered as well.

We would welcome the opportunity to brief you or your staff on the matters addressed in this letter in additional detail. If you have any additional questions, please feel free to contact me or Mr. Jeff Lane, Assistant Secretary for Congressional and Intergovernmental Affairs, at (202) 586-5450.

Sincerely yours,

Daniel B. Poneman

Statement of
Christopher Smith
Deputy Assistant Secretary for Oil and Natural Gas
Office of Fossil Energy
U.S. Department of Energy

Before the

Committee on Energy and Natural Resources
United States Senate

The Department of Energy's Role in Liquefied Natural Gas Export Applications

November 8, 2011

Thank you Chairman Bingaman, Ranking Member Murkowski, and members of the Committee; I appreciate the opportunity to be here today to discuss the Department of Energy's (DOE) program regulating the export of natural gas, including liquefied natural gas (LNG).

DOE's Statutory Authority

DOE's authority to regulate the export of natural gas arises under section 3 of the Natural Gas Act, 15 USC 717b, and section 301(b) of the DOE Organization Act, 42 USC 7151. That authority is vested in the Secretary of Energy and has been delegated to the Assistant Secretary for Fossil Energy.

Section 3(a) of the Natural Gas Act sets forth the standard for review of most LNG export applications:

> – [N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary of Energy] authorizing it to do so. The [Secretary] shall issue such order upon application, unless after opportunity for hearing, [he] finds that the proposed exportation or importation will not be consistent with the public interest. The [Secretary] may by [the Secretary's] order grant such application, in whole or part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate.

Section 3(a) thus creates a rebuttable presumption that a proposed export of natural gas is in the public interest, and requires DOE to grant an export application unless DOE finds that the record in the proceeding of the application overcomes that presumption. Section 3(a) also authorizes DOE to attach terms or conditions to the order that the Secretary finds are necessary or appropriate to protect the public interest.

In the Energy Policy Act of 1992 (EPAct 92), Congress introduced a new section 3(c) to the Natural Gas Act. Section 3(c) created a different standard of review for applications to export natural gas, including LNG, to those countries with which the United States has in effect a free trade agreement requiring the national treatment for trade in natural gas. Section 3(c) requires such applications to be deemed consistent with the public interest, and requires such applications to be granted without modification or delay.

There are currently 15 countries with which the United States has in place free trade agreements that require national treatment for trade in natural gas. These 15 countries include:

– Australia, Bahrain, Canada, Chile, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Peru, and Singapore.

There also are two countries—Israel and Costa Rica—that have free trade agreements with the United States that do not require national treatment for trade in natural gas. Additionally, there are three more countries—South Korea, Colombia, and Panama—that have negotiated free trade agreements with the United States. While these three free trade agreements have recently been ratified by the U.S. Senate, the agreements have not yet taken effect. However, as negotiated, the agreements require national treatment for trade in natural gas, which will have the effect of bringing applications to export LNG to those three countries under section 3(c) of the Natural Gas Act.

Because applications under section 3(c) must be granted without modification or delay and are deemed to be in the public interest, DOE does not conduct a public interest analysis of those applications and cannot condition them by the insertion of terms which otherwise might be considered necessary or appropriate.

For applications requesting authority to export LNG to countries that do not have free trade agreements requiring national treatment for trade in natural gas, DOE conducts a full public interest review. A wide range of criteria are considered as part of DOE's public interest review process, including:

- Domestic need for the natural gas proposed for export
- Adequacy of domestic natural gas supply
- U.S. energy security
- Impact on the U.S. economy (GDP), consumers, and industry
- Jobs creation
- U.S. balance of trade
- International considerations
- Environmental considerations
- Consistency with DOE's long-standing policy of promoting competition in the marketplace through free negotiation of trade arrangements
- Other issues raised by commenters and/or interveners deemed relevant to the proceeding

DOE's review of applications to export LNG to non-free trade agreement countries is conducted through a publicly transparent process. Upon receipt of an application, DOE issues a notice of the application in the *Federal Register*, posts the application and all subsequent pleadings and orders in the proceeding on its website, and invites interested persons to participate in the proceeding by intervening and/or filing comments or protests. Section 3(a) applicants are typically given an opportunity to respond to any such comments or protests and, after consideration of the evidence that has been introduced into the record, DOE issues an order either granting the application as requested, granting with additional terms or conditions, or denying the application.

Under the Natural Gas Act, DOE's orders are subject to a rehearing process that can be initiated by any party to a proceeding seeking to challenge DOE's determinations. Court review is available as well after the rehearing process is exhausted.

Recent Developments in LNG Exports

Over the last several years, domestic natural gas production has increased significantly, primarily due to the development of improved drilling technologies, including the ability to produce natural gas trapped in shale gas geologic formations. The most recent data and analysis prepared by the Energy Information Administration (EIA) within DOE shows an increasing volume of shale gas production. Specifically, EIA indicates that domestic gross gas production from shale increased to 3.4 trillion cubic feet (Tcf) in 2009, compared to 2.3 Tcf in 2008.[1] Further, in the Annual Energy Outlook 2011 (AEO 2011), EIA projected that, by 2015, annual dry shale gas production will increase to 7.2 Tcf and, by 2035, to 12.2 Tcf. Natural gas prices have declined and imports of LNG have significantly declined. Recently, the domestic price of natural gas at the Henry Hub for November 2011 delivery was $3.60 per million Btu.[2] International prices of LNG are significantly higher. Due in part to these changing market economics, DOE has begun to receive a growing number of applications to export domestically produced lower-48 natural gas to overseas markets in the form of LNG.

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[1] EIA, *Natural Gas Gross Withdrawals and Production, Release Date: October 29, 2011 http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm*

[2] The November 2011 contract price as of October 24, 2011, was $3.60 per million Btu.

Insofar as these applications have involved exports to free trade agreement countries, they are by statute, deemed consistent with the public interest and DOE is required to grant them without modification or delay. To the extent the applications involve non-free trade agreement countries, as I have indicated above, DOE conducts a thorough public interest analysis and attaches terms and conditions which are necessary or appropriate to protect the public interest.

Sabine Pass Liquefaction, LLC

DOE received the first application for long-term (greater than 2 years) authority to export LNG produced in the lower-48 States to non-free trade agreement countries on September 7, 2010, from Sabine Pass Liquefaction, LLC (Sabine Pass), a subsidiary of Cheniere Energy, Inc. This followed on DOE's earlier issuance of authority to Sabine Pass to export a like volume of natural gas to free trade agreement countries on September 7, 2010. A notice of the non-free trade agreement export application was published in the *Federal Register* and the public was provided 60 days to intervene and/or protest the application.

Sabine Pass' non-free trade agreement export application sought authority to export the equivalent of up to 2.2 billion cubic feet per day (Bcf/d) of natural gas, equivalent to about 3.3 percent of current domestic consumption. In its application, Sabine Pass pointed to several economic and public benefits likely to follow on a grant of the requested authorization, including:

- Creation of several thousand temporary and permanent jobs, both through direct and indirect job formation; and

– Improvement in U.S. balance of payments valued at approximately $6.7 billion from LNG exports and the impact of increased production of natural gas liquids.

Additionally, Sabine Pass addressed the question of the domestic need for the gas to be exported; the volume of domestic supplies; and the likely impact of the proposed exports on natural gas prices. To this end, it included with its application several economic and technical reports indicating that any increase in natural gas prices from the proposed exports would be relatively modest and not detrimental to domestic energy security.

Sabine Pass's application was opposed by the Industrial Energy Consumers of America and the American Public Gas Association. Those groups challenged Sabine Pass' claims of economic benefits and no detrimental impact on domestic energy security. However, neither opponent of the application introduced economic or technical studies to support their allegations.

DOE closely analyzed the evidence introduced by the applicant and by those opposing the application. Mindful of the statutory presumption favoring a grant of the application, the agency found that:

– The studies introduced by applicant indicated LNG exports will result in a modest projected increase in domestic market price for natural gas, which reflects the increasing marginal costs of domestic production; and

– The public record supported the conclusion that the requested authorization will yield tangible benefits to the public whereas the allegations of negative impacts submitted by interveners opposing the application were not substantiated on the record. In particular, the interveners failed to offer any rebuttal studies of natural gas supply, demand and/or price analysis to support their claim the application was not consistent with the public interest.

Following a review of the record in this proceeding, DOE concluded that the opponents of the application had not demonstrated that a grant of the requested authorization would be inconsistent with the public interest, and DOE granted the requested authorization subject to several terms and conditions.

Pending LNG Export Applications

As indicated above, applicants are increasingly seeking authorization from DOE to export domestic supplies of natural gas as LNG to higher priced overseas markets. The Natural Gas Act favors granting applications to export to non-free trade agreement countries unless it can be demonstrated that a proposed export is inconsistent with the public interest. In the case of exports of LNG to free trade agreement countries that require national treatment for trade in natural gas, DOE is without any authority to deny, condition, or otherwise limit such exports.

Mindful of the growing interest in exporting domestically produced LNG, DOE recognized in the Sabine Pass order that the cumulative impact of Sabine Pass and additional future LNG export authorizations could pose a threat to the public interest. DOE stated that it would monitor the cumulative impact and take such action as necessary in future orders.

DOE presently has before it four long-term applications to export lower-48 domestically produced LNG to countries with which the United States does not have a free trade agreement that requires national treatment for trade in natural gas. The volumes of LNG that could be authorized for export in these non-free trade agreement applications, including the 2.2 Bcf/d authorized for export in Sabine Pass, would total 6.6 Bcf/d, which represents 10 percent of total current domestic natural gas daily consumption in the United States. Consistent with the Natural Gas Act, DOE already has granted authorization from these five facilities to export this same volume to free trade agreement countries.

In order to address the potential cumulative impact of a grant of the pending applications, DOE has commissioned two studies: one by the EIA and the other by a private contractor. Taken together, these studies will address the impacts of additional natural gas exports on domestic energy consumption, production, and prices, as well as the cumulative impact on the U.S. economy, including the effect on gross domestic product, jobs creation, and balance of trade, among other factors. We anticipate that these studies will be completed in the first quarter of calendar year 2012. In this regard, we are mindful of the need for prompt action in each of the proceedings before us. However, we believe that a sound evidentiary record is essential in order to proceed to a decision and that the studies being undertaken are important elements of such a record.

Conclusion

I am happy to answer any questions that you may have.

LOOK BEFORE THE LNG LEAP:

Why Policymakers and the Public Need Fair Disclosure Before Exports of Fracked Gas Start

BEYOND NATURAL GAS

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LOOK BEFORE THE LNG LEAP:

Why Policymakers and the Public Need Fair Disclosure Before Exports of Fracked Gas Start

By **Craig Segall,** Staff Attorney, Sierra Club Environmental Law Program. Thanks to legal fellow **Philip Goo** for very helpful research assistance.

EXECUTIVE SUMMARY

Exporting American natural gas to the world market would spur unconventional natural gas production across the country, increasing pollution and disrupting landscapes and communities. Deciding whether to move forward is among the most pressing environmental and energy policy decisions facing the nation. Yet, as the Department of Energy (DOE) considers whether to greenlight gas exports of as much as 45% of current U.S. gas production — more gas than the entire domestic power industry burns in a year — it has refused to disclose, or even acknowledge, the environmental consequences of its decisions. In fact, DOE has not even acknowledged that its own National Energy Modeling System can be used to help develop much of this information, instead preferring to turn a blind eye to the problem. DOE needs to change course. Even much smaller volumes of export have substantial environmental implications and exporting a large percentage of the total volume proposed would greatly affect the communities and ecosystems across America. The public and policymakers deserve, and are legally entitled to, a full accounting of these impacts.

Gas exports are only possible because of the unconventional natural gas boom which hydraulic fracturing ("fracking") has unlocked. DOE's own advisory board has warned of the boom's serious environmental impacts. DOE is charged with determining whether such exports are in the public interest despite the damage that would result. To do that, it needs a full accounting of the environmental impacts of increasing gas production significantly to support exports.

These environmental considerations include significant threats to air and water quality from the industry's wastes, and the industrialization of entire landscapes. Gas production is associated with significant volumes of highly-contaminated wastewater and the risk of groundwater contamination; it has also brought persistent smog problems to entire regions, along with notable increases in toxic and carcinogenic air pollutants. Regulatory measures to address these impacts have been inadequate, meaning that increased production very likely means increased environmental harm. Natural gas exports also have important climate policy implications on several fronts: Even if exported gas substitutes for coal abroad (which it may or may not do), it will not produce emissions reductions sufficient to stabilize the climate, and gas exports will increase our investment in fossil fuels. Moreover, the gas export process is particularly carbon-intensive, and gas exports will likely raise gas prices domestically, increasing the market share of dirty coal power, meaning that perceived climate benefits may be quite limited if they exist at all. The upshot is that increasing gas production comes with significant domestic costs.

The National Environmental Policy Act (NEPA) process is designed to generate just such an analysis. NEPA analyses, properly done, provide full, fair, descriptions of a project's environmental implications, remaining uncertainties, and alternatives that could avoid environmental damage. A full NEPA environmental impact statement looking programmatically at export would help DOE and the public fairly weigh these proposals' costs and benefits, and to work with policymakers at the federal, state, and local levels to address any problems. In fact, the U.S. Environmental Protection Agency has repeatedly called for just such an analysis.Without one, America risks committing itself to a permanent role as a gas supplier to the world without determining whether it can do so safely while protecting important domestic interests.

Equally troublingly, even as DOE has thus far failed to fulfill its obligation to protect the public interest by weighing environmental impacts, it risks losing its authority altogether. A drafting quirk in the export licensing statute intended to speed gas imports from Canada means that DOE must grant licenses for gas exports to nations with which the United States has signed a free trade agreement which includes national treatment of natural gas. This rubber-stamp applies even if the proposed exports would not otherwise be in the public interest. As the U.S. negotiates a massive trade agreement which may include nations hungry for U.S. exports, the Trans-Pacific Partnership, this mandatory rubber-stamp risks undercutting DOE's ability to protect the public.

The bottom line is that before committing to massive gas exports, federal decisionmakers need to ensure that they, and the public, have the environmental information they need to make a fair decision, and the authority to do so. That means ensuring that a full environmental impact statement discloses exports' impacts and develops alternatives to reduce them. It also means defending DOE's prerogatives against the unintended effects of trade pacts. Congress and the U.S. trade negotiators must ensure that agreements like the Trans-Pacific Partnership are designed to maintain DOE's vital public interest inquiry.

Gas exports would transform the energy landscape and communities across the country. We owe ourselves an open national conversation to test whether they are in the public interest. We need to look before we leap.

I. Introduction

For the first time ever, the United States has the ability to become a major natural gas exporter, but that possibility comes with substantial economic and environmental risks. The huge volumes of natural gas proposed for export as liquefied natural gas (LNG) would raise domestic energy prices and require a significant expansion of unconventional gas production using hydraulic fracturing ("fracking").

This shift in the energy landscape raises serious questions: What will export-induced production mean for people living in the gas fields? What will it mean for utilities weighing coal and gas prices as they chart the future of their generation fleets? What it will mean for environmental regulators seeking to manage risk? What will it mean for our air and water quality? What will it mean for climate policy if we increase the extraction and use of this fossil fuel? In the end, are exports worth higher prices and more pollution from fracked gas?

The policy debate continues, but without crucial information: Incredibly, neither the Department of Energy ("DOE")'s Office of Fossil Energy nor the Federal Energy Regulatory Commission ("FERC"), which share responsibility over LNG export proposals under the Natural Gas Act, have completed a full assessment of the environmental risks associated with export and the expanded gas production needed to support it. The agencies could do so using publicly available information and modeling systems, but have so far refused, implausibly insisting that it is impossible to predict *any* upstream impacts from expanded LNG exports.

For more than forty years, Congress has directed federal agencies to use the National Environmental Policy Act (NEPA)'s environmental impact statement process to address environmental decisions like this one. The NEPA process allows agencies to generate comprehensive data, weigh alternatives, and expose assumptions to public scrutiny, so they can base decisions on a fully developed analysis of the impacts of a proposed activity. Amidst the ongoing raucous public debate on export, the information NEPA can provide is not just legally required, but sorely needed.

DOE and FERC have failed to provide this critical analysis. Only one LNG export proposal, for a terminal at Sabine Pass on the Louisiana-Texas border, has moved most of the way through the federal licensing process. FERC, which focuses largely on terminal siting, refused to consider any of the upstream consequences of Sabine Pass's plan to export 2.2 billion cubic feet of gas every day.[2] It did so even though Sabine Pass's export application trumpets that the project intends to "play an influential role in contributing to the growth of natural gas production in the U.S." and relies substantially on this point to argue that the project is in the public interest.[3] DOE followed suit, adopting FERC's analysis to support its own public interest determination, while maintaining that the induced gas production necessary to support export is not

[2] FERC, *Order Granting Section 3 Authorization [to Sabine Pass]*, 139 FERC ¶ 61,039 (Apr. 16, 2012).
[3] Sabine Pass Export Application at 56, DOE/FE Docket 10-111-LNG (Sept. 7, 2010).

“reasonably foreseeable,” and so warrants no consideration.[4] DOE recently announced that it would take time to consider whether to stand by this decision, but it has not yet reversed course.[5]

Thus, even while authorizing a proposal which, on its own, would increase U.S. gas exports by more than 50% annually,[6] and which explicitly relies on increased natural gas production to support itself, the federal decisionmakers charged with protecting the public interest were asleep at the switch. Even though export proponents themselves advertise that their projects will drive unconventional natural gas production, DOE and FERC are willfully blind to this major impact. This position is particularly untenable because the National Energy Modeling System (NEMS) which the Energy Information Administration (“EIA”) within DOE administers, is designed to project changes in gas production caused by new demand, and could therefore predict precisely the production-level impacts which DOE and FERC insist cannot be foreseen at all.[7]

Instead, applications to export more than ten times the gas which was authorized in the Sabine Pass matter are moving forward in a piecemeal terminal-by-terminal licensing process which has not provided any meaningful analysis of the national and regional environmental challenges linked to export. This ongoing legal and policy failure warrants immediate correction.

Not only have DOE and FERC failed to provide a proper accounting, they may lose even their authority to do so if a controversial trade agreement now under negotiation is finalized. That deal, the Trans-Pacific Partnership (“TPP”), could further liberalize trade with much of the Pacific Rim, including major natural gas importers like Japan. Thanks to a little-known provision of the Natural Gas Act, it could also remove federal oversight of LNG exports. Twenty years ago, in an effort to speed Canadian gas *imports*, Congress provided that LNG shipments between countries with which the U.S. has a free trade agreement were to be automatically granted. Although Congress never anticipated massive LNG exports, that same provision could nonetheless remove DOE and FERC’s discretion to weigh whether huge volumes of export are in the public interest, or to meaningfully regulate the process. Yet neither agency has insisted that TPP negotiators protect this critical federal authority.

For communities across the country, therefore, the future is in real question. If LNG export goes forward, they will experience a surge of unconventional new gas production, along with all

[4] DOE, *Final Opinion and Order Granting Long-Term Authorization to Export Liquefied Natural Gas from Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations*, FE Docket No. 10-111-LNG (Aug. 7, 2012).
[5] *See* DOE, *Order Granting Rehearing for Further Consideration*, FE Docket No. 10-111-LNG (Oct. 5, 2012).
[6] *See* EIA, *U.S. Natural Gas Imports & Exports 2011* (July 18, 2012). The U.S. now exports about 1,500 billion cubic feet “bcf” of natural gas annually, with the vast majority travelling by pipeline to Mexico and Canada. Sabine Pass would export 2.2 bcf/day, or 803 bcf annually.
[7] *See, e.g.*, EIA, *The National Energy Modeling System: An Overview* (2009) at 54-55 (explaining that NEMS contains “play-level” production models for each unconventional natural gas play and projects production based on demand); 59-62 (transmission and distribution module of NEMS allocates demand based through modeling the transmission network and can account for imports and exports).

the environmental burdens of the boom that are outlined below. If DOE and FERC do not analyze and disclose these impacts, neither they or state and local governments can weigh whether they are in the public interest, or take action to lessen them. And if the TPP and pacts like it are signed without due reflection and before a full NEPA environmental impact statement is available, the U.S. will be locked into a future of gas export without ever having considered the cost.

It is not yet too late to change course. DOE has committed not to release any more export licenses until an economic study has been finalized, which will not occur until this winter. Negotiations for the TPP have not concluded. FERC has not sited any more new terminals. So, although the United States has begun to edge into exports, that future has not yet been chosen. Cooler heads can still prevail, and decisionmakers can develop the information we and they so clearly need.

II. The Magnitude of the Export Boom

Even if only some of the 19 export projects now before DOE are approved, they would, once operational, transform the domestic energy market and greatly increase unconventional natural gas production. There is no domestic precedent for changes of the magnitude which DOE is now considering.

Before the shale gas boom began, the U.S. exported almost no gas beyond Canada and Mexico, and even those North American exports were not very large. In 2006, for instance, the U.S. exported a total of 723.9 bcf per year of natural gas, with 663 of that by pipeline.[8] Only the remaining approximately 60 bcf per year are exported as LNG, essentially all of it going to Japan from a single Alaskan terminal, with a few bcf to Mexico by truck.[9] Policymakers largely assumed that this pattern would continue, urging that the U.S. develop gas *import* capacity to accommodate growing domestic demand.[10]

The situation now is very different. Projections of abundant domestic natural gas from unconventional, largely shale, plays has dropped domestic gas prices to record lows while prices abroad remain high. As a result, U.S. pipeline exports have risen, pushing total exports over 1,500 bcf per year (or about 4 bcf per day), and investors have flooded DOE with an ever-growing number of export proposals. As of late October 2012, the 19 different export projects before DOE proposed to export as much as 28.39 bcf *per day* of LNG.[11] Of this, 23.71 bcf per day was proposed for export to countries with which the U.S. has not signed a free trade

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[8] EIA, U.S. Natural Gas Exports by Country, *available at*: http://www.eia.gov/dnav/ng/ng_move_expc_s1_a.htm.
[9] *See id.*
[10] *See, e.g.*, National Petroleum Council, *Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy* at 36-40 (2003)
[11] Department of Energy Office of Fossil Energy, *Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of October 26, 2012)*, available at http://www.fossil.energy.gov/programs/gasregulation/reports/Long_Term_LNG_Export_10-26-12.pdf. Other proposals to export at least 2.5 bcf/d of LNG have also been reported, but have not yet been filed with DOE.

agreement providing for national treatment of natural gas; DOE has clear authority to disapprove such proposals if they are not in the public interest.

How much gas is 28.39 bcf per day? It is equivalent to 10,362 bcf per year. By comparison, the entire country produced just 23,000 bcf in 2011, meaning that exports equivalent to about 45% of domestic production are now before DOE.[13] Exporting this much gas would be bound to strongly affect domestic gas production and consumption patterns. For example, the country consumed 24,316 bcf of gas last year – slightly more than it produced, with imports making up much of the difference.[14] Dedicating forty percent of U.S. gas production to export would, therefore, cause big shifts in the domestic market. The amount of gas slated for export is considerably more than the 7,602 bcf that the entire electric power sector used last year, and nearly twice as much gas as was used for electricity by every home in the country.[15] If this amount of gas is exported, the United States must produce more gas, use less, or do both.

The Energy Information Administration ("EIA") has come to just that conclusion in a DOE-commissioned January 2012 report, which estimated that about two-thirds (63%) of export demand will be met by increased production, rather than by decreases in gas consumption elsewhere in the economy.[16] That new production, in turn, will come almost entirely (93%) from unconventional gas plays, and so will be produced by fracking. [17]

Thus, if the DOE authorizes all of the 10,362 bcf of exports now before it, about 63% of that exported gas, or 6,5282 bcf, would likely be from new production, and 6,397 bcf of that new production would be fracked gas. Total domestic gas production would increase by 27%.

To be sure, there are legitimate questions as to the real scope of the export boom. The global LNG market may be hungry for U.S. gas, but limits on near-term demand and regasification capacity may mean that not every export terminal will be built, or operate at capacity. On the other hand, the scramble for export licenses shows no signs of diminishing. In fact, the pace and intensity of this export boom seems to have caught decisionmakers by surprise. In January 2012, DOE and the EIA assumed that exports of 12 bcf/d were at the high end of possible export futures.[18] Export applications for more than double that volume have now been lodged with DOE. The "high end" scenario now looks decidedly mid-range compared to pending applications.[19]

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[13] EIA, Natural Gas Monthly November 2012, Table 1 (volume reported is dry gas).
[14] *Id.*, Table 2.
[15] *Id.* (electric power sector gas use in 2011 was 7,602 bcf; residential use was 4,730 bcf).
[16] EIA, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* (Jan. 2012) at 6, 10-11.
[17] *Id.* at 11.
[18] EIA, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* at 1.
[19] In its Annual Energy Outlook for 2012, EIA very conservatively projects that only 2.2 bcf/d of LNG will be exported by 2035, noting that this projection is subject to considerable regulatory uncertainty. *See* EIA, *Annual Energy Outlook* (2012) at 94. This amount would correspond to about a 470 bcf annual increase in unconventional natural gas production – about a 2% national increase. Notably, the 2.2 bcf of annual LNG export EIA conservatively projects are equivalent to the export proposed by the Sabine Pass facility which DOE has already all

Moreover, even a much smaller gas export increase would still mean major changes in the U.S. gas market. If only one-quarter of the proposed projects move forward, about 6 bcf/d of gas would still be exported – the equivalent of 2,190 bcf annually. That demand would, in turn, be accompanied by about 1,172 bcf of new unconventional gas production if the EIA is correct, increasing U.S. gas production overall by 5%.

Proposed export terminal sites are on all three U.S. sea coasts. Most applications are focused on the Gulf Coast, but applicants have also filed to export from Atlantic coastal sites in Maryland and Georgia and from Pacific coastal sites in Oregon. Between the terminals themselves, the pipelines required to feed them with gas, the barge traffic they will engender and, of course, the fracking boom they will support and extend, few regions of the United States will be untouched by LNG export.

III. Environmental Implications of Export

Producing and exporting large volumes of natural gas will have significant environmental implications that are best evaluated in the NEPA process with an Environmental Impact Statement. The urgency of a comprehensive look is clear from an examination of a subset of those effects: impacts associated directly with increasing gas production, impacts from changes in the gas market associated with export, and impacts associated with export itself, particularly its implications for climate change.

A. The Environmental Impacts of Increased Unconventional Gas Production

While the DOE's Office of Fossil Energy continues to consider pending export applications, the Secretary of Energy Advisory Board has been sounding the alarm about the fracking process on which export depends. Its Shale Gas Production Subcommittee issued a detailed set of recommendations in late 2011, emphasizing that a substantially enhanced regulatory and research effort is needed to ensure that unconventional natural gas production can move forward safely.

The Subcommittee, composed of nationally-regarded independent experts, wrote that it "believes that if action is not taken to reduce the environmental impact accompanying the very considerable expansion of shale gas production expected across the country – perhaps as many as 100,000 wells over the next several decades – there is a real risk of serious environmental consequences causing a loss of public confidence that could delay or stop this activity."[20] As of late 2011, the Subcommittee warned that "progress to date is less than the Subcommittee

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but approved. The EIA projection thus functionally assumes that *none* of the other projects now before DOE are built. While that might occur, it is obviously prudent to consider the impacts of other projects.

[20] Secretary of Energy Advisory Board Shale Gas Production Subcommittee ("SEAB"), *Second-Ninety Day Report* (Nov. 18, 2011) at 10.

hoped."[21] It cautioned that "some concerted and sustained action is needed to avoid excessive environmental impacts of shale gas production and the consequent risk of public opposition to its continuation and expansion."[22]

As the Subcommittee recognized, the impacts of unconventional gas production stretch across multiple mediums and contexts. Its recommendations identify areas for improvement in managing air pollution, water pollution, subsurface contamination, land use, and community impacts.[23] The Subcommittee also issued an urgent call for improved transparency and disclosure throughout the process, and for greatly enhanced research and development to better understand and improve production processes.[24]

Significant environmental impacts associated with unconventional natural gas production, and hence with export, include the following:

Air Pollution

Natural gas production has significant air quality impacts. As the DOE's Shale Gas Subcommittee summarized the matter last August:

> Shale gas production, including exploration, drilling, venting/flaring, equipment operation, gathering, accompanying vehicular traffic, results in the emission of ozone precursors (volatile organic compounds (VOCs), and nitrogen oxides), particulates from diesel exhaust, toxic air pollutants and greenhouse gases (GHG), such as methane.
>
> As shale gas operations expand across the nation these air emissions have become an increasing matter of concern at the local, regional and national level. Significant air quality impacts from oil and gas operations in Wyoming, Colorado, Utah and Texas are well documented, and air quality issues are of increasing concern in the Marcellus region (in parts of Ohio, Pennsylvania, West Virginia and New York).[25]

The tight link between gas production and ground-level ozone, or smog, is a particularly pressing problem. The gas industry is a major source of two major ozone precursors: VOCs and NO_x.[26] Smog harms the respiratory system and has been linked to premature death, heart

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[21] *Id.*
[22] *Id.*
[23] *Id.* at Annex C.
[24] *Id.*
[25] SEAB, *First Ninety Day Report* (August 18, 2011) at 15.
[26] *See, e.g.,* Al Armendariz, *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements* (Jan. 26, 2009), *available at* http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf (hereinafter "Barnett Shale Report").

failure, chronic respiratory damage, and premature aging of the lungs.[27] Smog may also exacerbate existing respiratory illnesses, such as asthma and emphysema, or cause chest pain, coughing, throat irritation and congestion. Children, the elderly, and people with existing respiratory conditions are the most at risk from ozone pollution.[28]

As a result of significant VOC and NO_x emissions associated with oil and gas development, numerous areas of the country with heavy concentrations of drilling are now suffering from serious ozone problems. For example, the Dallas Fort Worth area in Texas is home to substantial oil and gas development. Within the Barnett shale region, as of July 2012, there were 16,213 gas wells and another 2,764 wells permitted.[29] Of the nine counties surrounding the Dallas Fort Worth area that EPA has designated as in "nonattainment" with national air quality standards for ozone, five contain significant oil and gas development.[30] A 2009 study found that summertime emissions of smog-forming pollutants from gas production in these counties were roughly comparable to emissions from all the cars in those same areas.[31] These nonattainment designations are particularly striking because the current ozone standard is set below the level EPA's own scientific advisors recommend as adequate to protect public health.[32] That gas production emissions can cause violations even of this relatively *lax* standard underlines their severity.

Oil and gas development has also brought serious ozone pollution problems to rural areas, such as western Wyoming.[33] On March 12, 2009, the governor of Wyoming recommended that EPA designate Wyoming's Upper Green River Basin as an ozone nonattainment area under EPA's current ozone.[34] The Wyoming Department of Environmental Quality conducted an extended assessment of the ozone pollution problem and found that it was "primarily due to local emissions from oil and gas . . . development activities: drilling, production, storage, transport, and treating."[35] In the winter of 2010-2011, the residents of Sublette County suffered thirteen

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[27] *See, e.g.*, Jerrett *et al.*, *Long-Term Ozone Exposure and Mortality*, New England Journal of Medicine (Mar. 12, 2009), *available at* http://www.nejm.org/doi/full/10.1056/NEJMoa0803894#t=articleTop.

[28] *See* EPA, *Ground-Level Ozone, Health Effects*, *available at* http://www.epa.gov/glo/health.html; EPA, Nitrogen Dioxide, Health, available at http://www.epa.gov/air/nitrogenoxides/health.html.

[29] Texas Railroad Commission, http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf (Accessed Sept. 25, 2012).

[30] Barnett Shale Report at 1, 3.

[31] *Id.* at 1, 25-26.

[32] *See,e.g.*, Elizabeth Shogren, NPR, *EPA Seeks to Tighten Ozone Standards* (July 24, 2011) (when EPA set the current standards it "ignored the advice of its own panel of outside scientific advisers"). EPA has since opted not to immediately update the out-dated standards, but revisions may be forthcoming next year.

[33] Schnell, R.C, et al. (2009), "Rapid photochemical production of ozone at high concentrations in a rural site during winter," *Nature Geosci.* 2 (120 – 122). DOI: 10.1038/NGEO415.

[34] *See* Letter from Wyoming Governor Dave Freudenthal to Carol Rushin, Acting Regional Administrator, USEPA Region 8, (Mar. 12, 2009) ("Wyoming 8-Hour Ozone Designation Recommendations"), *available at* http://deq.state.wy.us/out/downloads/Rushin%20Ozone.pdf; Wyoming Department of Environmental Quality, Technical Support Document I for Recommended 8-hour Ozone Designation of the Upper Green River Basin (March 26, 2009) ("Wyoming Nonattainment Analysis"), at vi-viii, 23-26, 94-05, *available at* http://deq.state.wy.us/out/downloads/Ozone%20TSD_final_rev%203-30-09_jl.pdf.

[35] Wyoming Nonattainment Analysis at viii.

days with ozone concentrations considered "unhealthy" under EPA's current air-quality index, including days when the ozone levels exceeded the worst days of smog pollution in Los Angeles.[36]

As oil and gas production moves into new areas ozone problems are likely to follow. For example, regional air quality models predict that gas development in the Haynesville shale will increase ozone pollution in northeast Texas and northwest Louisiana and may lead to violations of ozone air quality standards.[37] Experts also anticipate air quality problems associated with development of the Marcellus shale in the Mid-Atlantic region.[38]

Ozone pollution is not the only danger associated with natural gas production, however. Toxic air emissions are also a significant concern. Emissions from gas fields contain carcinogenic compounds, including benzene, which are associated with significant increases in cancer risk. In fact, Colorado researchers sampling the air near a field there recently determined that residents living within half a mile of from wells were at increased risk of cancer, compared to those living further away, due to long-term exposure to toxic leaks.[39] As the industry expands, this toxic problem will come with it.

In addition to these serious problems, the industry poses a significant threat to the global climate. The natural gas industry is also among the very largest sources of methane pollution in the country. Methane is a potent greenhouse gas, and these emissions rank the industry as the second largest industrial greenhouse gas source, second only to power production.[40] Because fracking operations tend to produce substantially more methane, and are also supporting new well development across the country, unconventional natural gas production is increasing these emissions. EPA has recently estimated annual industry methane emissions as the equivalent of 328 million metric tons of CO_2.[41]

This pollution will remain a serious danger even though EPA has recently finalized its first attempt at comprehensive air pollution controls for the industry.[42] While these standards will

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[36] EPA, *Daily Ozone AQI Levels in 2011 for Sublette County, Wyoming*, *available at* http://www.epa.gov/cgi-bin/broker?msaorcountyName=countycode&msaorcountyValue=56035&poll=44201&county=56035&msa=-1&sy=2011&flag=Y&_debug=2&_service=data&_program=dataprog.trend_tile_dm.sas.; *see also* Wendy Koch, *Wyoming's Smog Exceeds Los Angeles' Due to Gas Drilling*, USA Today, *available at* http://content.usatoday.com/communities/greenhouse/post/2011/03/wyomings-smog-exceeds-los-angeles-due-to-gas-drilling/1.

[37] *See* Kemball-Cook et al., *Ozone Impacts of Natural Gas development in the Haynesville Shale* 44 Environ. Sci. Technol. 9357, 9362 (Nov. 18, 2010).

[38] Elizabeth Shogren, *Air Quality Concerns Threaten Natural Gas's Image*, National Public Radio (June 21, 2011), *available at* http://www.npr.org/2011/06/21/137197991/air-quality-concerns-threaten-natural-gas-image.

[39] *See generally* Lisa McKenzie *et al.*, *Human health risk assessment of air emissions from development of unconventional natural gas resources*, Sci. Total Environment (May 2012), *abstract available at*: http://www.ncbi.nlm.nih.gov/pubmed/22444058.

[40] *See* EPA, Inventory of US Greenhouse Gas Emissions and Sinks 1990-2010 (2012).

[41] *See* 74 Fed. Reg. 52,738, 52,756 (Aug. 23, 2011).

[42] *See* 77 Fed. Reg. 49,490 (Aug. 16, 2012).

play a significant role in reducing air pollution from new infrastructure, many new sources and existing infrastructure escape regulation. Moreover, the standards do not regulate methane directly. As a result, air pollution from production will continue to be a serious problem, despite this important first regulatory effort.

Water Pollution

Much public concern over expanded fracking operations has focused on water pollution, and with good reason. Significant water resource impacts can occur throughout the production process.

Fracking requires large volumes of water per well. While operators have sought to reduce their water demands in some areas, numerous sources indicate that fracturing a single well requires at least 1 to 5 million gallons of water.[43] Water withdrawals can harm aquatic ecosystems and human communities by reducing instream flows—especially in small headwaters streams -- and by harming aquatic organisms at water intake structures.[44] Where water is withdrawn from aquifers rather than surface sources, withdrawal risks permanent depletion.[45] Withdrawals for fracking pose a greater risk than other withdrawals, because fracking is a consumptive use. Fluid injected during the fracking process is ideally deposited below freshwater aquifers and into sealed formations, so much of it never returns to the surface.

The well-site management of fracking fluid and wastes, including flowback water, poses water quality risks throughout the process. Spills at the surface, leaks through well casings, and contaminant migration from the fracking site itself can all contaminate ground and surface water.

Fracturing fluid itself contains many chemicals that present health risks. Diesel fuel and similar compounds pose particularly pressing risks. The DOE Subcommittee singled out diesel for its harmful effects and recommended that it be banned from use as a fracturing fluid additive.[46] The minority staff of the House Committee on Energy and Commerce determined that despite diesel's risks, between 2005 and 2009, "oil and gas service companies injected 32.2 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states."[47]

Fracking fluids are not the only source of potential contamination.[48] Fluid naturally occurring in the target formation "may include brine, gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium) and organic compounds." [49] Inadequate

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[43] *See, e.g.*, SEAB, *First Ninety-Day Report* at 19; NY RDSGEIS 6-10.
[44] NY RDSGEIS at 6-3, 6-4.
[45] *Id.* 6-5; SEAB, *First Ninety Day report* at 19 ("[I]n some regions and localities there are significant concerns about consumptive water use for shale gas development.").
[46] *Id.* at 25.
[47] Letter from Reps. Waxman, Markey, and DeGette to EPA Administrator Lisa Jackson (Jan. 31, 2011) at 1.
[48] NY RDSGEIS at 5-75 to 5-78
[49] SEAB *First Ninety-Day Report* at 21.

well cementing, among other faults, can allow these substances to contaminate groundwater resources.[50] Storage, transport, and treatment of produced water on the surface create risks of spills and inadequate disposal, providing another vector for contamination of surface and groundwater resources.[51]

Properly treating these waste products, and other production waste, is essential to protecting water quality. Limited treatment capacity and the challenges of safely using underground injection as an alternative disposal method for large volumes of waste are pressing problems. Treating and discharging extremely salty, highly-contaminated wastewater is energy-intensive and technically difficult, and can put surface streams at risk. Meanwhile, injection also faces challenges, as not all regions have substantial injection capacity and injection wells themselves have been associated with earthquakes of up to 4.0 on the Richter scale.[52]

Finally, sediment contamination associated with the significant land disturbance and construction activities needed to construct and manage a well field is a persistent challenge. Run-off from production sites can readily contaminate streams without careful management.

Incidents of water contamination from various phases of the production process have been widely reported. Although EPA, other federal agencies and some states have begun to move forward with regulatory responses, many of these challenges remain unresolved. Thus, increased gas production for export will be accompanied by increasing risks of water pollution.

Land and Community Impacts

Intense gas production can transform entire regions. The gas boom means hundreds of thousands of new wells, along with the vast infrastructure of roads, pipelines, and support facilities they require. This landscape-level industrialization can transform formerly rural areas into vast construction sites, with thousands of trucks moving down an expanding webwork of gravel roads. This landscape change, too, is a significant environmental impact of increasing gas production.

The scope of potential change is great. Each well pad alone occupies roughly 3 acres, and associated infrastructure (roads, water impoundments, and pipelines) more than doubles this figure.[53] Many of these acres remain disturbed through the life of the well, estimated to be 20 to 40 years.[54] This directly disturbed land is generally no longer suitable as wildlife habitat. *Id.* at 6-68. In addition to this direct disturbance, indirect habitat loss occurs as areas around the directly disturbed land lose essential habitat characteristics. As New York regulators, for

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[50] *Id.* at 20.
[51] *See* NY RDSGEIS at 1-12 (describing risks of fluid containment at the well pad).
[52] *See, e.g.*, Columbia University, Lamont-Doherty Earth Observatory, *Ohio Quakes Probably Triggered by Waste Disposal Well, Say Seismologists* (Jan. 6, 2012); Alexis Flynn, *Study Ties Fracking to Quakes in England*, Wall Street Journal (Nov. 3, 2011).
[53] NY RDSGEIS at 5-5.
[54] *Id.* at 6-13.

instance, report, "[r]esearch has shown measureable impacts often extend at least 330 feet (100 meters) into forest adjacent to an edge."[55]

These effects will harm rural economies and decrease property values, as major gas infrastructure transforms and distorts the existing landscape. United States Geological Survey researchers, reviewing recent patterns of unconventional gas extraction, combined with coalbed methane projects, report that these activities create "potentially serious patterns of disturbance on the landscape."[56]

Pennsylvania presents a particularly striking example of the many ways in which gas production can transform a landscape. A recent state study of drilling in Pennsylvania's hitherto relatively undisturbed forest lands found that the forests have been so thoroughly fragmented and disrupted by the influx of gas activity that "zero" remaining acres of the state forests are suitable for further leasing with surface disturbing activities.[57]

Increased gas production for export can be expected to intensify and extend these impacts to new regions as drilling continues to meet increased demand.

Summary

The environmental impacts of increasing gas production of course extend well beyond those captured by this short summary. There are real environmental risks inherent in every phase of gas's life-cycle, from site preparation to drilling to waste disposal. Greatly increasing gas demand will increase the scope and intensity of these risks. The DOE's Shale Gas Subcommittee has already found that our regulatory infrastructure is not adequate to manage these risks at their current level of intensity. The United States is even less prepared for a greater and more rapid expansion of natural gas extraction.

B. Environmental Impacts Due to Fuel Market Shifts

Increasing demand for gas will necessarily raise gas and energy prices. These price effects have important environmental impacts as well because changing gas prices and availability affects the domestic fuel market. If natural gas is relatively more expensive, utilities, in particular, may be more likely to use competing fuels and generation technologies, each of which has its own environmental implications.

The prospect that LNG exports could incentivize domestic coal-fired generation is particularly important to understand. Coal-fired generation is a major source of many air pollutants,

[55] *Id.* at 6-75.
[56] E.T. Slonecker *et al.*, USGS, *Landscape Consequences of Natural Gas Extraction in Bradford and Washington Counties, Pennsylvania, 2004–2010* (2012) at 1.
[57] PA DCNR, *Impacts of Leasing Additional State Forest for Natural Gas Development* (2011).

including asthma-inducing SO_2, and among the very largest sources of combustion-related CO_2. Thus, LNG-induced market changes could have important implications for domestic air quality.

The EIA has modeled this fuel-shifting effect for gas exports of up to 12 bcf/d.[58] It reports that as exports rise, domestic gas consumption falls. Utilities largely switch to coal, while also making up a bit of the displaced gas generation with energy efficiency and renewable energy.[59] On balance, this shift results in increased emissions because the bulk of the new energy (72% of the total) comes from coal generation.[60]

More coal generation means greater carbon dioxide emissions from combustion, which are more than sufficient to balance out any emissions savings from greater use of efficiency and renewable energy in most of the scenarios that the EIA considered.[61] In fact, even in the few scenarios where the EIA predicted a larger market share for low carbon sources, LNG exports still resulted in a net increase in CO_2 emissions nationally, once emissions from the liquefaction process itself were accounted for.[62] The size of this increase depends upon the volume and size of exports, and the baseline price of gas and coal under various scenarios, so the EIA analysis estimates it within a broad range of 187 to 1,587 million metric tons of CO_2 over the next twenty years. These are large amounts. Even at the low end, 187 million metric tons is equivalent to the CO_2 emitted in a year by roughly 44 coal-fired power plants.[63] These emissions have the potential to increase as more LNG is exported with commensurate impacts on the market. They would be accompanied by corresponding increases in other coal-generation-related air pollutants, like SO_2.

This market-linked pollution effect could work to disrupt important policy work at the national and local level. Many utilities, public service commissions, and environmental regulators increasingly assume that coal generation's market share will steadily fall, in favor of gas, renewable energy, and energy efficiency. These entities are planning accordingly. Indeed, the EPA's recent proposed carbon pollution standards for fossil-fired generation are premised on EPA's understanding that "in light of a number of economic factors, including the increased availability and significantly lower price of natural gas … few, if any, new coal-fired power plants will be built in the foreseeable future."[64] As policymakers adapt to a world of more readily-available natural gas, export's tendency to make gas *less* available and more expensive will have important environmental implications throughout the country.

C. Impacts from Export Itself: Focus on Climate

[58] EIA, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* at 17-19.
[59] *Id.*
[60] *Id.* at 18.
[61] *See id.* at 18-19.
[62] *Id.*
[63] Calculated with EPA's *Greenhouse Gas Equivalencies Calculator*, available at http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results.
[64] *See* 77 Fed. Reg. 22,392, 22,399 (Apr. 13, 2012).

Finally, exports themselves have substantial environmental impacts.

Export terminals are large industrial sites. The liquefaction facilities needed to chill natural gas until it condenses into a liquid well below zero are energy-intensive and can produce substantial amounts of air and water pollution. Likewise, the pipeline and compressor networks needed to transport gas to the terminal, and the international shipping system needed to carry it onward all have significant impacts on the environments they traverse. The highly explosive nature of LNG means that carefully mapping out the potential for serious accidents around terminals and ships is an ongoing and important exercise in worst-case scenario analysis.

Looking more broadly, the use of LNG itself has environmental impacts, both positive and negative. Examining the climate implications of LNG is particularly important because LNG proponents have touted the fuel for its supposed potential to substantially reduce greenhouse gas pollution by displacing coal.

This claim is not well-supported. Because of the energy used to liquefy, transport, and re-gasify LNG, its life-cycle climate footprint is greater than that of most gas sources. Indeed, at least one peer-reviewed study has found LNG's life-cycle greenhouse gas emissions approach the low-end of coal life-cycle emissions.[65] Notably, that study was based on emissions from conventionally-produced natural gas, which are considerably lower than those from unconventional gas. Other studies, though concluding that LNG emissions are still lower than those of coal, have likewise documented that LNG life-cycle emissions are on the order of 30% greater than those of ordinary gas.[66] Whichever figures ultimately turn out to be correct, it is clear that LNG is among the most carbon-intensive forms of natural gas.

Further, whether or not LNG produces as much greenhouse gas pollution as coal, increased use of *any* fossil fuel is not consistent with preventing dangerous climate change. Recent climate studies show that increased natural gas use (from whatever source), without aggressive additional carbon control efforts, will not prevent dangerous increases in global temperature. The International Energy Agency, for instance, recently considered a future in which global gas use (including LNG use) sharply increases because of the unconventional gas boom.[67] In this scenario, despite gas's presumed life-cycle emissions advantage over coal, atmospheric CO_2 concentrations nonetheless rise on a trajectory towards 650 ppm, up from near 400 ppm today, pushing towards a 3.5°C temperature increase.[68] As a result, even if LNG emits less greenhouse gas pollution than coal, and even if it displaces some amount of coal power (which may or may not occur), it will not put on a path towards safe climate.

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[65] Jaramillo et al., *Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, 41 Environ. Sci. Technol. 6,290, 6,295 (2007).
[66] *See* European Commission Joint Research Centre, *Liquefied Natural Gas for Europe – Some Important Issues for Consideration* (2009) at 16-17; European Commission Joint Research Centre, *Climate impact of potential shale gas production in the European Union* (2012).
[67] International Energy Agency, *Golden Rules for a Golden Age of Gas* (2012).
[68] *Id.* at 91.

We can only avoid the worst impacts of climate change if emissions fall sharply. As IEA explains, "reaching the international goal of limiting the long-term increase in global mean temperature to 2°C above pre-industrial levels cannot be accomplished through greater reliance on natural gas alone."[69] Thus, expanded natural gas exports may, at best, very slightly slow the pace of warming. In the worst case, they will maintain the status quo, while deepening a national and global investment in climate-disrupting fossil fuels and delaying the transition to renewable energy sources.

D. Conclusions on Environmental Impacts

In sum, the environmental impact of LNG export is large, and stretches from local effects near individual gas wells to significant cumulative impacts on the country as gas production increases and gas prices rise to significant shifts in the international energy market. Some of these impacts are better understood than others, but all are worthy of careful analysis.

That analysis has not been forthcoming. DOE and FERC have prepared no environmental reports studying the impacts of export and, worse, have so far declined to do so, as is explained below. Export proponents, who generally trumpet production increases as a central benefit of their projects, are silent on the environmental costs of these production shifts.

The policy community has not yet seriously engaged these questions either. Two much-discussed recent LNG export papers, which generally favor exports, devote almost no attention to the environmental impacts of exports and the increased gas production that would accompany them. A report from the Brookings Institution, titled *Liquid Markets*, cites the DOE's Shale Gas Subcommittee's serious concerns and reviews ongoing regulatory initiatives, but makes no effort to quantify the likely environmental impacts of increased production.[70] Instead, it settles for predicting only that the "current regulatory environment" – the one which DOE has judged to be inadequate – should not put any insuperable hurdles in the way of new drilling.[71]

A second report, from Michael Levi of the Council on Foreign Relations and the Hamilton Project, also lacks a detailed treatment of these issues.[72] The environmental portion of that analysis also largely considers whether public backlash over environmental damage will be sufficient to derail exports, warning that the EIA projects "that a large part of increased production spurred by export demand would be in the Northeast, where opposition to shale gas development has been strongest."[73] Levi views this possibility as an argument for improved regulation, such as the DOE has called for. He implies, however, that because LNG exports will

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[69] *Id.* at 100.
[70] Brookings Energy Security Initiative, *Liquid Markets: Assessing the Case for U.S. exports of Liquefied Natural Gas* (May 2012) at 6-12.
[71] *Id.* at 11.
[72] Michael Levi, The Hamilton Project, *A Strategy for U.S. Natural Gas Exports* (June 2012).
[73] *Id.* at 20-21.

not commence "for several years," there will be time to put the necessary rules in place before hand.[74] Suffice to say that this is back-to-front thinking: There is no guarantee that rules will be in place to manage a wave of increased fracking. On the contrary, with billions of dollars sunk into export terminals, one might expect export proponents to oppose new regulation.

These two recent reports are representative: There has been a great deal of discussion of the economic potential of LNG exports, but the environmental discussion has lagged dangerously behind. Mere assertions that environmental impacts will not be sufficiently disturbing as to cause a massive public backlash, or that regulations will doubtless be in place by the time exports occur, are not enough to support careful consideration of these transformative changes. The decision to allow substantial LNG exports requires a thorough accounting of the likely impacts and how they can best be managed.

To be sure, a great deal of useful information is being developed on the environmental impacts of unconventional gas production generally, as state and federal regulators grapple with the implications of the boom. That information, however, has not been integrated into an analysis of the impacts of LNG exports or used to inform export decisions. If DOE or FERC began that study, they would find a rich and developing literature to draw upon and synthesize. The export licensing system, supported by the NEPA process, should produce just an analysis. That information is long overdue.

IV. The Regulatory Infrastructure

The Natural Gas Act and NEPA provide a framework under which DOE and FERC must weigh the environmental impacts of export, and then ensure that exports, if any, are regulated to protect the public interest. Thus far, this fundamental oversight machinery has not been fully used.

Natural gas imports and exports have been regulated under the Natural Gas Act since the late 1930s. Until very recently, however, large-scale exports of LNG were not in the picture. The two core regulatory bodies, DOE's Office of Fossil Energy, and FERC, dealt largely with pipeline shipments to Canada and Mexico and with LNG import terminals. Although they occasionally handled periodic permit renewals for a sole, small, LNG export terminal in Alaska that has served the Asian market off and on since the 1960s, this minor project does not remotely compare to the enormous export proposals now before them. This striking shift underlines the importance of proceeding carefully now.

A. The Public Interest Determination and Siting Process

The Natural Gas Act provides that "no person" may export or import natural gas without a license.[75] Such a license will be granted unless the proposal "will not be consistent with the

[74] *See id.* at 21.
[75] 15 U.S.C. § 717b(a).

public interest."[76] This public interest standard is broad and invites careful analysis. Among other points, it includes "the authority to consider conservation, environmental, and antitrust questions."[77] The Supreme Court has made clear that environmental considerations, in particular, are due close attention in this analysis.[78] DOE has recently affirmed that it is required to examine a "wide range of criteria" to best understand the public interest, "including… U.S. energy security… [i]mpact on the U.S. economy… [e]nvironmental considerations… [and] [o]ther issues raised by commenters and/or interveners deemed relevant to the proceeding."[79]

DOE and FERC share responsibility for Natural Gas Act determinations, with DOE taking, in many ways, the more fundamental role. Under their current division of authority, FERC is charged with location-specific concerns: Its primary responsibility is to investigate how to safely site and operate export and import terminals themselves.[80] DOE, by contrast, is charged with more broadly considering whether the project should move forward at all: It must make the public interest determination, and so must survey the information before it in order to discern how a given export or import proposal will affect the many considerations relevant to the public interest.[81] Although DOE reads its governing statute to afford export applicants a rebuttable presumption that their project is in the public interest, this presumption is not dispositive and a detailed public interest analysis is required in each case.[82]

NEPA analysis supports this public interest determination by providing the environmental information which DOE must weigh under the Natural Gas Act. The NEPA process, described in detail below, is the joint responsibility of DOE and FERC, and must be completed before either one issues a final order. Since 2005, FERC has been charged by statute as the "lead" agency for NEPA compliance, meaning that it coordinates the environmental assessment process.[83] DOE, however, must contribute to and review the documents which FERC prepares, and must independently determine whether they are sufficient to support its public interest determination, or whether more analysis is needed.[84] Only once DOE determines that it has NEPA documents which fully analyze the environmental impacts of the decision before it does it weigh those impacts and make its final public interest decision.

This process applies to all the export applications now before FERC and DOE with one important exception, which is discussed in more detail in the final section of this paper. In the 1992

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[76] *Id.*

[77] *Nat'l Ass'n for the Advancement of Colored People v. Federal Power Commission*, 425 U.S. 662, 670 n.4 & n.6 (1976).

[78] *See Udall v. Federal Power Comm'n*, 387 U.S. 428, 450 (1967).

[79] Testimony of Christopher Smith, Deputy Assistant Secretary of Oil and Gas Before the Senate Committee on Energy and Natural Resources (Nov. 8, 2011).

[80] Department of Energy Delegation Order No. 00-004.00A § 1.21 (May 16, 2006).

[81] *See* Department of Energy Redelegation Order No. 00-002.04E § 1.3 (Apr. 29, 2011).

[82] *See Panhandle Producers and Royalty Owners Ass'n v. Economic Regulatory Administration*, 822 F.2d 1105, 1110-1111 (D.C. Cir. 1987).

[83] *See* 15 U.S.C. § 717n.

[84] *See* 40 C.F.R. § 1501.6.

Energy Policy Act, Congress amended DOE's Natural Gas Act authority to provide that DOE *must* grant applications for export to (or import from) nations with which the United States has signed a free trade agreement providing for national treatment in natural gas.[85] In those cases, FERC still oversees terminal siting, but DOE loses its broad oversight role as to whether export is wise in the first place. This loophole was created to support natural gas imports from Canada – rather than massive LNG *exports* from the U.S. – but it has been relatively unimportant until recently. Significant export projects generally must go through the usual public interest process because the United States does not have free trade agreements with most major LNG importers. The 2010 free trade agreement with South Korea, a large LNG importer, changed this picture somewhat, but the South Korean market is still relatively limited and the free-trade "loophole" has not short-circuited DOE's usual process in most cases. That situation highlights, however, the importance of maintaining the public interest determination process as trade negotiations continue with other importers.

Accordingly, though most exporters do secure the "free" license to export to free-trade-agreement nations, the license to export to non-free-trade-act nations remains more valuable, and is often essential to doing business. Of the 19 projects now before DOE, only 4 rely exclusively on a free-trade-agreement license.[86] The remaining proposals are proceeding through the full public interest determination process.

B. The NEPA Process

The NEPA phase of this process must provide DOE and the public with a full and fair understanding of the environmental implications of export.

NEPA is our bedrock environmental statute.[87] It is rooted in democratic decisionmaking informed by excellent information. NEPA directs federal agencies to look before they leap: by requiring the preparation of environmental impact statements (EISs) for major federal actions, it helps ensure sound decisions before bulldozers roll. Policymakers have a pressing need for the information the NEPA process can provide as they consider whether and how to permit LNG export. NEPA analysis, accordingly, is not just a legal mandate but a prudent measure.

NEPA requires all federal agencies to "utilize a systematic, interdisciplinary approach" to make decisions, ensuring that their decisions are fully informed before they act with a goal of maintaining "the environment for succeeding generations."[88] The core of this obligation is the EIS, which must be prepared for every major Federal action which could significantly affect "the quality of the human environment."[89]

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[85] *See* 15 U.S.C. 717b(c).

[86] Those four are the SB Power Solutions, Golden Pass Productions, Main Pass Energy Hub, and Waller LNG Services proposals.

[87] It is codified at 42 U.S.C. §§ 4321 *et seq.*

[88] 42 U.S.C. §§ 4332(A) & 4331(b)(1).

[89] 42 U.S.C. § 4332(C).

An EIS is designed to develop information describing the environmental impact of a proposed action, alternatives to the proposal, and the relationship between the short-term proposal and "the maintenance and enhancement of long-term [environmental] productivity."[90] NEPA, in other words, helps prompt agencies to look more broadly than the immediate matter at hand, to understand how their actions fit within a larger environmental context. As the first court to review the statute explained, "NEPA, first of all, makes environmental protection a part of the mandate of every federal agency and department."[91]

This is not a paper exercise. The Council on Environmental Quality, the high-level body which administers NEPA across the government, explains in its regulations that "[u]ltimately, of course, it is not better documents but better decisions that count. NEPA's purpose is not to generate paperwork--even excellent paperwork--but to foster excellent action."[92] This means that "[t]he NEPA process is intended to help public officials make decisions that are based on an understanding of environmental consequences, and take actions that protect, restore, and enhance the environment."[93]

This process proceeds in several steps, designed to build a strong platform for the final decision. It is to begin as early as possible in order to ensure that the EIS can "serve practically as an important contribution to the decisionmaking process and will not be used to rationalize or justify decisions already made."[94] After an initial "scoping" phase during which the agency gathers comments from stakeholders to identify key issues,[95] the agency prepares a draft and then a final EIS.

The "heart of the environmental impact statement" is a careful discussion of the proposal and all relevant alternatives, "sharply defining the issues and providing a clear basis for choice among options by the decisionmaker and the public."[96] With regard to each option, the agency must develop a careful description of its environmental consequences.[97]

These consequences are generally divided between direct, indirect, and cumulative impacts.[98] Direct impacts are simply those immediately caused by the action at issue; indirect impacts are those which may occur a bit further afield, but which are still causally linked to the federal action.[99] The agency must cast a wide net, analyzing all "reasonabl[y] foreseeable" impacts, including those "induced" by its action – think, for instance, of the "growth inducing" impacts of building a highway, or, for that matter, an export terminal inducing drilling with its attendant

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[90] *Id.*
[91] *Calvert Cliffs' Coordinating Committee, Inc. v. U.S. Atomic Energy Comm'n*, 449 F.2d 1109, 1112 (D.C. Cir. 1971).
[92] 40 C.F.R. § 1500.1(c).
[93] *Id.*
[94] 40 C.F.R. § 1502.5.
[95] 40 C.F.R. § 1501.7.
[96] 40 C.F.R. § 1502.14.
[97] 40 C.F.R. § 1502.16.
[98] 40 C.F.R. §§ 1508.7 & 1508.8.
[99] 40 C.F.R. § 1508.8.

effects on "air and water and other natural systems."[100] The analysis must also include the "cumulative" impacts of federal action – the "incremental impact of the action when added to other past, present, and reasonably foreseeable future actions."[101] For instance, in the LNG context, the cumulative production inducing effects of all relevant LNG terminals should be considered together. It would also make sense to consider the cumulative impact of new production from export along with the impact of existing gas production.

The EIS, in short, ultimately presents a full accounting of all the reasonably foreseeable impacts of the agency's proposed course of action, along with alternatives to that course of action. It is designed to bring information to light and to generate syntheses of formerly scattered information.

Congress recognized, in this regard, that some uncertainty will always be present in any prediction of environmental impacts. Such uncertainty does not excuse agencies from complying with NEPA – if it did, NEPA analyses would never succeed in developing the new research agencies need to inform their decisions. Rather, the NEPA process is designed to limit uncertainty, while carefully characterizing remaining questions. Where information is incomplete, the agency must gather it (expending reasonable funds to do so) to fill in key aspects of the picture.[102] If costs are truly exorbitant, or it is very difficult to generate a particular piece of information, an agency must still do its best, providing a careful description of what it believes to be missing from its evaluation, a "summary of existing credible scientific evidence" relevant to its problem, and the agency's best "evaluation" of the impacts before it based upon what it knows.[103] In all cases, the goal is to develop the best-informed analysis possible, advancing the public's understanding, even of uncertainties, before the final decision is made.

Uncertainties can also be managed by beginning at a higher level of generality with a special form of EIS known as a "programmatic" environmental impact statement, and then filling in more specific information down the road as individual projects are considered. As the name suggests, programmatic EISs are intended to provide a broad overview of entire programs, or classes of activity.[104] Such documents are particularly useful as road maps. They provide an overview of how a class of decisions – such as granting many different export applications – will affect the environment. As the D.C. Circuit Court of Appeals has explained, this process has "a number of advantages" which recommend it here:[105] A programmatic EIS, the court explained, "provides an occasion for a more exhaustive consideration of effects and alternatives than would be practicable in a statement on an individual action. It ensures consideration of

[100] *See id.*
[101] 40 C.F.R. § 1508.7.
[102] 40 C.F.R. § 1502.22(a).
[103] 40 C.F.R. § 1502.22(b)(1).
[104] *See* 40 C.F.R. § 1502.14(b)-(c).
[105] *Scientists' Institute for Public Information, Inc. v. Atomic Energy Comm'n*, 481 F.2d 1079, 1087 (D.C. Cir. 1973).

cumulative impacts that might be slighted in a case-by-case analysis. And it avoids duplicative reconsideration of basic policy questions."[106]

To facilitate this broad overview, the NEPA regulations in turn explain that agencies can structure programmatic EISs by looking, for instance, geographically at "actions occurring in the same general location"; generically, by looking at actions with, for instance, "common timing, impacts, alternatives, methods of implementation, media, or subject matter"; or even by "stage of technical development" as processes and technologies mature.[107] Once such an overview is in hand, an agency is free to rely upon it to guide more specific analyses of particular projects, thereby saving work and time down the road.[108]

Whether an EIS is programmatic or project-specific, as the Supreme Court has explained, by ensuring that agencies take a "hard look" at the environmental consequences of their decisions, NEPA is "almost certain to affect the agency's substantive decision."[109] In this sense, NEPA reflects a fundamentally democratic approach to decisionmaking, a faith that putting the best information forward transparently will help policymakers and the public navigate uncertainty and make difficult choices. The Supreme Court identifies these two purposes this way:

> First, [NEPA] ensures that the agency, in reaching its decision, will have available, and will carefully consider, detailed information concerning significant environmental impacts. Second, it guarantees that the relevant information will be made available to the larger audience that may also play a role in both the decisionmaking process and the implementation of that decision.[110]

With this process in place, the goal is that "the most intelligent, optimally beneficial decision will ultimately be made."[111]

There is a pressing need for such careful, deliberate, decisionmaking in the LNG export context.

V. Applying NEPA to LNG Exports

DOE affirms in its governing regulations that it will "follow the letter and spirit of NEPA" and will "apply the NEPA review process early in the planning stages" of its projects.[112] These rules are clear that DOE must base its final decisions on matters with significant environmental impacts on a carefully developed environmental impact statement.[113] But DOE has refused to prepare

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[106] *Id.* (internal quotations and citation omitted).
[107] 40 C.F.R. § 1502.14(c)(1)-(3).
[108] *See*, *e.g.*, 40 C.F.R. § 1502.20
[109] *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 350 (1989).
[110] *Dep't of Transp. v. Public Citizen*, 541 U.S. 752, 767 (2004) (internal quotations omitted).
[111] *Calvert Cliffs*, 449 F.2d at 1114.
[112] 10 C.F.R. § 1021.102.
[113] *See, e.g.*, 10 C.F.R. §§ 1021.210 (affirming that DOE will complete NEPA review "before making a decision"); 1021.214 (affirming that this standard applies for adjudicatory proceedings, such as licensing processes).

an environmental impact statement to help it wrestle with the weighty export decisions now before it. Worse, it has refused even to acknowledge that it has the tools to do so, even though its own modeling system could go far to help answer the vital questions now before it.

DOE *should* have approached NEPA compliance in a far more considered way. It should have begun by preparing a national programmatic environmental impact statement – either on its own or as a partner with FERC, the usual NEPA lead agency -- that would have considered the cumulative effect of the export proposals before it and ways to mitigate those effects. Such an analysis would be a natural counterpart to a national economic study it is now preparing. In fact, the U.S. Environmental Protection Agency (EPA) has now twice filed formal comments making clear that just such an analysis is necessary.[114] With both such studies in hand, DOE and FERC could then have developed shorter, subsidiary studies for each proposal before it, considering their particular circumstances in the context of its comprehensive public disclosures.
The unwise course the agencies have thus far taken in the environmental arena contrasts sharply with DOE's far wiser commitment to consider national economic impacts before moving forward on any further export applications. These two approaches are irreconcilable. DOE must undertake a full EIS for LNG export, including the effects of increased gas production, if it is to make prudent decisions and satisfy its legal mandates.

A. DOE's Failure to Properly Apply NEPA Thus Far

DOE has assured Congress that it recognizes that the cumulative impact of "future LNG export authorizations could affect the public interest."[115] Unfortunately, though DOE is attempting to better understand some of the economic implications of LNG export, it has thus far actively refused to consider the environmental implications.

The only nearly-complete example of DOE's deliberative process thus far is its handling of the Sabine Pass LNG export project proposed for southern Louisiana. Sabine Pass was the first LNG export application filed in the current wave of proposals, and proposed to export 803 bcf of gas annually. This volume of export, alone, would increase *total* U.S. gas exports by more than 50%.[116] One might have expected DOE to analyze this historic application in detail, but it did not.

Instead, applying the rebuttable presumption-based approach to export, DOE did not develop significant independent analyses when considering the application. It relied almost entirely on Sabine Pass's own assertions. In spring 2011, it "conditionally" approved the Sabine Pass's request to export up to 2.2 bcf/d of natural gas, largely on the ground that no opposing party

[114] Letter from Christine B, Reichgott, EPA Region 10 to FERC (Oct. 29, 2012) at 12-13; Letter from Jeffrey D. Lapp, EP Region 3 to FERC (Nov. 15, 2012) at 2.
[115] Letter from Christopher Smith, Deputy Assistant Secretary of Oil and Gas to Representative Edward Markey (Feb. 24, 2012) at 3.
[116] *See* n. 3, *supra*.

had shown that the project was *not* in the public interest.[117] DOE thus approved the beginning of the export boom largely on the export proponents' say-so, without preparing its own analysis.

The "conditional" part of the approval referred in large part to DOE's decision to defer its consideration of environmental matters pending FERC's work on NEPA documents for Sabine Pass as the lead agency for NEPA compliance. Because FERC had not yet prepared an environmental analysis or environmental impact statement, DOE opted not to weigh any environmental factors in its public interest analysis. Instead, it stated that FERC, with DOE's cooperation, would undertake the environmental study for both agencies as part of FERC's facility siting process.[118] DOE stated that it would review FERC's final product before finally signing off on Sabine Pass.

But FERC did not prepare an EIS for Sabine Pass and did not consider the national implications of the application, including its implications for production. FERC recognized that Sabine Pass itself identified the purpose and need of the facility as to "provide a market solution to allow the further development of unconventional (particularly shale gas-bearing formation) sources in the United States."[119] Nonetheless, it instead prepared only a more limited document called an environmental assessment (an "EA"), which focused only on the environmental impacts of the facility siting decision before it.[120]

FERC justified this decision on the grounds that the impacts from increased gas development were not "reasonably foreseeable" because "no specific shale-gas play is identified."[121] It did so even though Sabine Pass itself affirmed that the "most likely" sources of supply for its project were "the historically prolific Gulf Coast Texas and Louisiana onshore gas fields, the gas fields in the Permian, Anadarko, and Hugoton basins, and the emerging unconventional gas fields in the Barnett, Fayetteville, Woodford, and Bossier basins."[122] FERC apparently felt that the applicant's own assurances that export would spur production, and would likely do so in specific places, provided no ground for analysis. Because FERC believed that it could not identify precisely where Sabine Pass would catalyze gas production, it refused to consider these impacts at all.[123]

But NEPA analyses are not dependent on this sort of location-specific analysis. Instead, a programmatic EIS, for instance, could readily have presented the environmental choices before DOE on a national level, with particular attention to potential production patterns in prolific shale plays. Even a project-specific EIS could have addressed pressing environmental issues directly. FERC could have evaluated the sorts of pollution risks and ecosystem threats

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[117] DOE, Order 2961 (May 20, 2011) at 42.
[118] *Id.* at 40-41.
[119] *Id.* at 1-10.
[120] *See* FERC, *Environmental Assessment for the Sabine Pass Liquefaction Project* (December 2011).
[121] FERC, Order Granting Section 3 Authorization, 139 FERC ¶ 61,039 at ¶¶ 96-97 (Apr. 16, 2012).
[122] Sabine Pass Export Application (Sept. 7, 2010) at 16.
[123] *Id.* at ¶¶ 98-100.

associated with increased fracking. It could have described the likely cumulative impacts of the many proposed LNG projects, including those at Sabine Pass, and could have estimated the scale of environmental disruption that they may cause. Instead, FERC provided none of this information. Perversely, because it concluded that Sabine Pass might promote gas production "in any of the numerous shale plays that exist in most of the eastern United States," and hence could have nationwide impacts, FERC decided that these impacts swept too broadly to be analyzed.[124]

DOE did not have to accept this blinkered view, but it nonetheless did so, declaring, on its review of FERC's EA, that FERC had "examined all reasonably foreseeable impacts" of the project.[125] DOE therefore accepted FERC's EA as a "complete picture for purposes of meeting DOE's NEPA responsibilities and fulfilling its duty to examine environmental factors as a public interest consideration under the [Natural Gas Act]."[126] In doing so, DOE also accepted FERC's reasoning that because it was "impossible" to know precisely how much new production Sabine Pass would cause, or exactly where this production would occur, there was no way to discuss these impacts at all.[127]

Thus, though DOE affirmed that it was "fully aware of concerns of the environmental effects of shale gas production," it insisted that it could not provide a "meaningful analysis" of Sabine Pass – or of the cumulative impacts of LNG export as a whole.[128] Sierra Club petitioned for rehearing of this decision, and DOE has announced that it continues to consider whether its decision was correct.[129]

DOE has not moved forward on any other LNG export applications (with the exception of licenses for export to countries with which the U.S. has a free trade agreement, discussed below), so the Sabine Pass order stands as its current word on the subject. If DOE does not change course, huge volumes of natural gas will be produced and exported without any consideration of how this massive production increase will affect communities across the country. Far from working to protect the public interest, DOE will not acknowledge, much less address, the challenge before it.

B. How NEPA Should Be Applied to LNG Exports

The Sabine Pass decisions made a bad beginning, but they need not determine the rest of the story. DOE may yet reconsider its Sabine Pass order. Moreover, many other LNG export applications have been filed with DOE and, as it considers them, it may still treat this environmental challenge with the seriousness it deserves. Before granting any further licenses,

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[124] FERC, Order Denying Rehearing and Stay, 140 FERC ¶ 61,076 at ¶ 12 (July 26, 2012).
[125] DOE, Order 2961-A (Aug. 7, 2012) at 27.
[126] *Id.*
[127] *Id.* at 28.
[128] *Id.*
[129] DOE, *Order Granting Rehearing for Further Consideration*, FE Docket No. 10-111-LNG (Oct. 5, 2012).

DOE should ensure that the NEPA process develops the information it needs to make a sound public interest determination.

For purposes of this discussion, DOE or FERC could undertake the tasks described below. FERC would be the most likely coordinator, given its lead agency role under the Natural Gas Act, but it is ultimately DOE's responsibility to ensure that the final NEPA analysis is sufficient to support a careful public interest determination, whether it is prepared entirely by FERC or later supplemented by DOE. For ease of reference, this section therefore refers to "DOE" as conducting the analysis, though FERC would play an important coordinating role.

In this context, a programmatic EIS makes a great deal of sense. By looking first at the common questions inherent in export, DOE could help develop a fundamental shared understanding of their impacts before turning to the particular impacts of specific proposals.

i. Determining Foreseeable Production Associated with Export

The most important first question for DOE is to determine a "reasonably foreseeable" range of natural gas which may be exported and the corresponding range of reasonably foreseeable increases in production. So far, DOE and FERC have insisted that *no* production impacts are reasonably foreseeable, as the Sabine Pass decisions state. This conclusion is simply wrong. The DOE's own NEMS program can forecast these production impacts. DOE's failure to develop such projections is unjustifiable.

NEMS is a very well-established modeling system designed to model the economy's energy use through a series of interlocking "modules" that represent different energy sectors on regional and national levels.[130] Relevant here, NEMS has an "Oil and Gas Supply Module"[131] and a "Natural Gas Transmission and Distribute Module."[132] Rhese modules jointly represent the entire domestic natural gas sector, and describe how production responds to demand across the country. They can be used, therefore, to model the effects of increased export demand on gas production. In fact, they *have* been used for this purpose by DOE already: The January 2012 EIA special report on LNG, which included production forecasts, relies on NEMS, as does the summer 2012 Annual Energy Outlook, which contains LNG projections.[133]

EIA's formal documentation for NEMS is available online, and thoroughly describes the system. That documentation demonstrates that DOE/FE is in error when it states that the implications of LNG export demand for the production and supply of domestic gas are not foreseeable. In fact, NEMS's natural gas sub-models are explicitly designed to project how supply will respond to demand on a national and a regional basis; indeed, they *must* do so for the model to

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130 *See* EIA, *The National Energy Modeling System: An Overview* (2009) at 1-2 ("NEMS Overview").
131 *See* EIA, *Documentation of the Oil and Gas Supply Module* (2012 ("OGSM Documentation").
132 *See* EIA, *Model Documentation: Natural Gas Transmission and Distribution Module of the National Energy Modeling System* (2012) (TDM Documentation).
133 *See, e.g.*, EIA, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* at 3 (EIA used NEMS for this forecast); EIA, . *See* EIA, *Annual Energy Outlook* (2012) at App. E (describing NEMS).

generate predictions. As such, NEMS could (and in fact has) be used to project likely production increases in response to increased demand caused by LNG exports. NEMS therefore provides the analysis of "when, where, and how shale-gas development will be affected" that the DOE has so far stated it would be impossible to produce.

To begin with, the Supply Module is built on detailed state-by-state reports of gas production across the country.[134] These reports allow the EIA to develop regionally differentiated models of the costs of production in each gas field, and how readily production can be increased in those fields. As the EIA explains, "production type curves have been used to estimate the technical production from known fields" as the basis for a sophisticated "play-level model that projects the crude oil and natural gas supply from the lower 48."[135] The module reports its results for regions throughout the United States, including the Northeast, the Gulf Coast, and areas in Texas and Arkansas with large gas plays.[136] It also distinguishes coalbed methane, shale gas, and tight gas from other resources, allowing for specific predictions distinguishing unconventional gas production from conventional natural gas production.[137] The module further projects the number of wells drilled each year, and their likely production; these are important figures for estimating environmental impacts.[138]

In short, this module "includes a comprehensive assessment method for determining the relative economics of various prospects based on future financial considerations, the nature of the undiscovered and discovered resources, prevailing risk factors, and the available technologies. The model evaluates the economics of future exploration and development from the perspective of an operator making an investment decision."[139] Thus, for each play in the lower 48 states, the EIA is able to predict future production based on existing data. Importantly, the EIA makes clear that "the model design provides the flexibility to evaluate … environmental, or other policy changes in a consistent and comprehensive manner."[140] Those policy changes include permitting LNG export.

LNG export creates new demand and transmission needs. The next NEMS module, the Transmission and Distribution Module, can address these impacts. It integrates supply projections with regional and national demand to help determine how gas will flow to areas experiencing increased demand. As EIA explains, the module "represents the transmission, distribution, and pricing of natural gas" using a national module of the transmission system, which, in turn, is divided by region.[141] The module "links natural gas suppliers (including importers) and consumers in the lower 48 States and across the Mexican and Canadian borders via a natural gas transmission and distribution network, while determining the flow of natural

[134] *See* OGSM Documentation at 2-2.
[135] *Id.* at 2-3.
[136] *Id.* at 2-4.
[137] *Id.* at 2-7.
[138] *See id.* at 2-25 -2-26
[139] *Id.*
[140] *Id.*
[141] TDM Documentation at 2.

gas and the regional market clearing prices between suppliers and end-users."[142] Because the Transmission Module represents demand regionally, it can distinguish, for instance, between LNG export demand on the Gulf Coast and demand in the Northeast.[143] For each region, the module then links supply and demand annually, taking transmission costs into account, in order to project how demand will be met by the transmission system.[144] Thus, it interacts with the Supply Module to develop projections for how supply in each production region will evolve in response to demand.[145]

Importantly, the Transmission Module already is designed to model LNG imports and exports, and contains an extensive modeling apparatus to do so.[146] The Module includes import/export pipelines and the sole existing LNG export terminal in Alaska.[147] There is, thus, no technical barrier to modeling increased export demand going forward.[148] One source of demand is much like any other, so additional export terminals can simply be modeled as additional demand centers in the regions in which terminals are proposed. The Module could, for instance, readily model additional demand along the Gulf Coast or other coasts, and translate that demand back to the Supply Module. Again, this process is essentially what the EIA already did in the context of its January 2012 LNG export study, which relied on NEMS to forecast the production and price impacts of export.

In short, NEMS is already set up to do the sort of work which DOE needs to do here.[149] In response to a given demand in a particular region, it projects transmission system flows and

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[142] *Id.*
[143] *See id.* at 12-14.
[144] *See id.* at 15-16.
[145] *See id.* at 16-20.
[146] *See id.* at 22-32.
[147] *Id.* at 3.
[148] *See id.* at 30-31.
[149] As are several models used by private consultants. For instance, the Deloitte consultancy regularly makes such predictions. *See, e.g.*, Deloitte, *Made in America: The Economic Impact of LNG Exports from the United States* (2011) at 6 (explaining that if LNG is "exported from one particular geographic point, the entire eastern part of the United States reorients production and flows and basis differentials change substantially"); *see also id.* at 6 (explaining that the reference case for the model predicts increased production in the Marcellus and Haynesville shales) & 8 (explaining that Deloitte considers how producers will "develop more reserves in anticipation of demand growth, such as LNG exports" and forecasting different prices depending on where exports occur).

According to Deloitte, its "World Gas Model" and its component "North American Gas Model" are designed precisely to provide this sort of finer-grained analysis. Deloitte explains that "[t]he North American Gas Model is designed to simulate how regional interactions of supply, transportation, and demand determine market clearing prices, flowing volumes, storage, reserve additions, and new pipelines throughout the North American natural gas market." *See* Deloitte, *Natural Gas Models.* The model "contains field size and depth distributions for every play, with a finding and development cost model included. This database connects these gas plays with other energy products such as coal, power, and emissions." *Id.* According to Deloitte, its modeling thus allow it to predict how gas production, infrastructure construction, and storage will respond to changing demand conditions, including those resulting from LNG export: "The end result is that valuing storage investments, identifying maximally effectual storage field operation, positioning, optimizing cycle times, demand following modeling, pipeline sizing and location, and analyzing the impacts of LNG has become easier and generally more accurate." *Id.* The point here is that linking exports to production is plainly possible.

production responses at the level of individual plays across the country. Thus, DOE is fully capable of analyzing the production impacts of particular levels of LNG export. Its failure to do so – and its insistence that such projections are somehow impossible to make – is inexplicable.

Given this capability, DOE should look at a range of possible export volumes and timing, just as the EIA did in the economic study that DOE commissioned. It should then consider the amount of natural gas (either produced or diverted from other uses) necessary to meet this demand, and can, using the same analysis EIA applied, predict how much of this gas is likely to come from new production.

Because NEPA is rooted in the alternatives analysis, DOE should also develop alternative approaches to the range of possible exports. It might, for instance, look at the impacts of allowing the maximum and minimum volumes of exports it thinks are plausible, along with its projection of the most likely scenario. It also makes sense to look at variations in export timing and volume driven by public interest concerns. For instance, DOE could consider permitting exports only after the environmental safeguards the Shale Gas Subcommittee identified are in place, or only permitting exports at a volume that would not cause serious price disruptions or economic harm domestically. And, of course, DOE must consider a "no action" alternative baseline, in which exports do not move forward at all. The point of the analysis, as always, is to ensure that the agency thoroughly explores the possible solution space, rather than simply pursuing its preconceived plans.

DOE, in short, has many options before it open for analysis. The only option which it simply may not pursue, however, is the one that it has picked: It cannot and must not refuse to use its *own models* to help inform the public as to the vital choices ahead.

ii. Estimating the Impacts of Production

With this array of options in mind, the next task for DOE is to identify the environmental impacts associated with each of the reasonable alternatives it has developed. EPA has twice instructed FERC (in its role as the lead agency) that just such an analysis is necessary.

EPA's formal comments put the matter well. As EPA explained in comments on a proposal to export LNG from Oregon:

> The 2012 report from the Energy Information Administration states that[] "natural gas markets in the United States balance in response to increased natural gas exports largely through increased production." That report goes on to say that about three-quarters of that increase[d] production would be from shale resources. We believe it is appropriate to consider available information about the extent to which drilling activity might be stimulated

by the construction of an LNG export facility on the west coast, and any potential environmental effects associated with that drilling expansion.[150]

EPA made a similar point in comments on another, Maryland-based, export facility. It wrote:

> We also recommend expanding the scope of analysis to include indirect effects related to gas drilling and combustion. … Th[e EIA] report also indicated that about three-quarters of that increase[d] production would be from shale gas resources and that domestic natural gas prices could rise by more than 50% if permitted to be exported. We believe it is appropriate to consider the extent to which implementation of the proposed project, combined with implementation of other similar facilities nationally, could increase the demand for domestic natural gas extraction and increase domestic nautral gas prices.[151]

EPA, in short, recognizes that the important national debate needs to be informed by careful environmental analysis. Because this analysis may best be done at the programmatic level, DOE should look at the impacts of export-linked production across the country, before applying this programmatic analysis to informed consideration of particular project proposals. The NEMS system and similar models will help DOE to project national impacts and to regionalize them. As it considers these options, it will need to answer several key questions. These include, but are certainly not limited to, the following:

What is the magnitude and timing of the increased natural gas production associated with a range of export scenarios?

This is the most fundamental question that the NEPA process should answer. The EIA has already developed models linking export to increased production. A NEPA analysis could use this starting point to investigate the magnitude of production needed to support a range of export volumes. This inquiry, on its own, would meaningfully assist decisionmakers. If they know, for instance, that permitting 1 bcf/d of export means that some dozens, hundreds, or thousands, of additional wells will need to be drilled, that consideration should be balanced transparently in the public interest analysis. Again, NEMS should be able to supply this analysis and, indeed, to do so on play-by-play and regional levels, as well as nationally.

What incremental air pollution risk is associated with increased natural gas production generally, and with increased unconventional gas production in particular?

The air pollution impacts of both conventional and unconventional gas production are serious and need to be better understood – especially if exports significantly increase production, as they are likely to do. The DOE can use the NEPA process to better describe these impacts. For instance, the Environmental Protection Agency has developed

[150] Letter from Christine B, Reichgott, EPA Region 10 to FERC (Oct. 29, 2012) at 12.
[151] Letter from Jeffrey D. Lapp, EP Region 3 to FERC (Nov. 15, 2012) at 2.

increasingly accurate emissions figures corresponding to processes through the natural gas production system, from well drilling to gas transport.[152] By estimating the amount production is likely to increase, DOE can evaluate the approximate range of new air pollution likely to be associated with increased production. Likewise, it can assess the likely emissions associated with any upgrades to pipeline transmission networks required to get natural gas to export terminals. DOE can, in other words, forecast whether a given export scenario is likely to be associated with many thousands of tons of additional air pollution, or a more limited amount.

Going further, DOE can predict where this pollution is most likely to occur. Although exported gas can be produced in many places, some natural gas basins are declining or stable, while others – such as those near the Texas Gulf coast and the Marcellus shale of the east coast -- are rapidly growing and are near proposed export terminal sites, reducing transportation costs. DOE can and should forecast the most likely targets for additional development in response to increasing gas demand; these locations are, in turn, the most likely to suffer from increased air pollution and to have to invest in appropriate control efforts. NEMS will it allow it do so.

In short, DOE can map out the air pollution control challenge ahead under various export scenarios. It can also forecast which regions are most likely to have to manage this increased pollution, and some of its likely public health and environmental impacts.

What incremental water pollution risk is associated with increased natural gas production generally, and with increased unconventional gas production in particular?

As with air pollution, water pollution risk increases with increased gas production. Here, too, an overview of pollution risk and response needs with substantially higher production will assist policymakers and the public. Although many other questions should be answered here, two areas of investigation within this general field jump out for investigation at the programmatic level.

First, increased gas production will generate a predictable amount of waste for treatment. Looking at the national scale, a proper EIS would consider the adequacy of treatment available for this increase in wastewater and other substances. Does existing treatment plant capacity correspond to the likely increased volume and can those plants properly treat all pollutants from the industry? Do injection wells appear ready to take up the slack? If not, where is waste likely to go? Before licensing exports, it makes sense to make sure that the nation is ready to handle the waste they leave behind.

Second, water *quantity* issues also deserve a close look. A substantial increase in fracking means a substantial increase in water use. Even though water use varies among gas

[152] *See generally*, EPA, *Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry* (Apr. 2012).

fields, DOE can calculate a range of water demand likely to be associated with increased gas production. That range will help to determine whether gas export will add substantially to water stress in the nation's gas fields.

DOE's task here, as in the air pollution analysis, will thus generally be to forecast the likely scope of increased threats to water quantity and quality. Because both waste and water can be transported significant distances, this analysis does not depend on knowing precisely which fields will increase their production, but such forecasts will be helpful in assessing the most likely impacts. That said, where DOE can localize these impacts, as NEMS allows, it will be able to provide extremely important information to policymakers working to protect particular watersheds and aquifers.

What degree of land and community disturbance will be associated with increased gas production for export?

A given volume of export will be associated with an approximate number of new wells, well pads, roads, and associated infrastructure. In some gas fields, this infrastructure is already causing serious conflicts and challenges for communities and for wildlife. For instance, DOE might answer questions like these: What acreage of new disturbance is necessary to meet the increased demand for gas? How many new truck trips and how many new miles of pipeline are likely to be necessary? How many people are living in areas likely to see increased production? And how able are the already disrupted communities and ecosystems in the most likely areas for new production to absorb these impacts without excessive damage? This area of inquiry should prompt DOE to think seriously about the degree of landscape transformation that export will drive.

What are the domestic energy and environmental policy implications of export?

As we have discussed above, gas exports will likely raise gas and energy prices. These market shifts have the potential to change the electrical generation mix and also have implications for domestic industry. DOE is already analyzing these economic questions and is beginning to chart their implications. EIA's initial look at shifts in CO_2 emissions from the utility sector is a good example of this analysis. DOE should extend it to consider, at a range of export volumes and timings, what changes in emissions from other sources are likely. If price increases from export, for instance, prompt increased use of highly polluting coal plants, DOE should carefully address the impacts resulting from that shift.

What are the international energy and environmental policy implications of export?

The atmosphere does not respect national boundaries. Accordingly, if LNG exports lead to changes in climate-disrupting pollution – by replacing either cleaner or dirtier energy sources or simply by increasing the load of carbon in the atmosphere – the United States will feel the effects. The country will also experience changes in transboundary transport of other chemicals and pollutants. To the extent possible, DOE can help forecast these impacts by considering which energy sources LNG is most likely to replace, and the extent of any such replacement.

What alternatives are available to reduce these impacts?

The alternatives analysis is the heart of the EIS. Developing a range of export policies – from permitting all exports, to only a subset of exports; from giving the green light now to waiting until protective regulations are in place – will allow DOE to test these alternatives against their impacts. The EIS should produce a map of possible trade-offs, showing how export decisions affect the environment and which export plans will best protect communities and ecosystems.

With answers to these and other questions in hand, DOE will be far better placed to understand the trade-offs inherent in LNG export and to decide whether export are in the public interest (and, if so, the proper volumes and timing which can best protect the public). This information is, in fact, necessary to properly conclude that process. Moreover, if the NEPA process reveals pressing risks from LNG export, DOE will be able to address them in advance or help other federal or state agencies do so. It will also have contributed to a crucial public conversation on a matter of vital national importance. When and if DOE does license exports, in this future, it will do so with its eyes wide open and will able to develop appropriate mitigation strategies.

Not all of the questions above are easy to answer. Many of them are difficult to address with complete precision, though DOE modeling and publicly available data will provide useful projections and estimates. But residual uncertainty is not a reason to shirk the task. The alternative, after all, is not safe inaction: It is blindly permitting a major change in the nation's energy system, committing to billions of dollars in LNG export infrastructure, and licensing a major increase in fracking activity across the country without any proper analysis. That course should not be undertaken casually. The nation will discover the answers to these questions with or without NEPA compliance, but without NEPA, the answers will come directly from suffering communities and ecosystems. NEPA ensures that decision-makers instead discover them in advance, "at a stage where real environmental protection may come about [rather] than at a stage where corrective action may be so costly as to be impossible."[153]

Forecasts of this sort are thus extraordinarily helpful, even if they are not entirely precise. As the D.C. Circuit Court of Appeals explained in a seminal NEPA case, the statute is designed to help outline crucial questions and answers early on, in order to guide continued decisionmaking and inquiry:

> The agency need not foresee the unforeseeable, but by the same token neither can it avoid drafting an impact statement simply because describing the environmental effects of and alternatives to particular agency action involves some degree of forecasting. And

[153] *Calvert Cliffs*, 449 F.2d at 1129.

> one of the functions of a NEPA statement is to indicate the extent to which environmental effects are essentially unknown. *It must be remembered that the basic thrust of an agency's responsibility under NEPA is to predict the environmental effects of proposed action before the action is taken and those effects are known.*[154]

The point is not that NEPA analysis at this phase will answer every question about export definitively and completely. Instead, "[r]easonable forecasting and speculation is… implicit in NEPA."[155] What DOE can, at a minimum, do now is to map out the fundamental environmental implications of LNG export. It can identify the scope and magnitude of likely impacts, and it can point to key unknowns that warrant more research. It can underline key concerns (such as the availability of treatment capacity to manage the waste associated with increased production for export) and offer alternatives that could address them. It can consider which regions are most likely to bear the costs of export, and where the benefits are most likely to fall. It can offer the sort of well-balanced, comprehensive, projections for which NEPA is designed.

Such an analysis, at an appropriate level of generality, is plainly required. There is absolutely no serious question that increased unconventional gas production is a "reasonably foreseeable" consequence of licensing LNG exports. Export proponents themselves predict such production increases; indeed, they premise their arguments that their projects are in the public interest in large part on the economic growth which they contend will follow from increased gas production.

For instance, Sabine Pass's promoters promised that their project would "play an influential role in contributing to the growth of natural gas production in the U.S."[156] The proponents of the Freeport project, likewise affirmed their project was "positioned to provide the Gulf Coast region and the United States with significant economic benefits by increasing domestic gas production."[157] Likewise, the Lake Charles project's backers maintained that their export would "spur[] the development of new natural gas resources that might not otherwise make their way to market."[158] The Gulf Coast LNG project's supporters asserted that their project will "allow the U.S. to benefit now from the natural gas resources that may not otherwise be produced for many decades, if ever."[159]

The litany goes on: In Oregon, the investors behind the Jordan Cove project assured DOE that it would be "instrumental in providing the increased demand to spur exploration and development of gas shale assets in North America."[160] And in Maryland, the Dominion Cove Point's project's supporters proclaimed that "[t]he most basic benefit of the proposed LNG exports will be to encourage and support increased domestic production of natural gas…. The

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[154] *Scientists' Institute*, 481 F.2d at 1092 (emphasis added).
[155] *Id.*
[156] Sabine Pass Application at 56 (Sept. 7, 2010).
[157] Freeport LNG Application at 14-15 (Dec. 19, 2011).
[158] Lake Charles Application at 20 (May 6, 2011).
[159] Gulf Coast Application at 11 (Jan. 10, 2012).
[160] Jordan Cove Application at 19 (Mar. 23, 2012).

steady new demand associated with LNG exports can spur the development of new natural gas resources that might not otherwise be developed."[161]

The bottom line is that increased domestic gas production is a necessary consequence of export. It is not just foreseeable: It is a principal *justification* for gas export projects. As such, its environmental impacts must be disclosed under NEPA and weighed in the Natural Gas Act public interest determination.[162]

Programmatic analyses of this sort are not unfamiliar to DOE. DOE, in fact, recognizes the importance of the NEPA process as a support for its decisionmaking, and has deep experience with programmatic EISs. Secretary Chu has written that he "cannot overemphasize the importance" of building NEPA compliance into DOE project management.[163] DOE has regularly done so. Over the years, the department has prepared draft and final programmatic EISs and environmental assessments for a nationwide effort to promote energy efficiency,[164] a solar energy promotion program in six western states,[165] energy "corridors" in 11 different states,[166] a global program supporting nuclear power,[167] and a national coal power research and development initiative.[168] Plainly, DOE has had no difficulty developing national-level environmental surveys of large-scale energy decisions, even when the precise location and nature of all site-specific impacts were not yet known. Instead, such broad overviews informed policy. An EIS for LNG export would fit well into this tradition and is certainly entirely possible using DOE's own modeling capacity, as is discussed above.

The courts have made clear, as well, that NEPA requires agencies to take a hard look at the upstream consequences of their decisions. In one recent decision, the Ninth Circuit Court of Appeals rejected the Surface Transportation Board's assertion that, when permitting a new train line serving a coal-producing area, it did not need to consider the coal production the line would doubtless make possible.[169] The agency insisted that such development was not "reasonably foreseeable," even though it relied on the coal production to determine that the train line would be financially viable.[170] The court rightly held that the agency could not permit an infrastructure project justified in large part on increasing fossil fuel production without considering those impacts in a NEPA analysis. The same analysis applies here. LNG export

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[161] Dominion Cove Point Application at 35 (Oct. 3, 2011).
[162] *See also Center for Biological Diversity v. National Highway Traffic and Safety Administration*, 538 F.3d 1172, 1200 (9th Cir. 2008) (where the impact of an agency action is uncertain, agency may not simply given that impact zero weight and fail to address it).
[163] DOE Memorandum, "Improved Decisionmaking Through the Integration of Program and Project Management with [NEPA] Compliance" (June 12, 2012).
[164] *See* DOE, Programmatic Environmental Assessment for the State Energy Conservation Program (1996).
[165] *See* 77 Fed. Reg. 44,267 (July 27, 2012).
[166] *See* 73 Fed. Reg. 72,477 (Nov. 28, 2008).
[167] *See* 73 Fed. Reg. 61,845 (Oct. 17, 2008).
[168] *See* DOE, Final Programmatic Environmental Impact Statement Clean Coal Technology Demonstration Program (1996).
[169] *Northern Plains Resource Council v. Surface Transportation Board*¸668 F.3d 1067, 1081-82 (9th Cir. 2011).
[170] *Id.*

terminals will drive new gas production and, in fact, depend upon that new production to justify their existence.

In the end, it should come as no surprise that DOE's own NEPA regulations provide that large LNG export projects will "normally require EISs."[171] When a project involves either "major operational changes (such as a major increase in the quantity of liquefied natural gas imported or exported)" or the "construction of major new facilities or the significant modification of existing facilities," an EIS is appropriate.[172] These rules, which have been in place since DOE first issued its NEPA regulations,[173] set a clear course for the agency. The applications before it now uniformly involve major increases in the quantity of LNG set for export – by many times over – and also require multi-billion dollar construction projects to create new facilities to support these facilities. An EIS, in these circumstances, is plainly mandated by DOE's own regulations.

C. DOE's National Economic Analyses Demonstrate That It Can Approach Environmental Impacts On A National Level

DOE's abdication of its environmental responsibilities is illegal and unwise. It is unjustifiable based on DOE's own modeling capabilities. It is also strikingly inconsistent with DOE's own approach to the national *economic* implications of LNG export. There, DOE has invested considerable effort in developing a comprehensive general understanding of the economic implications of LNG export, including the impacts of new production. That it can generate such an analysis at a national scale demonstrates that it can pursue the same course for environmental considerations. It should do so to ensure that policymakers and the public have a balanced view of *both* the economic and environmental impacts of exports.

The national economic analysis began, as DOE has explained to Congress, with DOE's realization, after the Sabine Pass conditional approval had issued and more LNG export applications were flooding in, that LNG exports could have real effects on the public interest.[174] DOE did not attempt to avoid grappling with these impacts just because it did not know with complete certainty exactly where production would occur. But, unlike in the environmental context, DOE correctly recognized that such uncertainties were not fatal to a proper national overview.

Instead, DOE immediately and responsibly embarked on two national studies, which were intended to help bring the national economic impacts of export into sharper focus. The first of these was the EIA report discussed above. At DOE's behest, EIA modeled a range of possible export and production scenarios, exploring combinations of different exports rate and timing

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[171] 10 C.F.R. Pt. 1021 App. D to Subpart D, § D8 & D9.
[172] *Id.*
[173] *See* 45 Fed. Reg. 20,694, 20,700 (Mar. 28, 1980).
[174] Letter from Christopher Smith, Deputy Assistant Secretary of Oil and Gas to Representative Edward Markey (Feb. 24, 2012) at 3.

and possible variations in gas supply and economic demand.[175] As a result, EIA was able to generate a range of well-supported impact predictions for these varying scenarios. This analysis uncovered important effects for DOE's consideration, including the prospect of sharp domestic gas and electricity price increases with some export scenarios. Rather than allowing uncertainty to defeat the analysis, EIA considered a range of reasonable outcomes to help better inform policy – just as NEPA requires in the environmental context.

The second study will build further on these results. According to DOE, it will look at sixteen different hypothetical export scenarios to investigate:

> (1) [t]he potential impacts of additional natural gas exports on domestic energy, consumption, production, and prices; (2) the cumulative impact on the U.S. economy, including the effect on gross domestic product, job creation balance of trade; and (3) the impact on the U.S. manufacturing sector (especially energy intensive manufacturing industries).[176]

Rather than dismissing this analysis as "impossible" because it involves some degree of uncertainty, DOE sensibly embraced the task of investigating likely national impacts under varying production scenarios. Although there is, of course, some uncertainty as to the precise effects a particular proposal will have on the economy, the major wave of export proposals will have a predictable effect which can be investigated despite uncertainty as to particular production patterns. Indeed, as noted above, export proponents rely upon induced gas production to help justify their projects.

It is thus not at all surprising that DOE felt it to be both possible and necessary to analyze the economic ramifications of these changes. Of course, such an analysis is appropriate. The surprising point, instead, is that DOE nonetheless has blinded itself to the environmental impacts of the very same production increases it is analyzing.

D. DOE Must Look at Environmental Impacts With the Same Rigor With Which It Examines Economic Impacts

This double-vision – with economics in sharp focus and environmental impacts blurred to invisibility – impermissibly skews the choice before DOE. Both economic impacts and environmental costs weigh in the public interest determination. If DOE is only willing to look at one side of the ledger, it cannot properly fulfill its obligations because it cannot understand the all the aspects of the public's interest which are implicated by export. Without a full NEPA analysis, it cannot make a sound final decision.

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[175] *See* EIA, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* at 1-2.

[176] Letter from Christopher Smith, Deputy Assistant Secretary of Oil and Gas to Representative Edward Markey at 4.

The courts have made this point clear. Very early in NEPA's history, the Atomic Energy Commission insisted that it could not forecast the environmental impacts of a power plant research program for which it had already developed an economic analysis.[177] The D.C. Circuit Court of Appeals held this position had a "hollow ring" given that the Commission was happy to use its economic analyses in "convincing Congress" to support its plans.[178] As the court held, if economic analyses can be prepared, then "in turn … parallel environmental forecasts would be accurate for use in planning how to cope with and minimize the detrimental effects attendant upon" the course the agency wishes to pursue, "and in evaluating the program's overall desirability."[179] Agencies cannot skew their analyses, or mask the costs of their actions, by examining only one side of a problem while refusing to consider the other.

The Ninth Circuit Court of Appeals corrected the same error in its coal train line case, discussed above. There, too, while insisting that coal mines triggered by a new train line were too speculative to analyze under NEPA, the agency nonetheless "relied on the coal mine development … to justify the financial soundness of the proposal" which it approved.[180] Once again, the court held that an agency may not rely on economic predictions while simultaneously refusing to acknowledge the environmental impacts of the economic activity it is permitting.

The same analysis applies, with great force, to DOE's situation here. The agency has proven willing and able to analyze the economic impacts of LNG export and is in the process of expending considerable funds to improve its forecasting. Further, in individual licensing proceedings, it is clearly open to relying on predictions of increased economic activity from gas production to justify the licensing export. The very same drilling and production forecasts it is now working up in that context could, and should, inform an analysis of the environmental impacts of those decisions. There is nothing inherently harder in saying that ten thousand new wells will produce *x* dollars in tax revenue or *y* tons of pollution than in predicting they will produce *z* new jobs. DOE cannot conduct one analysis while neglecting the other.

DOE cannot embrace sunny economic predictions while ignoring real environmental costs. Such a course is not only contrary to NEPA, but will render the public interest determination process fundamentally unreliable. DOE must tally up the benefits of export, but it must also count the costs.

E. The Need for NEPA

DOE has thus far refused to give any weight to the landscape-level changes large-scale LNG export would produce. This error is serious. Uncorrected, it will distort policy by masking the domestic consequences of export.

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177 *See Scientists' Institute*, 481 F.2d at 1096-97.
178 *Id.* at 1097.
179 *Id.*
180 *Northern Plains*, 668 F.3d at 1082.

Export proponents would, of course, prefer that these consequences go unremarked. Even as they tout the large increases in fracking that their projects will support, they insist that DOE must not and cannot even begin to account for the environmental consequences of their projects. But even if DOE ignores these impacts, American communities will feel the impacts of this production as exports ramp up. Rather than proceeding blindly while locking in these future harms, NEPA charges DOE with accounting for those impacts now, and the Natural Gas Act makes clear that it must take these harms into account as it considers the public interest.

DOE has the time it needs to do the right thing. It has already committed to Congress not to issue any further export licenses for export to non-free-trade-agreement nations until its second economic study is complete.[181] (Its decision to nonetheless finalize the in-process Sabine Pass license is a disturbing anomaly). DOE has recently announced that this economic study, originally slated for release in spring 2012, will not be released until this coming winter. It is taking the time it needs to gather meaningful economic information. It can and should do the same for environmental information.

There is no statutory deadline to issue licenses, and every reason to ensure that DOE's final decisions are as well-reasoned as possible. LNG export terminals represent billions of dollars in investment capital, and export licenses often last for decades. Before committing to this near-irrevocable investment, DOE owes it to itself and the public to take the time it needs to develop as full and careful analysis as possible.

VI. Preserving DOE's Authority to Protect the Public Interest

DOE must use its authority to prepare a proper EIS for LNG export. But, thanks to ongoing trade negotiations, this is not the only challenge DOE faces in order to protect the public interest. It must also act quickly, in coordination with Congress and the Executive, to ensure that its regulatory ability to protect the public is not inadvertently destroyed.

The problem confronting DOE is an unintended consequence of Congress's 1992 decision to speed LNG imports from Canada. To protect those imports, Congress directed that DOE *must* license LNG imports *and exports* from nations with which the U.S. has signed a free trade agreement providing for national treatment of natural gas.[182] Up to this point, this rubber stamp process has not been at issue, but that may be about to change.

The proposed Trans-Pacific Partnership (TPP) is a massive trade agreement currently under negotiation between the United States and ten other Pacific Rim nations.[183] Its influence could be even broader, however. The TPP is intended to be a "docking station" for new signatories,

[181] Letter from Christopher Smith, Deputy Assistant Secretary of Oil and Gas to Representative Edward Markey at 4.
[182] *See*15 U.S.C. § 717b(c).
[183] *See* http://www.ustr.gov/tpp.

permanently open for expansion, so it could establish an ever-expanding web of countries to which LNG *must* be exported if the market can sustain the demand.

Already, several potential signatories, including Chile and Singapore, are LNG importers and so would be able to take imports from the United States without any public interest oversight. And, critically, there is a very real possibility that Japan may join the talks and the final agreement.[184] Japan is the largest LNG importer in the world.[185]

If Japan is included in the TPP, with national treatment of natural gas, DOE will lose its discretion to condition any exports to Japan on the public interest. Such exports would be automatically licensed. Because Japan has the potential to absorb large amounts of U.S. gas, the loss of DOE's ability to carefully examine the consequences of those exports before licensing them is a serious concern. Regardless of the results of the NEPA analysis we recommend here, or of the economic studies DOE is conducting, exports would be legally mandated.

This result is not what Congress intended when it inserted the free-trade-agreement exception language in 1992. At that time, LNG export from the United States was neither possible nor contemplated. Instead, Congress was focused on removing barriers to natural gas imports from Canada.

The 1992 amendments, in fact, did not even reference export when proposed. Congressman Phil Sharp (D-IN), Chairman of the House Subcommittee on Energy and Power (and H.R. 776's original sponsor) stated that the amendments' purpose was only "deregulating Canadian natural gas imports."[186] Likewise Congressman Norman Lent (R-NY), Ranking Member of the House Committee on Energy and Commerce, explained that the amendments were "vital to assuring that U.S. regulators do not interfere with the importation of natural gas to customers in the United States."[187]Congressman Edward Markey (D-OR), who is a current skeptical voice on export, strongly supported the provisions, describing them as "important new statutory assurances that U.S. regulators will not discriminate against *imported* natural gas."[188]

Language providing for automatic approval of export applications as well as import applications in the free trade context was added in the final conference on the bill, with no recorded debate. The conference report does not justify this discussion, noting only that the final bill "includes an

[184] *See, e.g.*, Paul McBeth, National Business Review, "Pressure on Japan as Canada joins TPP talks" (June 20, 2012); ICIS Heren, "Japan Warms to U.S. Liquefaction Prospects" (Mar. 12, 2012).
[185] *See* EIA Country Statistics for Japan, http://www.eia.gov/countries/country-data.cfm?fips=JA#ng.
[186] 138 Cong. Rec. 32,075 (Oct. 5, 1992).
[187] 138 Cong. Rec. 32,083 (Oct. 5, 1992)
[188] Extension of Remarks, Cong. Rec. (Oct. 9, 1992), "Concerning Gas Import Provisions in H.R. 776, The Energy Policy Act of 1992) (emphasis added).

amended section… regarding fewer restrictions on certain natural gas imports and exports."[189] Whatever the justification for this expansion, it seems very clear that large-scale LNG exports were not on Congress's mind. The debate to this point had focused on Canadian imports, and, large-scale LNG exports were, in any event, not possible at the time. Indeed, Chairman Sharp described the final amended language as concerning "exports of natural gas *to Canada* from the United States" and affirmed (despite the seemingly open-ended final language) that "as drafted, the new fast task track process would not be available for LNG exports to, for example, Pacific rim nations other than Canada."[190]

At bottom, as DOE explained in a recent letter to Congress, "Congress's attention [in 1992] was focused on North American trade, not on the potential impact of the amendment on United States trade with other countries overseas."[191] Yet, the TPP, and the prospect of other such agreements, threatens to expand this exemption into a wholesale roll-back of DOE's regulatory discretion to protect the public interest. Should this occur, both the careful NEPA process and the public interest determination themselves would be suddenly and inappropriately truncated. In essence, the U.S. would see as much fracking activity as is necessary to support exports for the Asian market, with no direct domestic oversight of these exports.

This serious unintended consequence argues for swift remedial action. Several courses could be available. It may, first, be possible for the U.S. Trade Representative to draft the TPP to include exceptions for national treatment in natural gas, which could preserve DOE's authority. Second, Congress could certainly modify the provision to remove fast track authority for exports. Third, at a minimum, agreements that would remove DOE's discretion to regulate exports certainly should not be concluded until a full environmental impact statement for export has been completed. That report will help policymakers determine how exports should be managed – critically important information for U.S. trade negotiators before they finalize any deal that would commit the nation to exports without any further oversight.

So far, however, DOE has not taken any of these steps, and neither has the U.S. Trade Representative. In meetings and phone conversations with the Sierra Club, the Trade Representative has insisted that DOE, not the Representative, must address the issue. DOE, in turn, has placed responsibility for protecting the public interest review process back on the Trade Representative. The result is that both agencies are pointing fingers at each other, and neither is taking responsibility for addressing this serious matter. Unless they change course,or Congress or the Executive act to insist that they do so, the result may be that the U.S. gives up its ability to manage LNG exports without even thinking about it.

VII. Conclusion: A Full EIS is Needed to Inform Policymakers and the Public

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[189] H.R. Conf. Rep. 102-1018, 1992 USCCAN 2472, 2477 (Oct. 5, 1992); *see also* 138 Cong. Rec. 34,043 (Oct.8. 1992) (statement of conferees, explaining only that the final bill "has been expanded to include fewer restrictions on exports of natural gas to countries with which the United States has a Free Trade Agreement.").

[190] 38 Cong. Rec. 32,076 (Oct. 5, 1992) (emphasis added).

[191] Letter from Christopher Smith, Deputy Assistant Secretary of Oil and Gas to Representative Edward Markey (Feb. 24, 2012) at 1.

The United States is sleepwalking through one of the biggest energy policy decisions of our time. Even as billions of dollars in investment capital are marshaled to support an ever-growing wave of export proposals, the federal agencies in charge of protecting the public interest have failed even to consider the environmental implications of exporting a large amount of the domestic gas supply – including the intensified fracking needed to support exports. Meanwhile, trade negotiators risk stripping away DOE's discretion ever to properly manage these problems, even if it does finally analyze and disclose them.

No matter where one stands on the ultimate wisdom of LNG exports, it is clear that this sort of blind, piecemeal, decisionmaking is what NEPA was designed to prevent. For more than 40 years, NEPA has reflected a national commitment to transparent, democratic, and careful decisionmaking to protect communities and our environment. That commitment applies with great force to DOE's decisionmaking now, and the agency should honor it. The possible conversion of the United States into one of the world's largest LNG exporters is a matter of national importance and a key shift in environmental and economic policy. If a full NEPA analysis of all the consequences, upstream and downstream, of an agency's decisions were ever appropriate for any agency action, then an EIS is surely appropriate now, when the nation's energy future is profoundly implicated by DOE's decisions. It is time for a full programmatic environmental impact statement for LNG export.

DOE has the time and the duty to do the right thing and begin the open, public, environmental impact statement process it should have initiated at the outset. It must retreat from its dereliction of duty in the Sabine Pass environmental process, and instead extend its national review process from the economic studies it has already begun to the environmental studies it also plainly needs. Before issuing another license on a piecemeal basis, it should change course, acknowledge its responsibilities, and begin the national conversation we urgently need to have.

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Table 1. Summary of natural gas supply and disposition in the United States, 2007-2012
(billion cubic feet)

Year and Month	Gross Withdrawals	Marketed Production	Extraction Loss[a]	Dry Gas Production[b]	Supplemental Gaseous Fuels[c]	Net Imports	Net Storage Withdrawals[d]	Balancing Item[e]	Consumption[f]
2007 Total	**24,664**	**20,196**	**930**	**19,266**	**63**	**3,785**	**192**	**-203**	**23,104**
2008 Total	**25,636**	**21,112**	**953**	**20,159**	**61**	**3,021**	**34**	**2**	**23,277**
2009 Total	**26,057**	**21,648**	**1,024**	**20,624**	**65**	**2,679**	**-355**	**-103**	**22,910**
2010									
January	[R]2,210	[R]1,824	[R]87	[R]1,737	5	291	822	[R]-46	[R]2,810
February	[R]2,048	[R]1,683	[R]80	[R]1,603	5	236	628	[R]9	[R]2,481
March	[R]2,277	[R]1,865	[R]89	[R]1,776	5	219	34	[R]109	[R]2,143
April	[R]2,190	[R]1,813	86	[R]1,727	5	223	-364	[R]102	[R]1,692
May	[R]2,237	[R]1,886	90	[R]1,797	5	212	-416	[R]19	[R]1,617
June	[R]2,139	[R]1,802	86	[R]1,717	5	192	-326	[R]61	[R]1,650
July	[R]2,209	[R]1,896	[R]90	[R]1,806	[R]5	243	-231	[R]2	[R]1,826
August	[R]2,235	[R]1,918	[R]91	[R]1,827	6	221	-190	[R]16	[R]1,879
September	[R]2,238	[R]1,861	89	[R]1,772	5	202	-363	[R]21	[R]1,637
October	[R]2,357	[R]1,956	93	[R]1,863	6	199	-360	[R]-42	[R]1,665
November	[R]2,277	[R]1,893	90	[R]1,802	5	150	77	[R]-61	[R]1,973
December	[R]2,400	[R]1,984	[R]95	[R]1,890	6	217	675	[R]-73	[R]2,714
Total	**[R]26,816**	**[R]22,382**	**[R]1,066**	**[R]21,316**	**65**	**2,604**	**-13**	**[R]115**	**[R]24,087**
2011									
January	[R]2,299	[R]1,953	92	[R]1,861	[R]5	[R]236	[R]811	[R]-31	[R]2,882
February	[R]2,104	[R]1,729	[R]82	[R]1,647	[R]4	[R]186	[R]594	[R]16	[R]2,448
March	[R]2,411	[R]2,002	[R]95	[R]1,908	[R]5	[R]171	[R]151	[R]-3	[R]2,232
April	[R]2,350	[R]1,961	[R]93	[R]1,868	5	[R]151	[R]-216	[R]20	[R]1,828
May	[R]2,411	[R]2,031	[R]96	[R]1,935	[R]5	139	[R]-405	[R]-10	[R]1,663
June	[R]2,313	[R]1,954	[R]92	[R]1,862	5	[R]147	[R]-346	[R]-15	[R]1,653
July	[R]2,340	[R]2,033	[R]96	[R]1,937	5	[R]180	[R]-248	[R]3	[R]1,877
August	[R]2,370	[R]2,057	[R]97	[R]1,960	5	[R]169	[R]-249	[R]-7	[R]1,878
September	[R]2,358	[R]1,987	[R]94	[R]1,893	5	[R]125	[R]-404	[R]27	[R]1,646
October	[R]2,502	[R]2,119	[R]100	[R]2,019	5	[R]173	[R]-391	[R]-65	[R]1,741
November	[R]2,476	[R]2,076	[R]98	[R]1,978	5	[R]121	[R]-41	[R]-50	[R]2,014
December	[R]2,544	[R]2,135	[R]101	[R]2,034	[R]5	[R]163	[R]390	[R]-69	[R]2,524
Total	**[R]28,479**	**[R]24,036**	**[R]1,134**	**[R]22,902**	**[R]60**	**[R]1,962**	**[R]-354**	**[R]-185**	**[R]24,385**
2012									
January	[R]2,573	[RE]2,149	109	[RE]2,041	6	[R]151	545	[R]8	[R]2,750
February	[R]2,378	[RE]1,989	102	[RE]1,887	5	[R]140	459	[R]10	[R]2,501
March	[R]2,537	[RE]2,123	109	[RE]2,014	6	124	-39	[R]19	[R]2,124
April	[R]2,445	[RE]2,065	105	[RE]1,960	[R]4	120	-137	[R]8	[R]1,956
May	[R]2,530	[RE]2,139	108	[RE]2,031	4	[R]126	-283	[R]-8	[R]1,871
June	[R]2,420	[RE]2,061	103	[RE]1,958	5	134	-230	[R]0	[R]1,868
July	[R]2,456	[RE]2,137	106	[RE]2,031	5	162	-134	[R]7	[R]2,071
August	[R]2,372	[RE]2,128	107	[RE]2,021	5	[R]142	-168	[R]1	[R]2,001
September	[R]2,428	[RE]2,086	109	[RE]1,978	5	[R]121	[R]-291	[R]-14	[R]1,798
October	2,571	[E]2,172	114	[E]2,058	5	113	-241	-46	1,888
2012 10-Month YTD	**24,710**	**[E]21,051**	**1,073**	**[E]19,978**	**51**	**1,332**	**-520**	**-14**	**20,827**
2011 10-Month YTD	**23,459**	**19,825**	**936**	**18,890**	**50**	**1,677**	**-704**	**-65**	**19,847**
2010 10-Month YTD	**22,139**	**18,505**	**882**	**17,623**	**53**	**2,238**	**-765**	**250**	**19,399**

[a] Monthly extraction loss is derived from sample data reported by gas processing plants on Form EIA-816, "*Monthly Natural Gas Liquids Report*," and Form EIA-64A, "*Annual Report of the Origin of Natural Gas Liquids Production*."

[b] Equal to marketed production minus extraction loss.

[c] Supplemental gaseous fuels data are collected only on an annual basis except for the Dakota Gasification Co. coal gasification facility which provides data each month. The ratio of annual supplemental fuels (excluding Dakota Gasification Co.) to the sum of dry gas production, net imports, and net withdrawals from storage is calculated. This ratio is applied to the monthly sum of these three elements. The Dakota Gasification Co. monthly value is added to the result to produce the monthly supplemental fuels estimate.

[d] Monthly and annual data for 2007 through 2010 include underground storage and liquefied natural gas storage. Data for January 2011 forward include underground storage only. See Appendix A, Explanatory Note 5, for discussion of computation procedures.

[e] Represents quantities lost and imbalances in data due to differences among data sources. Net imports and balancing item for 2007-2009 excludes net intransit deliveries. These net intransit deliveries were (in billion cubic feet): 44 for 2011; -9 for 2010; -14 for 2009; -31 for 2008; and -6 for 2007. See Appendix A, Explanatory Note 7, for full discussion.

[f] Consists of pipeline fuel use, lease and plant fuel use, vehicle fuel, and deliveries to consuming sectors as shown in Table 2.

[R] Revised data.

[E] Estimated data.

[RE] Revised estimated data.

Notes: Data for 2007 through 2010 are final. All other data are preliminary unless otherwise indicated. Geographic coverage is the 50 States and the District of Columbia. Totals may not equal sum of components because of independent rounding.

Sources: 2007-2010: Energy Information Administration (EIA), *Natural Gas Annual 2011*. January 2011 through current month: Form EIA-914, "*Monthly Natural Gas Production Report*"; Form EIA-857, "*Monthly Report of Natural Gas Purchases and Deliveries to Consumers*"; Form EIA-191M, "*Monthly Underground Gas Storage Report*"; EIA computations and estimates; and Office of Fossil Energy, "*Natural Gas Imports and Exports*." See Table 7 for detailed source notes for Marketed Production. See Appendix A, Notes 3 and 4, for discussion of computation and estimation procedures and revision policies.

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OFFICE OF
ECOSYSTEMS,
TRIBAL AND PUBLIC
AFFAIRS

October 29, 2012

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1A
Washington, DC 20426

Re: SCOPING COMMENTS – The Jordan Cove Energy Project LP and the Pacific Connector Gas Pipeline Notice of Intent to Prepare an Environmental Impact Statement. EPA Region 10 Project Number: 12-0042-FRC and 12-0049-AFS. *FERC Docket Nos. PF12-7-000 and PF12-17-000.*

Dear Secretary Bose:

The U.S. Environmental Protection Agency (EPA) would like to provide detailed scoping comments in response to the Federal Energy Regulatory Commission's (FERC's) August 13, 2012 Notice of Intent (NOI) to prepare an Environmental Impact Statement (EIS) for the Jordan Cove Energy Project and Pacific Connector Gas Pipeline. With these comments we are also responding to the September 21, 2012 NOI to prepare an EIS issued by the Forest Service and BLM for Right of Way grants and land use amendments related to the Pacific Connector Gas Pipeline. These comments were prepared in accordance with our authorities pursuant to the National Environmental Policy Act (NEPA), Section 309 of the Clean Air Act, the Clean Water Act, and our responsibilities as a Cooperating Agency. We appreciate the opportunity for early involvement at this step of the NEPA process.

The Clean Air Act Section 309 directs the EPA to review and comment in writing on the environmental impacts resulting from certain proposed actions of other federal agencies and the adequacy of the Draft EIS in meeting the procedural and public disclosure requirements in accordance with NEPA. Please see the EPA's review criteria for rating Draft EISs at the EPA web site: (http://www.epa.gov/compliance/nepa/comments/ratings.html). Our review authorities under Section 309 are independent of our responsibilities as a Cooperating Agency for this EIS.

The FERC's NOI describes Jordan Cove's proposal to construct and operate an LNG export terminal on the North Spit of Coos Bay. The terminal would have the capacity to produce approximately six million metric tons per annum of LNG (equivalent to 0.9 billion cubic feet per day [Bcf/d] of natural gas). Facilities would include:

- 7.3 mile long waterway in Coos Bay for about 80 LNG carriers per year;
- 0.3 mile long access channel and marine berth;
- A cryogenic transfer pipeline;
- Two 160,000 cubic meter LNG storage tanks;
- Four liquefaction trains (each with a capacity of 1.5 million metric tons per annum);
- Two feed gas and dehydration trains with a combined throughput of 1Bcf/d of natural gas; and
- A 350 megawatt South Dunes power plant.

The attendant Pacific Connector pipeline would be 36 inches in diameter and about 230 miles long, extending from interconnections with other interstate pipelines near Malin, Oregon to the Jordan Cove LNG terminal at Coos Bay. The pipeline would have a design capacity of 0.9 Bcf/d of natural gas. Related facilities include:

- Two meter stations at the interconnections with the existing Gas Transmission Northwest and Ruby pipelines near Malin, Oregon;
- A 23,000 horsepower compressor station adjacent to the GTN and Ruby meter stations;
- A meter station at the interconnection with the existing Williams Northwest Pipeline system near Myrtle Creek, Oregon; and
- A meter station at the Jordan Cove terminal.

The enclosed scoping comments were prepared based on our review of the NOIs referenced above and the draft Resource Reports 1 and 10. Our comments reflect a broad range of issues that we believe to be significant and warrant treatment in the EIS. Among these issues is the range of alternatives. We encourage the FERC to consider a broad range of reasonable alternatives in the EIS that are capable of meeting the project's purpose and need and we look forward to continued discussions on this matter. For example, we would be interested in discussing whether an intertie with the Williams pipeline could be considered as a reasonable alternative and examined in the EIS. We also recommend expanding the scope of analysis to capture the non-jurisdictional South Dunes power plant as well as indirect effects related to gas drilling and combustion.

As a Cooperating Agency, we look forward to continued communication with your office throughout the development of the EIS, and we are available to work with FERC to review and comment on preliminary sections of the document. If you have any questions regarding our scoping comments, please do not hesitate to contact me at (206) 553-1601 or by electronic mail at reichgott.christine@epa.gov, or you may contact Teresa Kubo of my staff in the Oregon Operations Office at (503) 326-2859 or by electronic mail at kubo.teresa@epa.gov. We look forward to our continued coordination and involvement in this project.

Sincerely,

Christine B. Reichgott

Christine B. Reichgott, Manager
Environmental Review and Sediment Management Unit

Enclosure

U.S. Environmental Protection Agency
Detailed Scoping Comments to Address the Federal Energy Regulatory Commission's
Notice of Intent to Prepare an Environmental Impact Statement
for the Jordan Cove Energy Project and Pacific Connector Gas Pipeline
FERC Docket Nos. PF12-7-000 and PF12-17-000

Purpose and Need
The EIS should include a clear and concise statement of the underlying purpose and need for the proposed project, consistent with the implementing regulations for NEPA (see 40 CFR 1502.13). In presenting the purpose and need for the project, the EIS should reflect not only the FERC's purpose, but also the broader public interest and need.

In supporting the statement of purpose and need, we recommend discussing the proposed project in the context of the larger energy market, including existing export capacity and export capacity under application to the Department of Energy, and clearly describe how the need for the proposed action has been determined.

Alternatives Analysis
NEPA requires evaluation of reasonable alternatives, including those that may not be within the jurisdiction of the lead agency[1]. A robust range of alternatives will include options for avoiding significant environmental impacts. The EIS should "rigorously explore and objectively evaluate all reasonable alternatives"[2] by developing a screening process. The screening process should rate each alternative against a set of pre-determined criteria. Each alternative should then be analyzed for its level of impact on a resource (e.g. no effect, negligible effect, minor effect, major effect, significant effect). Only the alternative that effectively meets or best meets all of the screening criteria should be recommended as the preferred alternative. The EIS should provide a clear discussion of the reasons for the elimination of alternatives which are not evaluated in detail.

We appreciate that Resource Report 10 for the Pacific Connector Pipeline Project (Section 10.4) evaluates system alternatives for the pipeline route. In the EIS we would like to see a more rigorous exploration of those alternatives. The basis for conclusions reached in Section 10.4.4 is not clear. Specifically, it is not clear how it was determined that an intertie with the Williams pipeline would result in prohibitive costs, associated rates, and environmental impacts. Because such a route would be significantly shorter than the currently proposed route, we recommend that the EIS give this route alternative additional consideration.

Non-Jurisdictional Facilities
In Section 1.9.2 of Resource Report 1, it is determined that as a non-jurisdictional facility, the South Dunes Power Plant does not need to be included in the DEIS. This assertion is based on the Report's interpretation of FERC's NEPA regulations at 18 CFR § 380.12(c)(2)(ii). Per those regulations, four factors are applied to determine the need for FERC to do an environmental review of project-related non-jurisdictional facilities. These factors include:

[1] 40 CFR 1502.14(c)
[2] 40 CFR 1502.14(a)

1. Whether or not the regulated activity comprises "merely a link" in a corridor type project (such as a transportation or utility transmission project);
2. Whether there are aspects of the non-jurisdictional facility in the immediate vicinity of the regulated activity which affect the location and configuration of the regulated activity;
3. The extent to which the entire project will be within the FERC's jurisdiction; and
4. The extent of cumulative federal control and responsibility.

Resource Report 1 considers each of these factors and finds that FERC environmental review is not warranted. We believe the Resource Report's interpretation of these criteria to be overly narrow. In particular, because the South Dunes Power Plant and the Jordan Cove Export Facility are interdependent and interconnected, we believe the power plant inherently affects the location of the export facility. Without the power supplied by the power plant, the export facility cannot be built; and without the export facility, there is no need for the power plant to be built.

In addition, CEQ NEPA regulations at 40 CFR 1508.25(a)(1) address connected actions, and clearly call for actions to be considered within the scope of an EIS if they "cannot or will not proceed unless other actions are taken previously or simultaneously" or " are interdependent parts of a larger action and depend on the larger action for their justification"[3]. It is clear from Resource Report 1 that the Power Plant is being constructed for the purpose of supporting the Project. The Power Plant is not being constructed for a purpose independent from the Project. On the contrary, it is being constructed specifically to support the power needs of the Project.

Section 40 C.F.R. 1508.25(a)(3) states that two actions should be evaluated in a single EIS when they are "similar actions, which when viewed with other reasonably foreseeable or proposed agency actions have similarities that provide a basis for evaluating their environmental consequences together, such as common timing and geography." The Power Plant will be built in a timeframe that will coincide with the Project's power needs. The Power Plant is specifically sited in proximity to the Project so that it can operate in conjunction with the Project. Because the South Dunes Power Plan and the Jordan Cove Export Facility are interdependent and interconnected, the locations of the two were selected to enhance the effectiveness of their co-operation. Therefore, we recommend that the FERC include the South Dunes Power Plant within the scope of the EIS.

Environmental Consequences

According to 40 CFR Part 1502.1, an Environmental Impact Statement, "...shall provide full and fair discussion of significant environmental impacts and shall inform decision makers and the public of the reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the environment." In order to facilitate a full and fair discussion on significant environmental issues, we encourage the FERC to establish thresholds of significance for each resource of concern, and to analyze environmental consequences in a clear, repeatable manner. For each action, a series of questions should be considered: 1) What is the action? 2) What is the intensity or extent of impacts? 3) Based on identified thresholds, is that significant? If an impact of the action is significant, then the EIS must contain appropriate mitigation measures.

[3] 40 CFR 1508.25(a)(1)(ii) and (iii)

Water Quality
In order to adequately address water quality issues, the EPA recommends the EIS identify water bodies likely to be impacted by the project, the nature of the potential impacts, and the specific discharges and pollutants likely to impact those waters (addressing both Section 402 and 404 discharges and potential impairments to water quality standards). We also recommend the EIS disclose information regarding relevant Total Maximum Daily Load allocations, the water bodies to which they apply, water quality standards and pollutants of concern.

Clean Water Act Section 303(d) listed waters should not be further degraded. If additional pollutant loading is predicted to occur to a 303(d) listed stream as a result of a project, the EIS should include measures to control existing sources of pollution to offset pollutant additions.

Consider implementing watershed or aquatic habitat restoration activities to compensate for past impacts to water resources, particularly in watersheds with 303(d) listed waters where development may have contributed to impairments through past channelization, riverine or floodplain encroachments, sediment delivery during construction, and other activities that may have affected channel stability, water quality, aquatic habitat, and designated waterbody uses. Provisions for antidegradation of water quality apply to water bodies where water quality standards are presently being met. We recommend the EIS describe how antidegradation provisions would be met.

Hydrostatic Test Water
Hydrostatic testing of pipelines and tanks will be required to verify their integrity. We recommend that the EIS identify the water sources and withdrawal rates that would be required for hydrostatic testing. We recommend that the EIS identify and describe the location of these water sources (surface areas, depth, volumes, withdrawal rates, and project requirements). For each water source, we recommend that the EIS discuss the presence of any anadromous and/or resident fish species, including a discussion of any direct and cumulative impacts to fisheries resources. In addition, we recommend that the locations of discharge to land and/or surface waters, and discharge methods be specified in the EIS. Emphasis should be placed on minimizing interbasin transfers of water to the maximum extent practicable in order to minimize the risk of mobilizing invasive species. We recommend that the EIS describe the mitigation measures and control devices that would be implemented to minimize environmental impacts.

Source Water Protection
Public drinking water supplies and/or their source areas often exist in many watersheds. Source water areas may exist within watersheds where the pipeline and associated facilities would be located. Source waters are streams, rivers, lakes, springs, and aquifers used as supply for drinking water. Source water areas are delineated and mapped by the states for each federally-regulated public water system. The 1996 amendments to the Safe Drinking Water Act require federal agencies to protect sources of drinking water for communities. As a result, state agencies have been delegated responsibility to conduct source water assessments and provide a database of information about the watersheds and aquifers that supply public water systems.

Since construction, operation, and maintenance of a buried natural gas pipeline may impact sources of drinking water, the EPA recommends that the FERC work with the Oregon Department of Environmental Quality to identify source water protection areas. Typical databases contain information about the watersheds and aquifer recharge areas, the most sensitive zones within those areas, and the numbers and types of potential contaminant sources for each system. We recommend that the EIS identify source water protection areas within the project area, activities (e.g., trenching and excavation, water withdrawal, etc.) that could potentially affect source water areas, potential contaminants that may result from the proposed project and mitigation measures that would be taken to protect the source water protection areas.

Wetlands and Aquatic Habitats

In the EIS, we recommend describing aquatic habitats in the affected environment (e.g., habitat type, plant and animal species, functional values, and integrity) and the environmental consequences of the proposed alternatives on these resources. Impacts to aquatic resources should be evaluated in terms of the areal (acreage) or linear extent to be impacted and by the functions they perform.

The proposed activities will require a Clean Water Act Section 404 permit from the Army Corps of Engineers. For wetlands and other special aquatic sites, the Section 404(b) (1) guidelines establish a presumption that upland alternatives are available for non-water dependent activities. The 404(b)(1) guidelines require that impacts to aquatic resources be (1) avoided, (2) minimized, and (3) mitigated, in that sequence. We recommend the EIS discuss in detail how planning efforts (and alternative selection) conform with Section 404(b)(1) guidelines sequencing and criteria. In other words, we request the FERC show that impacts to wetlands and other special aquatic sites have been avoided to the maximum extent practicable. The EPA also recommends the EIS discuss alternatives that would avoid wetlands and aquatic resource impacts from fill placement, water impoundment, construction, and other activities before proceeding to minimization/ mitigation measures.

The EPA recommends the EIS describe all waters of the U.S. that could be affected by the project alternatives, and include maps that clearly identify all waters within the project area. We also request the document include data on acreages and channel lengths, habitat types, values, and functions of these waters. As discussed above, projects affecting waters of the U.S. may need to comply with CWA Section 404 requirements. If project alternatives involve discharge of dredged or fill material into waters of the U.S., the EIS should include information regarding alternatives to avoid the discharges or how potential impacts caused by the discharges would be minimized and mitigated. This mitigation discussion would include the following elements:

- acreage and habitat type of waters of the U.S. that would be created or restored;
- water sources to maintain the mitigation area;
- re-vegetation plans, including the numbers and age of each species to be planted, as well as special techniques that may be necessary for planting;
- maintenance and monitoring plans, including performance standards to determine mitigation success;
- size and location of mitigation zones;
- mitigation banking and/or in lieu fees where appropriate;
- parties that would be ultimately responsible for the plan's success; and
- contingency plans that would be enacted if the original plan fails.

Where possible, mitigation should be implemented in advance of the impacts to avoid habitat losses due to the lag time between the occurrence of the impact and successful mitigation.

Water Body Crossing
As noted in Section 1.6.4 of Resource Report 1, the PCGP Project would affect 383 waterbodies. We appreciate the effort that the FERC and the proponent have made in the past to establish appropriate water body crossing procedures. We encourage the FERC to build upon these efforts through the use of risk screening tools that have been developed since the FEIS for the Jordan Cove LNG Export Facility was finalized. Specifically, we encourage the use of 1) a Project Screening Risk Matrix to evaluate the potential risks posed by the project to species or habitat, and to prioritize reviews; 2) a Project Information Checklist to evaluate whether all the necessary information is available to facilitate critical and thorough project evaluation; and 3) the River Restoration Assessment Tool, which can promote consistent and comprehensive project planning and review. These tools are available at www.restorationreview.com.

Maintenance Dredging
Resource Report 1 (Section 1.1.2.2) states that maintenance dredging requirements have been revised based on new modeling. The new estimate is that approximately 37,700 cubic yards would need to be dredged for maintenance at year 1. At year 10 that volume would be expected to decrease to 34,600 cubic yards. This is a substantial reduction from estimates of maintenance dredging included in the FEIS for the Jordan Cove Import Facility. We continue to request the inclusion of an analysis supporting the assertion that the capacity of the EPA's Ocean Disposal Site F would be unaffected by the addition of maintenance dredging material over the next 20 years in the EIS. In order for the EPA to concur with the issuance of a Section 103 permit, this will need to be clearly demonstrated.

In addition, we encourage the development of a Maintenance Dredging Plan in consultation with the U.S. Army Corps of Engineers and the EPA. That plan, including disposal, should be consistent with the site management and monitoring plan and reviewed and approved as part of the Section 103 permit process.

Air Quality
The EPA recommends the EIS provide a detailed discussion of ambient air conditions (baseline or existing conditions), National Ambient Air Quality Standards, criteria pollutant nonattainment areas, and potential air quality impacts of the proposed project (including cumulative and indirect impacts). Such an evaluation is necessary to assure compliance with State and Federal air quality regulations, and to disclose the potential impacts from temporary or cumulative degradation of air quality. The EPA recommends the EIS describe and estimate air emissions from potential construction, operation, and maintenance activities, including emissions associated with LNG carriers at berth. The analysis should also include assumptions used regarding the types of fuel burned and/or the ability for carriers to utilize dockside power (i.e. cold ironing). Emissions at berth are of particular relevance because the deep draft LNG carriers would be required to remain docked between high tides. We also recommend proposing mitigation measures in the EIS to address identified emissions impacts.

Fugitive Dust Emissions
Fugitive dust may contain small airborne particles that have the potential to adversely affect human health and the environment. The EPA defines fugitive dust as "particulate matter that is generated or emitted from open air operations (emissions that do not pass through a stack or a vent)". The most common forms of particulate matter (PM) are known as PM_{10} and $PM_{2.5}$ (particulate matter size less than 10 and 2.5 microns, respectively).

Sources of fugitive dust from this project may include unpaved gravel roads and facility pads, and clearing and construction sites. Effects of fugitive dust to the natural environment may include visibility reduction and haze, surface water impacts, impacts to wetlands, and reduction in plant growth. Fugitive dust may pose a human health risk due to chronic exposure in areas with vulnerable populations, such as infants and the elderly. The EPA recommends the EIS evaluate the magnitude and significance of fugitive dust emissions resulting from this project and potential impacts on human health.

We also recommend that a Dust Control Plan be developed and included as an appendix to the EIS. This plan should include provisions for monitoring fugitive dust during construction and operations, and implementing measures to reduce fugitive dust emissions, such as wetting the source material, installing barriers to prevent dust from leaving the source area, and halting operations during high wind events. We recommend that the EIS identify mitigation measures to avoid and minimize potential adverse impacts to the natural and human environment.

Biological Resources, Habitat and Wildlife

The EPA recommends the EIS identify all petitioned and listed threatened and endangered species under the Endangered Species Act, as well as critical habitat that might occur within the project area. We also recommend the EIS identify and quantify which species or critical habitat might be directly, indirectly, or cumulatively affected by each alternative and mitigate impacts to those species. The EPA recommends that the FERC continue to work with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service. The EPA also recommends that the FERC continue to coordinate with the Oregon Department of Fish and Wildlife to ensure that State sensitive species are adequately addressed within the analysis and that current and consistent surveying, monitoring, and reporting protocols are applied in protection and mitigation efforts.

The EPA recommends the EIS also identify species listed under the Marine Mammal Protection Act. Marine barge/vessel traffic may result in potential conflicts with threatened and/or endangered marine mammals and their migration patterns and routes. We also recommend that the EIS describe the barge/vessel traffic schedule, patterns and marine transportation routes, as well as the migration period, patterns, and routes of potentially affected marine mammals. The direct, indirect and cumulative impacts from barge/vessel traffic on marine mammals, threatened and endangered species, critical habitats, and subsistence resources should be analyzed in the EIS.

Land Use Impacts

Land use impacts would include, but not be limited to, disturbance of existing land uses within construction work areas during construction and creation of permanent right-of-ways for construction, operations, and maintenance of the pipeline and above ground facilities. The EPA recommends the EIS document all land cover and uses within the project corridor, impacts by the project to the land cover and uses, and mitigation measures that would be implemented to reduce the impacts.

The primary impact of construction on forests and other open land use types would be the removal of trees, shrubs, and other vegetation. Although these can be regenerated or replanted, their re-establishment can take up to 20 years or more, making the construction impacts to these resources long term and in some cases permanent. The impact on forest land use, for example, in the permanent right-of-way areas would be a permanent change to open land. We recommend the EIS describe the impacts to forest and open land use types, indicate if the impacts would be permanent or temporary, and state measures that would be taken to compensate landowners for loss of their resources because of the project.

If the project would cross sensitive areas then the EIS should specify the areas, indicate impacts to the areas, and document any easement conditions for use of the areas, including mitigation measures.

Invasive Species

The establishment of invasive nuisance species has become an issue of environmental and economic significance. The EPA recommends consideration of impacts associated with invasive nuisance species consistent with *E.O. 13112 Invasive Species*. In particular, construction activities associated with buried pipelines which disturb the ground may expose areas and could facilitate propagation of invasive species. Mitigation, monitoring and control measures should be identified and implemented to manage establishment of invasive species throughout the entire pipeline corridor right-of-way. We recommend that the EIS include a project design feature that calls for the development of an invasive species management plan to monitor and control noxious weeds, and to utilize native plants for restoration of disturbed areas after construction.

If pesticides and herbicides will be applied during construction, operation, and maintenance of the project, we recommend that the EIS address any potential toxic hazards related to the application of the chemicals, and describe what actions will be taken to assure that impacts by toxic substances released to the environment will be minimized.

Ballast water from barges/vessels is a major source of introducing non-native species into the marine ecosystems where they would not otherwise be present. Non-native species can adversely impact the economy, the environment, or cause harm to human health. Impacts may include reduction of biodiversity of species inhabiting coastal waters from competition between non-native and native species for food and resources. We recommend that the EIS discuss potential impacts from non-native invasive species associated with ballast water and identify mitigation measures to minimize adverse impacts to the marine environment and human health.

Hazardous Materials/Hazardous Waste/Solid Waste

The EPA recommends EIS address potential direct, indirect, and cumulative impacts of hazardous waste from construction and operation of the proposed project. The document should identify projected hazardous waste types and volumes, and expected storage, disposal, and management plans. It should identify any hazardous materials sites within the project's study area and evaluate whether those sites would impact the project in any way.

Seismic and Other Risks

Construction and operation of the proposed facility and pipeline may cause or be affected by increased seismicity (earthquake activity) in tectonically active zones. We recommend that the EIS identify potentially active and inactive fault zones where the proposed pipeline may cross. This analysis should discuss the potential for seismic risk and how this risk will be evaluated, monitored, and managed. A map depicting these geologic faults should be included in the EIS. The construction of the proposed project must use appropriate seismic design and construction standards and practices. Ground movement on these faults can cause a pipeline to rupture, resulting in discharge of gas and subsequent explosion. Particular attention should be paid to areas where the pipeline may cross areas with high population densities. Mitigation measures should be identified in the EIS to minimize effects on the pipeline due to seismic activities.

Blasting Activities

During project construction, blasting may be required in certain areas along the pipeline route corridor and adjacent facilities, resulting in increased noise and related effects to local residents, and disruption and displacement of bird and wildlife species. We recommend that the EIS discuss where blasting in the project area would be required, blasting methods that would be used, and how blasting effects would be controlled and mitigated. Noise levels in the project area should be quantified and the effects of blasting to the public and to wildlife should also be evaluated in the EIS. We recommend that a Blasting Management Plan be developed and the environmental impacts evaluated in the EIS.

National Historic Preservation Act

Consultation for tribal cultural resources is required under Section 106 of the National Historic Preservation Act (NHPA). Historic properties under the NHPA are properties that are included in the National Register of Historic Places or that meet the criteria for the National Register. Section 106 of the NHPA requires a federal agency, upon determining that activities under its control could affect historic properties, consult with the appropriate State Historic Preservation Officer /Tribal Historic Preservation Officer. Under NEPA, any impacts to tribal, cultural, or other treaty resources must be discussed and mitigated. Section 106 of the NHPA requires that federal agencies consider the effects of their actions on cultural resources, following regulation in 36 CFR 800.

Environmental Justice and Impacted Communities

In compliance with NEPA and with Executive Order (EO) 12898 on Environmental Justice, actions should be taken to conduct adequate public outreach and participation that ensures the public and Native American tribes understand the possible impacts to their communities and trust resources.

EO 12898 requires each Federal agency to identify and address disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations, low-income populations, and Native American tribes.[4] The EPA also considers children, the disabled, the elderly, and those of limited English proficiency to be potential Environmental Justice communities due to their unique vulnerabilities.

According to the Council on Environmental Quality, when determining whether environmental effects are disproportionately high and adverse, agencies should consider the following factors: [5]

- Whether environmental effects are or may be having an adverse impact on minority populations, low-income populations, or Indian tribes that appreciably exceeds or is likely to appreciably exceed those on the general population or other appropriate comparison group
- Whether the disproportionate impacts occur or would occur in a minority population, low-income population, or Indian tribe affected by cumulative or multiple adverse exposures from environmental hazards

[4] EO 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-income Populations. February 11, 1994.

[5] http://ceq.hss.doe.gov/nepa/regs/ej/justice.pdf

Socioeconomic Impacts
Council on Environmental Quality Regulations at 40 CFR 1500-1508 state that the "human environment" is to be "interpreted comprehensively" to include "the natural and physical environment and the relationship of people with that environment" (40 CFR 1508.14). Consistent with this direction, agencies need to assess not only "direct" effects, but also "aesthetic, historic, cultural, economic, social, or health" effects, "whether direct, indirect, or cumulative" (40 CFR 1508.8).

Social impact assessment variables point to measurable change in human population, communities, and social relationships resulting from a development project or policy change. We suggest that the EIS analyze the following social variables:

- Population Characteristics
- Community and Institutional Structures
- Political and Social Resources
- Individual and Family Changes
- Community Resources

Impacts to these social variables should be considered for each stage of the project (development, construction, operation, decommissioning). With regard to the construction and operation phase of the project, we recommend the analysis give consideration to how marine traffic might change, and how this may affect commercial or recreational use on the bay and travel over the bar.

Greenhouse Gas (GHG) Emissions
On February 18, 2010, the CEQ issued draft guidance to Federal Agencies on analyzing the effects of Greenhouse Gas (GHG) emissions and climate change when describing the environmental effects of a proposed agency action in accordance with NEPA[6].

CEQ's draft guidance defines GHG emissions in accordance with Section 19(i) of *E.O. 13514 Federal Leadership in Environment, Energy, and Economic Performance (October 5, 2009)* to include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorcarbon (HFCs), perfluorcarbon (PFCs), and sulfurhexafluoride (SF_6). Because CO_2 is the reference gas for climate change based on their potential to absorb heat in the atmosphere, measures of non-CO_2 GHGs should be reflected as CO_2-equivalent (CO_2-e) values.

The EPA supports evaluation and disclosure of GHG emissions and climate change effects resulting from the proposed project during all project phases, including (1) pre-construction (e.g., transportation, mobilization, and staging), (2) construction, (3) operation, (4) maintenance, and (5) decommissioning. We recommend that the GHG emission accounting/inventory include each proposed stationary source (e.g., power plant, liquefaction facility, compressor and metering stations, etc.) and mobile emission source (e.g., heavy equipment, supply barges, rail transports, etc.). We also recommend that the EIS establish reasonable spatial and temporal boundaries for this analysis, and that the EIS quantify and disclose the expected annual direct and indirect GHG emissions for the proposed action. In the analysis of direct effects, we recommend that the EIS quantify cumulative emissions over the life of the project, discuss measures to reduce GHG emissions, including consideration of reasonable alternatives

[6] See http://ceq.hss.doe.gov/current_developments/new_ceq_nepa_guidance.html

We recommend that the EIS consider mitigation measures and reasonable alternatives to reduce action-related GHG emissions, and include a discussion of cumulative effects of GHG emissions related to the proposed action. We recommend that this discussion focus on an assessment of annual and cumulative emissions of the proposed action and the difference in emissions associated with the alternatives.

In addition, greenhouse gas emission sources in the petroleum and natural gas industry are required to report GHG emissions under 40CFR Part 98 (subpart W), the Greenhouse Gas Reporting Program. Consistent with draft CEQ guidance[5], we recommend that this information be included in the EIS for consideration by decision makers and the public. Please see http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

Climate Change
Scientific evidence supports the concern that continued increases in greenhouse gas emissions resulting from human activities will contribute to climate change. Global warming is caused by emissions of carbon dioxide and other heat-trapping gases. On December 7, 2009, the EPA determined that emissions of GHGs contribute to air pollution that "endangers public health and welfare" within the meaning of the Clean Air Act. Higher temperatures and increased winter rainfall will be accompanied by a reduction in snow pack, earlier snowmelts, and increased runoff. Some of the impacts, such as reduced groundwater discharge, and more frequent and severe drought conditions, may impact the proposed projects. The EPA recommends the EIS consider how climate change could potentially influence the proposed project, specifically within sensitive areas, and assess how the projected impacts could be exacerbated by climate change.

Coordination with Tribal Governments
Executive Order 13175, Consultation and Coordination with Indian Tribal Governments (November 6, 2000), was issued in order to establish regular and meaningful consultation and collaboration with tribal officials in the development of federal policies that have tribal implications, and to strengthen the United States government-to-government relationships with Indian tribes. The EIS should describe the process and outcome of government-to-government consultation between the FERC and tribal governments within the project area, issues that were raised, and how those issues were addressed in the selection of the proposed alternative.

Indirect Impacts
Per CEQ regulations at CFR 1508.8(b), the indirect effects analysis "may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems." The 2012 report from the Energy Information Administration[7] states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report goes on to say that about three-quarters of that increase production would be from shale resources. We believe it is appropriate to consider available information about the extent to which drilling activity might be stimulated by the construction of an LNG export facility on the west coast, and any potential environmental effects associated with that drilling expansion.

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[7] Energy Information Administration, Effects of Increased Natural Gas Exports on Domestic Energy Markets, 6 (January 2012) available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf

Cumulative Impacts
The cumulative impacts analysis should identify how resources, ecosystems, and communities in the vicinity of the project have already been, or will be affected by past, present, or future activities in the project area. These resources should be characterized in terms of their response to change and capacity to withstand stresses. Trends data should be used to establish a baseline for the affected resources, to evaluate the significance of historical degradation, and to predict the environmental effects of the project components.

For the cumulative impacts assessment, we recommend focusing on resources of concern or resources that are "at risk" and /or are significantly impacted by the proposed project, before mitigation. For this project, the FERC should conduct a thorough assessment of the cumulative impacts to aquatic and biological resources (including plover habitat), air quality, and commercial and recreational use of the bay. We believe the EIS should consider the Oregon Gateway Marine Terminal Complex as described by the Port of Coos Bay (http://www.portofcoosbay.com/orgate.htm) as reasonably foreseeable for the purposes of cumulative effects analysis. We recognize that uncertainty about future development of the North Spit remains, but we believe the stated aspirations of the Port and the Oregon Department of State Lands' 2011 issuance of a removal-fill permit for the development of an access channel and multi-purpose vessel slip provide sufficient reason for including the marine terminal complex in the effects analysis.

The EPA also recommends the EIS delineate appropriate geographic boundaries, including natural ecological boundaries, whenever possible, and should evaluate the time period of the project's effects. For instance, for a discussion of cumulative wetland impacts, a natural geographic boundary such as a watershed or sub-watershed could be identified. The time period, or temporal boundary, could be defined as from 1972 (when the Clean Water Act established section 404) to the present.

Please refer to CEQ's "Considering Cumulative Effects Under the National Environmental Policy Act"[8] and the EPA's "Consideration of Cumulative Impacts in EPA Review of NEPA Documents"[9] for assistance with identifying appropriate boundaries and identifying appropriate past, present, and reasonably foreseeable future projects to include in the analysis.

Mitigation and Monitoring
On February 18, 2010, CEQ issued draft guidance on the Appropriate Use of Mitigation and Monitoring. This guidance seeks to enable agencies to create successful mitigation planning and implementation procedures with robust public involvement and monitoring programs[10].

We recommend that the EIS include a discussion and analysis of proposed mitigation measures and compensatory mitigation under CWA §404. The EIS should identify the type of activities which would require mitigation measures either during construction, operation, and maintenance phases of this project. To the extent possible, mitigation goals and measureable performance standards should be identified in the EIS to reduce impacts to a particular level or adopted to achieve an environmentally preferable outcome.

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[8] http://ceq.hss.doe.gov/nepa/ccenepa/ccenepa.htm
[9] http://www.epa.gov/compliance/resources/policies/nepa/cumulative.pdf
[10] http://ceq.hss.doe.gov/current_developments/docs/Mitigation_and_Monitoring_Guidance_14Jan2011.pdf

Mitigation measures could include best management practices and options for avoiding and minimizing impacts to important aquatic habitats and to compensate for the unavoidable impacts. Compensatory mitigation options could include mitigation banks, in-lieu fee, preservation, applicant proposed mitigation, etc. and should be consistent with the *Compensatory Mitigation for Losses of Aquatic Resources; Final Rule* (33 CFR Parts 325 and 332 and 40 CFR Part 230). A mitigation plan should be developed in compliance with 40 CFR Part 230 Subpart J 230.94, and included in the EIS.

An environmental monitoring program should be designed to assess both impacts from the project and that mitigation measures being implemented are effective. We recommend the EIS identify clear monitoring goals and objectives, such as what parameters are to be monitored, where and when monitoring will take place, who will be responsible, how the information will be evaluated, what actions (contingencies, triggers, adaptive management, corrective actions, etc.) will be taken based on the information. Furthermore, we recommend the EIS discuss public participation, and how the public can get information on mitigation effectiveness and monitoring results.

ORIGINAL

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

November 15, 2012

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

RE: EPA Region 3 Scoping Comments in Response to FERC's Notice of Intent to Prepare an Environmental Assessment (EA) for the Planned Cove Point Liquefaction Project; FERC Docket No. PF12-16-000

Dear Secretary Bose:

The U.S. Environmental Protection Agency (EPA), Region III Office, has conducted a review of the above Notice in conjunction with our responsibilities under the National Environmental Policy Act (NEPA), the Clean Water Act (CWA) and Section 309 of the Clean Air Act. As part of the FERC pre-filing process of soliciting public and agency comments for development of the EA, EPA offers the following scoping comments.

The NOI describes Dominion's proposal to add an LNG export terminal to its existing LNG import terminal on the Chesapeake Bay in Lusby, Maryland. The new terminal would have capacity to process and export up to 750 million standard cubic feet of natural gas per day (0.75 billion cubic feet/day). Facilities would include:

- Natural gas fired turbines to drive the main refrigerant compressors;
- One or two LNG drive trains and new processing facilities;
- 29,000 to 34,000 additional horsepower compression at its existing Loudon County, VA
- Compressor Station and/or its existing Pleasant Valley (Fairfax County, VA) Compressor Station;
- Additional on-site power generation
- Minor modifications to the existing off-shore pier;
- Use of nearby properties and possible relocation of administrative functions

The Project would not include new LNG storage tanks or an increase in the size and/or frequency of LNG marine traffic currently authorized for the Cove Point LNG Terminal. The NEPA document should include a clear and robust justification of the underlying purpose and need for the proposed project. In order for the project to move forward, FERC would need to issue a certificate of "public convenience and necessity". We recommend discussing the proposal in the context of the broader energy market, including existing and proposed LNG export capacity, describing the factors involved in determining public convenience and necessity for this facility.

EPA recommends assessing the cumulative environmental effects resulting from implementation of the proposed project, when combined with other past, present and reasonably foreseeable future actions, regardless of whether these actions are energy related or not, or whether or not FERC has jurisdiction over them. We recommend focusing on resources or communities of concern, or resources "at risk" which could be cumulatively impacted by all of the above actions. Please refer to the Council on Environmental Quality (CEQ) guidance on "Considering Cumulative Effects Under the National Environmental Policy Act", and EPA's "Consideration of Cumulative Impacts in EPA Review of NEPA Documents" for further assistance in identifying appropriate spatial and temporal boundaries for this analysis.

We also recommend expanding the scope of analysis to include indirect effects related to gas drilling and combustion. A 2012 report (http://www.eia.gov/analysis/requests/fe/) from the Energy Information Administration (EIA) states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report also indicated that about three-quarters of that increase production would be from shale resources and that domestic natural gas prices could rise by more than 50% if permitted to be exported. We believe it is appropriate to consider the extent to which implementation of the proposed project, combined with implementation of other similar facilities nationally, could increase the demand for domestic natural gas extraction and increase domestic natural gas prices. As part of this assessment, please discuss the extent to which implementation of the proposed project would create a demand for construction of new gas pipelines or expansion of existing pipelines, in order to accommodate the increased volumes of gas supplied to the Cove Point and other facilities.

In the air impact analysis for the Cove Point Project, we recommend considering the direct, temporary emissions from construction of all facilities, as well as permanent air emission impacts from facility operations, including all compressor stations and any vessel traffic related to LNG exports. Additionally, indirect and reasonably foreseeable cumulative impacts from past, present and future actions, when added to the incremental impacts of the Project proposed should be evaluated. These other actions should include FERC jurisdictional facilities and energy generating and transporting-related facilities, as well as actions or facilities which might have air emissions which could impact the same air receptors as the Project, including downstream combustion.

Please note whether construction or operation of the Project would involve any discharges to Waters of the United States, and whether it would affect the Chesapeake Bay Total Maximum Daily Load (TMDL) or any related Watershed Implementation Plans (WIPs).

As part of any environmental documentation, please include evaluation of the Project's direct and indirect impacts on the nearby Chesapeake Bay fisheries and fishermen (both recreational and commercial). Will any additional dredging of waterways be required to accommodate the vessels exporting LNG? What biosecurity controls and protocols will be instituted to prevent introduction of invasive species due to ballast water releases? Please include a discussion of how the Project will comply with the Magnuson-Stevens Fishery Conservation and Management Act, as amended by the Sustainable Fisheries Act of 1966 (PL 04-267)(Essential Fish Habitat).

Please express the volume of natural gas proposed to be exported in terms that the average reader can more easily understand. For example, in addition to indicating that the Project would be capable of processing an average of 750 million standard cubic feet of natural gas per day, also express that figure as an equivalent number of average homes this amount of gas could heat, or how many tankers, and of what size, this amount of gas would fill. Also, please calculate how many production wells, on average, would need to be drilled in order to produce this amount of gas.

The NOI states that the Project would not increase the size and/or frequency of LNG marine traffic currently authorized for the Cove Point LNG Terminal. Please discuss in the NEPA document whether this would be accomplished by reducing the volume of LNG imports to match the volume of proposed exports, or by employing some other approach.

Please indicate the number, location, size and capacity of the network of bidirectional pipelines from which the proposed Project would or could receive natural gas, and also indicate whether any of those pipelines would need to be expanded or modified in order to provide the volumes of gas anticipated.

Please indicate whether any aspect of the Project would trigger any requirements for hazardous waste management under the Resource Conservation and Recovery Act (RCRA) or other Federal statutes involving management of such waste.

The proposed Dominion Cove Point facility represents one of sixteen (16) applications currently pending before the U.S. Department of Energy (DOE) for approval to export LNG to countries which do not have Free Trade Agreements (FTA) with the United States. At this time, it appears that only one facility has been initially granted full approval (Sabine Pass in Cameron Parish, Louisiana). Although we are aware of the DOE national study in progress on the cumulative *economic* impacts of allowing natural gas exports, EPA believes that the Cove Point NEPA process represents an opportunity for FERC and DOE to jointly and thoroughly consider the indirect and cumulative *environmental* impacts of exporting LNG from Cove Point. The environmental study of the Cove Point Project should be a comprehensive and robust evaluation of potential impacts, which may require a higher level analysis particularly in consideration of the potential for significant cumulative impacts and the level of community interest.

Thank you for the opportunity to comment on this Notice. EPA welcomes the opportunity to discuss these topics by phone or in-person, at your convenience. If you have any questions concerning these comments, please contact Mr. Thomas Slenkamp of this Office at (215) 814-2750.

Sincerely,

Jeffrey D. Lapp, Associate Director
Office of Environmental Programs

Document Content(s)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 900
Seattle, WA 98101-3140

OFFICE OF
ECOSYSTEMS,
TRIBAL AND PUBLIC
AFFAIRS

December 26, 2012

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1A
Washington, DC 20426

Re: SCOPING COMMENTS – The Oregon LNG Export Project and Washington Expansion Project. EPA Region 10 Project Number: 12-0055-FRC. *FERC Docket Nos. PF12-18-000 and PF12-20-000.*

Dear Secretary Bose:

The U.S. Environmental Protection Agency would like to provide detailed scoping comments in response to the Federal Energy Regulatory Commission's (FERC's) September 24, 2012 Notice of Intent (NOI) to prepare an Environmental Impact Statement (EIS) for the Oregon Liquefied Natural Gas (LNG) Export Project and Washington Expansion. These comments were prepared in accordance with our authorities pursuant to the National Environmental Policy Act (NEPA), Section 309 of the Clean Air Act, the Clean Water Act, and our responsibilities as a Cooperating Agency. We appreciate the opportunity for early involvement at this step of the NEPA process.

The Clean Air Act Section 309 directs the EPA to review and comment in writing on the environmental impacts resulting from certain proposed actions of other federal agencies and the adequacy of the Draft EIS in meeting the procedural and public disclosure requirements in accordance with NEPA. Please see the EPA's review criteria for rating Draft EISs at the EPA web site: (http://www.epa.gov/compliance/nepa/comments/ratings.html). Our review authorities under Section 309 are independent of our responsibilities as a Cooperating Agency for this EIS.

As described in the NOI, the Oregon LNG export project would consist of components new to and modified from the originally proposed import-only LNG terminal and pipeline (Docket Nos. CP09-6-000 and CP09-7-000) to allow Oregon LNG to export LNG. The export project would be capable of liquefying approximately 1.3 billion cubic feet per day (Bcf/d) of pretreated natural gas for the export of approximately 9 million metric tons per annum (MTPA) of LNG via LNG carriers.

Specifically, the Export Project would be comprised of liquefaction and export facilities at Warrenton, Oregon and approximately 39 miles of new pipeline. Liquefaction facilities would include:

- A natural gas pretreatment facility to remove sulfur compounds, water, mercury, and other impurities;
- Two liquefaction process trains, each capable of a liquefaction capacity of approximately 4.5 MTPA;
- Refrigerant storage;
- New flare system;

- New water intake on the Columbia River and water delivery pipeline from the intake to a new water treatment system.

Pipeline facilities would include:

- 39 miles of new pipeline commencing at milepost (MP) 47.5 of the pending proposed Oregon Pipeline; and
- A new compressor station at MP 80.8.

The connected Washington Expansion Project (WEP) would expand the capacity of Northwest Pipeline GP (Northwest) between Sumas and Woodland, Washington, by 750,000 dekatherms per day to provide natural gas to the proposed Oregon LNG terminal, and to markets in the state of Washington.

Pipeline facilities for the WEP would include:

- Approximately 140 miles of 36-inch-diameter pipeline loop along Northwest's existing Northwest Pipeline in 10 segments; and
- An additional 96,000 horsepower (hp) of compression at five existing compressor stations.

The enclosed scoping comments were prepared based on our review of the NOI referenced above and the draft Resource Report 1. Our comments reflect a broad range of issues that we believe to be significant and warrant treatment in the EIS.

As a Cooperating Agency, we look forward to continued communication with your office throughout the development of the EIS, and we are available to work with FERC to review and comment on preliminary sections of the document. If you have any questions regarding our scoping comments, please do not hesitate to contact me at (206) 553-1601 or by electronic mail at reichgott.christine@epa.gov, or you may contact Teresa Kubo of my staff in the Oregon Operations Office at (503) 326-2859 or by electronic mail at kubo.teresa@epa.gov. We look forward to our continued coordination and involvement in this project.

Sincerely,

Christine B. Reichgott

Christine B. Reichgott, Manager
Environmental Review and Sediment Management Unit

Enclosure

U.S. Environmental Protection Agency
Detailed Scoping Comments to Address the Federal Energy Regulatory Commission's Notice of Intent to Prepare an Environmental Impact Statement for the Oregon LNG Export Project and Washington Expansion Project
FERC Docket Nos. PF12-18-000 and PF12-20-000

Purpose and Need

The EIS should include a clear and concise statement of the underlying purpose and need for the proposed project, consistent with the implementing regulations for NEPA (see 40 CFR 1502.13). In presenting the purpose and need for the project, the EIS should reflect not only the FERC's purpose, but also the broader public interest and need.

In supporting the statement of purpose and need, we recommend discussing the proposed project in the context of the larger energy market, including existing export capacity and export capacity under application to the Department of Energy, and clearly describing how the need for the proposed action has been determined.

Alternatives Analysis

NEPA requires evaluation of reasonable alternatives, including those that may not be within the jurisdiction of the lead agency[1]. A robust range of alternatives will include options for avoiding significant environmental impacts. The EIS should "rigorously explore and objectively evaluate all reasonable alternatives"[2] by developing a screening process. The screening process should rate each alternative against a set of pre-determined criteria. Each alternative should then be analyzed for its level of impact on a resource (e.g. no effect, negligible effect, minor effect, major effect, significant effect). Only the alternative that effectively meets or best meets all of the screening criteria should be recommended as the preferred alternative. The EIS should provide a clear discussion of the reasons for the elimination of alternatives which are not evaluated in detail.

Environmental Consequences

According to 40 CFR Part 1502.1, an Environmental Impact Statement, "...shall provide full and fair discussion of significant environmental impacts and shall inform decision makers and the public of the reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the environment." In order to facilitate a full and fair discussion on significant environmental issues, we encourage the FERC to establish thresholds of significance for each resource of concern, and to analyze environmental consequences in a clear, repeatable manner. For each action, a series of questions should be considered: 1) What is the action? 2) What is the intensity or extent of impacts? 3) Based on identified thresholds, is that significant? If an impact of the action is significant, then the EIS must contain appropriate mitigation measures.

Water Quality

In order to adequately address water quality issues, the EPA recommends the EIS identify water bodies likely to be impacted by the project, the nature of the potential impacts, and the specific discharges and pollutants likely to impact those waters (addressing both Section 402 and 404 discharges and potential impairments to water quality standards). We also recommend the EIS disclose information regarding

[1] 40 CFR 1502.14(c)
[2] 40 CFR 1502.14(a)

relevant Total Maximum Daily Load allocations, the water bodies to which they apply, water quality standards and pollutants of concern.

Clean Water Act Section 303(d) listed waters should not be further degraded. If additional pollutant loading is predicted to occur to a 303(d) listed stream as a result of a project, the EIS should include measures to control existing sources of pollution to offset pollutant additions.

Consider implementing watershed or aquatic habitat restoration activities to compensate for past impacts to water resources, particularly in watersheds with 303(d) listed waters where development may have contributed to impairments through past channelization, riverine or floodplain encroachments, sediment delivery during construction, and other activities that may have affected channel stability, water quality, aquatic habitat, and designated waterbody uses. Provisions for antidegradation of water quality apply to water bodies where water quality standards are presently being met. We recommend the EIS describe how antidegradation provisions would be met.

Hydrostatic Test Water

Hydrostatic testing of pipelines and tanks will be required to verify their integrity. We recommend that the EIS identify the water sources and withdrawal rates that would be required for hydrostatic testing. We recommend that the EIS identify and describe the location of these water sources (surface areas, depth, volumes, withdrawal rates, and project requirements). For each water source, we recommend that the EIS discuss the presence of any anadromous and/or resident fish species, including a discussion of any direct and cumulative impacts to fisheries resources. In addition, we recommend that the locations of discharge to land and/or surface waters, and discharge methods be specified in the EIS. Emphasis should be placed on minimizing interbasin transfers of water to the maximum extent practicable in order to minimize the risk of mobilizing invasive species. We recommend that the EIS describe the mitigation measures and control devices that would be implemented to minimize environmental impacts.

Source Water Protection

Public drinking water supplies and/or their source areas often exist in many watersheds. Source water areas may exist within watersheds where the pipeline and associated facilities would be located. Source waters are streams, rivers, lakes, springs, and aquifers used as supply for drinking water. Source water areas are delineated and mapped by the states for each federally-regulated public water system. The 1996 amendments to the Safe Drinking Water Act require federal agencies to protect sources of drinking water for communities. As a result, state agencies have been delegated responsibility to conduct source water assessments and provide a database of information about the watersheds and aquifers that supply public water systems.

Since construction, operation, and maintenance of a buried natural gas pipeline may impact sources of drinking water, the EPA recommends that the FERC work with the Oregon Department of Environmental Quality to identify source water protection areas. Typical databases contain information about the watersheds and aquifer recharge areas, the most sensitive zones within those areas, and the numbers and types of potential contaminant sources for each system. We recommend that the EIS identify source water protection areas within the project area, activities (e.g., trenching and excavation, water withdrawal, etc.) that could potentially affect source water areas, potential contaminants that may result from the proposed project and mitigation measures that would be taken to protect the source water protection areas.

Wetlands and Aquatic Habitats

In the EIS, we recommend describing aquatic habitats in the affected environment (e.g., habitat type, plant and animal species, functional values, and integrity) and the environmental consequences of the proposed alternatives on these resources. Impacts to aquatic resources should be evaluated in terms of the areal (acreage) or linear extent to be impacted and by the functions they perform.

The proposed activities will require a Clean Water Act Section 404 permit from the Army Corps of Engineers. For wetlands and other special aquatic sites, the Section 404(b) (1) guidelines establish a presumption that upland alternatives are available for non-water dependent activities. The 404(b)(1) guidelines require that impacts to aquatic resources be (1) avoided, (2) minimized, and (3) mitigated, in that sequence. We recommend the EIS discuss in detail how planning efforts (and alternative selection) conform with Section 404(b)(1) guidelines sequencing and criteria. In other words, we request the FERC show that impacts to wetlands and other special aquatic sites have been avoided to the maximum extent practicable. The EPA also recommends the EIS discuss alternatives that would avoid wetlands and aquatic resource impacts from fill placement, water impoundment, construction, and other activities before proceeding to minimization/ mitigation measures.

The EPA recommends the EIS describe all waters of the U.S. that could be affected by the project alternatives, and include maps that clearly identify all waters within the project area. We also request the document include data on acreages and channel lengths, habitat types, values, and functions of these waters. As discussed above, projects affecting waters of the U.S. may need to comply with CWA Section 404 requirements. If project alternatives involve discharge of dredged or fill material into waters of the U.S., the EIS should include information regarding alternatives to avoid the discharges or how potential impacts caused by the discharges would be minimized and mitigated. This mitigation discussion would include the following elements:

- acreage and habitat type of waters of the U.S. that would be created or restored;
- water sources to maintain the mitigation area;
- re-vegetation plans, including the numbers and age of each species to be planted, as well as special techniques that may be necessary for planting;
- maintenance and monitoring plans, including performance standards to determine mitigation success;
- size and location of mitigation zones;
- mitigation banking and/or in lieu fees where appropriate;
- parties that would be ultimately responsible for the plan's success; and
- contingency plans that would be enacted if the original plan fails.

Where possible, mitigation should be implemented in advance of the impacts to avoid habitat losses due to the lag time between the occurrence of the impact and successful mitigation.

Water Body Crossing

We appreciate the effort that the FERC and the proponent have made in the past to establish appropriate water body crossing procedures. We encourage the FERC to build upon these efforts through the use of risk screening tools that have been developed more recently. Specifically, we encourage the use of 1) a Project Screening Risk Matrix to evaluate the potential risks posed by the project to species or habitat, and to prioritize reviews; 2) a Project Information Checklist to evaluate whether all the necessary information is available to facilitate critical and thorough project evaluation; and 3) the River

Restoration Assessment Tool, which can promote consistent and comprehensive project planning and review. These tools are available at www.restorationreview.com.

Dredging

According to Resource Report 1, Oregon LNG expects that construction of the berth and turning basin will require an estimated 1,275,000 cubic yards of dredge material requiring removal. (Section 1.3.1). Oregon LNG has been actively working with agencies and stakeholders to identify an appropriate location for dredge material disposal. We understand that Oregon LNG priority sites have shifted to the USEPA Deepwater Site, the USEPA Shallow Water Site, the US Army Corps of Engineers (USACE) North Jetty S, and the USACE South Jetty Nearshore Site. We provide the following comments for FERC's consideration as Resource Report 10 and the DEIS are developed:

- Capacity at the USEPA Deep Water Site has been characterized by the proponent as "unlimited"[3]. The EPA agrees that capacity at the site is large, but it is not unlimited. The EPA has asked USACE to conduct an assessment of long term capacity as part of the Annual Use Plan for 2014.
- The USEPA Shallow Water Site is used to capacity every season, and accretion limits are very low. Because shoaling is an unacceptable outcome, disposals at this site would need to be monitored with USACE and the EPA.
- The South Jetty Nearshore Site (Oregon) was accepted by the Lower Columbia Solutions Group (LCSG) on a provisional basis in 2011. Future use of this site would need to be coordinated with the LCSG as well as the USACE. The crab fishing community has requested demonstrable proof over multiple seasons that crabs will not be affected by dredge material disposal activity.

The EPA supports and appreciates the long standing efforts of the proponents and FERC to identify alternative disposal site locations. We will continue to work with the proponent and FERC to identify disposal locations that meet established criteria under Section 103 of the Marine Protection, Research and Sanctuaries Act (MPRSA).

Air Quality

The EPA recommends the EIS provide a detailed discussion of ambient air conditions (baseline or existing conditions), National Ambient Air Quality Standards, criteria pollutant nonattainment areas, and potential air quality impacts of the proposed project (including cumulative and indirect impacts). Such an evaluation is necessary to assure compliance with State and Federal air quality regulations, and to disclose the potential impacts from temporary or cumulative degradation of air quality. The EPA recommends the EIS describe and estimate air emissions from potential construction, operation, and maintenance activities, including emissions associated with LNG carriers at berth. The analysis should also include assumptions used regarding the types of fuel burned and/or the ability for carriers to utilize dockside power (i.e. cold ironing). Emissions at berth are of particular relevance because the deep draft LNG carriers would be required to remain docked between high tides. We also recommend proposing mitigation measures in the EIS to address identified emissions impacts.

Fugitive Dust Emissions

Fugitive dust may contain small airborne particles that have the potential to adversely affect human health and the environment. The EPA defines fugitive dust as "particulate matter that is generated or emitted from open air operations (emissions that do not pass through a stack or a vent)". The most

[3] Attachment 10-1 Table of Dredge Material Disposal Sites

common forms of particulate matter (PM) are known as PM_{10} and $PM_{2.5}$ (particulate matter size less than 10 and 2.5 microns, respectively).

Sources of fugitive dust from this project may include unpaved gravel roads and facility pads, and clearing and construction sites. Effects of fugitive dust to the natural environment may include visibility reduction and haze, surface water impacts, impacts to wetlands, and reduction in plant growth. Fugitive dust may pose a human health risk due to chronic exposure in areas with vulnerable populations, such as infants and the elderly. The EPA recommends the EIS evaluate the magnitude and significance of fugitive dust emissions resulting from this project and potential impacts on human health.

We also recommend that a Dust Control Plan be developed and included as an appendix to the EIS. This plan should include provisions for monitoring fugitive dust during construction and operations, and implementing measures to reduce fugitive dust emissions, such as wetting the source material, installing barriers to prevent dust from leaving the source area, and halting operations during high wind events. We recommend that the EIS identify mitigation measures to avoid and minimize potential adverse impacts to the natural and human environment.

Biological Resources, Habitat and Wildlife

The EPA recommends the EIS identify all petitioned and listed threatened and endangered species under the Endangered Species Act, as well as critical habitat that might occur within the project area. We also recommend the EIS identify and quantify which species or critical habitat might be directly, indirectly, or cumulatively affected by each alternative and mitigate impacts to those species. The EPA recommends that the FERC continue to work with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service. The EPA also recommends that the FERC continue to coordinate with the Oregon Department of Fish and Wildlife to ensure that State sensitive species are adequately addressed within the analysis and that current and consistent surveying, monitoring, and reporting protocols are applied in protection and mitigation efforts.

The EPA recommends the EIS also identify species listed under the Marine Mammal Protection Act. Marine barge/vessel traffic may result in potential conflicts with threatened and/or endangered marine mammals and their migration patterns and routes. We also recommend that the EIS describe the barge/vessel traffic schedule, patterns and marine transportation routes, as well as the migration period, patterns, and routes of potentially affected marine mammals. The direct, indirect and cumulative impacts from barge/vessel traffic on marine mammals, threatened and endangered species, critical habitats, and subsistence resources should be analyzed in the EIS.

Land Use Impacts

Land use impacts would include, but not be limited to, disturbance of existing land uses within construction work areas during construction and creation of permanent right-of-ways for construction, operations, and maintenance of the pipeline and above ground facilities. The EPA recommends the EIS document all land cover and uses within the project corridor, impacts by the project to the land cover and uses, and mitigation measures that would be implemented to reduce the impacts.

The primary impact of construction on forests and other open land use types would be the removal of trees, shrubs, and other vegetation. Although these can be regenerated or replanted, their re-establishment can take up to 20 years or more, making the construction impacts to these resources long term and in some cases permanent. The impact on forest land use, for example, in the permanent right-of-way areas would be a permanent change to open land. We recommend the EIS describe the impacts to forest and open land use types, indicate if the impacts would be permanent or temporary, and state measures that would be taken to compensate landowners for loss of their resources because of the project.

If the project would cross sensitive areas then the EIS should specify the areas, indicate impacts to the areas, and document any easement conditions for use of the areas, including mitigation measures.

Invasive Species
The establishment of invasive nuisance species has become an issue of environmental and economic significance. The EPA recommends consideration of impacts associated with invasive nuisance species consistent with *E.O. 13112 Invasive Species*. In particular, construction activities associated with buried pipelines which disturb the ground may expose areas and could facilitate propagation of invasive species. Mitigation, monitoring and control measures should be identified and implemented to manage establishment of invasive species throughout the entire pipeline corridor right-of-way. We recommend that the EIS include a project design feature that calls for the development of an invasive species management plan to monitor and control noxious weeds, and to utilize native plants for restoration of disturbed areas after construction.

If pesticides and herbicides will be applied during construction, operation, and maintenance of the project, we recommend that the EIS address any potential toxic hazards related to the application of the chemicals, and describe what actions will be taken to assure that impacts by toxic substances released to the environment will be minimized.

Ballast water from barges/vessels is a major source of introducing non-native species into the marine ecosystems where they would not otherwise be present. Non-native species can adversely impact the economy, the environment, or cause harm to human health. Impacts may include reduction of biodiversity of species inhabiting coastal waters from competition between non-native and native species for food and resources. We recommend that the EIS discuss potential impacts from non-native invasive species associated with ballast water and identify mitigation measures to minimize adverse impacts to the marine environment and human health.

Hazardous Materials/Hazardous Waste/Solid Waste
The EPA recommends the EIS address potential direct, indirect, and cumulative impacts of hazardous waste from construction and operation of the proposed project. The document should identify projected hazardous waste types and volumes, and expected storage, disposal, and management plans. It should identify any hazardous materials sites within the project's study area and evaluate whether those sites would impact the project in any way.

As an example, page 1-9 of Draft Resource Report 1 indicates that as a part of the gas conditioning process, sweetened gas will pass through multiple, consumable parallel carbon beds for the removal of any mercury in the gas. Because the carbon beds cannot be regenerated, it will be necessary to replace them after a design life of several years. We recommend the EIS address the expected mercury content of the expended carbon beds, and address disposal requirements consistent with 40 CFR 268.40.

We also note that the proposed pipeline route between MP 3 and MP 4 passes just upstream of the Astoria Marine Construction Company Site. This site and adjacent river sediments are contaminated with tributyltin and heavy metals from ship refurbishment operations from 1926 to present[4]. The Oregon Department of Environmental Quality (DEQ) will oversee the investigation and cleanup of contaminated soil, groundwater and sediments at the site under an agreement signed with the EPA. We recommend that FERC and the proponents collaborate closely with Oregon DEQ as the pipeline route is analyzed. Should additional construction BMPs be required at this location, those measures should be included in the EIS.

Seismic and Other Risks

Construction and operation of the proposed facility and pipeline may cause or be affected by increased seismicity (earthquake activity) in tectonically active zones. We recommend that the EIS identify potentially active and inactive fault zones where the proposed pipeline may cross. This analysis should discuss the potential for seismic risk and how this risk will be evaluated, monitored, and managed. A map depicting these geologic faults should be included in the EIS. The construction of the proposed project must use appropriate seismic design and construction standards and practices. Ground movement on these faults can cause a pipeline to rupture, resulting in discharge of gas and subsequent explosion. Particular attention should be paid to areas where the pipeline may cross areas with high population densities. Mitigation measures should be identified in the EIS to minimize effects on the pipeline due to seismic activities.

Blasting Activities

During project construction, blasting may be required in certain areas along the pipeline route corridor and adjacent facilities, resulting in increased noise and related effects to local residents, and disruption and displacement of bird and wildlife species. We recommend that the EIS discuss where blasting in the project area would be required, blasting methods that would be used, and how blasting effects would be controlled and mitigated. Noise levels in the project area should be quantified and the effects of blasting to the public and to wildlife should also be evaluated in the EIS. We recommend that a Blasting Management Plan be developed and the environmental impacts evaluated in the EIS.

National Historic Preservation Act

Consultation for tribal cultural resources is required under Section 106 of the National Historic Preservation Act (NHPA). Historic properties under the NHPA are properties that are included in the National Register of Historic Places or that meet the criteria for the National Register. Section 106 of the NHPA requires a federal agency, upon determining that activities under its control could affect historic properties, consult with the appropriate State Historic Preservation Officer /Tribal Historic Preservation Officer. Under NEPA, any impacts to tribal, cultural, or other treaty resources must be discussed and mitigated. Section 106 of the NHPA requires that federal agencies consider the effects of their actions on cultural resources, following regulation in 36 CFR 800.

Environmental Justice and Impacted Communities

In compliance with NEPA and with Executive Order (EO) 12898 on Environmental Justice, actions should be taken to conduct adequate public outreach and participation that ensures the public and Native American tribes understand the possible impacts to their communities and trust resources.

EO 12898 requires each Federal agency to identify and address disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations,

[4] http://www.deq.state.or.us/lq/cu/nwr/AstoriaMarine/AstoriaMarineConstructionCo.pdf

low-income populations, and Native American tribes.[5] The EPA also considers children, the disabled, the elderly, and those of limited English proficiency to be potential Environmental Justice communities due to their unique vulnerabilities.

According to the Council on Environmental Quality, when determining whether environmental effects are disproportionately high and adverse, agencies should consider the following factors: [6]

- Whether environmental effects are or may be having an adverse impact on minority populations, low-income populations, or Indian tribes that appreciably exceeds or is likely to appreciably exceed those on the general population or other appropriate comparison group.
- Whether the disproportionate impacts occur or would occur in a minority population, low-income population, or Indian tribe affected by cumulative or multiple adverse exposures from environmental hazards.

Socioeconomic Impacts
Council on Environmental Quality Regulations at 40 CFR 1500-1508 state that the "human environment" is to be "interpreted comprehensively" to include "the natural and physical environment and the relationship of people with that environment" (40 CFR 1508.14). Consistent with this direction, agencies need to assess not only "direct" effects, but also "aesthetic, historic, cultural, economic, social, or health" effects, "whether direct, indirect, or cumulative" (40 CFR 1508.8).

Social impact assessment variables point to measurable change in human population, communities, and social relationships resulting from a development project or policy change. We suggest that the EIS analyze the following social variables:

- Population Characteristics
- Community and Institutional Structures
- Political and Social Resources
- Community Resources.

Impacts to these social variables should be considered for each stage of the project (development, construction, operation, decommissioning). With regard to the construction and operation phase of the project, we recommend the analysis give consideration to how marine traffic might change, and how this may affect commercial or recreational use within the project area and travel over the bar.

Greenhouse Gas (GHG) Emissions
On February 18, 2010, the CEQ issued draft guidance to Federal Agencies on analyzing the effects of Greenhouse Gas (GHG) emissions and climate change when describing the environmental effects of a proposed agency action in accordance with NEPA[7].

CEQ's draft guidance defines GHG emissions in accordance with Section 19(i) of *E.O. 13514 Federal Leadership in Environment, Energy, and Economic Performance (October 5, 2009)* to include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorcarbon (HFCs), perfluorcarbon (PFCs),

[5] EO 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-income Populations. February 11, 1994.
[6] http://ceq.hss.doe.gov/nepa/regs/ej/justice.pdf
[7] See http://ceq.hss.doe.gov/current_developments/new_ceq_nepa_guidance.html

and sulfurhexafluoride (SF_6). Because CO_2 is the reference gas for climate change based on their potential to absorb heat in the atmosphere, measures of non-CO_2 GHGs should be reflected as CO_2-equivalent (CO_2-e) values.

The EPA supports evaluation and disclosure of GHG emissions and climate change effects resulting from the proposed project during all project phases, including (1) pre-construction (e.g., transportation, mobilization, and staging), (2) construction, (3) operation, (4) maintenance, and (5) decommissioning. We recommend that the GHG emission accounting/inventory include each proposed stationary source (e.g., power plant, liquefaction facility, compressor and metering stations, etc.) and mobile emission source (e.g., heavy equipment, supply barges, rail transports, etc.). We also recommend that the EIS establish reasonable spatial and temporal boundaries for this analysis, and that the EIS quantify and disclose the expected annual direct and indirect GHG emissions for the proposed action. In the analysis of direct effects, we recommend that the EIS quantify cumulative emissions over the life of the project, discuss measures to reduce GHG emissions, including consideration of reasonable alternatives
We recommend that the EIS consider mitigation measures and reasonable alternatives to reduce action-related GHG emissions, and include a discussion of cumulative effects of GHG emissions related to the proposed action. We recommend that this discussion focus on an assessment of annual and cumulative emissions of the proposed action and the difference in emissions associated with the alternatives.

In addition, greenhouse gas emission sources in the petroleum and natural gas industry are required to report GHG emissions under 40CFR Part 98 (subpart W), the Greenhouse Gas Reporting Program. Consistent with draft CEQ guidance[5], we recommend that this information be included in the EIS for consideration by decision makers and the public. Please see http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

Climate Change
Scientific evidence supports the concern that continued increases in greenhouse gas emissions resulting from human activities will contribute to climate change. Global warming is caused by emissions of carbon dioxide and other heat-trapping gases. On December 7, 2009, the EPA determined that emissions of GHGs contribute to air pollution that "endangers public health and welfare" within the meaning of the Clean Air Act. Higher temperatures and increased winter rainfall will be accompanied by a reduction in snow pack, earlier snowmelts, and increased runoff. Some of the impacts, such as reduced groundwater discharge, and more frequent and severe drought conditions, may impact the proposed projects. The EPA recommends the EIS consider how climate change could potentially influence the proposed project, specifically within sensitive areas, and assess how the projected impacts could be exacerbated by climate change.

Coordination with Tribal Governments
Executive Order 13175, Consultation and Coordination with Indian Tribal Governments (November 6, 2000), was issued in order to establish regular and meaningful consultation and collaboration with tribal officials in the development of federal policies that have tribal implications, and to strengthen the United States government-to-government relationships with Indian tribes. The EIS should describe the process and outcome of government-to-government consultation between the FERC and tribal governments within the project area, issues that were raised, and how those issues were addressed in the selection of the proposed alternative.

Indirect Impacts

Per CEQ regulations at CFR 1508.8(b), the indirect effects analysis "may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems." The 2012 report from the Energy Information Administration[8] states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report also notes that about three-quarters of that increased production would be from shale resources. We recommend that FERC consider available information about the extent to which drilling activity might be stimulated by the construction of an LNG export facility on the west coast, and any potential environmental effects associated with that drilling expansion.

Cumulative Impacts

The cumulative impacts analysis should identify how resources, ecosystems, and communities in the vicinity of the project have already been, or will be affected by past, present, or future activities in the project area. These resources should be characterized in terms of their response to change and capacity to withstand stresses. Trends data should be used to establish a baseline for the affected resources, to evaluate the significance of historical degradation, and to predict the environmental effects of the project components.

For the cumulative impacts assessment, we recommend focusing on resources of concern or resources that are "at risk" and /or are significantly impacted by the proposed project, before mitigation. For this project, the FERC should conduct a thorough assessment of the cumulative impacts to aquatic and biological resources, air quality, and commercial and recreational use of the Columbia River within the projects area of influence.

The EPA also recommends the EIS delineate appropriate geographic boundaries, including natural ecological boundaries, whenever possible, evaluate the time period of the project's effects. For instance, for a discussion of cumulative wetland impacts, a natural geographic boundary such as a watershed or sub-watershed could be identified. The time period, or temporal boundary, could be defined as from 1972 (when the Clean Water Act established section 404) to the present.

Please refer to CEQ's "Considering Cumulative Effects Under the National Environmental Policy Act"[9] and the EPA's "Consideration of Cumulative Impacts in EPA Review of NEPA Documents"[10] for assistance with identifying appropriate boundaries and identifying appropriate past, present, and reasonably foreseeable future projects to include in the analysis.

Mitigation and Monitoring

On February 18, 2010, CEQ issued draft guidance on the Appropriate Use of Mitigation and Monitoring. This guidance seeks to enable agencies to create successful mitigation planning and implementation procedures with robust public involvement and monitoring programs[11].

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[8] Energy Information Administration, Effects of Increased Natural Gas Exports on Domestic Energy Markets, 6 (January 2012) available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf

[9] http://ceq.hss.doe.gov/nepa/ccenepa/ccenepa.htm

[10] http://www.epa.gov/compliance/resources/policies/nepa/cumulative.pdf

[11] http://ceq.hss.doe.gov/current_developments/docs/Mitigation_and_Monitoring_Guidance_14Jan2011.pdf

We recommend that the EIS include a discussion and analysis of proposed mitigation measures and compensatory mitigation under CWA §404. The EIS should identify the type of activities which would require mitigation measures either during construction, operation, and maintenance phases of this project. To the extent possible, mitigation goals and measureable performance standards should be identified in the EIS to reduce impacts to a particular level or adopted to achieve an environmentally preferable outcome.

Mitigation measures could include best management practices and options for avoiding and minimizing impacts to important aquatic habitats and to compensate for the unavoidable impacts. Compensatory mitigation options could include mitigation banks, in-lieu fee, preservation, applicant proposed mitigation, etc. and should be consistent with the *Compensatory Mitigation for Losses of Aquatic Resources; Final Rule* (33 CFR Parts 325 and 332 and 40 CFR Part 230). A mitigation plan should be developed in compliance with 40 CFR Part 230 Subpart J 230.94, and included in the EIS.

An environmental monitoring program should be designed to assess both impacts from the project and that mitigation measures being implemented are effective. We recommend the EIS identify clear monitoring goals and objectives, such as what parameters are to be monitored, where and when monitoring will take place, who will be responsible, how the information will be evaluated, what actions (contingencies, triggers, adaptive management, corrective actions, etc.) will be taken based on the information. Furthermore, we recommend the EIS discuss public participation, and how the public can get information on mitigation effectiveness and monitoring results.

From:	Craig Segall - Sierra
To:	LNGStudy
Subject:	2012 LNG Export Study
Date:	Thursday, January 24, 2013 3:31:41 PM
Attachments:	NERA Study Comments - final_submitted.pdf Ex 5_Synapse LNG Exports Study.pdf

January 24, 2013

Please find attached comments from the Sierra Club and a large coalition of non-profit organizations on the DOE's LNG Export Study. I am also attaching an expert report that these comments rely upon.

We are filing these comments both electronically and by hand-delivery because the comments have many more exhibits than just the attached expert report. In total, the comments have 79 exhibits -- CDs with copies of those exhibits are being hand-delivered to your office. The exhibits should, of course, be filed with the comments.

Thank you for confirming receipt of these comments and the exhibits.

Best,
Craig Segall

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I check email infrequently. Please call me if you need a quick reply.

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January 24, 2013

U.S. Department of Energy (FE–34)
Office of Natural Gas Regulatory Activities
Office of Fossil Energy
Forrestal Building, Room 3E-042
Independence Ave SW,Washington, DC 20585
LNGStudy@hq.doe.gov.

Dear Secretary Chu:

Thank you and the Department of Energy's Office of Fossil Energy ("DOE/FE") for accepting these comments on NERA Economic Consulting's study (the "NERA Study," or "the Study") on the macroeconomic impacts of liquefied natural gas ("LNG") export on the U.S. economy. We submit these comments on behalf of the Sierra Club, including its Atlantic (New York), Colorado, Kansas, Michigan, Pennsylvania, Ohio, Oregon, Texas, Virginia, West Virginia, and Wyoming Chapters; and on behalf of Catskill Citizens for Safe Energy, the Center for Biological Diversity, Center for Coalfield Justice, Clean Air Council, Clean Ocean Action, Columbia Riverkeeper, Damascus Citizens for Sustainability, Delaware Riverkeeper Network, Earthworks' Oil and Gas Accountability Project, Food and Water Watch, Lower Susquehanna Riverkeeper, Shenandoah Riverkeeper, and Upper Green River Alliance, and on behalf of our millions of members and supporters.[1]

DOE/FE is required to determine whether gas exports are "consistent with the public interest." 15 U.S.C. § 717b(a). Although the NERA Study purports to demonstrate that LNG export is in the economic interest (if not the public interest) of the United States, it does not do so. In fact the study, prepared by a consultant with deep ties to fossil fuel interests, actually shows that LNG export would weaken the United States economy as a whole, while transferring wealth from the poor and middle class to a small group of wealthy corporations that own natural gas resources. This wealth transfer comes along with significant

[1] We have submitted these comments electronically. Hard copies of this document and CDs of all exhibits were also hand-delivered to TVA for filing, as requested by John Anderson at DOE/E today.

structural economic costs caused by increased gas production, which destabilizes regional economies and leaves behind a legacy of environmental damage.

Indeed, an independent analysis, attached to these comments and incorporated to them, demonstrates that NERA's own study shows that LNG export will harm essentially every other sector of the U.S. economy, driving down wages and potentially reducing employment by hundreds of thousands of jobs annually. While LNG exporters will certainly benefit, the nation will not.

An extensive economic literature demonstrates that nations that depend on exporting raw materials, rather than finished goods and intellectual capital, are worse off – a condition sometimes referred to as the "resource curse." The same curse often applies at the smaller scale of the towns and counties in which extraction occurs; those communities are often left with hollowed-out economies, damaged infrastructure, and environmental contamination once a resource boom passes. These dangers apply here with considerable force, but NERA did not even acknowledge, much less analyze them. Indeed, the basic economic model NERA used (which has not been shared with the public) is not suited for this analysis.

Moreover, NERA has entirely failed to account for, or even to acknowledge, the real economic costs which *environmental* harms impose. Intensifying gas production for export will also intensify the air and water pollution problems, public health threats, and ecological disruption associated with gas production – effects which DOE's own experts have cautioned are inadequately managed. The air pollution that gas production for export would generate would alone impose hundreds of millions or potentially billions of dollars of costs, and would greatly erode or even cancel the benefits of recent federal gas pollution standards. Yet, NERA omits this entire negative side of the ledger.

The NERA study, in short, is fundamentally flawed. DOE would be acting arbitrarily and capriciously if it relied upon that report to decide upon export licenses, because NERA misstates or entirely fails to consider critical aspects of this vital public interest question. *See* 5 U.S.C. § 706(2)(A); *see also Motor Vehicle Mftrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*¸ 463 U.S. 29, 43 (1983).

I. Introduction: The Magnitude of the LNG Export Issue and DOE/FE's Obligation to Protect the Public Interest

Recognizing the importance of the natural gas market to the national interest, Congress has vested DOE/FE with the power to license gas exports and imports. This direct regulatory control underlines the gravity of DOE/FE's responsibility. Gas exports, if they occur, will fundamentally affect the nation's environmental and economic future. DOE/FE has a strict Congressional charge to ensure that these exports only go forward if they are "consistent with the public interest." 15 U.S.C. § 717b(a).[2]

This inquiry has never before been so pointed because it has never before been possible for the United States even to consider exporting a large quantity of natural gas as LNG. Becoming a major supplier of LNG to the world market will increase gas production (and, hence, hydro-fracturing or "fracking"), and will also increase gas and energy prices.

These effects have the potential to be very large. DOE/FE is currently considering licenses to export 24.8 billion cubic feet per day ("bcf/d") of natural gas as LNG to nations with which the United States has not signed a free trade agreement ("nFTA" nations). It has already authorized 31.41 bcf/d of export to free-trade-agreement ("FTA") nations because it believes it lacks discretion to deny such FTA applications – though such FTA licenses are of somewhat less moment because most major gas importers are nFTA nations.[3] These are very large volumes of gas. In 2011, the United States produced just under 23,000 bcf of gas over the year.[4] The 24.8 bcf/d of nFTA exports are equivalent to 9,052 bcf/y, or about 39% of total U.S. production. Exporting such a large volume would have major effects on the U.S. economy and the environment, as production both increases and shifts away from domestic uses. While NERA assumes that lower volumes will ultimately be exported, the amounts involved are still large: The 4,380/y bcf case it uses as a high bar sees about 19% of current

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[2] We note that the concerns raised below apply with equal force to exports from both onshore and offshore facilities.

[3] The Act separately provides that DOE/FE must approve exports to nations that have signed a free trade agreement requiring national treatment for trade in natural gas "without modification or delay." 15 U.S.C.§ 717b(c). This provision was intended to speed *imports* of natural gas from Canada. Congress never understood it to allow automatic licenses for export. *See generally*, C. Segall, *Look Before the LNG Leap*, Sierra Club White Paper (2012) at 40-41 (discussing the congressional history of this provision), attached as Ex. 1. That DOE/FE has nonetheless issued export licenses under it, without raising the issue for Congressional correction, is itself an arbitrary and dangerous decision, inconsistent with Congressional intent.

[4] EIA, Natural Gas Monthly December 2012, Table 1 (volume reported is dry gas), attached as Ex. 2.

U.S. production sent abroad; the 1,370 bcf/y "low" case is still 5% of current production.[5]

Although the effects of export would, of course, likely be smaller with smaller volumes of export, applications for 9,052 bcf/y are before DOE/FE, and it would be arbitrary not to consider the cumulative impacts of the full volume of export which DOE/FE is now weighing. But even exporting smaller volumes of gas would necessarily alter the domestic economy and environment in significant ways. The Energy Information Administration ("EIA") has concluded that about two-thirds of gas for export would be drawn from new production, while the remaining third would be diverted from domestic uses, such as power production and manufacturing.[6] On the order of 93% of the new production would come from unconventional gas sources, and so would require fracking to extract the gas.[7]

DOE/FE's earlier public interest investigations of LNG imports did not so directly implicate such shifts in daily domestic life. As a result, DOE/FE's past, largely laissez-faire approach to gas import questions does not translate to gas export. DOE/FE has recognized as much, writing, in response to Congressional inquiries, that the public interest inquiry is to be applied with a careful look across a wide range of factors, informed by reliable data. DOE/FE Deputy Assistant Secretary Christopher Smith has testified that "[a] wide range of criteria are considered as part of DOE's public interest review process, including . . . U.S. energy security . . . [i]mpact on the U.S. economy . . . [e]nvironmental considerations . . . [and] [o]ther issues raised by commenters and/or interveners deemed relevant to the proceeding."[8]

Such care is manifestly appropriate here, and is legally required. As well as charging DOE with "assur[ing] the public a reliable supply of gas at reasonable prices," *United Gas Pipe Line Co v. McCombs*, 442 U.S. 529 (1979), he Natural Gas Act also grants DOE/FE "authority to consider conservation, environmental, and antitrust questions." *NAACP v. Federal Power Comm'n*, 425 U.S. 662, 670 n.4 (1976) (citing 15 U.S.C. § 717b as an example of a public interest provision); *see*

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[5] *See* NERA Study at 10 (Figure 5).

[6] EIA, Effects of Increased Natural Gas Exports on Domestic Energy Markets (Jan. 2012) at 6, 10--11, attached as Ex. 3.

[7] *See id.*

[8] *The Department of Energy's Role in Liquefied Natural Gas Export Applications: Hearing Before the S. Comm. on Energy and Natural Resources*, 112th Cong. 4 (2011) (testimony of Christopher Smith, Deputy Assistant Secretary of Oil and Gas), attached as Ex 4.

also id. at 670 n.6 (explaining that the public interest includes environmental considerations). In interpreting an analogous public interest provision applicable to hydroelectric power, the Court has explained that the public interest determination "can be made only after an exploration of all issues relevant to the 'public interest,' including future power demand and supply, alternate sources of power, the public interest in preserving reaches of wild rivers and wilderness areas, the preservation of anadromous fish for commercial and recreational purposes, and the protection of wildlife." *Udall v. Fed. Power Comm'n*, 387 U.S. 428, 450 (1967) (interpreting § 7(b) of the Federal Water Power Act of 1920, as amended by the Federal Power Act, 49 Stat. 842, 16 U.S.C. § 800(b)). Other courts have applied *Udall*'s holding to the Natural Gas Act. See, e.g., *N. Natural Gas Co. v. Fed. Power Comm'n*, 399 F.2d 953, 973 (D.C. Cir. 1968) (interpreting section 7 of the Natural Gas Act).

Despite these clear legal requirements, DOE/FE has thus far failed actually to conduct a careful and reasoned analysis of LNG export. Such an analysis would offer a thorough description of LNG exports' implications for the economy on both a macro-scale and on the scale on which people actually live. It would consider the effects of increasing dependence on resource exports on communities in the gas fields, on domestic industry, on the environment, and on U.S. energy policy. It would also offer counterfactuals, considering whether or not the nation would be better off without LNG export, or with lower volumes of export than are now proposed.

The NERA Study does none of these things. Instead, it reduces its analysis ultimately to a consideration solely of U.S. GDP, concluding that because GDP rises with export in its model, even though real wages and incomes fall, export must benefit the country. This conclusion is unsupported, and fails even to weigh the real effects of exports on the nation's life. The NERA Study's many flaws, in particular, prevent that document from serving as a meaningful contribution to DOE/FE's decisionmaking. Rather than relying upon it, DOE/FE should prepare a new study, with full public participation, investigating the many fundamental economic issues which NERA entirely fails to consider.[9]

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[9] Of course, economic issues are not the only matters germane to the public interest analysis. Environmental factors are also vital, and not only because environmental damage necessarily imposes economic costs (a point which we discuss in detail below). They are also relevant in their own right, as the Supreme Court has held and DOE/FE itself has repeatedly acknowledged.

Because DOE/FE must consider environmental impacts in addition to economic considerations, it must gather considerable additional information before deciding whether LNG exports are in the

II. The NERA Study Fails to Account for LNG Export's Significant Negative Impacts on the U.S. Economy

The NERA Study's fundamental flaw is that it mistakes an increase in U.S. GDP, which, even if real, would be captured largely by a narrow set of moneyed interests, for the public interest. It simplistically sums the gains from export that a few accrue with the losses of the many to conclude that Americans benefit overall. A fair look at NERA's own results, and the extensive literature on how resource extraction affects countries and communities, demonstrates that this facile equivalence is simply false.

NERA's flawed approach is perhaps best summed up by its own figures. The figure below, drawn directly from NERA's report[10] for one export scenario, shows a net change in GDP (the black line on the figure) occurring only because NERA expects the natural gas "resource income" which exporters and producers reap to rise somewhat more than labor and capital income fall in response to exports. Even if that is so, the groups that benefit are not the same as those that suffer. Many Americans would experience some portion of the approximately $45 billion in declining wages that NERA forecasts in a single year, and many would suffer the pollution and community disruption that comes with gas production for export. Only a few would reap the revenues. In essence, LNG export transfers billions from the middle class to gas companies.

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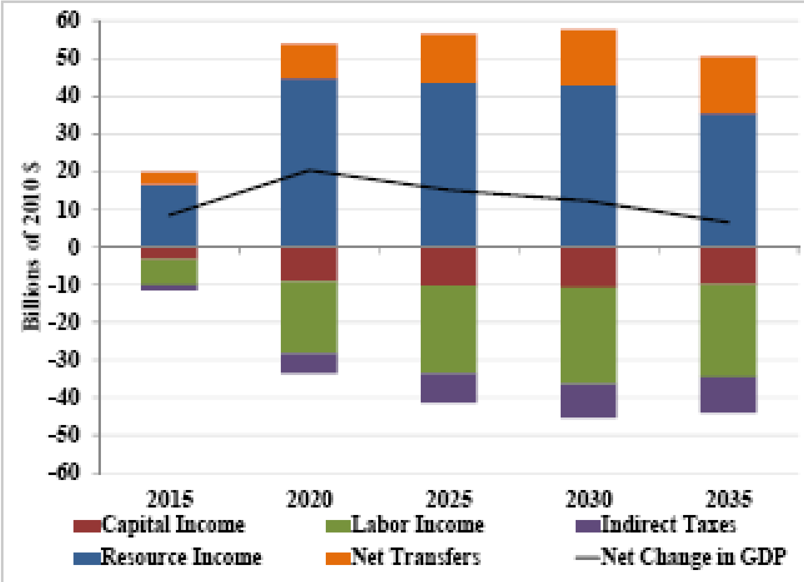
public interest. It can and must do so by complying with NEPA, which requires federal agencies to consider and disclose the "environmental impacts" of proposed agency actions. 42 U.S.C. § 4332(C)(i). NEPA requires preparation of an "environmental impact statement" (EIS) where, as is the case with LNG export proposals, the proposed major federal action would "significantly affect[] the quality of the human environment." 42 U.S.C. § 4332(C). DOE/FE regulations similarly provide that "[a]pprovals or disapprovals of authorizations to import or export natural gas . . . involving major operational changes (such as a major increase in the quantity of liquefied natural gas imported or exported)" will "normally require [an] EIS." 10 C.F.R. Part 1021, Appendix D, D9. DOE must assess these impacts cumulatively across all terminals and export proposals.

A full programmatic EIS is required here, and must consider, among many other points, both the immediate environmental consequences of constructing and operating LNG export facilities and the consequences of the increased gas production necessary to supply them.

[10] NERA Study at 8 (Figure 3).



The costs suffered by the rest of the country to procure a GDP increase that even NERA acknowledges is "very small"[11] are very large – and grow larger as the volume of export increases. They include falling wages and employment, a lasting legacy of community disruption, and likely long-term damage to the national economy's resilience and diversity. They also, as we discuss later in these comments, come with environmental damage, which imposes both economic and ecological costs.

A. The NERA Study Itself Demonstrates that LNG Exports Will Cause Economic Harm and That NERA Does Not Reliably Support Its Claims of Benefits

Sierra Club asked Synapse Energy Economics to conduct a thorough independent review of the NERA Study. Synapse's review is attached to these comments[12] and incorporated in full by reference. Synapse concluded, consistent with other comments in the record, that the NERA study is not reliable and does not demonstrate that LNG exports are in the national economic interest, much less in the public interest generally.[13]

Critical points in that analysis include:

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[11] *Id*. at 8.

[12] See attached, as Ex. 5.

[13] *See also, e.g.*, the Comments of Jannette Barth, Wallace Tyner, David Bellman, and Carlton Buford, in this docket.

LNG Exports Cause The Other Components of GDP To Fall

Just as NERA's own figures suggest, LNG export raises GDP almost entirely because LNG exporters can sell their product at a high price, and capture those revenues. Yet, because LNG export raises gas prices and diverts investment from other sectors, NERA's own results show that the other components of GDP either stay level or *decline* in response to export. In essence, the rest of the economy shrinks as exports expand, leaving a less diversified, and smaller, economy for those who do not profit directly from exports.

LNG Exports Cause Job Losses, According to NERA's Own Methodology

NERA avoided providing employment figures in this report, but the methodology that NERA has used in other studies for that purpose shows major job losses. The declining labor income NERA predicts translates into job losses of between 36,000 to 270,000 "job-equivalents"[14] *per year*; the greater the pace and magnitude of exports, the greater the job losses.

Most Americans Will *Only* Experience the Costs of Export

NERA acknowledges that "[h]ouseholds with income solely from wages" will not benefit from LNG export.[15] But that group contains *most* Americans. Only about half of all Americans own any stock, and only a few, generally wealthy, people own a significant amount. That means very few Americans will benefit at all from enriching LNG and gas companies. For most people, LNG exports simply mean declining wages and employment.

A Significant Amount of LNG and Natural Gas Revenues May Leave America

NERA assumes that LNG export revenues all rest in domestic companies. In fact, many of the companies which now propose to run export terminals are foreign-owned, in whole or in part (including one entity which is owned by the government of Qatar, which would be one of America's competitors in the LNG market), and some are not publicly-held. The complex ownership structure of these companies raises the real possibility that

[14] A "job-equivalent' is the salary of a worker earning the average salary.

[15] NERA Study at 8.

revenues will leave the United States and so may escape domestic taxation and securities markets.[16]

Increasing Exports of Raw Materials Is Associated with Economic Damage
Nations which emphasize raw material export often suffer from significant harm, as export impedes manufacturing and other economic mainstays. This "resource curse" has caused the decline of middle class industrial jobs in other nations, and is also associated with higher levels of corruption and other governance problems. Because the NERA Report relies on stale data that underestimates gas demand, it may underestimate the scope of these potential problems.

NERA Fails Even to Acknowledge the Economic Implications of Environmental Harm from Export
LNG export would significantly increase fracking and other environmental and public health threats. Increased environmental and health damage imposes substantial economic costs. Yet NERA does not acknowledge, much less analyze, these costs.

The Synapse analysis, in short, shows that NERA has entirely missed the point of its own report. Export will cause many wage-earners to lose their jobs or suffer decreased wage income as a result of increases in gas prices. Even employees whose jobs are not directly affected will suffer decreased "real wage growth" as gas prices and household gas expenditures increase relative to nominal wages.[17] All consumers of natural gas—residential, commercial, industrial, and electricity generating users—will suffer higher gas bills despite reducing their gas consumption.[18] While NERA trumpets GDP increases driven by increasing export revenues, its report really shows those increasing export dollars are coming out of the pockets of the American middle class.[19]

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[16] A detailed analysis of the ownership of LNG export companies is attached as Ex 6.

[17] NERA Report at 9.

[18] EIA Export study, at 11, 15. These increases are very large in absolute terms. At a minimum, in the EIA's low/slow scenario, gas and electricity bills increase by $9 billion per year, and this increase grows to $20 billion per year in other scenarios. *Id.* at 14.

[19] The very wealthy do not need more money. An extensive body of economic and philosophical literature demonstrates that the marginal utility of money declines with income—an extra $100 matters less the more money a person has. *See, e.g.*, Matthew D. Adler, *Risk Equity: A New Proposal*, 32 Harv. Envtl. L. Rev. 1 (2008), attached as Ex 7.

The more economic activity that is dedicated to gas production for LNG export, the less focus will there be on building a diversified and strong economic base in this country. Likewise, as LNG export wealth flows to a lucky few, income inequality will grow.

The public interest analysis must account for these effects. Indeed, the Obama Administration has repeatedly emphasized the need to avoid regressive policies that transfer wealth from the middle classes to the wealthy.[20] As the President has explained that "Our economic success has never come from the top down; it comes from the middle out. It comes from the bottom up."[21] Similarly, the President has warned against short-sighted management of wealth. As he explained in the 2009 State of the Union address, the nation erred when "too often short-term gains were prized over long-term prosperity, where we failed to look beyond the next payment, the next quarter, or the next election."[22] DOE/FE must not allow a "surplus [to] bec[o]me an excuse to transfer wealth to the wealthy instead of an opportunity to invest in our future."[23]

B. The NERA Study Underestimates Economic Harm to Manufacturing and Other Sectors That Will Offset the Purported Economic Benefits of Export

The Synapse report explains in detail that, as a result of several flawed assumptions and oversimplifications, the NERA study understates economic harms to manufacturing and other sectors that will result from LNG export. These errors may, in fact, be great enough, on their own, to actually depress total GDP, contrary to NERA's conclusions, as another macroeconomic study in the record, by Purdue economist Dr. Wallace Tyner, explains.[24] Certainly, little in the NERA study inspires any confidence:

First, NERA's use of outdated forecasts of domestic demand for natural gas caused it to significantly understate both price impacts and harm to gas-

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[20] *See, e.g.*, State of the Union Address (January 24, 2012), available at http://www.whitehouse.gov/the-press-office/2012/01/24/remarks-president-state-union-address
[21] Remarks by the President at the Daimler Detroit Diesel Plant, Redford, MI (Dec. 10, 2012), attached as Ex 8 and available at http://www.whitehouse.gov/the-press-office/2012/12/10/remarks-president-daimler-detroit-diesel-plant-redford-mi
[22] State of the Union Address (Feb. 24, 2009), attached as Ex 9 available at http://www.whitehouse.gov/the_press_office/Remarks-of-President-Barack-Obama-Address-to-Joint-Session-of-Congress
[23] *Id.*
[24] *See* Comments of Dr. Wallace Tyner in this docket.

dependent sectors of the U.S. economy. Second, NERA failed to model exports' impact on each economic sector potentially impacted by price increases, and thus impacts to individual industries are obscured. Third, NERA failed to assess impacts to several industries likely to be affected by export. Finally, NERA failed to account for LNG transaction costs that are likely to increase export volumes and exacerbate the price impacts of export. Unless these flaws are corrected, any LNG export decision based on the NERA study will "entirely fail[] to consider . . . important aspect[s]" of the export problem, and will thus be arbitrary and capricious. *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*¸ 463 U.S. 29, 43 (1983).

First, as Synapse explains in detail, the NERA Study inexplicably failed to use the EIA's most recent natural gas demand forecasts, even though NERA has used the more recent data in other reports. NERA used EIA's Annual Energy Outlook (AEO) 2011, even though AEO 2012 was finalized in June 2012, months before the NERA study was completed.[25] Indeed, an October 2012 report entitled *Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector* used the more recent data, showing that it would not have been infeasible for NERA to use it in its December 2012 export study. Moreover, an early release of AEO 2013 was published just days after NERA's report was finalized. NERA nonetheless failed to use the 2013 data – or even the 2012 data – in its analysis.

NERA's failure to use the most recent data significantly altered the outcome of its analysis. Between AEO 2011 and AEO 2012, projections of domestic consumption of natural gas rose above previously predicted levels. Accordingly, NERA's use of the older 2011 data resulted in an underestimate of domestic demand for gas. Using the more recently, higher predictions of demand would decrease the amount of natural gas available for export, thus increasing domestic prices and in turn increasing economic impacts that flow from price increases, including lost income to wage earners and increased costs to household and business consumers of natural gas for heating and electricity.[26]

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[25] See Synapse Report at 17.

[26] Synapse Report at 8. Contrasted against its willingness to use higher demand figures to generate inflated cost estimates for EPA rules controlling toxic mercury emissions, NERA's failure to use the same demand figures here underscores the appearance of bias discussed in detail in part IV, below. For DOE to rely on a study that contains such flaws would "raise questions as to whether the agency is fulfilling its statutory mandates impartially and competently." *Humane Soc'y v. Locke*, 626 F.3d 1040, 1049 (9th Cir. 2010).

Second, by its own admission NERA failed to model exports' impact on each economic sector potentially impacted by price increases, obscuring impacts to individual industries.[27] NERA fails to explain why sector-specific modeling could not be accomplished, stating simply that "it was not possible to model impacts of each of the potentially affected sectors."[28] As Congressman Markey points out in his letter to DOE, however, sector-specific modeling *was* recently conducted in an interagency report designed to assess the economic impacts of the Waxman-Markey cap-and-trade bill, demonstrating that such analysis is both feasible and useful.[29] Without sector-by-sector modeling that uses the most recent data available, impacts to individual economic sectors remain unknown, and those harmed by exports are consequently unable to fully understand and comment on these impacts. The failure to fully describe impacts sector-by-sector, using the most current data available, thus obscures exports' true costs and constrains public participation in export decisions.

Third, NERA failed to fully assess economic impacts to all industries likely to be affected by price increases. NERA states that energy-intensive, trade-exposed industries likely to be affected by price increases are "not high value-added industries," but it does not grapple with the contention – offered by Congressman Markey and by Dow Chemical – that impacts to the manufacturing sector propagate through the economy because they dampen production throughout the value chain.[30] DOE must address this shortcoming in NERA's analysis in order to make an informed decision whether to subject American industry to such far-reaching effects.

Finally, NERA fails to accurately account for transaction costs of LNG exports and thus fails to accurately predict the behavior of market participants. When properly accounted for, these costs tend to increase exports to levels exceeding those predicted by NERA, thus intensifying the impact of export on U.S. gas prices. NERA first potentially overstates the transportation costs associated with export of U.S. gas by assuming that all U.S. gas will be exported from the

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[27] NERA Study at 70.
[28] *Id*.
[29] Letter from Rep. Edward J. Markey to Hon. Steven Chu (Dec. 14, 2012), *available at* http://democrats.naturalresources.house.gov/sites/democrats.naturalresources.house.gov/files/documents/2012-12-14_Chu_NERA.pdf, at 5, attached as Ex 10. Senator Wyden has also written to express similar concerns. *See* Letter from Senator Ron Wyden to Hon. Steven Chu (Jan. 10, 2013), attached as Ex 11.
[30] *Id*. at 6.

Gulf Coast.[31] Exports from the Gulf Coast to Asia have high transportation costs, raising prices paid by the importer and thus making exports less economically attractive. Several export terminals are proposed for the West Coast, however, and these terminals will be able to transport gas to Asia with fewer transportation costs. Accordingly, completion of these terminals may lead to higher volumes of exports than NERA predicts.

In addition, NERA ignores the possibility that long-term contracts at export terminals will lock in exports regardless of subsequent domestic price increases. Under the "take or pay" liquefaction services arrangements that many LNG export terminals will likely adopt, would-be exporters will be required to pay a fee to reserve terminal capacity, regardless of whether that capacity is actually used to liquefy and export gas.[32] This arrangement may cause exporters to continue to export U.S. gas even if prices increase, because the required liquefaction services charges will discourage them from switching to alternative energy sources. As a result, exports may continue to occur – and prices may continue to rise – even where NERA predicts that exports will cease.[33] Such price increases would exacerbate harms to residential and commercial gas consumers, as well as wage earners in manufacturing and other energy-intensive sectors.

In short, NERA not only wrongly attempts to offset harm to the base of the American economy with benefits to a few gas corporations to reach its sunny conclusions, it also very likely understates the real magnitude of the harm.

C. LNG Exports Will Harm Communities Across the Country

Harms associated with LNG export are not limited to other industrial sectors. A closer look at the real consequences of increasing dependence on export and gas production underlines NERA's core error of mistaking gas company profits for the public interest. Indeed, the real costs extend beyond the national-level declines in middle class welfare and industry. The "resource curse" which LNG export portends for the nation as a whole is echoed by the stories of similarly "cursed" regions across the country that are dependent upon resource extraction as an economic driver. In those regions, the same patterns recur: Weak growth or decline in other industries, population losses, soaring infrastructure costs, and

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[31] NERA Study at 88-89, 210.

[32] *See Sabine Pass* DOE Order No. 2961, at 4 (May 20, 2011); Cheniere Energy April 2011 Marketing Materials, *available at* http://tinyurl.com/cqpp2h8 (last visited Jan. 13, 2013), at 14.

[33] *See* NERA Study at 37-46.

all the other consequences of being at the receiving end of an extractive apparatus that channels the wealth of a resource boom from an entire landscape into just a few pockets.[34]

Of course, many communities are already suffering these costs as the shale gas boom sweeps the nation. But the question now is whether to double-down on that economic strategy. Export will intensify the demand for gas, and accelerate the shift towards extraction-based economies around the country, with all the costs that attach to that choice. NERA entirely fails to consider these impacts, but they are central to the public interest question before DOE/FE, and it would be arbitrary and capricious to ignore them in the way that NERA has done. DOE/FE must weigh them in its analysis.

i. Resource Extraction Is Associated with Economic Damage

"Resource curse" effects are well documented in the economic literature. One of the most comprehensive surveys, by Professors Freudenburg and Wilson, of economic studies of "mining" communities (including oil and gas communities) concludes that the long-term economic outcomes are "consistently and significantly negative."[35] That research surveys a broad body of international and national work to conclude that strikingly few studies report long-term positive consequences for mining-dependent communities. One of the many papers recorded in that comprehensive survey concludes that census data from across the country showed that "mining-dependent counties had lower incomes and more persons in poverty than did the nonmining counties."[36]

These results occur because resource extraction dependent economies are fragile economies. Increasing dependence on raw material markets diverts investment from more durable industries, less influenced by resource availability and changing market costs. The inherent boom and bust cycle of such activities also stresses the infrastructure and social fabrics of regions focused on resource

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[34] Other workers have raised further important questions, which DOE/FE must consider, about the shale gas boom's implications for the domestic economy and environment, as well as for U.S. energy security. *See, e.g.*, Food and Water Watch, *U.S. Energy Insecurity: Why Fracking for Oil and Natural Gas is a False Solution* (2012), available at http://documents.foodandwaterwatch.org/doc/USEnergyInsecurity.pdf, and attached as Ex 12.
[35] W.R. Freudenburg & L.J. Wilson, *Mining the Data: Analyzing the Economic Implications of Mining for Nonmetropolitan Regions*, 72 Sociological Inquiry 549 (2002) at 549, attached as Ex 13.
[36] *Id.* at 552.

extraction to the exclusion of more sustainable growth. As Freudenburg & Wilson explain:

> [T]here is a potentially telling contrast in two types of studies that have gauged the reaction of local leaders. In regions that are expected increased mining or just beginning to experience a "boom," it is typical to find … "euphoria." Unfortunately, in regions that have actually experienced natural resource extraction, local leaders have been found to view their economic prospects less in terms of jubilation than of desperation.[37]

Indeed, the Rural Sociological Society's Task Force on Rural Poverty "ultimately identified resource extraction not as an antidote to poverty but as something more like a cause or correlate."[38]

A study of the long-term prospects of western U.S counties which focused on resource extraction rather than more durable economic growth strategies documents this trend. That 2009 study by Headwaters Economics looked at the performance of "energy-focusing" regions compared to comparable counties over the decades since 1970.[39] It concludes that "counties that have focused on energy development are underperforming economically compared to peer counties that have little or no energy development."[40]

These differences are stark. The economic data Headwaters gathered shows that energy-focused counties have careened through periods of intense booms and lasting busts which have impaired the resilience and long-term growth of their economies.[41] Although growth spiked during boom periods, it cratered when energy production faltered, creating economies "characterized by fast acceleration and fast deceleration."[42] This stutter-step depresses long-term growth. In energy-focusing counties from 1990 to 2005, for instance, the average rate of personal income growth was 0.6% lower than in more diversified counties, and the employment growth rate was 0.5% lower.[43]

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[37] *Id.* at 553.
[38] *Id.*
[39] Headwaters Economics, *Fossil Fuel Extraction as a County Economic Development Strategy: Are Energy-Focusing Counties Benefiting?* (revised. July 2009), attached as Ex 14.
[40] *Id.* at 2.
[41] *See id.* at 8-10.
[42] *Id.* at 10.
[43] *Id.*

These slow growth rates are symptomatic of deep structural differences. As Headwaters explains, the energy-focusing counties did not diversify their economies; indeed, they were nearly three times less diversified than their peer counties, meaning that they hosted far fewer different industries than their peers.[44] As a result, when growth occurred, it occurred only in a few sectors, leaving those counties vulnerable to contractions in energy use and to energy price spikes.[45]

Narrowly focusing on energy jobs also rendered these counties less broadly prosperous. A wage gap of over $30,000 annually opened between energy workers and workers in other fields in these counties between 1990 and 2006.[46] This "is not a healthy sign" because it means that "more people, including teachers, nurses, and farm workers, will be left behind if renewed energy development increases the general cost of living, especially the cost of housing."[47] The energy-focusing counties show this divergence between haves and have-nots: their income distributions show a larger proportion of relatively poorer families and a few very wealthy ones, indicating that energy wealth does not flow readily into the larger economy.[48]

The energy-focusing counties also had systematically lower levels of education, and lower levels of retirement and investment dollars than their peers.[49] By focusing on energy, rather than providing a broad range of services, they were less able than their peers to attract a broad economic base that could attract new investors and educated workers.

The upshot is that, on almost every measure, energy production did not prove to be a successful development strategy. Only one of the 30 energy-focused counties Headwaters studied ranked among the top 30 economic performers in the western United States in 2009, and more than half were losing population.[50] As Headwaters summarized its conclusions:

> EF ["Energy-focusing"] counties are today less well positioned to compete economically. EF counties are less diverse economically, which makes them

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[44] *Id.* at 17.
[45] *See id.* at 17-18.
[46] *Id.* at 19.
[47] *Id.*
[48] *Id.* at 20.
[49] *Id.* at 20-21.
[50] *Id.* at 2.

> less resilient but also means they are less successful at competing for new jobs and income in growing service sectors where most of the West's economic growth has taken place in recent decades. EF counties are also characterized by a greater gap between high and low income households, and between the earnings of mine and energy workers and all other workers. And EF counties are less well educated and attract less investment and retirement income, both important areas for future competitiveness.[51]

The experience of one of these counties, Sublette County, Wyoming, is particularly telling in this regard. A 2009 report prepared for the Sublette County Commissioners[52] describes experiences consistent with those analyzed by Freudenburg & Wilson and by Headwaters.

The Sublette study shows that a gas boom accompanied by thousands of wells, has caused real economic stress in the country, even as it enriched some residents. It determined that the 34% population increase in the county, which far outstripped historical trends, and accompanying demands on infrastructure and social services, were seriously disrupting the regional economy.[53]

The study records a region struggling under the impacts of a boom. The population of the country increased by over 3,000 people in under a decade, and is expected to grow by another 3,000.[54] This huge influx of energy-related employees is badly stressing regional social and physical infrastructure. The regional governments have already spent over $60 million on capital upgrades to improve roads and sewers which are crumbling under the strain, but remain at least $160 million in the hole relative to projects which they need to undertake to accommodate their new residents.[55] One town will need to spend the equivalent of ten years of annual revenue for just one necessary sewer project and "[s]imilar scenarios exist for all jurisdictions within Sublette County."[56] Municipalities across the country are unable to afford upgrades necessary to maintain their systems.[57]

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[51] *Id.* at 22.
[52] Ecosystem Research Group, *Sublette County Socioeconomic Impact Study Phase II- Final Report* (Sept. 28, 2009), attached as Ex 15
[53] *See id* at ES-3 – ES-5.
[54] *Id.*at 10-15.
[55] *Id.* at 55.
[56] *Id.*
[57] *Id.* at 115-116.

Meanwhile, just as Headwaters reported for the West generally, energy extraction is driving up economic inequality and making it more difficult to sustain other county residents. Housing prices in Sublette County increased by over $21,000 *annually*,[58] far ahead of income growth. Indeed, the gap between the qualifying income to buy an average Sublette County home and the median wage was over $17,000 in 2007.[59] The report concludes that "[i]f this trend continues fewer and fewer families will be able to afford an average home."[60] Only employees in the gas sector could afford such purchases; "all other employment sectors had average annual incomes significantly below that required to buy a house."[61]

Consistent with the increase in housing costs, the cost of living increased throughout the county, with energy job wages far outpacing those in all other sectors meaning that "[w]orkers in sectors with lower average wages may find it difficult to keep up."[62]

The boom has also come with social disruption. Traffic has vastly increased and accidents have more than doubled, with over a quarter of them resulting in injury.[63] Over $87 million in road projects are necessary to manage this increased traffic.[64] Crime has also jumped: there were only 2 violent offenses (such as rape and murder) in 2000, before the boom but there were 17 in 2007.[65] Juvenile arrests rose by 92% and DUI cases have spiked sharply upwards, increasing by 57% from 2000 to 2007.[66]

All these disruptions and tens of millions in spending come to support a boom that will not last. The report records that the oil and gas companies operating in the counties expect to see employment drop from thousands of workers to only several hundred within the next decades.[67] Once the wave passes, Sublette County will be left with lingering infrastructure costs, a less diversified economy, and the pollution from thousands of wells and associated equipment. That path

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[58] *Id.*at 90.
[59] *Id.* at 92.
[60] *Id.*
[61] *Id.*
[62] *Id.*at 87.
[63] *Id.*at 102.
[64] *Id.* at 107.
[65] *Id.*
[66] *Id.* at 110-11.
[67] *Id*. at 81.

leads, as the Headwaters report shows, towards a less resilient, less prosperous, future.

ii. The Shale Gas Boom is Causing Similar Problems, and LNG Export Will Worsen Them

The shale gas production boom which LNG export would exacerbate is very likely to follow this familiar pattern of short-term gain for a few, accompanied by long-term economic suffering for many more residents of resource production regions. Although the boom is still in a relatively early phase, available analysis already suggests that the same problems will recur. Export-linked production will intensify the pace and severity of the boom, causing further economic dislocation.

One recent study by Amanda Weinstein and Professor Mark Partridge of Ohio State University, for instance, documents patterns that mimic those seen in the Headwaters and Sublette studies, and in the Freudenburg and Wilson review paper.[68] Using Bureau of Economics Analysis statistics, the study directly compared employment and income in counties in Pennsylvania with significant Marcellus drilling and without significant drilling, and before after the boom started. As Table 1, below, shows, counties in both areas *lost* jobs even as drilling accelerated during the economic recession of 2008, and that the drilling counties lost jobs more quickly. Income increased more quickly in those counties at the same time in a pattern that tracks the results from the western United States studies discussed above: Drilling activities brings more wealth into an area, but that wealth is concentrated in the extraction sector, even as job losses occur in other sectors

Table 1: Comparing Pennsylvania Counties, With and Without Drilling, Over Time[69]

	Employment Growth Rate 2001-2005	**Employment Growth Rate 2005-2009**	**Income Growth Rate 2001-2005**	**Income Growth Rate 2005-2009**
Drilling	1.4%	-0.6%	12.8%	18.2%

[68] Amanda Weinstein and Mark D. Partridge, *The Economic Value of Shale Natural Gas in Ohio*, OHIO STATE UNIVERSITY, Swank Program in Rural-Urban Policy Summary and Report (December 2010) ("Ohio Study"), attached as Ex 16.
[69] Adapted from Table 1 of the *Ohio Study* at 15.

Counties				
Non-Drilling Counties	5.3%	-0.4%	12.6%	13.6%

These shifts in the job market are accompanied by the same set of infrastructure costs and harms to other industries that are familiar from the western case studies.[70] Tourism, a particularly lucrative industry in the northeastern regions where the Marcellus Shale boom is expanding, is likely to be particularly hard hit. Gas production harms tourism by clogging roads, impacting infrastructure, diminishing the scenic value of rural areas, and through other means. These threats to the tourism industry are particularly concerning for many parts of the Marcellus region, including New York's Southern Tier, where tourism is a major source of income and employment. In the Southern Tier, according to one recent study, the tourism industry directly accounts for $66 million in direct labor income, and 4.7% of all jobs, and supports 6.7% of the region's employment.[71]

And, once again, job losses seem likely to follow the boom, as the initial production phase ends. As the Ohio Study explains, "impact studies do not produce continuous employment numbers. If an impact study says there are 200,000 jobs, this does not mean 200,000 workers are continuously employed on a permanent basis. . . . [W]hile the public is likely more interested in continuous ongoing employment effects, impact studies are producing total numbers of supported jobs that occur in a more piecemeal fashion."[72] This failing is particularly relevant here, because the manufacturing and other jobs LNG exports and export-related production will eliminate are typically permanent positions,[73] whereas the gas production jobs induced production will create typically do not provide sustainable, well-paying local employment. This is in part because the industry's employment patterns are uneven: one study found that, in Pennsylvania, "*the drilling phase accounted for over 98% of the natural gas*

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[70] Infrastructure costs include, for example, costs to roads, water, and hospitals. *See, e.g.*, CJ Randall, *Hammer Down: A Guide to Protecting Local Roads Impacted by Shale Gas Drilling* (Dec. 2010), attached as Ex 17; Susan Riha & Brian G. Rahm, *Framework for Assessing Water Resource Impacts from Shale Gas Drilling* (Dec. 2010), attached as Ex 18; Associated Press, *Gas Field Workers Cited in Pa. Hospital's Losses*, Pressconnects.com (Dec. 24, 2012), attached as Ex 19.

[71] Andrew Rumbach, *Natural Gas Drilling in the Marcellus Shale: Potential Impacts on the Tourism Economy of the Southern Tier* (2011), attached as Ex 20.

[72] Ohio Study at 11.

[73] NERA report at 62.

industry workforce engaged at the drilling site," and that complementary Wyoming data showed a similar drop-off.[74]

Drilling jobs, in short, correspond to the boom and bust cycle inherent to resource extraction industries.[75] The remaining, small, percentage of production-phase and office jobs are far more predictable, but must be filled with reasonably experienced workers.[76] Although job training at the local level can help residents compete, the initial employment burst is usually made up for people from out of the region moving in and out of job sites; indeed, "[t]he gas industry consistently battles one of the highest employee turnover problems of any industrial sector."[77]

A set of studies from Cornell University's Department of City and Regional Planning confirm this pattern of a short burst of economic activity followed by general economic decline. Those researchers spent more than a year studying the economic impacts of the gas boom on Pennsylvania and New York. Their core conclusion is that boom-bust cycle inherent in gas extraction makes employment benefits tenuous, and may leave some regions hurting if they are unable to convert the temporary boom into permanent growth. As the researchers put it:

> The extraction of non-renewable natural resources such as natural gas is characterized by a "boom-bust" cycle in which a rapid increase in economic activity is followed by a rapid decrease. The rapid increase occurs when drilling crews and other gas-related businesses move into a region to extract the resource. During this period, the local population grows and jobs in construction, retail and services increase, though because the natural gas extraction industry is capital rather than labor intensive, drilling activity itself will produce relatively few jobs for locals. Costs to communities also rise significantly, for everything from road maintenance and public safety to schools. When drilling ceases because the commercially recoverable resource is depleted, there is an economic "bust" – population and jobs depart the region, and fewer people are left to support the boomtown infrastructure.[78]

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[74] *See* Jeffrey Jacquet, *Workforce Development Challenges in the Natural Gas Industry*, at 4 (Feb. 2011) (emphasis in original), attached as Ex 21.

[75] *Id.*

[76] *Id.* at 4-5, 12-14.

[77] *Id.* at 13.

[78] Susan Cristopherson, CaRDI Reports, *The Economic Consequences of Marcellus Shale Gas Extraction: Key Issues* (Sept. 2011) at 4, attached as Ex 22.

This boom and bust cycle is exacerbated by the purportedly vast resources of the Marcellus play, because regional impacts will persist long after local benefits have dissipated, as the authors explain, and may be destructive if communities are not able to plan for, and capture, the benefits of industrialization:

> [B]ecause the Marcellus Play is large and geologically complex, the play as a whole is likely to have natural gas drilling and production over an extended period of time. While individual counties and municipalities within the region experience short-term booms and busts, the region as a whole will be industrialized to support drilling activity, and the storage and transportation of natural gas, for years to come. Counties where drilling-related revenues were never realized or could have ended may still be impacted by this <u>regional</u> industrialization: truck traffic, gas storage facilities, compressor plants, and pipelines. The cumulative effect of these seemingly contradictory impacts – a series of localized short-term boom-bust cycles coupled with regional long-term industrialization of life and landscape – needs to be taken into account when anticipating what shale gas extraction will do communities, their revenues, and the regional labor market, as well as to the environment.[79]

Some people will prosper and some will not during the resultant disruption and, warn the Cornell researchers, the long-term effects may well not be positive, based upon years of research on the development of regions dependent on resource extraction:

> [T]he experience of many economies based on extractive industries warns us that short-term gains frequently fail to translate into lasting, community-wide economic development. *Most alarmingly, a growing body of credible research evidence in recent decades shows that resource dependent communities can and often do end up worse than they would have been without exploiting their extractive reserve.* When the economic waters recede, the flotsam left behind can look more like the aftermath of a flood than of a rising tide.

Id. at 6 (emphasis supplied).

[79] *Id.* (emphasis in original).

A later, peer-reviewed and formally published version of this work, builds upon these lessons.[80] Collecting research from around the country, including the Sublette County experience discussed above, it canvasses the infrastructure stresses,[81] social dislocations and population shifts,[82] and environmental costs of resource extraction,[83] to conclude that expanding the shale gas boom may well harm many communities, explaining that "rural regions whose economies are dependent on natural resource extraction frequently have poor long-term development outcomes."[84]

In fact, the researchers conclude that in some cases communities "may wind up worse off" than they were before the boom started.[85] They explain that the boom-related cost of living and materials expense increases may well crowd out other industries, such as the fragile dairy industry now operating in many northeastern shale plays.[86] Gas boom regions may even wind up shrinking. Counties in New York and Pennsylvania with significant natural gas drilling between 1994 and 2009 have lost more population than peers without drilling activity.[87]

After the boom recedes, the weakened local economy struggles to provide for the infrastructure that was required to support the boom:

> During the boom period, the county's physical infrastructure was planned and installed to accommodate an expanding population. The nature of infrastructure such as roads, sewer and water facilities, and schools is that once it is built, it generates ongoing maintenance costs (as well as debt service costs) even if consumption of the facilities declines…. The departure of [boom time] workers and higher income, mobile professionals [will leave] the burden of paying for such costs to remaining smaller, lower-income, population.[88]

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[80] S. Christopherson & N. Rightor, *How shale gas extraction affects drilling localities: Lessons for regional and city policy makers*, 2 Journal of Town & City Management 1 (2012), attached as Ex 23.
[81] *Id.* at 11-12.
[82] *Id.* at 10-11.
[83] *Id.* at 12-13.
[84] *Id.* at 15.
[85] *Id.*
[86] *Id.*
[87] *Id.*
[88] *Id.* at 16.

In short, resource booms may bring wealth to a few companies, and, transiently, to some regions, but the long-term consequences are negative.[89] After the boom passes, those who remain behind must live with a lasting negative legacy. If LNG exports drive regional economies towards an even more intense boom, the bust, when it comes, will be all the worse.

D. Conclusions on Industrial Costs and Community Impacts

At bottom, LNG export means intensifying an economic strategy that has failed nations and communities over and over again. It would mark a path towards increasing economic inequality, a weaker social fabric in communities across the country, and a weaker middle class. Even during the boom, infrastructure costs and social disruption impose major burdens on extraction regions. DOE/FE must consider all these costs. But NERA sets all those costs at naught because the raw revenues from LNG export are so large for those that capture them. DOE/FE's task, though, is to look to the *public* interest, not the interest of a narrow segment of industry. It would be arbitrary and capricious to approve of exports on the basis of the NERA Report, which so entirely under-values the very considerations which must be at the heart of DOE/FE's analysis.

III. NERA Fails to Account for the Economic Implications of Environmental Harm Caused by LNG Export; DOE/FE Must Do So.

Just as NERA ignores or improperly downplays the serious negative consequences of developing a resource-extraction based economy for export, it also entirely fails to acknowledge that LNG exports impose substantial environmental costs. These costs range from the immediate costs of treating waste from fracking to the public health costs of air and water pollution from the gas production sector to the increased risk of global climate change inherent in deepening our dependence on fossil fuels. Indeed, air pollution emissions alone likely impose costs in the hundreds of millions of dollars, at a minimum, and would erode recent pollution control efforts.

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[89] Indeed, there is significant evidence that many studies touting high benefits from gas extraction suffer from systematic procedural flaws which render them unreliable. *See* T. Kinnaman, *The economic impact of shale gas extraction: A review of existing studies*, 70 Ecological Economics 1243 (2011). Dr. Kinnaman concludes that a careful review of actual data on shale gas reserves in Pennsylvania, Arkansas, and Texas shows that "shale drilling and extraction activities decreased per capita incomes" rather than benefitting residents of gas fields in those areas, attached as Ex 24.

The existence of these impacts, and their importance, should be familiar to DOE/FE, based upon the work of DOE's own Secretary of Energy Advisory Board Subcommittee on Shale Gas Production.[90] In response to Presidential and Secretarial directives, the Subcommittee met for months to assess measures to be taken to reduce the environmental impact of shale gas production. It concluded that "if action is not taken to reduce the environmental impact accompanying the very considerable expansion of shale gas production expected across the country… there is real risk of serious environmental consequences."[91] Action is especially necessary because the gas production industry currently enjoys exemptions to many federal environmental statutes, and as such, gas producers have greater ability act in ways that impose external costs on the public.[92] The Subcommittee recommended building a "strong foundation of regulation and enforcement" to improve shale gas production practices, and set forth twenty regulatory recommendations addressing air and water pollution and other threats from current production practices.[93] The Subcommittee was alarmed that progress on these recommendations was less than it had hoped, and urged "concerted and sustained action is needed to avoid excessive environmental impacts of shale gas production."[94]

The vast majority of the Subcommittee's recommendations, which were made in 2011, remain unfulfilled, meaning that the risk of "excessive environmental impacts" remains pressing, as the Subcommittee put it. The LNG exports DOE/FE is now considering would intensify these risks by intensifying shale gas production around the country. The environmental costs of that decision are very real. They are measured in the costs of treatment plants and landfills, of emergency room visits and asthma attacks, of lost property values and rising seas. They will be felt as acutely as the wage and income losses export will cause, and must be accounted for in any proper economic analysis. Indeed, the very existence of these impacts, and the continued absence of the "strong foundation" of regulation recommended by the expert Subcommittee

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[90] Secretary of Energy Advisory Board Shale Gas Production Subcommittee, *Second 90-Day Report* (Nov. 18, 2011), attached as Ex 25.

[91] *Id.* at 10.

[92] For example, gas production is exempt from various provisions of the Safe drinking Water Act, 42 U.S.C. § 300h(d)(1)(B), certain hazardous air pollution regulations under the Clean Air Act, 42 U.S.C. § 7412(n)(4)(B) , stormwater provisions of the Clean Water Act, 33 U.S.C. § 1362(24), and the Comprehensive Environmental Response, Compensation, and Liability Act 42 U.S.C. § 9601(10)(I), (14), (33).

[93] *See SEAB Second 90-Day Report* at 10, 16-18.

[94] *Id.* at 10.

demonstrates that LNG exports counsels strongly against moving forward with export.

Yet, NERA ignores these impacts completely. Because its report fails to even acknowledge this critically important negative side of the ledger, the study is ultimately incomplete and unreliable.

A. Induced Production Can and Must be Analyzed as Part of This Accounting

Before turning to some of the many environmental costs imposed by LNG export, it is important to emphasize that DOE/FE can, in fact, account for them. These costs fall into two classes: The environmental impacts associated with LNG export infrastructure itself (such as the emissions from liquefaction facilities, increased traffic of LNG tankers, and the network of pipelines and compressors needed to support them); and the environmental impacts of the major increase in natural gas production to supply gas for export. There is no real dispute, even within DOE/FE, that the first set of impacts can be estimated. But DOE/FE has previously questioned whether it can analyze the second set of impacts. In fact, DOE's own models allow it to do so.

As the NERA Study acknowledges, LNG exports will increase U.S. gas production.[95] Indeed, these production increases provide at least a portion of the purported benefits of export that the Study touts.[96] If DOE/FE intends to advance induced production as part of the justification for exports, then induced production is plainly a reasonably foreseeable effect of exports that must be analyzed under NEPA. DOE/FE must consider the considerable impacts on air, land, water, and human health from induced production.[97]

These impacts can be calculated. EIA and DOE have precise tools enabling them to estimate how U.S. production will change in response to LNG exports. These tools enable DOE/FE to predict how and when production will increase in individual gas plays. EIA's core analytical tool is the National Energy Modeling System ("NEMS"). NEMS was used to produce the EIA exports study that

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[95] NERA Study at 51-52 & fig. 30.

[96] *See, e.g.*, *id.* at 9 fig.4; 62 fig.39.

[97] Sierra Club has described these impacts in numerous comments on individual export proposals. *E.g.*, Sierra Club Mot. Intervene, Protest, and Comments, *In the Matter of Southern LNG Company*, DOE/FE Dkt. No. 12-100-LNG (Dec. 17, 2012), attached as Ex 26.

preceded the NERA study. NEMS models the economy's energy use through a series of interlocking modules that represent different energy sectors on geographic levels.[98] Notably, the "Natural Gas Transmission and Distribution" module already models the relationship between U.S. and Canadian gas production, consumption, and trade, specifically projecting U.S. production, Canadian production, imports from Canada, etc.[99] For each region, the module links supply and demand annually, taking transmission costs into account, in order to project how demand will be met by the transmission system.[100] Importantly, the Transmission Module is *already* designed to model LNG imports and exports, and contains an extensive modeling apparatus allowing it to do so on the basis of production in the U.S., Canada, and Mexico.[101] At present, the Module focuses largely on LNG imports, reflecting U.S. trends up to this point, but it also already links the Supply Module to the existing Alaskan *export* terminal and projects exports from that site and their impacts on production.[102]

Similarly, the "Oil and Gas Supply" module models individual regions and describes how production responds to demand across the country. Specifically, the Supply Module is built on detailed state-by-state reports of gas production curves across the country.[103] As EIA explains, "production type curves have been used to estimate the technical production from known fields" as the basis for a sophisticated "play-level model that projects the crude oil and natural gas supply from the lower 48."[104] The module distinguishes coalbed methane, shale gas, and tight gas from other resources, allowing for specific predictions distinguishing unconventional gas supplies from conventional supplies.[105] The module further projects the number of wells drilled each year, and their likely production – which are important figures for estimating environmental impacts.[106] In short, the supply module "includes a comprehensive assessment method for

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[98] Energy Information Administration ("EIA"), *The National Energy Modeling System: An Overview*, 1-2 (2009), attached as Ex 27, available at http://www.eia.gov/oiaf/aeo/overview/pdf/0581(2009).pdf.
[99] *Id.* at 59.
[100] EIA, *Model Documentation: Natural Gas Transmission and Distribution Module of the National Energy Modeling System*, 15-16 (2012), attached Ex 28, *available at* http://www.eia.gov/FTPROOT/modeldoc/m062(2011).pdf.
[101] *See id.* at 22-32.
[102] *See id.* at 30-31.
[103] EIA, *Documentation of the Oil and Gas Supply Module*, 2-2 (2011), attached as Ex 29, *available at* http://www.eia.gov/FTPROOT/modeldoc/m063(2011).pdf.
[104] *Id.* at 2-3.
[105] *Id.* at 2-7.
[106] *See id.* at 2-25 to 2-26.

determining the relative economics of various prospects based on future financial considerations, the nature of the undiscovered and discovered resources, prevailing risk factors, and the available technologies. The model evaluates the economics of future exploration and development from the perspective of an operator making an investment decision."[107] Thus, for each play in the lower 48 states, the EIA is able to predict future production based on existing data. The model is also equipped to evaluate policy changes that might impact production; according to EIA, "the model design provides the flexibility to evaluate alternative or new taxes, environmental, or other policy changes in a consistent and comprehensive manner."[108]

EIA is not alone in its ability to predict localized effects of LNG exports. A study and model developed by Deloitte Marketpoint claims the ability to make localized predictions about production impacts, and numerous other LNG export terminal proponents have relied on this study in applications to FERC and DOE.[109] According to Deloitte, its "North American Gas Model" and "World Gas Model" allow it to predict how gas production, infrastructure construction, and storage will respond to changing demand conditions, including those resulting from LNG export. According to Deloitte, the model connects to a database that contains "field size and depth distributions for every play," allowing the company to model dynamics between these plays and demand centers. "The end result," Deloitte maintains, "is that valuing storage investments, identifying maximally effectual storage field operation, positioning, optimizing cycle times, demand following modeling, pipeline sizing and location, and analyzing the impacts of LNG has become easier and generally more accurate."[110]
But even if not all impacts can be precisely estimated and monetized, DOE/FE cannot avoid acknowledging them. Where uncertainty exists, DOE/FE could still meaningfully analyze the environmental impacts of induced drilling by estimating impacts from all permitted exports in the aggregate, based on industry-wide data regarding the impacts of gas drilling.

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[107] *Id.* at 2-3.
[108] *Id.*
[109] Deloitte Marketpoint, *Made in America: The Economic Impact of LNG Exports from the United States* (2011), available at http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/Energy_us_er/us_er_MadeinAmerica_LNGPaper_122011.pdf and attached as
[110] Deloitte, *Natural Gas Models*, http://www.deloitte.com/view/en_US/us/Industries/power-utilities/deloitte-center-for-energy-solutions-power-utilities/marketpoint-home/marketpoint-data-models/b2964d1814549210VgnVCM200000bb42f00aRCRD.htm (last visited Dec. 20, 2012).

Thus, there is no technical barrier to modeling where exports will induce production going forward, or to beginning to monetize and disclose the costs they will impose. Indeed, EIA used such models for its export study, which forecast production and price impacts, and which DOE/FE already relies upon. DOE/FE cannot assert that it is unable to count the significant environmental and economic costs associated with increased gas production for export. It must do disclose and consider these costs.

B. Gas Production for Export Will Come With Significant Environmental Costs

The environmental toll of increased unconventional gas production is very great, especially without full implementation of the Shale Gas Subcommittee report. We do not intend here to fully count these costs: That is DOE/FE's charge, under both NEPA and the Natural Gas Act. The discussion in these comments merely indicates some of the many costs which DOE/FE must consider, and which NERA failed to disclose.

In this regard, we draw DOE/FE's attention to a recent report by researchers at Environment America, which attempts to monetize many costs from fracking activities, ranging from direct pollution costs to infrastructure costs to lost property values.[111] We incorporate that report by reference. DOE/FE should fully account for all the costs enumerated therein.

It is true that some uncertainty necessarily attaches to environmental costs like the ones we discuss below. But, as the Ninth Circuit Court of Appeals explained in *Center for Biological Diversity v. NHTSA*, some uncertainty in estimation methodologies does not support declining to quantitatively value benefits associated with reducing climate change pollution at all.[112] Where, as here, "the record shows that there is a range of values [for these benefits], the value of carbon emissions reduction is certainly not zero."[113] Therefore, the agency is obligated to consider such a value, or range of values.[114] Since LNG export plainly imposes these significant environmental costs, DOE/FE should calculate and disclose them (accompanied by an explanation of any limitations or

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[111] *See* T. Dutzik *et al.*, *The Costs of Fracking* (2012), attached as Ex 30.

[112] *See Center for Biological Diversity*, 538 F.3d 1172, 1200 (9th Cir. 2008) (citing Office of Management and Budget Circular A-4 as providing that "agencies are to monetize costs and benefits whenever possible.").

[113] *See id.*

[114] *See id.* at 1203.

uncertainties in each methodology, as necessary). It may not, however, simply ignore them.

i. Air Pollution and Climate Costs

Oil and gas production, transmission, and distribution sources are among the very largest sources of methane and volatile organic compounds in the country, and also emit large amounts of hazardous air pollutants ("HAPs") and nitrogen oxide, among other pollutants.[115] Although EPA has recently issued pollution standards that control some pollutants from new sources, the majority of the industry remains unregulated. Increasing gas production will necessarily increase air pollution from the industry. Indeed, gas export would produce enough air pollution to diminish – if not to entirely offset – the benefits of EPA's recent standards.

LNG exports would also increase air pollution costs in other ways. They would, for instance, likely increase the use of coal-fired electricity, which imposes significant public health costs. They would also deepen our economic dependence on fossil fuels, which are exacerbating global climate change. DOE/FE must account for all of these costs.

Direct Emissions Costs

The potential air pollution increase from LNG exports is very large. 9,052 bcf per year of gas are proposed for export, and NERA considered scenarios of between 4,380 bcf and 1,370 bcf of exports per year by 2035. The EIA's induced production models indicate that 63% of this gas (or more) will come from new production.[116] Although the range of estimates for gas leaked from productions systems varies, if even a small amount of this newly produced gas escapes to the atmosphere the pollution consequences are major.

EPA's current greenhouse gas inventory implies that about 2.4% of gross gas production leaks to the atmosphere in one way or another, a leak rate that makes

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[115] *See generally* U.S. EPA, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution* : *Background Supplemental Technical Support Document for the Final New Source Performance Standards* (2012) (discussing these and other pollutants), attached as Ex 31; U.S. EPA, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards* (2011) (hereinafter "2011 TSD"), attached as Ex 32.
[116] EIA Study at 10.

oil and gas production the single largest source of industrial methane emissions in the country, and among the very largest sources of greenhouse gases of any kind.[117] More recent work by National Oceanic and Atmospheric Administration ("NOAA") scientists suggest, based on direct measurement at gas fields, that this leak rate may be between 4.8% and 9%, at least in some fields.[118] These leak rates, and EPA conversion factors between the typical volumes of methane, VOC, and HAP in natural gas,[119] make it possible to calculate the potential impact of increasing gas production in the way that LNG export would require. We note that fugitive emissions include additional pollutants not discussed here, such as radioactive radon.[120]

The table below shows our calculations of expected pollution from fugitive emissions of methane, VOCs, and HAP based on these conversion factors, at varying leak rates (starting at 1% of production and going to 9%).[121] We acknowledge, of course, that these calculations are necessarily only a first cut at the problem. The point, here, is not to generate the final analysis (which DOE/FE must conduct) but to demonstrate that the problem is a serious one.

Export Volume in	Methane (tons)	VOC (tons)	HAP (tons)

[117] Alvarez *et al.*, *Greater focus needed on methane leakage from natural gas infrastructure*, Proceedings of the National Academy of Science (Apr. 2012) at 1, attached as Ex 33; *see also* EPA, *U.S. Greenhouse Gas Emissions and Sinks 1990-2010* (Apr. 15, 2012) at Table ES-2, attached as Ex 34.

[118] *See* G. Petron *et al.*, *Hydrocarbon emissions characterization in the Colorado Front Range – A pilot study*, Journal of Geophysical Research (2012), attached as Ex 35; J. Tollefson, *Methane leaks erode green credentials of natural gas*, Nature (2013), attached as Ex 36.

[119] *See* EPA, 2011 TSD at Table 4.2. EPA calculated average composition factors for gas from well completions. These estimates, which are based on a range of national data are robust, but necessarily imprecise for particular fields and points along the line from wellhead to LNG terminal. Nonetheless, they provide a beginning point for quantitative work. EPA's conversions are: 0.0208 tons of methane per mcf of gas; 0.1459 lb VOC per lb methane; and 0.0106 lb HAP per lb methane.

[120] *See* Marvin Resnikoff, *Radon in Natural Gas from Marcellus Shale* (Jan. 10, 2012), attached as Ex 37**.** Insofar as LNG exports induce greater gas production nationwide, and exports predominantly draw on wells in the Gulf (as NERA assumes), then exports will presumably increase the share of gas used in households in the Northeast that is provided by Marcellus shale wells, and thereby aggravate the radon exposure issues highlighted by Resnikoff.

[121] These figures were calculated by multiplying the volume of gas to be exported (in bcf) by 1,000,000 to convert to mcf, and then by 63% to generate new production volumes. The new production volumes of gas were, in turn, multiplied by the relevant EPA conversion factors to generate tonnages of the relevant pollutants. These results are approximations: Although we reported the arithmetic results of this calculation, of course only the first few significant figures of each value should be the focus.

2035 (bcf)			
1% Leak Rate			
9,052 bcf	1,186,174	173,062.8	12,573.45
4,380 bcf	573,955.2	83,740.06	6,083.925
1,370 bcf	179,524.8	26,192.67	1,902.963
2.4% Leak Rate			
9,052 bcf	2,846,818	415,350.7	30,176.27
4,380 bcf	1,377,492	200,976.2	14,601.42
1,370 bcf	430,859.5	62,862.4	45,67.111
4.8% Leak Rate			
9,052 bcf	5,693,636	830,701.4	60,352.54
4,380 bcf	2,754,985	401,952.3	29,202.84
1,370 bcf	861,719	125,724.8	9,134.222
9% Leak Rate			
9,052 bcf	10,675,567	1,557,565	113,161
4,380 bcf	5,165,597	753,660.6	54,755.33
1,370 bcf	1,615,723	235,734	17,126.67

The *total* emissions reductions associated with EPA's new source performance standards for oil and gas production are, according to EPA, about 1.0 million tons of methane, 190,000 tons of VOC, and 12,000 tons of HAP. As the table demonstrates, the additional air pollution which would leak from the oil and gas system substantially erodes those figures, even at the lowest volume of LNG export and the lowest leak rate of 1% -- which is well below the 2.4% leak rate which EPA now estimates. It would generate over 179,000 tons of methane, over 26,000 tons of VOC, and over 1,902 tons of HAP. More realistic leak rates make the picture even worse: At the EPA's estimated 2.4% leak rate, the figures for the lowest export volume are over 430,000 tons of methane, over 62,000 tons of VOC, and over 45,000 tons of HAP.

Put differently, even if LNG export is almost 9 times less than the current volume proposed for license before DOE/FE, and even if the natural gas system leak rate is less than half that which EPA now estimates, LNG export will still produce enough air pollution to erode the benefits of EPA's air standards by on the order of 20%. If export volumes increase, or if the leak rate is higher, the surplus emissions swamp the air standards completely. At a 4.8% leak rate and the mid-range 4,380 bcf export figure, LNG export would produce almost three times as many methane emissions – 2.7 million tons -- as the EPA air standards control.

In short, ramping up production for export comes with major air pollution increases. This additional pollution would impose real public health and environmental burdens.

Methane emissions, for instance, are linked to ozone pollution and to global climate change. The climate change risks associated with methane are monetizable using the Social Cost of Carbon framework developed by a federal working group led by EPA.[122] These costs vary based on assumptions of the discount rate at which to value future avoided harm from emissions reductions, and also likely vary by gas (methane, for instance, is a more potent climate forcer than carbon dioxide). Nonetheless, in its recent air pollution control rules, EPA estimated monetized climate emissions benefits from methane reductions simply by multiplying the reductions by the social cost of carbon dioxide (at a 3% discount rate) and the global warming potential of methane (which converts the radiative forcing of other greenhouse gases to their carbon dioxide equivalents).[123]

The global warming potential of methane, on a 100-year basis,[124] is at least 25,[125] and the social cost of carbon at a 3% discount rate is $25/ton (in 2008 dollars).[126] Thus, the social cost of the roughly 179,000 tons of methane emissions produced even by the lowest volume of export at the lowest leak rate is (25)(25)(179,000) or $111,875,000 *per year*. The same volume of export at 2.4% leak rate imposes methane costs of approximately $274 million per year. Again, higher volumes of export, and higher leak rates are associated with even higher costs.

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[122] EPA, *The Social Cost of Carbon*, available at http://www.epa.gov/climatechange/EPAactivities/economics/scc.html, attached as Ex 38.

[123] EPA, *Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry* (2012) at 4-32 – 4-33, attached as Ex 39. EPA acknowledges that its method is still provisional, but it does provide at least a sense of the real economic costs of methane emissions.

[124] Methane acts more quickly than carbon dioxide to warm the climate, and also oxidizes rapidly. As such, many argue that a shorter time period (20 years or less) is appropriate to calculate its global warming potential. We have conservatively used a 100 years here. The true cost of methane emissions is thus likely higher.

[125] Intergovermental Panel on Climate Change*, Direct Global Warming Potentials* (2007), available at http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html, attached as Ex 39.

[126] 2012 RIA at 4-33.

Our calculation is notably conservative: It uses a global-warming potential that is lower than that reported in more recent literature,[127] and a higher discount rate for climate damages than may be appropriate. Yet even this conservative calculation identifies hundreds of millions of dollars in damages from methane associated with export. More recent global warming potentials (which exceed 70) or more appropriate discount rates (which arguably should be zero or negative), would readily push these costs into the billions of dollars annually.

Other large costs arise from the VOC emissions from production. VOCs are often themselves health hazards, and interact with other gases in the atmosphere to produce ozone.[128] Ozone is a potent public health threat associated with thousands of asthma attacks annually, among other harm to public health. Ground-level ozone has significant and well-documented negative impacts on public health and welfare, and gas production is already strongly linked to ozone formation. One recent study, for instance, showed that over half of the ozone precursors in the atmosphere near Denver arise from gas operations.[129] Other studies show that ozone can increase by several parts per billion immediately downwind of individual oil and gas production facilities.[130] The cumulative impact of dozens or hundreds of such individual facilities can greatly degrade air quality – so much so that the study's author concludes that gas facilities may make it difficult for production regions to come into compliance with public health air quality standards if not controlled.[131]

Some studies have documented how reductions in ground-level ozone would benefit public health and welfare, and so also demonstrate how increases in ozone levels will harm the public. Using a global value of a statistical life (VSL) of $1 million (substantially lower than the value used by EPA, currently $7.4 million (in 2006 dollars)[132]), West *et al.* calculate a monetized benefit from avoided mortality due to methane reductions of $240 per metric ton (range of

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[127] We use the IPCC's methane 100-year global warming potential of 25, *see supra* n.125. A more recent study puts this figure at approximately 34, while acknowledging that it could be significantly higher. Drew T. Shindell, *et al.*, *Improved Attribution of Climate Forcing Emissions*, 326 Science No. 5953, page 717 fig. 2 (Oct. 30 2009), attached as Ex 40.

[128] Methane is also an ozone precursor, albeit a somewhat less potent one

[129] J.B. Gilman *et al.*, *Source signature of volatile organic compounds from oil and natural gas operations in northeastern Colorado*, Env. Sci. & Technology (2013), attached as Ex 41.

[130] E.P. Olaguer, *The potential near-source ozone impacts of upstream oil and gas industry emissions*, Journal of the Air & Waste Management Assoc. (2012), attached as Ex 42.

[131] *Id.* at 976.

[132] http://yosemite.epa.gov/ee/epa/eed.nsf/pages/MortalityRiskValuation.html, attached as Ex 43.

$140 - $450 per metric ton).[133] Because VOCs are more potent ozone precursors than methane,[134] the monetary benefits of VOC reduction for avoided mortality are certainly greater on a tonnage basis. Further, as well as direct mortality and morbidity impacts, ozone can significantly reduce the productivity of individual workers, even at low levels. One recent study shows that even a 10 ppb increase in ozone concentrations can decrease the productivity of field workers by several percentage points – a difference that translates into something on the order of $700 million in annual productivity costs.[135]

Ground-level ozone also significantly reduces yields of a wide variety of crops. A recent study finds that in 2000, ozone damage reduced global yields 3.9-15% for wheat, 8.5-14% for soybeans, and 2.2-5.5% for corn, with total costs for these three crops of $11 billion to $18 billion and costs within the US alone over $3 billion (all in year 2000 dollars).[136] Due to the growth in the emissions of ozone precursors in coming years, these crop losses are likely to increase. In 2030, ozone is predicted to reduce global yields 4-26% for wheat, 9.5-19% for soybeans, and 2.5-8.7% for corn, with total costs for these three crops (2000 dollars) of $12 billion to $35 billion.[137] Another recent study included damage to rice (3-4% reduction in yield for year 2000) and finds even higher total costs for year 2000 ($14 billion to $26 billion).[138] Many other crops are damaged by ozone, so these estimates only capture a portion of the economic damage to crops from ground-level ozone. Ozone precursors from export-linked production would add to these costs.

The HAPs from gas production for export also impose significant public health costs. HAPs, by definition, are toxic and also may be carcinogenic. High levels of carcinogens, including benzene compounds, are associated with gas production sites. Unsurprisingly, recent risk assessments from Colorado

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133 West *et al.* at 3991.

134 Methane, technically, *is* a VOC; it is often referred to separately, however, and we do so here.

135 J. Graff Zivin & M. Neidell, *Pollution and Worker Productivity*, 102 American Economic Review 3652 at 3671 (2012), attached as Ex 44.

136 Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 1. Year 2000 crop production losses and economic damage," *Atmos. Env.*, 45, 2284-2296, attached as Ex 45.

137 Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 2. Year 2030 potential crop production losses and economic damage under two scenarios of O_3 pollution," *Atmos. Env.*, 45, 2297-2309, attached as Ex 46.

138 Van Dingenen, R, F.J. Dentener, F. Raes, M.C. Krol, L. Emberson, and J. Cofala, (2009) "The global impact of ozone on agricultural crop yields under current and future air quality legislation," *Atmos. Env.*, 43, 604-618, attached as Ex 47.

document elevated health risks for residents living near gas wells.[139] Indeed, levels of benzene and other toxics near wells in rural Colorado were "higher than levels measured at 27 out of 37 EPA air toxics monitoring sites … including urban sites" in major industrial areas."[140] These pollution levels are even more concerning than these high concentrations would suggest because several of the toxics emitted by gas operations are endocrine disruptors, which are compounds known to harm human health by acting on the endocrine system even at very low doses; some such compounds may, in fact, be especially dangerous specifically at the low, chronic, doses one would expect near gas operations.[141]

Other air pollutants add to all of these public health burdens. Particulate matter from flares and dusty roads, diesel fumes from thousands of truck trips, NO_x emissions from compressors and other onsite engines, and so on all add to the stew of pollution over gas fields. LNG export will increase all of these emissions in proportion to the scale of export.

Further, these emissions would not be spread uniformly around the country. Instead, they would be concentrated in and around gas fields. Those fields, like the Barnett field in Dallas Fort-Worth, or the Marcellus Shale near eastern cities, often are not far from (or are even directly within) major population centers. Residents of those cities will receive concentrated doses of air pollution, as will residents of the fields themselves. They thus will suffer public health harms from particularly concentrated pollution.

Costs from Increased Use of Coal

The EIA estimates that gas price increases associated with LNG export will favor continued and increased use of coal power, on the margin.[142] Another recent study, prepared by the Joint Institute for Strategic Energy Analysis (JISEA), also modeled power sector futures resulting from increasing U.S. reliance on natural gas.[143] That study found that, under baseline assumptions for future electricity

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[139] L. McKenzie *et al.*, *Human health risk assessment of air emissions from development of unconventional natural gas resources*, Science of the Total Environment (2012), attached as Ex 48.
[140] *Id.* at 5.
[141] *See* L. Vandenberg *et al.*, *Hormones and Endocrine-Disrupting Chemicals: Low-Dose Effects and Nonmonotonic Dose Responses*, Endocrine Disruption Review (2012), attached as Ex 49.
[142] EIA Study at 17-18.
[143] Jeffrey Logan et al., Joint Inst. for Strategic Analysis, Natural Gas and the Transformation of the U.S. Energy Sector (2012) ("JISEA report"), available at http://www.nrel.gov/docs/fy13osti/55538.pdf, attached as Ex 50.

demand and policy measures, "natural gas and coal swap positions compared to their historical levels," with wind energy growing at a rate that represents "a significant reduction from deployment in recent years;" as a result, CO_2 emissions "do not begin to transition to a trajectory that many scientists believe is necessary to avoid dangerous impacts from climate change."[144]

The costs of the increased CO_2 emissions triggered by LNG export are along significant, and DOE/FE must disclose and weigh them. DOE/FE suggests that they are on the order of 200-1500 million metric tons of CO_2.[145] Again, depending on the social cost of carbon figure used, these increased emissions may impose hundreds of millions or billions in additional costs.

And costs extend beyond climate disruption. Coal combustion is a particularly acute public health threat. It is among the largest sources of all forms of air pollution in the country, including toxic mercury emissions and emissions particulate matter, which is linked to asthma and to heart attacks. To the extent that LNG export prolongs or intensifies the use of coal power, the public health costs of that additional coal use are attributable to export, and must be accounted for.

Likewise, EPA, in calculating compliance costs for several of its clean air rules, has assumed that some portion of these costs will be addressed by switching from coal to natural gas. If these switches still occur, but LNG exports have raised natural gas prices, the compliance costs of necessary public health measures will be higher than they otherwise would be.

Costs from Further Investment in Fossil Fuels

LNG exports will also deepen our national investment in fossil fuels, even though those fuels are causing destructive climate change. The costs of increased climate risks must be factored into the export calculation.

Specifically, a recent study by the International Energy Agency predicts that international trade in LNG and other measures to increase global availability of natural gas will lead many countries to use natural gas in place of wind, solar, or other renewables, displacing these more environmentally beneficial energy sources instead of displacing other fossil fuels, and that these countries may also

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[144] *Id.* at 98.
[145] EIA Study at 19.

increase their overall energy consumption beyond the level that would occur with exports.[146] In the United States alone, the IEA expects the gas boom to result in a 10% reduction in renewables relative to a baseline world without increased gas use and trade.[147] The IEA goes on to conclude that high levels of gas production and trade will produce "only a small net shift" in global greenhouse gas emissions, with atmospheric CO_2 levels stabilizing at over 650 ppm and global warming in excess of 3.5 degrees Celsius, "well above the widely accepted 2°C target."[148]

Such temperature increases would be catastrophic. Yet, an LNG export strategy commits the United States, and the world, to further fossil fuel combustion, increasing the risk of hundreds of billions of economic costs imposed by severe climate change.

Summing up air pollution impacts

Across all of these harms, the public health damage associated just with air pollution from increased production to support export very likely runs into the hundreds of millions, if not billions, of dollars. DOE/FE must account for these costs as it weighs the economic merits of expanding gas production, and gas pollution, for export.

ii. Water Pollution Costs

The hundreds or thousands of wells required to support export will require millions of gallons of water to frack and will produce millions of gallons of wastewater. The extraction process will likewise increase the risk of contamination from surface spills and casing failures, as well as from the fracking process itself. All of these contamination and treatment risks impose economic costs which DOE must take into account.

Water Withdrawal Costs

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[146] International Energy Agency, *Golden Rules for a Golden Age of Gas*, Ch. 2 p. 91 (2012), available at http://www.iea.org/publications/freepublications/publication/WEO2012_GoldenRulesReport.pdf, attached as Ex 51.

[147] *Id.* at 80.

[148] *Id.*

Fracking requires large quantities of water. The precise amount of water varies by the shale formation being fracked. The amount of water varies by well and by formation. For example, estimates of water needed to frack a Marcellus Shale wells range from 4.2 to over 7.2 million gallons.[149] In the Gulf States' shale formations (Barnett, Haynesville, Bossier, and Eagle Ford), fracking a single well requires from 1 to over 13 million gallons of water, with averages between 4 and 8 million gallons.[150] Fresh water constitutes 80% to 90% of the total water used to frack a well even where operators recycle "flowback" water from the fracking of previous wells for use in drilling the current one.[151] Many wells are fractured multiple times over their productive life.

DOE/FE can and must predict the number of wells that will be needed to provide the volume of gas exported. We provide an unrealistically conservative (i.e., industry-friendly) estimate here to illustrate the magnitude of the problem, although DOE/FE can and must engage in a more sophisticated analysis of the issue. As noted above, EIA predicts that at least 63% percent of the gas exported will come from additional production, and that roughly 72% of this production will come from shale gas sources, with an additional 23% coming from other unconventional gas reserves. The USGS has estimated that even in the most productive formations, average expected ultimate recoveries for unconventional shale gas wells are less than 3 bcf, and that most formations provided drastically

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[149] TNC, Pennsylvania Energy Impacts Assessment, Report 1: Marcellus Shale Natural Gas and Wind 10, 18 (2010), attached as Ex 52. *Accord* N.Y. Dep't of Envtl. Conservation, Revised Draft Supplemental General Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, 5-5 (2011) ("NY RDSGEIS") at 6-10, available at http://www.dec.ny.gov/energy/75370.html ("Between July 2008 and February 2011, average water usage for high-volume hydraulic fracturing within the Susquehanna River Basin in Pennsylvania was 4.2 million gallons per well, based on data for 553 wells."). Other estimates suggest that as much as 7.2 million gallons of frack fluid may be used in a 4000 foot well bore. NRDC, *et al.*, *Comment on NY RDSGEIS on the Oil, Gas and Solution Mining Regulatory Program* (Jan. 11, 2012) (Attachment 2, Report of Tom Myers, at 10), attached as Ex 53 ("Comment on NY RDSGEIS").

[150] Jean-Philippe Nicot, *et al.*, *Draft Report – Current and Projected Water Use in the Texas Mining and Oil and Gas Industry*, 52-54 (Feb. 2011) (water use from 1 to over 13 million gallons), attached as Ex 54; Jean-Philippe Nicot, *et al.*, *Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report* 11-14 (Sept. 2012) (updated data presented as averages), attached as Ex. 55. DOE's Shale Gas Subcommittee generally states that nationwide, fracking an individual well requires between 1 and 5 million gallons of water. DOE, Shale Gas Production Subcommittee First 90-Day Report (2012), at 19, attached as Ex 56.

[151] NY RDSGEIS at 6-13, *accord* Nicot 2012, *supra* n.150, at 54.

lower average expected ultimate recoveries.[152] As noted above, the average horizontal fracked well requires roughly 4 million gallons of water, at least 80% of which (3.2 million gallons) is new fresh water.[153]

Combining these figures and assuming high average recovery, low/average water per frack jobs, only a single frack per well, and maximal use of recycled water, we see the following volumes of water. These figures are only for *shale* gas production, because we have water use figures for such wells; additional unconventional production, of the sort that the EIA predicts, would increase water use.

Volume of exports (bcf/y)	Induced Shale Gas Production (bcf/y)[a]	Equivalent Number of Shale Wells Needed Per Year[b]	New Fresh Water Required (millions of gallons per year)[c]
9,052	4,105	1,368	4,378
4,308	1,954	651	2,038
1,370	621	207	662

a. Volume of export * 0.63 * 0.72

b. Volume of production / 3.

c. Number of wells * 3.2

Of course, we reiterate that this forecast methodology is crude and that the inputs we use are unrealistically conservative, but at the very least, this illustrates the minimum scale of the problem. This calculation ignores the production curves for gas wells and the fact that although wells produce over a number of years, all of the water (under the assumption of one frack job per well) is consumed up front; the table naively averages water requirements out over the duration of exports. Additionally, this only considers water withdrawals associated with the shale gas production EIA predicts: EIA predicts that other forms of production (primarily other unconventional production) will also

152 USGS, *Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United* States, USGS Open-File Report 212-1118 (2012), attached as Ex 57. Although some oil and gas producers have publicly stated higher expected ultimate recoveries, DOE/FE must begin with the data-backed assessment of its expert and impartial sister agency.

153 Taking the most industry friendly of each of these values is particularly unrealistic because the values are not independent. For example, higher-producing wells are likely to be wells with a longer fracked lateral, which are in turn wells that use higher volumes of water. Using the high range of the average expected ultimate recovery but the low range of the average water requirement therefore represents a combination unlikely to occur in reality.

increase alongside the above increases in shale gas production, and this other production will also require significant water withdrawals. In its public interest analysis, DOE/FE must engage in a more considered evaluation of the water consumption exports will require, and the costs (environmental and economic) thereof.

These water withdrawals would drastically impact aquatic ecosystems and human communities. Their effects are larger than their raw volumes because withdrawals would be concentrated in particular watersheds and regions. Reductions in instream flow negatively affect aquatic species by changing flow depth and velocity, raising water temperature, changing oxygen content, and altering streambed morphology.[154] Even when flow reductions are not themselves problematic, the intake structures can harm aquatic organisms.[155] Where water is withdrawn from aquifers, rather than surface sources, withdrawal may cause permanent depletion of the source. This risk is even more prevalent with withdrawals for fracking than it is for other withdrawal, because fracking is a consumptive use. Fluid injected during the fracking process is (barring accident) deposited below freshwater aquifers and into sealed formations.[156] Thus, the water withdrawn from the aquifer will be used in a way that provides no opportunity to percolate back down to the aquifer and recharge it.

The impacts of withdrawing this water – especially in arid regions of the west – are large, and can greatly change the demand upon local water systems. The Environment America report notes that fracking is expected to comprise 40% of water consumption in one county in the Eagle Ford shale region of Texas, for example.[157] As fracking expands, and operators seek to secure water rights to divert water from other uses, these withdrawal costs will also rise.

Groundwater Contamination

Gas extraction activities pose a substantial risk of groundwater contamination. Contaminants include chemicals added to the fracturing fluid and naturally

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[154] *Id.* at 6-3 to 6-4; *see also* Maya Weltman-Fahs, Jason M. Taylor, *Hydraulic Fracturing and Brook Trout Habitat in the Marcellus Shale Region: Potential Impacts and Research Needs*, 38 Fisheries 4, 6-7 (Jan. 2013), attached as Ex 58.

[155] *Id.* at 6-4.

[156] *Id.* at 6-5; First 90-Day Report at 19 ("[I]n some regions and localities there are significant concerns about consumptive water use for shale gas development.").

[157] *The Cost of Fracking* at 26.

occurring chemicals that are mobilized from deeper formations to groundwater via the fracking process. Contamination may occur through several methods, including where the well casing fails or where the fractures created through drilling intersect an existing, poorly sealed well. Although information on groundwater contamination is incomplete, the available research indicates that contamination has already occurred on multiple occasions.

Once groundwater is contaminated, the clean-up costs are enormous. The Environment America report, for instance, documents costs of over $109,000 for methane removal for just 14 households with contaminated groundwater.[158] EPA has estimated treatment costs for some forms of groundwater remediation at between $150,000 to $350,000 per acre.[159] Such costs can continue for years, with water replacement costs adding additional hundreds of thousands in costs.[160] Indeed, a recent National Research Council report observed that for many forms of subsurface and groundwater hazardous chemical contamination, "significant limitations with currently available remedial technologies" make it unlikely that contaminated aquifers can be fully remediated "in a time frame of 50-100 years."[161]

There are several vectors by which gas production can contaminate groundwater supplies. Perhaps the most common or significant are inadequacies in the casing of the vertical well bore.[162] The well bore inevitably passes through geological strata containing groundwater, and therefore provides a conduit by which chemicals injected into the well or traveling from the target formation to the surface may reach groundwater. The well casing isolates the groundwater from intermediate strata and the target formation. This casing must be strong enough to withstand the pressures of the fracturing process—the very purpose of which is to shatter rock. Multiple layers of steel casing must be used, each pressure tested before use, then centered within the well bore. Each layer of casing must be cemented, with careful testing to ensure the integrity of the cementing.[163]

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[158] *Id.* at 13.
[159] *Id.* at 14.
[160] *Id.*
[161] National Research Council, *Prepublication Copy- Alternatives for Managing the Nation's Complex Contaminated Groundwater Sites*, ES-5 (2012), executive summary attached as Ex 59, full report available at http://www.nap.edu/catalog.php?record_id=14668#toc.
[162] DOE, Shale Gas Production Subcommittee First 90-Day Report at 20.
[163] Natural Resources Defense Council, Earthjustice, and Sierra Club, Comments [to EPA] on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels 3, (June 29, 2011), at 5-9, attached as Ex 60.

Separate from casing failure, contamination may occur when the zone of fractured rock intersects an abandoned and poorly-sealed well or natural conduit in the rock.[164] One recent study concluded, on the basis of geologic modeling, that frack fluid may migrate from the hydraulic fracture zone to freshwater aquifers in less than ten years.[165]

Available empirical data indicates that fracking has resulting in groundwater contamination in at least five documented instances. One study "documented the higher concentration of methane originating in shale gas deposits . . . into wells surrounding a producing shale production site in northern Pennsylvania."[166] By tracking certain isotopes of methane, this study – which the DOE Subcommittee referred to as "a recent, credible, peer-reviewed study" determined that the methane originated in the shale deposit, rather than from a shallower source.[167] Two other reports "have documented or suggested the movement of fracking fluid from the target formation to water wells linked to fracking in wells."[168] "Thyne (2008)[[169]] had found bromide in wells 100s of feet above the fracked zone. The EPA (1987)[[170]] documented fracking fluid moving into a 416-foot deep water well in West Virginia; the gas well was less than 1000 feet horizontally from the water well, but the report does not indicate the gas-bearing formation."[171]

More recently, EPA has investigated groundwater contamination in Pavillion, Wyoming and Dimock, Pennsylvania. In the Pavillion investigation, EPA's draft

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[164] Comment on NY RDSGEIS, attachment 3, Report of Tom Myers, at 12-15.

[165] Tom Myers, *Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers* (Apr. 17, 2012), attached Ex 61.

[166] DOE, Shale Gas Production Subcommittee First 90-Day Report at 20 (citing Stephen G. Osborn, Avner Vengosh, Nathaniel R. Warner, and Robert B. Jackson, *Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing*, Proceedings of the National Academy of Science, 108, 8172-8176, (2011), attached as Ex 62).

[167] *Id.*

[168] Comment on NY RDSGEIS, attachment 3, Report of Tom Myers, at 13.

[169] Dr. Myers relied on Geoffrey Thyne, *Review of Phase II Hydrogeologic Study* (2008), prepared for Garfield County, Colorado, *available at* http://cogcc.state.co.us/Library/Presentations/Glenwood_Spgs_HearingJuly_2009/(1_A)_ReviewofPhase-II-HydrogeologicStudy.pdf.

[170] Environmental Protection Agency, *Report to Congress, Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, vol. 1 (1987), *available at* nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=20012D4P.txt, attached as Ex 63.

[171] Comment on NY RDSGEIS, attachment 3, Report of Tom Myers, at 13.

report concludes that "when considered together with other lines of evidence, the data indicates likely impact to ground water that can be explained by hydraulic fracturing."[172] EPA tested water from wells extending to various depths within the range of local groundwater. At the deeper tested wells, EPA discovered inorganics (potassium, chloride), synthetic organic (isopropanol, glycols, and tert-butyl alcohol), and organics (BTEX, gasoline and diesel range organics) at levels higher than expected.[173] At shallower levels, EPA detected "high concentrations of benzene, xylenes, gasoline range organics, diesel range organics, and total purgeable hydrocarbons."[174] EPA determined that surface pits previously used for storage of drilling wastes and produced/flowback waters were a likely source of contamination for the shallower waters, and that fracturing likely explained the deeper contamination.[175] The U.S. Geological Survey, in cooperation with the Wyoming Department of Environmental Quality, also provided data regarding chemicals found in wells surrounding Pavillion.[176] Although the USGS did not provide analysis regarding the likely source of the contaminants found, an independent expert who reviewed the USGS and EPA data at the request of Sierra Club and other environmental groups concluded that the USGS data supports EPA's findings.[177]

EPA also identified elevated levels of hazardous substances in home water supplies near Dimock, Pennsylvania.[178] EPA's initial assessment concluded that

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[172] EPA, Draft Investigation of Ground Water Contamination near Pavillion, Wyoming, at xiii (2011), available at http://www.epa.gov/region8/superfund/wy/pavillion/EPA_ReportOnPavillion_Dec-8-2011.pdf, attached as Ex 64. EPA has not yet released a final version of this report, instead recently extending the public comment period to September 30, 2013. 78 Fed. Reg. 2396 (Jan. 11, 2013).

[173] *Id.* at xii.

[174] *Id.* at xi.

[175] *Id.* at xi, xiii.

[176] USGS, *Groundwater-Quality and Quality-Control Data for two Monitoring Wells near Pavillion, Wyoming, April and May 2012*, USGS Data Series 718 p.25 (2012), attached as Ex 65.

[177] Tom Myers, *Assessment of Groundwater Sampling Results Completed by the U.S. Geological Survey* (Sept. 30, 2012), attached as Ex 66. Another independent expert, Rob Jackson of Duke University, has stated that the USGS and EPA data is "suggestive" of fracking as the source of contamination. Jeff Tollefson, *Is Fracking Behind Contamination in Wyoming Groundwater?*, Nature (Oct. 4, 2012), attached as Ex 67. *See also* Tom Meyers, *Review of DRAFT: Investigation of Ground Water Contamination near Pavillion Wyoming* (April 30, 2012) (concluding that EPA's initial study was well-supported), attached as Ex 68.

[178] EPA Region III, Action Memorandum - Request for Funding for a Removal Action at the Dimock Residential Groundwater Site (Jan. 19, 2012), available at http://www.epaosc.org/sites/7555/files/Dimock%20Action%20Memo%2001-19-12.PDF, attached

“a number of home wells in the Dimock area contain hazardous substances, some of which are not naturally found in the environment,” including arsenic, barium, bis(2(ethylhexyl)phthalate, glycol compounds, manganese, phenol, and sodium.[179] Arsenic, barium, and manganese were present in five home wells “at levels that could present a health concern.”[180] Many of these chemicals, including arsenic, barium, and manganese, are hazardous substances as defined under CERCLA section 101(14). *See* 42 U.S.C. § 9604(a); 40 C.F.R. § 302.4. EPA’s assessment was based in part on “Pennsylvania Department of Environmental Protection (PADEP) and Cabot Oil and Gas Corporation (Cabot) sampling information, consultation with an EPA toxicologist, the Agency for Toxic Substances and Disease Registry (ATSDR) Record of Activity (AROA), issued, 12/28/11, and [a] recent EPA well survey effort.”[181] The PADEP information provided reason to believe that drilling activities in the area led to contamination of these water supplies. Drilling in the area began in 2008, and was conducted using the hazardous substances that have since been discovered in well water. Shortly thereafter methane contamination was detected in private well water. The drilling also caused several surface spills. Although EPA ultimately concluded that the five homes with potentially unsafe levels of hazardous substances had water treatment systems sufficient to mitigate the threat, [182] the Dimock example indicates the potential for gas development to contaminate groundwater.

The serious groundwater contamination problems experienced at the Pavillion and Dimock sites demonstrate a possibility of contamination, and attendant human health risks. Such risks are not uncommon in gas field sites, and will be intensified by production for export. DOE/FE must account for these risks, as well, in its economic evaluation.

Surface Water Contamination

Of course the same chemicals that can contaminate groundwater can also contaminate surface water, either through spills or communication with groundwater, or simply through dumping or improper treatment. Even the extensive road and pipeline networks created by gas extraction come with a risk

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as Ex 69; EPA, *EPA Completes Drinking Water Sampling in Dimock, Pa.* (Jul. 25, 2012), attached as Ex 70.

[179] *Id.* at 1, 3-4.

[180] *EPA Completes Drinking Water Sampling in Dimock, Pa.*, *supra* n.178

[181] *Id.* at 1.

[182] *EPA Completes Drinking Water Sampling in Dimock, Pa.*, *supra* n.178

of significant stormwater and sediment run-off which can contaminate surface waters. Gas field operations themselves, with their significant waste production and spill potential exacerbate these risks.

The Environment America report, for instance, documents fish kills caused by pipeline ruptures in the Marcellus Shale region, which impose costs on Pennsylvania's multi-billion dollar recreational fishing industry.[183] Such risks will be intensified by extraction for export.

Summing up water pollution costs

Water pollution is expensive to treat and can impose enormous burdens on public health and ecosystem function. Even a single instance of contamination can lead to hundreds of thousands of dollars in treatment costs, and many such incidents are not only possible, but likely, with an expansion of gas production for export. DOE/FE must account for these risks.

iii. Waste Management Costs

Fracturing produces a variety of liquid and solid wastes that must be managed and disposed of. These include the drilling mud used to lubricate the drilling process, the drill cuttings removed from the well bore, the "flowback" of fracturing fluid that returns to the surface in the days after fracking, and produced water that is produced over the life of the well (a mixture of water naturally occurring in the shale formation and lingering fracturing fluid). Because these wastes contain the same contaminants described in the preceding section, environmental hazards can arise from their management and ultimate disposal. Managing these wastes is costly, and all waste management options come with significant infrastructure costs and environmental risk.

On site, drilling mud, drill cuttings, flowback and produced water are often stored in pits. Open pits can have harmful air emissions, can leach into shallow groundwater, and can fail and result in surface discharges. Many of these harms can be minimized by the use of seal tanks in a "closed loop" system.[184] Presently, only New Mexico mandates the use of closed loop waste management systems, and pits remain in use elsewhere.

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[183] *The Cost of Fracking* at 20.
[184] *See, e.g.*, NY RDSGEIS, at 1-12.

Flowback and produced water must ultimately be disposed of offsite. Some of these fluids may be recycled and used in further fracturing operations, but even where a fluid recycling program is used, recycling leaves concentrated contaminants that must be disposed of. The most common methods of disposal are disposal in underground injection wells or through water treatment facilities leading to eventual surface discharge.

Underground injection wells present risks of groundwater contamination similar to those identified above for fracking itself. Gas production wastes are not categorized as hazardous under the Safe Drinking Water Act, 42 U.S.C. § 300f *et seq*., and may be disposed of in Class II injection wells. Class II wells are brine wells, and the standards and safeguards in place for these wells were not designed with the contaminants found in fracking wastes in mind.[185]

Additionally, underground injection of fracking wastes appears to have induced earthquakes in several regions. For example, underground injection of fracking waste in Ohio has been correlated with earthquakes as high as 4.0 on the Richter scale.[186] Underground injection may cause earthquakes by causing movement on existing fault lines: "Once fluid enters a preexisting fault, it can pressurize the rocks enough to move; the more stress placed on the rock formation, the more powerful the earthquake."[187] Underground injection is more likely than fracking to trigger large earthquakes via this mechanism "because more fluid is usually being pumped underground at a site for longer periods."[188] In light of the apparent induced seismicity, Ohio has put a moratorium on injection in the affected region. Similar associations between earthquakes and injection have occurred in Arkansas, Texas, Oklahoma and the United Kingdom.[189] In light of these effects, Ohio and Arkansas have placed moratoriums on injection in the

[185] *See* NRDC et al., *Petition for Rulemaking Pursuant to Section 6974(a) of the Resource Conservation and Recovery Act Concerning the Regulation of Wastes Associated with the Exploration, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy* (Sept. 8, 2010), attached as Ex 71.
[186] Columbia University, Lamont-Doherty Earth Observatory, Ohio Quakes Probably Triggered by Waste Disposal Well, Say Seismologists (Jan. 6, 2012), available at http://www.ldeo.columbia.edu/news-events/seismologists-link-ohio-earthquakes-waste-disposal-wells, attached as Ex 72.
[187] *Id.*
[188] *Id.*
[189] *Id.*; *see also* Alexis Flynn, Study Ties Fracking to Quakes in England, Wall Street Journal (Nov. 3, 2011), *available at* http://online.wsj.com/article/SB10001424052970203804204577013771109580352.html.

affected areas.[190] The recently released abstract of a forthcoming United States Geological Survey study affirms the connection between disposal wells and earthquakes.[191]

As an alternative to underground injection, flowback and produced water is also sent to water treatment facilities, leading to eventual surface discharge. This presents a separate set of environmental hazards, because these facilities (particularly publicly owned treatment works) are not designed to handle the nontraditional pollutants found in fracking wastes. For example:

> One serious problem with the proposed discharge (dilution) of fracture treatment wastewater via a municipal or privately owned treatment plant is the observed increases in trihalomethane (THM) concentrations in drinking water reported in the public media (Frazier and Murray, 2011), due to the presence of increased bromide concentrations. Bromide is more reactive than chloride in formation of trihalomethanes, and even though bromide concentrations are generally lower than chloride concentrations, the increased reactivity of bromide generates increased amounts of bromodichloromethane and dibromochloromethane (Chowdhury, et al., 2010). Continued violations of an 80microgram/L THM standard may ultimately require a drinking water treatment plant to convert from a standard and cost effective chlorination disinfection treatment to a more expensive chloramines process for water treatment. Although there are many factors affecting THM production in a specific water, simple (and cheap) dilution of fracture treatment water in a stream can result in a more

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[190] Lamont-Doherty Earth Observatory; Arkansas Oil and Gas Commission, Class II Commercial Disposal Well or Class II Disposal Well Moratorium (Aug. 2, 2011), *available at* http://www.aogc.state.ar.us/Hearing%20Orders/2011/July/180A-2-2011-07.pdf.

[191] Ellsworth, W. L., et al., Are Seismicity Rate Changes in the Midcontinent Natural or Manmade?, Seismological Society of America, (April 2012), available at http://www2.seismosoc.org/FMPro?-db=Abstract_Submission_12&-recid=224&-format=%2Fmeetings%2F2012%2Fabstracts%2Fsessionabstractdetail.html&-lay=MtgList&-find, attached as Ex 73.

> expensive treatment for disinfection of drinking water. This transfer of costs to the public should not be permitted.[192]

Similarly, municipal treatment works typically to not treat for radioactivity, whereas produced water can have high levels of naturally occurring radioactive materials. In one examination of three samples of produced water, radioactivity (measured as gross alpha radiation) were found ranging from 18,000 pCi / L to 123,000 pCi/L, whereas the safe drinking water standard is 15 pCi/L.[193]

A recent NRDC expert report describes these options in detail, and we direct DOE/FE's attention to it.[194] The report demonstrates that all waste treatment options have significant risks, and require substantial investments to manage properly. Fracking for export, again, has the potential to significantly increase these waste management costs. Such costs will largely fall on communities in the gas fields, which may be ill-equipped to bear them.

Summing Up Waste Management Costs

More drilling means significantly greater waste management problems, and more waste management costs.[195] It is not surprising DOE's own Shale Gas Subcommittee urged significant new regulatory work on waste management rules and research. Thus far, though, these problems have not been addressed systematically. LNG export will exacerbate them, imposing further costs on communities across the country.

iv. Costs Arising from Damage to Property and Landscapes

Expanding gas production alters entire landscapes, fundamentally compromising ecosystem services and reducing property values. Land use disturbance associated with gas development impacts plants and animals

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[192] Comment on NY RDSGEIS, attachment 3, Report of Glen Miller, at 13.
[193] *Id.* at 4.
[194] R. Hammer *et al.*, *In Fracking's Wake: New Rules are Needed to Protect Our Health and Environment from Contaminated Wastewater* (2012), attached as Ex 74.
[195] Indeed, the waste from existing fracking operations are already on the verge of overwhelming disposal infrastructure. *See, e.g.*, Bob Downing, Akron Beacon-Journal, *Pennsylvania Drilling Wastes Might Overwhelm Ohio Injection Wells* (Jan. 23, 2012), available at http://www.ohio.com/news/local/pennsylvania-drilling-wastes-might-overwhelm-ohio-injection-wells-1.367102, attached as Ex 75.

through direct habitat loss, where land is cleared for gas uses, and indirect habitat loss, where land adjacent to direct losses loses some of its important characteristics. These costs, too, must figure in the export economic analysis.

The presence of gas production equipment can markedly reduce property values, both through direct resource damage and through perceived increases in risk. A recent Resources for the Future study, for instance, canvasses empirical data from Pennsylvania to show that concerns (rather than any demonstrated damage) over groundwater contamination reduced property values for groundwater dependent homes by as much as 24%.[196] A study from Texas saw decreases in value of between 3-14% for homes near wells, and a Colorado study saw decreases of up to 22% for homes near wells.[197] Notably, the Resources for the Future study concluded that the property value declines it measured completely offset any increased value from expected lease payments.[198] And these decreases are only those associated with ordinary operation of gas activities. Actual contamination will, of course, reduce property values still more. Thus, as gas extraction spreads across the landscape, many properties may actually lose value, even as some owners secure royalty payments.

Other threats to property values come through risks to home financing. Gas extraction is a major industrial activity inconsistent with essentially all home mortgage policies.[199] Accordingly, signing a gas lease without the consent of the lender may cause an immediate mortgage default, leading to foreclosure.[200] And most lenders will refuse such consent, and will refuse to grant new mortgages allowing gas development.[201] The result is that that expansion of gas drilling, including extraction for export, may significantly limit the ability of many people to extract value from their homes.

In addition to these immediate threats to property values, gas production also threatens ecosystems and the services they provide. Land is lost through development of well pads, roads, pipeline corridors, corridors for seismic testing, and other infrastructure. The Nature Conservancy (TNC) estimated that in

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[196] L. Muehlenbachs *et al.*, *Shale Gas Development and Property Values Differences across Drinking Water Sources*, Resources for the Future Discussion Paper (2012), attached as Ex 76.
[197] *The Costs of Fracking* at 30.
[198] Muehlenbachs *et al.* at 29-30.
[199] E. Radow, *Homeowners and Gas Drilling Leases: Boom or Bust?*, New York State Bar Association Journal (Dec. 2011), attached as Ex 77.
[200] *Id.* at 20.
[201] *Id.* at 21.

Pennsylvania, "[w]ell pads occupy 3.1 acres on average while the associated infrastructure (roads, water impoundments, pipelines) takes up an additional 5.7 acres, or a total of nearly 9 acres per well pad."[202] New York's Department of Environmental Conservation reached similar estimates.[203] After initial drilling is completed the well pad is partially restored, but 1 to 3 acres of the well pad will remain disturbed through the life of the wells, estimated to be 20 to 40 years.[204] Associated infrastructure such as roads and corridors will likewise remain disturbed. Because these disturbances involve clearing and grading of the land, directly disturbed land is no longer suitable as habitat.[205]

Indirect losses occur on land that is not directly disturbed, but where habitat characteristics are affected by direct disturbances. "Adjacent lands can also be impacted, even if they are not directly cleared. This is most notable in forest settings where clearings fragment contiguous forest patches, create new edges, and change habitat conditions for sensitive wildlife and plant species that depend on "interior" forest conditions."[206] "Research has shown measureable impacts often extend at least 330 feet (100 meters) into forest adjacent to an edge."[207]

These effects are profound. Although impacts could be reduced with proper planning,[208] more development makes mitigation more difficult. Indeed, the Pennsylvania Department of Conservation and Natural Resources, for instance, recently concluded that "zero" remaining acres of the state forests are suitable for leasing with surface disturbing activities, or the forests will be significantly degraded.[209]

The lost ecosystem services from wild land and clean rivers and wetlands are valuable. Such services can be monetized in various ways, including through surveys of citizens' "willingness to pay" for them, which generally show that people view ecosystem services as major economic assets. Work in

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[202] TNC, Pennsylvania Energy Impacts Assessment, Report 1: Marcellus Shale Natural Gas and Wind 10, 1.
[203] NY RDSGEIS at 5-5.
[204] Id. at 6-13.
[205] *Id.* at 6-68.
[206] Pennsylvania Energy Impacts Assessment at 10.
[207] NY RDSGEIS at 6-75.
[208] *See id.*
[209] Penn. Dep't of Conservation and Natural Resources, *Impacts of Leasing Additional State Forest for Natural Gas Development* (2011), attached as Ex 78.

Pennsylvania, for instance, showed that undisturbed forests were worth at least $294 per acre to residents.[210] Thus, increased production for export effectively costs Pennsylvanians at least this much per acre of forest disrupted. Similarly, in the gas fields of western Pennsylvania, households are willing to pay up to $51 per household to improve water quality in a single stream.[211] Water degradation can properly be said to impose these costs in return. Direct recreational spending also provides an index of the costs to society of landscape disruption; for instance, if export-linked production risks disrupting Pennsylvania's over $1.4 billion in spending by anglers and $1.8 billion in spending by hunters,[212] these costs, too, must be taxed against export projects.

Summing Up Land-Related Costs

Just as with direct pollution costs, the costs of landscape disruption may well be in the hundreds of millions of dollars in harm to property values and ecosystem services. NERA ignores these costs, as well, but DOE/FE must account for them.

C. Conclusions on Environmental Costs

Our discussion of environmental costs only scratches the surface. It is clear that these costs are in the billions of dollars annually, and range from burdens on regional infrastructure to long-lasting ecosystem service disruptions. These costs are just as real as reduced income to labor, and just as pressing for policymakers. DOE/FE is required to consider them under its public interest mandate. NERA's conclusions that export would produce economic benefits are completely unfounded because they neglect these costs entirely.

IV. DOE/FE's Use of the NERA Study is Procedurally Flawed and Raises a Serious and Inappropriate Appearance of Bias

DOE/FE reliance on the NERA study would be inappropriate not just for the many substantive reasons discussed above but because the study process has been procedurally flawed from the outset in ways that limit public participation and raise serious questions of bias. NERA has significant ties to the fossil fuel industry, including to parties which would benefit financially from LNG export,

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[210] ECONorthwest, *An Economic Review of the Environmental Assessment of the MARC I Hub Line Project* at 25 (July 2011), attached as Ex 79.
[211] *Id.* at 24.
[212] *Id.* at 29.

and the consultant who authored the report is known for his hostility to government regulation of the energy sector. NERA was selected through a secret contracting process and developed its results with a proprietary model which has not been released to the public. NERA's ideological commitments, financial conflicts, and closed process all raise, at a minimum, the appearance of serious bias and conflicts of interest. DOE/FE cannot properly rely upon a study that is tainted in this way.

NERA has spent years attacking environmental regulations on behalf of the American Petroleum Institute and the coal industry, among others. The LNG export report's author, NERA senior vice president W. David Montgomery, has strongly opposed regulatory and legislative efforts to control climate change, raise fuel efficiency, and improve air quality. These ideological commitments, and business relationships, all raise serious questions about NERA's role in this process.

NERA was founded in 1961 by conservative economists and has maintained this ideological anti-regulation bent.[213] Indeed, co-founder Irwin Stelzer is now a senior fellow at the right-wing Hudson Institute, which advocates against environmental regulations and supports climate skeptics.[214] Following that lead, NERA itself has been a consistent voice against environmental safeguards. In recent years, NERA staff have repeatedly opposed environmental efforts on behalf of industry groups. NERA staff have:

- Written, on behalf of the American Petroleum Institute, against the tightened ozone smog standards recommended by EPA's science advisors.[215]
- On behalf of the American Coalition for Clean Coal Energy, generated inflated cost estimates for EPA rules controlling toxic mercury emissions, asthma-inducing SO_2, and other pollutants.[216]
- Testified against EPA's efforts to control mercury emissions.[217]

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[213] http://www.nera.com/7250.htm.

[214] *See* http://www.hudson.org/learn/index.cfm?fuseaction=staff_bio&eid=StelIrwi.

[215] NERA, *Summary and Critique of the Benefits Estimates in the RIA for the Ozone NAAQS Reconsideration* (2011), available at: http://www.nera.com/nera-files/PUB_Smith_OzoneNAAQS_0711.pdf.

[216] NERA, *Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector* (2012), available at: http://www.nera.com/nera-files/PUB_ACCCE_1012.pdf.

[217] Testimony of Anne E. Smith before the House Subcommittee on Energy and Power (Feb. 8, 2012), available at: http://www.nera.com/nera-files/PUB_Smith_Testimony_ECC_0212.pdf.

- Testified against new soot standards designed to protect the public from the respiratory problems and heart disease.[218]
- Prepared a report, on behalf of the Utility Water Group, opposing standards designed to reduce fish kills and protect aquatic ecosystems from cooling water withdrawals.[219]

Dr. Montgomery, a NERA Senior Vice President, shares the basic ideological commitments of his firm. He has repeatedly spoken against President Obama's green jobs agenda and the Department of Energy's efforts to promote renewable energy. He has also consistently opposed legislative efforts to reduce domestic carbon pollution, including the Kyoto Protocols. Dr. Montgomery has also been a fellow at the far-right Marshall Institute, an industry-funded group which devotes much of its resources to attacking climate science.[220] In recent years Dr. Montgomery has:

- Testified against capping U.S. carbon pollution emissions.[221]
- Testified repeatedly against EPA's public health air rules, arguing that they have high costs and should be reconsidered.[222]
- Testified against DOE's programs supporting green energy investment, arguing that "the entire concept of using stimulus money to create a Green Economy is unsound."[223]
- Testified opposing the Federal Green Jobs Agenda.[224]

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[218] Testimony of Anne E. Smith before the House Subcommittee on Energy and Power (June 28, 2012), available at: http://www.nera.com/nera-files/PUB_Smith_EPA_0612.pdf.

[219] NERA, *Comments on EPA's Notice of Data Availability for § 316(b) Stated Preference Survey* (July 2012), available at: http://www.nera.com/nera-files/PUB_UWAG_0712_final.pdf.

[220] *See http://www.marshall.org/experts.php?id=103.*

[221] Testimony of W. David Montgomery before the House Committee on Science, Space and Technology (March 31, 2011), available at: http://science.house.gov/sites/republicans.science.house.gov/files/documents/hearings/Montgomery%203_31_11%20v2.pdf.

[222] *See* Testimony of W. David Montgomery before the Senate Committee on Environment and Public Works (Feb. 15, 2011), available at: http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=5abed004-c3d2-4f28-a721-734ad78cdd99; and Testimony of W. David Montgomery Senate Committee on Environment and Public Works (Mar. 17, 2011), available at: http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=227a0fdb-905d-47b1-ac1d-b5dad9c6a605.

[223] Testimony of W. David Montgomery before the House Committee on Oversight and Government Spending (Nov. 2, 2011), available at: http://democrats.oversight.house.gov/images/stories/Montgomery_testimony.pdf

- Opposed raising fuel efficiency standards as "the worst strategy you could think of."[225]

Dr. Montgomery and NERA, in short, share intellectual commitments that have made them preferred advocates of business interests seeking to oppose President Obama's public health and environmental efforts, as well as DOE's own efforts to increase the use of cleaner energy in this country. Many of those same interests have much to gain from LNG exports. The members and funders of the American Petroleum Institute, a NERA client, will naturally benefit from increased gas production. Likewise, coal interests, which are also frequent NERA clients, stand to benefit if LNG export leads to an increase in U.S. coal use, as the EIA has predicted. NERA does not acknowledge, much less address, these and similar conflicts in the LNG study. Nor does DOE/FE.

This failure of disclosure has infected the process as a whole. To our knowledge, DOE/FE issued no public solicitation of bids for the LNG export analysis, nor offered the public any chance, until now, to comment upon the contractors it selected. Nor have either DOE/FE or NERA provided the underlying NewERA model which NERA used to produce its results. Obviously, it is difficult to fully evaluate the study without access to the modeling files and underlying assumptions which NERA used. Other commenters[226] have made clear that it is good contracting practice to provide such materials as a matter of course. It is certainly appropriate to do so here, where DOE/FE must transparently justify its decisions after a full public process, as required by the Natural Gas Act and the Administrative Procedure Act. DOE/FE's failure to provide these critical disclosures undermines the public's ability to critically assess and analyze the study.

DOE/FE also has not disclosed how it has funded the NERA study, nor how DOE/FE influenced the study's conclusions. The magnitude of DOE/FE's involvement and investment here is of critical importance because DOE/FE claims that it has taken no position on the study or its conclusions and will dispassionately weigh public comments. Yet, if DOE/FE staff have funded the

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[224] Testimony of W. David Montgomery before the House Committee on Energy and Commerce (June 19, 2012), available at: http://energycommerce.house.gov/sites/republicans.energycommerce.house.gov/files/Hearings/OI/20120619/HHRG-112-IF02-WState-DMontgomery-20120619.pdf.

[225] Heritage Foundation, *Fuel Economy Standards: Do they Work? Do they Kill?* (2002), available at: http://www.heritage.org/research/reports/2002/03/fuel-economy-standards.

[226] *See* the Comments of Dr. Jannette Barth in this docket, for instance.

study, and, more importantly, shared in its development, there is a serious question whether DOE/FE will be able to fairly weight the finished product on its own merits. Staff clearly had some such involvement: Dr. Montgomery writes on the first page of the document that he is providing a "clean" copy, implying that past DOE/FE comments have been incorporated and addressed. The scope and nature of this involvement, however, remains unclear. DOE/FE must make its involvement transparent if it is set itself up as a neutral arbiter of the merits of NERA's work.

If DOE does not share this information in time for it inform public comment, it will have prevented the public from participating in a pressing policy debate. The courts have repeatedly held that such a denial is an irreparable injury, so preventing such an injury is plainly a compelling need. *See, e.g.*, *Electronic Privacy Info. Ctr. v. Dep't of Justice*, 416 F. Supp. 2d 30, 41-42 (D.D.C. 2006); *Washington Post v. Dep't of Homeland Security*, 459 F. Supp. 2d 61, 74-75 (D.D.C. 2006); *Electronic Frontier Found. v. Office of the Director*, 2007 WL 4208311, *6 (N.D. Cal. 2007); *EFF v. Office of the Director*, 542 F. Supp. 2d 1181,1186 (N.D. Cal. 2008).

DOE/FE must not take the arbitrary and capricious step of relying upon the questionable results of a study infected with the appearance (and perhaps the reality) of bias. Nor may it finally adopt or seriously weigh the conclusions of the study if it shuts out of the process in the way that it has done.

V. Conclusion

NERA is able to conclude that LNG export is in the nation's economic interest only because it wrongly believes that transferring billions of dollars from the nation's middle class to a small group of gas export companies benefits the country as a whole. It does not: As we have demonstrated in these comments, the likely consequences of a major shift towards LNG export will be a weakened domestic economy, "resource-cursed" communities, and lasting environmental damage.

Even if one were to accept NERA's indefensible attempt to balance national suffering against the private economic prosperity of a few, its conclusions are not maintainable. NERA projects at most a net GDP increase of at most $ 20 billion in a single year when it does this sum, subtracting labor income from LNG export revenues; the net benefit is often much less – on the order of a few billion dollars.[227] We have identified billions of dollars in pollution costs, infrastructure damage, and property value losses that NERA has not accounted for. Indeed, the cost just of increased methane emissions from LNG export is at least in the hundreds of millions annually. These costs almost certainly offset the nominal benefits which NERA claims to have identified. Certainly, NERA cannot claim otherwise, since it has not even considered them.

The Natural Gas Act charges DOE/FE with the weighty responsibility of protecting the public interest. Licensing LNG export would not serve that interest, and the NERA study certainly does not provide a basis to think otherwise. DOE/FE must not approve export licenses in reliance upon that flawed study, prepared by a contractor with at least the appearance of serious conflicts of interest. Instead, DOE/FE should begin an open, public process intended to fully identify and accurately account for the many economic and environmental impacts of LNG export.

Sincerely,

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[227] NERA Study at 8.

Synapse
Energy Economics, Inc.

Will LNG Exports Benefit the United States Economy?

January 23, 2013

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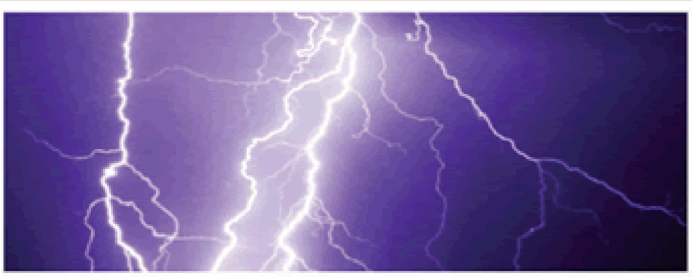

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1. Overview

DOE is considering whether large scale exports of liquefied natural gas (LNG) are in the public interest. As part of that inquiry, DOE has commissioned a team of researchers from NERA Economic Consulting, led by W. David Montgomery, to prepare a report entitled "Macroeconomic Impacts of LNG Exports from the United States" (hereafter, the NERA Report) in December 2012.[1] Unfortunately, that report suffers from serious methodological flaws which lead it to significantly underestimate, and, in some cases, to entirely overlook, many negative impacts of LNG exports on the U.S. economy.

NERA finds that LNG exports would be very good for the United States in every scenario they examined:

> …the U.S. was projected to gain net economic benefits from allowing LNG exports. Moreover, for every one of the market scenarios examined, net economic benefits increased as the level of LNG exports increased. (NERA Report, p.1)

The measure of benefits used by NERA, however, reflects only the totals for the U.S. economy as a whole. In fact, the NERA study finds that natural gas exports are beneficial to the natural gas industry alone, at the expense of the rest of the U.S. economy—reducing the size of the U.S. economy excluding LNG exports.

This white paper examines the NERA Report, and identifies multiple problems and omissions in its analyses of the natural gas industry and the U.S. economy:

- NERA's own modeling shows that LNG exports in fact cause GDP to decline in all other economic sectors.
- Although NERA does not calculate employment figures, the methods used in previous NERA reports would indicate job losses linked to export of tens to hundreds of thousands.
- NERA undervalues harm to the manufacturing sector of the U.S. economy.
- NERA ignores significant economic burdens from environmental harm caused by export.
- NERA ignores the distribution of LNG-export benefits among different segments of society, and makes a number of questionable and unrealistic economic assumptions:
    - In NERA's model, everyone who wants a job has one; by definition, LNG exports cannot cause unemployment.
    - All economic benefits of LNG export return to U.S. consumers without any leakage to foreign investors.
    - Changes to the balance of U.S. trade are constrained to be very small.

[1] W. David Montgomery, et al., *Macroeconomic Impacts of LNG Exports from the United States,* December 2012. http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf

- NERA's modeling of economic impacts is based entirely on the proprietary N_{ew}ERA model, which is not available for examination by other economists.
- NERA's treatment of natural gas resources and markets makes selective use of data to portray exports in a favorable light. In some cases, the NERA Report uses older data when newer revisions from the same sources were available; at times, it disagrees with other analysts who have carefully studied the same questions about the gas industry.

Even if NERA's flawed and incomplete analysis were to be accepted at face value, its conclusion that opening LNG exports would be good for the United States as a whole is not supported by its own modeling. Instead, NERA's results demonstrate that manufacturing, agriculture, and other sectors of the U.S. economy would suffer substantial losses. The methodology used to estimate job losses in other NERA reports, if applied in this case, would show average losses of wages equivalent to up to 270,000 jobs lost in each year.

2. LNG exports: Good for the gas industry, bad for the United States

According to the NERA Report, LNG exports would benefit the natural gas industry at the expense of the rest of the U.S. economy. Two sets of evidence illustrate this point: a comparison of natural gas export revenues with changes in gross domestic product (GDP), and a calculation, employed by NERA in other reports, of the "job-equivalents" from decreases in labor income. Applying this calculation to the NERA Report analysis suggests that opening LNG exports would result in hundreds of thousands of job losses. These losses would not be confined to narrow sections of U.S. industry, as NERA implies.

The NERA Report presents 13 "feasible" economic scenarios for LNG export, with projections calculated by NERA's proprietary N_{ew}ERA model for 2015, 2020, 2025, 2030, and 2035. The scenarios differ in estimates of the amount of natural gas that will ultimately be recovered per new well: seven scenarios (with labels beginning with USREF) use the estimate from the federal Energy Information Administration's AEO 2011; five (beginning with HEUR) assume 150 percent of the AEO level; and one (beginning with LEUR) assumes 50 percent of the AEO level. In the LEUR scenario, LNG exports are barely worthwhile; in the HEUR scenarios, exports are more profitable than in the USREF scenarios.

LNG exports cause U.S. GDP (excluding LNG exports) to fall

Careful analysis of these LNG export scenarios reveals that the gain in GDP predicted by the NERA Report is driven—almost entirely—by revenues to gas exporters and gas companies; the remainder of the economy declines.

On average (across the five reporting years), export revenues were 74 percent or more of GDP growth in every scenario; in the eight scenarios with average or low estimated gas recovery per well, export revenues averaged more than 100 percent of GDP growth. In the median scenario, export revenues averaged 169 percent of GDP growth; in the worst case, export revenues averaged 240 percent of GDP growth.

Table 1 compares natural gas export revenues to the increase in GDP for each scenario.[2] When export revenues are greater than 100 percent of GDP growth, the size of the U.S. economy, excluding gas exports, is shrinking. For instance, for the year 2035 in the first two scenarios in Table 1, LNG export revenues are almost $9 billion higher than in the reference case, while GDP—which includes those export revenues along with everyone else's incomes—is only $3 billion higher. Thus, as a matter of arithmetic, everyone else's incomes (i.e., GDP excluding LNG export revenues) must have gone down by almost $6 billion. (If your favorite baseball team scored 3 more home runs this year than last year, and one of its players scored 9 more than he did last year, then it must be the case that the rest of the team scored 6 fewer.)

Similarly, in every case where natural gas export revenues exceed 100 percent of the increase in GDP—cases that appear throughout Table 1—the export revenues are part of GDP, so the remainder of GDP must have gone down.

Table 1: LNG Exports as a Share of GDP Gains[3]

Scenario	Exports as Percent of GDP Gains					
	2015	2020	2025	2030	2035	average
USREF_D_LSS	72%	75%	193%	225%	286%	170%
USREF_D_LS	50%	89%	193%	225%	286%	169%
USREF_D_LR	62%	112%	257%	338%	429%	240%
USREF_SD_LS	50%	77%	204%	258%	468%	211%
USREF_SD_LR	59%	90%	244%	258%	702%	271%
USREF_SD_HS	50%	67%	140%	216%	429%	180%
USREF_SD_HR	59%	75%	158%	216%	501%	202%
HEUR_SD_LSS	19%	38%	69%	109%	152%	77%
HEUR_SD_LS	24%	40%	82%	109%	152%	81%
HEUR_SD_LR	31%	42%	82%	123%	152%	86%
HEUR_SD_HS	24%	37%	64%	106%	142%	74%
HEUR_SD_HR	28%	39%	74%	111%	142%	79%
LEUR_SD_LSS	0%	164%	*NA*	*NA*	158%	107%

NA - not applicable (GDP did not increase over the no-export reference case)
Source: Author's calculations based on NERA Report, Figures 144-162.

As Table 1 demonstrates, export revenues exceed GDP growth: GDP (not including gas exports) is shrinking by 2030 or earlier in all scenarios, and by 2025 or earlier in all scenarios using the AEO assumption about gas recovery per well (i.e., USREF). In other words, after the initial years of construction of export facilities, when construction activities may create some local economic

[2] The increase in GDP is the difference between the scenario GDP projections and the GDP in the corresponding no-export reference case (for USREF, HEUR, or LEUR assumptions). Data from NERA Report, pp.179-197.

[3] In the second term in the scenario names, international cases are defined by increases in global demand and/or decreases in global supply: D=International Demand Shock, SD=International Supply/Demand Shock. In the third term in the scenario names, export cases for quantity/growth are defined as follows: LSS=Low/Slowest, LS=Low/Slow, LR=Low/Rapid, HS=High/Slow, HR=High/Rapid.

benefits, gas exports create increased income for the gas industry, at the expense of everyone else.[4]

Loss of labor income from LNG exports is equivalent to huge job losses

NERA avoids predicting the employment implications of LNG export, and downplays the aggregate billions of dollars in decreased labor income predicted by its report. In fact, using NERA's own methods, the following analysis shows the potential for hundreds of thousands of job losses per year.

In other reports using the N_{ew}ERA model, NERA has reported losses of labor income in terms of "job-equivalents." This may seem paradoxical, since the N_{ew}ERA model assumes full employment, as discussed later in this white paper. As NERA has argued elsewhere, however, a loss of labor income can be expressed in terms of job-equivalent losses, by assuming that it consists of a loss of workers earning the average salary.[5] In other words, a given decrease in labor income can be interpreted as a loss of workers who would make that income.

This method can be applied to the losses of labor income projected for each of the 13 scenarios in the NERA Report. These losses are expressed as percentages of gross labor income; we have assumed that NERA's "job-equivalent losses" represent the same percentage of the labor force. For example, we assume the loss of 0.1 percent of gross labor income in scenario HEUR_SD_HS in 2020 is equivalent to job losses of 0.1 percent of the projected 2020 labor force of 159,351,000 workers, or roughly 159,000 job-equivalent losses.[6]

The results of this analysis are shown in Table 2. Job-equivalent losses, averaged across the five reporting years, range from 36,000 to 270,000 per year; the median scenario has an average job-equivalent loss of 131,000 per year. We do not necessarily endorse this method of calculation of labor impacts, but merely note that NERA has adopted it in other reports using the same model. If NERA had used this method in the NERA Report analysis, it would have shown that LNG exports have the potential to significantly harm employment in many sectors.

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[4] Other modeled results in the record cast further doubt on NERA's study. See Wallace E. Tyner, "Comparison of Analysis of Natural Gas Export Impacts," January 14, 2013. http://www.fossil.energy.gov/programs/gasregulation/authorizations/export_study/30_Wallace_Tyner01_14_13.pdf

[5] See, e.g., NERA's Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector, October 2012, p. ES-6: "Job-equivalents are calculated as the total loss in labor income divided by the average salary." http://www.nera.com/nera-files/PUB_ACCCE_1012.pdf

[6] The Bureau of Labor Statistics projects annual growth of the civilian labor force at 0.7% per year from 2010 to 2020 (Mitra Toosi. "Labor force projections to 2020: a more slowly growing workforce." Monthly Labor Review, January 2012. http://www.bls.gov/opub/mlr/2012/01/art3full.pdf.) We have used the same annual growth rate to project the labor force through 2035.

Table 2: Employment equivalents of reduced labor income

	Job-equivalent loss, NERA method					
	2015	2020	2025	2030	2035	average
USREF_D_LSS	15,000	77,000	108,000	77,000	62,000	68,000
USREF_D_LS	31,000	77,000	108,000	77,000	62,000	71,000
USREF_D_LR	108,000	92,000	108,000	77,000	62,000	89,000
USREF_SD_LS	31,000	200,000	169,000	139,000	123,000	132,000
USREF_SD_LR	123,000	215,000	169,000	139,000	123,000	154,000
USREF_SD_HS	31,000	185,000	292,000	292,000	246,000	209,000
USREF_SD_HR	108,000	292,000	308,000	292,000	246,000	249,000
HEUR_SD_LSS	15,000	62,000	108,000	108,000	92,000	77,000
HEUR_SD_LS	15,000	169,000	139,000	108,000	92,000	105,000
HEUR_SD_LR	108,000	169,000	139,000	108,000	92,000	123,000
HEUR_SD_HS	15,000	154,000	246,000	215,000	200,000	166,000
HEUR_SD_HR	92,000	385,000	292,000	231,000	200,000	240,000
LEUR_SD_LSS	0	92,000	77,000	0	0	34,000
Labor force	*153,889,000*	*153,889,000*	*153,889,000*	*153,889,000*	*153,889,000*	

Source: Author's calculations based on NERA Report, Figures 144-162.

NERA downplays their estimated shifts in employment from one sector to another saying that is smaller than normal rates of turnover in those industries, but, of course, normal labor turnover is enormous. It is true that job losses caused by LNG exports will be less than the annual total of all retirements, voluntary resignations, firings, layoffs, parental and medical leaves, new hires, moves to new cities and new jobs, and switching from one employer to another for all sorts of reasons: Throughout the entire U.S. labor force normal turnover amounts to almost 40 million people each year.[7] The comparison of job losses to job turnover is irrelevant.

Harm to U.S. economy is not confined to narrow sections of industry, as NERA implies

The NERA Report emphasizes the fact that only a few branches of industry are heavily dependent on natural gas (NERA Report, pp.67-70). This discussion is described as an attempt "to identify where higher natural gas prices might cause severe impacts such as plant closings" (p.67). The NERA Report makes two principal points in this discussion. First, it quotes a 2009 study of the expected impacts of the Waxman-Markey proposal for climate legislation, which found that only a limited number of branches of industry would be harmed by higher carbon costs; NERA argues that price increases caused by LNG exports will have an even smaller but similarly narrow effect on industry. Second, NERA observes that industries where value added (roughly the sum of wages and profits) makes up a large fraction of sales revenue are unlikely to have high energy costs, while industries with high energy costs probably have a low ratio of value added to sales.

[7] "Job Openings and Labor Turnover," Bureau of Labor Statistics, November 2012, Table 3. http://www.bls.gov/news.release/pdf/jolts.pdf

Both points may be true, but they are largely irrelevant to the evaluation of LNG exports. NERA's use of the Waxman-Markey study is inappropriate, as Representative Markey himself has pointed out, because that proposed bill directed significant resources to industries harmed by higher costs to mitigate any negative impact.[8] No such mitigation payments are associated with LNG export, so relying upon Waxman-Markey examples to downplay potential economic damage is inappropriate. If those exports increase domestic gas prices, industry will be harmed both by higher electricity prices and by higher costs for direct use of natural gas. Further, it is true that direct use of natural gas is relatively concentrated, but it is concentrated in important sectors; as the natural gas industry itself explains, "Natural gas is consumed primarily in the pulp and paper, metals, chemicals, petroleum refining, stone, clay and glass, plastic, and food processing industries."[9] These are not small or unimportant sectors of the U.S. economy.[10] In any case, discussion of sectors where higher natural gas prices might cause "severe impacts such as plant closings" is attacking a straw man; NERA's own calculations imply moderate harm would be imposed throughout industry, both by rising electricity prices and by the costs of direct gas consumption—offset by benefits exclusively concentrated in the hands of the natural gas industry.

Similarly, it does not seem particularly important to know whether industries that use a lot of natural gas have high or low ratios of value added to sales. Are aluminum, cement, fertilizer, paper, and chemicals less important to the economy because they have many purchased inputs, and therefore low ratios of value added to sales?

3. Costs and benefits from LNG exports are unequally distributed

As the results above show, LNG exports essentially transfer revenue away from the rest of the economy and into the hands of companies participating in these exports. This shift has significant economic implications that are not addressed in the NERA Report's analysis.

The NERA Report asserts that "all export scenarios are welfare-improving for U.S. consumers" (NERA Report, p.55). While LNG exports will result in higher natural gas prices for U.S. residents, NERA projects that these costs will be outweighed by additional income received from the exports—and thus, "consumers, in aggregate are better off as a result of opening LNG exports." (NERA Report, p.55) Or, to put this another way, the gains of every resident of the United States, added together, will be greater than the losses of every resident of the United States, added together. The distribution of these benefits and costs—who will suffer costs and who will reap gains—is discussed only tangentially in the NERA Report, but is critical to a complete understanding of the effects of LNG exports on the U.S. economy. A closer look reveals that LNG exports benefit only a very narrow section of the economy, while causing harm to a much broader group.

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[8] Letter from Rep. Markey to Secretary Steve Chu (Dec. 14, 2012).
[9] http://www.naturalgas.org/overview/uses_industry.asp.
[10] Other commenters also point out that NERA does not even appear to have included some gas-dependent industries, including fertilizer and fabric manufacture, in its analysis. *See* Comments of Dr. Jannette Barth (Dec. 14, 2012).

Focus on "net impacts" ignores key policy issues

The results presented in the NERA Report focus on the net impacts on the entire economy—combining together everyone's costs and benefits—and on the "welfare" of the typical or average family, measured in terms of equivalent variation.[11] NERA dismisses the need to discuss the distribution of the costs and benefits among groups that are likely to experience very different impacts from LNG exports, stating that: "[t]his study addresses only the net economic effects of natural gas price changes and improved export revenues, not their distribution." (NERA Report, p.211) NERA alludes to an unequal distribution of costs and benefits in its results, but does not present a complete analysis:

> Although there are costs to consumers of higher energy prices and lower consumption and producers incur higher costs to supply the additional natural gas for export, these costs are more than offset by increases in export revenues along with a wealth transfer from overseas received in the form of payments for liquefactions services. The net result is an increase in U.S. households' real income and welfare. (NERA Report, p.6)

Instead, the NERA Report combines the economic impacts of winners and losers from LNG exports. In the field of economics, this method of asserting that a policy will improve welfare for society as a whole as long as gains to the winners are greater than costs to the losers is known as the "Kaldor-Hicks compensation principle" or a "potential Pareto improvement." The critiques leveled at cost-benefit analyses that ignore important distributional issues have as long a history as these flawed methods. Policy decisions cannot be made solely on the basis of aggregated net impacts: costs to one group are never erased by the existence of larger gains to another group. The net benefit to society as a whole shows only that, if the winners choose to share their gains, they have the resources to make everyone better off than before—but not that they *will* share their gains. In the typical situation, when the winners choose to keep their winnings to themselves, there is no reason to think that everyone, including the losers, is better off.

As previous congressional testimony by W. David Montgomery—the lead author of the NERA Report—on the impacts of cap-and-trade policy support explained it: "There are enough hidden differences among recipients of allowances within any identified group that it takes far more to compensate just the losers in a group than to compensate the average. Looking at averages assumes that gainers compensate losers within a group, but that will not occur in practice."[12]

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[11] One of the complications in estimating the costs and benefits of a policy with the potential to impact prices economy-wide, is that simply measuring changes in income misses out on the way in which policy-driven price changes affect how much can be bought for the same income. (For example, if a policy raises incomes but simultaneously raises prices, it takes some careful calculation to determine whether people are better or worse off.) The NERA Report uses a measure of welfare called "equivalent variation," which is the additional income that the typical family would have to receive today (when making purchases at current prices) in order to be just as well off as they would be with the new incomes and new price levels under the proposed policy. It can be thought of as the change in income caused by the policy, adjusted for any change in prices caused by the policy.

[12] Prepared Testimony of W. David Montgomery, before the Committee on Energy and Commerce Subcommittee on Energy and Environment, U.S. House of Representatives, Hearing on Allowance Allocation Policies in Climate Legislation, June 9, 2009.
http://democrats.energycommerce.house.gov/Press_111/20090609/testimony_montgomery.pdf.

Wage earners in every sector except natural gas will lose income

In every scenario reviewed in the NERA Report, labor income rises in the natural gas industry, and falls in every other industry.[13] Economy-wide, NERA finds that "capital income, wage income, and indirect tax revenues drop in all scenarios, while resource income and net transfers associated with LNG export revenues increase in all scenarios." (NERA Report, p.63)[14] Even without a detailed distributional analysis, the NERA Report demonstrates that some groups will lose out from LNG exports:

> Overall, both total labor compensation and income from investment are projected to decline, and income to owners of natural gas resources will increase… Nevertheless, impacts will not be positive for all groups in the economy. Households with income solely from wages or government transfers, in particular, might not participate in these benefits. (NERA Report, p.2)

NERA's "might not participate in these benefits" could and should be restated more accurately as "will bear costs." Although NERA doesn't acknowledge it, most Americans will not receive revenues from LNG exports; many more Americans will experience decreased wages and higher energy prices than will profit from LNG exports.

Wage earners in every major sector except for natural gas will lose income, and, as domestic natural gas prices increase, households and businesses will have to pay more for natural gas (for heat, cooking, etc.), electricity, and other goods and services with prices that are strongly impacted by natural gas prices. The NERA Report briefly mentions these price effects:

> Natural gas is also an important fuel for electricity generation, providing about 20% of the fuel inputs to electricity generation. Moreover, in many regions and times of the year natural gas-fired generation sets the price of electricity so that increases in natural gas prices can impact electricity prices. These price increases will also propagate through the economy and affect both household energy bills and costs for businesses. (NERA Report, p.13-14)

Additional analysis required to understand electricity price impacts

There are no results presented in the NERA Report to display the effect of changes in electricity prices on consumers. Negative effects on the electricity sector itself are shown in NERA's Figure 38, but changes in electric rates and electricity bills, and the distributional consequences of these changes, are absent from the results selected for display in this report. NERA certainly could have conducted such an analysis. NERA's October 2012 report on recent and anticipated EPA regulations affecting the U.S. electricity sector using the N_{ew}ERA model displayed electricity price impacts for eleven regions and three scenarios.[15]

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13 See NERA Report, Figure 39.
14 See NERA Report, Figure 40.
15 Harrison, et al., Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector, October 2012. NERA Economic Consulting. See Table 17. http://www.nera.com/67_7903.htm.

Dr. Montgomery previous testimony also presents increases in household electric utility bills.[16] He describes a "decline in purchasing power" for the average household, claiming that "the cost for the average family will be significant" and "generally the largest declines in household purchasing power are occurring in the regions with the lowest baseline income levels."[17] A careful distributional analysis would greatly improve the policy relevance of the NERA Report's economic impact projections.

Benefits of stock ownership are not as widespread as NERA assumes

There is no evidence to support NERA's implication that the benefits of stock ownership are broadly shared among U.S. families across the economic spectrum—and therefore no evidence that they will "participate" in benefits secured by LNG exports.

NERA's claim of widespread benefits is not supported by data from the U.S. Census Bureau. In 2007, just before the financial crash, only about half of all families owned any stock, including indirect holdings in retirement accounts. Indeed, only 14 percent of families with the lowest incomes (in the bottom 20 percent) held any stock at all, compared to 91 percent of families with the highest incomes (the top 10 percent).[18]

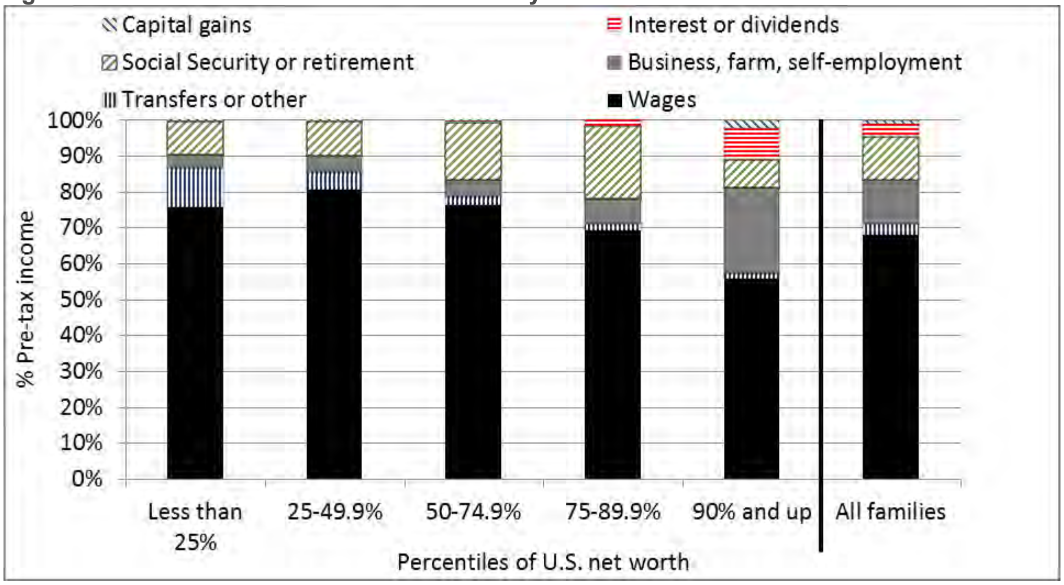
For most households the primary source of income is wages. According to the Federal Reserve, 68 percent of all family income in 2010 (the latest data available) came from wages, while interest, dividends and capital gains only amounted to 4.5 percent (see Figure 1). Families with the least wealth (the bottom 25 percent) received 0.2 percent of their income from interest, dividends, and capital gains, compared to 11 percent for the wealthiest families (the top 10 percent).

[16] Prepared Testimony of W. David Montgomery, before the Committee on Energy and Commerce Subcommittee on Energy and Environment, U.S. House of Representatives, Hearing on Allowance Allocation Policies in Climate Legislation, June 9, 2009. http://democrats.energycommerce.house.gov/Press_111/20090609/testimony_montgomery.pdf.

[17] Ibid.

[18] U.S. Census Bureau, Statistical Abstract of the United States: 2012, 2012. See Table 1211. http://www.census.gov/compendia/statab/2012/tables/12s1211.pdf.

Figure 1: U.S. Households Source of Income by Percentile of Net Worth in 2010



Source: Federal Reserve, Changes in U.S. Family Finances from 2007 to 2010: Evidence from the Survey of Consumer Finances, Table 2.

And yet the NERA Report appears to assume that the benefits of owning stock in natural gas export companies are widespread, explaining that:

> U.S. consumers receive additional income from…the LNG exports provid[ing] additional export revenues, and…consumers who are owners of the liquefaction plants, receiv[ing] take-or-pay tolling charges for the amount of LNG exports. These additional sources of income for U.S. consumers outweigh the loss associated with higher energy prices. Consequently, consumers, in aggregate, are better off as a result of opening up LNG exports. (NERA Report, p.55)

In the absence of detailed analysis from NERA, it seems safe to assume that increases to U.S. incomes from LNG exports will accrue to those in the highest income brackets. Lower income brackets, where more income is derived from wages, are far more likely to experience losses in income—unless they happen to work in the natural gas industry—and natural gas extraction currently represents less than 0.1 percent of all jobs in the United States.[19] At the same time, everyone will pay more on their utility bills.

[19] Share of jobs in oil and gas extraction. Data for the share of jobs in the natural gas industry alone is not available but would, necessarily, be smaller. Support activities for mining represents an additional 0.25 percent of jobs, petroleum and coal products 0.08 percent, and pipeline transportation 0.03 percent. Taken together, these industries, which include oil, coal and other mining operations, represent 0.5 percent of all U.S. employment. Bureau of Economic Analysis, Full-Time and Part-Time Employees by Industry, 2011 data. http://bea.gov/iTable/iTable.cfm?ReqID=5&step=1

NERA's assumption that all income from LNG exports will return to U.S. residents is incorrect

In the N_{ew}ERA analysis, two critical assumptions assure that all LNG profits accrue to U.S. residents. First, "Consumers own all production processes and industries by virtue of owning stock in them." (NERA Report, p.55) The unequal distribution of stock ownership (shown as interest, dividend, and capital gains income in the Federal Reserve data in Figure 1) is not made explicit in the NERA Report, nor is the very small share that natural-gas-related assets represent in all U.S.-based publically traded stock.[20] In discussing impacts on households' wealth, NERA only mention that "if they, or their pensions, hold stock in natural gas producers, they will benefit from the increase in the value of their investment." (NERA Report, p.13) A more detailed distributional analysis would be necessary to determine the exact degree to which LNG profits benefit different income groups; however, it is fair to conclude that lower-income groups and the middle class are much less likely to profit from LNG exports than higher-income groups that receive a larger portion of income from stock ownership.

Second, the NERA Report assumes that "all of the investment in liquefaction facilities and natural gas drilling and extraction comes from domestic sources." (NERA Report, p.211) This means that the N_{ew}ERA model implausibly assumes that all U.S.-based LNG businesses are solely owned by U.S. residents. There is no evidence to support this assumption. On the contrary, many players in this market have significant foreign ownership shares or are privately held, and may be able to move revenues in ways that avoid both the domestic stock market and U.S. taxes. Cheniere Energy, the only LNG exporter licensed in the United States, is currently building an export terminal on the Gulf of Mexico for $5.6 billion—$1 billion of which is coming from investors in China and Singapore.[21] Cheniere's largest shareholders include holding companies in Singapore and Bermuda, as well as a hedge fund and a private equity firm, which in turn have a mix of domestic and foreign shareholders.[22] This situation is not atypical. As illustrated in Figure 2, 29 percent (by Bcf/day capacity) of the applications for U.S. LNG export licenses are foreign-owned, including 6 percent of total applications from foreign governments. Additionally, 70 percent of domestic applicants are publicly owned and traded, most of which have both domestic and foreign stock holders. Gas extraction companies, similarly, operate with a diverse mix of foreign and domestic investment, and of public and private ownership structures. NERA's claim that profits from LNG exports will be retained in the United States is unfounded.

NERA certainly could have addressed this issue in its analysis. Dr. Montgomery's previous testimony on cap-and-trade assumed that "all auction revenues would be returned to households,

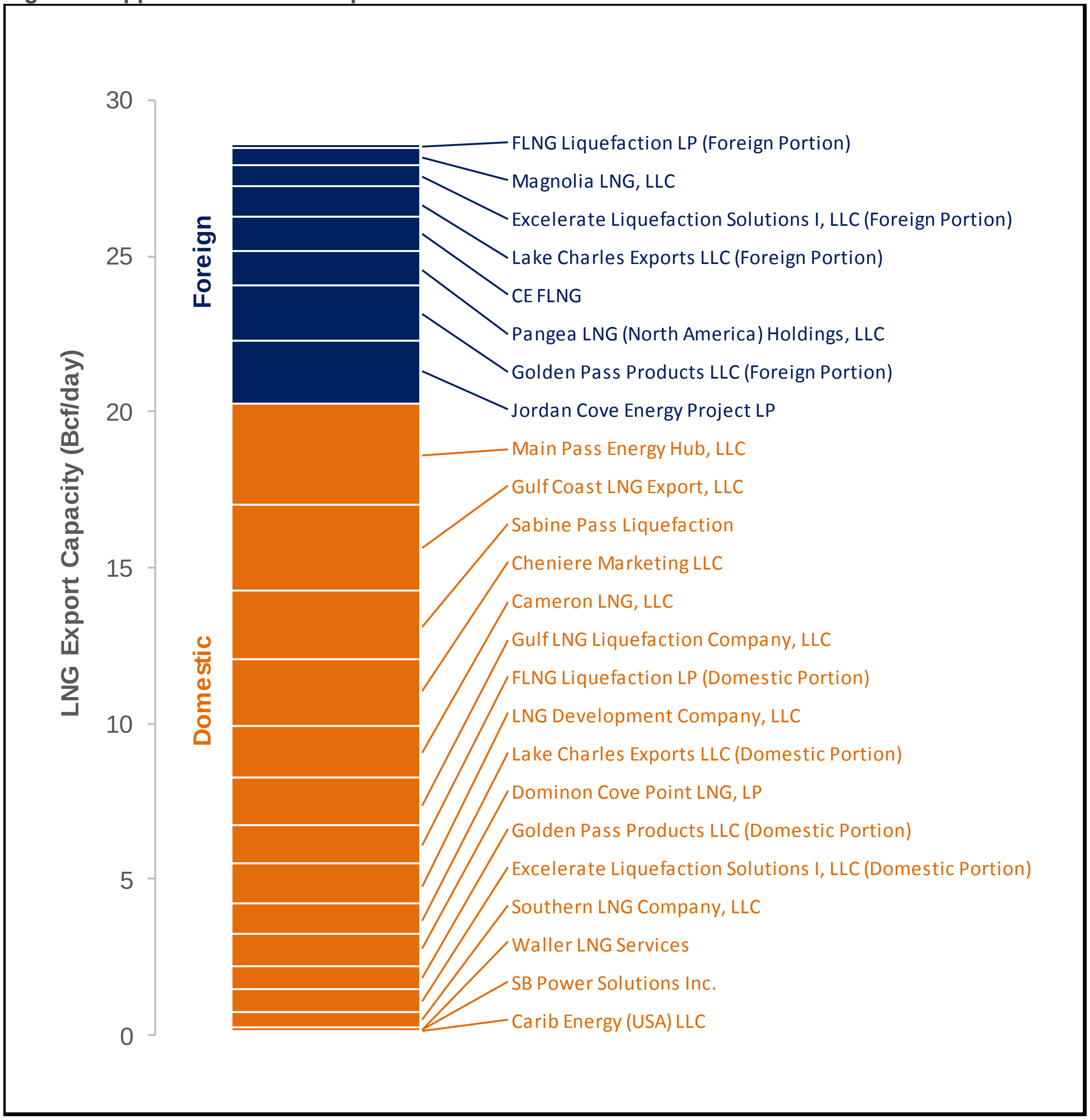
[20] NYSE companies involved in LNG export applications account for 5.8 percent of the total market capitalization, but this includes the value of shares from Exxon Mobil—by itself 2.9 percent of the NYSE market cap—as well as several other corporations with diverse business interests, such as General Electric, Dow, and Seaboard (owner of Butterball Turkeys among many other products). Reuters Stocks website, downloaded January 22, 2013 (following marketclose), http://www.reuters.com/finance/stocks. World Federation of Exchanges, "2012 WFE Market Highlights" (January 2013), page 6. http://www.world-exchanges.org/files/statistics/2012%20WFE%20Market%20Highlights.pdf.

[21] "UPDATE 2-China, Singapore wealth funds invest $1 bln in US LNG export plant-source." Reuters, August 21, 2012. http://www.reuters.com/article/2012/08/21/cic-cheniere-idUSL4E8JL0SC20120821

[22] Ownership data from NASDAQ for Cheniere Energy, Inc. (LNG). http://www.nasdaq.com/symbol/lng/ownership-summary#.UPmZgCfLRpU.

except for the allowance allocations that are given to foreign sources."[23] This assumption led him to conclude that, for the cap-and-trade program, a "large part of the impact on household costs is due to wealth transfers to other countries."[24] This level of analytical rigor should have been applied when estimating the U.S. domestic benefits from opening natural gas exports.

Figure 2: Applicants for LNG Export Licenses



[23] Prepared Testimony of W. David Montgomery, before the Committee on Energy and Commerce Subcommittee on Energy and Environment, U.S. House of Representatives, Hearing on Allowance Allocation Policies in Climate Legislation, June 9, 2009, http://democrats.energycommerce.house.gov/Press_111/20090609/testimony_montgomery.pdf.
[24] Ibid.

Source: See Appendix A for a full list of sources.

Opening LNG export will also incur environmental costs

The discussion of LNG exports in the NERA Report, and most of our analysis of the report, is concerned with monetary costs and benefits: Exports cause an increase in natural gas prices, boosting incomes in the natural gas industry itself while increasing economic burdens on the rest of the economy. There are, in addition, environmental impacts of natural gas production and distribution that do not have market prices, but may nonetheless become important if LNG exports are expanded. Increases in exports are likely to increase production of natural gas, entailing increased risks of groundwater pollution and other environmental problems potentially associated with hydraulic fracturing ("fracking"). Increases in production, transportation of natural gas from wells to export terminals, and the liquefaction process itself, all increase the risks of leaks of natural gas, a potent greenhouse gas that contributes to global warming. These environmental impacts should be weighed, alongside the monetary costs and benefits of export strategies, in evaluation of proposals for LNG exports.

Clearly, as NERA itself acknowledges, the NERA Report would benefit from more detailed analysis of the distribution of costs and benefits from opening LNG exports: "Although convenient to indicate that there are winners and losers from any market or policy change, this terminology gives limited insight into how the gains and losses are distributed in the economy." (NERA Report, p.211)

4. Dependence on resource exports has long-run drawbacks

The harm that LNG exports cause to the rest of the U.S. economy, even in NERA's model, are consistent with an extensive body of economic literature warning of the dangers of resource-export-based economies.

If NERA's economic modeling is accepted at face value, it implies that the United States should embrace resource exports, even at the expense of weakening the rest of the economy. GDP, net incomes, and "welfare" as measured by NERA would all rise in tandem with LNG exports. There would be losses in manufacturing and other sectors, especially the energy-intensive sectors of paper and pulp, chemicals, glass, cement, and primary metal (iron, steel, aluminum, etc.) manufacturing (NERA Report, p. 64). But NERA asserts that these would be offset by gains in the natural gas industry. There would be losses of labor income, equivalent to a decline of up to 270,000 average-wage jobs per year. But, according to NERA, these losses would be offset by increased incomes for resource (natural gas) owners.

For those who are indifferent to the distribution of gains and losses—or who imagine that almost everyone owns a share of the natural gas industry—the shift away from manufacturing and labor income toward raw material exports could be described as good for the country as a whole. (So, too, could any shift among types of income, as long as its net result is an increase in GDP.) The rising value of the dollar relative to other currencies would allow affluent Americans to buy more imports, further increasing their welfare, even as the ability of industry to manufacture and export from the United States would decline.

There is, however, a longer-term threat of LNG exports to the U.S. economy: NERA's export scenarios would accelerate the decline of manufacturing and productivity throughout the country, pushing the nation into increased dependence on raw material exports. Developing countries have often struggled to escape from this role in the world economy, believing that true economic development requires the creation of manufacturing and other high-productivity industries. International institutions such as the IMF and the World Bank have often insisted that developing countries can maximize their short-run incomes by sticking to resource exports.

NERA is in essence offering the same advice to the United States: Why strive to make things at home, if there is more immediate profit from exporting raw materials to countries that can make better use of them? Europe, China, Japan, and Korea have much more limited natural resources per capita, but they are very good at making things out of resources that they buy from the United States and other resource-rich countries. In the long run, which role do we want the United States to play in the world economy? Do we want to be a resource exporter, with jobs focused in agriculture, mining, petroleum and other resource-intensive industries? Or do we want to export industrial goods, with jobs focused in manufacturing and high-tech sectors?

Economists have recognized that resource exports can impede manufacturing, even in a developed country; the problem has been called the "resource curse" or the "Dutch disease." The latter name stems from the experience of the Netherlands after the discovery of natural gas resources in 1959; gas exports raised the value of the guilder (the Dutch currency in pre-Euro days), making other Dutch exports less competitive in world markets and resulting in the eventual decline of its manufacturing sector.[25] In other countries, the "resource curse" has been associated with increased corruption and inequality; countries that depend on a few, very profitable resource exports may be less likely to have well-functioning government institutions that serve the interests of the majority.[26] Protecting an economy against the resource curse requires careful economic management of prospective resource exports.

In particular, it may be more advantageous in the long run to nurture the ability to manufacture and export value-added products based on our natural resources—even if it is not quite as profitable in the short run. The NERA Report is notably lacking in analysis of this strategy; there are no scenarios exploring promotion of, for example, increased use of natural gas in the chemical industry and increased exports of chemicals from the United States. The 25-year span of NERA's analysis provides for scope to develop a longer-term economic strategy with a different pattern of winners and losers. The benefits in this case might extend well beyond the narrow confines of the natural gas industry itself.

5. Unrealistic assumptions used in NERA's N$_{ew}$ERA model

Despite its sunny conclusions, the NERA Report indicates that LNG exports pose serious challenges to the U.S. economy. It is troubling, then, that the underlying modeling in the report is notably difficult to assess, and is reliant on a number of unrealistic assumptions.

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[25] "The Dutch Disease." *The Economist*, November 26, 1977, pp. 82-83.

[26] Papyrakis and Gerlagh. "The resource curse hypothesis and its transmission channels." *Journal of Comparative Economics*, 2004, 32:1 p.181-193; Mehlum, Moene and Torvik. "Institutions and the Resource Curse." *The Economic Journal*, 2006, 116:508 p.1-20.

The NERA Report relies on NERA Consulting's proprietary model, called N$_{ew}$ERA. Detailed model assumptions and relationships have never been published; we are not aware of any use of the model, or even evaluation of it in detail, by anyone outside NERA.

According to the NERA Report, N$_{ew}$ERA is a computable general equilibrium (CGE) model. Such models typically start with a series of assumptions, adopted for mathematical convenience, that are difficult to reconcile with real-world conditions. The base assumptions of the N$_{ew}$ERA model are described as follows: "The model assumes a perfect foresight, zero profit condition in production of goods and services, no changes in monetary policy, and full employment within the U.S. economy." (NERA Report, p. 103)

Here we discuss the implications of each of these assumptions, together with two additional critical modeling assumptions described elsewhere in the NERA Report: limited changes to the balance of trade, and sole U.S. financing of natural gas investments.

Full employment

The full employment assumption, common to most (though not all) CGE models, means that in every year in every scenario, anyone who wants a job can get one. This assumption is arguably appropriate—or at least, introduces only minor distortions—at times of very high employment such as the late 1990s. It is, however, transparently wrong under current conditions, when unemployment rates are high and millions of people who want jobs cannot find them.

The NERA Report expands on its Pollyannaish vision of the labor market, saying:

> The model assumes full employment in the labor market. This assumption means total labor demand in a policy scenario would be the same as the baseline policy projection… The model assumes that labor is fungible across sectors. That is, labor can move freely out of a production sector into another sector without any adjustment costs or loss of productivity. (NERA Report, p.110)

It also includes, in its "Key Findings," the statement that: "LNG exports are not likely to affect the overall level of employment in the U.S." (NERA Report, p.2)

In fact, this is an assumption—baked into the model—and not a finding. N$_{ew}$ERA, by design, never allows policy changes to affect the overall assumed level of employment. The unemployment rate must, by definition, always be low and unchanging in NERA's model.

For this reason, the potential economic impact that is of the greatest interest to many policymakers, namely the effects of increased LNG exports on jobs, cannot be meaningfully studied with NERA's model. Addressing that question requires a different modeling framework, one that recognizes the existence of involuntary unemployment (when people who want jobs cannot find them) and allows for changes in employment levels. (Despite N$_{ew}$ERA's full employment assumption, NERA has used the model results to calculate the "job-equivalents" lost to other environmental policies, as discussed above. Had NERA seriously addressed the question, as we discussed earlier, it might have discovered serious job loss potential.)

Perfect foresight

N_{ew}ERA, like other CGE models, assumes that decision-makers do not make systematic errors (that is, errors that bias results) when predicting the future. This is a common assumption in economic modeling and, while more complex theories regarding the accuracy of expectations of the future do exist, they only rarely enter into actual modeling of future conditions.

Zero profit condition

A more puzzling assumption is the "zero profit condition," mentioned in the quote above. Analyzing fossil fuel markets under the assumption of zero profits sounds like a departure from the familiar facts of modern life. The picture is less than clear, since the N_{ew}ERA model includes calculations of both capital income and "resource" income (the latter is received by owners of resources such as natural gas); these may overlap with what would ordinarily be called profits. Without a more complete description of the N_{ew}ERA model, it is impossible to determine exactly how it treats profits in the fossil fuel industries. In any case, the business media are well aware of the potential for profits in natural gas; a recent article, based in part on the NERA Report, includes the subheading "How LNG Leads to Profits."[27]

Invariable monetary policy

N_{ew}ERA also assumes that economy-wide interest rates and other monetary drivers will stay constant over time. Changes to monetary policy could, of course, have important impacts on modeling results, but forecasting these kinds of changes may well be considered outside of the scope of NERA's analysis. That being said, several of NERA's classes of scenarios involve supply and demand shocks to the economy as a whole: exactly the kind of broad-based change in economic conditions that tends to provoke changes in monetary policy.

Limited changes to the balance of trade

NERA's treatment of foreign trade involves yet another unrealistic assumption:

> We balance the international trade account in the N_{ew}ERA model by constraining changes in the current account deficit over the model horizon. The condition is that the net present value of the foreign indebtedness over the model horizon remains at the benchmark year level. (NERA Report, p.109)

Although U.S. exports increase in many scenarios, NERA assumes that there can be very little change in the balance of trade. Instead, increases in exports largely have the effect of driving up the value of the dollar relative to other currencies (NERA Report, p. 110). This assumption results in a benefit to consumers of imports, who can buy them more cheaply; conversely, it harms exporters, by making their products more expensive and less competitive in world markets.

[27] Ben Gersten, "Five U.S. Natural Gas Companies Set to Soar from an Export Boom," December 14, 2012. http://moneymorning.com/tag/natural-gas-stocks/

Sole U.S. financing of natural gas investments

Finally, NERA assumes that all income from natural gas investments will be received by U.S. residents: "[F]inancing of investment was assumed to originate from U.S. sources." (NERA Report, p.5) This improbable assumption, discussed in more detail above, means that benefits of investment in U.S. LNG export facilities and extraction services return, in full, to the United States. As discussed earlier, under the more realistic assumption that LNG exports are in part financed by foreign investors, some of the benefits of U.S. exports would flow out of the country to those investors.

6. Use of stale data leads to underestimation of domestic demand for natural gas

An additional important concern regarding the NERA Report is its use of unnecessarily outdated data from the rapidly changing U.S. Energy Information Administration (EIA) *Annual Energy Outlook* natural gas forecasts. Inexplicably, the NERA Report failed to use the EIA's most recent data, even though it had done so in prior reports.

The following timeline of EIA data releases and NERA reports illustrates this point:

- April 2011: EIA's Final **AEO 2011**[28] published
- December 2011: EIA's **AEO 2012**[29] Early Release published
- June 2012: EIA's Final **AEO 2012**[30] published
- October 2012: NERA's "Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector"[31] N_{ew}ERA model report published using **AEO 2012** data
- December 3, 2012: NERA's "Macroeconomic Impacts of LNG Exports from the United States"[32] N_{ew}ERA model report published using **AEO 2011** data
- December 5, 2012: EIA's **AEO 2013** Early Release published[33]

NERA's October 2012 N_{ew}ERA report on regulations affecting the electricity sector used AEO 2012 data, but its December 2012 report on LNG exports used older, AEO 2011 data. Days after NERA's December 2012 release of its LNG analysis, EIA released its AEO 2013 data.

By choosing to use stale data in its report, NERA changed the outcome of its analysis in significant ways. There have been important changes to EIA's natural gas forecasts in each recent AEO release. Even between AEO 2011 (used in NERA's LNG analysis) and AEO 2012 (which was available but not used by NERA), projected domestic consumption, production, and export of

[28] EIA, Annual Energy Outlook 2011, 2011. http://www.eia.gov/forecasts/archive/aeo11/er/
[29] EIA, *Annual Energy Outlook 2012 Early Release*, 2012. http://www.eia.gov/forecasts/archive/aeo12/er/
[30] EIA, *Annual Energy Outlook 2012,* 2012. http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf
[31] David Harrison, et al., *Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector*, October 2012. http://www.nera.com/nera-files/PUB_ACCCE_1012.pdf
[32] W. David Montgomery, et al., *Macroeconomic Impacts of LNG Exports from the United States*, December 2012. http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf
[33] EIA, *Annual Energy Outlook 2013 Early Release*, 2013. http://www.eia.gov/forecasts/aeo/er/

natural gas rise, imports fall, and projected (Henry Hub) gas prices take a deeper drop in the next decades than previously predicted.

NERA's use of the older AEO 2011 data results in an underestimate of domestic demand for natural gas. The assumed level of domestic demand for natural gas is critical to NERA's modeling results; higher domestic demand—as predicted by more recent AEO data—would decrease the amount of natural gas available for export and would increase domestic prices. Domestic natural gas prices—both in the model's reference case baseline and its scenarios assuming LNG exports—are a key determinant of U.S. LNG's profitability in the global market.

7. Conclusions and policy recommendations

NERA's study of the macroeconomic impacts of LNG exports from the United States is incomplete, and several of its modeling choices appear to bias results towards a recommendation in favor of opening LNG exports. NERA's imagined future clashes with the obvious facts of economic life.

NERA's own modeling shows that LNG exports depress growth in the rest of the U.S. economy.

- NERA's results demonstrate that when LNG exports are opened, the size of the U.S. economy (excluding these export revenues) will shrink. An example helps to illustrate this point: In some cases, when LNG export revenues are $9 billion, GDP is $3 billion larger than in the no-export reference case. This means that GDP excluding gas exports has shrunk by almost $6 billion.
- Using a methodology adopted by NERA in other N_{ew}ERA analyses, job-equivalent losses from opening LNG exports can be estimated as ranging from 36,000 to 270,000 per year; the median scenario has an average job-equivalent loss of 131,000 per year.
- NERA's assumption that all income from LNG exports will return to U.S. residents is simply incorrect, and results in an overestimate of the benefits that will accrue to U.S.-based resource owners.
- Most American households do not own significant amounts of stock in general, and natural gas stocks represent just a tiny fraction of total stock ownership. The benefits to the typical American household from a booming gas industry are too small to measure.
- Higher prices for natural gas and electricity, and declining job prospects outside of the natural gas industry, would cause obvious harm to people throughout the country.
- NERA's export strategy would have the effect of maximizing short-run incomes at the expense of long-term economic stability. If NERA's export scenarios were to be carried out as federal policy, the result would be an acceleration of the decline of U.S. manufacturing and productivity, and an increased national dependence on raw material exports. Too strong of a dependence on resource exports—a problem often called the "resource curse" or the "Dutch disease"—can weaken the domestic manufacturing sector, even in a developed country.
- In the long run, it may prove more advantageous to nurture U.S. manufacture and export of value-added products made from our natural resources—even if it is not quite as

profitable in the short run. For example, surplus natural gas could be used to increase the U.S. manufacture and export of products, such as chemicals, that use natural gas as a raw material.

- The NERA Report has significant methodological issues. The proprietary N_{ew}ERA model is not available for examination by reviewers outside of NERA. The application of this type of closed-source model to U.S. federal policy decisions seems inappropriate.
- The limited documentation provided by NERA points to several unrealistic modeling assumptions, including: decision-makers' perfect foresight regarding future conditions; zero profits in the production of goods and services; no change to monetary policy, even in the face of economy-wide demand and supply shocks; and constraints on how much the U.S. balance of trade can shift in response to opening LNG exports.
- Full employment—also assumed in NERA's modeling—is not guaranteed, and nothing resembling full employment has occurred for quite a few years. At the writing of this white paper, the U.S. unemployment rate stood at 7.8 percent of the labor force (that is, of those actively employed or seeking work).[34] Furthermore, unemployed factory workers do not automatically get jobs in natural gas production, or in other industries.
- The NERA Report used outdated AEO 2011 data when AEO 2012 data were available. These older data underestimate U.S. domestic consumption of natural gas. Accurate modeling of domestic demand for natural gas is essential to making a creditable case for the benefits of opening LNG exports.

The Department of Energy is charged with determining whether or not approving applications—and thus opening U.S. borders—for LNG exports is in the public interest. At this important juncture in the development of U.S. export and resource extraction policy, a higher standard for data sources, methodology, and transparency of analysis is clearly required. Before designating LNG exports as beneficial to the U.S. public, the Department of Energy must fully exercise its due diligence by considering a far more complete macroeconomic analysis, including a detailed examination of distributional effects.

[34] December 2012 unemployment rate; U.S. Bureau of Labor Statistics, *Labor Force Statistics from the Current Population Survey*, Series ID: LNS14000000, Seasonal Unemployment Rate. http://data.bls.gov/timeseries/LNS14000000.

Appendix A

This appendix contains source information for Figure 2: Applicants for LNG Export Licenses.

Table A-1: Source information for Figure 3

Company	Status	Publicly traded?	Source	Quantity	FTA Applications (Docket Number)	Non-FTA Applications (Docket Number)
Golden Pass Products LLC	Foreign / Domestic	yes: XOM ExxonMobil	Golden Pass Products LLC is a joint venture between ExxonMobil Corp and Qatar Petroleum http://online.wsj.com/article/SB10000872396390444375104577595760678718068.html#articleTabs%3Darticle	2.6 Bcf/d(d)	Approved (12-88 -LNG)	Under DOE Review (12-156-LNG)
Lake Charles Exports, LLC	Foreign / Domestic	yes: SUG Southern Union Company, Foreign: BG Bg Group on London Stock Exchange	Lake Charles Exports LLC is a jointly owned subsidiary of Southern Union Company and BG Group http://www.fossil.energy.gov/programs/gasregulation/authorizations/2011_applications/11_59_lng.pdf	2.0 Bcf/d (e)	Approved (11-59-LNG)	Under DOE Review (11-59-LNG)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC (h)	Foreign / Domestic	Foreign: stock 9532:JP (Osaka Gas Co., Japan)	Osaka Gas's subsidiary Turbo LNG, LLC has a 10% stake in FLNG Development, which is a parent company for Freeport LNG Expansion, L.P, which in turn is a parent company of FLNG Liquafaction LP http://www.freeportlng.com/ownership.asp	1.4 Bcf/d (d)	Approved (12-06-LNG)	Under DOE Review (11-161-LNG)
Main Pass Energy Hub, LLC	Domestic	yes: MMR Freeport-MacMoRan Exploration Co.	Freeport-MacMoRan Exploration Co. owns a 50% stake in Main Pass Energy Hub, LLC http://www.fossil.energy.gov/programs/gasregulation/authorizations/2012_applications/12_114_lng.pdf	3.22 Bcf/d	Approved (12-114-LNG)	n/a
Gulf Coast LNG Export, LLC (i)	Domestic	privately held	97% owned by Michael Smit, 1.5 % each by trusts http://www.fossil.energy.gov/programs/gasregulation/authorizations/2012_applications/12_05_lng.pdf	2.8 Bcf/d(d)	Approved (12-05-LNG)	Under DOE Review (12-05-LNG)
Sabine Pass Liquefaction, LLC	Domestic	yes: CQP Cheniere Energy Partners L.P	Sabine Pass Liquefaction is a subsidiary of Cheniere Energy Partners L.P http://www.cheniereenergypartners.com/liquefaction_project/liquefaction_project.shtml	2.2 billion cubic feet per day (Bcf/d) (d)	Approved (10-85-LNG)	#N/A
Cheniere Marketing, LLC	Domestic	yes: LNG Cheniere Energy Inc.	Cheniere Marketing is a subsidiary of Cheniere Energy Inc. http://www.cheniere.com/corporate/about_us.shtml	2.1 Bcf/d(d)	Approved (12-99-LNG)	Under DOE Review (12-97-LNG)

Table A-1: Source information for Figure 3 (Continued)

Company	Status	Publicly traded?	Source	Quantity	FTA Applications (Docket Number)	Non-FTA Applications (Docket Number)
Cameron LNG, LLC	Domestic	yes: SRE Sempra Energy	Cameron LNG is a Sempra affiliate http://cameron.sempralng.com/about-us.html	1.7 Bcf/d (d)	Approved (11-145-LNG)	#N/A
Gulf LNG Liquefaction Company, LLC	Domestic	yes: KMI Kinder Morgan and GE General Electric (GE Energy Financial Services, a unit of GE)	KMI owns 50 pct stake in Gulf LNG Holdings http://www.kindermorgan.com/business/gas_pipelines/east/LNG/gulf.cfm. GE Energy Financial Services, directly and indirectly, controls its 50 percent stake in Gulf LNG http://www.geenergyfinancialservices.com/transactions/transactions.asp?transaction=transactions_archoldings.asp	1.5 Bcf/d(d)	Approved (12-47-LNG)	Under DOE Review (12-101-LNG)
Excelerate Liquefaction Solutions I, LLC	Foreign / Domestic	Foreign: stock RWE.DE domestic: privately held	Owned by Excelerate Liquefaction Solutions, source: http://www.gpo.gov/fdsys/pkg/FR-2012-12-06/html/2012-29475.htm . Those are owned by Excelerate Energy, LLC (same source). THAT is owned 50% by RWE Supply & Tradding and 50% by Mr. George B. Kaiser (an individual). George Kaiser is the American $10B George Kaiser: http://en.wikipedia.org/wiki/George_Kaiser and http://excelerateenergy.com/about-us	1.38 Bcf/d(d)	Approved (12-61-LNG)	Under DOE Review (12-146-LNG)
LNG Development Company, LLC (d/b/a Oregon LNG)	Domestic	privately held	Owned by Oregon LNG source: http://www.gpo.gov/fdsys/pkg/FR-2012-12-06/html/2012-29475.htm	1.25 Bcf/d(d)	Approved (12-48-LNG)	Under DOE Review (12-77-LNG)
Dominion Cove Point LNG, LP	Domestic	yes: D Dominion	source: https://www.dom.com/business/gas-transmission/cove-point/index.jsp	1.0 Bcf/d (d)	Approved (11-115-LNG)	#N/A
Southern LNG Company, L.L.C.	Domestic	yes: KMI Kinder Morgan	KMI owns El Paso Pipeline Partners source: http://investor.eppipelinepartners.com/phoenix.zhtml?c=215819&p=irol-newsArticle&id=1624861 . El Paso Pipeline Partners owns El Paso Pipeline Partners Operating Company source: http://investing.businessweek.com/research/stocks/private/snapshot.asp?privcapId=46603039 . El Paso Pipeline Partners Operating Company owns Southern LNG page 2 of http://www.ferc.gov/whats-new/comm-meet/2012/051712/C-2.pdf	0.5 Bcf/d(d)	Approved (12-54-LNG)	Under DOE Review (12-100-LNG)

Table A-1: Source information for Figure 3 (Continued)

Company	Status	Publicly traded?	Source	Quantity	FTA Applications (Docket Number)	Non-FTA Applications (Docket Number)
Waller LNG Services, LLC	Domestic	privately held	Wholly owned by Waller Marine: http://www.marinelog.com/index.php?option=com_content&view=article&id=3196:waller-marine-to-develop-small-scale-lng-terminals&catid=1:latest-news . Waller Marine private: http://www.linkedin.com/company/waller-marine-inc.	0.16 Bcf/d	Approved (12-152-LNG)	n/a
SB Power Solutions Inc.	Domestic	yes: SEB Seaboard	p. 2 of http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders_Issued_2012/ord3105.pdf	0.07 Bcf/d	Approved (12-50-LNG)	#N/A
Carib Energy (USA) LLC	Domestic	privately held	http://companies.findthecompany.com/l/21346146/Carib-Energy-Usa-Llc-in-Coral-Springs-FL	0.03 Bcf/d: FTA 0.01 Bcf/d: non-FTA (f)	Approved (11-71-LNG)	#N/A

Synapse
Energy Economics, Inc.

Will LNG Exports Benefit the United States Economy?

January 23, 2013

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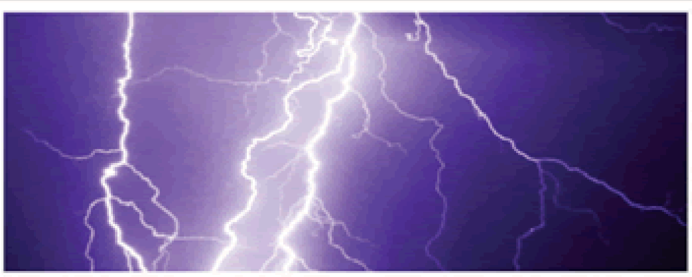

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1. Overview

DOE is considering whether large scale exports of liquefied natural gas (LNG) are in the public interest. As part of that inquiry, DOE has commissioned a team of researchers from NERA Economic Consulting, led by W. David Montgomery, to prepare a report entitled "Macroeconomic Impacts of LNG Exports from the United States" (hereafter, the NERA Report) in December 2012.[1] Unfortunately, that report suffers from serious methodological flaws which lead it to significantly underestimate, and, in some cases, to entirely overlook, many negative impacts of LNG exports on the U.S. economy.

NERA finds that LNG exports would be very good for the United States in every scenario they examined:

> …the U.S. was projected to gain net economic benefits from allowing LNG exports. Moreover, for every one of the market scenarios examined, net economic benefits increased as the level of LNG exports increased. (NERA Report, p.1)

The measure of benefits used by NERA, however, reflects only the totals for the U.S. economy as a whole. In fact, the NERA study finds that natural gas exports are beneficial to the natural gas industry alone, at the expense of the rest of the U.S. economy—reducing the size of the U.S. economy excluding LNG exports.

This white paper examines the NERA Report, and identifies multiple problems and omissions in its analyses of the natural gas industry and the U.S. economy:

- NERA's own modeling shows that LNG exports in fact cause GDP to decline in all other economic sectors.
- Although NERA does not calculate employment figures, the methods used in previous NERA reports would indicate job losses linked to export of tens to hundreds of thousands.
- NERA undervalues harm to the manufacturing sector of the U.S. economy.
- NERA ignores significant economic burdens from environmental harm caused by export.
- NERA ignores the distribution of LNG-export benefits among different segments of society, and makes a number of questionable and unrealistic economic assumptions:
    - In NERA's model, everyone who wants a job has one; by definition, LNG exports cannot cause unemployment.
    - All economic benefits of LNG export return to U.S. consumers without any leakage to foreign investors.
    - Changes to the balance of U.S. trade are constrained to be very small.

[1] W. David Montgomery, et al., *Macroeconomic Impacts of LNG Exports from the United States,* December 2012. http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf

- NERA's modeling of economic impacts is based entirely on the proprietary N$_{ew}$ERA model, which is not available for examination by other economists.
- NERA's treatment of natural gas resources and markets makes selective use of data to portray exports in a favorable light. In some cases, the NERA Report uses older data when newer revisions from the same sources were available; at times, it disagrees with other analysts who have carefully studied the same questions about the gas industry.

Even if NERA's flawed and incomplete analysis were to be accepted at face value, its conclusion that opening LNG exports would be good for the United States as a whole is not supported by its own modeling. Instead, NERA's results demonstrate that manufacturing, agriculture, and other sectors of the U.S. economy would suffer substantial losses. The methodology used to estimate job losses in other NERA reports, if applied in this case, would show average losses of wages equivalent to up to 270,000 jobs lost in each year.

2. LNG exports: Good for the gas industry, bad for the United States

According to the NERA Report, LNG exports would benefit the natural gas industry at the expense of the rest of the U.S. economy. Two sets of evidence illustrate this point: a comparison of natural gas export revenues with changes in gross domestic product (GDP), and a calculation, employed by NERA in other reports, of the "job-equivalents" from decreases in labor income. Applying this calculation to the NERA Report analysis suggests that opening LNG exports would result in hundreds of thousands of job losses. These losses would not be confined to narrow sections of U.S. industry, as NERA implies.

The NERA Report presents 13 "feasible" economic scenarios for LNG export, with projections calculated by NERA's proprietary N$_{ew}$ERA model for 2015, 2020, 2025, 2030, and 2035. The scenarios differ in estimates of the amount of natural gas that will ultimately be recovered per new well: seven scenarios (with labels beginning with USREF) use the estimate from the federal Energy Information Administration's AEO 2011; five (beginning with HEUR) assume 150 percent of the AEO level; and one (beginning with LEUR) assumes 50 percent of the AEO level. In the LEUR scenario, LNG exports are barely worthwhile; in the HEUR scenarios, exports are more profitable than in the USREF scenarios.

LNG exports cause U.S. GDP (excluding LNG exports) to fall

Careful analysis of these LNG export scenarios reveals that the gain in GDP predicted by the NERA Report is driven—almost entirely—by revenues to gas exporters and gas companies; the remainder of the economy declines.

On average (across the five reporting years), export revenues were 74 percent or more of GDP growth in every scenario; in the eight scenarios with average or low estimated gas recovery per well, export revenues averaged more than 100 percent of GDP growth. In the median scenario, export revenues averaged 169 percent of GDP growth; in the worst case, export revenues averaged 240 percent of GDP growth.

Table 1 compares natural gas export revenues to the increase in GDP for each scenario.[2] When export revenues are greater than 100 percent of GDP growth, the size of the U.S. economy, excluding gas exports, is shrinking. For instance, for the year 2035 in the first two scenarios in Table 1, LNG export revenues are almost $9 billion higher than in the reference case, while GDP—which includes those export revenues along with everyone else's incomes—is only $3 billion higher. Thus, as a matter of arithmetic, everyone else's incomes (i.e., GDP excluding LNG export revenues) must have gone down by almost $6 billion. (If your favorite baseball team scored 3 more home runs this year than last year, and one of its players scored 9 more than he did last year, then it must be the case that the rest of the team scored 6 fewer.)

Similarly, in every case where natural gas export revenues exceed 100 percent of the increase in GDP—cases that appear throughout Table 1—the export revenues are part of GDP, so the remainder of GDP must have gone down.

Table 1: LNG Exports as a Share of GDP Gains[3]

Scenario	Exports as Percent of GDP Gains					
	2015	2020	2025	2030	2035	average
USREF_D_LSS	72%	75%	193%	225%	286%	170%
USREF_D_LS	50%	89%	193%	225%	286%	169%
USREF_D_LR	62%	112%	257%	338%	429%	240%
USREF_SD_LS	50%	77%	204%	258%	468%	211%
USREF_SD_LR	59%	90%	244%	258%	702%	271%
USREF_SD_HS	50%	67%	140%	216%	429%	180%
USREF_SD_HR	59%	75%	158%	216%	501%	202%
HEUR_SD_LSS	19%	38%	69%	109%	152%	77%
HEUR_SD_LS	24%	40%	82%	109%	152%	81%
HEUR_SD_LR	31%	42%	82%	123%	152%	86%
HEUR_SD_HS	24%	37%	64%	106%	142%	74%
HEUR_SD_HR	28%	39%	74%	111%	142%	79%
LEUR_SD_LSS	0%	164%	*NA*	*NA*	158%	107%

NA - not applicable (GDP did not increase over the no-export reference case)
Source: Author's calculations based on NERA Report, Figures 144-162.

As Table 1 demonstrates, export revenues exceed GDP growth: GDP (not including gas exports) is shrinking by 2030 or earlier in all scenarios, and by 2025 or earlier in all scenarios using the AEO assumption about gas recovery per well (i.e., USREF). In other words, after the initial years of construction of export facilities, when construction activities may create some local economic

[2] The increase in GDP is the difference between the scenario GDP projections and the GDP in the corresponding no-export reference case (for USREF, HEUR, or LEUR assumptions). Data from NERA Report, pp.179-197.

[3] In the second term in the scenario names, international cases are defined by increases in global demand and/or decreases in global supply: D=International Demand Shock, SD=International Supply/Demand Shock. In the third term in the scenario names, export cases for quantity/growth are defined as follows: LSS=Low/Slowest, LS=Low/Slow, LR=Low/Rapid, HS=High/Slow, HR=High/Rapid.

benefits, gas exports create increased income for the gas industry, at the expense of everyone else.[4]

Loss of labor income from LNG exports is equivalent to huge job losses

NERA avoids predicting the employment implications of LNG export, and downplays the aggregate billions of dollars in decreased labor income predicted by its report. In fact, using NERA's own methods, the following analysis shows the potential for hundreds of thousands of job losses per year.

In other reports using the N_{ew}ERA model, NERA has reported losses of labor income in terms of "job-equivalents." This may seem paradoxical, since the N_{ew}ERA model assumes full employment, as discussed later in this white paper. As NERA has argued elsewhere, however, a loss of labor income can be expressed in terms of job-equivalent losses, by assuming that it consists of a loss of workers earning the average salary.[5] In other words, a given decrease in labor income can be interpreted as a loss of workers who would make that income.

This method can be applied to the losses of labor income projected for each of the 13 scenarios in the NERA Report. These losses are expressed as percentages of gross labor income; we have assumed that NERA's "job-equivalent losses" represent the same percentage of the labor force. For example, we assume the loss of 0.1 percent of gross labor income in scenario HEUR_SD_HS in 2020 is equivalent to job losses of 0.1 percent of the projected 2020 labor force of 159,351,000 workers, or roughly 159,000 job-equivalent losses.[6]

The results of this analysis are shown in Table 2. Job-equivalent losses, averaged across the five reporting years, range from 36,000 to 270,000 per year; the median scenario has an average job-equivalent loss of 131,000 per year. We do not necessarily endorse this method of calculation of labor impacts, but merely note that NERA has adopted it in other reports using the same model. If NERA had used this method in the NERA Report analysis, it would have shown that LNG exports have the potential to significantly harm employment in many sectors.

[4] Other modeled results in the record cast further doubt on NERA's study. See Wallace E. Tyner, "Comparison of Analysis of Natural Gas Export Impacts," January 14, 2013. http://www.fossil.energy.gov/programs/gasregulation/authorizations/export_study/30_Wallace_Tyner01_14_13.pdf

[5] See, e.g., NERA's Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector, October 2012, p. ES-6: "Job-equivalents are calculated as the total loss in labor income divided by the average salary." http://www.nera.com/nera-files/PUB_ACCCE_1012.pdf

[6] The Bureau of Labor Statistics projects annual growth of the civilian labor force at 0.7% per year from 2010 to 2020 (Mitra Toosi. "Labor force projections to 2020: a more slowly growing workforce." Monthly Labor Review, January 2012. http://www.bls.gov/opub/mlr/2012/01/art3full.pdf.) We have used the same annual growth rate to project the labor force through 2035.

Table 2: Employment equivalents of reduced labor income

	Job-equivalent loss, NERA method					
	2015	**2020**	**2025**	**2030**	**2035**	**average**
USREF_D_LSS	15,000	77,000	108,000	77,000	62,000	68,000
USREF_D_LS	31,000	77,000	108,000	77,000	62,000	71,000
USREF_D_LR	108,000	92,000	108,000	77,000	62,000	89,000
USREF_SD_LS	31,000	200,000	169,000	139,000	123,000	132,000
USREF_SD_LR	123,000	215,000	169,000	139,000	123,000	154,000
USREF_SD_HS	31,000	185,000	292,000	292,000	246,000	209,000
USREF_SD_HR	108,000	292,000	308,000	292,000	246,000	249,000
HEUR_SD_LSS	15,000	62,000	108,000	108,000	92,000	77,000
HEUR_SD_LS	15,000	169,000	139,000	108,000	92,000	105,000
HEUR_SD_LR	108,000	169,000	139,000	108,000	92,000	123,000
HEUR_SD_HS	15,000	154,000	246,000	215,000	200,000	166,000
HEUR_SD_HR	92,000	385,000	292,000	231,000	200,000	240,000
LEUR_SD_LSS	0	92,000	77,000	0	0	34,000
Labor force	*153,889,000*	*153,889,000*	*153,889,000*	*153,889,000*	*153,889,000*	

Source: Author's calculations based on NERA Report, Figures 144-162.

NERA downplays their estimated shifts in employment from one sector to another saying that is smaller than normal rates of turnover in those industries, but, of course, normal labor turnover is enormous. It is true that job losses caused by LNG exports will be less than the annual total of all retirements, voluntary resignations, firings, layoffs, parental and medical leaves, new hires, moves to new cities and new jobs, and switching from one employer to another for all sorts of reasons: Throughout the entire U.S. labor force normal turnover amounts to almost 40 million people each year.[7] The comparison of job losses to job turnover is irrelevant.

Harm to U.S. economy is not confined to narrow sections of industry, as NERA implies

The NERA Report emphasizes the fact that only a few branches of industry are heavily dependent on natural gas (NERA Report, pp.67-70). This discussion is described as an attempt "to identify where higher natural gas prices might cause severe impacts such as plant closings" (p.67). The NERA Report makes two principal points in this discussion. First, it quotes a 2009 study of the expected impacts of the Waxman-Markey proposal for climate legislation, which found that only a limited number of branches of industry would be harmed by higher carbon costs; NERA argues that price increases caused by LNG exports will have an even smaller but similarly narrow effect on industry. Second, NERA observes that industries where value added (roughly the sum of wages and profits) makes up a large fraction of sales revenue are unlikely to have high energy costs, while industries with high energy costs probably have a low ratio of value added to sales.

[7] "Job Openings and Labor Turnover," Bureau of Labor Statistics, November 2012, Table 3. http://www.bls.gov/news.release/pdf/jolts.pdf

Both points may be true, but they are largely irrelevant to the evaluation of LNG exports. NERA's use of the Waxman-Markey study is inappropriate, as Representative Markey himself has pointed out, because that proposed bill directed significant resources to industries harmed by higher costs to mitigate any negative impact.[8] No such mitigation payments are associated with LNG export, so relying upon Waxman-Markey examples to downplay potential economic damage is inappropriate. If those exports increase domestic gas prices, industry will be harmed both by higher electricity prices and by higher costs for direct use of natural gas. Further, it is true that direct use of natural gas is relatively concentrated, but it is concentrated in important sectors; as the natural gas industry itself explains, "Natural gas is consumed primarily in the pulp and paper, metals, chemicals, petroleum refining, stone, clay and glass, plastic, and food processing industries."[9] These are not small or unimportant sectors of the U.S. economy.[10] In any case, discussion of sectors where higher natural gas prices might cause "severe impacts such as plant closings" is attacking a straw man; NERA's own calculations imply moderate harm would be imposed throughout industry, both by rising electricity prices and by the costs of direct gas consumption—offset by benefits exclusively concentrated in the hands of the natural gas industry.

Similarly, it does not seem particularly important to know whether industries that use a lot of natural gas have high or low ratios of value added to sales. Are aluminum, cement, fertilizer, paper, and chemicals less important to the economy because they have many purchased inputs, and therefore low ratios of value added to sales?

3. Costs and benefits from LNG exports are unequally distributed

As the results above show, LNG exports essentially transfer revenue away from the rest of the economy and into the hands of companies participating in these exports. This shift has significant economic implications that are not addressed in the NERA Report's analysis.

The NERA Report asserts that "all export scenarios are welfare-improving for U.S. consumers" (NERA Report, p.55). While LNG exports will result in higher natural gas prices for U.S. residents, NERA projects that these costs will be outweighed by additional income received from the exports—and thus, "consumers, in aggregate are better off as a result of opening LNG exports." (NERA Report, p.55) Or, to put this another way, the gains of every resident of the United States, added together, will be greater than the losses of every resident of the United States, added together. The distribution of these benefits and costs—who will suffer costs and who will reap gains—is discussed only tangentially in the NERA Report, but is critical to a complete understanding of the effects of LNG exports on the U.S. economy. A closer look reveals that LNG exports benefit only a very narrow section of the economy, while causing harm to a much broader group.

[8] Letter from Rep. Markey to Secretary Steve Chu (Dec. 14, 2012).
[9] http://www.naturalgas.org/overview/uses_industry.asp.
[10] Other commenters also point out that NERA does not even appear to have included some gas-dependent industries, including fertilizer and fabric manufacture, in its analysis. *See* Comments of Dr. Jannette Barth (Dec. 14, 2012).

Focus on "net impacts" ignores key policy issues

The results presented in the NERA Report focus on the net impacts on the entire economy—combining together everyone's costs and benefits—and on the "welfare" of the typical or average family, measured in terms of equivalent variation.[11] NERA dismisses the need to discuss the distribution of the costs and benefits among groups that are likely to experience very different impacts from LNG exports, stating that: "[t]his study addresses only the net economic effects of natural gas price changes and improved export revenues, not their distribution." (NERA Report, p.211) NERA alludes to an unequal distribution of costs and benefits in its results, but does not present a complete analysis:

> Although there are costs to consumers of higher energy prices and lower consumption and producers incur higher costs to supply the additional natural gas for export, these costs are more than offset by increases in export revenues along with a wealth transfer from overseas received in the form of payments for liquefactions services. The net result is an increase in U.S. households' real income and welfare. (NERA Report, p.6)

Instead, the NERA Report combines the economic impacts of winners and losers from LNG exports. In the field of economics, this method of asserting that a policy will improve welfare for society as a whole as long as gains to the winners are greater than costs to the losers is known as the "Kaldor-Hicks compensation principle" or a "potential Pareto improvement." The critiques leveled at cost-benefit analyses that ignore important distributional issues have as long a history as these flawed methods. Policy decisions cannot be made solely on the basis of aggregated net impacts: costs to one group are never erased by the existence of larger gains to another group. The net benefit to society as a whole shows only that, if the winners choose to share their gains, they have the resources to make everyone better off than before—but not that they *will* share their gains. In the typical situation, when the winners choose to keep their winnings to themselves, there is no reason to think that everyone, including the losers, is better off.

As previous congressional testimony by W. David Montgomery—the lead author of the NERA Report—on the impacts of cap-and-trade policy support explained it: "There are enough hidden differences among recipients of allowances within any identified group that it takes far more to compensate just the losers in a group than to compensate the average. Looking at averages assumes that gainers compensate losers within a group, but that will not occur in practice."[12]

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[11] One of the complications in estimating the costs and benefits of a policy with the potential to impact prices economy-wide, is that simply measuring changes in income misses out on the way in which policy-driven price changes affect how much can be bought for the same income. (For example, if a policy raises incomes but simultaneously raises prices, it takes some careful calculation to determine whether people are better or worse off.) The NERA Report uses a measure of welfare called "equivalent variation," which is the additional income that the typical family would have to receive today (when making purchases at current prices) in order to be just as well off as they would be with the new incomes and new price levels under the proposed policy. It can be thought of as the change in income caused by the policy, adjusted for any change in prices caused by the policy.

[12] Prepared Testimony of W. David Montgomery, before the Committee on Energy and Commerce Subcommittee on Energy and Environment, U.S. House of Representatives, Hearing on Allowance Allocation Policies in Climate Legislation, June 9, 2009.
http://democrats.energycommerce.house.gov/Press_111/20090609/testimony_montgomery.pdf.

Wage earners in every sector except natural gas will lose income

In every scenario reviewed in the NERA Report, labor income rises in the natural gas industry, and falls in every other industry.[13] Economy-wide, NERA finds that "capital income, wage income, and indirect tax revenues drop in all scenarios, while resource income and net transfers associated with LNG export revenues increase in all scenarios." (NERA Report, p.63)[14] Even without a detailed distributional analysis, the NERA Report demonstrates that some groups will lose out from LNG exports:

> Overall, both total labor compensation and income from investment are projected to decline, and income to owners of natural gas resources will increase… Nevertheless, impacts will not be positive for all groups in the economy. Households with income solely from wages or government transfers, in particular, might not participate in these benefits. (NERA Report, p.2)

NERA's "might not participate in these benefits" could and should be restated more accurately as "will bear costs." Although NERA doesn't acknowledge it, most Americans will not receive revenues from LNG exports; many more Americans will experience decreased wages and higher energy prices than will profit from LNG exports.

Wage earners in every major sector except for natural gas will lose income, and, as domestic natural gas prices increase, households and businesses will have to pay more for natural gas (for heat, cooking, etc.), electricity, and other goods and services with prices that are strongly impacted by natural gas prices. The NERA Report briefly mentions these price effects:

> Natural gas is also an important fuel for electricity generation, providing about 20% of the fuel inputs to electricity generation. Moreover, in many regions and times of the year natural gas-fired generation sets the price of electricity so that increases in natural gas prices can impact electricity prices. These price increases will also propagate through the economy and affect both household energy bills and costs for businesses. (NERA Report, p.13-14)

Additional analysis required to understand electricity price impacts

There are no results presented in the NERA Report to display the effect of changes in electricity prices on consumers. Negative effects on the electricity sector itself are shown in NERA's Figure 38, but changes in electric rates and electricity bills, and the distributional consequences of these changes, are absent from the results selected for display in this report. NERA certainly could have conducted such an analysis. NERA's October 2012 report on recent and anticipated EPA regulations affecting the U.S. electricity sector using the N$_{ew}$ERA model displayed electricity price impacts for eleven regions and three scenarios.[15]

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[13] See NERA Report, Figure 39.
[14] See NERA Report, Figure 40.
[15] Harrison, et al., Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector, October 2012. NERA Economic Consulting. See Table 17. http://www.nera.com/67_7903.htm.

Dr. Montgomery previous testimony also presents increases in household electric utility bills.[16] He describes a “decline in purchasing power” for the average household, claiming that “the cost for the average family will be significant” and “generally the largest declines in household purchasing power are occurring in the regions with the lowest baseline income levels.”[17] A careful distributional analysis would greatly improve the policy relevance of the NERA Report’s economic impact projections.

Benefits of stock ownership are not as widespread as NERA assumes

There is no evidence to support NERA’s implication that the benefits of stock ownership are broadly shared among U.S. families across the economic spectrum—and therefore no evidence that they will “participate” in benefits secured by LNG exports.

NERA’s claim of widespread benefits is not supported by data from the U.S. Census Bureau. In 2007, just before the financial crash, only about half of all families owned any stock, including indirect holdings in retirement accounts. Indeed, only 14 percent of families with the lowest incomes (in the bottom 20 percent) held any stock at all, compared to 91 percent of families with the highest incomes (the top 10 percent).[18]

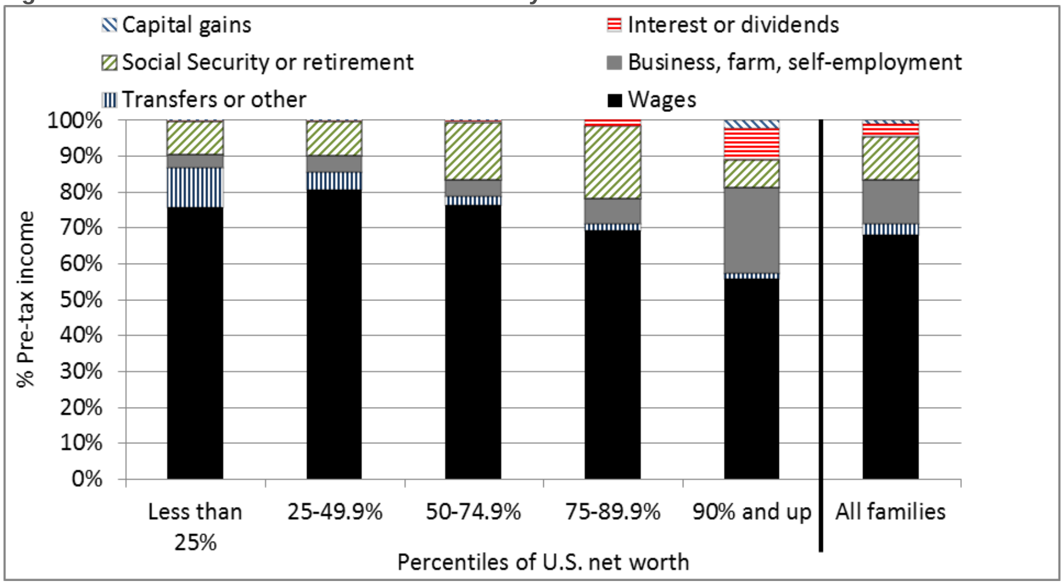
For most households the primary source of income is wages. According to the Federal Reserve, 68 percent of all family income in 2010 (the latest data available) came from wages, while interest, dividends and capital gains only amounted to 4.5 percent (see Figure 1). Families with the least wealth (the bottom 25 percent) received 0.2 percent of their income from interest, dividends, and capital gains, compared to 11 percent for the wealthiest families (the top 10 percent).

[16] Prepared Testimony of W. David Montgomery, before the Committee on Energy and Commerce Subcommittee on Energy and Environment, U.S. House of Representatives, Hearing on Allowance Allocation Policies in Climate Legislation, June 9, 2009. http://democrats.energycommerce.house.gov/Press_111/20090609/testimony_montgomery.pdf.

[17] Ibid.

[18] U.S. Census Bureau, Statistical Abstract of the United States: 2012, 2012. See Table 1211. http://www.census.gov/compendia/statab/2012/tables/12s1211.pdf.

Figure 1: U.S. Households Source of Income by Percentile of Net Worth in 2010



Source: Federal Reserve, Changes in U.S. Family Finances from 2007 to 2010: Evidence from the Survey of Consumer Finances, Table 2.

And yet the NERA Report appears to assume that the benefits of owning stock in natural gas export companies are widespread, explaining that:

> U.S. consumers receive additional income from…the LNG exports provid[ing] additional export revenues, and…consumers who are owners of the liquefaction plants, receiv[ing] take-or-pay tolling charges for the amount of LNG exports. These additional sources of income for U.S. consumers outweigh the loss associated with higher energy prices. Consequently, consumers, in aggregate, are better off as a result of opening up LNG exports. (NERA Report, p.55)

In the absence of detailed analysis from NERA, it seems safe to assume that increases to U.S. incomes from LNG exports will accrue to those in the highest income brackets. Lower income brackets, where more income is derived from wages, are far more likely to experience losses in income—unless they happen to work in the natural gas industry—and natural gas extraction currently represents less than 0.1 percent of all jobs in the United States.[19] At the same time, everyone will pay more on their utility bills.

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[19] Share of jobs in oil and gas extraction. Data for the share of jobs in the natural gas industry alone is not available but would, necessarily, be smaller. Support activities for mining represents an additional 0.25 percent of jobs, petroleum and coal products 0.08 percent, and pipeline transportation 0.03 percent. Taken together, these industries, which include oil, coal and other mining operations, represent 0.5 percent of all U.S. employment. Bureau of Economic Analysis, Full-Time and Part-Time Employees by Industry, 2011 data. http://bea.gov/iTable/iTable.cfm?ReqID=5&step=1

NERA's assumption that all income from LNG exports will return to U.S. residents is incorrect

In the N_{ew}ERA analysis, two critical assumptions assure that all LNG profits accrue to U.S. residents. First, "Consumers own all production processes and industries by virtue of owning stock in them." (NERA Report, p.55) The unequal distribution of stock ownership (shown as interest, dividend, and capital gains income in the Federal Reserve data in Figure 1) is not made explicit in the NERA Report, nor is the very small share that natural-gas-related assets represent in all U.S.-based publically traded stock.[20] In discussing impacts on households' wealth, NERA only mention that "if they, or their pensions, hold stock in natural gas producers, they will benefit from the increase in the value of their investment." (NERA Report, p.13) A more detailed distributional analysis would be necessary to determine the exact degree to which LNG profits benefit different income groups; however, it is fair to conclude that lower-income groups and the middle class are much less likely to profit from LNG exports than higher-income groups that receive a larger portion of income from stock ownership.

Second, the NERA Report assumes that "all of the investment in liquefaction facilities and natural gas drilling and extraction comes from domestic sources." (NERA Report, p.211) This means that the N_{ew}ERA model implausibly assumes that all U.S.-based LNG businesses are solely owned by U.S. residents. There is no evidence to support this assumption. On the contrary, many players in this market have significant foreign ownership shares or are privately held, and may be able to move revenues in ways that avoid both the domestic stock market and U.S. taxes. Cheniere Energy, the only LNG exporter licensed in the United States, is currently building an export terminal on the Gulf of Mexico for $5.6 billion—$1 billion of which is coming from investors in China and Singapore.[21] Cheniere's largest shareholders include holding companies in Singapore and Bermuda, as well as a hedge fund and a private equity firm, which in turn have a mix of domestic and foreign shareholders.[22] This situation is not atypical. As illustrated in Figure 2, 29 percent (by Bcf/day capacity) of the applications for U.S. LNG export licenses are foreign-owned, including 6 percent of total applications from foreign governments. Additionally, 70 percent of domestic applicants are publicly owned and traded, most of which have both domestic and foreign stock holders. Gas extraction companies, similarly, operate with a diverse mix of foreign and domestic investment, and of public and private ownership structures. NERA's claim that profits from LNG exports will be retained in the United States is unfounded.

NERA certainly could have addressed this issue in its analysis. Dr. Montgomery's previous testimony on cap-and-trade assumed that "all auction revenues would be returned to households,

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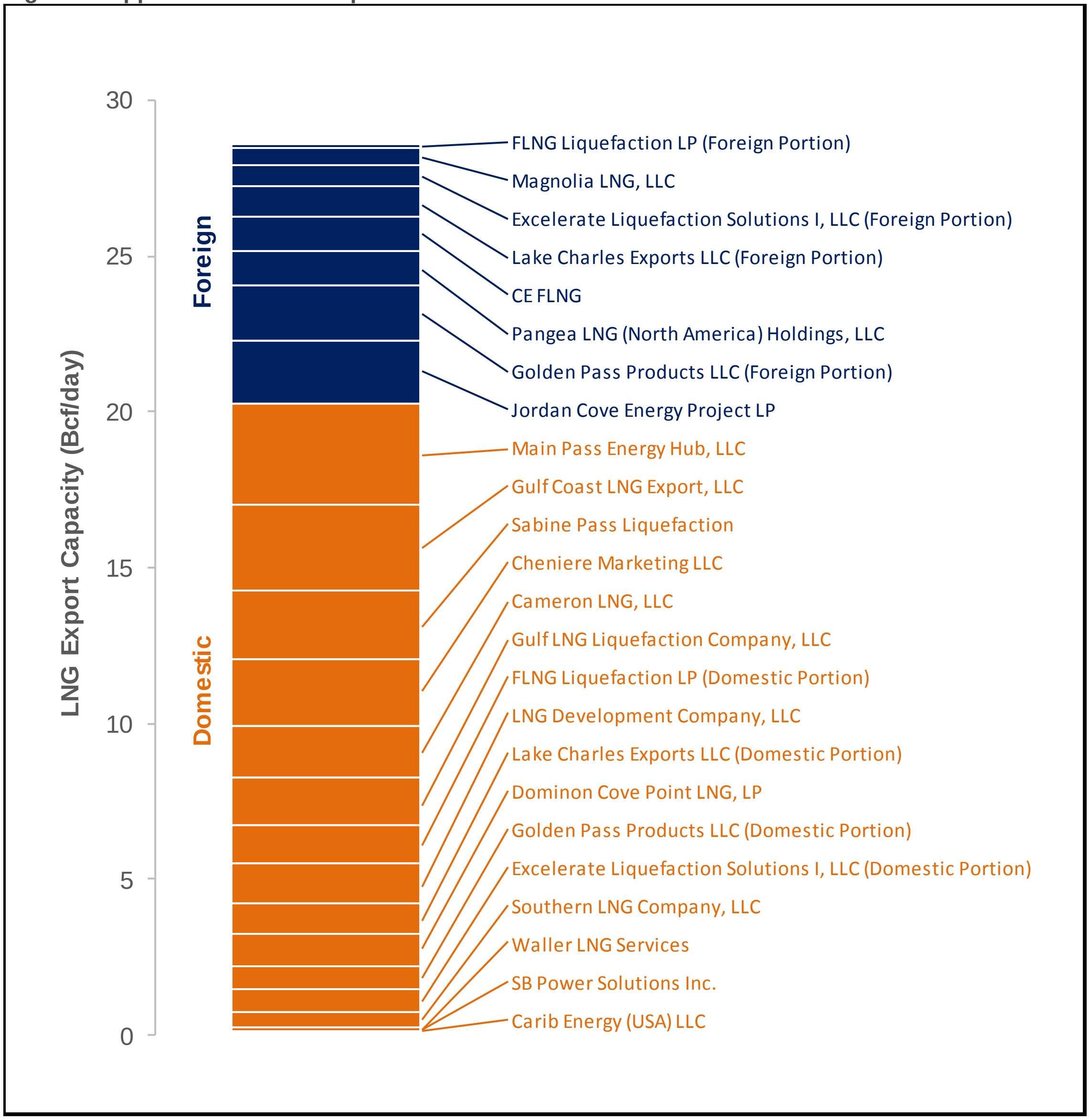
[20] NYSE companies involved in LNG export applications account for 5.8 percent of the total market capitalization, but this includes the value of shares from Exxon Mobil—by itself 2.9 percent of the NYSE market cap—as well as several other corporations with diverse business interests, such as General Electric, Dow, and Seaboard (owner of Butterball Turkeys among many other products). Reuters Stocks website, downloaded January 22, 2013 (following marketclose), http://www.reuters.com/finance/stocks. World Federation of Exchanges, "2012 WFE Market Highlights" (January 2013), page 6. http://www.world-exchanges.org/files/statistics/2012%20WFE%20Market%20Highlights.pdf.

[21] "UPDATE 2-China, Singapore wealth funds invest $1 bln in US LNG export plant-source." Reuters, August 21, 2012. http://www.reuters.com/article/2012/08/21/cic-cheniere-idUSL4E8JL0SC20120821

[22] Ownership data from NASDAQ for Cheniere Energy, Inc. (LNG). http://www.nasdaq.com/symbol/lng/ownership-summary#.UPmZgCfLRpU.

except for the allowance allocations that are given to foreign sources."[23] This assumption led him to conclude that, for the cap-and-trade program, a "large part of the impact on household costs is due to wealth transfers to other countries."[24] This level of analytical rigor should have been applied when estimating the U.S. domestic benefits from opening natural gas exports.

Figure 2: Applicants for LNG Export Licenses



23 Prepared Testimony of W. David Montgomery, before the Committee on Energy and Commerce Subcommittee on Energy and Environment, U.S. House of Representatives, Hearing on Allowance Allocation Policies in Climate Legislation, June 9, 2009, http://democrats.energycommerce.house.gov/Press_111/20090609/testimony_montgomery.pdf.

24 Ibid.

Source: See Appendix A for a full list of sources.

Opening LNG export will also incur environmental costs

The discussion of LNG exports in the NERA Report, and most of our analysis of the report, is concerned with monetary costs and benefits: Exports cause an increase in natural gas prices, boosting incomes in the natural gas industry itself while increasing economic burdens on the rest of the economy. There are, in addition, environmental impacts of natural gas production and distribution that do not have market prices, but may nonetheless become important if LNG exports are expanded. Increases in exports are likely to increase production of natural gas, entailing increased risks of groundwater pollution and other environmental problems potentially associated with hydraulic fracturing ("fracking"). Increases in production, transportation of natural gas from wells to export terminals, and the liquefaction process itself, all increase the risks of leaks of natural gas, a potent greenhouse gas that contributes to global warming. These environmental impacts should be weighed, alongside the monetary costs and benefits of export strategies, in evaluation of proposals for LNG exports.

Clearly, as NERA itself acknowledges, the NERA Report would benefit from more detailed analysis of the distribution of costs and benefits from opening LNG exports: "Although convenient to indicate that there are winners and losers from any market or policy change, this terminology gives limited insight into how the gains and losses are distributed in the economy." (NERA Report, p.211)

4. Dependence on resource exports has long-run drawbacks

The harm that LNG exports cause to the rest of the U.S. economy, even in NERA's model, are consistent with an extensive body of economic literature warning of the dangers of resource-export-based economies.

If NERA's economic modeling is accepted at face value, it implies that the United States should embrace resource exports, even at the expense of weakening the rest of the economy. GDP, net incomes, and "welfare" as measured by NERA would all rise in tandem with LNG exports. There would be losses in manufacturing and other sectors, especially the energy-intensive sectors of paper and pulp, chemicals, glass, cement, and primary metal (iron, steel, aluminum, etc.) manufacturing (NERA Report, p. 64). But NERA asserts that these would be offset by gains in the natural gas industry. There would be losses of labor income, equivalent to a decline of up to 270,000 average-wage jobs per year. But, according to NERA, these losses would be offset by increased incomes for resource (natural gas) owners.

For those who are indifferent to the distribution of gains and losses—or who imagine that almost everyone owns a share of the natural gas industry—the shift away from manufacturing and labor income toward raw material exports could be described as good for the country as a whole. (So, too, could any shift among types of income, as long as its net result is an increase in GDP.) The rising value of the dollar relative to other currencies would allow affluent Americans to buy more imports, further increasing their welfare, even as the ability of industry to manufacture and export from the United States would decline.

There is, however, a longer-term threat of LNG exports to the U.S. economy: NERA's export scenarios would accelerate the decline of manufacturing and productivity throughout the country, pushing the nation into increased dependence on raw material exports. Developing countries have often struggled to escape from this role in the world economy, believing that true economic development requires the creation of manufacturing and other high-productivity industries. International institutions such as the IMF and the World Bank have often insisted that developing countries can maximize their short-run incomes by sticking to resource exports.

NERA is in essence offering the same advice to the United States: Why strive to make things at home, if there is more immediate profit from exporting raw materials to countries that can make better use of them? Europe, China, Japan, and Korea have much more limited natural resources per capita, but they are very good at making things out of resources that they buy from the United States and other resource-rich countries. In the long run, which role do we want the United States to play in the world economy? Do we want to be a resource exporter, with jobs focused in agriculture, mining, petroleum and other resource-intensive industries? Or do we want to export industrial goods, with jobs focused in manufacturing and high-tech sectors?

Economists have recognized that resource exports can impede manufacturing, even in a developed country; the problem has been called the "resource curse" or the "Dutch disease." The latter name stems from the experience of the Netherlands after the discovery of natural gas resources in 1959; gas exports raised the value of the guilder (the Dutch currency in pre-Euro days), making other Dutch exports less competitive in world markets and resulting in the eventual decline of its manufacturing sector.[25] In other countries, the "resource curse" has been associated with increased corruption and inequality; countries that depend on a few, very profitable resource exports may be less likely to have well-functioning government institutions that serve the interests of the majority.[26] Protecting an economy against the resource curse requires careful economic management of prospective resource exports.

In particular, it may be more advantageous in the long run to nurture the ability to manufacture and export value-added products based on our natural resources—even if it is not quite as profitable in the short run. The NERA Report is notably lacking in analysis of this strategy; there are no scenarios exploring promotion of, for example, increased use of natural gas in the chemical industry and increased exports of chemicals from the United States. The 25-year span of NERA's analysis provides for scope to develop a longer-term economic strategy with a different pattern of winners and losers. The benefits in this case might extend well beyond the narrow confines of the natural gas industry itself.

5. Unrealistic assumptions used in NERA's N_{ew}ERA model

Despite its sunny conclusions, the NERA Report indicates that LNG exports pose serious challenges to the U.S. economy. It is troubling, then, that the underlying modeling in the report is notably difficult to assess, and is reliant on a number of unrealistic assumptions.

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[25] "The Dutch Disease." *The Economist*, November 26, 1977, pp. 82-83.

[26] Papyrakis and Gerlagh. "The resource curse hypothesis and its transmission channels." *Journal of Comparative Economics*, 2004, 32:1 p.181-193; Mehlum, Moene and Torvik. "Institutions and the Resource Curse." *The Economic Journal*, 2006, 116:508 p.1-20.

The NERA Report relies on NERA Consulting's proprietary model, called N_{ew}ERA. Detailed model assumptions and relationships have never been published; we are not aware of any use of the model, or even evaluation of it in detail, by anyone outside NERA.

According to the NERA Report, N_{ew}ERA is a computable general equilibrium (CGE) model. Such models typically start with a series of assumptions, adopted for mathematical convenience, that are difficult to reconcile with real-world conditions. The base assumptions of the N_{ew}ERA model are described as follows: "The model assumes a perfect foresight, zero profit condition in production of goods and services, no changes in monetary policy, and full employment within the U.S. economy." (NERA Report, p. 103)

Here we discuss the implications of each of these assumptions, together with two additional critical modeling assumptions described elsewhere in the NERA Report: limited changes to the balance of trade, and sole U.S. financing of natural gas investments.

Full employment

The full employment assumption, common to most (though not all) CGE models, means that in every year in every scenario, anyone who wants a job can get one. This assumption is arguably appropriate—or at least, introduces only minor distortions—at times of very high employment such as the late 1990s. It is, however, transparently wrong under current conditions, when unemployment rates are high and millions of people who want jobs cannot find them.

The NERA Report expands on its Pollyannaish vision of the labor market, saying:

> The model assumes full employment in the labor market. This assumption means total labor demand in a policy scenario would be the same as the baseline policy projection… The model assumes that labor is fungible across sectors. That is, labor can move freely out of a production sector into another sector without any adjustment costs or loss of productivity. (NERA Report, p.110)

It also includes, in its "Key Findings," the statement that: "LNG exports are not likely to affect the overall level of employment in the U.S." (NERA Report, p.2)

In fact, this is an assumption—baked into the model—and not a finding. N_{ew}ERA, by design, never allows policy changes to affect the overall assumed level of employment. The unemployment rate must, by definition, always be low and unchanging in NERA's model.

For this reason, the potential economic impact that is of the greatest interest to many policymakers, namely the effects of increased LNG exports on jobs, cannot be meaningfully studied with NERA's model. Addressing that question requires a different modeling framework, one that recognizes the existence of involuntary unemployment (when people who want jobs cannot find them) and allows for changes in employment levels. (Despite N_{ew}ERA's full employment assumption, NERA has used the model results to calculate the "job-equivalents" lost to other environmental policies, as discussed above. Had NERA seriously addressed the question, as we discussed earlier, it might have discovered serious job loss potential.)

Perfect foresight

N_{ew}ERA, like other CGE models, assumes that decision-makers do not make systematic errors (that is, errors that bias results) when predicting the future. This is a common assumption in economic modeling and, while more complex theories regarding the accuracy of expectations of the future do exist, they only rarely enter into actual modeling of future conditions.

Zero profit condition

A more puzzling assumption is the “zero profit condition,” mentioned in the quote above. Analyzing fossil fuel markets under the assumption of zero profits sounds like a departure from the familiar facts of modern life. The picture is less than clear, since the N_{ew}ERA model includes calculations of both capital income and “resource” income (the latter is received by owners of resources such as natural gas); these may overlap with what would ordinarily be called profits. Without a more complete description of the N_{ew}ERA model, it is impossible to determine exactly how it treats profits in the fossil fuel industries. In any case, the business media are well aware of the potential for profits in natural gas; a recent article, based in part on the NERA Report, includes the subheading “How LNG Leads to Profits.”[27]

Invariable monetary policy

N_{ew}ERA also assumes that economy-wide interest rates and other monetary drivers will stay constant over time. Changes to monetary policy could, of course, have important impacts on modeling results, but forecasting these kinds of changes may well be considered outside of the scope of NERA’s analysis. That being said, several of NERA’s classes of scenarios involve supply and demand shocks to the economy as a whole: exactly the kind of broad-based change in economic conditions that tends to provoke changes in monetary policy.

Limited changes to the balance of trade

NERA’s treatment of foreign trade involves yet another unrealistic assumption:

> We balance the international trade account in the N_{ew}ERA model by constraining changes in the current account deficit over the model horizon. The condition is that the net present value of the foreign indebtedness over the model horizon remains at the benchmark year level. (NERA Report, p.109)

Although U.S. exports increase in many scenarios, NERA assumes that there can be very little change in the balance of trade. Instead, increases in exports largely have the effect of driving up the value of the dollar relative to other currencies (NERA Report, p. 110). This assumption results in a benefit to consumers of imports, who can buy them more cheaply; conversely, it harms exporters, by making their products more expensive and less competitive in world markets.

[27] Ben Gersten, “Five U.S. Natural Gas Companies Set to Soar from an Export Boom,” December 14, 2012. http://moneymorning.com/tag/natural-gas-stocks/

Sole U.S. financing of natural gas investments

Finally, NERA assumes that all income from natural gas investments will be received by U.S. residents: "[F]inancing of investment was assumed to originate from U.S. sources." (NERA Report, p.5) This improbable assumption, discussed in more detail above, means that benefits of investment in U.S. LNG export facilities and extraction services return, in full, to the United States. As discussed earlier, under the more realistic assumption that LNG exports are in part financed by foreign investors, some of the benefits of U.S. exports would flow out of the country to those investors.

6. Use of stale data leads to underestimation of domestic demand for natural gas

An additional important concern regarding the NERA Report is its use of unnecessarily outdated data from the rapidly changing U.S. Energy Information Administration (EIA) *Annual Energy Outlook* natural gas forecasts. Inexplicably, the NERA Report failed to use the EIA's most recent data, even though it had done so in prior reports.

The following timeline of EIA data releases and NERA reports illustrates this point:

- April 2011: EIA's Final **AEO 2011**[28] published
- December 2011: EIA's **AEO 2012**[29] Early Release published
- June 2012: EIA's Final **AEO 2012**[30] published
- October 2012: NERA's "Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector"[31] N_{ew}ERA model report published using **AEO 2012** data
- December 3, 2012: NERA's "Macroeconomic Impacts of LNG Exports from the United States"[32] N_{ew}ERA model report published using **AEO 2011** data
- December 5, 2012: EIA's **AEO 2013** Early Release published[33]

NERA's October 2012 N_{ew}ERA report on regulations affecting the electricity sector used AEO 2012 data, but its December 2012 report on LNG exports used older, AEO 2011 data. Days after NERA's December 2012 release of its LNG analysis, EIA released its AEO 2013 data.

By choosing to use stale data in its report, NERA changed the outcome of its analysis in significant ways. There have been important changes to EIA's natural gas forecasts in each recent AEO release. Even between AEO 2011 (used in NERA's LNG analysis) and AEO 2012 (which was available but not used by NERA), projected domestic consumption, production, and export of

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[28] EIA, Annual Energy Outlook 2011, 2011. http://www.eia.gov/forecasts/archive/aeo11/er/
[29] EIA, *Annual Energy Outlook 2012 Early Release*, 2012. http://www.eia.gov/forecasts/archive/aeo12/er/
[30] EIA, *Annual Energy Outlook 2012,* 2012. http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf
[31] David Harrison, et al., *Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector*, October 2012. http://www.nera.com/nera-files/PUB_ACCCE_1012.pdf
[32] W. David Montgomery, et al., *Macroeconomic Impacts of LNG Exports from the United States*, December 2012. http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf
[33] EIA, *Annual Energy Outlook 2013 Early Release*, 2013. http://www.eia.gov/forecasts/aeo/er/

natural gas rise, imports fall, and projected (Henry Hub) gas prices take a deeper drop in the next decades than previously predicted.

NERA's use of the older AEO 2011 data results in an underestimate of domestic demand for natural gas. The assumed level of domestic demand for natural gas is critical to NERA's modeling results; higher domestic demand—as predicted by more recent AEO data—would decrease the amount of natural gas available for export and would increase domestic prices. Domestic natural gas prices—both in the model's reference case baseline and its scenarios assuming LNG exports—are a key determinant of U.S. LNG's profitability in the global market.

7. Conclusions and policy recommendations

NERA's study of the macroeconomic impacts of LNG exports from the United States is incomplete, and several of its modeling choices appear to bias results towards a recommendation in favor of opening LNG exports. NERA's imagined future clashes with the obvious facts of economic life.

NERA's own modeling shows that LNG exports depress growth in the rest of the U.S. economy.

- NERA's results demonstrate that when LNG exports are opened, the size of the U.S. economy (excluding these export revenues) will shrink. An example helps to illustrate this point: In some cases, when LNG export revenues are $9 billion, GDP is $3 billion larger than in the no-export reference case. This means that GDP excluding gas exports has shrunk by almost $6 billion.
- Using a methodology adopted by NERA in other N_{ew}ERA analyses, job-equivalent losses from opening LNG exports can be estimated as ranging from 36,000 to 270,000 per year; the median scenario has an average job-equivalent loss of 131,000 per year.
- NERA's assumption that all income from LNG exports will return to U.S. residents is simply incorrect, and results in an overestimate of the benefits that will accrue to U.S.-based resource owners.
- Most American households do not own significant amounts of stock in general, and natural gas stocks represent just a tiny fraction of total stock ownership. The benefits to the typical American household from a booming gas industry are too small to measure.
- Higher prices for natural gas and electricity, and declining job prospects outside of the natural gas industry, would cause obvious harm to people throughout the country.
- NERA's export strategy would have the effect of maximizing short-run incomes at the expense of long-term economic stability. If NERA's export scenarios were to be carried out as federal policy, the result would be an acceleration of the decline of U.S. manufacturing and productivity, and an increased national dependence on raw material exports. Too strong of a dependence on resource exports—a problem often called the "resource curse" or the "Dutch disease"—can weaken the domestic manufacturing sector, even in a developed country.
- In the long run, it may prove more advantageous to nurture U.S. manufacture and export of value-added products made from our natural resources—even if it is not quite as

profitable in the short run. For example, surplus natural gas could be used to increase the U.S. manufacture and export of products, such as chemicals, that use natural gas as a raw material.

- The NERA Report has significant methodological issues. The proprietary N_{ew}ERA model is not available for examination by reviewers outside of NERA. The application of this type of closed-source model to U.S. federal policy decisions seems inappropriate.
- The limited documentation provided by NERA points to several unrealistic modeling assumptions, including: decision-makers' perfect foresight regarding future conditions; zero profits in the production of goods and services; no change to monetary policy, even in the face of economy-wide demand and supply shocks; and constraints on how much the U.S. balance of trade can shift in response to opening LNG exports.
- Full employment—also assumed in NERA's modeling—is not guaranteed, and nothing resembling full employment has occurred for quite a few years. At the writing of this white paper, the U.S. unemployment rate stood at 7.8 percent of the labor force (that is, of those actively employed or seeking work).[34] Furthermore, unemployed factory workers do not automatically get jobs in natural gas production, or in other industries.
- The NERA Report used outdated AEO 2011 data when AEO 2012 data were available. These older data underestimate U.S. domestic consumption of natural gas. Accurate modeling of domestic demand for natural gas is essential to making a creditable case for the benefits of opening LNG exports.

The Department of Energy is charged with determining whether or not approving applications—and thus opening U.S. borders—for LNG exports is in the public interest. At this important juncture in the development of U.S. export and resource extraction policy, a higher standard for data sources, methodology, and transparency of analysis is clearly required. Before designating LNG exports as beneficial to the U.S. public, the Department of Energy must fully exercise its due diligence by considering a far more complete macroeconomic analysis, including a detailed examination of distributional effects.

[34] December 2012 unemployment rate; U.S. Bureau of Labor Statistics, *Labor Force Statistics from the Current Population Survey*, Series ID: LNS14000000, Seasonal Unemployment Rate. http://data.bls.gov/timeseries/LNS14000000.

Appendix A

This appendix contains source information for Figure 2: Applicants for LNG Export Licenses.

Table A-1: Source information for Figure 3

Company	Status	Publicly traded?	Source	Quantity	FTA Applications (Docket Number)	Non-FTA Applications (Docket Number)
Golden Pass Products LLC	Foreign / Domestic	yes: XOM ExxonMobil	Golden Pass Products LLC is a joint venture between ExxonMobil Corp and Qatar Petroleum http://online.wsj.com/article/SB10000872396390444375104577595760678718068.html#articleTabs%3Darticle	2.6 Bcf/d(d)	Approved (12-88 -LNG)	Under DOE Review (12-156-LNG)
Lake Charles Exports, LLC	Foreign / Domestic	yes: SUG Southern Union Company, Foreign: BG Bg Group on London Stock Exchange	Lake Charles Exports LLC is a jointly owned subsidiary of Southern Union Company and BG Group http://www.fossil.energy.gov/programs/gasregulation/authorizations/2011_applications/11_59_lng.pdf	2.0 Bcf/d (e)	Approved (11-59-LNG)	Under DOE Review (11-59-LNG)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC (h)	Foreign / Domestic	Foreign: stock 9532:JP (Osaka Gas Co., Japan)	Osaka Gas's subsidiary Turbo LNG, LLC has a 10% stake in FLNG Development, which is a parent company for Freeport LNG Expansion, L.P, which in turn is a parent company of FLNG Liquafaction LP http://www.freeportlng.com/ownership.asp	1.4 Bcf/d (d)	Approved (12-06-LNG)	Under DOE Review (11-161-LNG)
Main Pass Energy Hub, LLC	Domestic	yes: MMR Freeport-MacMoRan Exploration Co.	Freeport-MacMoRan Exploration Co. owns a 50% stake in Main Pass Energy Hub, LLC http://www.fossil.energy.gov/programs/gasregulation/authorizations/2012_applications/12_114_lng.pdf	3.22 Bcf/d	Approved (12-114-LNG)	n/a
Gulf Coast LNG Export, LLC (i)	Domestic	privately held	97% owned by Michael Smit, 1.5 % each by trusts http://www.fossil.energy.gov/programs/gasregulation/authorizations/2012_applications/12_05_lng.pdf	2.8 Bcf/d(d)	Approved (12-05-LNG)	Under DOE Review (12-05-LNG)
Sabine Pass Liquefaction, LLC	Domestic	yes: CQP Cheniere Energy Partners L.P	Sabine Pass Liquefaction is a subsidiary of Cheniere Energy Partners L.P http://www.chenierenergypartners.com/liquefaction_project/liquefaction_project.shtml	2.2 billion cubic feet per day (Bcf/d) (d)	Approved (10-85-LNG)	#N/A
Cheniere Marketing, LLC	Domestic	yes: LNG Cheniere Energy Inc.	Cheniere Marketing is a subsidiary of Cheniere Energy Inc. http://www.cheniere.com/corporate/about_us.shtml	2.1 Bcf/d(d)	Approved (12-99-LNG)	Under DOE Review (12-97-LNG)

Table A-1: Source information for Figure 3 (Continued)

Company	Status	Publicly traded?	Source	Quantity	FTA Applications (Docket Number)	Non-FTA Applications (Docket Number)
Cameron LNG, LLC	Domestic	yes: SRE Sempra Energy	Cameron LNG is a Sempra affiliate http://cameron.sempralng.com/about-us.html	1.7 Bcf/d (d)	Approved (11-145-LNG)	#N/A
Gulf LNG Liquefaction Company, LLC	Domestic	yes: KMI Kinder Morgan and GE General Electric (GE Energy Financial Services, a unit of GE)	KMI owns 50 pct stake in Gulf LNG Holdings http://www.kindermorgan.com/business/gas_pipelines/east/LNG/gulf.cfm. GE Energy Financial Services, directly and indirectly, controls its 50 percent stake in Gulf LNG http://www.geenergyfinancialservices.com/transactions/transactions.asp?transaction=transactions_archoldings.asp	1.5 Bcf/d(d)	Approved (12-47-LNG)	Under DOE Review (12-101-LNG)
Excelerate Liquefaction Solutions I, LLC	Foreign / Domestic	Foreign: stock RWE.DE domestic: privately held	Owned by Excelerate Liquefaction Solutions, source: http://www.gpo.gov/fdsys/pkg/FR-2012-12-06/html/2012-29475.htm . Those are owned by Excelerate Energy, LLC (same source). THAT is owned 50% by RWE Supply & Tradding and 50% by Mr. George B. Kaiser (an individual). George Kaiser is the American $10B George Kaiser: http://en.wikipedia.org/wiki/George_Kaiser and http://excelerateenergy.com/about-us	1.38 Bcf/d(d)	Approved (12-61-LNG)	Under DOE Review (12-146-LNG)
LNG Development Company, LLC (d/b/a Oregon LNG)	Domestic	privately held	Owned by Oregon LNG source: http://www.gpo.gov/fdsys/pkg/FR-2012-12-06/html/2012-29475.htm	1.25 Bcf/d(d)	Approved (12-48-LNG)	Under DOE Review (12-77-LNG)
Dominion Cove Point LNG, LP	Domestic	yes: D Dominion	source: https://www.dom.com/business/gas-transmission/cove-point/index.jsp	1.0 Bcf/d (d)	Approved (11-115-LNG)	#N/A
Southern LNG Company, L.L.C.	Domestic	yes: KMI Kinder Morgan	KMI owns El Paso Pipeline Partners source: http://investor.eppipelinepartners.com/phoenix.zhtml?c=215819&p=irol-newsArticle&id=1624861 . El Paso Pipeline Partners owns El Paso Pipeline Partners Operating Company source: http://investing.businessweek.com/research/stocks/private/snapshot.asp?privcapId=46603039 . El Paso Pipeline Partners Operating Company owns Southern LNG page 2 of http://www.ferc.gov/whats-new/comm-meet/2012/051712/C-2.pdf	0.5 Bcf/d(d)	Approved (12-54-LNG)	Under DOE Review (12-100-LNG)

Table A-1: Source information for Figure 3 (Continued)

Company	Status	Publicly traded?	Source	Quantity	FTA Applications (Docket Number)	Non-FTA Applications (Docket Number)
Waller LNG Services, LLC	Domestic	privately held	Wholly owned by Waller Marine: http://www.marinelog.com/index.php?option=com_content&view=article&id=3196:waller-marine-to-develop-small-scale-lng-terminals&catid=1:latest-news . Waller Marine private: http://www.linkedin.com/company/waller-marine-inc.	0.16 Bcf/d	Approved (12-152-LNG)	n/a
SB Power Solutions Inc.	Domestic	yes: SEB Seaboard	p. 2 of http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders_Issued_2012/ord3105.pdf	0.07 Bcf/d	Approved (12-50-LNG)	#N/A
Carib Energy (USA) LLC	Domestic	privately held	http://companies.findthecompany.com/l/21346146/Carib-Energy-Usa-Llc-in-Coral-Springs-FL	0.03 Bcf/d: FTA 0.01 Bcf/d: non-FTA (f)	Approved (11-71-LNG)	#N/A

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Annual Energy Outlook 2012

with Projections to 2035

Independent Statistics & Analysis
U.S. Energy Information Administration

For further information . . .

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The *Annual Energy Outlook 2012* is available on the EIA website at www.eia.gov/forecasts/aeo. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available, at www.eia.gov/forecasts/aeo/assumptions. Model documentation reports for the National Energy Modeling System are available at website www.eia.gov/analysis/model-documentation.cfm and will be updated for the *Annual Energy Outlook 2012* during 2012.

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Preface

The *Annual Energy Outlook 2012 (AEO2012)*, prepared by the U.S. Energy Information Administration (EIA), presents long-term projections of energy supply, demand, and prices through 2035, based on results from EIA's National Energy Modeling System (NEMS). EIA published an "early release" version of the *AEO2012* Reference case in January 2012.

The report begins with an "Executive summary" that highlights key aspects of the projections. It is followed by a "Legislation and regulations" section that discusses evolving legislative and regulatory issues, including a summary of recently enacted legislation and regulations, such as: the Mercury and Air Toxics Standards (MATS) issued by the U.S. Environmental Protection Agency (EPA) in December 2011 [*1*]; the Cross-State Air Pollution Rule (CSAPR) as finalized by the EPA in July 2011 [*2*]; the new fuel efficiency standards for medium- and heavy-duty vehicles published by the EPA and the National Highway Traffic Safety Administration (NHTSA) in September 2011 [*3*]; and regulations pertaining to the power sector in California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006 [*4*].

The "Issues in focus" section contains discussions of selected energy topics, including a discussion of the results in two cases that adopt different assumptions about the future course of existing policies: one case assumes the extension of a selected group of existing public policies—corporate average fuel economy (CAFE) standards, appliance standards, production tax credits, and the elimination of sunset provisions in existing energy policies; the other case assumes only the elimination of sunset provisions. Other discussions include: oil price and production trends in the *AEO2012*; potential efficiency improvements and their impacts on end-use energy demand; energy impacts of proposed CAFE standards for light-duty vehicles (LDVs), model years (MYs) 2017 to 2025; impacts of a breakthrough in battery vehicle technology; heavy-duty (HD) natural gas vehicles (NGVs); changing structure of the refining industry; changing environment for fuel use in electricity generation; nuclear power in *AEO2012*; potential impact of minimum pipeline throughput constraints on Alaska North Slope oil production; U.S. crude oil and natural gas resource uncertainty; and evolving Marcellus shale gas resource estimates.

The "Market trends" section summarizes the projections for energy markets. The analysis in *AEO2012* focuses primarily on a Reference case, Low and High Economic Growth cases, and Low and High Oil Price cases. Results from a number of other alternative cases also are presented, illustrating uncertainties associated with the Reference case projections for energy demand, supply, and prices. Complete tables for the five primary cases are provided in Appendixes A through C. Major results from many of the alternative cases are provided in Appendix D. Complete tables for all the alternative cases are available on EIA's website in a table browser at www.eia.gov/oiaf/aeo/tablebrowser.

AEO2012 projections are based generally on Federal, State, and local laws and regulations in effect as of the end of December 2011. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections. In certain situations, however, where it is clear that a law or regulation will take effect shortly after the *AEO* is completed, it may be considered in the projection.

AEO2012 is published in accordance with Section 205c of the U.S. Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

Projections by EIA are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular scenario. The Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other scenarios with different macroeconomic growth rates, world oil prices, and rates of technology progress. The main cases in *AEO2012* generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide policy-neutral baselines that can be used to analyze policy initiatives.

While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2012* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

Updated *Annual Energy Outlook 2012* Reference case (June 2012)

The *Annual Energy Outlook 2012 (AEO2012)* Reference case included as part of this complete report, released in June 2012, was updated from the Reference case released as part of the *AEO2012* Early Release Overview in January 2012. The Reference case was updated to incorporate modeling changes and reflect new legislation or regulation that was not available when the Early Release Overview version of the Reference case was published. Major changes made in the Reference include:

- The Mercury and Air Toxics Standards (MATS) issued by the EPA in December 2011 was incorporated.
- The long-term macroeconomic projection was revised, based on the November 2011 long-term projection from IHS Global Insights, Inc.
- The Cross-State Air Pollution Rule (CSAPR), which was included in the Early Release Reference case, was kept in the final Reference case. In December 2011, a District Court delayed the rule from going into effect while in litigation.
- The California Low Carbon Fuel Standard (LCFS) was removed from the final Reference case, given the Federal court ruling in December 2011 that found some aspects of it to be unconstitutional.
- Historical data and equations for the transportation sector were revised to reflect revised data from NHTSA and FHWA.
- A new cement model was incorporated in the industrial sector.
- Photovoltaic capacity estimates for recent historical years (2009 and 2010) were updated to line up more closely with Solar Energy Industries Association (SEIA) and Interstate Renewable Energy Council (IREC) reports.
- Gulf of Mexico production data were revised downward to reflect data reported by the Bureau of Ocean Energy Management more closely.
- Data in the electricity model were revised to reflect 2009 electric utility financial data (electric utility plant in service, operations and maintenance costs, etc.) and refine the breakdown of associated costs between the generation, transmission, and distribution components.
- Higher capital costs for fabric filters were adopted in the analysis of MATS, based on EPA data.
- Reservoir-level oil data were updated to improve the API gravity and sulfur content data elements.
- The assumed volume of natural gas used at export liquefaction facilities was revised.

Future analyses using the *AEO2012* Reference case will start from the version of the Reference case released with this complete report.

Endnotes for Preface

Links current as of June 2012

1. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," website www.epa.gov/mats.
2. U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)," website epa.gov/airtransport.
3. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *Federal Register*, Vol. 76, No. 179 (September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.
4. California Environmental Protection Agency, Air Resources Board, "Assembly Bill 32: Global Warming Solutions Act of 2006," website www.arb.ca.gov/cc/ab32/ab32.htm.

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Executive summary

The projections in the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2012 (AEO2012)* focus on the factors that shape the U.S. energy system over the long term. Under the assumption that current laws and regulations remain unchanged throughout the projections, the *AEO2012* Reference case provides the basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future. It also serves as a starting point for analysis of potential changes in energy policies. But *AEO2012* is not limited to the Reference case. It also includes 29 alternative cases (see Appendix E, Table E1), which explore important areas of uncertainty for markets, technologies, and policies in the U.S. energy economy. Many of the implications of the alternative cases are discussed in the "Issues in focus" section of this report.

Key results highlighted in *AEO2012* include continued modest growth in demand for energy over the next 25 years and increased domestic crude oil and natural gas production, largely driven by rising production from tight oil and shale resources. As a result, U.S. reliance on imported oil is reduced; domestic production of natural gas exceeds consumption, allowing for net exports; a growing share of U.S. electric power generation is met with natural gas and renewables; and energy-related carbon dioxide emissions remain below their 2005 level from 2010 to 2035, even in the absence of new Federal policies designed to mitigate greenhouse gas (GHG) emissions.

The rate of growth in energy use slows over the projection period, reflecting moderate population growth, an extended economic recovery, and increasing energy efficiency in end-use applications

Overall U.S. energy consumption grows at an average annual rate of 0.3 percent from 2010 through 2035 in the *AEO2012* Reference case. The U.S. does not return to the levels of energy demand growth experienced in the 20 years prior to the 2008-2009 recession, because of more moderate projected economic growth and population growth, coupled with increasing levels of energy efficiency. For some end uses, current Federal and State energy requirements and incentives play a continuing role in requiring more efficient technologies. Projected energy demand for transportation grows at an annual rate of 0.1 percent from 2010 through 2035 in the Reference case, and electricity demand grows by 0.7 percent per year, primarily as a result of rising energy consumption in the buildings sector. Energy consumption per capita declines by an average of 0.6 percent per year from 2010 to 2035 (Figure 1). The energy intensity of the U.S. economy, measured as primary energy use in British thermal units (Btu) per dollar of gross domestic product (GDP) in 2005 dollars, declines by an average of 2.1 percent per year from 2010 to 2035. New Federal and State policies could lead to further reductions in energy consumption. The potential impact of technology change and the proposed vehicle fuel efficiency standards on energy consumption are discussed in "Issues in focus."

Domestic crude oil production increases

Domestic crude oil production has increased over the past few years, reversing a decline that began in 1986. U.S. crude oil production increased from 5.0 million barrels per day in 2008 to 5.5 million barrels per day in 2010. Over the next 10 years, continued development of tight oil, in combination with the ongoing development of offshore resources in the Gulf of Mexico, pushes domestic crude oil production higher. Because the technology advances that have provided for recent increases in supply are still in the early stages of development, future U.S. crude oil production could vary significantly, depending on the outcomes of key uncertainties related to well placement and recovery rates. Those uncertainties are highlighted in this *Annual Energy Outlook*'s "Issues in focus" section, which includes an article examining impacts of uncertainty about current estimates of the crude oil and natural gas resources. The *AEO2012* projections considering variations in these variables show total U.S. crude oil production in 2035 ranging from 5.5 million barrels per day to 7.8 million barrels per day, and projections for U.S. tight oil production from eight selected plays in 2035 ranging from 0.7 million barrels per day to 2.8 million barrels per day (Figure 2).

Figure 1. Energy use per capita and per dollar of gross domestic product, 1980-2035 (index, 1980=1)

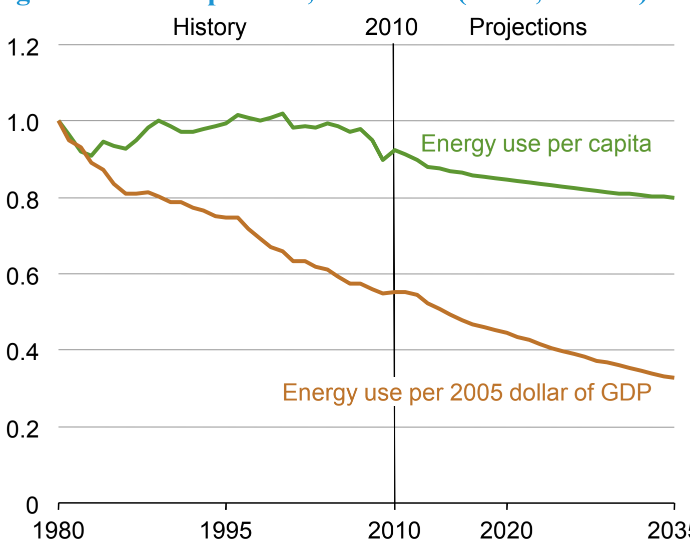
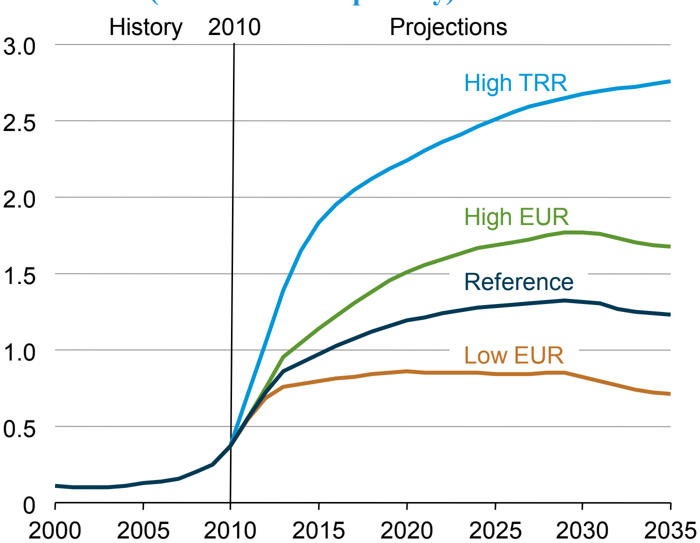


Figure 2. U.S. production of tight oil in four cases, 2000-2035 (million barrels per day)



With modest economic growth, increased efficiency, growing domestic production, and continued adoption of nonpetroleum liquids, net imports of petroleum and other liquids make up a smaller share of total U.S. energy consumption

U.S. dependence on imported petroleum and other liquids declines in the *AEO2012* Reference case, primarily as a result of rising energy prices; growth in domestic crude oil production to more than 1 million barrels per day above 2010 levels in 2020; an increase of 1.2 million barrels per day crude oil equivalent from 2010 to 2035 in the use of biofuels, much of which is produced domestically; and slower growth of energy consumption in the transportation sector as a result of existing corporate average fuel economy standards. Proposed fuel economy standards covering vehicle model years (MY) 2017 through 2025 that are not included in the Reference case would further reduce projected need for liquid imports.

Although U.S. consumption of petroleum and other liquid fuels continues to grow through 2035 in the Reference case, the reliance on imports of petroleum and other liquids as a share of total consumption declines. Total U.S. consumption of petroleum and other liquids, including both fossil fuels and biofuels, rises from 19.2 million barrels per day in 2010 to 19.9 million barrels per day in 2035 in the Reference case. The net import share of domestic consumption, which reached 60 percent in 2005 and 2006 before falling to 49 percent in 2010, continues falling in the Reference case to 36 percent in 2035 (Figure 3). Proposed light-duty vehicles (LDV) fuel economy standards covering vehicle MY 2017 through 2025, which are not included in the Reference case, could further reduce demand for petroleum and other liquids and the need for imports, and increased supplies from U.S. tight oil deposits could also significantly decrease the need for imports, as discussed in more detail in "Issues in focus."

Natural gas production increases throughout the projection period, allowing the United States to transition from a net importer to a net exporter of natural gas

Much of the growth in natural gas production in the *AEO2012* Reference case results from the application of recent technological advances and continued drilling in shale plays with high concentrations of natural gas liquids and crude oil, which have a higher value than dry natural gas in energy equivalent terms. Shale gas production increases in the Reference case from 5.0 trillion cubic feet per year in 2010 (23 percent of total U.S. dry gas production) to 13.6 trillion cubic feet per year in 2035 (49 percent of total U.S. dry gas production). As with tight oil, when looking forward to 2035, there are unresolved uncertainties surrounding the technological advances that have made shale gas production a reality. The potential impact of those uncertainties results in a range of outcomes for U.S. shale gas production from 9.7 to 20.5 trillion cubic feet per year when looking forward to 2035.

As a result of the projected growth in production, U.S. natural gas production exceeds consumption early in the next decade in the Reference case (Figure 4). The outlook reflects increased use of liquefied natural gas in markets outside North America, strong growth in domestic natural gas production, reduced pipeline imports and increased pipeline exports, and relatively low natural gas prices in the United States.

Power generation from renewables and natural gas continues to increase

In the Reference case, the natural gas share of electric power generation increases from 24 percent in 2010 to 28 percent in 2035, while the renewables share grows from 10 percent to 15 percent. In contrast, the share of generation from coal-fired power plants declines. The historical reliance on coal-fired power plants in the U.S. electric power sector has begun to wane in recent years.

Figure 3. Total U.S. petroleum and other liquids production, consumption, and net imports, 1970-2035 (million barrels per day)

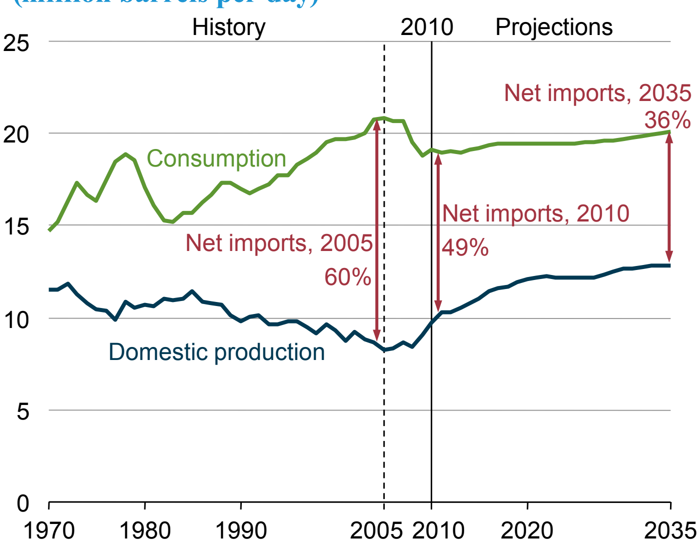
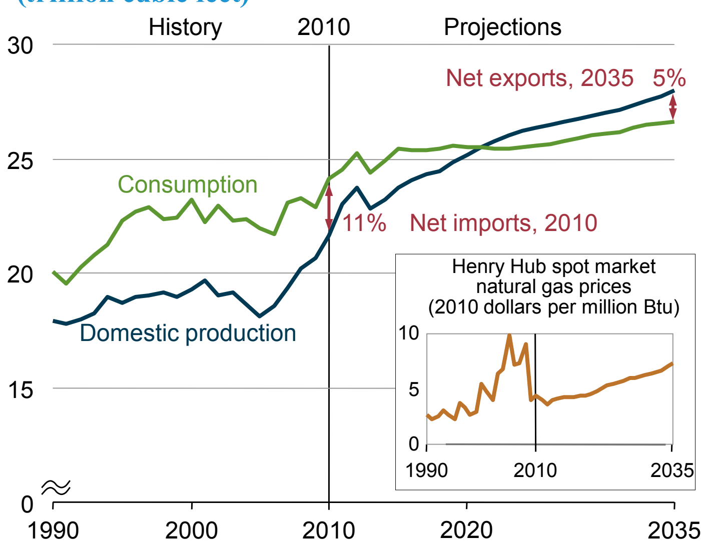


Figure 4. Total U.S. natural gas production, consumption, and net imports, 1990-2035 (trillion cubic feet)



Over the next 25 years, the share of electricity generation from coal falls to 38 percent, well below the 48-percent share seen as recently as 2008, due to slow growth in electricity demand, increased competition from natural gas and renewable generation, and the need to comply with new environmental regulations. Although the current trend toward increased use of natural gas and renewables appears fairly robust, there is uncertainty about the factors influencing the fuel mix for electricity generation. *AEO2012* includes several cases examining the impacts on coal-fired plant generation and retirements resulting from different paths for electricity demand growth, coal and natural gas prices, and compliance with upcoming environmental rules.

While the Reference case projects 49 gigawatts of coal-fired generation retirements over the 2011 to 2035 period, nearly all of which occurs over the next 10 years, the range for cumulative retirements of coal-fired power plants over the projection period varies considerably across the alternative cases (Figure 5), from a low of 34 gigawatts (11 percent of the coal-fired generator fleet) to a high of 70 gigawatts (22 percent of the fleet). The high end of the range is based on much lower natural gas prices than those assumed in the Reference case; the lower end of the range is based on stronger economic growth, leading to stronger growth in electricity demand and higher natural gas prices. Other alternative cases, with varying assumptions about coal prices and the length of the period over which environmental compliance costs will be recovered, but no assumption of new policies to limit GHG emissions from existing plants, also yield cumulative retirements within a range of 34 to 70 gigawatts. Retirements of coal-fired capacity exceed the high end of the range (70 gigawatts) when a significant GHG policy is assumed (for further description of the cases and results, see "Issues in focus").

Total energy-related emissions of carbon dioxide in the United States remain below their 2005 level through 2035

Energy-related carbon dioxide (CO_2) emissions grow slowly in the *AEO2012* Reference case, due to a combination of modest economic growth, growing use of renewable technologies and fuels, efficiency improvements, slow growth in electricity demand, and increased use of natural gas, which is less carbon-intensive than other fossil fuels. In the Reference case, which assumes no explicit Federal regulations to limit GHG emissions beyond vehicle GHG standards (although State programs and renewable portfolio standards are included), energy-related CO_2 emissions grow by just over 2 percent from 2010 to 2035, to a total of 5,758 million metric tons in 2035 (Figure 6). CO_2 emissions in 2020 in the Reference case are more than 9 percent below the 2005 level of 5,996 million metric tons, and they still are below the 2005 level at the end of the projection period. Emissions per capita fall by an average of 1.0 percent per year from 2005 to 2035.

Projections for CO_2 emissions are sensitive to such economic and regulatory factors due to the pervasiveness of fossil fuel use in the economy. These linkages result in a range of potential GHG emissions scenarios. In the *AEO2012* Low and High Economic Growth cases, projections for total primary energy consumption in 2035 are, respectively, 100.0 quadrillion Btu (6.4 percent below the Reference case) and 114.4 quadrillion Btu (7.0 percent above the Reference case), and projections for energy-related CO_2 emissions in 2035 are 5,356 million metric tons (7.0 percent below the Reference case) and 6,117 million metric tons (6.2 percent above the Reference case).

Figure 5. Cumulative retirements of coal-fired generating capacity, 2011-2035 (gigawatts)

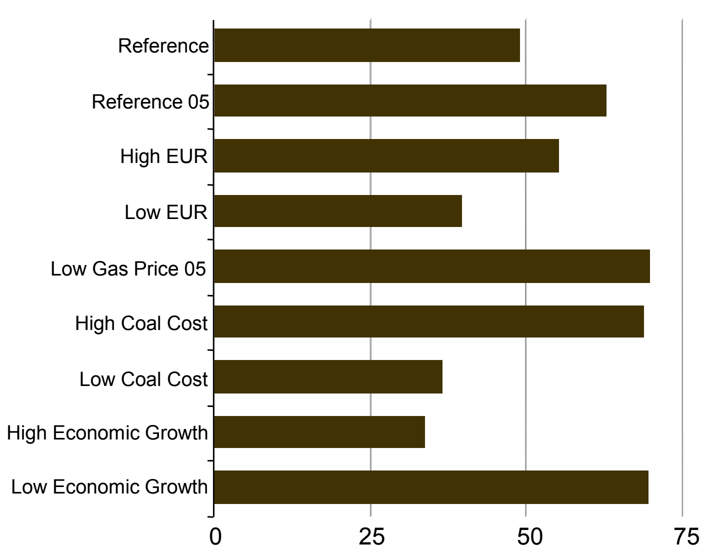
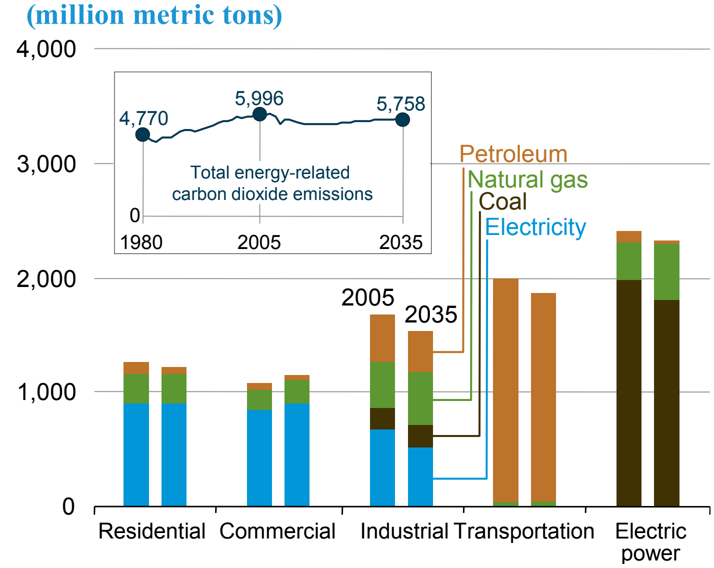


Figure 6. U.S. energy-related carbon dioxide emissions by sector and fuel, 2005 and 2035 (million metric tons)



Legislation and regulations

Introduction

The *Annual Energy Outlook 2012 (AEO2012)* generally represents current Federal and State legislation and final implementation regulations available as of the end of December 2011. The *AEO2012* Reference case assumes that current laws and regulations affecting the energy sector are largely unchanged throughout the projection period (including the implication that laws that include sunset dates do, in fact, become ineffective at the time of those sunset dates) [*5*]. The potential impacts of proposed legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in the *AEO2012* Reference case, but some are considered in alternative cases. This section summarizes Federal and State legislation and regulations newly incorporated or updated in *AEO2012* since the completion of the *Annual Energy Outlook 2011.*

Examples of recently enacted Federal and State legislation and regulations incorporated in the *AEO2012* Reference case include:

- New greenhouse gas (GHG) emissions and fuel consumption standards for medium- and heavy-duty engines and vehicles, published by the U.S. Environmental Protection Agency (EPA) and the National Highway Transportation Safety Administration (NHTSA) in September 2011 [*6*]
- The Cross-State Air Pollution Rule (CSAPR), as finalized by the EPA in July 2011 [*7*]
- Mercury and Air Toxics Standards (MATS) rule, issued by the EPA in December 2011 [*8*].

There are many other pieces of legislation and regulation that appear to have some probability of being enacted in the not-too-distant future, and some laws include sunset provisions that may be extended. However, it is difficult to discern the exact forms that the final provisions of pending legislation or regulations will take, and sunset provisions may or may not be extended. Even in situations where existing legislation contains provisions to allow revision of implementing regulations, those provisions may not be exercised consistently. Many pending provisions are examined in alternative cases included in *AEO2012* or in other analyses completed by the U.S. Energy Information Administration (EIA). In addition, at the request of the Administration and Congress, EIA has regularly examined the potential implications of proposed legislation in Service Reports. Those reports can be found on the EIA website at www.eia.gov/oiaf/service_rpts.htm.

1. Greenhouse gas emissions and fuel consumption standards for heavy-duty vehicles, model years 2014 through 2018

On September 15, 2011, the EPA and NHTSA jointly announced a final rule, called the HD National Program [*9*], which for the first time established GHG emissions and fuel consumption standards for on-road heavy-duty trucks with a gross vehicle weight rating (GVWR) above 8,500 pounds (Classes 2b through 8) [*10*] and their engines. The *AEO2012* Reference case incorporates the new standards for heavy-duty vehicles (HDVs).

Due to the tremendous diversity of HDV uses, designs, and power requirements, the HD National Program separates GHG and fuel consumption standards into discrete vehicle categories within combination tractors, vocational vehicles, and heavy-duty pickups and vans (Table 1). Further, the rule recognizes that reducing GHG emissions and fuel consumption will require changes to both the engine and the body of a vehicle (to reduce the amount of work demanded by an engine). The final rule sets separate standards for the different engines used in combination tractors and vocational vehicles. *AEO2012* represents standard compliance among HDV regulatory classifications that represent the discrete vehicle categories set forth in the rule.

The HD National Program standards begin for model year (MY) 2014 vehicles and engines and are fully phased in by MY 2018. The EPA, under authority granted by the Clean Air Act, has issued GHG emissions standards that begin with MY 2014 for all engine and body categories. NHTSA, operating under regulatory timelines mandated by the Energy Independence and Security Act [*11*], set voluntary fuel consumption standards for MY 2014 and 2015, with the standards becoming mandatory for MY 2016 and beyond, except for diesel engine standards, which become mandatory for MY 2017 and beyond. Standards reach the most stringent levels for combination tractors and vocational vehicles in MY 2017, with subsequent standards then holding constant. Heavy-duty pickup and van standards are required to reach the highest level of stringency in MY 2018. *AEO2012* includes the HD

Table 1. HD National Program vehicle regulatory categories

Category	Description	GVWR
Combination tractors	Combination tractors are semi trucks designed to pull trailers. Standards are set separately for tractor cabs and their engines. There are no GHG or fuel consumption standards for trailers.	Class 7 and 8 (26,001 pounds and above)
Vocational vehicles	Vocational vehicles include a wide range of truck configurations, such as delivery, refuse, utility, dump, cement, fire, and tow trucks, school buses, and ambulances. The rulemaking defines vocational vehicles as all heavy-duty trucks that are not combination tractors or heavy-duty pickups or vans. Vocational vehicle standards are set separately for chassis and engines.	Class 2b through 8 (8,501 pounds and above)
Heavy-duty pickups and vans	Pickup trucks and vans are primarily 3/4-ton or 1-ton pickups used on construction sites or 12- to 15-person passenger vans.	Class 2b and 3 (8,501 to 14,000 pounds)

National Program standards beginning in MY 2014 as set by the GHG emissions portion of the rule, with standards represented by vehicle, including both the chassis and engine. *AEO2012* assumes that vehicle chassis and engine manufacturers comply with the voluntary portion of the rule covering the fuel consumption standard. *AEO2012* does not model the chassis and engine standards separately but allows the use of technologies to meet the HD National Program combined engine and chassis standards.

Although they are not modeled separately in *AEO2012*, GHG emission and fuel consumption standards for combination tractors are set for the tractor cabs and the engines used in those cabs separately in the HD National Program. Combination tractor cab standards are subdivided by GVWR (Class 7 or 8), cab type (day or sleeper), and roof type (low, mid, or high). Combination tractor engine standards are subdivided into medium heavy-duty diesel (for use in Class 7 tractors) and heavy heavy-duty diesel (for use in Class 8 tractors) (Table 2). Each tractor cab and engine combination is required to meet the GHG and fuel consumption standards for a given model year, unless they are made up by credits or other program flexibilities.

Again, although they are not modeled separately in *AEO2012*, GHG emission and fuel consumption standards for vocational vehicles are set separately in the HD National Program for the vehicle chassis and the engines used in the chassis. Vocational vehicle chassis standards are subdivided in the rule by GVWR (Classes 2b to 5, Classes 6 and 7, and Class 8). Vocational vehicle engine standards are subdivided into light heavy-duty diesel (for use in Classes 2b through 5), medium heavy-duty diesel (for use in Classes 6 and 7), heavy heavy-duty diesel (for use in Class 8), and spark-ignited (primarily gasoline) engines (for use in all classes) (Table 3). Each vocational vehicle chassis and engine combination is required to meet the GHG and fuel consumption standard for a given model year, unless made up by credits or other program flexibilities.

Standards for heavy-duty pickups and vans are based on the "work factor"—a weighted average of the vehicle's payload and towing capacity, adjusted for four-wheel drive capability. The standards for heavy-duty pickups and vans are different for diesel

Table 2. HD National Program standards for combination tractor greenhouse gas emissions and fuel consumption (assuming fully compliant engine)

	Day cab		Sleeper cab
Roof type	Class 7	Class 8	Class 8
2014 GHG emissions standards (grams CO_2 per ton-mile)			
Low roof	107	81	68
Mid roof	119	88	76
High roof	124	92	75
2014-2016 voluntary fuel consumption standards (gallons per 1,000 ton-miles)			
Low roof	10.5	8.0	6.7
Mid roof	11.7	8.7	7.4
High roof	12.2	9.0	7.3
2017 GHG emissions standards (grams CO_2 per ton-mile)			
Low roof	104	80	66
Mid roof	115	86	73
High roof	120	89	72
2017 fuel consumption standards (gallons per 1,000 ton-miles)			
Low roof	10.2	7.8	6.5
Mid roof	11.3	8.4	7.2
High roof	11.8	8.7	7.1

Table 3. HD National Program standards for vocational vehicle greenhouse gas emissions and fuel consumption (assuming fully compliant engine)

Standard	Light heavy-duty (Classes 2b-5)	Medium heavy-duty (Classes 6-7)	Heavy heavy-duty (Class 8)
2014 GHG emissions standard (grams CO_2 per ton-mile)	388	234	226
2016 fuel consumption standard (gallons per 1,000 ton-miles)	38.1	23.0	22.2
2017 GHG emissions standards (grams CO_2 per ton-mile)	373	225	222
2017 fuel consumption standard (gallons per 1,000 ton-miles)	36.7	22.1	21.8

and gasoline engines (Figures 7 and 8). They differ from the standards for combination tractors and vocational vehicles in that they apply to the vehicle fleet average for each manufacturer for a given model year, based on a production volume-weighted target for each model, with targets differing by work factor attribute.

The final rulemaking exempts small manufacturers of heavy-duty engines, combination tractor cabs, or vocational vehicle chassis from the GHG emissions and fuel consumption standards. Fuel consumption and GHG emissions for alternative-fuel vehicles, such as compressed natural gas vehicles, will be calculated according to their tailpipe emissions. Finally, the rulemaking contains four provisions designed to give manufacturers flexibility in meeting the GHG and fuel consumption standards. Both the EPA and NHTSA will allow for early compliance credits in MY 2013; manufacturer averaging, banking, and trading; advanced technology credits; and innovative technology credits. Those flexibility provisions are not included in the *AEO2012* Reference case.

2. Cross-State Air Pollution Rule

The CSAPR was created to regulate emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from power plants greater than 25 megawatts that generate electric power from fossil fuels. CSAPR is intended to assist States in achieving their National Ambient Air Quality Standards for fine particulate matter and ground-level ozone. Limits on annual emissions of SO_2 and NO_x are designed to address fine particulate matter. The seasonal NO_x limits address ground-level ozone. Twenty-three States are subject to the annual limits, and 25 States are subject to the seasonal limits [*12*].

CSAPR replaces the Clean Air Interstate Rule (CAIR). CAIR is an interstate emissions cap-and-trade program for SO_2 and NO_x that would have allowed for unlimited trading among 28 eastern States. It was finalized in 2005, and requirements for emissions reductions were scheduled to begin 2009. In 2008, however, the U.S. Court of Appeals for the D.C. Circuit found that CAIR did not sufficiently meet the Clean Air Act requirements and directed the EPA to fix the flaws that it identified while CAIR remained in effect.

In July 2011, the EPA published CSAPR, with State coverage as shown in Figure 9. CSAPR consists of four individual cap-and-trade programs:

- Group 1 SO_2 covers 16 States.
- Group 2 SO_2 covers 7 States [*13*].
- Annual NO_x Group consists of an annual cap-and-trade program that covers all Group 1 and Group 2 SO_2 States.
- Seasonal NO_x Group covers a separate set of States, 20 of which are also in the Annual NO_x Group and 5 of which are not.

There are two SO_2 control groups, because the EPA has determined that the States in Group 1 need to meet more stringent emissions reduction requirements.

All cap-and-trade programs specified in CSAPR are included in *AEO2012*, but because the National Energy Modeling System (NEMS) does not represent electric power markets at the State level, the four group emissions caps and corresponding allowance trading could not be explicitly represented. The cap-and-trade systems for annual SO_2 and NO_x emissions are implemented for the coal demand regions by aggregating the allowance budget for each State within a region.

Figure 7. HD National Program model year standards for diesel pickup and van greenhouse gas emissions and fuel consumption, 2014-2018

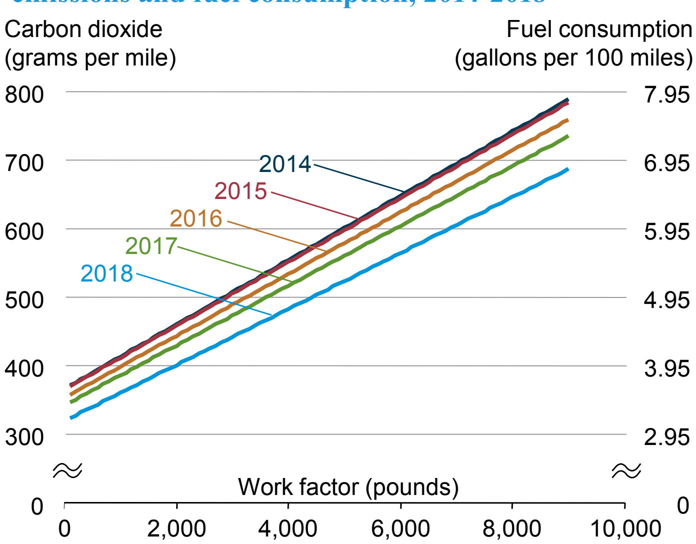
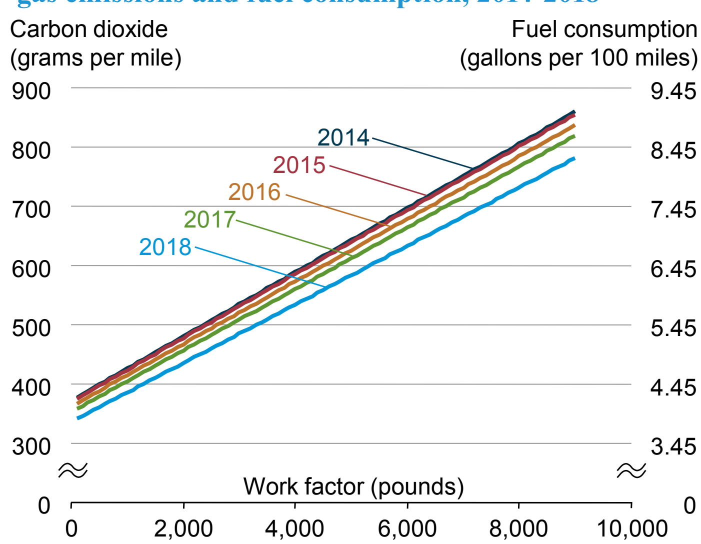


Figure 8. HD National Program model year standards for gasoline pickup and van greenhouse gas emissions and fuel consumption, 2014-2018



The EPA scheduled three annual cap-and-trade programs to commence in January 2012 and the summer season NO_x program to begin in May 2012. For three of the four programs, the initial annual cap does not change over time. For the Group 1 SO_2 program, the emissions cap across States is reduced substantially in 2014.

Emissions trading is unrestricted within a group but is not allowed across groups. Therefore, emissions allowances exist for four independent trading programs. Each State is designated an annual emissions budget, with the sum of the budgets making up the overall group emissions cap. Sources can collectively exceed State emissions budgets by close to 20 percent without any penalty. If the sources collectively exceed the State emission budget by more than the 20 percent, the sources responsible must "pay a penalty" in addition to submitting the additional allowances. The EPA set the penalties with the goal of ensuring that emissions produced by upwind States would not exceed assurance levels and contribute to air quality problems in downwind States. The emissions allowances are allocated to generating units primarily on the basis of historical energy use.

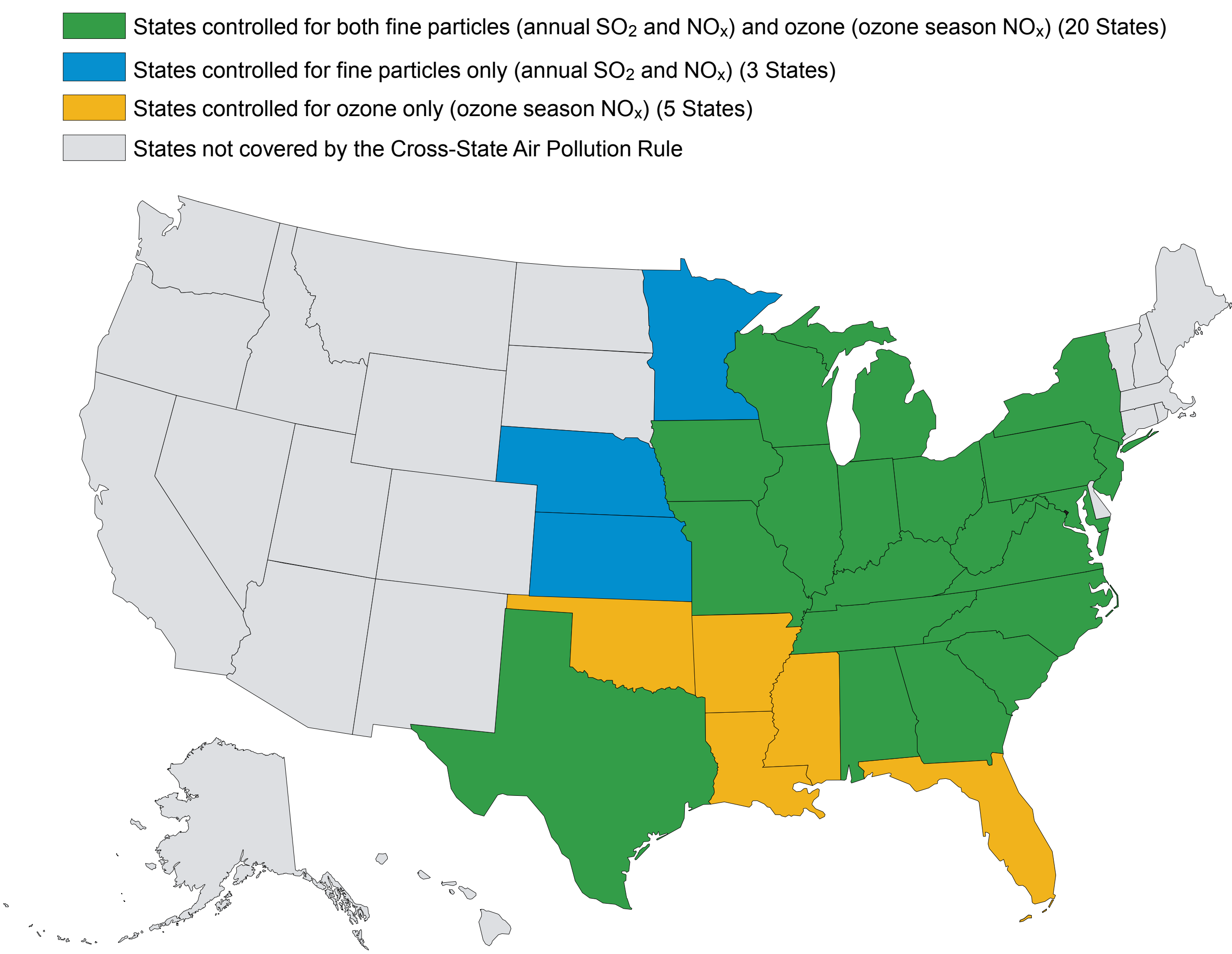
CSAPR was scheduled to begin on January 1, 2012, but the Court of Appeals issued a stay that is delaying implementation while it addresses legal challenges to the rule that have been raised by several power companies and States [*14*]. CSAPR is included in *AEO2012* despite the stay, because the Court of Appeals had not made a final ruling at the time *AEO2012* was completed.

3. Mercury and air toxics standards

The MATS [*15*] are required by Section 112 of the 1990 Clean Air Act Amendments, which requires that maximum achievable control technology be applied to power plants to control emissions of hazardous air pollutants (HAPs) [*16*]. The MATS rule, finalized in December 2011, regulates mercury (Hg) and other HAPs from power plants. MATS applies to Hg and hazardous acid gases, metals, and organics from coal- and oil-fired power plants with nameplate capacities greater than 25 megawatts [*17*]. The standards take effect in 2015.

The *AEO2012* Reference case assumes that all coal-fired generating units with capacity greater than 25 megawatts will comply with the MATS rule beginning in 2015. The MATS rule is not applied to oil-fired steam units in *AEO2012* because of their small size and limited importance. In order to comply with the MATS rule for coal, the NEMS model requires all coal-fired power plants to

Figure 9. States covered by CSAPR limits on emissions of sulfur dioxide and nitrogen oxides



reduce Hg emissions to 90 percent below their uncontrolled emissions levels by using scrubbers and activated carbon injection controls. NEMS does not explicitly model the emissions of acid gases, toxic metals other than Hg, or organic HAPs. Therefore, in order to measure the impact of these rules, specific control technologies—either flue gas desulfurization scrubbers or dry sorbent injection systems—are assumed to be used to achieve compliance. A full fabric filter also is required to meet the limits on emissions of metals other than Hg and to improve the effectiveness of the dry sorbent injection systems. NEMS does not model the best practices associated with reductions in dioxin emissions, which also are covered by the MATS rule.

4. Updated State air emissions regulations

As its first 3-year compliance period came to a close, the Regional Greenhouse Gas Initiative (RGGI) continued to apply to fossil-fuel-fired power plants larger than 25 megawatts capacity in the northeastern United States, despite New Jersey's decision to withdraw from the program at the end of 2011. There are now nine States in the accord, which caps carbon dioxide (CO_2) emissions from covered electricity generating facilities and requires each ton of CO_2 emitted to be offset by an allowance purchased at auction. Because the program is binding, it is included in *AEO2012* as specified in the agreement.

The reduction of CO_2 emissions from the power sector in the RGGI region since 2009 is primarily a result of broader market trends. Since mid-2008, natural gas prices and electricity demand in the Northeast have fallen, while coal prices have increased. Because the RGGI baseline and projected emissions were calculated before the economic recession that began in 2008, the emissions caps are higher than actual emissions have been, leading to an excess of available allowances in recent auctions. In the past seven auctions, allowances have sold at the floor price of $1.89 per ton [*18*], indicating that emissions in the region are at or below the program-mandated ceiling.

As a result of the noncompetitive auctions, in which credits have not actually been traded but simply purchased at a floor price, several States have decided to retire their excess allowances permanently [*19*], which will result in the removal of 67 million tons of CO_2 from the RGGI emissions ceiling. Moreover, the program began a stakeholder hearing process in January 2012 that will last through the summer of 2012. The hearings, which are designed to adjust the program at the end of the first compliance period, may alter the program significantly. Because no changes have been finalized, however, modeling of the provisions in *AEO2012* is the same as in previous *Annual Energy Outlook*s.

The Western Climate Initiative is another program designed to establish a GHG emissions trading program, although the final details of the program remain undecided [*20*]. At the stakeholders meeting in January 2012, the commitment to emissions trading was reaffirmed. Because of the continued uncertainty over the implementation and design of the final program, it is not included in the *AEO2012* projections.

The California cap-and-trade system for GHG emissions, designed by the California Air Resources Board (CARB) in response to California Assembly Bill 32, the Global Warming Solutions Act of 2006 [*21*], is discussed in the following section.

5. California Assembly Bill 32: The Global Warming Solutions Act of 2006

California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, authorized the CARB to set California's GHG reduction goals for 2020 and establish a comprehensive, multi-year program to reduce GHG emissions in California. As one of the major initiatives for AB 32, CARB designed a cap-and-trade program that started on January 1, 2012, with the enforceable compliance obligations beginning in 2013.

The cap-and-trade program is intended to help California achieve its goal of reducing emissions to 1990 levels by 2020. The program covers several GHGs, with the most significant being CO_2 [*22*]. In 2007, CARB determined that 427 million metric tons carbon dioxide equivalent ($MMTCO_2e$) was the total State-wide GHG emissions level in 1990 and, therefore, would be the 2020 emissions target. All electric power plants, large industrial facilities, suppliers of transportation fuel, and suppliers of natural gas in California are required to submit emissions allowances for each ton of CO_2 or CO_2-equivalent emissions they produce, in order to comply with the final rule [*23*]. Emissions resulting from electricity generated outside California but consumed in the State also are subject to the cap.

The cap-and-trade program applies to multiple economic sectors throughout the State's economy, but for *AEO2012*, due to modeling limitations, it is assumed to be implemented only in the electric power sector. *AEO2012* places limits on emissions from electric power plants and cogeneration facilities in California, as well as power plants in other States that sell power to California. The cap is set to begin in 2013 and to decline linearly to 85 percent of the 2013 value by 2020.

The enforceable cap goes into effect in 2013, and there are three compliance periods—multi-year periods for which the compliance obligation is calculated for covered entities. The first compliance period lasts for 2 years, and the second and third periods last for 3 years each, as follows:

- Compliance Period 1: 2013-2014
- Compliance Period 2: 2015-2017
- Compliance Period 3: 2018-2020.

The electricity and industrial sectors are required to comply with the cap starting in 2013. Suppliers of natural gas and transportation fuels are required to comply starting in 2015, when the second compliance period begins. For the first compliance period, covered entities are required to submit allowances for up to 30 percent of their annual emissions in each year; however, at the end of 2014 they are required to account for all the emissions for which they were responsible during the 2-year period.

Annual GHG allowance budgets for the State (i.e., emissions caps) are set by the final rule [*24*] as follows: for 2013, 162.8 $MMTCO_2e$; for 2014, 159.7 $MMTCO_2e$; for 2015, 394.5 $MMTCO_2e$; for 2016, 382.4 $MMTCO_2e$; for 2017, 370.4 $MMTCO_2e$; for 2018, 358.3 $MMTCO_2e$; for 2019, 346.3 $MMTCO_2e$; and for 2020, 334.2 $MMTCO_2e$.

A majority of the allowances (51 percent) [*25*] allocated over the initial 8 years of the program will be distributed through auctions, which will be held quarterly when the program commences. Auctions are set to begin in 2012, and the program caps will take effect in 2013. Revenue gained from the auctions is intended to be used for purposes related to AB 32, as determined by the Governor and the State Legislature.

Twenty-five percent of the allowances are allocated directly to electric utilities that sell electricity to consumers in the State. The utilities are then required to put their allowances up for auction and use the revenue generated from the auction to credit ratepayers. An exception is made for public power agencies, which will be able to keep allowances for compliance.

Seventeen percent of the allowances are allocated directly to industrial facilities covered by the rule, in order to mitigate the economic impact of the cap on the industrial sector. Over the 2013-2020 period, the number of allowances allocated annually to the industrial sector declines linearly, by a total of 50 percent.

The remaining 7 percent of the allowances issued in a given year go into a cost containment reserve and forward reserve auction. The cost containment reserve is intended to be called on only if allowance prices rise above a set amount. Each entity can also use offsets to meet up to 8 percent of its compliance obligation. Offsets used as part of the program must be approved by the CARB.

6. State renewable energy requirements and goals: Update through 2011

To the extent possible, *AEO2012* incorporates the impacts of State laws requiring the addition of renewable generation or capacity by utilities doing business in the States. Currently, 30 States and the District of Columbia have an enforceable renewable portfolio standard (RPS) or similar laws (Table 4). Under such standards, each State determines its own levels of renewable generation, eligible technologies [*26*], and noncompliance penalties. *AEO2012* includes the impacts of all laws in effect at the end of 2011 (with the exception of Alaska and Hawaii, because NEMS provides electricity market projections for the contiguous lower 48 States only). However, the projections do not include policies with either voluntary goals or targets that can be substantially satisfied with nonrenewable resources. In addition, the model is not able to treat fuel-specific provisions—such as those for solar and offshore wind energy—as distinct targets. Where applicable, these distinct targets (sometimes referred to as "tiers," "set-asides," or "carve-outs") may be subsumed into the broader targets, or are not modeled because they may be met with existing capacity and/or projected growth based on modeled economic and policy factors.

In the *AEO2012* Reference case, States generally are assumed to meet their ultimate RPS targets. The RPS compliance constraint in most regions is approximated, because NEMS is not a State-level model, and each State generally represents only a portion of one of the NEMS electricity regions. Compliance costs in each region are tracked, and the projection for total renewable generation is checked for consistency with any State-level cost-control provisions, such as caps on renewable credit prices, limits on State compliance funding, or impacts on consumer electricity prices. In general, EIA has confirmed the States' requirements through original documentation, although the Database of State Incentives for Renewables & Efficiency was also used to support those efforts [*27*].

No new RPS programs were enacted over the past year; however, some States with existing RPS programs made modifications in 2011. The aggregate RPS requirement for the various State programs, as modeled in *AEO2012*, is shown in Figure 10. By 2025, these targets account for about 10 percent of U.S. sales. The requirement is derived from the legal targets and projected sales, and does not account for any discretionary or nondiscretionary waivers or limits on compliance found in most State RPS programs. State RPS policies are not the only driver of growth in renewable generation, and a more complete discussion of those factors can be found in "Market trends." The following sections detail the significant changes made by the States. In addition, Table 4 provides a summary of all State RPS laws.

Figure 10. Total combined requirement for State renewable portfolio standards, 2015-2035 (billion kilowatthours)

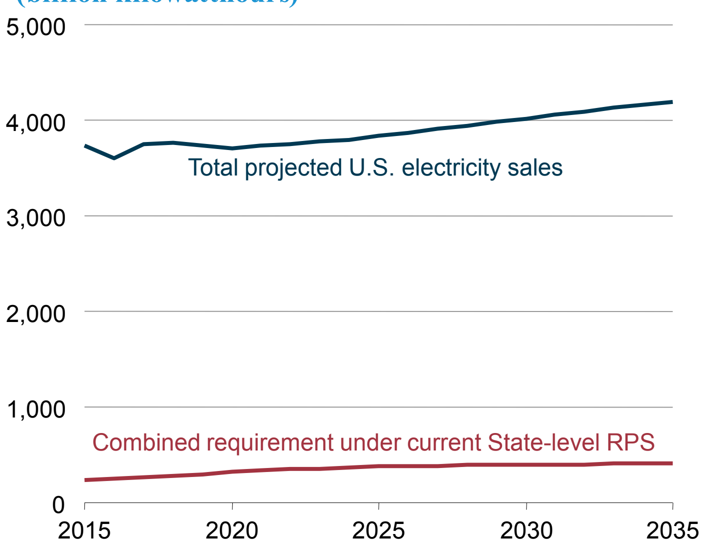


Table 4. Renewable portfolio standards in the 30 States with current mandates

State	Program mandate
AZ	Arizona Corporate Commission Decision No. 69127 requires 15 percent of electricity sales to be renewable by 2025, with interim goals increasing annually. A specific percentage of the target must be from distributed generation. Multiple credits may be provided to solar generation and systems manufactured in-State.
CA	SBX1-2, enacted in 2011, requires that 33 percent of electricity sales be met by renewable sources by 2020. The legislation codifies the 33 percent requirement in Executive Order S-21-09, which served as a continuation of California's first RPS, in which investor-owned utilities (IOUs) were required to deliver 20 percent of sales from renewable sources. Under SBX1-2, both IOUs and publicly owned municipal utilities are subject to the RPS.
CO	Enacted in March of 2010, House Bill (HB) 1001 strengthens the State's existing RPS program by requiring that 20 percent of electricity generated by IOUs in 2015 be renewable, increasing to 30 percent in 2020. There is also a distributed generation requirement. In-State generation receives a 25-percent credit premium.
CT	Public Act 07-242 mandates a 27-percent renewable sales requirement by 2020, including a 4-percent mandate for higher efficiency or combined heat and power systems. Of the overall total, 3 percent may be met by waste-to-energy and conventional biomass facilities.
DE	Senate Substitute 1 amended Senate Bill (SB) 119 to extend the increasing RPS targets to 2025; 25 percent of generation is now required to come from renewable sources in 2025. There is a separate requirement for solar generation (3.5 percent of the total in 2025), and there are penalty payments for compliance failure. Offshore wind generation receives 3.5 times the credit amount, and solar technologies receive 3 times the credit amount.
HI	HB 1464 sets the renewable mandate at 40 percent by 2030. All existing renewable facilities are eligible to meet the target, which has two interim milestones. (Not included in NEMS.)
IL	Public Act 095-0481 created an agency responsible for overseeing the mandate of 25-percent renewable sales by 2025, with escalating annual targets. In addition, 75 percent of the required sales must be generated from wind, 6 percent from solar, and 1 percent from distributed generation. The plan also includes a cap on the incremental costs resulting from the penetration of renewable generation. In 2009, the rule was modified to cover sales outside a utility's home territory.
IA	In 1983, a capacity mandate of 105 megawatts of renewable energy capacity was adopted. By the end of 2010, Iowa had well over 3,000 megawatts of wind-powered capacity alone.
KS	In 2009, HB 2369 established a requirement that 20 percent of installed capacity must use renewable resources by 2020.
ME	In 2007, Public Law 403 was added to the State's RPS requirements. The law requires that 10 percent of sales come from new renewable capacity by 2017, and that level must be maintained in subsequent years. The years leading up to 2017 also have new generation milestones. Generation from eligible community-owned facilities receives a 10-percent credit premium.
MD	In April 2008, HB 375 revised the preceding RPS to contain a 20-percent target by 2022, including a 2-percent solar target. HB 375 also raised penalty payments for "Tier 1" compliance shortfalls to 4 cents per kilowatthour. SB 277, while preserving the 2-percent by 2022 solar target, made the interim solar requirements and penalty payments slightly less stringent. In 2011, SB 717 extended the eligibility of the solar target to include solar water heating systems.
MA	The State RPS has a goal of a 15-percent renewable share of total sales by 2020 and includes necessary payments for compliance shortfalls. Eligible biomass is restricted to low-carbon life cycle emission sources. A Solar Carve-Out Program was also added, which seeks to establish 400 megawatts of solar generating capacity.
MI	Public Act 295, enacted in 2008, established an RPS that will require 10 percent of all electricity sales to be generated from renewable sources by 2015. Double credits are given to solar energy. In addition, the State's large utilities are required to procure an additional combined total of 1,100 megawatts of renewable capacity by 2015, although generation from those facilities may be counted toward the generation-based RPS.
MN	SF 4 created a 30-percent renewable requirement by 2020 for Xcel, the State's largest supplier, and a 25-percent requirement by 2025 for other suppliers. The 30-percent requirement for Xcel consists of 24 percent that must be from wind, 1 percent that can be from wind or solar, and 5 percent that can be from other resources.
MO	In November 2008, Missouri voters approved Proposition C, which mandates a 2-percent renewable energy requirement in 2011, increasing incrementally to 15 percent of generation in 2021. Bonus credits are given to renewable generation within the State.
MT	HB 681, approved in April 2007, expanded the State RPS provisions to all suppliers. Initially the law covered only regulated utilities. A 15-percent share of sales must be renewable by 2015. The State operates a renewable energy credit market.
NV	The State has an escalating renewable target, established in 1997 and most recently revised in 2009 by SB 358, which mandates a 25-percent renewable generation share of sales by 2025. Up to one-quarter of the 25-percent share may be met through efficiency measures. There is also a minimum requirement for photovoltaic systems, which receive bonus credits.

(continued on next page)

Table 4. Renewable portfolio standards in the 30 States with current mandates (continued)

State	Program mandate
NH	HB 873, passed in May 2007, legislated that 23.8 percent of electricity sales must be met by renewables in 2025. Compliance penalties vary by generation type.
NJ	In 2006, the New Jersey Board of Public Utilities revised the State RPS to increase the renewable generation target to 22.5 percent of sales by 2021, with interim targets. Assembly Bill (AB) 3520, enacted in 2010, further refines the mandate to include 5,300 gigawatthours of solar generation by 2026, with the percentage-based RPS component to reach 20.38 percent by 2021, not including the required solar generation. SB 2036 has a specific provision for offshore wind, with a goal to develop 1,100 megawatts of capacity.
NM	SB 418, passed in March 2007, directs investor-owned utilities to derive 20 percent of their sales from renewable generation by 2020. The renewable portfolio must consist of diversified technologies, with wind and solar each accounting for 20 percent of the target. There is a separate standard of 10 percent by 2020 for cooperatives.
NY	The Public Service Commission issued updated RPS rules in January 2010 that expand the program to a 30-percent requirement by 2015. There is also a separate end-use standard. The program is administered and funded by the State.
NC	In 2007, SB 3 created an RPS of 12.5 percent by 2021 for investor-owned utilities. There is also a 10-percent requirement by 2018 for cooperatives and municipals. Through 2018, 25 percent of the target may be met through efficiency standards, increasing to 40 percent in later years. Verifiable electricity demand reduction can also satisfy the RPS, with no upper limit.
OH	SB 221, passed in May 2008, requires 25 percent of electricity sales to be produced from alternative energy resources by 2025, including low-carbon and renewable technologies. One-half of the target must come from renewable sources. Municipals and cooperatives are exempt.
OR	SB 838, signed into law in June 2007, requires that renewable generation account for 25 percent of sales by 2025 for large utilities, and 5 to 10 percent of sales by 2025 for smaller utilities. Renewable electricity on line after 1995 is considered eligible.
PA	The Alternative Energy Portfolio Standard, signed into law in November 2004, has an 18-percent requirement by 2020. Most of the qualifying generation must be renewable, but there is also a provision that allows waste coal resources to receive credits.
RI	The Renewable Energy Standard was signed into law in 2004. The program requires that 16 percent of total sales be renewable by 2019. The interim program targets escalate more rapidly in later years. If the target is not met, a generator must pay an alternative compliance penalty. State utilities also must procure 90 megawatts of new renewable capacity, including 3 megawatts of solar, by 2014.
TX	SB 20, passed in August 2005, strengthened the State RPS by mandating 5,880 megawatts of renewable capacity by 2015. There is also a target of 500 megawatts of renewable capacity other than wind.
WA	In November 2006, Washington voters approved Initiative 937, which specifies that 15 percent of sales from the State's largest generators must come from renewable sources by 2020. There is an administrative penalty of 5 cents per kilowatthour for noncompliance. Generation from any otherwise qualified facility that came on line after 1999 is eligible.
WV	HB 103, passed in June 2009, established a requirement that 25 percent of electricity sales must come from alternative energy resources by 2025. Alternative energy was defined to include various renewables, along with several different fossil energy technologies.
WI	SB 459, passed in March 2006, strengthened the State RPS with a requirement that, by 2015, 10 percent of electricity sales must be generated from renewable resources, and that the renewable share of total generation must be at least 6 percentage points above the average renewable share from 2001 to 2003.

California

The State codified its RPS of 33 percent by 2020 through the passage of SBX1-2, the California Renewable Energy Resources Act [*28*]. The California Public Utilities Commission and California Energy Commission are the primary implementing authorities for SBX1-2, which builds on California's prior RPS mandate for 20 percent of electricity sales by 2010 [*29*]. SBX1-2 extends the application of the RPS to local publicly owned utilities, which had greater flexibility under the State's previous RPS mandate. SBX1-2 supersedes the 2009 Executive Order that charged the CARB with implementing the 33-percent RPS; however, CARB does retain an enforcement role over publicly owned local utilities. Because implementing regulations were not available at the time the *AEO2012* projections were being developed, the 2009 Executive Order was modeled. Although the targets specified in the two programs are similar, enforcement mechanisms may differ significantly.

Connecticut

Public Act 11-80 adds a solar-specific component to the existing RPS target, which requires that renewables should account for 27 percent of sales by 2020 [*30*]. The State's Clean Energy Finance and Investment Authority is tasked with creating an investment program that will result in the procurement of 30 megawatts of residential solar installations that can be counted toward the general RPS requirement.

Delaware

Delaware enacted SB 124, which extends the list of sources eligible to meet the State's RPS to include fuel cells under certain conditions [*31*]. Fuel cell projects that can be fueled by renewable sources and that are owned or operated by qualified providers can apply to earn renewable energy credits and, on a limited basis, solar renewable energy credits.

Illinois

With the enactment of SB 1652, the State augmented its existing RPS to include a distributed generation requirement [*32*]. SB 1652 requires that 1 percent of the renewable target (25 percent of sales from renewable sources by 2025 for large utilities) be fulfilled by distributed generation by mid-2015, with incremental targets beginning to take effect in 2013.

Maryland

The State enacted two pieces of legislation that allow for additional flexibility in meeting the existing RPS target of 20 percent of sales from renewable generation by 2022. SB 690 extends the designation of waste-to-energy facilities as qualifying to meet the 20-percent target beyond 2022, rather than sunsetting [*33*]. In addition, SB 717 specifies that solar water heating systems may also fulfill the solar set-aside requirement, which requires that solar sources account for 2 percent of electricity sales by 2022 [*34*].

North Carolina

North Carolina enacted SB 75, which allows reductions in electricity demand to qualify toward meeting the State's existing renewable energy and energy efficiency portfolio standard. The legislation defines electricity demand reduction as a "measureable reduction in the electricity demand of a retail electric customer that is voluntary, under the real-time control of both the electric power supplier and the retail electric customer, and measured in real time, using two-way communications devices that communicate on the basis of standards" [*35*]. There is no upper limit on the portion of the RPS requirement that can be met by electricity demand reduction.

7. California low carbon fuel standard

The Low Carbon Fuel Standard (LCFS), administered by the CARB [*36*], was signed into law in January 2010. Regulated parties under the legislation generally are the fuel producers and importers who sell motor gasoline or diesel fuel in California. The LCFS legislation is designed to reduce the carbon intensity (CI) of motor gasoline and diesel fuels sold in California by 10 percent between 2012 and 2020 through the increased sale of alternative "low-carbon" fuels. Each alternative low-carbon fuel has its own CI, based on life-cycle analyses conducted under the guidance of CARB for a number of approved fuel pathways. The CIs are calculated on an energy-equivalent basis, measured in grams of CO_2 equivalent emissions per megajoule.

In December 2011, the U.S. District Court for the Eastern Division of California ruled in favor of several trade groups that claimed the LCFS violated the interstate commerce clause of the U.S. Constitution by seeking to regulate farming and ethanol production practices in other States, and granted an injunction blocking enforcement by CARB [*37*]. The future of the LCFS program remains uncertain. After the initial ruling, a request for a stay of the injunction was quickly filed by CARB, which would have allowed the LCFS to remain in place during the appeal process; however, that request was denied by the same judge who initially blocked enforcement of the LCFS [*38*]. A new request for a stay of injunction while CARB appeals the original ruling was filed with the U.S. Ninth District Court of Appeals and was granted as of April 23, 2012 [*39*]. A decision on the appeal filed by CARB is yet to be made. As a result of the initial ruling's timing, along with EIA's prior completion of modeling efforts, the LCFS is not included in the *AEO2012* Reference case [*40*].

Endnotes for Legislation and regulations

Links current as of June 2012

5. A complete list of the laws and regulations included in *AEO2012* is provided in *Assumptions to the Annual Energy Outlook 2012*, Appendix A, website www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2012).pdf.
6. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *Federal Register*, Vol. 76, No. 179 (Washington, DC: September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.
7. U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)," website epa.gov/airtransport.
8. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," website www.epa.gov/mats.
9. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *Federal Register*, Vol. 76, No. 179 (Washington, DC: September 15, 2011), website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.
10. For purposes of this final rulemaking, heavy-duty trucks are those with a gross vehicle weight rating of at least 8,501 pounds, except those Class 2 b vehicles of 8,501 to 10,000 pounds that are currently covered under light-duty vehicle fuel economy and greenhouse gas emissions standards.
11. Congressional Research Service, *Energy Independence and Security Act of 2007: A Summary of Major Provisions*, Order Code RL34294 (Washington, DC: December 2007), website www.seco.noaa.gov/Energy/2007_Dec_21_Summary_Security_Act_2007.pdf.
12. U.S. Environmental Protection Agency, *Cross-State Air Pollution Rule: Reducing Air Pollution, Protecting Public Health* (Washington, DC: December 15, 2011), website www.epa.gov/airtransport/pdfs/CSAPRPresentation.pdf.
13. U.S. Environmental Protection Agency, *Cross-State Air Pollution Rule: Reducing Air Pollution, Protecting Public Health* (Washington, DC: December 15, 2011), Slide 3, website www.epa.gov/airtransport/pdfs/CSAPRPresentation.pdf.
14. T. Schoenberg, B. Wingfield, and J. Johnsson, "EPA Cross-State Emissions Rule Put on Hold by Court," *Bloomberg Businessweek* (January 4, 2012), website www.businessweek.com/news/2012-01-04/epa-cross-state-emissions-rule-put-on-hold-by-court.html.
15. The *AEO2012* Early Release Reference case was prepared before the final MATS rule was issued and, therefore, did not include MATS.
16. U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units," *Federal Register*, Vol. 77, No. 32 (Washington, DC: February 16, 2012), pp. 9304-9513, website www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf.
17. The Clean Air Act, Section 112(a)(8), defines an electric generating unit.
18. Regional Greenhouse Gas Initiative, "CO_2 Auctions, Tracking & Offsets," website www.rggi.org/market.
19. M. Navarro, "Regional Cap-and-Trade Effort Seeks Greater Impact by Cutting Carbon Allowances," *The New York Times* (January 26, 2012), website www.nytimes.com/2012/01/27/nyregion/in-greenhouse-gas-initiative-many-unsold-allowances.html?_r=2.
20. Western Climate Initiative, *WCI Emissions Trading Program Update* (San Francisco, CA: January 12, 2012), website www.westernclimateinitiative.org/document-archives/Partner-Meeting-Materials/Jan-12-Stakeholder-Update-Presentation/%20.
21. California Code of Regulations, Subchapter 10 Climate Change, Article 5, Sections 95800 to 96023, Title 17, "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms" (Sacramento, CA: July 2011), website www.arb.ca.gov/regact/2010/capandtrade10/candtmodreg.pdf.
22. California Code of Regulations, Subchapter 10 Climate Change, Article 5, Sections 95800 to 96023, Title 17, "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms" (Sacramento, CA: July 2011), website www.arb.ca.gov/regact/2010/capandtrade10/candtmodreg.pdf.
23. California Code of Regulations, Subchapter 10 Climate Change, Article 5, Section 95810, "Covered Gases" (Sacramento, CA: July 2011), website www.arb.ca.gov/regact/2010/capandtrade10/candtmodreg.pdf.
24. California Code of Regulations, Subchapter 10 Climate Change, Article 5, Section 95841, "Annual Allowance Budgets for Calendar Years 2013-2020" (Sacramento, CA: July 2011), website www.arb.ca.gov/regact/2010/capandtrade10/candtmodreg.pdf.

25. California Air Resources Board, *Proposed Regulation to Implement the California Cap-and-Trade Program*, Appendix J, "Allowance Allocation" (Sacramento, CA: October 2010), p. 12, website www.arb.ca.gov/regact/2010/capandtrade10/capv4appj.pdf.
26. The eligible technology, and even the definition of the technology or fuel category, will vary by State. For example, one State's definition of renewables may include hydroelectric power generation, while another's definition may not. Table 4 provides more detail on how the technology or fuel category is defined by each State.
27. More information about the Database of State Incentives for Renewables & Efficiency can be found at website www.dsireusa.org/about.
28. State of California, Senate Bill 2, "California Renewable Energy Resources Act" (Sacramento, CA: April 2011), website www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html.
29. State of California, Public Utilities Code, Sections 399.11 to 399.31, website www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=399.11-399.31.
30. State of Connecticut, Public Act 11-80, "An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future" (Hartford, CT: July 1, 2011), website www.cga.ct.gov/2011/ACT/PA/2011PA-00080-R00SB-01243-PA.htm.
31. State of Delaware, Senate Bill 124, "An Act To Amend Title 26 Of The Delaware Code Relating To Delaware's Renewable Energy Portfolio Standards And Delaware-Manufactured Fuel Cells" (Dover, DE: July 7, 2011), website www.legis.delaware.gov/LIS/lis146.nsf/vwLegislation/SB+124/$file/legis.html?open.
32. State of Illinois, Senate Bill 1652, "An Act Concerning Public Utilities" (Springfield, IL: October 26, 2011), website www.ilga.gov/legislation/97/SB/PDF/09700SB1652lv.pdf.
33. State of Maryland, Senate Bill 690, "An Act Concerning Renewable Energy Portfolio – Waste-to-Energy and Refuse-Derived Fuel" (Annapolis, MD: May 29, 2011), website mlis.state.md.us/2011rs/bills/sb/sb0690e.pdf.
34. State of Maryland, Senate Bill 717, "An Act Concerning Renewable Energy Portfolio Standard – Renewable Energy Credits – Solar Water Heating Systems" (Annapolis, MD: May 29, 2011), website http://mlis.state.md.us/2011rs/bills/sb/sb0717e.pdf.
35. General Assembly of North Carolina, Senate Bill 75, "An Act to Promote the Use of Electricity Demand Reduction to Satisfy Renewable Energy Portfolio Standards" (Raleigh, NC: April 28, 2011), website www.ncleg.net/Sessions/2011/Bills/Senate/PDF/S75v4.pdf.
36. California Code of Regulations, Subchapter 10 Climate Change, Article 4, Sections 95480 to 95490, Title 17, Subarticle 7, "Low Carbon Fuel Standard," (Sacramento, CA: July 2011), website www.arb.ca.gov/regact/2009/lcfs09/finalfro.pdf.
37. State of California, "Low Carbon Fuel Standard (LCFS) Supplemental Regulatory Advisory 10-04B" (Sacramento, CA: December 2011), website www.arb.ca.gov/fuels/lcfs/123111lcfs-rep-adv.pdf.
38. Renewable Fuels Association, "Judge Denies California Attempt to Reimplement LCFS" (January 23, 2012), website www.ethanolrfa.org/news/entry/judge-denies-california-attempt-to-reimplement-lcfs.
39. State of California, "LCFS Enforcement Injunction is Lifted" (Sacramento, CA: April 24, 2012), website www.arb.ca.gov/fuels/lcfs/LCFS_Stay_Granted.pdf.
40. The LCFS was included in the *AEO2012* Early Release Reference case, which was completed before the ruling by the Court.

Issues in focus

Introduction

The "Issues in focus" section of the *Annual Energy Outlook (AEO)* provides an in-depth discussion on topics of special interest, including significant changes in assumptions and recent developments in technologies for energy production and consumption. Detailed quantitative results are available in Appendix D. The first topic updates a discussion included in the *Annual Energy Outlook 2011 (AEO2011)* that compared the results of two cases with different assumptions about the future course of existing energy policies. One case assumes the elimination of sunset provisions in existing energy policies; that is, the policies are assumed not to sunset as they would under current law. The other case assumes the extension or expansion of a selected group of existing policies—corporate average fuel economy (CAFE) standards, appliance standards, and production tax credits (PTCs)—in addition to the elimination of sunset provisions.

Other topics discussed in this section as identified by subsection number include (2) oil price and production trends in the *Annual Energy Outlook 2012 (AEO2012)*; (3) potential efficiency improvements and their impacts on end-use energy demand; (4) energy impacts of proposed CAFE standards for light-duty vehicles (LDVs), model years (MYs) 2017 to 2025; (5) impacts of a breakthrough in battery vehicle technology; (6) heavy-duty (HD) natural gas vehicles (NGVs); (7) changing structure of the refining industry; (8) changing environment for fuel use in electricity generation; (9) nuclear power in *AEO2012*; (10) potential impact of minimum pipeline throughput constraints on Alaska North Slope oil production; (11) U.S. crude oil and natural gas resource uncertainty; and (12) evolving Marcellus shale gas resource estimates.

The topics explored in this section represent current and emerging issues in energy markets; but many of the topics discussed in *AEO*s published in recent years also remain relevant today. Table 5 provides a list of titles from the 2011, 2010, and 2009 *AEO*s that are likely to be of interest to today's readers—excluding topics that are updated in *AEO2012*. The articles listed in Table 5 can be found on the U.S. Energy Information Administration (EIA) website at www.eia.gov/analysis/reports.cfm?t=128.

1. No Sunset and Extended Policies cases

Background

The *AEO2012* Reference case is best described as a "current laws and regulations" case, because it generally assumes that existing laws and regulations will remain unchanged throughout the projection period, unless the legislation establishing them sets a sunset date or specifies how they will change. The Reference case often serves as a starting point for the analysis of proposed legislative or regulatory changes. While the definition of the Reference case is relatively straightforward, there may be considerable interest in a variety of alternative cases that reflect the updating or extension of current laws and regulations. In that regard, areas of particular interest include:

- Laws or regulations that have a history of being extended beyond their legislated sunset dates. Examples include the various tax credits for renewable fuels and technologies, which have been extended with or without modifications several times since their initial implementation.

Table 5. Key analyses from "Issues in focus" in recent *AEO*s

AEO2011	*AEO2010*	*AEO2009*
Increasing light-duty vehicle greenhouse gas and fuel economy standards for model years 2017 to 2025	Energy intensity trends in *AEO2010*	Economics of plug-in hybrid electric vehicles
Fuel consumption and greenhouse gas emissions standards for heavy-duty vehicles	Natural gas as a fuel for heavy trucks: Issues and incentives	Impact of limitations on access to oil and natural gas resources in the Federal Outer Continental Shelf
Potential efficiency improvements in alternative cases for appliance standards and building codes	Factors affecting the relationship between crude oil and natural gas prices	Expectations for oil shale production
Potential of offshore crude oil and natural gas resources	Importance of low permeability natural gas reservoirs	Bringing Alaska North Slope natural gas to market
Prospects for shale gas	U.S. nuclear power plants: Continued life or replacement after 60?	Natural gas and crude oil prices in *AEO2009*
Cost uncertainties for new electric power plants	Accounting for carbon dioxide emissions from biomass energy combustion	Greenhouse gas concerns and power sector planning
Carbon capture and storage: Economics and issues		Tax credits and renewable generation
Power sector environmental regulations on the horizon		

- Laws or regulations that call for the periodic updating of initial specifications. Examples include appliance efficiency standards issued by the U.S. Department of Energy (DOE), and CAFE and greenhouse gas (GHG) emissions standards for vehicles issued by the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA).
- Laws or regulations that allow or require the appropriate regulatory agency to issue new or revised regulations under certain conditions. Examples include the numerous provisions of the Clean Air Act that require the EPA to issue or revise regulations if it finds that an environmental quality target is not being met.

To provide some insight into the sensitivity of results to scenarios in which existing tax credits do not sunset, two alternative cases are discussed in this section. No attempt is made to cover the full range of possible uncertainties in these areas, and readers should not view the cases discussed as EIA projections of how laws or regulations might or should be changed.

Analysis cases

The two cases prepared—the No Sunset and Extended Policies cases—incorporate all the assumptions from the *AEO2012* Reference case, except as identified below. Changes from the Reference case assumptions in these cases include the following.

No Sunset case

- Extension through 2035 of the PTC for cellulosic biofuels of up to $1.01 per gallon (set to expire at the end of 2012).
- Extension of tax credits for renewable energy sources in the utility, industrial, and buildings sectors or for energy-efficient equipment in the buildings sector, including:
  - The PTC of 2.2 cents per kilowatthour or the 30-percent investment tax credit (ITC) available for wind, geothermal, biomass, hydroelectric, and landfill gas resources, currently set to expire at the end of 2012 for wind and 2013 for the other eligible resources, are assumed to be extended indefinitely.
  - For solar power investment, a 30-percent ITC that is scheduled to revert to a 10-percent credit in 2016 is, instead, assumed to be extended indefinitely at 30 percent.
  - In the buildings sector, tax credits for the purchase of energy-efficient equipment, including photovoltaics (PV) in new houses, are assumed to be extended indefinitely, as opposed to ending in 2011 or 2016 as prescribed by current law. The business ITCs for commercial-sector generation technologies and geothermal heat pumps are assumed to be extended indefinitely, as opposed to expiring in 2016; and the business ITC for solar systems is assumed to remain at 30 percent instead of reverting to 10 percent.
  - In the industrial sector, the ITC for combined heat and power (CHP) that ends in 2016 in the *AEO2012* Reference case is assumed to be preserved through 2035, the end of the projection period.

Extended Policies case

The Extended Policies case includes additional updates in Federal equipment efficiency standards that were not considered in the Reference case or No Sunset case. Residential end-use technologies subject to updated standards are not eligible for tax credits in addition to the standards. Also, the PTC for cellulosic biofuels beyond 2012 is not included because the renewable fuel standard (RFS) program that is already included in the *AEO2012* Reference case tends to be the binding driver of cellulosic biofuels use. Other than these exceptions, the Extended Policies case adopts the same assumptions as the No Sunset case, plus the following:

- Federal equipment efficiency standards are updated at periodic intervals, consistent with the provisions in the existing law, with the levels based on ENERGY STAR specifications, or Federal Energy Management Program (FEMP) purchasing guidelines for Federal agencies. Standards are also introduced for products that are not currently subject to Federal efficiency standards.
- Updated Federal residential and commercial building energy codes reach 30-percent improvement in 2020 relative to the 2006 International Energy Conservation Code in the residential sector and the American Society of Heating, Refrigerating and Air-Conditioning Engineers Building Energy Code 90.1-2004 in the commercial sector. Two subsequent rounds in 2023 and 2026 each add an assumed 5-percent incremental improvement to building energy codes.

  The equipment standards and building codes assumed for the Extended Policies case are meant to illustrate the potential effects of these policies on energy consumption for buildings. No cost-benefit analysis or evaluation of impacts on consumer welfare was completed in developing the assumptions. Likewise, no technical feasibility analysis was conducted, although standards were not allowed to exceed “maximum technologically feasible” levels described in DOE’s technical support documents.
- The *AEO2012* Reference, No Sunset, and Extended Policies cases include both the attribute-based CAFE standards for LDVs for MY 2011 and the joint attribute-based CAFE and vehicle GHG emissions standards for MY 2012 to MY 2016. However, the Reference and No Sunset cases assume that LDV CAFE standards increase to 35 miles per gallon (mpg) by MY 2020, as called for in the Energy Independence and Security Act of 2007 (EISA2007), and that the CAFE standards are then held constant in subsequent model years, although the fuel economy of new LDVs continues to rise modestly over time.

  The Extended Policies case modifies the assumption in the Reference and No Sunset cases by assuming the incorporation of the proposed CAFE standards recently announced by the EPA and NHTSA for MY 2017 through MY 2025, which call for an annual average increase in fuel economy for new LDVs of 3.9 percent. After 2025, CAFE standards are assumed to increase at an average annual rate of 1.5 percent through 2035.

- In the industrial sector, the ITC for CHP is extended to cover all system sizes (limited to only capacities between 25 and 50 megawatts in the Reference case), which may include multiple units. Also, the ITC is modified to increase the eligible CHP unit cap from 15 megawatts to 25 megawatts. These extensions are consistent with previously proposed or pending legislation.

Analysis results

The changes made to Reference case assumptions in the No Sunset and Extended Policies cases generally lead to lower estimates for overall energy consumption, increased use of renewable fuels, particularly for electricity generation, and reduced energy-related emissions of carbon dioxide (CO_2). Because the Extended Policies case includes most of the assumptions in the No Sunset case but adds others, the impacts in the Extended Policies case tend to be greater than those in the No Sunset case. Although these cases show lower energy prices—because the tax credits and end-use efficiency standards lead to lower energy demand and reduce the cost of renewable fuels—consumers spend more on appliances that are more efficient in order to comply with the tighter appliance standards, and the Government receives lower tax revenues as consumers and businesses take advantage of the tax credits.

Energy consumption

Total energy consumption in the No Sunset case is close to the level in the Reference case (Figure 11). Improvements in energy efficiency lead to reduced consumption in this case, but somewhat lower energy prices lead to higher relative consumption, offsetting some of the impact of the improved efficiency.

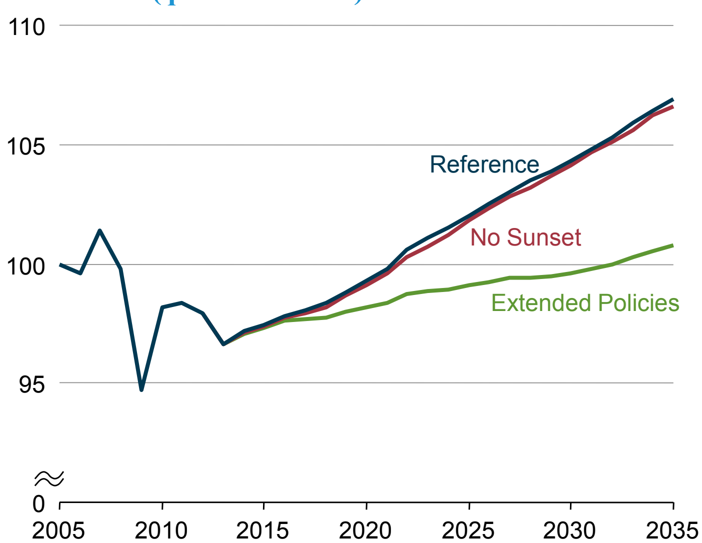
Total energy consumption growth in the Extended Policies case is markedly below the Reference case projection. In 2035, total energy consumption in the Extended Policies case is nearly 6 percent below its projected level in the Reference case.

Buildings energy consumption

The No Sunset case extends tax credits for residential and commercial renewable energy systems and for the purchase of energy-efficient residential equipment. The Extended Policies case builds on the No Sunset case by assuming updated Federal equipment efficiency standards and new standards for some products that are not currently subject to standards. For residential end-use technologies subject to standards, updated standards are assumed to replace any extension of incentives from the No Sunset case. Federal residential and commercial building energy codes are also improved as described above. Renewable distributed generation (DG) technologies (PV systems and wind turbines) provide much of the buildings-related energy savings in the No Sunset case. Extended tax credits in the No Sunset case spur increased adoption of renewable DG systems, leading to 110 billion kilowatthours of onsite electricity generation in 2035—more than four times the amount of onsite electricity generated in 2035 in the Reference case. Similar adoption of renewable DG takes place in the Extended Policies case. With the additional efficiency gains from assumed future standards and more stringent building codes, delivered energy consumption for buildings in 2035 is 6.8 percent (1.5 quadrillion Btu) lower in the Extended Policies case than in the Reference case, a reduction nearly five times as large as the 1.4-percent (0.3 quadrillion Btu) reduction in the No Sunset case.

Electricity use shows the largest reduction relative to the Reference case, with buildings electricity consumption 2.4 percent and 8.2 percent lower, respectively, in the No Sunset and Extended Policies cases in 2035. Space heating and cooling are affected by both assumed standards and building codes, leading to significant savings in energy consumption for heating and cooling in the Extended Policies case. In 2035, energy use for space heating in buildings is 6.9 percent lower, and energy use for space cooling is 17.3 percent lower, in the Extended Policies case than in the Reference case. In addition to improved standards and codes, extended tax credits for PV prompt increased adoption, offsetting some of the purchased electricity for cooling. New standards for televisions and for personal computers (PCs) and related equipment in the Extended Policies case lead to savings of 20.6 percent and 18.2 percent, respectively, in residential electricity use by this equipment in 2035 relative to the Reference case. Residential and commercial natural gas use declines from 8.3 quadrillion Btu in 2010 to 7.9 quadrillion Btu in 2035 in the Extended Policies case, representing a 6.2-percent reduction from the Reference case in 2035.

Figure 11. Total energy consumption in three cases, 2005-2035 (quadrillion Btu)



Industrial energy consumption

The Extended Policies case modifies the Reference case by extending the existing industrial CHP ITC through the end of the projection period, expanding it to include all industrial CHP system sizes, and raising the maximum credit that can be claimed from 15 megawatts of installed capacity to 25 megawatts. These assumptions are based on the current proposals in H.R. 2750 and H.R. 2784 of the 112th Congress. The changes result in 2.7 gigawatts of additional industrial CHP capacity over the Reference case level in 2035. Natural gas consumption in the industrial sector (excluding refining) increases from 7.3 quadrillion Btu in the Reference case to 7.4 quadrillion Btu in the Extended Policies case, a 1.6-percent rise. Electricity purchases are nearly unchanged in the Extended Policies case, as additional demand for electricity relative to the Reference case is fulfilled almost exclusively by increased generation from CHP.

Transportation energy consumption

The Extended Policies case modifies the Reference case and No Sunset case by assuming the incorporation of the CAFE standards recently proposed by the EPA and NHTSA for MY 2017 through 2025, which call for a 3.9-percent annual average increase in fuel economy for new LDVs, with CAFE standards applicable after 2025 assumed to increase at an average annual rate of 1.5 percent through 2035. Sales of vehicles that do not rely solely on a gasoline internal combustion engine for both motive and accessory power (including those that use diesel, alternative fuels, and/or hybrid electric systems) play a substantial role in meeting the higher fuel economy standards, growing to almost 80 percent of new LDV sales in 2035, compared with about 35 percent in the Reference case.

LDV energy consumption declines in the Extended Policies case, from 16.6 quadrillion Btu (8.9 million barrels per day) in 2010 to 12.9 quadrillion Btu (7.3 million barrels per day) in 2035, about a 20-percent reduction from the Reference case in 2035. Petroleum and other liquids fuels consumption in the transportation sector declines in the Extended Policies case, from 13.8 million barrels per day in 2010 to 12.7 million barrels per day in 2035, compared to an increase in the Reference case to 14.4 million barrels per day (Figure 12).

Renewable electricity generation

The extension of tax credits for renewables through 2035 would, over the long run, lead to more rapid growth in renewable generation than in the Reference case. When the renewable tax credits are extended without extending energy efficiency standards, as is assumed in the No Sunset case, there is a significant increase in renewable generation in 2035 relative to the Reference case (Figure 13). Extending both renewable tax credits and energy efficiency standards (Extended Policies case) results in more modest growth in renewable generation, because renewable generation in the near term is a significant source of new generation to meet load growth, and enhanced energy efficiency standards tend to reduce overall electricity consumption and the need for new generation resources.

In the No Sunset and Extended Policies cases, renewable generation more than doubles from 2010 to 2035, as compared with a 77-percent increase in the Reference case. In 2035, the share of total electricity generation accounted for by renewables is between 19 and 20 percent in both the No Sunset and Extended Policies cases, as compared with 15 percent in the Reference case.

In all three cases, the most rapid growth in renewable capacity occurs in the very near term, largely as the result of projects already under construction or planned. After that, the growth slows through 2020 before picking up again. Some of the current surge of renewable capacity additions is occurring in anticipation of the expiration of Federal incentives within the next year (for wind) or two (for other renewable fuels except solar). Results from the No Sunset and Extended Policies cases indicate that, given sufficient

Figure 12. Consumption of petroleum and other liquids for transportation in three cases, 2005-2035 (million barrels per day)

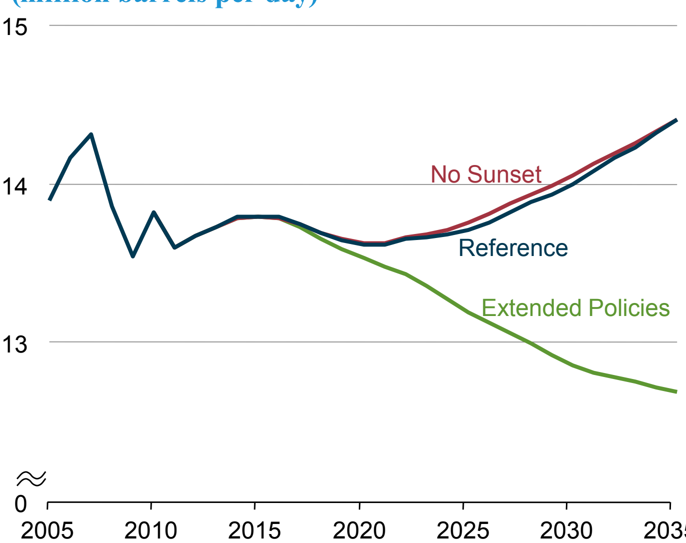
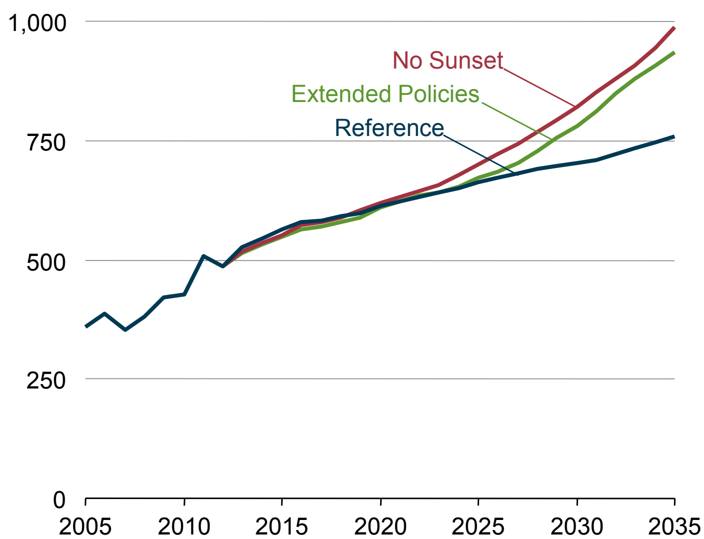


Figure 13. Renewable electricity generation in three cases, 2005-2035 (billion kilowatthours)



lead time, a long-term extension of these expiring provisions could result in the postponement of some near-term activity to better match projected patterns of load growth. With slow growth in electricity demand and the addition of capacity stimulated by renewable incentives, little new capacity is needed between 2015 and 2020. In addition, in some regions, attractive low-cost renewable resources already have been developed, leaving only less favorable sites that may require significant investment in transmission as well as other additional infrastructure costs. Starting around 2020, significant new sources of renewable generation also appear on the market as a result of cogeneration at biorefineries built primarily to produce renewable liquid fuels to meet the Federal RFS, where combustion of waste products to produce electricity is an economically attractive option.

Between 2020 and 2025, renewable generation in the No Sunset and Extended Policies cases starts to increase more rapidly than in the Reference case, and, as a result, generation from nuclear and fossil fuels is reduced from the levels in the Reference case. Natural gas represents the largest source of displaced generation. In 2035, electricity generation from natural gas is 11 percent lower in the No Sunset case and 15 percent lower in the Extended Policies case than in the Reference case (Figure 14).

Energy-related CO_2 emissions

In the No Sunset and Extended Policies cases, lower overall energy demand leads to lower levels of energy-related CO_2 emissions than in the Reference case. The Extended Policies case shows much larger emissions reductions than the No Sunset and Reference cases, due in part to the inclusion of tighter LDV fuel economy standards for MY 2017 through MY 2035. From 2010 to 2035, energy-related CO_2 emissions are reduced by a cumulative total of 4.3 billion metric tons (a 3.0-percent reduction over the period) in the Extended Policies case from the Reference case projection, as compared with 0.9 billion metric tons (a 0.6-percent reduction over the period) in the No Sunset case (Figure 15). The increase in fuel economy standards assumed for new LDVs in the Extended Policies case is responsible for more than 40 percent of the total reduction in CO_2 emissions in 2035 in comparison with the Reference case. The balance of the reduction in CO_2 emissions is a result of greater improvement in appliance efficiencies and increased penetration of renewable electricity generation.

The majority of the emissions reductions in the No Sunset case result from increases in renewable electricity generation. Consistent with current EIA conventions and EPA practice, emissions associated with the combustion of biomass for electricity generation are not counted, because they are assumed to be balanced by carbon uptake when the feedstock is grown. A small reduction in transportation sector emissions in the No Sunset case is counterbalanced by an increase in emissions from refineries during the production of synthetic fuels that receive tax credits. Relatively small incremental reductions in emissions are attributable to renewables in the Extended Policies case, mainly because electricity demand is lower than in the Reference case, reducing the consumption of all fuels used for generation, including biomass.

In the residential sector, in both the No Sunset and Extended Policies cases, water heating, space cooling, and space heating together account for most of the emissions reductions from Reference case levels. In the commercial sector, only the Extended Policies case projects substantial reductions of emissions in those categories. In the industrial sector, the Extended Policies case projects reduced emissions as a result of decreases in electricity purchases and petroleum use that are partially offset by increased reliance on natural gas—for example, increased use of natural gas fired industrial CHP.

Energy prices and tax credit payments

With lower levels of overall energy use and more consumption of renewable fuels in the No Sunset and Extended Policies cases, energy prices are lower than in the Reference case. In 2035, natural gas wellhead prices are $0.44 per thousand cubic feet (6.6

Figure 14. Electricity generation from natural gas in three cases, 2005-2035 (billion kilowatthours)

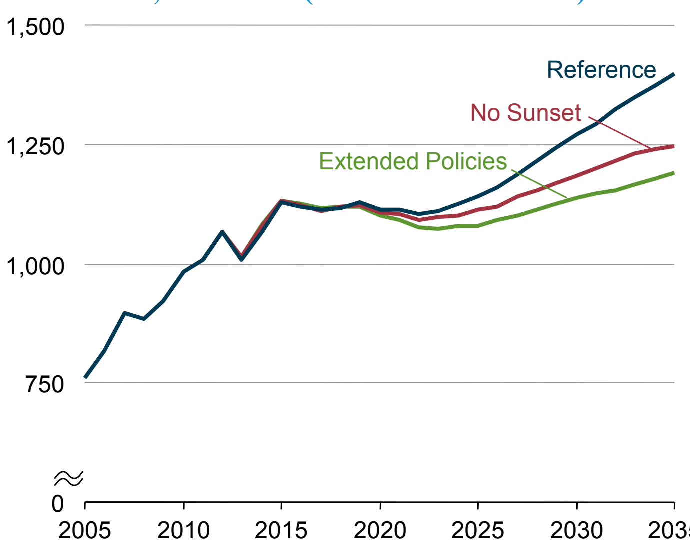
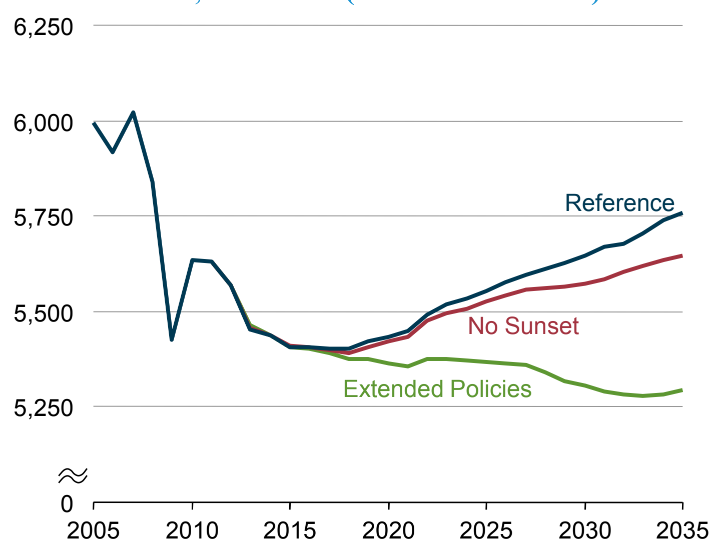


Figure 15. Energy-related carbon dioxide emissions in three cases, 2005-2035 (million metric tons)



percent) and $0.82 per thousand cubic feet (12.3 percent) lower in the No Sunset and Extended Policies cases, respectively, than in the Reference case (Figure 16), and electricity prices are about 2 percent and 5 percent lower than in the Reference case (Figure 17).

The reductions in energy consumption and CO_2 emissions in the Extended Policies case are accompanied by higher equipment costs for consumers and revenue reductions for the U.S. Government. From 2012 to 2035, residential and commercial consumers spend, on average, an additional $19 billion per year (in 2010 dollars) for newly purchased end-use equipment, distributed generation systems, and residential building shell improvements in the Extended Policies case as compared with the Reference case. On the other hand, they save an average of $22 billion per year on energy purchases.

Tax credits paid to consumers in the buildings sector (or, from the Government's perspective, reduced revenue) in the No Sunset case average $5 billion (real 2010 dollars) more per year than in the Reference case, which assumes that existing tax credits expire as currently scheduled, mostly by 2016.

The largest response to Federal tax incentives for new renewable generation is seen in the No Sunset case, with extension of the PTC and the 30-percent ITC resulting in annual average reductions in Government tax revenues of approximately $2.5 billion from 2011 to 2035, as compared with $520 million per year in the Reference case. Additional reductions in Government tax revenue in the No Sunset case result from extensions of the cellulosic biofuels PTC. These reductions increase rapidly from $52 million in 2013 to $7.2 billion (2010 dollars) in 2035 (a cumulative total of $75.1 billion) in comparison with the Reference case.

2. Oil price and production trends in *AEO2012*

The oil price in *AEO2012* is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, which is similar to the price for light, sweet crude oil, West Texas Intermediate (WTI), traded on the New York Mercantile Exchange. *AEO2012* also includes a projection of the U.S. annual average refiners' acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by domestic refiners. Currently there is a price differential between WTI and similar-quality marker crude oils delivered to international ports via tanker (e.g., Brent and Louisiana Light Sweet crudes). The *AEO2012* Reference case assumes that the large discrepancy will fade over time, as construction of more adequate pipeline capacity between Cushing and the Gulf of Mexico eases transportation of crude oil supplies to and from U.S. refineries.

Oil prices are influenced by a number of factors, including some that have mainly short-term impacts. Other factors, such as the Organization of the Petroleum Exporting Countries (OPEC) production decisions and expectations about future world demand for petroleum and other liquids, affect prices in the longer term. Supply and demand in the world oil market are balanced through responses to price movements, and the factors underlying supply and demand expectations are both numerous and complex. The key factors determining long-term supply, demand, and prices for petroleum and other liquids can be summarized in four broad categories: the economics of non-OPEC supply, OPEC investment and production decisions, the economics of other liquids supply, and world demand for petroleum and other liquids.

AEO2012 includes projections of future supply and demand for "petroleum and other liquids." The term "petroleum" refers to crude oil (including tight oil from shale [also referred to as shale oil], chalk, and other low-permeability formations), lease condensate, natural gas plant liquids, and refinery gain. The term "other liquids" refers to biofuels, bitumen (oil sands), coal-to-liquids (CTL), biomass-to-liquids (BTL), gas-to-liquids (GTL), extra-heavy oils (technically petroleum but grouped in "other liquids" in this report), and oil shale [*41*].

Figure 16. Natural gas wellhead prices in three cases, 2005-2035 (2010 dollars per thousand cubic feet)

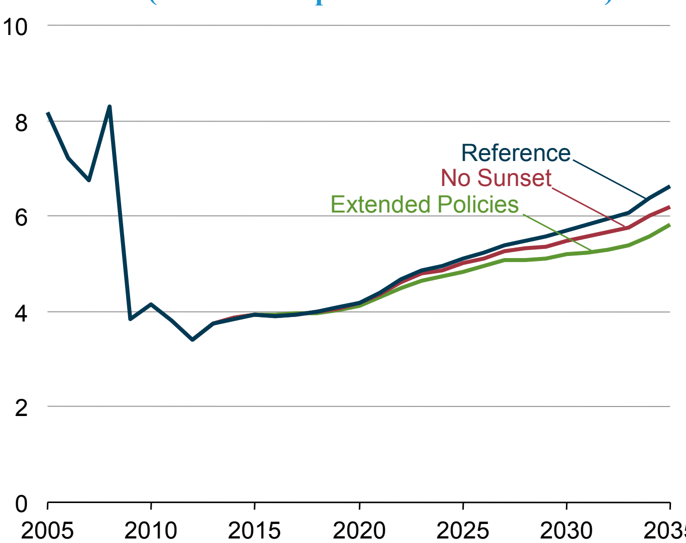
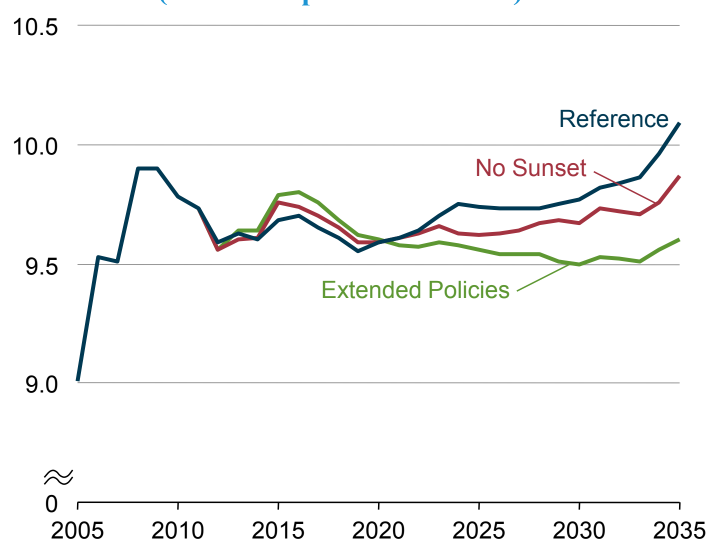


Figure 17. Average electricity prices in three cases, 2005-2035 (2010 cents per kilowatthour)



Reference case

The global oil market projections in the *AEO2012* Reference case are based on the assumption that current practices, politics, and levels of access will continue in the near to mid-term. The Reference case assumes that continued robust economic growth in the non-Organization for Economic Cooperative Development (OECD) nations, including China and India, will more than offset slower growth projected for many OECD nations. In the Reference case, non-OECD petroleum and other liquids consumption is about 21 million barrels per day higher in 2035 than it was in 2010, but OECD consumption grows by less than 2 million barrels per day over the same period. Total world consumption of petroleum and other liquids grows to 106 million barrels per day in 2030 and 110 million barrels per day in 2035.

The Reference case also assumes that limitations on access to resources in many areas restrain the growth of non-OPEC petroleum liquids production over the projection period, and that OPEC production maintains a relatively constant share of total world petroleum and other liquids supply—between 40 and 42 percent. With those constraining factors, satisfying the growing world demand for petroleum and other liquids in coming decades requires production from higher-cost resources, particularly for non-OPEC producers with technically challenging supply projects. In the Reference case, the increased cost of non-OPEC supplies, a constant OPEC market share, and easing of Cushing WTI infrastructure constraints combine to support average increases in real oil prices of about 5 percent per year from 2010 to 2020 and about 1 percent per year from 2020 to 2035. In 2035, the average real price of crude oil in the Reference case is $145 per barrel in 2010 dollars (Figure 18). The rapid increase in the near term is based on the assumption that the WTI price will return to parity with Brent by 2016 as current constraints on pipeline capacity between Cushing and the Gulf of Mexico are eliminated.

Increases in non-OPEC production of petroleum and other liquids in the Reference case come primarily from high-cost petroleum liquids projects in areas with inconsistent or unreliable fiscal or political regimes and from increasingly expensive other liquids projects that are made economical by rising oil prices and advances in production technology (Figure 19). Bitumen production in Canada and biofuels production mostly from the United States and Brazil are the most important components of the world's incremental supply of other liquids from 2010 to 2035 in the Reference case.

Low Oil Price case

In the Low Oil Price case, non-OECD economic growth is lower than in the Reference case, leading to slower growth in demand for petroleum and other liquids. Lower demand, combined with greater access to and production of petroleum liquids resources, results in sustained lower oil prices. In particular, the Low Oil Price case focuses on demand in non-OECD countries, where uncertainty about future growth is much higher than in the mature economies of the OECD. The Low Oil Price case assumes that oil prices fall steadily after 2011 to about $58 per barrel in 2017, then rise slowly to $62 per barrel in 2035. Growth in world demand for petroleum and other liquids is slowed by lower gross domestic product (GDP) growth in the non-OECD countries than is projected in the Reference case. Average annual GDP growth in the non-OECD nations is assumed to be 1.5 percentage points lower than in the Reference case, increasing by only 3.5 percent per year from 2010 to 2035. As a result, non-OECD demand for petroleum and other liquids in 2035 is 7 million barrels per day lower than in the Reference case, and total world consumption in 2035 is 2 million barrels per day lower, at 107 million barrels per day.

In the Low Oil Price case, the market power of OPEC producers is weakened, and they lose the ability to control prices and limit production. As a result, the OPEC market share of world petroleum and other liquids production is 46 percent in 2035, as

Figure 18. Average annual world oil prices in three cases, 1980-2035 (2010 dollars per barrel)

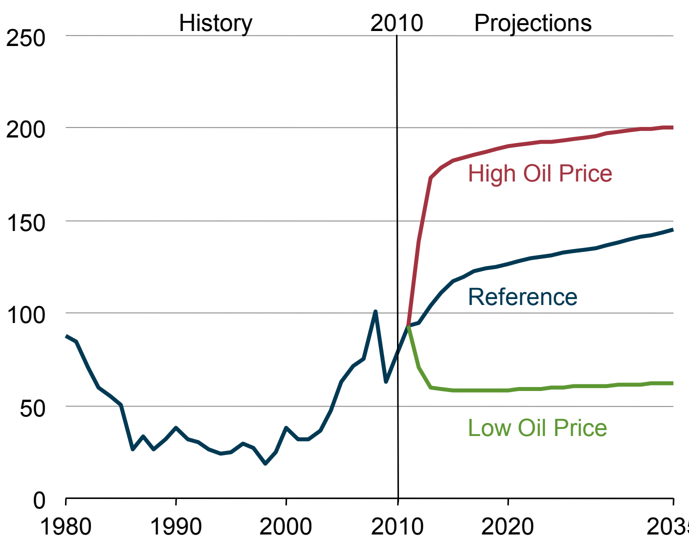
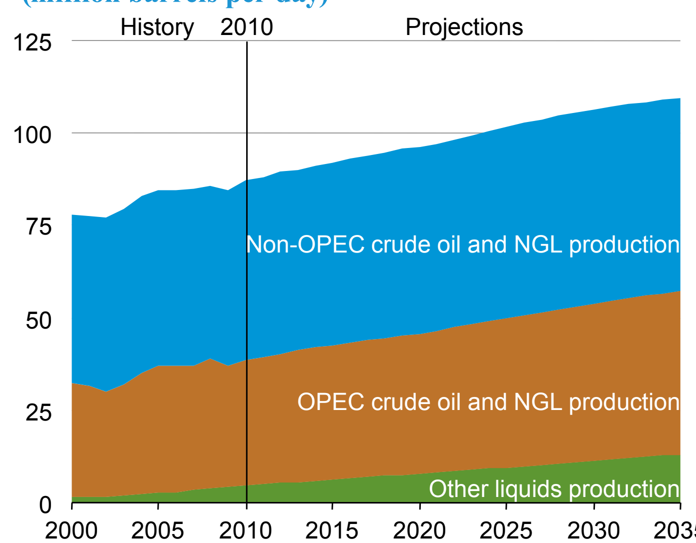


Figure 19. World petroleum and other liquids production in the Reference case, 2000-2035 (million barrels per day)



compared with 40 to 42 percent in the Reference case. Despite lower prices, non-OPEC levels of petroleum liquids production are maintained until about 2020, as projects currently underway or planned are completed and begin production. After 2020, non-OPEC petroleum liquids production declines as existing fields are depleted and not fully replaced by production from new fields and higher cost enhanced recovery technologies.

The Low Oil Price case assumes that technologies for producing biofuels, bitumen, CTL, BTL, GTL and extra-heavy oils achieve much lower costs than in the Reference case. As a result, production of those liquids increases to 16 million barrels per day in 2035 despite significantly lower oil prices.

High Oil Price case

In the High Oil Price case, the assumption of high demand for petroleum and other liquids in the non-OECD nations, combined with more constrained supply availability, results in higher oil prices than in the Reference case. Oil prices ramp up quickly to $186 per barrel (2010 dollars) in 2017 and continue rising slowly thereafter, to about $200 per barrel in 2035. The higher prices result from higher demand for petroleum and other liquid fuels in the non-OECD nations, resulting from the assumption of higher economic growth than in the Reference case. Specifically, GDP growth rates for China and India in 2012 are 1.0 percentage point higher than in the Reference case, and 0.3 percentage point higher in 2035. For most other non-OECD regions, GDP growth rates average about 0.5 percentage point above the Reference case in 2012. For the OECD regions, where prices rather than a higher economic growth rate are the main factor affecting demand, consumption of petroleum and other liquids remains fairly flat over the projection.

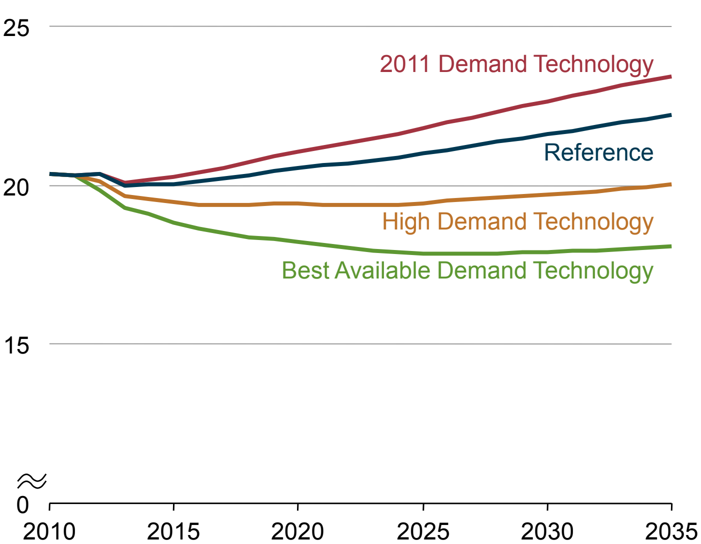
On the supply side, OPEC countries are assumed to reduce their market share somewhat, to less than 41 percent through 2035. Non-OPEC petroleum liquids resources outside the United States are assumed to be less accessible and/or more costly to produce than in the Reference case, and higher prices make other liquids supply more attractive. In 2035, other liquids production totals 17 million barrels per day in the High Oil Price case, about 4 million barrels per day above the Reference case level, and other liquids account for 15 percent of the total supply of petroleum and other liquids.

3. Potential efficiency improvements and their impacts on end-use energy demand

In 2010, the residential and commercial buildings sectors used 20.4 quadrillion Btu of delivered energy, or 28 percent of total U.S. energy consumption. The residential sector accounted for 57 percent of that energy use and the commercial sector 43 percent. In the *AEO2012* Reference case, delivered energy for buildings increases by a total of 9 percent, to 22.2 quadrillion Btu in 2035, which is modest relative to the rate of increase in the number of buildings and their occupants. In contrast, the U.S. population increases by 25 percent, commercial floorspace increases by 27 percent, and the number of households increases by 28 percent. Accordingly, energy use in the buildings sector on a per-capita basis declines in the projection. The decline of buildings energy use per capita in past years has been attributable in part to improvements in the efficiencies of appliances and building shells, and efficiency improvements continue to play a key role in projections of buildings energy consumption.

Existing policies, such as Federal appliance standards, along with evolving State policies, and market forces, are drivers of energy efficiency in the United States. A number of recent changes in the broader context of the U.S. energy system that affect energy prices, such as advances in shale gas extraction and the economic slowdown, also have the potential to affect the dynamics of energy efficiency improvement in the U.S. buildings sector. Although these influences are important, technology improvement remains a critical factor for energy use in the buildings sector. The emphasis for this analysis is on fundamental factors, particularly technology factors, that affect energy efficiency, rather than on potential policy or regulatory options.

Figure 20. Residential and commercial delivered energy consumption in four cases, 2010-2035 (quadrillion Btu)



Three alternative cases in *AEO2012* illustrate the impacts of different assumptions for rates of technology improvement on delivered energy use in the residential and commercial sectors (Figure 20). These cases are in addition to the Extended Policies and No Sunset cases discussed earlier, and they are intended to provide a broader perspective on changes in demand-side technologies. In the High Demand Technology case, high-efficiency technologies are assumed to penetrate end-use markets at lower consumer hurdle rates, with related assumptions in the transportation and industrial sectors. In the Best Available Demand Technology case, new equipment purchases are limited to the most efficient versions of technologies available in the residential and commercial buildings sectors regardless of cost. In the

2011 Demand Technology case, future equipment purchases are limited to the options available in 2011 ("frozen technology"), and 2011 building codes remain unchanged through 2035. Like the High Demand and Best Available Demand Technology cases, the 2011 Demand Technology case includes all current Federal standards.

Without the benefits of technology improvement, buildings energy use in the 2011 Demand Technology case grows to 23.4 quadrillion Btu in 2035, as compared with 22.2 quadrillion Btu in the Reference case. In the High Demand Technology case, energy delivered to the buildings sectors only reaches about 20 quadrillion Btu for any year in the projection period, and in the Buildings Best Available Demand Technology case it declines to 17.9 quadrillion Btu in 2026 before rising slightly to 18.1 quadrillion Btu in 2035.

Background

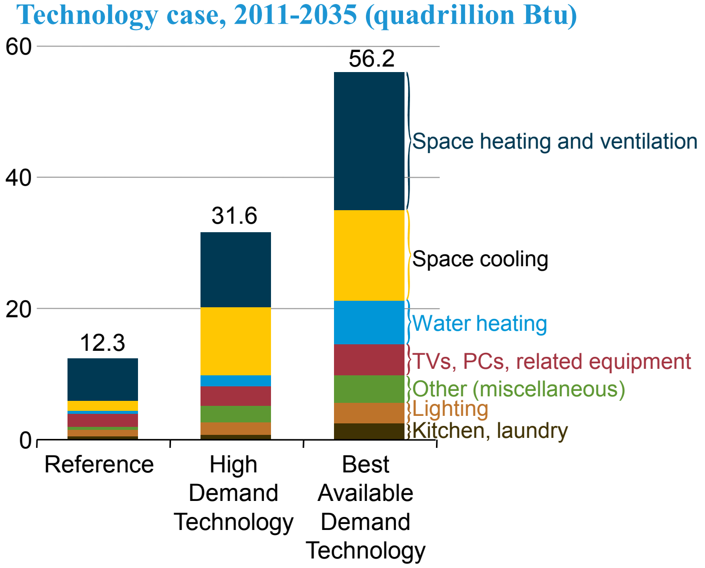
The residential and commercial sectors together are referred to as the "buildings sector." The cases discussed here are not policy-driven scenarios but rather "what-if" cases used to illustrate the impacts of alternative technology penetration trajectories on buildings sector energy use. In a general sense, this approach can be understood as reflecting uncertainty about technological progress itself, or uncertainty about consumer behavior, in that the market response to a new technology is uncertain. This type of uncertainty is being studied through market research, behavioral economics, and related disciplines that examine how purchasers perceive options, differentiate products, and react to information over time. By varying technology progress across the full range of end uses, the integrated demand cases provide estimates of potential changes in energy savings that, in reality, are likely to be less uniform and more specific to certain end uses, technologies, and consumer groups. Specific assumptions for each of the cases are summarized in Tables 6 and 7.

Results for the residential sector

To emphasize that efficiency is persistent and its effects accumulate over time, energy use is discussed in terms of cumulative reductions (2011-2035) relative to a case with no future advances in technology after 2011. An extensive range of residential equipment is covered by Federal efficiency standards, and the continuing effects of those standards contribute to the cumulative reduction in delivered energy use of 12.3 quadrillion Btu through 2035 in the Reference case relative to the 2011 Demand Technology case. Electricity and natural gas account for more than 85 percent of the difference, each showing a cumulative reduction greater than 5 quadrillion Btu over the period. Energy use for space heating shows the most improvement in the Reference case, affected by improvements in building shells and heating equipment (Figure 21). Televisions and PCs and related equipment use 1.9 quadrillion Btu less energy over the projection period, as devices with energy-saving features continue to penetrate the market, and laptops continue to gain market share over desktop PCs.

Cumulative savings in residential energy use from 2011 to 2035 total 31.6 quadrillion Btu in the High Demand Technology case and 56.2 quadrillion Btu in the Best Available Demand Technology case in comparison with the 2011 Demand Technology case. Electricity accounts for the largest share of the reductions in the High Demand Technology case (49 percent) and the Best Available Demand Technology case (51 percent). In addition to adopting more optimistic assumptions in the High Demand Technology and Best Available Demand Technology cases for end-use equipment, residential PV and wind technologies are assumed to have greater cost declines than in the Reference case, contributing to reductions in purchased electricity. In 2035, residential PV and wind systems produce 23 billion kilowatthours more electricity in the Best Available Demand Technology case than in the 2011 Demand Technology case.

Figure 21. Cumulative reductions in residential energy consumption relative to the 2011 Demand Technology case, 2011-2035 (quadrillion Btu)



In the High Demand Technology and Best Available Demand Technology cases, energy use for residential space heating again shows the most improvement relative to the 2011 Demand Technology case. Large kitchen and laundry appliances claim a small share of the reductions, as Federal standards limit increases in energy consumption for those uses even in the 2011 Demand Technology case. Light-emitting diodes (LED) lighting provide the potential for further savings in the High and Best Available Demand Technology cases beyond the reductions realized as a result of the EISA2007 (Public Law 110-140) lighting standards.

Results for the commercial sector

Like the residential sector, analysis results for the commercial sector are discussed here in terms of cumulative reductions relative to the 2011 Demand Technology case, in order to illustrate the effect of efficiency improvements over the period from 2011 to 2035. Buildings in the commercial sector are less homogeneous than those in the residential sector, in terms of both form and function. Although many commercial products

Table 6. Key assumptions for the residential sector in the *AEO2012* integrated demand technology cases

Assumptions	Integrated 2011 Demand Technology	Integrated High Demand Technology[a]	Integrated Buildings Best Available Demand Technology[a]
End-use equipment	Limited to technology menu available in 2011. Promulgated standards still take effect.	Earlier availability, lower cost, and/or higher efficiencies for advanced equipment.	Purchases limited to highest available efficiency for each technology class, regardless of cost.
Hurdle rates	Same as Reference case distribution; varies by end-use technology.	All energy efficiency investments evaluated at 7-percent real interest rate.	All energy efficiency investments evaluated at 7-percent real interest rate.
Building shells	Fixed at 2011 levels.	New buildings meet ENERGY STAR specifications after 2016. Efficiency improvement for existing buildings is 50 percent greater than in the Reference case.	New buildings meet most efficient specifications. Efficiency improvement for existing buildings is 100 percent greater than in the Reference case.
Distributed and combined heat and power generation	No improvement in technology cost or performance after 2011. Learning rates same as in the Reference case.	PV and wind costs based on Advanced Case in EIA Technology reports.[b] Learning rates adjusted for all technologies.	PV and wind costs reduced by twice the difference between the Reference and High Technology costs. Learning rates adjusted for all technologies.
Personal computers	ENERGY STAR sales and enabling rates; LCD and laptop shares fixed at 2011 values.	ENERGY STAR sales and enabling rates. LCD and laptop shares higher than in the Reference case.	ENERGY STAR sales and enabling rates. LCD share approaches 100 percent. Laptop share higher than in the Reference case.
TVs, cable boxes, and satellite systems	Fixed at 2011 values.	Unit energy consumption (UEC) values are average of Reference and Best Available Demand Technology cases.	Per-unit consumption levels reduced to ENERGY STAR specifications.
Miscellaneous electricity end uses	Unit energy consumption (UEC) values fixed at 2011 values.	Most efficient equipment selected after 2014.	Most efficient equipment selected in all years.

[a]All changes from the Reference case start in 2012 unless otherwise stated.
[b]U.S. Energy Information Administration, *Photovoltaic (PV) Costs and Performance Characteristics for Residential and Commercial Applications, Final Report* (August 2010), and *The Cost and Performance of Distributed Wind Turbines, 2010-2035, Final Report* (August 2010).

Table 7. Key assumptions for the commercial sector in the *AEO2012* integrated demand technology cases

Assumptions	Integrated 2011 Demand Technology	Integrated High Demand Technology[a]	Integrated Buildings Best Available Demand Technology[a]
End-use equipment	Limited to technology menu available in 2011. Promulgated standards still take effect.	Earlier availability, lower cost, and/or higher efficiencies for advanced equipment.	Purchases limited to highest available efficiency for each technology class, regardless of cost.
Hurdle rates	Same as Reference case distribution.	All energy efficiency investments evaluated at 7-percent real interest rate.	All energy efficiency investments evaluated at 7-percent real interest rate.
Building shells	Fixed at 2011 levels.	25 percent more improvement than in the Reference case by 2035.	50 percent more improvement than in the Reference case by 2035.
Distributed and combined heat and power generation	No improvement in technology cost or performance after 2011. Learning same as in the Reference case.	PV and wind costs, CHP cost and performance based on Advanced Case in EIA Technology reports.[b] Learning rates adjusted for advanced technologies.	PV and wind costs reduced by twice the difference between the Reference and High Technology costs. CHP based on Advanced Case in EIA Technology reports.[b] Learning rates adjusted for advanced technologies.
PC-related office equipment	ENERGY STAR sales and enabling rates; LCD and laptop shares fixed at 2011 values.	ENERGY STAR sales and enabling rates. LCD and laptop shares higher than in the Reference case.	ENERGY STAR sales and enabling rates. LCD share approaches 100 percent. Laptop share higher than in the Reference case.
Non-PC Office Equipment	Same as Reference case except for elimination of data center efficiency improvements.	Partial adoption of network power management for copiers, etc. Use of higher-efficiency power supplies for servers.	Greater adoption of network power management for copiers, etc. Use of higher-efficiency power supplies and continuous power management for servers.
Miscellaneous electricity	Less efficiency improvement than in the Reference case for uninterruptible power supplies (UPSs), network equipment, elevators, and water services.	Savings from high-efficiency UPSs and network equipment.	Greater savings from high-efficiency UPSs and network equipment.

[a]All changes from the Reference case start in 2012 unless otherwise stated.
[b]U.S. Energy Information Administration, *Photovoltaic (PV) Costs and Performance Characteristics for Residential and Commercial Applications, Final Report* (August 2010), *The Cost and Performance of Distributed Wind Turbines, 2010-2035, Final Report* (August 2010), and *Commercial and Industrial CHP Technology Costs and Performance Data* (June 2010).

are subject to Federal efficiency standards, FEMP guidelines, and ENERGY STAR specifications, coverage is not as comprehensive as in the residential sector. Still, those initiatives and the ensuing efficiency improvements contribute to a cumulative reduction in commercial delivered energy use of 4.1 quadrillion Btu in the Reference case relative to the 2011 Demand Technology case (Figure 22). Virtually all of the reduction is in purchased electricity. Increased adoption of DG and CHP accounts for 0.4 quadrillion Btu (115 billion kilowatthours) of the cumulative reduction in purchased electricity in the Reference case. Commercial natural gas use is actually slightly higher in the Reference case because of the increased penetration of CHP. Office-related computer equipment sees the most significant end-use energy savings relative to the 2011 Demand Technology case, primarily because laptop computers gain market share from desktop computers.

Commercial heating, ventilation and cooling account for almost 50 percent of the 17.1 quadrillion Btu in cumulative energy savings in the High Demand Technology case relative to the 2011 Demand Technology case. The more optimistic assumptions for end-use equipment in the High Demand Technology case offset the additional energy consumed as a result of greater adoption of CHP, resulting in a cumulative reduction in natural gas consumption of 0.9 quadrillion Btu. The increase in distributed and CHP generation contributes 0.8 quadrillion Btu (231 billion kilowatthours) to the cumulative reduction in purchased electricity use.

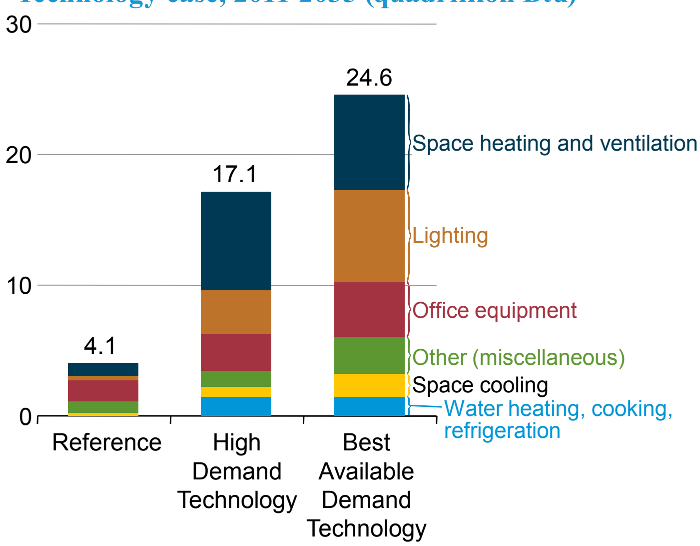
Technologies such as LED lighting result in almost as much improvement as space heating and ventilation in the Best Available Demand Technology case relative to the 2011 Demand Technology case. Significant reductions are seen for all end-use services, with a cumulative reduction in energy consumption of 24.6 quadrillion Btu. Even when consumers choose the most efficient type of each end-use technology, the more optimistic assumptions regarding technology learning for advanced CHP technologies result in more natural gas use in the Best Available Demand Technology case relative to the 2011 Demand Technology case.

In comparison to a case that restricts future equipment to the efficiencies available in 2011, the alternative cases show the potential for reductions in energy consumption from the adoption of more energy-efficient technologies. In the Reference case, technology improvement reduces residential energy consumption by 12.3 quadrillion Btu—equivalent to 4.1 percent of total residential energy use—from 2011 to 2035 in comparison with the 2011 Demand Technology case. In the commercial sector, energy consumption is reduced by 4.1 quadrillion Btu—equivalent to 1.7 percent of total commercial energy use—over the same period. With greater technology improvement in the High Demand Technology case, cumulative energy savings from 2011 to 2035 rise by an additional 6.4 percent and 5.5 percent in the residential and commercial sectors, respectively. In the Best Available Demand Technology case, the cumulative reductions in energy consumption grow by an additional 8.2 percent and 3.1 percent in the residential and commercial sectors, respectively. In the Reference case, a cumulative total of 16.4 quadrillion Btu of energy consumption is avoided over the projection period relative to the 2011 Demand Technology case. That reduction is roughly equivalent to 80 percent of the energy that the buildings sectors consumed in 2010. In the Best Available Demand Technology case, cumulative energy consumption is reduced by an additional 64.3 quadrillion Btu from 2011 to 2035.

4. Energy impacts of proposed CAFE standards for light-duty vehicles, model years 2017 to 2025

In response to environmental, economic, and energy security concerns, EPA and NHTSA in December 2011 jointly issued a proposed rule covering GHG emissions and CAFE standards for passenger cars and light-duty trucks in MY 2017 through MY 2025 [*42*]. EPA and NHTSA expect to announce a final rule in the second half of 2012. In this section, EIA uses the National Energy Modeling System (NEMS), which has been updated since last year but, due to the timing of the modeling process, does not incorporate all information from the pending rulemaking process, to assess potential energy impacts of the regulatory proposal.

Figure 22. Cumulative reductions in commercial energy consumption relative to the 2011 Demand Technology case, 2011-2035 (quadrillion Btu)



EPA is proposing GHG emissions standards that will reach a fleetwide LDV average of 163 grams CO_2 per mile (54.5 mpg equivalent) in MY 2025, or 49.6 mpg for the CAFE-only portion (Table 8). Passenger car standards are made more stringent by reducing the average annual CO_2 emissions allowed by 5 percent per year from MY 2016 through MY 2025. Average annual CO_2 emissions from light-duty trucks are reduced by 3.5 percent per year from MY 2016 through MY 2021, with larger average reductions for smaller light-duty trucks and smaller average reductions for larger light-duty trucks. For MY 2021 through MY 2025, light-duty trucks would be required to achieve a 5-percent average annual reduction rate. In this section, EIA assumes that the reductions in GHG emissions required under EPA standards exceed the reductions required under the NHTSA CAFE standards and are achieved through changes other than those that would provide further improvement in fuel economy as tested for compliance with the NHTSA standards.

NHTSA has proposed CAFE standards for LDVs that will reach a fleetwide average of 49.6 mpg in MY 2025, based on the projected inclusion of reductions in GHG emissions that are achieved by means other than improvements in fuel economy. CAFE standards are proposed for MY 2017 through MY 2021, and conditionally for MY 2022 through MY 2025. The proposed standards for passenger cars increase by 4.1 percent per year for MY 2017 through MY 2021 and 4.3 percent for MY 2022 through MY 2025. For light-duty trucks, the CAFE standards would increase by 2.9 percent per year for MY 2017 through MY 2021, with greater improvement required for smaller light-duty trucks and somewhat smaller improvement required for larger light-duty trucks. For MY 2022 through MY 2025, CAFE standards for all light-duty trucks would increase by 4.7 percent per year. Although there are complex dynamics in play among the CAFE standards and other policies, including those related to biofuels [*43*] and other gasoline alternatives, CAFE standards are the single most powerful regulatory mechanism affecting energy use in the U.S. transportation sector.

AEO2012 includes a CAFE Standards case that incorporates the proposed NHTSA fuel economy standards for MY 2017 through MY 2025. Fuel economy and GHG emissions standards for MY 2011 through MY 2016 have been promulgated already as final rules and are represented in the *AEO2012* Reference case. Further, the Reference case assumes that CAFE standards rise slightly to meet the requirement that LDVs reach 35 mpg by 2020 mandated in EISA2007.

As modeled by EIA, compliance with the more stringent fuel economy standards in the CAFE Standards case leads to a change in the vehicle sales mix. Vehicles that use electric power stored in batteries, or use a combination of a liquid fuel (including gasoline) and electric power stored in batteries for motive and/or accessory power—such as hybrid electric vehicles (HEVs) or plug-in hybrid electric vehicles (PHEVs)—or that use liquid fuels other than gasoline, such as diesel or E85, play a larger role than in the Reference case. The CAFE Standards case also projects a significant improvement in the fuel economy of traditional vehicles with gasoline internal combustion engines with and without micro hybrid technologies. In the analysis, vehicles that combine gasoline internal combustion engines with micro hybrid systems are projected to have the largest increase in sales relative to the Reference case (Figure 23 and Table 9).

Gasoline-only vehicles retain the single largest share of new vehicle sales in 2025. In order to meet increased fuel economy requirements, the average fuel economy of gasoline vehicles, including micro hybrids, is raised by the introduction of new fuel-efficient technologies and improved vehicle designs. The fuel economy of gasoline-only passenger cars, including micro hybrids, increases from 32 mpg in 2010 to 51 mpg in 2025 in the CAFE Standards case, compared with 38 mpg in 2025 in the Reference case. The fuel economy of gasoline-powered light-duty trucks, including micro hybrids, rises similarly, from 24 mpg in 2010 to 37 mpg in 2025 in the CAFE Standards case, compared with 31 mpg in 2025 in the Reference case.

As vehicle attributes, such as horsepower and weight, change in response to the more stringent fuel economy standards, some consumers switch from passenger cars to light trucks. Light-duty trucks account for 39 percent of new LDV sales in 2025 in the CAFE Standards case, higher than their 37 percent share in 2025 in the Reference case but still much lower than their 2005 share of more than 50 percent. In 2025, new passenger cars average 56 mpg and light-duty trucks average 40 mpg in the CAFE Standards case, compared with 41 mpg and 31 mpg, respectively, in the Reference case. Although more stringent standards stimulate sales of vehicles with higher fuel economy, it takes time for new vehicles to penetrate the vehicle fleet in numbers that are sufficiently large to affect the average fuel economy of the entire U.S. LDV stock. Currently there are about 230 million LDVs on the road in the United States, projected to increase to 276 million in 2035. As a consequence of the gradual scrapping of older vehicles and the introduction of new, more fuel-efficient models, the average on-road fuel economy of the LDV stock,

Table 8. Estimated[a] average fuel economy and greenhouse gas emissions standards proposed for light-duty vehicles, model years 2017-2025

	2016 (base)	2017	2018	2019	2020	2021	2022	2023	2024	2025
Fuel economy only (miles per gallon)										
Passenger cars	37.8	40.0	41.4	43.0	44.7	46.6	48.8	51.0	53.5	56.0
Light-duty trucks	28.8	29.4	30.0	30.6	31.2	33.3	34.9	36.6	38.5	40.3
All light-duty vehicles	34.1	35.3	36.4	37.5	38.8	40.9	42.9	45.0	47.3	49.6
Carbon dioxide emissions (grams per mile)										
Passenger cars	225	213	202	192	182	173	165	158	151	144
Light-duty trucks	298	295	285	277	270	250	237	225	214	203
All light-duty vehicles	250	243	232	223	213	200	190	181	172	163

[a]Based on projected mix of LDV sales.

representing the fuel economy realized by all vehicles in use, increases from around 20 mpg in 2010 to 22 mpg in 2016, 27.5 mpg in 2025, and 34.5 mpg in 2035, as compared with 28 mpg in 2035 in the Reference case (Figure 24).

More stringent fuel economy standards lead to reductions in total energy consumption. Total cumulative delivered energy consumption by LDVs from 2017 to 2035 is 8 percent lower in the CAFE Standards case than in the Reference case. LDV delivered energy consumption is 6 percent lower in 2025 in the CAFE Standards case than in the Reference case and 17 percent lower in 2035. Total consumption of petroleum and other liquids in the transportation sector is 0.5 million barrels per day lower in 2025 and 1.4 million barrels per day lower in 2035 in the CAFE Standards case than in the Reference case (Figure 25). The existing standards are modestly exceeded in the Reference case. If the standards are just met, the reduction in liquids consumption is 0.5 million barrels per day in 2025 and 1.6 million barrels per day in 2035 in the CAFE Standards case relative to the Reference case. The reductions in total delivered energy use and liquid fuel consumption become more pronounced later in the projection, as more of the total vehicle stock consists of vehicles with higher fuel economy.

The more stringent regulatory standards in the CAFE Standards case change the composition of the vehicle fleet by fuel type and shift the mix of fuels consumed. Nevertheless, motor gasoline, including gasoline blended with up to 15 percent ethanol (used in vehicles manufactured in MY 2001 and after), remains the predominant fuel by far for LDVs in the CAFE Standards case, accounting for 84 percent of LDV delivered energy consumption in 2035—only slightly less than its 86-percent share in 2035 in the Reference case.

Figure 23. Light-duty vehicle market shares by technology type in two cases, model year 2025 (percent of all light-duty vehicle sales)

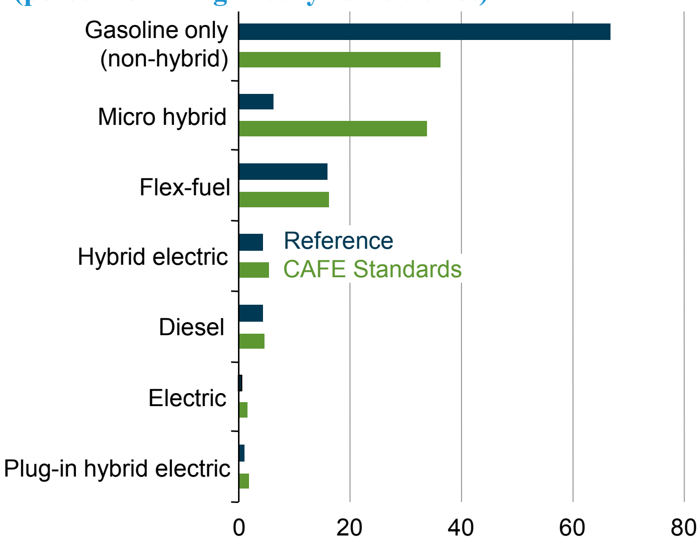


Figure 24. On-road fuel economy of the light-duty vehicle stock in two cases, 2005-2035 (miles per gallon)

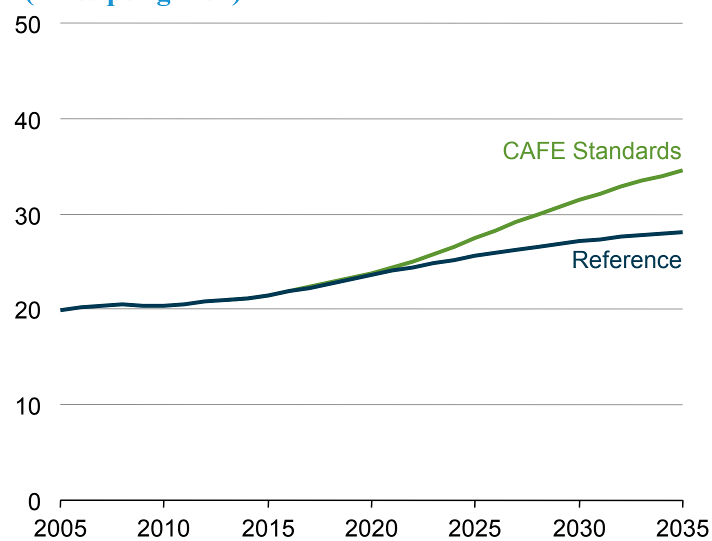


Table 9. Vehicle types that do not rely solely on a gasoline internal combustion engine for motive and accessory power

Vehicle type	Description
Micro hybrid	Vehicles with gasoline engines, larger batteries, and electrically powered auxiliary systems that allow the engine to be turned off when the vehicle is coasting or idling and then quickly restarted. Regenerative braking recharges the batteries but does not provide power to the wheels for traction.
Hybrid electric (gasoline or diesel)	Vehicles that combine internal combustion and electric propulsion engines but have limited all-electric range and batteries that cannot be recharged with grid power.
Diesel	Vehicles that use diesel fuel in a compression-ignition internal combustion engine.
Plug-in hybrid electric	Vehicles that use battery power for driving some distance, until a minimum level of battery power is reached, at which point they operate on a mixture of battery and internal combustion power. Plug-in hybrids also can be engineered to run in a "blended mode," where an onboard computer determines the most efficient use of battery and internal combustion power. The batteries can be recharged from the grid by plugging a power cord into an electrical outlet.
Electric	Vehicles that operate by electric propulsion from batteries that are recharged exclusively by electricity from the grid or through regenerative braking.
Flex-fuel	Vehicles that can run on gasoline or any gasoline-ethanol blend up to 85 percent ethanol.

Total motor gasoline demand for LDVs is 19 percent lower in the CAFE Standards case in 2035 than in the Reference case, and lower demand for motor gasoline reduces the amount of ethanol used in E10 and E15 gasoline blends. As a consequence, more E85 fuel is sold to meet the RFS. E85 accounts for 10 percent of delivered energy consumption by LDVs in 2035, compared with 8 percent in the Reference case. Diesel fuel accounts for 5 percent of LDV delivered energy consumption in 2035, similar to its share in the Reference case. Electricity use by LDVs grows in the CAFE Standards case but still makes up less than 1 percent of LDV delivered energy demand in 2035.

Reductions in LDV delivered energy consumption reduce GHG emissions from the transportation sector. From 2017 and 2035, cumulative CO_2 emissions from transportation are 357 million metric tons (mmt) lower in the CAFE Standards case compared to the Reference case, a reduction of 5 percent. Transportation GHG emissions decline from 1,876 mmt in 2010 to 1,759 mmt in 2025 and to 1,690 mmt in 2035, reductions of 4 percent and 10 percent from the Reference case, respectively (Figure 26).

5. Impacts of a breakthrough in battery vehicle technology

The transportation sector's dependence on petroleum-based fuels has prompted significant efforts to develop technology and alternative fuel options that address associated economic, environmental, and energy security concerns. Electric drivetrain vehicles, including HEVs, PHEVs, and plug-in electric vehicles (EVs), are particularly well suited to meet those objectives, because they reduce petroleum consumption by improving vehicle fuel economy and, in the case of PHEVs and EVs, substitute electric power for gasoline use (see Table 10 for a descriptive list of electric drivetrain technologies).

AEO2012 includes a High Technology Battery case that examines the potential impacts of significant breakthroughs in battery electric vehicle technology on vehicle sales, energy demand, and CO_2 emissions. Breakthroughs may include a dramatic reduction in the cost of battery and nonbattery systems, success in addressing overheating and life-cycle concerns, as well as the introduction of battery-powered electric vehicles in several additional vehicle size classes. A brief summary of the results of the High Technology Battery case follows a discussion of the current market for battery electric vehicles.

Sales of light-duty HEVs, introduced in the United States more than a decade ago, peaked at about 350,000 new sales in 2007 and have maintained a roughly 3-percent share of total LDV sales through 2011. PHEVs were introduced in the United States at the end of 2010 with the production of the Chevy Volt, a PHEV-40 (PHEV with a 40-mile range). Although manufacturer plans call for increased production of PHEVs, sales in the first full year were under 10,000 units [*44*]. EVs were first introduced in the early 1900s, and manufacturers again made EVs available in the 1990s but with a focus on niche markets. The Nissan Leaf, an EV-100 (EV with a 100-mile range) introduced around the same time as the Chevy Volt, has sparked interest in the wider commercial prospects for EVs; however, sales in 2011 remained below 10,000 units.

The individual decision to purchase a vehicle is influenced by many factors, including style, performance, comfort, environmental values, expected use, refueling capability, and expectations of future fuel prices. In general, one of the single most important factors consumers consider when deciding to purchase a vehicle is cost. Specifically, they generally are more willing to purchase new vehicle technologies, such as battery electric systems, instead of conventional gasoline internal combustion engines (ICEs) if the economic benefit over a period of ownership is greater than the initial price of the vehicle. Additional costs and benefits—such as refueling time or difficulty of refueling, increased or decreased maintenance, and resale value—also may enter into vehicle choice decisions. Further, consumers may be unwilling to spend more to purchase a vehicle, even if it accrues fuel cost savings beyond the initial cost over a relatively short period, because they are unfamiliar with the new technology or alternative fuel.

Figure 25. Total transportation consumption of petroleum and other liquids in two cases, 2005-2035 (million barrels per day)

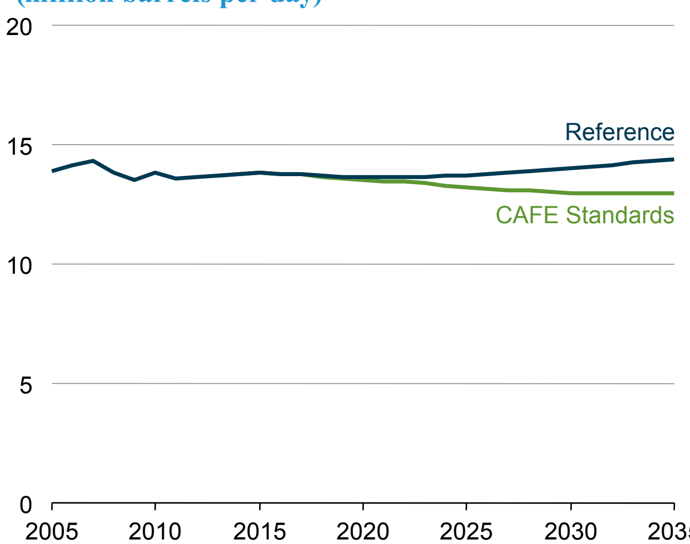
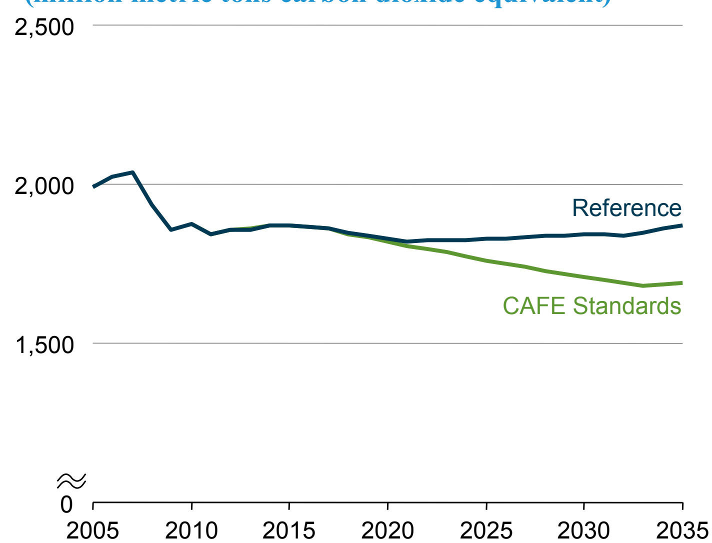


Figure 26. Total carbon dioxide emissions from transportation energy use in two cases, 2005-2035 (million metric tons carbon dioxide equivalent)



Battery electric vehicles offer an economic benefit to consumers over conventional gasoline ICEs in terms of significant fuel cost savings from both increased fuel economy for HEVs and PHEVs and the displacement of gasoline with electricity for PHEVs and EVs. Currently available battery electric vehicles such as the Toyota Prius (HEV), Chevy Volt (PHEV), and Nissan Leaf (EV) achieve much higher fuel economy (mpg) and, with the higher efficiency of electric motors, higher gasoline-equivalent mpg in electric mode, providing consumers with lower fueling costs. The Toyota Prius achieves an EPA-estimated 39 to 53 mpg, depending on trim and driving test cycle. The Chevy Volt achieves 35 to 40 mpg in charge-sustaining mode [*45*] and 93 to 95 mpg equivalent in charge-depleting mode. The Nissan Leaf achieves 99 mpg equivalent. In comparison, the Toyota Corolla, a passenger car generally similar to the Prius, achieves 26 to 34 mpg; the Chevy Cruze, a passenger car in the compact car size class similar to the Volt, achieves 25 to 42 mpg; and the Nissan Versa, a subcompact passenger car similar to the Leaf [*46*], achieves 24 to 34 mpg.

The inclusion of advanced battery technology that increases fuel economy and, in the case of PHEVs and EVs, displaces gasoline with electricity increases the initial cost of the vehicle to the consumer. The Toyota Prius has a manufacturer's suggested retail price (MSRP) between $24,000 and $29,500 (compared with $16,130 to $17,990 for the Toyota Corolla); the Chevy Volt has an MSRP between $39,145 and $42,085 (compared with $16,800 to $23,190 for the Chevy Cruze); and the Nissan Leaf has an MSRP between $35,200 and $37,250 (compared with $14,480 to $18,490 for the Nissan Versa) [*47*]. Based on these MSRPs, the current incremental consumer purchase cost of a battery electric vehicle relative to a comparable conventional gasoline vehicle is around $7,000 for an HEV and $20,000 for a PHEV or EV, before accounting for Federal and State tax incentives.

Although consumers may value high-cost battery electric vehicles for a variety of reasons, it is unlikely that they can achieve wide-scale market penetration while their additional purchase costs remain significantly higher than the present value of future fuel savings. Currently, the discounted fuel savings achieved, assuming five years of ownership with future fuel savings discounted at 7 percent, are significantly less than the incremental purchase cost of the vehicles (Table 11). This result is true even if gasoline is $6.00 per gallon. This calculation does not take into account any difference in maintenance cost or refueling infrastructure.

Recognizing the potential of HEVs, PHEVs, and EVs to reduce U.S. petroleum consumption and save consumers refueling costs, efforts are underway at both the public and private levels to address several of the barriers to wide-scale adoption of battery electric vehicle technology. Paramount among the barriers are reducing the cost of battery electric vehicles by lowering battery and nonbattery system costs and solving battery life-cycle and overheating limitations that will allow battery storage to downsize while maintaining a given driving range. For example, battery and nonbattery systems costs could be reduced by improving the manufacturing process, changing battery chemistry, or improving the electric motor. Solving battery life-cycle and overheating

Table 10. Description of battery-powered electric vehicles

Vehicle type	Description
Micro or "mild" hybrid	Vehicles with ICEs, larger batteries, and electrically powered auxiliary systems that allow the engine to be turned off when the vehicle is coasting or idle and then be quickly restarted. Regenerative braking recharges the batteries but does not provide power to the wheels for traction. Micro and mild hybrids are not connected to the electrical grid for recharging and are not considered as HEVs in this analysis.
Full hybrid electric (HEV)	Vehicles that combine an internal combustion engine with electric propulsion from an electric motor and battery. The vehicle battery is recharged by capturing some of the energy lost during braking. Stored energy is used to eliminate engine operation during idle, operate the vehicle at slow speeds for limited distances, and assist the ICE drivetrain throughout its drive cycle. Full HEV systems are configured in parallel, series, or power split systems, depending on how power is delivered to the drivetrain. HEVs are not connected to the electric grid for recharging.
Plug-in hybrid electric (PHEV)	Vehicles with larger batteries to provide power to drive the vehicle for some distance in charge-depleting mode, until a minimum level of battery power is reached (a "minimum state of charge"), at which point they operate on a mixture of battery and internal combustion power ("charge-sustaining mode"). The minimum state of charge is engineered to about 25 percent of full charge to ensure that the battery's life cycle matches the expected life of the vehicle. PHEVs also can be engineered to run in a "blended mode," using an onboard computer to determine the most efficient use of battery and internal combustion power. The battery can be recharged either from the grid by plugging a power cord into an electrical outlet or by the internal combustion engine. Current PHEV batteries are designed to recharge to about 75 percent of capacity for safety reasons related to battery overheating, leaving a depth of discharge of around 50 percent of total battery capacity. Typically, the distance a fully charged PHEV can travel in charge-depleting mode is indicated by its designation. For example, a PHEV-40 is engineered to travel around 40 miles on battery power alone before switching to charge-sustaining operation.
Plug-in electric (EV)	Vehicles that operate solely on an electric drivetrain with a large battery and electric motor and do not have an ICE to provide motive power. EVs are recharged primarily from the electrical grid by plugging into an electrical outlet, with some additional energy captured through regenerative braking. EV batteries also have a working depth of discharge capacity that is limited to both lower and upper levels due to life-cycle and safety concerns. EVs are designated by the distance a fully charged vehicle can travel in all-electric mode. For example, an EV-100 is designed to travel around 100 miles on battery power. EVs lack the "range extender" capability of PHEVs, which can switch instantly to an ICE when the battery reaches a minimum state of charge.

concerns would allow battery capacity to be downsized, which would improve the depth of discharge and make the battery less expensive. In addition, public and private efforts to address other obstacles to wider adoption of plug-in battery vehicles are underway, including the development of public charging infrastructure.

The *AEO2012* High Technology Battery case examines the potential impacts of battery technology breakthroughs by assuming the attainment of program goals established by DOE's Office of Energy Efficiency and Renewable Energy (EERE) for high-energy battery storage cost, maximum depth of discharge, and cost of a nonbattery traction drive system for 2015 and 2030 (Figures 27 and 28) [*48*]. EERE's program goals represent significant breakthroughs in battery and nonbattery systems, in terms of costs and life-cycle and safety concerns, in comparison with current electric vehicle technologies. Further, with breakthroughs in battery electric vehicle technology, more vehicle size classes are assumed to be available for passenger cars and light-duty trucks.

Reduced costs for battery and nonbattery systems in the High Technology Battery case lead to significantly lower HEV, PHEV, and EV costs to the consumer (Figures 29 and 30). The Reference case already projects a much lower real price to consumers for battery electric vehicles in 2035 relative to 2010 as a result of cost reductions for battery and nonbattery systems. Those declines are furthered in the High Technology Battery case. The prices of HEVs and PHEVs with a 10-mile range decline by an additional $1,500, or 5 percent, in 2035 in the High Technology Battery case relative to the Reference case. For PHEVs with a 40-mile range the relative decline is $3,500, or 11 percent, in 2035. For EVs with 100-mile (EV100) and 200-mile (EV200) ranges the relative declines are $3,600 and $13,300, or 13 percent and 30 percent, respectively, in 2035 relative to the Reference case.

Figure 27. Cost of electric vehicle battery storage to consumers in two cases, 2012-2035 (2010 dollars per kilowatthour)

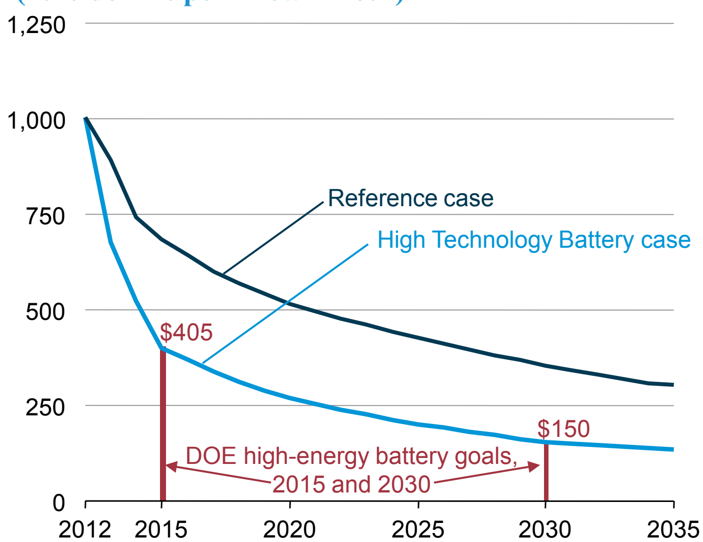


Figure 28. Costs of electric drivetrain nonbattery systems to consumers in two cases, 2012-2035 (2010 dollars)

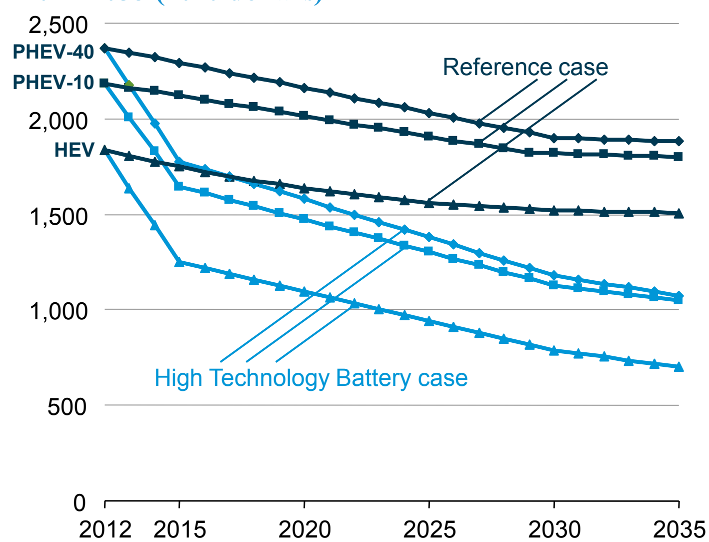


Table 11. Comparison of operating and incremental costs of battery electric vehicles and conventional gasoline vehicles

Characteristics	Hybrid electric vehicle (Prius)	Plug-in hybrid electric vehicle (Volt)	Plug-in electric vehicle (Leaf)
Fuel efficiency (mpg equivalent)	45	38 (charge-sustaining mode) 94 (charge-depleting mode)	99 (charge-depleting mode)
Annual vehicle miles traveled			12,500
Percent vehicle miles traveled electric only	0	58	100
Fuel savings vs. conventional gasoline ICE vehicle (at $3.50 per gallon)[a]	$1,169	$2,036	$3,314
Fuel savings vs. conventional gasoline ICE vehicle (at $6.00 per gallon)[a]	$2,004	$4,340	$7,071
Incremental vehicle cost (2010 dollars) relative to cost of 35-mpg conventional gasoline ICE vehicle[b]	$7,000	$20,000	$20,000

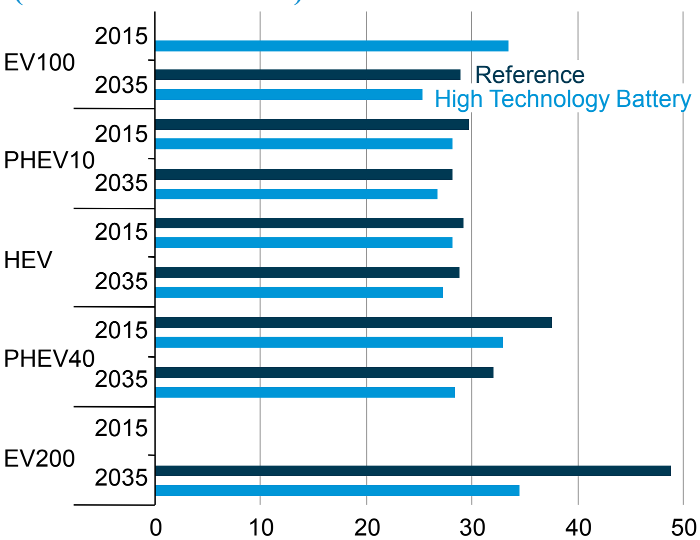
[a]5-year net present value of fuel savings, assuming 35 mpg for ICE, 7% discount rate, and $0.10 per kilowatthour electricity price.
[b]Does not include Federal, State, or local tax credits.

Lower vehicle prices lead to greater penetration of battery electric vehicle sales in the High Technology Battery case than projected in the Reference case. Battery electric vehicles, excluding mild hybrids, grow from 3 percent of new LDV sales in 2013 to 24 percent in 2035, compared with 8 percent in 2035 in the Reference case (Figure 31). Due to the still prohibitive incremental cost, EV200 vehicles do not achieve noticeable market penetration.

Plug-in vehicles, including both PHEVs and EVs, show the largest growth in sales in the High Technology Battery case, resulting from the relatively larger incremental reduction in vehicle costs. Plug-in vehicle sales grow to just over 13 percent of new vehicle sales in 2035, compared with 3 percent in 2035 in the Reference case, with EV sales growing to 8 percent of new LDV sales in 2035, compared with 2 percent in 2035 in the Reference case. Virtually all sales of plug-in vehicles are EVs with a 100-mile range, given the prohibitive cost, even in 2035, of batteries for EVs with a 200-mile range. PHEVs grow to just under 6 percent of total sales, compared with 2 percent in 2035 in the Reference case. Most PHEV sales are vehicles with a 10-mile all-electric range.

Although plug-in vehicle sales increase substantially in the High Technology Battery case, that growth is tempered by the lack of widespread high-speed recharging infrastructure. In the absence of such public infrastructure, consumers must rely almost entirely on recharging at home. According to data from the 2009 Residential Energy Consumption Survey, 49 percent of households that own vehicles park within 20 feet of an electrical outlet [*49*]. A widespread publicly available infrastructure was not considered as part of the High Technology Battery case, which limits the maximum market potential of PHEVs and EVs.

Figure 29. Total prices to consumers for compact passenger cars in two cases, 2015 and 2035 (thousand 2010 dollars)



HEV sales, including an ICE powered by either diesel fuel or gasoline, increase in the High Technology Battery case from 3 percent of sales in 2013 to 11 percent in 2035, compared with 5 percent in 2035 in the Reference case. Although the cost declines for HEVs are modest relative to those for other battery electric vehicle types, HEVs benefit from being unconstrained by the lack of recharging infrastructure.

Increased sales of battery electric vehicles in the High Technology Battery case lead to their gradual penetration throughout the LDV fleet. In 2035, HEVs represent 9 percent of the 276 million LDV stock, as compared with 4 percent in the Reference case. EVs and PHEVs each account for about 5 percent of the LDV stock in the High Technology Battery case in 2035, compared with 1 percent each in the Reference case.

The penetration of battery electric vehicles with relatively higher fuel economy and efficient electric motors reduces total energy use by LDVs from 15.6 quadrillion Btu in 2013 to 14.8 quadrillion Btu in 2035 in the High Technology Battery case, compared with 15.5 quadrillion Btu in 2035 in the Reference case (Figure 32). LDV liquid fuel use declines to

Figure 30. Total prices to consumers for small sport utility vehicles in two cases, 2015 and 2035 (thousand 2010 dollars)

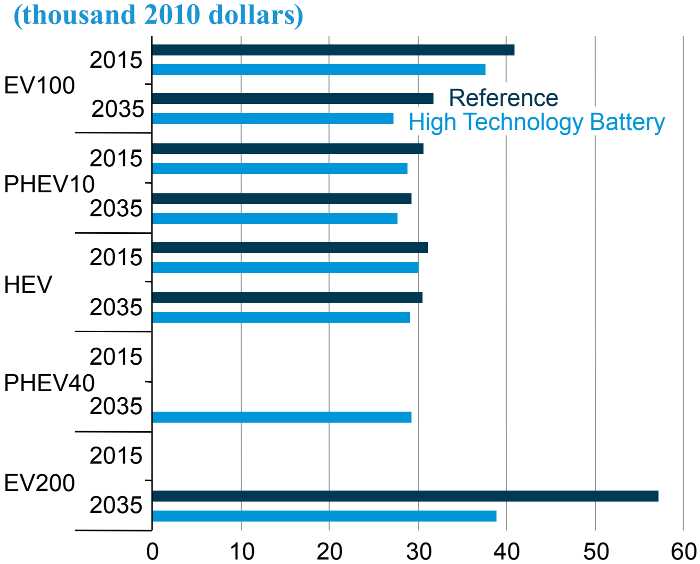
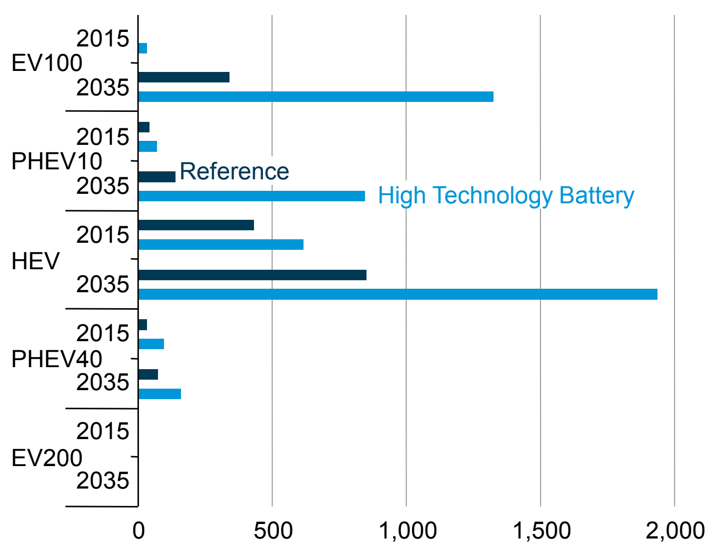


Figure 31. Sales of new light-duty vehicles in two cases, 2015 and 2035 (thousand vehicles)



14.6 quadrillion Btu in 2035 in the High Technology Battery case, and their electricity use increases to 0.2 quadrillion Btu—as compared with 15.4 quadrillion Btu of liquid fuel consumption and essentially no electricity consumption in 2035 in the Reference case. The reduction in liquid fuel consumption in the High Technology Battery case lowers U.S. net imports of petroleum from 8.5 million barrels per day in 2013 to 6.9 million barrels per day in 2035, compared with 7.2 million barrels per day in 2035 in the Reference case.

The reduction in total energy consumption by LDVs and displacement of petroleum and other liquid fuels with electricity decreases LDV energy-related CO_2-equivalent emissions from 1,030 million metric tons in 2013 to 935 million metric tons in 2035 in the High Technology Battery case, which represents a 2-percent decrease from 958 million metric tons in 2035 in the Reference case (Figure 33). CO_2 and other GHG emissions from the electric power consumed by PHEVs and EVs is treated as representative of the national electricity grid and not regionalized. Ultimately, the CO_2 and other GHG emissions of plug-in vehicles will depend on the fuel used in generating electricity.

The High Technology Battery case assumes a breakthrough in the costs of batteries and nonbattery systems for battery electric vehicles. Yet, despite the assumed dramatic decline in battery and nonbattery system costs, battery electric vehicles still face obstacles to wide-scale market penetration.

First, prices for battery electric vehicles remain above those for conventional gasoline counterparts, even with the assumption of technology breakthroughs throughout the projection period. The decline in sales prices relative to those for conventional vehicles may be enough to justify purchases by consumers who drive more frequently, consider relatively longer payback periods, or would purchase a more expensive but environmentally cleaner vehicle for a moderate additional cost. However, relatively more expensive battery electric vehicles may not pay back the higher purchase cost over the ownership period for a significant population of consumers.

In addition, EVs face the added constraint of plug-in infrastructure availability. Currently, there are about 8,000 public locations in the United States with at least one outlet for vehicle recharging, about 2,000 of which are in California [*50*]. In comparison, there are some 150,000 gasoline refueling stations available for public use. Without the construction of a much larger recharging network, consumers will have to rely on residential recharging, which is available for only around 40 percent of U.S. dwellings.

Further, recharging times differ dramatically depending on the voltage of the outlet. Typical 120-volt outlets can take up to 20 hours for a full EV battery to recharge; a 240-volt outlet can reduce the recharging time to about 7 hours [*51*]. Quick-recharging 480-volt outlets are under consideration for 30-minute "ultra-quick" recharges, but they may raise concerns related to safety and residential or commercial building codes. Even with ultra-quick recharging, EVs still would require substantially longer times for refueling than are required for ICE vehicles using liquid fuels. Given the concerns about availability and duration of recharging, the obstacle of severe range limitation, which does not affect PHEVs or HEVs, may inhibit the adoption of EVs by consumers.

Finally, another obstacle to wide-scale adoption of battery electric vehicles and other types of alternative-fuel vehicles is the increase in fuel economy for conventional gasoline vehicles and other types of AFVs resulting from higher fuel economy standards for LDVs. Final standards for LDV fuel economy currently are in place through MY 2016, and new CAFE standards proposed for MY 2017 through MY 2025 would increase combined LDV fuel economy to 49.6 mpg (56.0 mpg for passenger cars and 40.3 mpg for light-duty trucks) [*52*]. While the standards themselves may promote the adoption of battery electric vehicles, they also could considerably change the economic payback of electric drivetrain vehicles by decreasing consumer refueling costs for

Figure 32. Consumption of petroleum and other liquids, electricity, and total energy by light-duty vehicles in two cases, 2000-2035 (quadrillion Btu)

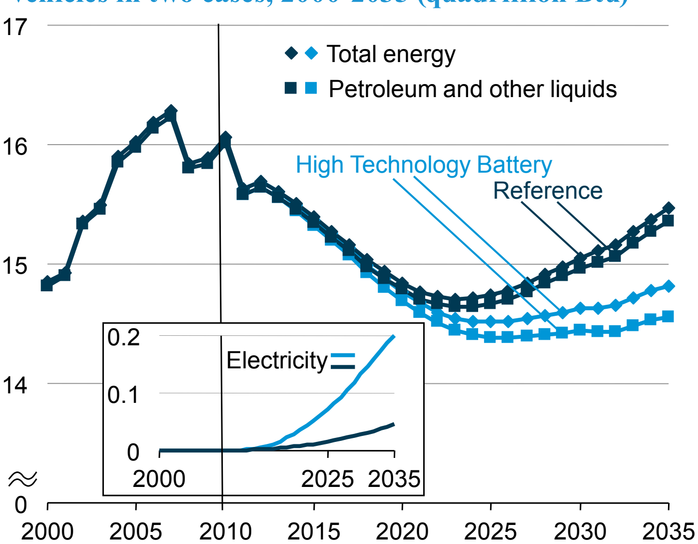
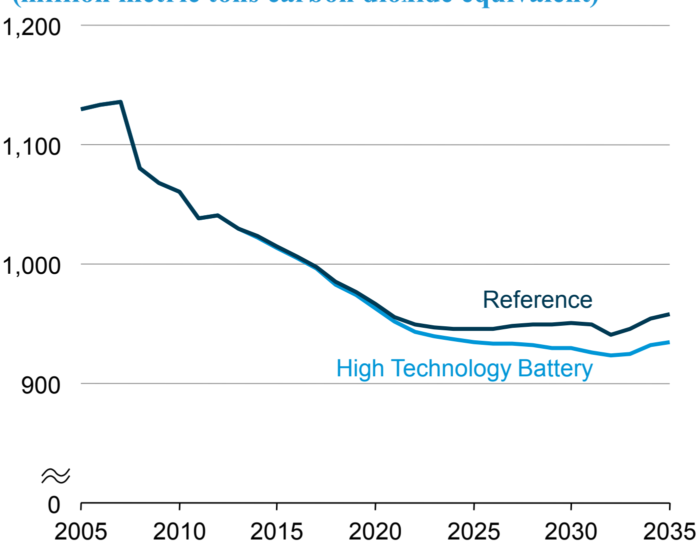


Figure 33. Energy-related carbon dioxide emissions from light-duty vehicles in two cases, 2005-2035 (million metric tons carbon dioxide equivalent)



conventional vehicles, thus lowering the fuel savings of electric drivetrain vehicles and making the upfront incremental cost more prohibitive. The potential impact of CAFE standards on other vehicle attributes, costs, and fuel savings adds to the complexity of this dynamic.

6. Heavy-duty natural gas vehicles

Environmental and energy security concerns, together with recent optimism about natural gas supply and recent lower natural gas prices, have led to significant interest in the potential for fueling heavy-duty vehicles (HDVs) with natural gas produced domestically. Key market uncertainties with regard to natural gas as a fuel for HDVs include fuel and infrastructure issues (such as the build-out process for refueling stations and whether there will be sufficient demand for refueling to cover the required capital outlays, and retail pricing and taxes for liquefied natural gas [LNG] and compressed natural gas [CNG] fuels); and vehicle issues (including incremental costs for HDVs fueled by natural gas, availability of fueling infrastructure, cost-effectiveness in view of average vehicle usage, vehicle residual value, vehicle weight, and vehicle refueling time).

Current state of the market

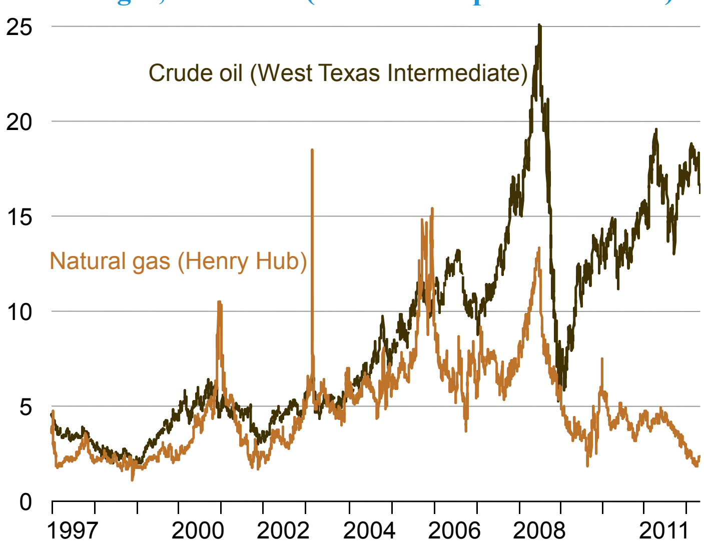
At present, HDVs in the United States are fueled almost exclusively by petroleum-based diesel fuel [*53*]. In 2010, use of petroleum-based diesel fuel by HDVs accounted for 17 percent (2.2 million barrels per day) of total petroleum consumption in the transportation sector (12.8 million barrels per day) and 12 percent of the U.S. total for all sectors (18.3 million barrels per day). Consumption of petroleum-based diesel fuel by HDVs increases to 2.3 million barrels per day in 2035 in the *AEO2012* Reference case, accounting for 19 percent of total petroleum consumption in the transportation sector (12.1 million barrels per day) and 14 percent of the U.S. total for all sectors (17.2 million barrels per day).

Historically, natural gas has played a negligible role as a highway transportation fuel in the United States. In 2010, there were fewer than 40,000 total natural gas HDVs on the road, or 0.4 percent of the total HDV stock of nearly 9 million vehicles. Sales of new HDVs fueled by natural gas peaked at about 8,000 in 2003, and fewer than 1,000 were sold in 2010 out of a total of more 360,000 HDVs sold. With relatively few vehicles on the road, natural gas accounted for 0.3 percent of total energy used by HDVs in 2010.

As of May 2012, there were 1,047 CNG fueling stations and 53 LNG fueling stations in the United States, with 53 percent of the CNG stations and 57 percent of the LNG stations being privately owned and not open to the public [*54*]. Further, the stations were not evenly distributed across the United States, with 22 percent (227) of the CNG stations and 68 percent (36) of the LNG stations located in California. In comparison, nationwide, there were more than 157,000 stations selling motor gasoline in 2010 [*55*].

Developments in natural gas and petroleum markets in recent years have led to significant price disparities between the two fuels and sparked renewed interest in natural gas as a transportation fuel. Led by technological breakthroughs in the production of natural gas from shale formations, domestic production of dry natural gas increased by about 14 percent from 2008 to 2011. In the *AEO2012* Reference case, U.S. natural gas production (including supplemental gas) increases from 21.6 trillion cubic feet in 2010 to 28.0 trillion cubic feet in 2035. Further, although the world market for oil and petroleum products is highly integrated, with prices set in the global marketplace, natural gas markets are less integrated, with significant price differences across regions of the world. With the recent growth in U.S. natural gas production, domestic natural gas prices in 2012 are significantly lower than crude oil prices on an energy-equivalent basis (Figure 34).

Figure 34. U.S. spot market prices for crude oil and natural gas, 1997-2012 (2010 dollars per million Btu)



Fuel and infrastructure issues

Even when it appears that an emerging technology can be profitable with significant market penetration, achieving significant penetration can be difficult and, potentially, unattainable. Refueling stations for NGVs are unlikely to be built without some assurance that there will be sufficient numbers of NGVs to be refueled, soon enough to allow for recovery of the capital investment within a reasonable period of time. In terms of estimating the prices that will be charged for NGV fuels beyond the cost of the dry natural gas itself, and the issue of expected utilization rates, there are additional uncertainties related to capital and operating costs, taxes, and the potential of prices being set on the basis of the prices of competing fuels.

Basic fuel issues

Diesel fuel falls into the category of distillate fuels, which have constituted more than 25 percent of U.S. refinery output in recent years. The cost of diesel fuel is linked closely to the value of crude oil inputs for the refining process. In 2011, the spot price of Gulf Coast ultra-low sulfur diesel fuel averaged $2.97 per gallon. The wholesale diesel price reflects crude oil costs, as well as the difference between the wholesale price at the refinery gate and the cost of crude oil input, commonly referred to as the "crack spread," which reflects the costs and profits of refineries. Beyond the wholesale price, the pump price of diesel fuel reflects distribution costs, Federal, State, and local fuel taxes, retailing costs, and profits. For diesel fuel, with an average energy content of 138,690 Btu per gallon, the 2011 national average retail price of $3.84 per gallon is equivalent to about $27.80 per million Btu.

Although early models of NGVs sometimes were less fuel-efficient than comparable diesel-fueled vehicles, current technologies allow for natural gas to be used as efficiently as diesel in HDV applications. Therefore, comparisons between natural gas and diesel fueling costs can be based on the price of energy-equivalent volumes of fuel. For this analysis, the cost and price of natural gas fuels are expressed in terms of diesel gallon equivalent (dge). For example, with an energy content of approximately 84,820 Btu per gallon, 1 gallon of LNG is equivalent in energy terms to 0.612 gallons of diesel fuel.

Fuel costs for LNG and CNG vehicles depend on the cost of natural gas used to produce the fuels, the cost of the liquefaction or compression process (including profits), the cost of moving fuel from production to refueling sites (if applicable), taxes, and retailing costs. Costs can vary with the scale of operations, but the significant disparity between current natural gas and crude oil prices suggests that the cost of CNG and LNG fuels in dge terms could be significantly below the price of diesel fuel.

There are different wholesale natural gas prices and capital costs associated with CNG and LNG stations. CNG retail stations, which typically have connections to the pipeline distribution network and thus require compression equipment and special refueling pumps, are likely to pay prices for natural gas that are similar to those paid by commercial facilities. For LNG stations, insulated LNG storage tanks and special refueling pumps are needed. LNG typically would be delivered from a liquefaction facility that, depending on its scale, would pay a natural gas price similar to the prices paid by electric power plants. The costs of liquefying and transporting the fuel to the retail station would ultimately be included in the retail price.

In a competitive market, retail fuel prices should reflect costs, including input, processing, distribution, and retailing costs, normal profit margins for processors, distributors, and retailers, and taxes. For example, the market for diesel fuel, which is produced by a large number of foreign and domestic refiners and is sold through numerous distributors and retail outlets, generally is considered to be a competitive market, in which retail prices follow costs.

CNG and LNG markets, at least in their initial stages, may not be as competitive as diesel fuel markets. For example, at public refueling stations, LNG and CNG currently sell at prices significantly higher than would be suggested by a long-term analysis of cost-based pricing. According to DOE's April 2012 "Clean Cities Alternative Fuel Price Report," the average nationwide nominal retail price for LNG was $3.05 per dge, and the average for CNG was $2.32 per dge [*56*].

If the use of LNG and/or CNG to fuel HDVs starts to grow, it is likely to take some time before fuel production and refueling infrastructure become sufficiently widespread for competition among fuel providers alone to assure that fuel prices are more closely linked to cost-based levels. However, even without many fuel providers, operators of an LNG and/or CNG vehicle fleet may be in a position to negotiate cost-based fuel prices with refueling station operators seeking to lock in demand for their initial investments in refueling infrastructure. Such arrangements provide an alternative to reliance on centrally fueled fleets as a means of circumventing the problem of how to introduce NGVs and natural gas refueling infrastructures concurrently.

Build-out process for refueling stations

It is not clear how NGVs and an expanded natural gas refueling infrastructure ultimately will evolve. One view is that a "hub-and-spoke" model for refueling infrastructure will expand sufficiently in multiple areas for a point-to-point system to take hold eventually. The "hubs" in the model would include the local refueling infrastructure, currently in place primarily to support local fleets. The "spokes" would ensure that refueling infrastructure is in place on the main transportation corridors connecting the hubs.

Several regional efforts are in place to encourage such "hub-and-spoke" growth for NGV refueling facilities. They include the Texas Clean Transportation Triangle [*57*], a strategic plan for CNG and LNG refueling stations between Dallas, San Antonio, and Houston; and the Interstate Clean Transportation Corridor [*58*], which aims to provide LNG fueling stations between such major western cities as Los Angeles, Las Vegas, Phoenix, Reno, Salt Lake City, and San Francisco. There also is a plan for a Pennsylvania Clean Transportation Corridor [*59*], which would provide CNG and LNG fueling stations between Pittsburgh, Harrisburg, Scranton, and Philadelphia.

In several corridors, Federal and State incentives are subsidizing both the construction of refueling stations and the production of heavy-duty LNG vehicles [*60*], in an effort to ensure that both demand and supply will be in place concurrently. A major question is whether gaps between isolated targeted markets can be bridged to provide a nationwide refueling structure that will allow heavy-duty NGVs to travel almost anywhere.

Sufficiency of demand for refueling to cover capital outlay

The cost of providing refueling services for NGVs depends on a number of factors and is distinctly different for CNG and LNG vehicles. Investment decisions are likely to be based on levels of demand. NGV refueling capability can be added at an existing facility or at a separate dedicated facility (which would require an additional investment). The costs depend in part on the number of fueling hoses added. LNG stations in particular benefit from higher volumes, but they also require significant additional land to accommodate storage tank(s), and they must satisfy special safety requirements—both of which add costs that can vary significantly from place to place. One added cost in operating an LNG station is the need for safety suits and specialized training for station attendants who dispense the fuel.

LNG typically is delivered to refueling stations via tanker truck from a separate liquefaction facility, the proximity of which is a major factor in the cost and frequency of deliveries. Any significant expansion of LNG refueling capacity also will require expanded liquefaction capacity, which currently is not sufficiently dispersed throughout the country to support a nationwide LNG refueling infrastructure. Although there are several dedicated large-scale natural gas liquefaction facilities in the United States, primarily in the West, there are smaller liquefaction plants and LNG storage tanks currently in use for meeting peak-shaving needs of utilities and pipelines during times of high demand. There are more than 100 such facilities in the United States, with a combined liquefaction capacity of more than 6 billion cubic feet per day. The majority are concentrated in the Northeast and Southeast [*61*].

Retail prices and taxes for LNG and CNG fuels

Even if the costs are fully known, retail prices for CNG and LNG transportation fuels remain uncertain, given questions about whether dispensers would charge higher prices in order to recover costs more rapidly if the facility were underutilized or would set prices to be competitive with the price of diesel. Prices charged at private stations for fleet vehicles presumably would be based on cost. With the number of refueling stations limited, competition between retailers is likely to be limited, at least initially. However, NGV refueling stations presumably would want to provide sufficient economic incentive in terms of the competitiveness of fuel prices to encourage more purchases of NGVs.

NGV fuel is taxed at State and Federal levels. Currently, on a Federal level, CNG is taxed at the same rate as gasoline on an energy-equivalent basis ($0.18 per gasoline gallon equivalent, or $0.21 per dge). However, LNG is taxed at a higher effective rate than diesel fuel, because it is taxed volumetrically at $0.24 per LNG gallon equivalent ($0.40 per dge) rather than on the basis of energy content [*62*]. State taxes vary, averaging $0.15 per dge for CNG and $0.24 per dge for LNG.

Vehicle Issues

Incremental vehicle cost

NGVs have significant incremental costs relative to their diesel-powered counterparts because of the need for pressurization and insulation of CNG or LNG tanks and the lower energy content of natural gas as a fuel. Total incremental costs relative to diesel HDVs range from about $9,750 to $36,000 for Class 3 trucks (GVWR 10,001 to 14,000 pounds), $34,150 to $69,250 for Class 4 to 6 trucks (GVWR 14,001 to 26,000 pounds), and $49,000 to $86,125 for Class 7 and 8 trucks (GVWR greater than 26,001 pounds). The incremental costs of heavy-duty NGVs depend in large part on the volume of the vehicle's CNG or LNG storage tank, which can be sized to match its typical daily driving range. Non-storage-tank incremental costs average about $2,000 for Class 3 vehicles, $20,000 for Class 4 to 6 vehicles, and $30,000 for Class 7 to 8 vehicles [*63*]. Fuel storage costs are about $350 per gallon diesel equivalent for CNG, with the incremental cost for Class 3 CNG vehicle storage tanks ranging between about $8,000 and $30,000; and about $475 per gallon diesel equivalent for LNG, with the incremental cost for Class 4 to 8 LNG vehicle storage tanks ranging between about $14,000 and $52,000. Natural gas fuel storage technology is relatively mature, leaving only modest opportunity for cost reductions.

Availability of fueling infrastructure

The absence of widespread public refueling infrastructure can impose a serious constraint on heavy-duty NGV purchases. Owners who typically refuel vehicles at a private central location do not face an absolute constraint based on infrastructure, however, and heavy-duty NGVs currently in operation have tended to be purchased by fleet operators who refuel consistently at a specific central location or in areas where their vehicles routinely operate on dedicated routes.

Cost-effectiveness with average vehicle usage

In order to take advantage of potential fuel cost savings from switching to NGVs, owners must operate the vehicles enough to pay back the higher incremental cost in a reasonable period of time. The payback period varies with miles driven and is shorter for trucks that are used more intensively. Payback periods for the upfront incremental costs of NGVs are greater than 5 years for Class 3 vehicles unless they are driven at least 20,000 to 40,000 miles per year, and for Class 7 and 8 vehicles unless they are driven at least 60,000 to 80,000 miles per year. Shorter payback periods, 3 years or less, may reflect typical owner expectations more accurately [*64*], but they require much more intensive use: around 60,000 to 80,000 miles annually for Class 3 vehicles and more than 100,000 miles annually for Class 7 and 8 vehicles. For example, for a Class 7 or 8 compression ignition NGV with average fuel economy of 6 miles per gallon (which has a similar fuel economy compared to a diesel counterpart) and an incremental cost of $80,000, the payback period would be just over 3 years if the vehicle were driven 100,000 miles per year, assuming a diesel fuel price of $4.00 per gallon and an LNG fuel price of $2.50 per gallon. If the same Class 7 or 8 vehicle were driven 40,000 miles per year, the payback period would be about 8 years. Further, without a widely available infrastructure, heavy-duty NGVs tend to be considered by centrally refueled fleets, which may have less mileage-intensive vehicle use.

According to the Department of Transportation's Vehicle Inventory and Use Survey [65], last completed in 2002, a large segment of the HDV market simply does not drive enough to justify the purchase of an NGV (Figure 35). Around 30 percent of Class 3 vehicles and 75 percent of Class 7 and 8 vehicles are not driven enough to reach the 5-year payback threshold mentioned above. This is a significant portion of the market that would require either more favorable fuel economics or lower vehicle costs before the purchase of an NGV could be justified.

Other market uncertainties

Other factors may also affect market acceptance of heavy-duty NGVs. First, the purchase decision could be affected by the considerable additional weight of CNG or LNG tanks. For owners who typically "weight-out" a vehicle (driving with a full payload), adding heavy CNG or LNG tanks necessitates a reduction in freight payload. The EPA and NHTSA have estimated that about one-third of Class 8 sleeper tractors routinely are "weighted-out" [66].

A diesel tractor with 200 gallons of tank capacity and a fuel economy of 6 miles per gallon can drive 1,200 miles on a single refueling. The same tractor would need up to 110 dge of LNG tank capacity, at a considerable weight penalty and an incremental cost of more than $80,000, to allow for a range of about 650 miles on a single refueling. Because owner/operators typically stop several times per day, the reduction in unrefueled maximum range would not require additional breaks for vehicles with large CNG or LNG tanks. However, CNG and LNG vehicles that do not opt for large tanks because of either weight or incremental cost considerations might have to refuel more frequently.

Finally, the owner perception of the balance of risk and reward for large capital investment is an uncertainty. Higher upfront capital costs can prove economically prohibitive for some potential owners. Even if the payback period for an investment in natural gas vehicles seemed acceptable, financing constraints or returns available on competing investment options could preclude the purchase. Additionally, the residual value of natural gas HDVs could, in theory, affect market uptake. With little natural gas refueling infrastructure in existence, the potential resale market is constrained to owners of centrally operated fleets. However, lease terms tend to limit the importance of this factor.

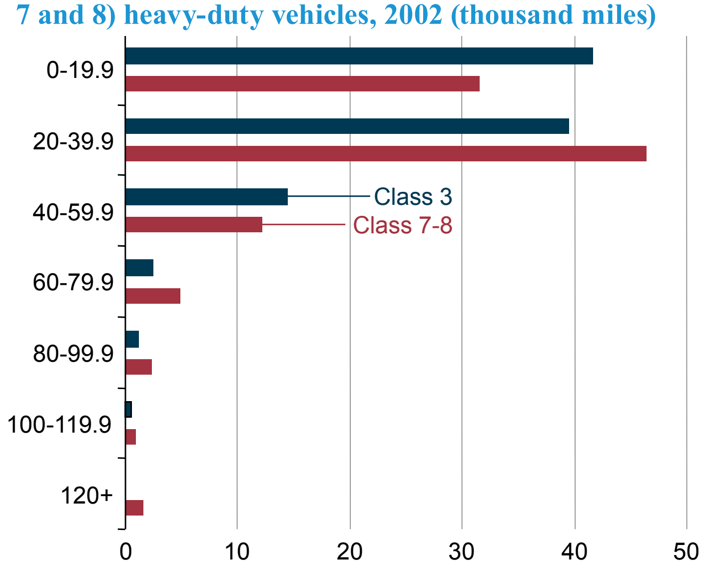
The complex set of factors influencing the potential for natural gas as a fuel for HDVs includes several areas for which policy mechanisms have been discussed. Most policy debates to date have considered the possibility of subsidies to reduce the incremental cost of natural gas vehicles (for example, in Senate and House versions of the New Alternative Transportation to Give Americans Solutions Act [67]) and Federal grant-based or other financial support for fueling station infrastructure. In addition, market hurdles related to consumer acceptance or payback periods might also be addressed through loan guarantees or related financial support policies, both for the vehicles and for the refueling infrastructure.

HD NGV Potential case results

The *AEO2012* HD NGV Potential case examines issues associated with expanded use of heavy-duty NGVs, under an assumption that the refueling infrastructure exists to support such an expansion. The HD NGV Potential case differs from an earlier sensitivity case completed as part of the *Annual Energy Outlook 2010*, which focused on possible subsidies to expand the market potential for heavy-duty NGVs and limited its attention to vehicles operating within 200 miles of a central CNG refueling facility.

The *AEO2012* HD NGV Potential case permits expansion of the HDV market to allow a gradual increase in the share of HDV owners who would consider purchasing an NGV if justified by the fuel economics over a payback distribution with a weighted average of 3 years. The gradual increase in the maximum natural gas market share reflects the fact that a national natural gas refueling program would require time to build out. The natural gas refueling infrastructure is expanded in the HD NGV Potential case simply by assumption; it is not clear how (or whether) specific barriers to natural gas refueling infrastructure investment can be overcome.

Figure 35. Distribution of annual vehicle-miles traveled by light-medium (Class 3) and heavy (Class 7 and 8) heavy-duty vehicles, 2002 (thousand miles)



Incremental costs for NGVs in the HD NGV Potential case differ from those in the Reference case. In the HD NGV Potential case, incremental costs are determined by assuming a set cost for CNG or LNG engines plus a CNG or LNG tank cost based on the average amount of daily travel and vehicle size class. The HD NGV Potential case includes separate delivered CNG and LNG fuel prices for fleet and nonfleet operators. Added per-unit charges to recover infrastructure are set and held constant in real terms throughout the projection period, based on the assumptions that refueling stations would be utilized at a sufficiently high rate to warrant the capital investment, and that the prices charged for the fuel would be cost-based (i.e., station operators would not set prices on the basis of prices for competing fuels). Motor fuels taxes are assumed to remain at their current levels in nominal terms, maintaining the higher energy-equivalent tax on LNG relative to diesel fuel.

In defining CNG and LNG prices for the HD NGV Potential case, EIA examined current motor fuel taxes and any charges added to the commodity price of dry natural gas sold at private central refueling stations (fleets) and at retail stations where actual data were available. Accordingly, an HDV Reference case was developed from the *AEO2012* Reference case, by including the updated fleet and retail CNG and LNG prices, to provide a consistent basis for comparison with the HD NGV Potential case (Figure 36). The HDV Reference case assumes that Class 3 through 6 vehicles use CNG, obtained from either fleet operators (using fleet prices) or nonfleet operators (using retail prices), and that Class 7 and 8 vehicles, both fleet and nonfleet, use LNG.

Sales of heavy-duty NGVs rise dramatically in the HD NGV Potential case, based on the national availability of refueling infrastructure and expanded market potential (Figure 37). Sales of new heavy-duty NGVs increase from 860 in 2010 (0.2 percent of total new HDV sales) to about 275,000 in 2035 (34 percent of total new vehicle sales), as compared with 26,000 in the HDV Reference case (3 percent of total new HDV sales). New heavy-duty NGVs gradually claim a more significant share of the vehicle stock, from 0.4 percent in 2010 to 21.8 percent (2,750,000 vehicles) in 2035, as compared with 2.4 percent (300,000 vehicles) in 2035 in the HDV Reference case.

As a result of the large projected increase in sales of new heavy-duty NGVs, natural gas demand in the HDV sector rises from about 0.01 trillion cubic feet in 2010 to 1.8 trillion cubic feet in 2035 in the HD NGV Potential case, as compared with 0.1 trillion cubic feet in the HDV Reference case (Figure 38). The natural gas share of total energy use by HDVs grows from 0.2 percent in 2010 to 32 percent in 2035 in the HD NGV Potential case, compared with 1.6 percent in the HDV Reference case.

Roughly speaking, about 1 trillion cubic feet of natural gas consumed per year replaces 0.5 million barrels per day of petroleum and other liquids. Thus, natural gas consumption by HDVs in the HD NGV Potential case displaces about 850,000 barrels per day of petroleum and other liquids consumption in 2035 (Figure 39). Without a major impact on world oil prices, which is not expected to result from the gradual but significant adoption of natural gas as a fuel for U.S. HDVs, nearly all the reduction in petroleum and other liquids use by U.S. HDVs would be reflected by a decline in imports.

In the HD NGV Potential case, projected total U.S. natural gas consumption in 2035 is 1.4 trillion cubic feet (5 percent) higher than in the Reference case, as the increase in natural gas use by vehicles is partially offset by lower consumption in other sectors, in response to higher natural gas prices (Figure 40). The electric power and industrial sectors account for the

Figure 36. Diesel and natural gas transportation fuel prices in the HDV Reference case, 2005-2035 (2010 dollars per diesel gallon equivalent)

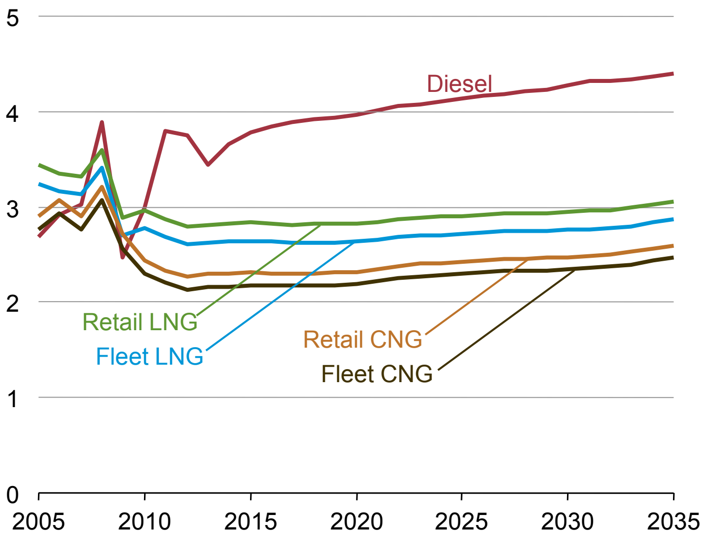


Figure 37. Annual sales of new heavy-duty natural gas vehicles in two cases, 2008-2035 (thousand vehicles)

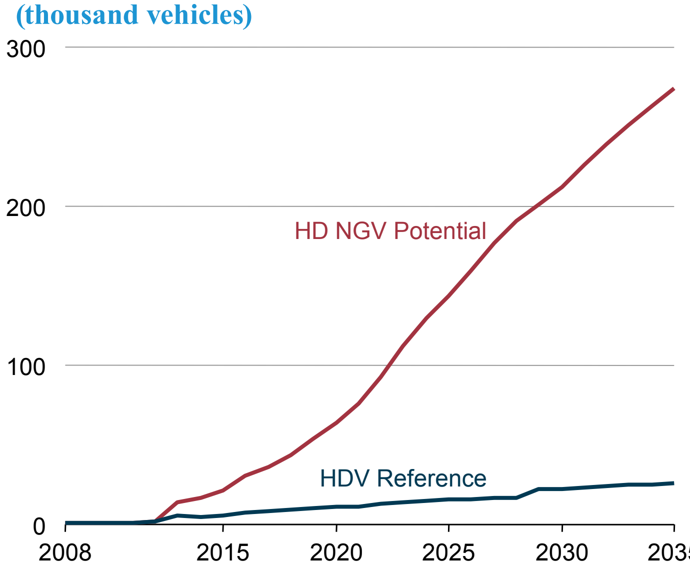
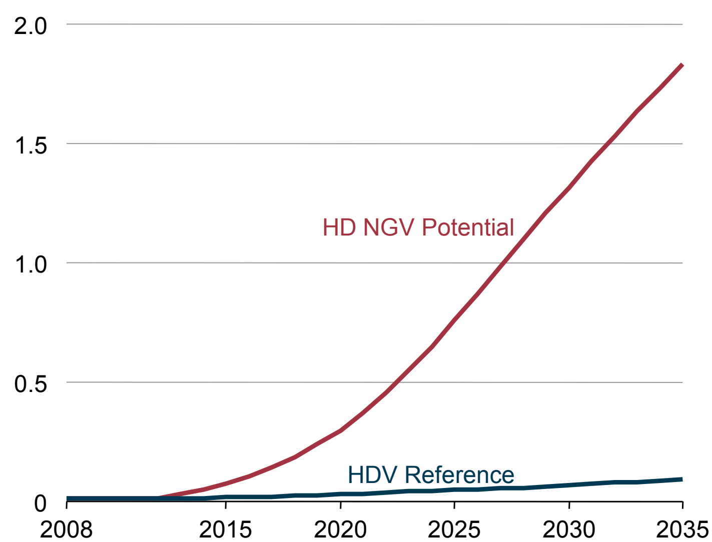


Figure 38. Natural gas fuel use by heavy-duty vehicles in two cases, 2008-2035 (trillion cubic feet)



bulk of the consumption offsets, as their 2035 natural gas use is, respectively, 0.3 trillion cubic feet (3.1 percent) and 0.2 trillion cubic feet (2.7 percent) lower than in the Reference case.

In 2035, U.S. domestic natural gas production in the HD NGV Potential case is 1.1 trillion cubic feet (3.9 percent) higher than in the HDV Reference case. The higher level of natural gas production needed to support the growth in HDV fuel use results in a 10-percent increase in natural gas prices—$0.76 per million Btu (2010 dollars)—at the Henry Hub in 2035 in comparison with the HDV Reference case. Percentage increases in delivered natural gas prices to other sectors, which include transmission and distribution costs that are not affected by higher prices to producers, are smaller, with delivered natural gas prices increasing by 4.9 percent in the residential sector, 5.9 percent in the commercial sector, 8.9 percent in the industrial sector, and 7.9 percent in the electricity generation sector in comparison with the HDV Reference case in 2035.

7. Changing structure of the refining industry

Petroleum-based liquid fuels represent the largest source of U.S. energy consumption, accounting for about 37 percent of total energy consumption in 2010. The mix and composition of liquids, however, have changed in recent years in response to changes in regulations and other factors, and the structure of the liquid fuels production industry has changed in response [*68*]. The changes in the industry require that analytical tools used for market analysis of the liquid fuels produced by the industry also be reevaluated.

In recognition of the fundamental changes in the liquid fuels production industry, EIA is developing a new Liquid Fuels Market Module (LFMM), which it intends to use in place of the existing Petroleum Market Module (PMM) to produce the *Annual Energy Outlook 2013.* The LFMM will allow EIA to address more adequately the current and anticipated domestic and international market environments, to analyze the implications of emerging technologies and fuel alternatives, and to evaluate the impact of complex emerging energy-related policy, legislative, and regulatory issues. Some results from an early simulation of the LFMM, the LFMM case, are provided here.

The landscape for both production and consumption of liquid fuels in the United States continues to evolve, leading to changes in the mix of liquid fuel feedstocks, with greater emphasis on renewable fuels. The liquid fuels markets are not homogeneous; regional differences have become more pronounced. Furthermore, U.S. policymakers are paying more attention to evolving markets for liquid fuels and the potential for improving the efficiency of liquid fuels consumption, reducing GHG emissions associated with the production and consumption of liquid fuels, and improving the Nation's energy security by reducing reliance on imports. Major industry changes and their implications are discussed below.

New feedstocks and technologies

Over the past 25 years, the U.S. liquid fuels production industry has changed from being based primarily on domestic petroleum to using a variety of feedstocks and finished products from sources around the world. Regulatory and policy changes have resulted in the use of feedstocks other than crude oil, such as natural gas and renewable biomass, and could lead to the use of other feedstocks (such as coal) in the coming years. These changes have resulted in a transition from a relatively straightforward supply chain relying on crude oil and finished products to an increasingly complex system, which must be reflected in models to produce valid projections.

Figure 39. Reduction in petroleum and other liquid fuels use by heavy-duty vehicles in the HD NGV Potential case compared with the HDV Reference case, 2010-2035 (thousand barrels per day)

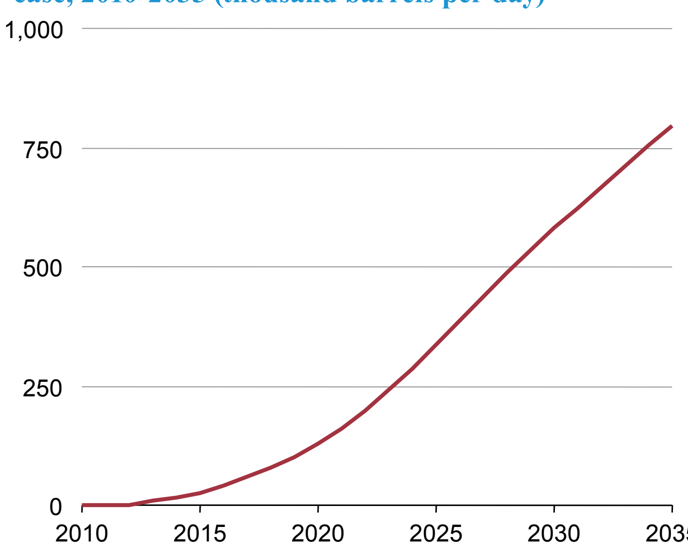
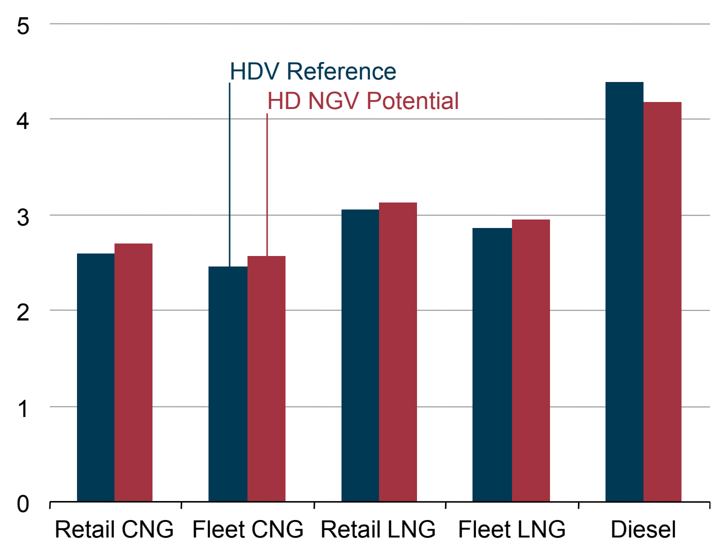


Figure 40. Diesel and natural gas transportation fuel prices in two cases, 2035 (2010 dollars per diesel gallon equivalent)



The term "liquid fuels production industry" refers to all the participants in the production and delivery of liquid fuels, from production of feedstocks to delivery of both liquid and non-liquid end-use products to customers. It includes participants in the more traditional petroleum refining sector, relying on crude oil as a primary feedstock; in the nonpetroleum fossil fuel sector, using natural gas and coal to produce liquid fuels; and in the biofuel sector, using biomass to produce biofuels such as ethanol and biodiesel. The complexity of the industry supply chain is inadequately described by nomenclature predicated on specific feedstocks (e.g., crude oil), processes (e.g. refinery hydrotreating), or end-use products (e.g., diesel fuel and gasoline), which fail to capture the significant economic implications of non-liquid-fuel products for the industry.

The components of the U.S. liquid fuels production industry—including petroleum, nonpetroleum fossil fuel, and biofuel sectors—are shown in Figure 41, along with examples illustrating processes and products. Figure 41 also highlights the differences between the new expanded "liquid fuels production industry," which the entire figure represents, and the less extensive "petroleum and other liquids industry," the components of which are highlighted in red.

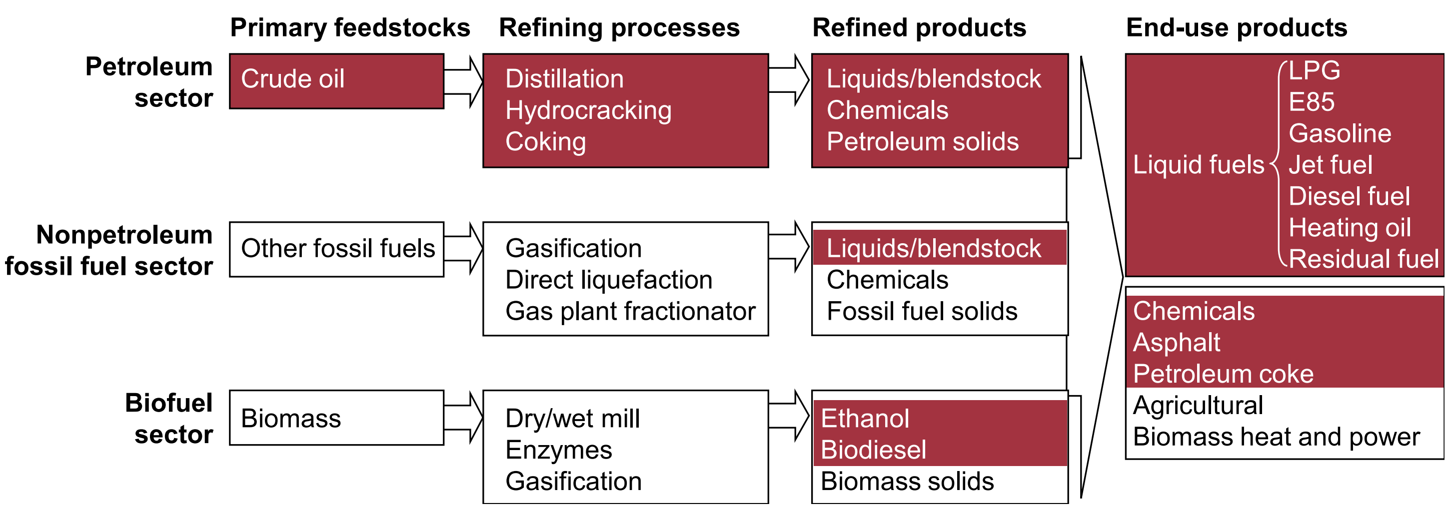
Nonpetroleum feedstocks are used in many new and emerging technologies, such as fermentation, enzymatic conversion, GTL, CTL, biomass-to-liquids, and algae-based biofuels. The new technologies provide valuable non-liquid-fuel co-products—such as chemical feedstocks, distiller's grains, and vegetable oils—that significantly affect the economics of liquid fuels production. The emergence of renewable biofuels has led to the introduction of midstream components such as ethanol and biodiesel, which are blended with petroleum products such as gasoline and diesel fuel during the final stages of the supply chain at refineries, blending sites, or retail pumps. The increase in biofuel production has led to new distribution channels and infrastructure investments and recognition of new production regions, such as the high concentration of ethanol producers in the Midwest. The new LFMM will include the entire liquid fuels production industry, providing greater flexibility for integrating new technologies and their associated products into the liquid fuels supply chain, better reflecting the industry's evolution.

In *AEO2012*, the "petroleum and other liquids" category includes the petroleum sector and those non-petroleum-based liquid products shaded in red in Figure 41, such as ethanol and biodiesel, which are blended with petroleum products to make end-use liquid fuels. Because this approach treats nonpetroleum products as exogenously produced feedstocks, the petroleum and other liquids concept used in *AEO2012* does not explicitly link the industrial processes that yield nonpetroleum liquid fuels (nor their feedstocks, nonpetroleum fossil fuels and biomass) with liquids production. The more inclusive definition of the liquid fuels production industry illustrated in Figure 41 is necessary to capture and model the full range of product flows and economic drivers of decisionmaking by firms involved in this complex industry.

Nonpetroleum feedstocks do not exist in traditional liquid form, and they require a different analytical approach for analysis of their conversion to liquid fuels. Traditional volumetric measures, such as process gain, are not applicable to an analysis of the liquids produced from nonpetroleum feedstocks. It is more appropriate to use the fundamental principles of mass and energy balance to evaluate process performance, market penetration, and supply/demand dynamics when the uses of nonpetroleum feedstocks are being examined. This approach allows for comparison among the different sectors of the liquid fuels production industry. Figure 42 provides an overview of the liquid fuels production industry on a mass basis.

The variety and changing dynamics of nonpetroleum feedstocks and the resulting end-use products also are illustrated in Figure 42. In recent history, biomass has taken significant market share from petroleum feedstocks, correlated with shifts in product yields—a trend that is expected to continue in the future, along with further diversification into nonpetroleum fossil feedstocks. In 2000, nearly all liquid fuels were derived from petroleum. Since then, however, the share of petroleum has dropped while the shares of biomass and other fossil fuels have increased. In 2011, the combined biomass and other fossil fuels share of feedstocks was almost 18 percent, measured on a mass basis. In the LFMM case, the biomass share of feedstock consumption increases to

Figure 41. U.S. liquid fuels production industry



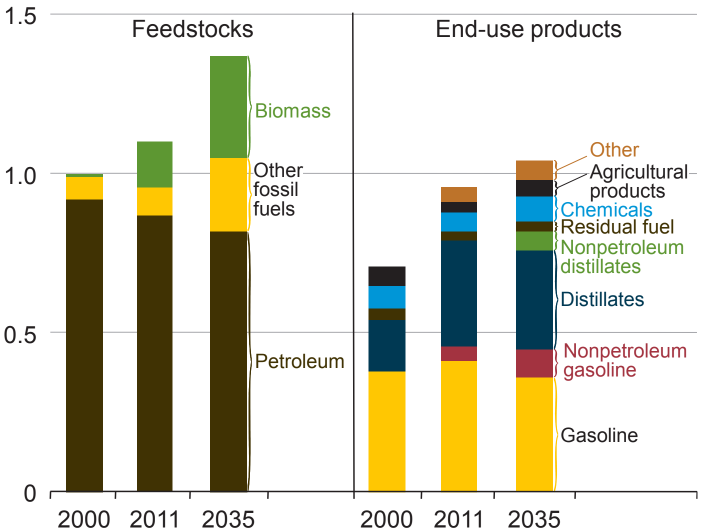
30 percent in 2035, and the petroleum share falls to about 57 percent. The biomass share of end-use products increases only to 10 percent in 2035, reflecting differences in conversion efficiencies between petroleum and nonpetroleum feedstocks, as highlighted by the growing but still small nonpetroleum content of gasoline and distillates.

Changes in crude oil types

Economic growth in the developing countries over the past decade has increased global demand for crude oil. Over the same period, new technologies for recovering crude oil, changes in the yields of existing crude oil fields, and a global increase in exploration have expanded the number and variety of crude oil types. The United States currently imports more than 100 different types of crude oil from around the world, including a growing number from Canada and Mexico, with a wide range of API gravities (between 10.4 and 64.6) and sulfur content (between 0.02 and 5.5 percent). Consequently, it is difficult to group them according to the categories used in the existing NEMS PMM. A new and more comprehensive representation of the numerous crude types is required, as well as flexibility to add new sources.

The United States increasingly is using crude oil extracted from oil sands and oil shale, as well as other nontraditional petroleum sources that require additional processing. The new sources have led to shifts in crude oil flows and changes in the distribution network. The increased variety and regional availability of certain crude types has created new market dynamics and pricing relationships that are difficult to capture using existing methods, especially considering the rapid emergence of "tight oil" production, which, to date, has been substantially different in quality from the crude oil previously expected to be available to U.S. refineries. For example, light sweet crude oil sourced from the Bakken shale formation in North Dakota has been sold to refiners on the Gulf Coast in recent years at a substantial discount relative to heavier imported crudes, because of limitations in the delivery infrastructure.

Figure 42. Mass-based overview of the U.S. liquid fuels production industry in the LFMM case, 2000, 2011, and 2035 (billion tons per year)

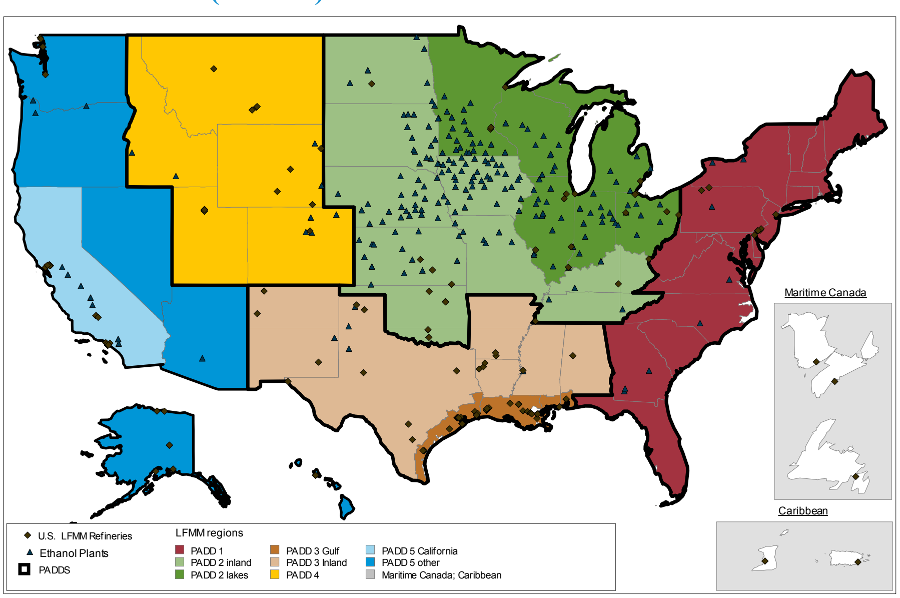


The growing number of sources, changes in characteristics of crudes, and shifting price relationships in crude oil markets require an updated representation of different crude types in NEMS. The model also needs an updated and more dynamic representation of the crude oil distribution network in order to provide better estimates of changes in crude oil flows and potential new regional sources in the future.

Regional updates

The Petroleum Administration for Defense Districts (PADD), which were developed by the Department of Defense during World War II, have been traditionally used as the regional framework for analyzing liquid fuels production. Because the topology and configuration of the liquid fuels market have changed significantly, and new feedstocks have emerged from regions that are subsets of PADDs, the regional definitions for processing liquid fuels need to be redefined. Toward this end, EIA has redefined the refining regions on the basis of market potential and availability of feedstocks. The redefined regions will be further divided as market conditions change. The new regional configuration of the NEMS LFMM will use eight domestic regions and adds a new international region (Figure 43).

Figure 43. New regional format for EIA's Liquid Fuels Market Module (LFMM)



Each new refining region has unique characteristics. PADD 1 has been left unchanged in the new configuration, but can be further divided based on recent and possible future refinery closures and shifts in imports from Europe. PADD 2 was subdivided into the Great Lakes and Inland regions due to the concentrated production of biofuels and access to Canadian crudes. PADD 3 was divided into the Gulf Coast and Inland regions due to the inability of the interior refineries to handle heavy sour crude. PADD 4 was left unchanged. California was separated from the rest of PADD 5 due to the State's unique gasoline and diesel specifications and regulatory policies. A new international region was added comprising Maritime Canada and the Caribbean.

The modified regional refinery format will allow EIA's analyses to more accurately capture regional refinery trends and potential regional regulatory policies that affect the liquid fuels market. For example, California often enacts its own regulatory policies earlier than the rest of its PADD region, and its individual actions could not be represented accurately in the PADD framework. As a further example, recent refinery closures and other developments on the East Coast evidence the need for a dynamic and flexible representation of the refinery regions that supply the U.S. market.

Changing product markets

Crude oil is still the most important and valuable feedstock for the liquid fuels production industry. More than 650 refineries, located in more than 116 countries, have the capacity to refine 86 million barrels of crude oil per day. In the past, most of the complex refineries that could transform a wide variety of crudes into numerous different products to meet demand were located in the United States. Now, however, complex refineries are becoming more common in Europe and the developing countries of Asia and Latin America, and the products from export-focused merchant refineries in those countries have the potential to compete with U.S. products. An example is the regular export of surplus gasoline from refiners in Europe to the Northeast United States.

Traditional measures of profitability, such as the 3-2-1 crack spread, require modification in NEMS in view of the changing market for liquid fuels. The calculation of margins requires consideration of multiple feedstocks and multiple products produced in refineries, biorefineries, and production facilities for nonpetroleum fuels. Operators in the liquid fuels production industry are faced with a choice of investing in facilities and modifying their configurations to meet changing market demand, or exchanging domestic feedstocks and products with merchant refineries in a global market. For example, increased U.S. efficiency standards for LDVs have reduced demand for gasoline and increased demand for diesel fuel, which has led to more gasoline exports and more investment to increase diesel output from domestic refineries.

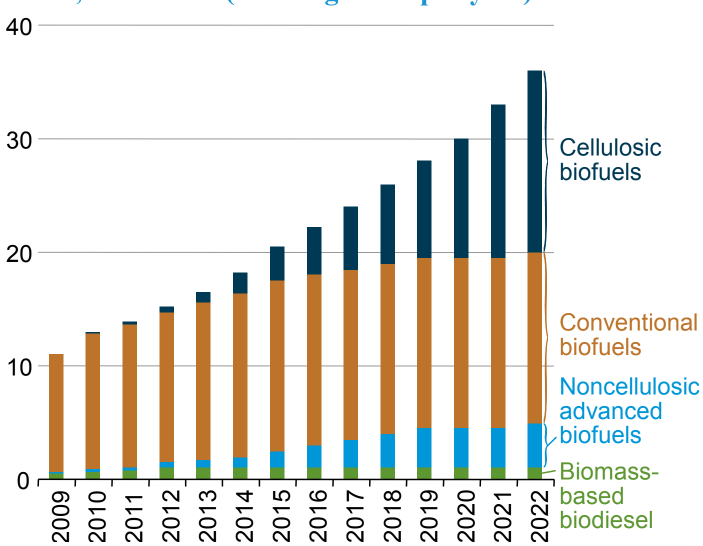
EIA's new LFMM representation of the liquid fuels production industry will need to account for global competition for both crude oil and end-use products. As refineries around the world become larger and more complex, smaller refineries may not be able to compete with imports produced at low margins. Therefore, it is necessary to have a more robust and dynamic representation of the liquid fuel producers, as well as additional flexibility to adjust inputs, refinery configurations, and crude and product demands as the industry evolves.

Regulations and policies

It is important for EIA's models to represent existing laws and regulations accurately, in addition to being flexible enough to model proposed laws and regulations. One of the most important regulations currently affecting the U.S. liquid fuels industry is the RFS, which not only has increased production and use of renewable fuels, but also has changed how fuels are distributed and consumed both here and abroad. The RFS mandates the use of biofuels that are consumed primarily as blends with traditional petroleum products, such as gasoline and diesel fuel (Figure 44). Because of their chemical properties, ethanol, biodiesel, and other first-generation biofuels generally require their own distribution networks or investments in new infrastructure. In addition, because they are produced outside traditional petroleum refineries, the new products are added at different points in the supply chain, either at blending terminals or at retail sites via blender pumps. Modeling those changes requires an update to the traditional PADD regional format used to represent the liquid fuels market, as well as an update to the transportation network that distributes the fuels.

The RFS also requires consideration of many new technologies and increases the complexity of decisionmaking in the liquid fuels production industry. Fuel volumes by product are mandated by the RFS. For each year, regulated parties must make the decision to either buy the available renewable fuels in proportion to their RFS requirements or purchase the necessary credits. For example, the cellulosic biofuel credit price is set as the greater of $0.25 cents per gallon or $3.00 per gallon minus the wholesale gasoline price, both based on 2008 real dollars. The RFS also contains a general waiver based on technical, economic, or environmental feasibility that the EPA Administrator has discretionary authority to act on to reduce the mandates for advanced and total biofuels.

Figure 44. RFS mandated consumption of renewable fuels, 2009-2022 (billion gallons per year)



In addition, use of biofuels has broader implications for the global market, in terms of both feedstocks and the fuels themselves. A good example is ethanol. Its primary feedstocks are corn and sugar, both of which are global commodities in high demand as food sources as well as biofuel feedstocks. U.S. ethanol producers compete globally in other countries, such as Brazil, that have their own renewable fuels mandates.

Finally, coproducts from biofuels production have a significant influence on their economics. For example, the value of the dried distillers grains coproduct from corn ethanol production, which can be sold to the agricultural sector, can offset up to one-third of the purchase cost for the corn feedstock. Thus, the economics of biofuels production are complex, and they require a model that accounts for numerous investment decisions, feedstock markets, and global interactions. The RFS adds to the liquids fuels market a number of fuel technologies, midstream products and coproducts, evolving regional production and distribution networks, and complex domestic and global market interactions.

The U.S. liquid fuels market has evolved substantially over the past 20 years in terms of available fuel types, production regions, global market dynamics, and regulations and policies. The transition has resulted in a liquid fuels market that uses both petroleum- and nonpetroleum-based inputs, distributes them around the country by a variety of methods, and makes investment decisions based on both economic and regulatory factors. The changes are significant enough to make the framework and metrics used in traditional refinery models no longer adaptable or robust enough for proper modeling of the transformed liquid fuels market. EIA currently is in the process of updating its framework to allow better representation of the transformed industry.

8. Changing environment for fuel use in electricity generation

Introduction

The *AEO2012* Reference case shows considerable change in the mix of generating technologies over the next 25 years. Coal remains the dominant source of electricity generation in the Reference case, with a 38-percent share of total generation in 2035, but that is down from shares of 45 percent in 2010 and nearly 50 percent in 2005. The decrease in coal's share of total generation is offset primarily by increases in the shares of natural gas and renewables. Key factors contributing to the shift away from coal are sustained low natural gas prices, higher coal prices, slow growth in electricity demand, and the implementation of Mercury and Air Toxics Standards (MATS) [*69*] and Cross-State Air Pollution Rule (CSAPR) [*70*]. These factors influence how existing plants are used, which plants are retired, and what types of new plants are built.

Fuel prices and dispatch of power plants

The price of fuel is a major component of a power plant's variable operating costs [*71*]. The fuel-related variable cost of generating electricity is a function of the fuel price and the efficiency of the plant's conversion of the fuel into electricity, also referred to as the heat rate. Although natural gas prices declined dramatically in the second half of 2011 and the first half of 2012, coal-fired power plants have generally had the advantage of lower fuel prices and the disadvantage of higher heat rates in comparison to combined-cycle plants fueled by natural gas.

Power plants are dispatched primarily on the basis of their variable costs of operation. Plants with the lowest operating costs generally operate continuously. Plants with higher variable costs are brought on line sequentially as demand for generation increases. Because fuel prices influence variable costs, changes in fuel prices can affect the choice of plants dispatched. For instance, if the price of natural gas decreases, the variable costs for combined-cycle plants may fall below those for competing coal-fired plants, and, as a result, the combined-cycle plant may be dispatched before the coal-fired plant. Coal and natural gas plants can vary their outputs on the basis of fuel prices, but there are some cases in which plants may cycle off completely until they can be operated economically. In order to examine the overall impacts of changes in projected fuel price trends on the electric power sector, *AEO2012* includes alternative cases that assume higher and lower prices for natural gas and coal.

Demand for electricity

Electricity demand determines how much generating capacity is needed. When demand increases, plants with higher operating costs are brought into service, increasing average operating costs and, as a result, average electricity prices. Higher prices, in turn, provide economic incentives for the construction of new capacity. Conversely, when demand declines, plants with higher operating costs are taken off line or run at lower intensities, and the economic incentives for new plant construction are reduced. If a plant is not profitable, the owner may decide to retire it.

Mercury and Air Toxics Standards and Cross-State Air Pollution Rule

Both MATS and CSAPR are included in the *AEO2012* Reference case [*72*]. Both rules have significant implications for the U.S. generating fleet, especially coal-fired power plants. MATS requires all U.S. coal- and oil-fired power plants with capacities greater than 25 megawatts to meet emission limits consistent with the average performance of the top 12 percent of existing units—known as the maximum achievable control technology. MATS applies to three pollutants: mercury, hydrogen chloride (HCl), and fine particulate matter ($PM_{2.5}$). HCl and $PM_{2.5}$ are intended to serve as surrogate pollutants for acid gases and nonmercury metals, respectively. CSAPR is a cap-and-trade program that sets caps on sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from all fossil-fueled plants greater than 25 megawatts in 28 States in most of the eastern half of the United States. CSAPR is scheduled to begin in 2012, although implementation was delayed by a court-issued stay at the time this article was completed [*73*]. See also "Cross-State Air Pollution Rule" in the "Legislation and regulations" section of this report.

Although the two rules differ in their makeup and the pollutants covered, the technologies that can be used to meet their requirements are not mutually exclusive. For instance, in order to meet the MATS acid gas standard, it is assumed that coal-fired plants without appropriate existing controls will need to install either flue-gas desulfurization (FGD) or dry sorbent injection (DSI) systems, which also reduce SO_2 emissions. Therefore, by complying with the MATS standards for acid gases, plants will lower overall SO_2 emissions, facilitating compliance with CSAPR.

AEO2012 assumes that all coal-fired power plants will be required to reduce mercury emissions to 90 percent below their pre-control levels in order to comply with MATS. The *AEO2012* NEMS explicitly models mercury emissions from power plants. Reductions in mercury emissions can be achieved with a combination of FGDs and selective catalytic reduction, which is primarily used to reduce SO_2 and NO_x emissions, or by installing activated carbon injection (ACI) systems. FGD systems may be effective in reducing mercury emissions from bituminous coal (due to its chemical makeup), but ACI systems may be necessary to remove mercury emissions from plants burning subbituminous and lignite coal.

NEMS does not explicitly model emissions of acid gases or toxic metals other than mercury. In order to represent the MATS limits for those emissions, *AEO2012* assumes that plants must install either FGD or DSI systems to meet the acid gas standard and, in the absence of a scrubber, a full fabric filter to meet the MATS standard for nonmercury metals. *AEO2012* assumes that the appropriate control technologies will be installed by 2015 in order to meet the MATS requirements.

DSI and wet and dry FGD systems are technologies that will allow plants to meet the MATS standards for acid gases. As of 2010, 43 percent of U.S. generating capacity already had FGDs installed [*74*]. For a number of the remaining, uncontrolled plants, operators will need to assess the effectiveness of installing FGD or DSI systems to comply with MATS. There are economic and engineering tradeoffs between the two technologies. FGD systems require significant upfront investment but have relatively low operating costs. DSI systems generally do not require significant capital expenses but may use significant quantities of sorbent to operate effectively, which increases their operating costs. Waste disposal for DSI also may be a significant variable cost, whereas the waste products from FGD systems can be sold as feedstock for industrial processes.

The EPA set an April 2015 compliance deadline for MATS, but the rule allows State environmental permitting agencies to extend the deadline by a year. Beyond 2016, the EPA stated that it will handle noncompliant units that need to operate for reliability purposes on a case-by-case basis [*75*]. *AEO2012* assumes that all plants will comply with MATS by the beginning of 2015.

Economics of plant retirements

The decision to retire a power plant is an economic one. Plant owners must determine whether a plant's future operations will be profitable. Environmental regulations, low natural gas prices, higher coal prices, and future demand for electricity all are key factors in the decision. Coal plants without FGD systems and with high heat rates, high delivered coal costs, and strong competition from neighboring natural gas plants in regions with slow growth in electricity demand may be especially prone to retirement.

Greenhouse gas policy in *AEO2012*

Uncertainty about possible future regulation of GHG emissions will continue to influence investment decisions in the power sector. Despite a lack of Congressional action, many utilities include simulations with a future CO_2 emissions price when evaluating long-term investment decisions. A carbon price would increase the cost of generation for all fossil fuel plants, but the largest impact would be on coal-fired plants. Thus, plant owners could be reluctant to retrofit existing coal plants to control for non-GHG pollutants, given the possibility that GHG regulations might be enacted in the near future. This uncertainty may influence the assumptions plant owners make about the economic lives of particular facilities.

In the Reference case, the costs of environmental retrofits are assumed to be recovered over a 20-year period. Two alternative cases assume that the costs would be recovered over 5 years, reflecting concern that future laws or regulations aimed at limiting GHG emissions will have significant negative effects on the economics of investing in existing coal plants.

AEO2012 also includes two alternative cases that assume enactment of an explicit GHG control policy. In each case, a CO_2 price is applied across all sectors starting in 2013 and increased at a 5-percent annual real rate through 2035. The price starts at $25 per metric ton in the GHG25 case and $15 per metric ton in the GHG15 case. The CO_2 price is applied across sectors and has a significant impact on the cost of generating electricity from fossil fuels, particularly coal.

Alternative cases

In order to illustrate the impacts of the various influences on the electric power sector, *AEO2012* includes several alternative cases that include varying assumptions about fuel prices, electricity demand, and the cost recovery period for environmental control equipment investments:

- The Reference 05 case assumes that the cost recovery period for investments in new environmental controls is reduced from 20 years to 5 years.

- The Low Estimated Ultimate Recovery (EUR) case assumes that the EUR per tight oil or shale gas well is 50 percent lower than in the Reference case, increasing the per-unit cost of developing the resource and, ultimately, the price of natural gas used at power plants (Figure 45).
- The High EUR case assumes that the EUR per tight oil or shale gas well is 50 percent higher than in the Reference case, decreasing the per-unit cost of developing the resource and the price of natural gas for power plants.
- The Low Gas Price 05 case combines the more optimistic assumptions about future volumes of shale gas production from the High EUR case with a 5-year recovery period for investments in new environmental controls.
- The High Coal Cost case assumes lower mining productivity and higher costs for labor, mine equipment, and coal transportation, which ultimately result in higher coal prices for electric power plants.
- The Low Coal Cost case assumes higher mining productivity and lower costs for labor, mine equipment, and coal transportation, which ultimately result in lower coal prices for electric power plants.
- The Low Economic Growth case assumes lower growth rates for population and labor productivity, higher interest rates, and lower growth in industrial output, which ultimately reduce demand for electricity (Figure 46), which is reflected in electricity sales, relative to the Reference case.
- The High Economic Growth case assumes higher growth rates for population and labor productivity. With higher productivity gains and employment growth, inflation and interest rates are lower than in the Reference case, and, consequently, economic output grows at a higher rate, ultimately increasing demand for electricity, which is reflected in electricity sales, relative to the Reference case.
- In the GHG15 case, the CO_2 price is set at $15 per metric ton in 2013 and increases at a real annual rate of 5 percent per year over the projection period. Price is set to target the same reduction in CO_2 emissions as in the *AEO2011* GHG Price Economywide case.
- In the GHG25 case, the CO_2 price is set at $25 per metric ton in 2013 and increases at a real annual rate of 5 percent per year over the projection period. Price is set to target the same dollar amount as in the *AEO2011* GHG Price Economywide case.

Analysis results

Coal-fired plant retirements

Significant amounts of coal-fired generating capacity are retired in all the alternative cases considered (Figure 47). (For a map of the electricity regions projected, see Appendix F.) In the Reference 05 case, 63 gigawatts of coal-fired capacity is retired through 2035, 28 percent higher than in the Reference case. In the High EUR case, 55 gigawatts of coal-fired capacity is retired, as lower wholesale electricity prices and competition from natural gas combined-cycle units makes the operation of some coal plants uneconomical. In the Low Economic Growth case, 69 gigawatts of coal-fired capacity is retired, because lower demand for electricity reduces the need for new capacity and makes investments in older plants unattractive.

The High Economic Growth case results in fewer retirements, as existing coal-fired capacity is needed to meet growing electricity demand, and higher economic growth pushes up natural gas prices. In the Low Coal Cost case, the lower relative coal prices increase the profit margins for coal-fired power plants, making it more likely that investments in retrofit equipment will be recouped over the life of the plants.

Figure 45. Natural gas delivered prices to the electric power sector in three cases, 2010-2035 (2010 dollars per million Btu)

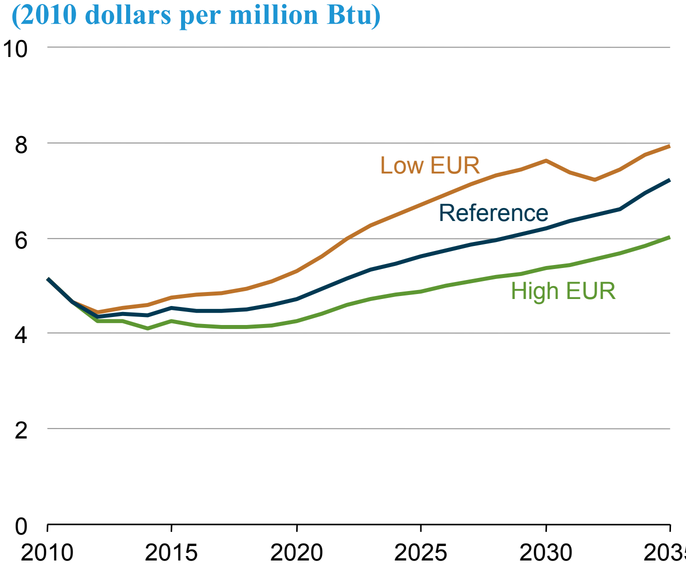
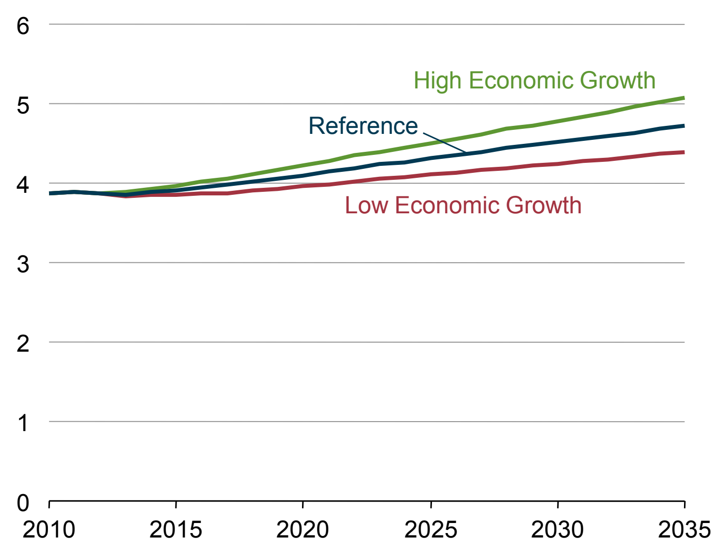


Figure 46. U.S. electricity demand in three cases, 2010-2035 (trillion kilowatthours)



Coal-fired capacity retirements are concentrated in two North American Electric Reliability Corporation (NERC) regions: the SERC Reliability Corporation (SERC) region, which covers the Southeast region, and the Reliability First Corporation (RFC), which includes most of the Mid-Atlantic and Ohio Valley region [76]. Many coal-fired plants in those regions are sensitive to the factors that influence retirement decisions, as discussed above. In the SERC and RFC regions, which in 2010 accounted for 65 percent of U.S. coal-fired generating capacity, 43 percent of the coal-fired plants do not have FGD units installed. Coal plants in the RFC and SERC regions are fueled primarily by bituminous coal, generally the coal with the highest cost. Projected demand for electricity in the early years of the Reference case is low nationwide and, especially, in the RFC region, where demand in 2015 is slightly lower than in 2010. In both the GHG15 and GHG25 cases, even larger amounts of coal-fired capacity are retired by 2035 than in the non-GHG policy cases.

Generation by fuel

Coal

In all cases, generation from coal is lower in 2020 than in 2010. Higher coal prices, relatively low natural gas prices, retirements of coal-fired capacity, and slow growth in electricity demand are responsible for the decrease. Generation from coal is lower than in the Reference case in the Reference 05, High EUR, Low Gas Price 05, High Coal Cost, and Low Economic Growth cases as a result of additional retirements of coal-fired capacity, lower natural gas prices, higher coal prices, or lower electricity demand. In cases where the opposite assumptions are incorporated, coal-fired generation is higher.

Generation from coal begins to recover after 2020, as electricity demand and natural gas prices start to rise. The strongest increases in coal-fired electricity generation occur in the Low EUR, Low Coal Cost, and High Economic Growth cases. When lower natural gas prices, lower economic growth, and/or higher coal prices are assumed, coal-fired generation still increases after 2020 but at a slower rate. In all cases, utilization of existing coal-fired power plants increases, because there is no significant growth in new coal-fired capacity. In the most optimistic case, the High Economic Growth case, only 3.3 gigawatts of new coal-fired capacity is added from 2017 to 2035 [77].

Despite a declining share of the generation mix, coal still has the highest share of total electricity generation in 2035 in all non-GHG or High TRR cases. However, it never again reaches the 2010 share of 45 percent, even in the Low EUR case (where it reaches 40 percent in 2035). Conversely, the coal share of total generation in 2035 is 34 percent in the Low Gas Price 05 case. The lower coal share is offset by increased generation from natural gas, which grows significantly in all the cases. The natural gas share of total generation almost equals that of coal in the Low Gas Price 05 case. In the GHG15 and GHG25 cases, coal-fired generation drops to 16 percent and 4 percent, respectively, of the total generation mix in 2035, and in both cases generation from coal declines significantly as the explicit price on CO_2 emissions increases costs. In the GHG15 and GHG25 cases, decreases in coal-fired generation are offset by a mix of natural gas, nuclear, and renewable generation.

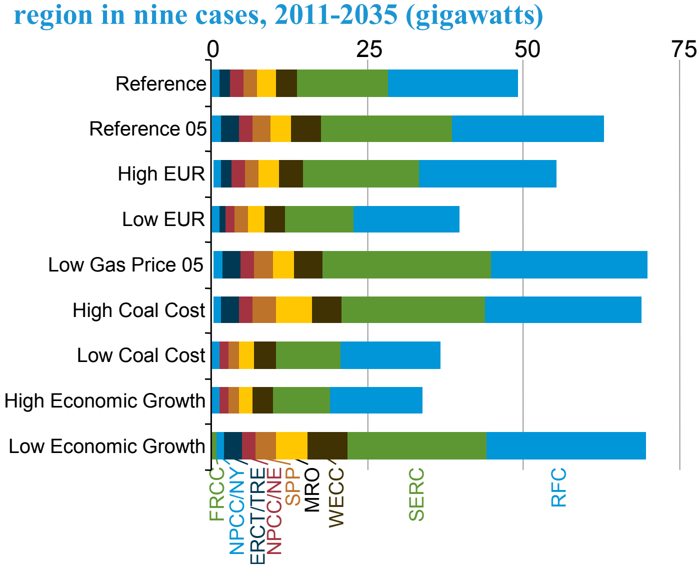
Natural gas

In the *AEO2012* Reference case, electricity generation from natural gas in 2020 is 13 percent above the 2010 level, despite an increase of only 5 percent in overall electricity generation. Low natural gas prices result in greater utilization of existing combined-cycle plants as well as the addition of 16 gigawatts of natural gas combined-cycle capacity from 2010 to 2020. The same trends are amplified in cases with lower natural gas prices and more coal-fired capacity retirements and muted in cases with higher natural gas prices and fewer coal-fired capacity retirements. Generation from combustion turbines does not change significantly across the cases, demonstrating that changes in the relative economics of coal and natural gas affect primarily the dispatch of combined-cycle plants to meet base and intermediate load requirements, not combustion turbines to meet peak load requirements.

In the Reference case, 58 gigawatts of natural gas combined-cycle capacity is added from 2020 to 2035, causing an increase in generation from natural gas during the period (Figures 48 and 49). In the Low EUR and Low Coal Cost cases, growth in natural gas combined-cycle capacity is slower. Although generation from natural gas increases overall with the addition of new capacity, utilization of existing combined-cycle plants drops slightly as higher natural gas prices reduce the frequency at which combined-cycle plants are dispatched.

In the GHG15 and GHG25 cases, electricity generation from natural gas exceeds generation from coal in 2020. Natural gas has one-half the CO_2 emissions of coal, and at relatively low CO_2 prices, natural gas generation is seen as an attractive

Figure 47. Cumulative retirements of coal-fired generating capacity by Electric Market Module region in nine cases, 2011-2035 (gigawatts)



alternative to coal. However, as CO_2 prices rise over the projection period, the increasing cost of generating electricity with natural gas causes the growth in natural gas generation to slow. In the GHG25 case, natural gas combined-cycle plants with CCS play a role in CO_2 mitigation, with 34 gigawatts of natural gas combined-cycle capacity added between 2022 and 2035.

Nuclear

Generation from nuclear power plants does not change significantly from Reference case levels in any of the non-GHG cases, due to the high cost of new nuclear plant construction relative to natural gas and renewables. In the GHG15 and GHG25 cases, nuclear power plants become more competitive with fossil plants, because they do not emit CO_2 and are needed to replace coal-fired capacity that is retired due to the cost of CO_2 emissions. In the GHG15 and GHG25 cases, generation from nuclear power is 57 percent and 121 percent higher, respectively, in 2035 than in 2010.

Renewables

Generation from renewable energy sources grows by 77 percent from 2010 to 2035 in the Reference case. Most of the growth in renewable electricity generation is a result of State RPS requirements, Federal tax credits, and—in the case of biomass—the availability of low-cost feedstocks. The change in renewable generation over the 2010-2035 period varies from a 102-percent increase in the High Economic Growth case to a 62-percent increase in the Low Economic Growth case. The largest growth in renewable generation is projected in the GHG15 and GHG25 cases, where renewable generation increases by about 150 percent from 2010 and 2035 in both cases. A price on CO_2 emissions makes generation from renewables more competitive with fossil plants without CCS.

Figure 48. Electricity generation by fuel in eleven cases, 2010 and 2020 (trillion kilowatthours)

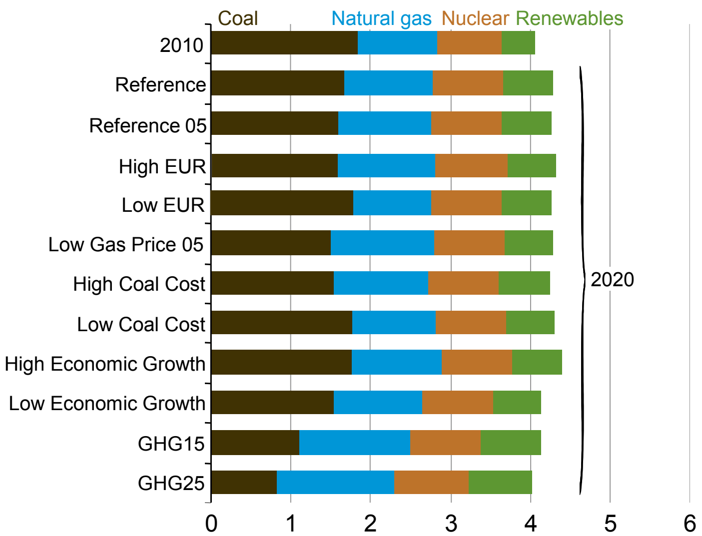
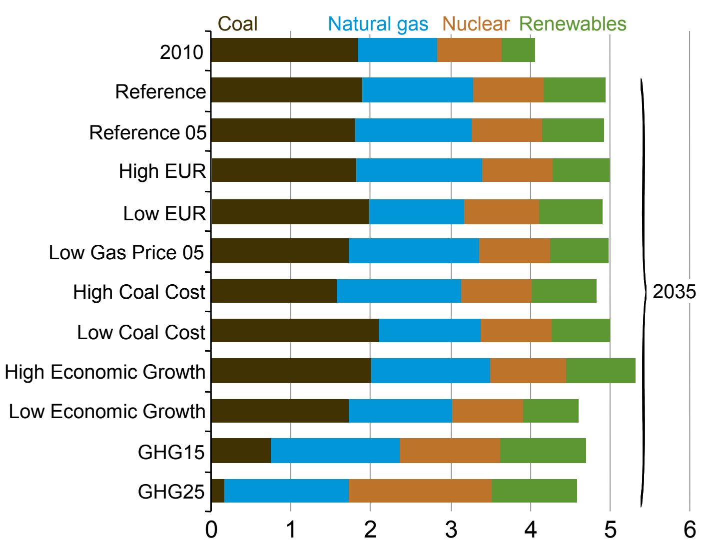


Figure 49. Electricity generation by fuel in eleven cases, 2010 and 2035 (trillion kilowatthours)



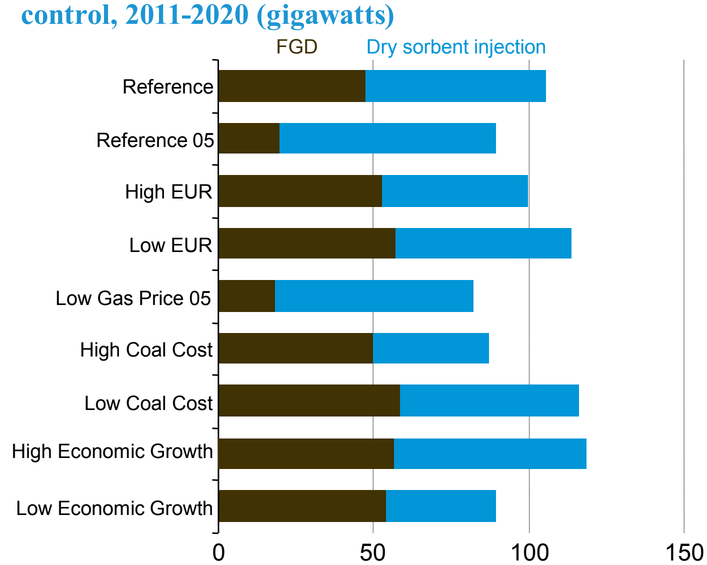
Installations of retrofit equipment

As discussed above, it is assumed that all coal-fired plants must have either FGD or DSI systems installed by 2015 to comply with environmental regulations. Because retirement is the only other option, cases with more retirements have fewer retrofits and vice versa (Figure 50). In the Reference 05 and Low Gas Price 05 cases, the relative cost of FGD units is higher because of the short payback period, making DSI a relatively more attractive option.

Emissions

SO_2 emissions are significantly below 2010 levels in 2015 in all cases, as a result of coal-fired capacity retirements and the installation of pollution control equipment to comply with MATS. *AEO2012* assumes that a DSI system, combined with a fabric filter, will remove 70 percent of a coal plant's SO_2 emissions, and an FGD unit 95 percent. As a result of the requirement for FGD or DSI systems, all coal plants larger than 25 megawatts that did not have FGD units installed in 2010 significantly reduce their SO_2 emissions after 2015 by

Figure 50. Cumulative retrofits of generating capacity with FGD and dry sorbent injection for emissions control, 2011-2020 (gigawatts)



installing control equipment. In all cases, coal-fired generation is down overall, which also contributes to the decline in emissions. SO_2 emissions increase after 2020 in all non-GHG cases, as coal-fired generation increases with rising natural gas prices. Because DSI and FGD retrofits do not remove all the SO_2 from coal-fired power plant emissions, increases in coal-fired generation result in higher SO_2 emissions, although they are still much lower than comparable 2010 levels. Also, the level of SO_2 reduction is proportional to the amount of coal-fired generation, and therefore the cases with the highest projected levels of coal-fired generation also project the highest levels of SO_2 emissions.

The projections for mercury emissions are similar. After a sharp drop in 2015, mercury emissions begin to rise slowly as coal-fired generation increases in all non-GHG cases. However, mercury emissions in 2035 still are significantly below 2010 levels, as the requirement for a 90-percent reduction in uncontrolled emissions of mercury remains binding throughout the projection.

NO_x emissions are not directly affected by MATS, but both annual and seasonal cap-and-trade programs are included in CSAPR. Emissions reductions relative to 2010 levels are small throughout the projection period in most cases, mainly because compliance with CSAPR NO_x regulations is required in only 26 States, and 2010 emissions levels already were close to the cap.

CO_2 emissions from the electric power sector fall slightly in cases that project declines in coal use, but the largest reductions occur in the GHG15 and GHG25 cases. In the GHG15 case, CO_2 emissions from the electric power sector are 46 percent below 2010 levels in 2035, and in the GHG25 case they are 76 percent below 2010 levels.

Electricity prices

Real electricity prices in 2035 are 3 percent above the 2010 level in the Reference case. The increase is relatively modest because natural gas prices increase slowly, and several alternatives for complying with the environmental regulations are available. When lower natural gas prices are assumed, real electricity prices decline relative to the Reference case. Both the GHG15 and GHG25 cases assume that costs for CO_2 emission allowances are passed through directly to customers. Therefore, average electricity prices in the GHG15 and GHG25 cases in 2035 are 25 percent and 33 percent higher, respectively, than in the Reference case. The GHG15 and GHG25 cases do not include any of the rebates to electricity consumers included in some other GHG policy proposals, which would reduce the impact on electricity prices.

9. Nuclear power in *AEO2012*

In the *AEO2012* Reference case, electricity generation from nuclear power in 2035 is 10 percent above the 2010 total. The nuclear share of overall generation, however, declines from 20 percent in 2010 to 18 percent in 2035, reflecting increased shares for natural gas and renewables.

In the Reference case, 15.8 gigawatts of new nuclear capacity is added from 2010 through 2035, including both new builds (a total of 8.5 gigawatts) and power uprates at operating nuclear power plants (7.3 gigawatts). A total of 6.1 gigawatts of nuclear capacity is retired in the Reference case, with most of the retirements coming after 2030. However, given the current uncertainty about likely lifetimes of nuclear plants now in operation and the potential for new builds, *AEO2012* includes several alternative cases to examine the impacts of different assumptions about future nuclear power plant uprates and operating lifetimes.

Uprates

Power plant uprates involve projects that are intended to increase the licensed capacity of existing nuclear power plants and permit those plants to generate more electricity. The U.S. Nuclear Regulatory Commission (NRC) must approve all uprate projects before they are undertaken and verify that the reactors will be able to operate safely at higher levels of output. Power plant uprates can increase plant capacity by 1 to 20 percent, depending on the size and type of the uprate project. Capital expenditures may be small (e.g., installing a more accurate sensor) or significant (e.g., replacing key plant components, such as turbines).

In developing projections for nuclear power, EIA relies on both reported data and estimates. Reported data come from Form EIA-860 [*78*], which requires all nuclear power plant owners to report any plans for building new plants or making major modifications to existing plants (such as uprates) over the next 10 years. In 2010, operators reported that they intended to complete uprate projects sometime during the next 10 years, which together would add a total of 0.8 gigawatts of new capacity. In addition to the reported plans for capacity uprates, EIA assumed that additional power uprates over the period from 2011 to 2035 would add another 6.5 gigawatts of capacity, based on interactions with EIA stakeholders with significant experience in implementing power plant uprates.

New builds

Building a new nuclear power plant is a tremendously complex project that can take many years to complete. Specialized high-wage workers, expensive materials and components, and engineering and construction expertise are required, and only a select group of firms worldwide can provide them. In the current economic environment of low natural gas prices and flat demand for electricity, the overall market conditions for new nuclear power plants are challenging.

Nuclear power plants are among the most expensive options for new generating capacity available today [*79*]. In the *AEO2012* Reference case, the overnight capital costs associated with building a nuclear power plant planned in 2012 are assumed to be $5,335 per kilowatt of capacity, which translates to $11.7 billion for a dual-unit 2,200-megawatt power plant. The overnight costs do not include additional costs such as financing, interest carried forward, and peripheral infrastructure updates [*80*]. Despite the cost, however, deployment of new nuclear capacity supports the long-term resource plans of many utilities, by allowing fuel diversification and providing a hedge in the future against potential GHG emissions regulations or natural gas prices that are higher than expected.

Incentive programs exist to encourage the construction of new reactors in the United States. At the Federal level, the Energy Policy Act of 2005 (EPACT05) established a loan guarantee program for new nuclear plants completed and in operation by 2020 [*81*]. A total of $18.5 billion is available, of which $8.3 billion has been conditionally committed to the construction of Southern Company's Vogtle Units 3 and 4 [*82*]. EPACT05 also provides a PTC of $18 per megawatthour for electricity produced during the first 8 years of operation for a new nuclear plant [*83*]. New nuclear plants must be operational by 2021 to be eligible for the PTC, and the credit is limited to the first 6 gigawatts of new nuclear plant capacity. In addition to Federal incentives, several States provide favorable regulatory environments for new nuclear plants by allowing plant owners to recover their investments through retail electricity rates.

Several utilities are moving forward with plans to deploy new nuclear power plants in the United States. The Reference case reflects those plans by including 6.8 gigawatts of new nuclear capacity over the projection period. As reported on Form EIA-860, 5.5 gigawatts of new capacity (Vogtle Units 3 and 4, Summer Units 2 and 3, and Watts Bar Unit 2) are expected to be operational by 2020 [*84*]. The Reference case also includes 1.3 gigawatts associated with the construction of Bellefonte Unit 1, which the Tennessee Valley Authority reflects in its Integrated Resource Plan [*85*].

In addition to reported plans for new nuclear power plants, 1.8 gigawatts of unplanned capacity is built in the later years of the Reference case. Higher natural gas prices, recovering demand for electricity, and the need to make up for the loss of a limited amount of nuclear capacity all play a role in the additional builds.

Long-term operation of the existing nuclear power fleet

The NRC has the authority to issue initial operating licenses for commercial nuclear power plants for a period of 40 years. As of December 31, 2011, there were 7 reactors that received their initial full power operating licenses over 40 years ago. Among this set of reactors, Oyster Creek Unit 1 was the first reactor to operate for over 40 years, after receiving its initial full power operating license in August 1969. Oyster Creek Unit 1 was followed by Dresden Units 2 and 3, H.B. Robinson Unit 2, Monticello, Point Beach 1, and R.E. Ginna. The decision to apply for an operating license renewal is made by nuclear power plant owners, typically based on economics and the ability to meet NRC requirements. As of January 2012, the NRC had granted license renewals to 71 of the 104 operating reactors in the United States, allowing them to operate for a total of 60 years [*86*]. Currently, the NRC is reviewing license renewal applications for 15 reactors and expects to receive applications from another 14 reactors between 2012 and 2016 [*87*].

NRC regulations do not limit the number of license renewals a nuclear power plant may be granted. The nuclear power industry is preparing applications for license renewals that would allow continued operation beyond 60 years. The first application seeking approval to operate for 80 years is tentatively scheduled to be submitted by 2013. Some aging nuclear plants may, however, pose a variety of issues that could lead to decisions not to apply for a second license renewal, such as high operation and maintenance costs or the need for large capital expenditures to meet NRC requirements. Industry research on long-term reactor operations and aging management is focused on identifying challenges that aging facilities might encounter and formulating potential approaches to meet those challenges [*88*]. Typical challenges involve materials degradation, safety margins, and assessing the integrity of concrete structures. In the Reference case, 6.1 gigawatts of nuclear power plant capacity is retired by 2035, based on uncertainty related to issues associated with long-term operations and aging management [*89*].

It should be noted that although the Oyster Creek Generating Station in Lacey Township, New Jersey, received a license renewal and could operate until 2029, the plant's owner has reported to EIA that it will be retired in 2019, after 50 years of operation. The *AEO2012* Reference case includes this reported early retirement. Also, given the evolving nature of the NRC's regulatory response to the accident at Japan's Fukushima Daiichi nuclear power plant in March 2011, the Reference case does not include retirements directly related to the accident (for example, retirements prompted by potential new NRC regulatory requirements for safety retrofits).

Sensitivity cases

The *AEO2012* Low Nuclear case assumes that only the planned nuclear plant uprates already reported to EIA will be completed. Uprates that are currently under review or expected to be submitted to the NRC are not included. The Low Nuclear case also assumes that all nuclear power plants will be retired after 60 years of operation, resulting in a 30.9-gigawatt reduction in U.S. nuclear power capacity from 2010 to 2035. Figure 51 shows nuclear capacity retirements in the Low Nuclear case by NERC region. It should be noted that after the retirement of Oyster Creek in 2019, the next nuclear plant retirement occurs in 2029 in the Low Nuclear case. No new nuclear plants are built in the Low Nuclear case beyond the 6.8 gigawatts already planned.

In the High Nuclear case, in addition to plants already under construction, plants with active license applications at the NRC are constructed, provided that they have a tentatively scheduled mandatory hearing before the NRC or Atomic Safety and Licensing Board and deploy a currently certified design for the nuclear steam supply system, such as the AP1000. With this assumption, an additional 6.2 gigawatts of new nuclear capacity is added relative to the Reference case. The High Nuclear case also assumes that all existing nuclear power plants will receive their second license renewals and will operate through 2035. Uprates in the

High Nuclear case are consistent with those in the Reference case. The only retirement included in the High Nuclear case is the announced early retirement of Oyster Creek in 2019.

Results

In the Reference case, 8.5 gigawatts of new nuclear power plant capacity is added from 2010 to 2035, including the 6.8 gigawatts reported to EIA (referred to as "planned") and 1.8 gigawatts built endogenously in NEMS (referred to as "unplanned"). Unplanned capacity is added starting in 2030 in response to rising natural gas prices, which make new nuclear power plants a more competitive option for new electric capacity. In the High Nuclear case, planned capacity additions are almost double those in the Reference case, but unplanned additions are lower. The price of natural gas delivered to the power sector in the High Nuclear case is lower than in the Reference case, making the economics of nuclear power plants slightly less attractive. The additional planned capacity in the High Nuclear case also reduces the need for new unplanned capacity. No unplanned capacity is added in the Low Nuclear case.

Nuclear power generation in 2035 reflects the differences in capacity that occur in the nuclear cases. In the High Nuclear case, nuclear generation in 2035 is 10 percent higher than in the Reference case, and the nuclear share of total generation is 20 percent, as compared with 18 percent in the Reference case. The increase in nuclear capacity in the High Nuclear case contributes to an increase in total electricity generation, in spite of lower levels of generation from natural gas (4 percent lower than in the Reference case in 2035) and coal and renewables (less than 1 percent lower for each fuel).

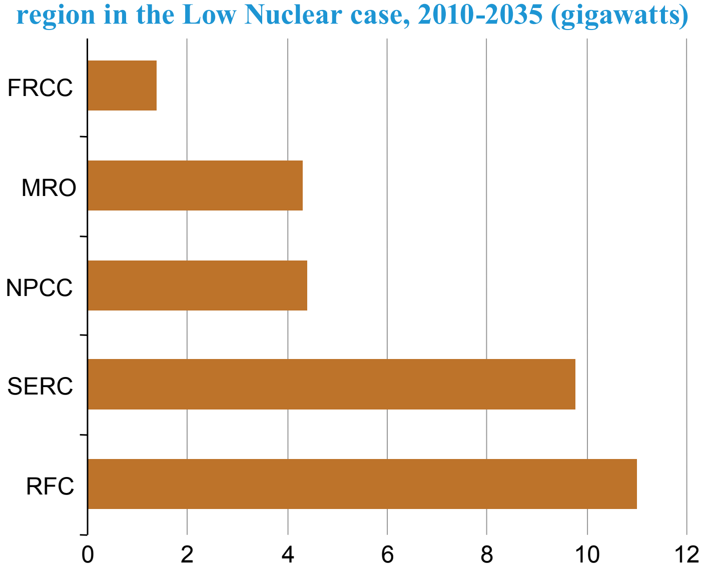
In the Low Nuclear case, generation from nuclear power in 2035 is 30 percent lower than in the Reference case, due to the loss of 30.9 gigawatts of nuclear capacity that is retired after 60 years of operation. As a result, the nuclear share of total generation is reduced to 13 percent. The loss of generation is made up primarily by increased generation from natural gas (12 percent higher than in the Reference case in 2035), coal (1 percent higher), and renewables (3 percent higher).

Real average electricity prices in 2035 are 1 percent lower in the High Nuclear case than in the Reference case, as slightly less natural gas capacity is dispatched, lowering the marginal price of electricity. In the Low Nuclear case, average electricity prices in 2035 are 5 percent higher than in the Reference case as a result of the retirement of a significant amount of nuclear capacity, which has relatively low operating costs, and its replacement with natural gas capacity, which has higher fuel costs that are passed through to consumers in retail electricity prices. With all nuclear power plants being retired after 60 years of operation in the Low Nuclear case, an additional 12 gigawatts of nuclear capacity would be shut down between 2035 and 2040.

The impacts of nuclear plant retirements on retail electricity prices in the Low Nuclear case are more apparent in regions with relatively large amounts of nuclear capacity. For example, electricity prices in the Low Nuclear case are 7 percent higher than in the Reference case for the NERC MRO Region, and 6 percent higher in the Northeast, Mid-Atlantic, and Southeast regions. Even in regions where no nuclear capacity is retired, there are small increases in electricity prices relative to the Reference case, because higher demand for natural gas in regions with nuclear plant retirements affect prices nationwide.

The Reference case projections for CO_2 emissions also are affected by changes in assumptions about nuclear plant lifetimes. In the Low Nuclear case, CO_2 emissions from the electric power sector in 2035 are 3 percent higher than in the Reference case as a result of switching from nuclear generation to natural gas and coal, both which produce more CO_2 emissions. In the High Nuclear case, CO_2 emissions from the power sector are slightly (1 percent) lower than in the Reference case. Table 12 summarizes key results from the *AEO2012* Reference, High Nuclear, and Low Nuclear cases.

Figure 51. Nuclear power plant retirements by NERC region in the Low Nuclear case, 2010-2035 (gigawatts)



10. Potential impact of minimum pipeline throughput constraints on Alaska North Slope oil production

Introduction

Alaska's North Slope oil production has been declining since 1988, when average annual production peaked at 2.0 million barrels per day. In 2010, about 600,000 barrels per day of oil was produced on the North Slope. Although new North Slope oil fields have started production since 1988, the decline of North Slope production has resulted largely from depletion of the North Slope's two largest fields, Prudhoe Bay and Kuparuk River. Recently, Alyeska Pipeline Service Company (Alyeska), the operator of the Trans-Alaska Pipeline System (TAPS), stated that oil pipeline transportation problems could begin when throughput falls below 550,000 barrels per day and become increasingly severe with further declines [*90*].

Alyeska estimates that TAPS operational problems could become considerable when throughput falls below 350,000 barrels per day. The decline of both North Slope oil production and TAPS throughput raises the possibility that North Slope oil production might be shut down, with the existing oil fields plugged and abandoned sometime before 2035. That possibility is discussed here, as well as alternatives that could prolong the life of North Slope oil fields and TAPS beyond 2035.

Background

Declining TAPS throughput

TAPS is an 800-mile crude oil pipeline that transports North Slope oil production south to the Alyeska marine terminal in Valdez, Alaska. The crude oil is then transported by tankers to West Coast refineries. TAPS currently is the only means for transporting North Slope crude oil to refineries and the petroleum consumption markets they serve.

From 2004 through 2006, Alyeska reconfigured and refurbished TAPS, spending about $400 million to $500 million [*91*] both to reduce operating expenses and to permit TAPS to operate at lower flow rates, with a potential minimum mechanical throughput rate thought to be about 200,000 barrels per day at that time [*92*]. As North Slope oil production has declined, however, concern about TAPS operation under low flow conditions has grown [*93*]. In August 2008, Alyeska initiated its Low Flow Impact Study, which was released on June 15, 2011 [*94*].

The Alyeska study identified the following potential problems that might occur as TAPS throughput declines from the current production levels:

- Water dropout from the crude oil, which could cause pipeline corrosion
- Ice formation in the pipe if the oil temperature drops below freezing
- Wax precipitation and deposition
- Soil heaving.

Other potential operational issues at low flow rates include sludge dropout, reduced ability to remove wax, reduction in pipeline leak detection efficiency, pipeline shutdown and restart, and the running of pipeline pigs that both clean the pipeline and check its integrity.

Although TAPS low flow problems could begin at volumes around 550,000 barrels per day in the absence of any mitigation, their severity is expected to increase as throughput declines further. As the types and severity of problems multiply, the investment required to mitigate these is expected to increase significantly. Because of the many and diverse operational problems expected to occur at throughput volumes below 350,000 barrels per day, considerable investment could be required to keep the pipeline operational below that threshold. The Alyeska study does not provide any estimates of what it might cost to keep the pipeline operational below either 550,000 or 350,000 barrels per day. Currently, Alyeska is conducting tests and analyses to determine the likely efficacy and costs of different remedies.

Mitigating the decline of North Slope oil production

Although much of the public focus has been on the operational capability of TAPS at low flow rates, the more fundamental issue is declining oil production. The TAPS low flow issue would be alleviated most readily by discovery and production of large new sources of oil on the North Slope. Potential sources of significant North Slope oil production are located offshore in the Chukchi and Beaufort Seas and onshore in shale and heavy oil deposits. The Arctic National Wildlife Refuge (ANWR) is also estimated to hold approximately 10.4 billion barrels of technically recoverable oil resources, but Federal oil and gas leasing in ANWR currently is prohibited [*95*]. Another potential source of new TAPS volumes would be the conversion of North Slope natural gas resources to either methanol or Fischer-Tropsch petroleum products that could be transported to market via TAPS. Finally, in the absence of new North Slope petroleum supplies, alternative crude oil transportation facilities could be developed, such as a new small-diameter pipeline running parallel to the TAPS route [*96*] or a new offshore oil terminal for North Slope production.

Table 12. Summary of key results from the Reference, High Nuclear, and Low Nuclear cases, 2010-2035

Projection	Reference	High Nuclear	Low Nuclear
Nuclear plant cumulative retirements (gigawatts)	6.1	0.6	30.9
Generating capacity cumulative additions (gigawatts)			
Coal	16.6	16.1	18.9
Natural gas	141.6	126.2	147.6
Nuclear capacity uprates	7.3	7.3	0.8
Planned nuclear capacity additions	6.8	13.5	6.8
Unplanned nuclear capacity additions	1.8	1.3	--
Renewables	67.4	64.5	73.4
Average delivered electricity price, 2035 (2010 cents per kilowatthour)	10.1	10.0	10.6
Average delivered natural gas price for electric power, 2035 (2010 dollars per million Btu)	7.21	7.00	8.03
CO_2 emissions from electric power generation, 2035 (million metric tons)	2,330	2,301	2,404

Which of these potential low-flow solutions (or combination thereof) may ultimately come to fruition is impossible to determine at this time. Moreover, each solution comes with its own unique set of costs, risks, and lead times. Not only does each solution entail its own set of risks, there is also a significant risk that production from existing North Slope fields might decline much faster than anticipated and/or that the cost of operating those fields might escalate much faster than expected. Under those circumstances, there is a risk that any solution(s) could be both too little and too late, because the North Slope oil fields would be shut down before a TAPS solution could be implemented.

How quickly TAPS flows will decline, the types of low flow problems that might develop, and the degree of mitigation required depend on the success or failure of current offshore and onshore oil exploration and development programs and the quality of the oil produced. For example, low-viscosity oil is less problematic to TAPS operations than heavy, viscous oil. Because the future success of North Slope oil exploration and development is unknown, it is prudent to consider the circumstances under which North Slope oil production might cease altogether, causing a shutdown of the TAPS pipeline.

Aside from the question of what it might cost to keep TAPS operating at lower flow rates, an additional question is what it might cost to keep the existing North Slope oil fields producing. Even if the continued operation of TAPS were not in question, each North Slope oil field's production will eventually decline to a point at which it is no longer economical to keep the field operating. Oil and gas fields typically are shut down and abandoned when operating and maintenance costs exceed production revenues. At that point, wells are plugged and abandoned, surface equipment is removed, and the land is remediated to meet State and Federal requirements.

Although the cost structure of North Slope field production as production declines is unknown, production generally can be sustained profitably at lower production rates when oil prices are higher. Similarly, the economic feasibility of mitigating the problems arising from TAPS low flow rates improves when oil prices are higher. Consequently, revenues generated by North Slope oil production will play a pivotal role in determining the continued economic viability of existing North Slope oil fields, the development of new oil fields, the continued operation of TAPS at lower flow rates, and the potential development of new transportation facilities.

Several basic strategies have been employed to mitigate declining oil production and revenues from existing oil fields. First, the field operator can drill in-fill wells into those portions of the reservoir where oil cannot flow to existing production wells. Second, the operator can use enhanced oil recovery (EOR) that involves injecting steam or gases (along with water) to reduce viscosity and increase oil volumes as an aid to moving oil to the production wells. Currently, methane and natural gas liquids are being reinjected with water into many North Slope oil fields to achieve this outcome, which is referred to as "miscible hydrocarbon" EOR [*97*].

Drilling in-fill and EOR injection wells requires investments that are paid for through "maintenance" capital expenditures [*98*]. Both activities provide diminishing returns over time, as less oil typically is recovered with each new in-fill or EOR well, causing the cost per barrel of oil recovered to rise over time. Table 13 shows the number of in-fill and gas/water injection wells completed in 2010 at the three largest North Slope oil fields.

The diminishing returns from new in-fill and EOR wells is demonstrated in recent remarks by a ConocoPhillips official who noted that approximately $630 million was to be spent on maintenance capital expenditures in 2011, compared with about $240 million in 2001 [*99*]. In 2001 and 2010, ConocoPhillips provided 37.4 percent and 39.1 percent, respectively, of total North Slope oil production [*100*]. Using those percentages to scale up ConocoPhillips maintenance capital expenditures so that they represent total capital expenditures for North Slope maintenance, then total North Slope maintenance costs can be estimated at about $640 million in 2001 and $1.6 billion in 2011—a 150-percent increase over a period in which total North Slope oil production declined from 931,000 barrels per day to 562,000 barrels per day. If maintenance capital expenditures increased at the same rate (150 percent) over the next 10 years, they could be as high as $4 billion in 2021.

Another method for extending oil production is to produce increasing amounts of water relative to oil [*101*]. As oil is produced from a reservoir, water typically enters the formation, causing the water-to-oil ratio to increase exponentially over time as oil production volumes decline [*102*]. Because the cost per barrel for handling and reinjecting reservoir water typically is relatively constant, the operating cost per barrel of oil produced increases exponentially over time.

Shutdown and abandonment assumptions

According to the Alyeska study, a TAPS throughput of about 350,000 barrels per day appears to be the threshold at which significant investment would be required to permit lower TAPS throughput. *AEO2012* adopts the 350,000 barrel per day figure as

Table 13. Alaska North Slope wells completed during 2010 in selected oil fields

Production unit	Miscible hydrocarbon EOR	In-fill development wells	Gas/water injection wells	Total wells
Colville River	Yes	8	6	**14**
Kuparuk River	Yes	25	26	**51**
Prudhoe Bay	Yes	68	8	**76**
Subtotal		101	40	**141**
Total North Slope				**168**

the threshold for either making significant investments in TAPS or the alternatives, or shutting down and decommissioning TAPS and the North Slope oil fields [*103*].

In the *AEO2012* analysis, the shutdown and decommissioning of TAPS and the North Slope oil fields are also conditional on whether North Slope wellhead oil production revenues fall below a specific level. The appropriate revenue threshold is uncertain, because there is little or no information available to the public on operating and maintenance costs for existing oil fields, how those costs have grown historically as production has declined, or how they might grow in the future. Similarly, there are no public data available on what it might cost to keep TAPS operating as throughput declines [*104*]. Given the lack of public information, this analysis endeavors to determine both future North Slope production revenues in alternative oil price cases and an order-of-magnitude estimate of wellhead production costs.

AEO2012 assumes that, in order for the North Slope fields to be shut down, plugged, and abandoned, two conditions would need to be met simultaneously: TAPS throughput at or below 350,000 barrels per day and total North Slope oil production revenues at or below $5 billion per year. It is also assumed that if those two conditions were met, TAPS would be decommissioned and dismantled, and North Slope oil exploration and production activities would cease [*105*].

The $5 billion threshold for North Slope oil production revenue used in *AEO2012* is not intended to be conclusive regarding the conditions under which the North Slope oil fields and TAPS would remain in operation. As noted earlier, in-fill and EOR well drilling requirements could escalate to about $4 billion per year by 2021 [*106*]. Moreover, with the State of Alaska royalty rate currently at about 18.5 percent [*107*], a $5 billion revenue level would equate to almost $1 billion in royalties.

Also, an order of magnitude estimate of operating costs can be made by examining what oil companies report for their annual production expenses. For example, ExxonMobil reported a range of regional production costs per barrel of oil equivalent (excluding taxes) of $6.17 to $20.07 per barrel in 2010, with the U.S. average production cost being $10.67 per barrel [*108*]. At 350,000 barrels per day, a North Slope operating expense of $10 to $20 per barrel would equate to $1.28 to $2.56 billion per year in annual operating expenses. Of course, production costs could well exceed $20 per barrel as North Slope oil production declines.

Although the $5 billion North Slope revenue figure is not conclusive with regard to the actual annual costs faced by North Slope field operators in the future, it is a reasonable estimate in light of the sum of current maintenance capital expenditures ($1.6 billion), estimated operating expenses at 350,000 barrels per day ($1.28 to $2.56 billion), and a royalty cost of about $1 billion. As discussed below, the oil production revenue threshold serves to either advance or delay the date when TAPS and North Slope oil production would be shut down.

The final assumption is that a complete shutdown of North Slope oil production would occur in the year in which both the throughput and revenue criteria are satisfied. In reality, the actual shutdown of North Slope oil production might be extended over a number of years and could begin either before or after the year in which the criteria employed by North Slope producers are met.

Projections

A shutdown of North Slope oil production before 2035 is projected only in the Low Oil Price case, which shows both TAPS throughput and North Slope oil revenues falling below the 350,000 barrels per day and $5 billion per year thresholds, respectively, in 2026 (Figures 52 and 53). In both the Reference and High Oil Price cases, oil prices are sufficiently high both to stimulate the

Figure 52. Alaska North Slope oil production in three cases, 2010-2035 (million barrels per day)

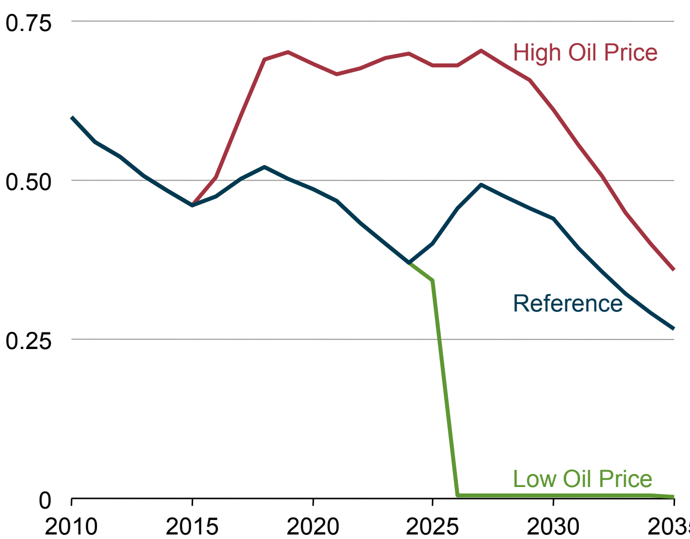
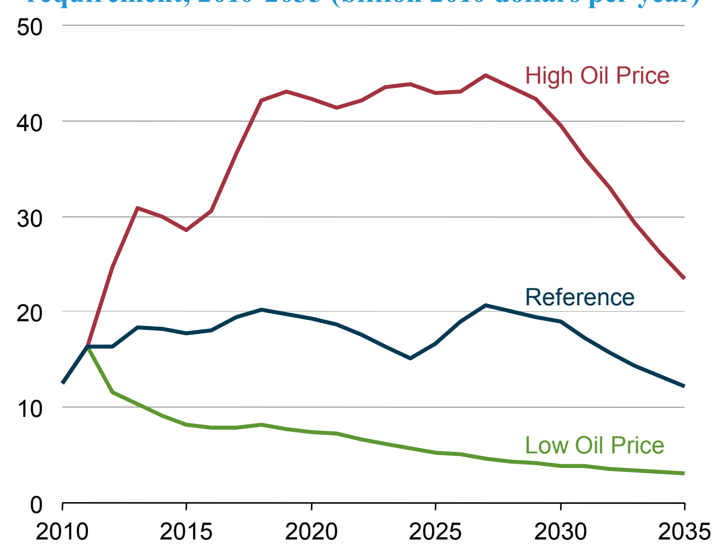


Figure 53. Alaska North Slope wellhead oil revenue in three cases, assuming no minimum revenue requirement, 2010-2035 (billion 2010 dollars per year)



development of new North Slope oil fields, especially offshore, and to provide sufficient oil production revenues to keep the North Slope producing oil through 2035.

Figure 53 shows the projected North Slope oil production revenue stream over time in the three price cases, with North Slope oil production continuing even after production volume and revenue requirements are no longer met in the Low Oil Price case. Thus, if the minimum North Slope revenue requirement were $7.5 billion, a shutdown of North Slope production could occur as soon as 2020, but only in the Low Oil Price case.

There is considerable uncertainty about the long-term viability of North Slope oil production and continued operation of TAPS through 2035. The two most important determinants of their future viability are the wellhead oil price that North Slope producers receive and the availability and cost of developing new North Slope oil resources. Those two factors will determine whether new oil fields are developed, whether existing oil fields remain sufficiently profitable to continue operating, and whether the investments required to keep TAPS operating at flow rates below 350,000 barrels per day are economically feasible.

The *AEO2012* Low and High Oil Price cases suggest that North Slope oil production will remain viable across a wide range of oil prices. Only in the Low Oil Price case are North Slope wellhead oil revenues sufficiently low to cause a shutdown of North Slope oil production. If the Low Oil Price case represents a low-probability outer boundary for future oil prices, then the likely future outcome is that North Slope oil production will continue until at least 2035, if not longer.

11. U.S. crude oil and natural gas resource uncertainty

A common measure of the long-term viability of U.S. domestic crude oil and natural gas as an energy source is the remaining technically recoverable resource (TRR). Estimates of TRR are highly uncertain, however, particularly in emerging plays where few wells have been drilled. Early estimates tend to vary and shift significantly over time as new geological information is gained through additional drilling, as long-term productivity is clarified for existing wells, and as the productivity of new wells increases with technology improvements and better management practices. TRR estimates used by EIA for each *AEO* are based on the latest available well production data and on information from other Federal and State governmental agencies, industry, and academia.

The remaining TRR consist of "proved reserves" and "unproved resources." *Proved reserves* of crude oil and natural gas are the estimated volumes expected to be produced, with reasonable certainty, under existing economic and operating conditions [*109*]. Proved reserves are also company financial assets reported to investors, as determined by U.S. Securities and Exchange Commission regulations. *Unproved resources* are additional volumes estimated to be technically recoverable without consideration of economics or operating conditions, based on the application of current technology [*110*]. As wells are drilled and field equipment is installed, unproved resources become proved reserves and, ultimately, production.

AEO estimates of TRR for shale gas and tight oil [*111*] have changed significantly in recent years (Table 14) [*112*]. In particular, the estimates of shale gas TRRs have changed significantly since the *AEO2011* was published, based on new well performance data and United States Geological Survey (USGS) resource assessments. For example, in the past year the USGS has released resource assessments for five basins: Appalachian (Marcellus only), Arkoma, Texas-Louisiana-Mississippi Salt, Western Gulf, and Anadarko [*113*]. The shale gas and tight oil formations in those five basins were the primary focus of EIA's resource revisions for *AEO2012*. In 2002, the USGS estimated Marcellus TRR at 1.9 trillion cubic feet; in 2011, the updated USGS estimate for Marcellus was 84 trillion cubic feet (see the following article for more discussion). For the four other basins, shale gas and tight oil TRR had not been assessed previously. The USGS has not published an assessment of the Utica play in the Appalachian Basin.

The remainder of this discussion describes how estimates of remaining U.S. unproved technically recoverable resources of shale gas and tight oil are developed for *AEO*, and how uncertainty in those estimates could affect U.S. crude oil and natural gas markets in the future.

Estimating technically recoverable resources of shale gas and tight oil

The remaining unproved TRR for a continuous-type shale gas or tight oil area is the product of (1) land area, (2) well spacing (wells per square mile), (3) percentage of area untested, (4) percentage of area with potential, and (5) EUR per well [*114*]. The USGS periodically publishes shale gas resource assessments that are used as a guide for selection of key parameters in the calculation of the TRR used in the *AEO*. The USGS seeks to assess the recoverability of shale gas and tight oil based on the wells drilled and technologies deployed at the time of the assessment.

The *AEO* TRRs incorporate current drilling, completion, and recovery techniques, requiring adjustments to the USGS estimates, as well as the inclusion of shale gas and tight oil resources not yet assessed by USGS. When USGS assessments and underlying data become publicly available, the USGS assumptions for land area, well spacing, and percentage of area with potential typically are used by EIA to develop the *AEO* TRR estimates. EIA may revise the well spacing assumptions in future *AEOs* to reflect evolving drilling practices. If well production data are available, EIA analyzes the decline curve of producing wells to calculate the expected EUR per well from future drilling.

Of the five basins recently assessed by the USGS, underlying details have been published only for the Marcellus shale play in the Appalachian basin. *AEO2012* assumptions for the other shale plays are based on geologic surveys provided from State agencies (if available), analysis of available production data, and analogs from current producing plays with similar geologic properties (Table 15). For *AEO2012*, only eight plays are included in the tight oil category (Table 16). Additional tight oil resources are expected to be included in the tight oil category in future *AEOs* as more work is completed in identifying currently producing reservoirs that may be categorized as tight formations, and as new tight oil plays are identified and incorporated.

A key assumption in evaluating the expected profitability of drilling a well is the EUR of the well. EURs vary widely not only across plays but also within a single play. To capture the economics of developing each play, the unproved resources for each play within each basin are divided into subplays—first across States (if applicable), and then into three productivity categories: best, average, and below average. Although the average EUR per well for a play may not change by much from one *AEO* to the next, the range of well performance encompassed by representative EURs can change substantially (Table 17).

For every *AEO*, the EUR for each subplay is determined by fitting a hyperbolic decline curve to the latest production history, so that changes in average well performance can be captured. Annual reevaluations are particularly important for shale gas and tight oil formations that have undergone rapid development. For example, because there has been a dramatic change from drilling vertical wells to drilling horizontal wells in most tight oil and shale gas plays since 2003, EURs for those plays based on vertical well performance are less useful for estimating production from future drilling, given that most new wells are expected to be primarily horizontal.

In addition, the shape of the annual well production profiles associated with the EUR varies substantially across the plays (Figure 54). For example, in the Marcellus, Fayetteville, and Woodford shale gas plays, nearly 65 percent of the well EUR is produced in the first 4 years. In contrast, in the Haynesville and Eagle Ford plays, 95 percent and 82 percent, respectively, of the well EUR is produced in the first four years. For a given EUR level, increased "front loading" of the production profile improves well economics, but it also implies an increased need for additional drilling to maintain production levels.

At the beginning of a shale play's development, high initial well production rates result in significant production growth as drilling activity in the play increases. The length of time over which the rapid growth can be sustained depends on the size of the

Table 14. Unproved technically recoverable resource assumptions by basin

Basin	*AEO2006* (as of 1/1/2004)	*AEO2007* (as of 1/1/2005)	*AEO2008* (as of 1/1/2006)	*AEO2009* (as of 1/1/2007)	*AEO2010* (as of 1/1/2008)	*AEO2011* (as of 1/1/2009)	*AEO2012* (as of 1/1/2010)
Shale gas (trillion cubic feet)							
Appalachian	15	15	14	51	59	441	187
Fort Worth	40	39	38	60	60	20	19
Michigan	11	11	11	10	10	21	18
San Juan	10	10	10	10	10	12	10
Illinois	3	3	3	4	4	11	11
Williston	4	4	4	4	4	7	3
Arkoma	--	42	42	49	45	54	27
Anadarko	--	3	3	7	6	3	13
TX-LA-MS Salt	--	--	--	72	72	80	66
Western Gulf	--	--	--	--	18	21	59
Columbia	--	--	--	--	51	41	12
Uinta	--	--	--	--	7	21	11
Permian	--	--	--	--	--	67	27
Greater Green River	--	--	--	--	--	18	13
Black Warrior	--	--	--	--	--	4	5
Shale gas total	**83**	**126**	**125**	**267**	**347**	**827**	**482**
Tight oil (billion barrels)							
Williston	--	3.7	3.7	3.7	3.6	3.6	5.4
San Joaquin/Los Angeles	--	--	--	--	15.4	15.4	13.7
Rocky Mountain basins	--	--	--	--	5.1	5.1	6.5
Western Gulf	--	--	--	--	5.6	5.6	5.7
Permian	--	--	--	--	--	1.6	1.6
Anadarko	--	--	--	--	--	0.2	0.3
Tight oil total	**--**	**3.7**	**3.7**	**3.7**	**29.7**	**31.5**	**33.2**

technically recoverable resource in each play, the rate at which drilling activity increases, and the extent of the play's "sweet spot" area [115]. In the longer term, production growth tapers off as high initial production rates of new wells in "sweet spots" are offset by declining rates of existing wells, and as drilling activity moves into less-productive areas. As a result, in the later stages of a play's resource development, maintaining a stable production rate requires a significant increase in drilling.

Table 15. Attributes of unproved technically recoverable resources for selected shale gas plays as of January 1, 2010

Basin/Play	Area (square miles)	Average well spacing (wells per square mile)	Percent of area untested	Percent of area with potential	Average EUR (billion cubic feet per well)	Number of potential wells	TRR (billion cubic feet)
Appalachian							
Marcellus	104,067	5	99	18	1.56	90,216	140,565
Utica	16,590	4	100	21	1.13	13,936	15,712
Arkoma							
Woodford	3,000	8	98	23	1.97	5,428	10,678
Fayetteville	5,853	8	93	23	1.30	10,181	13,240
Chattanooga	696	8	100	29	0.99	1,633	1,617
Caney	2,890	4	100	29	0.34	3,369	1,135
TX-LA-MS Salt							
Haynesville/Bossier	9,320	8	98	34	2.67	24,627	65,860
Western Gulf							
Eagle Ford	7,600	6	99	47	2.36	21,285	50,219
Pearsall	1,420	6	100	85	1.22	7,242	8,817
Anadarko							
Woodford	3,350	4	99	29	2.89	3,796	10,981
Total, selected shale gas plays						**181,714**	**318,825**
Total, all U.S. shale gas plays						**410,722**	**481,783**

Table 16. Attributes of unproved technically recoverable tight oil resources as of January 1, 2010

Basin/Play	Area (square miles)	Average well spacing (wells per square mile)	Percent of area untested	Percent of area with potential	Average EUR (million barrels per well)	Number of potential wells	TRR (million barrels)
Western Gulf							
Austin Chalk	16,078	3	72	61	0.13	21,165	2,688
Eagle Ford	3,200	5	100	54	0.28	8,665	2,461
Anadarko							
Woodford	3,120	6	100	88	0.02	16,375	393
Permian							
Avalon/Bone Springs	1,313	4	100	78	0.39	4,085	1,593
Spraberry	1,085	6	99	72	0.11	4,636	510
Rocky Mountain basins							
Niobrara	20,385	8	97	80	0.05	127,451	6,500
Williston Bakken[a]	6,522	2	77	97	0.55	9,767	5,372
San Joaquin/Los Angeles							
Monterey/Santos	2,520	12	98	93	0.50	27,584	13,709
Total tight oil						**219,729**	**33,226**

[a]Includes Sanish-Three Forks formation.

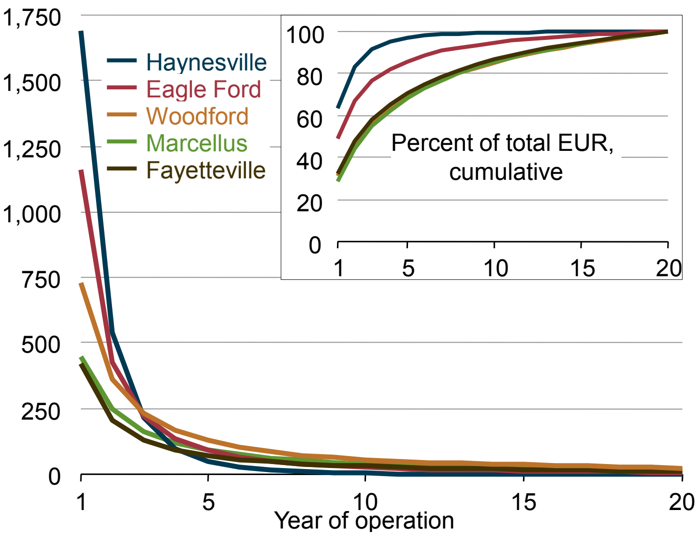
The amount of drilling that occurs each year depends on company budgets and finances and the economics of drilling, completing, and operating a well—determined largely by wellhead prices for oil and natural gas in the area. For example, current high crude oil prices and low natural gas prices are directing drilling toward those plays or portions of plays with a high concentration of liquids (crude oil, condensates, and natural gas plant liquids). Clearly, not all the wells that would be needed to develop each play fully can be drilled in one year—for example, more than 630,000 new wells would be needed to bring total U.S. shale gas and tight oil resources into production. In 2010, roughly 37,500 total oil and natural gas wells were drilled in the United States. It takes time and money to evaluate, develop, and produce hydrocarbon resources.

Although changes in the overall TRR estimates are important, the economics of developing the TRR and the timing of the development determine the projections for production of domestic crude oil and natural gas. TRR adjustments that affect resources which are not economical to develop during the projection period do not affect the *AEO* projections. Thus, significant variation in the overall TRR does not always result in significant changes in projected production.

EUR sensitivity cases and results

Estimated ultimate recovery per well is a key component in estimates of both technically recoverable resources and economically recoverable resources of tight oil and shale gas. The EUR for future wells is highly uncertain, depending on the application of new and/or improved technologies as well as the geology of the formation where the wells will be drilled. EUR assumptions typically have more impact on projected production than do any of the other parameters used to develop TRR estimates. For *AEO2012*, two cases were created to examine the impacts of higher and lower TRR for tight oil and shale gas by varying the assumed EUR per well.

Figure 54. Average production profiles for shale gas wells in major U.S. shale plays by years of operation (million cubic feet per year)



These High and Low EUR cases are not intended to represent a confidence interval for the resource base, but rather to illustrate how different EUR assumptions can affect projections of domestic production, prices, and consumption. To emphasize this point, an additional case was developed that combines a change in the assumed well spacing for all shale gas and tight oil plays with the EUR assumptions in the High EUR case. Well spacing is also highly uncertain, depending on the application of new and/or improved technologies as well as the geology of the formation where the well is being drilled. In the *AEO2012* Reference case, the well spacing for shale gas and tight oil drilling ranges from 2 to 12 wells per square mile.

Table 17. Estimated ultimate recovery for selected shale gas plays in three *AEO*s (billion cubic feet per well)

	AEO2010		*AEO2011*		*AEO2012*	
Basin/Play	Range	Average	Range	Average	Range	Average
Appalachian						
Marcellus	0.25–0.74	0.49	0.86–4.66	1.62	0.02–7.80	1.56
Utica	--	--	--	--	0.10–2.75	1.13
Arkoma						
Woodford	1.43–4.28	2.85	3.00–5.32	4.06	0.40–4.22	1.97
Fayetteville	0.91–2.73	1.82	0.86–2.99	2.03	0.19–3.22	1.30
Chattanooga	--	--	--	--	0.14–1.94	0.99
Caney	--	--	--	--	0.05–0.66	0.34
TX-LA-MS Salt						
Haynesville/Boosier	2.30–6.89	4.59	1.13–8.65	3.58	0.08–5.76	2.67
Western Gulf						
Eagle Ford	1.10–3.29	2.19	1.73–7.32	2.63	0.41–4.93	2.36
Pearsall	--	--	--	--	0.12–2.91	1.22
Anadarko						
Woodford	--	--	2.65–4.54	3.42	0.68–5.37	2.89

Low EUR case. In the Low EUR case, the EUR per tight oil or shale gas well is assumed to be 50 percent lower than in the Reference case, increasing the per-unit cost of developing the resource. The total unproved tight oil TRR is decreased to 17 billion barrels, and the shale gas TRR is decreased to 241 trillion cubic feet, as compared with 33 billion barrels of tight oil and 482 trillion cubic feet of shale gas in the Reference case.

High EUR case. In the HIGH EUR case, the EUR per tight oil or shale gas well is assumed to be 50 percent higher than in the Reference case, decreasing the per-unit cost of developing the resource. The total unproved tight oil TRR is increased to 50 billion barrels and the shale gas TRR is increased to 723 trillion cubic feet.

High TRR case. In the High TRR case, the well spacing for all tight oil and shale gas plays is assumed to be 8 wells per square mile (i.e., each well has an average drainage area of 80 acres), and the EUR per tight oil or shale gas well is assumed to be 50 percent higher than in the Reference case. In addition, the total unproved tight oil TRR is increased to 89 billion barrels and the shale gas TRR is increased to 1,091 trillion cubic feet, more than twice the TRRs for tight oil and shale gas wells in the Reference case.

The effects of the changes in assumptions in the three cases on supply, demand, and prices for oil and for natural gas are significantly different in magnitude, because the domestic oil and natural gas markets are distinctly different markets. Consequently, the following discussion focuses first on how the U.S. oil market is affected in the three sensitivity cases, followed by a separate discussion of how the U.S. natural gas market is affected in the three cases.

Crude oil and natural gas liquid impacts

The primary impact of the Low EUR, High EUR, and High TRR cases with respect to oil production is a change in production of tight oil and natural gas plant liquids (NGPL) (Table 18). NGPL production is discussed in conjunction with tight oil production, because significant volumes of NGPL are produced from tight oil and shale gas formations. Thus, changing the EURs directly affects NGPL production. Relative to the Reference case, tight oil production increases more slowly in the Low EUR case and more rapidly in the High EUR and High TRR cases. On average, tight oil production from 2020 to 2035 is approximately 450,000 barrels per day lower in the Low EUR case, 410,000 barrels per day higher in the High EUR case, and 1.3 million barrels per day higher in the High TRR case than in the Reference case (Figure 55). NGPL production in 2035 is more than 350,000 barrels per day lower in the Low EUR case than in the Reference case, nearly 320,000 barrels per day higher in the High EUR case, and 1.0 million barrels per day higher in the High TRR case.

Tight oil production is highest in the High TRR case, which assumes both higher EUR per well and generally lower drainage area per well than in the Reference case. In the High TRR case, tight oil production increases from roughly 400,000 barrels per day in 2010 to nearly 2.8 million barrels per day in 2035, with the Bakken formation accounting for most of the increase. The TRR estimate for the Bakken is more than 7 times higher in the High TRR case than in the Reference case—39.3 billion barrels compared to 5.4 billion barrels—which supports a continued dramatic production increase through 2015 and a longer plateau at a much higher production level through 2035 than in the Reference case. Bakken crude oil production (excluding NGPLs) increases from roughly 270,000 barrels per day in 2010 to nearly 800,000 barrels per day in 2015 before reaching over 1 million barrels per day in 2021 and remaining at that level through 2035 in the High TRR case, compared with peak tight oil production of roughly 530,000 barrels per day in the Reference case. Cumulative crude oil production from the Bakken from 2010 to 2035 is roughly 8.5 billion barrels in the High TRR case, compared with 4.3 billion barrels in the Reference case.

Table 18. Petroleum supply, consumption, and prices in four cases, 2020 and 2035

		2020				2035			
Projection	2010	Reference	Low EUR	High EUR	High TRR	Reference	Low EUR	High EUR	High TRR
Low-sulfur light crude oil price (2010 dollars per barrel)	79	127	128	125	122	145	147	143	140
Total U.S. production of crude oil and natural gas plant liquids (million barrels per day)	7.5	9.6	8.8	10.3	11.6	9.0	8.1	10.0	11.8
Tight oil	0.4	1.2	0.9	1.5	2.2	1.2	0.7	1.7	2.8
Natural gas plant liquids	2.1	2.9	2.6	3.1	3.6	3.0	2.7	3.3	4.0
Other U.S. crude oil	5.1	5.5	5.3	5.6	5.7	4.8	4.8	4.9	5.0
Tight oil share of total U.S. crude oil and NGPL production (percent)	5	12	10	15	19	14	9	17	23
U.S. net import share of petroleum product supplied (percent)	50	37	41	34	27	36	41	32	24

Every incremental barrel of domestic crude oil production displaces approximately one barrel of imports, because U.S. consumption of liquid fuels varies little across the cases. Consequently, the projected share of net petroleum imports in total U.S. liquid fuel consumption in 2035 varies considerably across the EUR and TRR cases, from 41 percent in the Low EUR case to 24 percent in the High TRR case, as compared with 36 percent in the Reference case. However, additional downstream infrastructure may be required to process the high levels of NGPL production in the High EUR and High TRR cases.

Changes in domestic oil production have only a modest impact on domestic crude oil and petroleum product prices, because any change in domestic oil production is diluted by the much larger world oil market. The United States produced 5.5 million barrels per day, or 7 percent of total world crude oil production of 73.9 million barrels per day in 2010 and is projected generally to maintain that share of world crude oil production through 2035 in the Reference case.

Natural gas impacts

The EUR and TRR cases show more significant impacts on U.S. natural gas supply, consumption, and prices than that projected for crude oil and petroleum products for two reasons (Table 19). First, the U.S. natural gas market constitutes the largest regional submarket within the relatively self-contained North American natural gas market. Second, in the Reference case, shale gas production accounts for 49 percent of total U.S. natural gas production in 2035, while tight oil production accounts for only 14 percent of total U.S. crude oil and NGPL production and 1 percent of world crude oil production. As a result, changes in shale gas production have a commensurately larger impact on North American natural gas prices than tight oil production has on world oil prices.

The projections for domestic shale gas production are highly sensitive to the assumed EUR per well. In 2035, total shale gas production varies from 9.7 trillion cubic feet in the Low EUR case to 16.0 trillion cubic feet in the High EUR case and 20.5 trillion cubic feet in the High TRR case, as compared with 13.6 trillion cubic feet in the Reference case (Figure 56). Because shale gas production accounts for such a large proportion of total natural gas production in 2035, the large changes in shale gas production result in commensurately large swings in total U.S. natural gas production. In 2035, total U.S. natural gas production ranges from 26.1 trillion cubic feet in the Low EUR case to 34.1 trillion cubic feet in the High TRR case, a difference of 8.0 trillion cubic feet production between the two cases.

In comparison with the Reference case, per-unit production costs are nearly double in the Low EUR case and about one-half in the High EUR case. In the Low EUR case, the Henry Hub natural gas price of $8.26 per million Btu in 2035 (2010 dollars) is $0.89 per million Btu higher than the Reference case price of $7.37 per million Btu. In the High EUR case, the 2035 Henry Hub natural gas price of $5.99 per million Btu is $1.38 per million Btu lower than the Reference case price. In the High TRR case, the 2035 Henry Hub natural gas price of $4.25 per million Btu is $3.12 per million Btu less than the Reference case price.

The natural gas prices projected in the Low EUR case are sufficiently high to enable completion of an Alaska gas pipeline, with operations beginning in 2031. Because an Alaska gas pipeline would make up for some of the reduction in Lower 48 shale gas production, differences between the Reference and Low EUR case projections for natural gas production, prices, and consumption in 2035 are somewhat less than would otherwise be expected.

The 2035 price spread of $4.01 per million Btu across the cases is reflected in the projected levels of U.S. natural gas consumption. Higher natural gas prices in the Low EUR case reduce total natural gas consumption to 25.0 trillion cubic feet in 2035, compared with 26.6 trillion cubic feet in the Reference case; and lower natural gas prices in the High EUR and High TRR cases increase consumption in 2035 to 28.4 trillion cubic feet and 31.9 trillion cubic feet, respectively.

Figure 55. U.S. production of tight oil in four cases, 2000-2035 (million barrels per day)

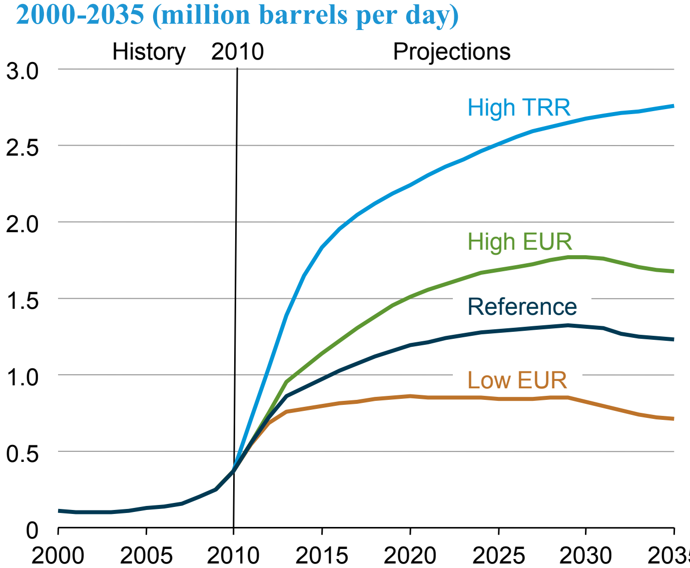
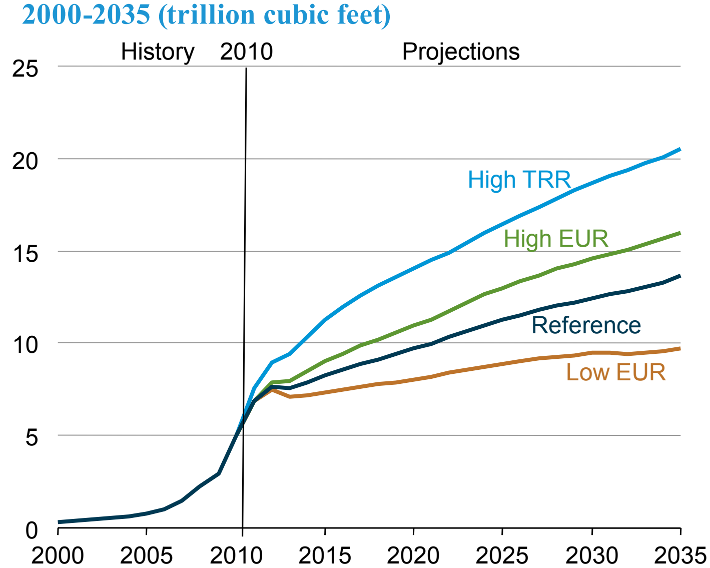


Figure 56. U.S. production of shale gas in four cases, 2000-2035 (trillion cubic feet)



The variation in total U.S. natural gas consumption between the High EUR and High TRR cases is reflected to some degree in each end-use category. The electric power sector shows the greatest sensitivity to natural gas prices, with natural gas use for electricity generation being more responsive to changes in fuel prices than is consumption in the other sectors, because much of the electric power sector's fuel consumption is determined by the dispatching of existing generation units based on the operating cost of each unit, which in turn is determined largely by the costs of competing fuels—especially coal and natural gas. Natural gas consumption in the electric power sector in 2035 totals 7.7 trillion cubic feet in the Low EUR case, compared with 9.0 trillion cubic feet in the Reference case, 10.1 trillion cubic feet in the High EUR case, and 12.6 trillion cubic feet in the High TRR case.

In the end-use consumption sectors, opportunities to switch fuels generally are limited to when a new facility is built or when a facility's existing equipment is retired and replaced. Collectively, for all the end-use sectors, natural gas consumption in 2035 varies by only about 1.9 trillion cubic feet across the cases, from 17.3 trillion cubic feet in the Low EUR case to 19.2 trillion cubic feet in the High TRR case, as compared with 17.7 trillion cubic feet in the Reference case.

In 2035, the United States is projected to be a net exporter of natural gas in all the cases. The projected volumes of net exports vary, with lower natural gas prices resulting in higher net exports. However, the High TRR, High EUR, and Low EUR cases assume that U.S. gross exports of LNG remain constant at 0.9 trillion cubic feet from 2020 through 2035, because of the inherent complexities and uncertainties of projecting foreign natural gas production, consumption, and trade. It is likely, however, that actual levels of net LNG exports would be affected by changes in U.S. prices, which in turn, would dampen the extent of the price difference across the resource cases.

The variation in levels of net U.S. natural gas exports shown in Table 20 reflects the impact of domestic natural gas prices on natural gas pipeline imports and exports. Generally, lower natural gas prices, as in the High TRR case, result in lower natural gas imports from Canada and higher natural gas exports to Mexico. In 2035, net natural gas exports from the United States vary from 1.2 trillion cubic feet in the Low EUR case to 2.4 trillion cubic feet in the High TRR case, as compared with 1.4 trillion cubic feet in the Reference case.

The sensitivity cases in this discussion are not intended to provide a confidence interval for estimates of recoverable resources of domestic tight oil and shale gas but rather to illustrate the significance of key assumptions underlying the tight oil and shale

Table 19. Natural gas prices, supply, and consumption in four cases, 2020 and 2035

		2020				2035			
Projection	2010	Reference	Low EUR	High EUR	High TRR	Reference	Low EUR	High EUR	High TRR
Henry Hub natural gas spot price (2010 dollars per million Btu)	4.39	4.58	5.31	4.04	3.02	7.37	8.26	5.99	4.25
Total U.S. natural gas production (trillion cubic feet)	21.6	25.1	23.6	26.3	29.1	27.9	26.1	30.1	34.1
Onshore lower 48	18.7	22.5	21.0	23.6	26.6	25.0	21.2	27.2	31.7
Shale gas	5.0	9.7	8.0	10.9	14.0	13.6	9.7	16.0	20.5
Other natural gas	13.7	12.8	12.9	12.7	12.6	11.3	11.4	11.2	11.1
Offshore lower 48	2.6	2.3	2.4	2.3	2.2	2.7	3.1	2.6	2.3
Alaska	0.4	0.3	0.3	0.3	0.3	0.2	1.8	0.2	0.2
Shale gas production as percent of total U.S. natural gas production	23	39	34	42	48	49	37	53	60
Total net U.S. imports of natural gas (trillion cubic feet)	2.6	0.3	0.5	0.2	-0.2	-1.4	-1.2	-1.7	-2.4
Total U.S. consumption of natural gas (trillion cubic feet)	24.1	25.5	24.2	26.5	28.9	26.6	25.0	28.4	31.9
Electric Power	7.4	7.9	6.8	8.7	10.5	9.0	7.7	10.1	12.6
Residential	4.9	4.8	4.8	4.9	4.9	4.6	4.6	4.7	4.8
Commercial	3.2	3.4	3.4	3.5	3.6	3.6	3.5	3.7	4.0
Industrial	6.6	7.1	7.0	7.1	7.4	7.0	6.9	7.2	7.6
Other	2.0	2.3	2.2	2.3	2.5	2.4	2.4	2.6	2.8

gas TRRs used in *AEO2012*. TRR estimates are highly uncertain and can be expected to change in subsequent *AEOs* as additional information is gained through continued exploration, development, and production.

12. Evolving Marcellus shale gas resource estimates

As discussed in the preceding article, estimates of crude oil and natural gas TRR are uncertain. Estimates of the Marcellus shale TRR, which have received considerable attention over the past year, are no exception. TRR estimates are likely to continue evolving as drilling continues and more information becomes publicly available. The Marcellus shale gas play covers more than 100,000 square miles in parts of eight States, but most of the drilling to date has been in two areas of northeast Pennsylvania and southwest Pennsylvania/northern West Virginia. Until 2010, the State of Pennsylvania had maintained a 5-year embargo on the release of well-level production data, which severely limited the publicly available information about Marcellus well production. Now Pennsylvania provides well production data on a cumulative basis—annually for the years before 2010 and semi-annually starting in the second half of 2010. Even with more data available, however, it is still a challenge to estimate TRR for the Marcellus play.

In 2002, the USGS estimated that 0.8 trillion cubic feet to 3.7 trillion cubic feet of technically recoverable shale gas resources existed in the Marcellus, with a mean estimate of 1.9 trillion cubic feet [*116*]. At that time, most of the well production data available were for vertical wells drilled in West Virginia. Since 2003, technological improvements have led to more-productive and less-costly wells. The newer horizontal wells have higher EURs [*117*] than the older vertical wells. In 2011, the USGS released an updated assessment for the Marcellus resource, with a mean estimate of 84 trillion cubic feet of undiscovered TRR (ranging from 43 trillion cubic feet to 144 trillion cubic feet) [*118*]. For its 2011 assessment, the USGS evaluated well production data from Pennsylvania and West Virginia that were available in early 2011 and determined that the data were “not sufficient for the construction of individual well Estimated Ultimate Recovery distributions” [*119*]. Instead, the USGS chose analogs from other U.S. shale gas plays to determine the EUR distributions for its three Marcellus assessment units—Foldbelt, Interior, and Western Margin (Figure 57).

Estimates of the TRR for U.S. shale gas are updated each year for the *AEO*. For *AEO2011*, an independent consultant was hired to estimate the Marcellus TRR as the available USGS TRR estimate issued in 2003 was clearly too low, since cumulative production from the Marcellus shale was on a path to exceed it within a year or two. For *AEO2012*, EIA adopted the 2011 USGS estimates of the Marcellus assessment areas, well spacing, and percent of area with potential. However, EIA examines available well production data each year to estimate shale EURs for use in the *AEO* (Table 20).

The revised Marcellus EUR for *AEO2012* is close to the EUR used in *AEO2011* but nearly 70 percent higher than the EUR used in the 2011 USGS assessment. The Interior Assessment Unit EURs developed by EIA reflects the current practice of horizontal drilling and well production data through June 2011 for Pennsylvania and West Virginia [*120*]. Because there has been very little, if any, drilling in the Western Margin and Foldbelt Assessment Units, the USGS EURs were used for the States in those areas. The resulting *AEO2012* estimate for the Marcellus TRR is 67 percent lower than the *AEO2011* estimate, primarily as a result of increased well spacing (132 acres per well vs. 80 acres per well) and a lower percentage of area with potential (18 percent vs. 34 percent) (Table 21).

The estimation of Marcellus shale gas resources is highly uncertain, given both the short production history of current producing wells and the concentration of most producing wells in two small areas, Northeast Pennsylvania and Southwest Pennsylvania/Northern West Virginia. The Marcellus EURs are expected to change as additional data are released and the methodology for developing EURs is refined. Also, as more wells are drilled over a broader area, and as operators optimize well spacing to account for evolving drilling practices, the assumption for average well spacing may be revised. Although the Marcellus shale resource estimate will be updated for every *AEO*, revisions will not necessarily have a significant impact on projected natural gas production, consumption, and prices.

Figure 57. United States Geological Survey Marcellus Assessment Units

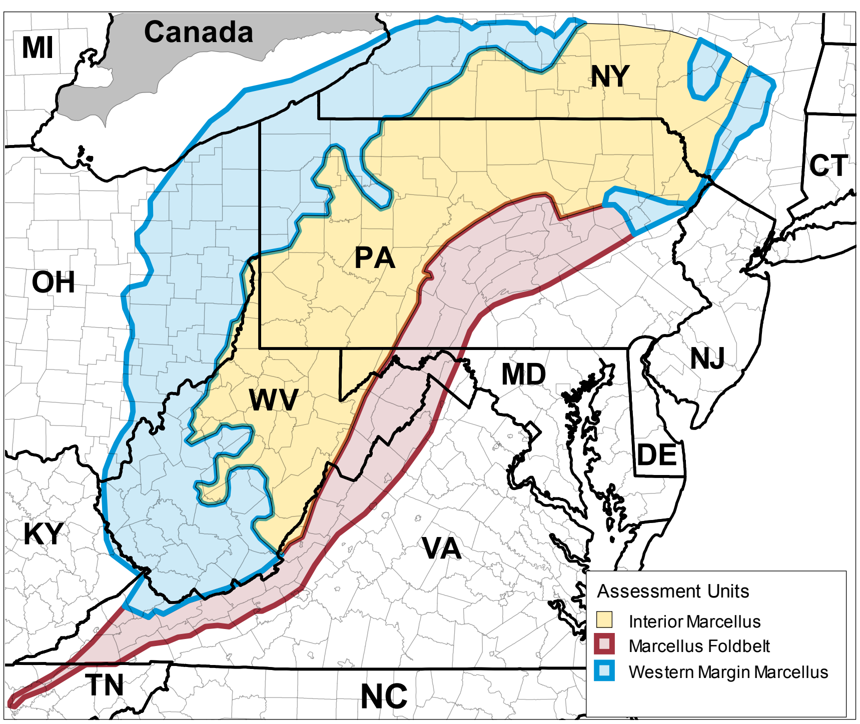


Table 20. Marcellus unproved technically recoverable resources in *AEO2012* (as of January 1, 2010)

Assessment Unit/State	Area (square miles)	Well spacing (wells per square mile)	Percent of area untested	Percent of area with potential	EUR (billion cubic feet per well) High	Mid	Low	Average	TRR (billion cubic feet)
Foldbelt	19,063	4	100	5	0.50	0.18	0.03	0.21	757
Maryland	435	4	100	5	0.50	0.18	0.03	0.21	17
Pennsylvania	7,951	4	100	5	0.50	0.18	0.03	0.21	316
Tennessee	353	4	100	5	0.50	0.18	0.03	0.21	14
Virginia	7,492	4	100	5	0.50	0.18	0.03	0.21	298
West Virginia	2,833	4	100	5	0.50	0.18	0.03	0.21	113
Interior	45,161	4	99	37	6.33	1.41	0.06	1.95	137,677
Maryland	763	4	100	37	2.02	0.30	0.02	0.52	629
New York	10,381	4	100	37	7.80	1.79	0.07	2.43	40,124
Ohio	361	4	99	37	2.02	0.30	0.02	0.52	296
Pennsylvania	23,346	4	98	37	7.80	1.79	0.07	2.43	88,182
Virginia	321	4	100	37	2.02	0.30	0.02	0.52	264
West Virginia	9,989	4	99	37	2.02	0.30	0.02	0.52	8,182
Western	39,844	5	100	7	0.35	0.11	0.03	0.13	2,107
Kentucky	207	5	100	7	0.35	0.11	0.03	0.13	11
New York	7,985	5	100	7	0.35	0.11	0.03	0.13	424
Ohio	13,515	5	100	7	0.35	0.11	0.03	0.13	718
Pennsylvania	6,582	5	100	7	0.35	0.11	0.03	0.13	350
Virginia	653	5	100	7	0.35	0.11	0.03	0.13	35
West Virginia	10,901	5	98	7	0.35	0.11	0.03	0.13	569
Total Marcellus	**104,067**	**5**	**99**	**18**	**5.05**	**1.13**	**0.05**	**1.56**	**140,541**

Table 21. Marcellus unproved technically recoverable resources: *AEO2011*, USGS 2011, and *AEO2012*

Estimate	Area (square miles)	Well spacing: Acres	Well spacing: Wells per square mile	Percent of area untested	Percent of area with potential	Average EUR (billion cubic feet per well)	TRR (billion cubic feet)
AEO2011 (as of 1/1/2009)							
Marcellus	**94,893**	**80**	**8**	**99%**	**34%**	**1.62**	**410,374**
USGS (2011 assessment)							
Marcellus	**104,067**	**132**	**4.9**	**99%**	**18%**	**0.93**	**84,198**
Foldbelt	19,063	149	4.3	100%	5%	0.21	765
Interior	45,156	149	4.3	99%	37%	1.15	81,374
Western	39,844	117	5.5	99%	7%	0.13	2,059
AEO2012 (as of 1/1/2010)							
Marcellus	**104,067**	**132**	**4.9**	**99%**	**18%**	**1.56**	**140,541**
Foldbelt	19,063	149	4.3	100%	5%	0.21	757
Interior	45,161	149	4.3	99%	37%	1.95	137,677
Western	39,844	117	5.5	100%	7%	0.13	2,107

Endnotes for Issues in focus

Links current as of June 2012

41. Oil shale liquids, derived from heating kerogen, are distinct from shale oil and also from tight oil, which is classified by EIA as crude oil. Oil shale is not expected to be produced in significant quantities in the United States before 2035.
42. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Proposed Rule," Federal Register, Vol. 76, No. 231 (Washington, DC: December 1, 2011), website www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/2017-25_CAFE_NPRM.pdf.
43. The EISA2007 RFS requirement for increasing volumes of biofuels results in a significant number of FFVs in both the Reference case and the CAFE case.
44. S. Bianco, "Chevy Volt Has Best Month Ever, But Nissan Leaf Still Wins 2011 Plug-in Sales Contest," autobloggreen, website green.autoblog.com/2012/01/04/chevy-volt-has-best-month-ever-but-nissan-leaf-still-wins-2011.
45. Battery electric vehicle charge-depleting mode occurs when the vehicle relies on battery power for operation. Charge-sustaining mode occurs when battery electric power is coupled with power provided by the internal combustion engine. Vehicles can be designed to operate on a blended mode that uses both charge-depleting and charge-sustaining modes while in operation, depending on the drive cycle.
46. Toyota, "Toyota Cars, Trucks, SUVs, and Accessories," website www.toyota.com; Nissan USA, "Nissan Cars, Trucks, Crossovers, & SUVs," website www.nissanusa.com; and Chevrolet, "2012 Cars, SUVs, Trucks, Crossovers & Vans," website www.chevy.com. **Note:** Miles per gallon equivalent, as listed by automotive manufacturers, is derived by the U.S. Environmental Protection Agency, www.fueleconomy.gov.
47. Toyota, "Toyota Cars, Trucks, SUVs, and Accessories," website www.toyota.com; Nissan USA, "Nissan Cars, Trucks, Crossovers, & SUVs," website www.nissanusa.com; and Chevrolet, "2012 Cars, SUVs, Trucks, Crossovers & Vans," website www.chevy.com. **Note:** Miles per gallon equivalent, as listed by automotive manufacturers, is derived by the U.S. Environmental Protection Agency, www.fueleconomy.gov.
48. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Vehicle Technologies Program," website www.eere.energy.gov/vehiclesandfuels/technologies/systems/index.html.
49. U.S. Energy Information Administration, "Residential Energy Consumption Survey (RECS), 2009 RECS Survey Data," website 205.254.135.7/consumption/residential/data/2009.
50. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Alternative Fuels & Advanced Vehicles Data Center," website www.afdc.energy.gov.
51. Indiana University, School of Public and Environmental Affairs, "Plug-in Electric Vehicles: A Practical Plan for Progress," website www.indiana.edu/~spea/pubs/TEP_combined.pdf.
52. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Proposed Rule," Federal Register, Vol. 76, No. 231 (Washington, DC: December 1, 2011), website www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/2017-25_CAFE_NPRM.pdf.
53. For this analysis, heavy-duty vehicles include trucks with a Gross Vehicle Weight Rating of 10,001 pounds and higher, corresponding to Gross Vehicle Weight Rating classes 3 through 8 vehicles.
54. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Alternative Fueling Station Database Custom Query" (Washington, DC: June 3, 2010), website www.afdc.energy.gov/afdc/fuels/stations_query.html. Accessed June 30, 2012.
55. National Petroleum News, Market Facts 2011.
56. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Clean Cities Alternative Fuel Price Report* (Washington, DC: April, 2012), website www.afdc.energy.gov/afdc/pdfs/afpr_apr_12.pdf.
57. The Texas Clean Transportation Triangle is supported by Texas State Senate Bill 20, which provides vehicle rebates and fueling grants. See West, Williams, House Research Organization, "Bill Analysis: SB 20" (Austin, TX: May 21, 2011), website www.hro.house.state.tx.us/pdf/ba82r/sb0020.pdf.
58. The Interstate Clean Transportation Corridor was developed in 1996. The corridor is now partially established with LNG truck refueling infrastructure in California and to Reno, Las Vegas, and Phoenix. See Gladstein, Neandross & Associates, "Interstate Clean Transportation Corridor" (Santa Monica, CA: February 2, 2012), website ictc.gladstein.org.

59. The Pennsylvania Clean Transportation Corridor was proposed in a report, "A Road Map to a Natural Gas Vehicle Future" (Canonsburg, PA: April 5, 2011), sponsored by the Marcellus Shale Coalition, website marcelluscoalition.org/wp-content/uploads/2011/04/MSC_NGV_Study.pdf.

60. The American Recovery and Reinvestment Act has provided more than $300 million toward cost-sharing projects related to alternative fuels. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "American Recovery and Reinvestment Act Project Awards" (Washington, DC: September 7, 2011) website www1.eere.energy.gov/cleancities/projects.html.

61. For a map of U.S. LNG peak shaving, see U.S. Energy Information Administration, "U.S. LNG Peaking Shaving and Import Facilities, 2008" (Washington, DC: December, 2008), website www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/lngpeakshaving_map.html.

62. The LNG Excise Tax Equalization Act of 2012, proposed in the U.S. House of Representatives, would require the tax treatment of LNG and diesel fuel to be equivalent on the basis of heat content. See Civic Impulse, LLC, "H.R. 3832: LNG Excise Tax Equalization Act of 2012" (Washington, DC: May 29, 2012), website legacy.govtrack.us/congress/bill.xpd?bill=h112-3832.

63. Developed from e-mail correspondence with Graham Williams, 4/11/12.

64. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles," Federal Register Vol. 76, No. 179 (Washington, DC: September 15, 2011), website www.federalregister.gov/articles/2011/09/15/2011-20740/greenhouse-gas-emissions-standards-and-fuel-efficiency-standards-for-medium--and-heavy-duty-engines#p-3.

65. U.S. Census Bureau, "Vehicle Inventory and Use Survey (VIUS) (discontinued after 2002)" (Washington, DC: May 29, 2012), website www.census.gov/econ/overview/se0501.html.

66. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles," Federal Register Vol. 76, No. 179 (Washington, DC: September 15, 2011), website www.federalregister.gov/articles/2011/09/15/2011-20740/greenhouse-gas-emissions-standards-and-fuel-efficiency-standards-for-medium--and-heavy-duty-engines#p-3.

67. For information on the New Alternative Transportation to Give Americans Solutions Act of 2012, see Civic Impulse, LLC, "H.R. 1380: New Alternative Transportation to Give Americans Solutions Act of 2011" (Washington, DC: May 29, 2012), website legacy.govtrack.us/congress/bill.xpd?bill=h112-1380.

68. The liquid fuels production industry includes all participants involved in the production of liquid fuels: producers of feedstocks, petroleum- and nonpetroleum-based refined products and blendstocks, and liquid and non-liquid end-use products.

69. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards" (Washington, DC: March 27, 2012), website www.epa.gov/mats.

70. U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)" (May 25, 2012), website www.epa.gov/airtransport.

71. Other components of variable cost include emissions control technology, waste disposal, and emissions allowance credits.

72. The *AEO2012* Early Release Reference case was prepared before the final MATS rule was issued and, therefore, did not include MATS.

73. United States Court of Appeals for the District of Columbia Circuit, "EME Homer City Generation, L.P., v. Environmental Protection Agency" (Washington, DC: December 30, 2011), website www.epa.gov/airtransport/pdfs/CourtDecision.pdf.

74. U.S. Energy Information Administration, *Electric Power Annual 2010* (Washington, DC, November 2011), Table 3.10, "Number and Capacity of Existing Fossil-Fuel Steam-Electric Generators with Environmental Equipment, 1991 through 2010," website www.eia.gov/electricity/annual/html/table3.10.cfm.

75. U.S. Environmental Protection Agency, Office of Enforcement and Compliance Assurance, "The Environmental Protection Agency's Enforcement Response Policy for Use of Clean Air Act Section 113(a) Administrative Orders in Relation to Electric Reliability and the Mercury and Air Toxics Standard" (Washington, DC: December 16, 2011), website www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf.

76. See Appendix F for a map of the EMM regions.

77. The EPA is proposing that new fossil-fuel-fired power plants begin meeting an output-based standard of 1,000 pounds CO_2 per megawatthour. See U.S. Environmental Protection Agency, "Carbon Pollution Standard for New Power Plants" (Washington, DC: May 23, 2012), website www.epa.gov/carbonpollutionstandard/actions.html. Existing coal plants without CCS will not be able to meet that standard, and the proposed rule does not apply to plants already under construction. The EPA proposal is not included in *AEO2012*.

78. U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report" (Washington, DC: November 30, 2011), website www.eia.gov/cneaf/electricity/page/eia860.html.

79. U.S. Energy Information Administration, "Levelized Cost of New Generation Resources in the Annual Energy Outlook 2012" (Washington, DC: March 2012), website www.eia.gov/forecasts/aeo/electricity_generation.cfm.

80. U.S. Energy Information Administration, "Assumptions to *AEO2012*" (Washington, DC: June 2012), website www.eia.gov/forecasts/aeo/assumptions.

81. U.S. Government Printing Office, "Energy Policy Act of 2005, Public Law 109-58, Title XVII—Incentives for Innovative Technologies" (Washington, DC: August 8, 2005), website www.gpo.gov/fdsys/pkg/PLAW-109publ58/html/PLAW-109publ58.htm.

82. U.S. Department of Energy, Loan Programs Office, "Loan Guarantee Program: Georgia Power Company" (Washington, DC: June 4, 2012), website lpo.energy.gov/?projects=georgia-power-company.

83. U.S. Government Printing Office, "Energy Policy Act of 2005, Public Law 109-58, Title XVII—Incentives for Innovative Technologies, paras. 638, 988, and 1306" (Washington, DC, August 2005), website www.gpo.gov/fdsys/pkg/PLAW-109publ58/html/PLAW-109publ58.htm.

84. U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," website www.eia.gov/cneaf/electricity/page/eia860.html.

85. Tennessee Valley Authority, "Integrated Resource Plan" (Knoxville, TN: March 2011), website www.tva.com/environment/reports/irp/index.htm.

86. U.S. Nuclear Regulatory Commission, "Status of License Renewal Applications and Industry Activities: Completed Applications" (Washington, DC: May 22, 2012), website www.nrc.gov/reactors/operating/licensing/renewal/applications.html#completed.

87. U.S. Nuclear Regulatory Commission, "Status of License Renewal Applications and Industry Activities: Completed Applications" (Washington, DC: May 22, 2012), website www.nrc.gov/reactors/operating/licensing/renewal/applications.html#completed.

88. Electric Power Research Institute, "Long-Term Operations (QA)" (Palo Alto, CA: June 4, 2012), website portfolio.epri.com/ProgramTab.aspx?sId=NUC&rId=210&pId=6177.

89. International Forum for Reactor Aging Management (IFRAM), "Inaugural Meeting of the International Forum for Reactor Aging Management (IFRAM)" (Colorado Springs, CO: August 5, 2011), website ifram.pnnl.gov.

90. Alyeska Pipeline Service Company, *Low Flow Impact Study, Final Report* (Anchorage, AL: June 15, 2011), at www.alyeska-pipe.com/Inthenews/LowFlow/LoFIS_Summary_Report_P6%2027_FullReport.pdf.

91. Tim Bradner, "Alyeska Invests in New Methods to Extend Pipeline Life," *Alaska Journal of Commerce* (June 1, 2009), website www.alaskajournal.com/Alaska-Journal-of-Commerce/May-2009/Alyeska-invests-in-new-methods-to-extend-pipeline-life/.

92. U.S. Department of Energy, National Energy Technology Laboratory, *Alaska North Slope Oil and Gas – A Promising Future or an Area in Decline? (Addendum Report),* DOE/NETL-2009/1385 (Washington, DC: April 8, 2009), website www.netl.doe.gov/technologies/oil-gas/publications/AEO/ANS_Potential.pdf, pp. 1-4 and 1-5.

93. Alan Bailey, "TAPS transitioning to a low flow future," *Petroleum News,* Vol. 14, No. 29 (Anchorage, AK: July 19, 2009), website www.petroleumnews.com/pntruncate/5456274.shtml (subscription site).

94. Alyeska Pipeline Service Company, *Low Flow Impact Study, Final Report* (Anchorage, AL: June 15, 2011), at www.alyeska-pipe.com/Inthenews/LowFlow/LoFIS_Summary_Report_P6%2027_FullReport.pdf.

95. U.S. Department of the Interior, U.S. Geological Survey, *The Oil and Gas Resource Potential of the Arctic National Wildlife Refuge 1002 Area, Alaska,* Open File Report 98-34 (Washington, DC: May 1998), website pubs.usgs.gov/of/1998/ofr-98-0034/ANWR1002.pdf; U.S. Geological Survey, *Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, Including Economic Analysis,* USGS Fact Sheet FS-028-01 (Washington, DC: April 2001), website pubs.usgs.gov/fs/fs-0028-01/fs-0028-01.pdf; and David W. Houseknecht and Kenneth J. Bird, *Oil and Gas Resources of the Arctic Alaska Petroleum Province,* U.S. Geological Survey Professional Paper 1732–A (Washington, DC: October 31, 2006), website pubs.usgs.gov/pp/pp1732/pp1732a/pp1732a.pdf.

96. In 2004, BP commissioned a study that examined the possibility of building a 20-inch pipeline to Fairbanks and using the Alaska railroad to transport the oil to Valdez, at an estimated cost of about $3 billion. Source: Alan Bailey, "A TAPS bottom line," *Petroleum News,* Volume 17, Number 3 (Anchorage, AK: January 15, 2012), website www.petroleumnews.com/pntruncate/225019711.shtml.

97. The most common miscible gas EOR technique is to alternate the injection of gas and water, referred to as water-alternating-gas or WAG. Source: Oil and Gas Journal, Special Report: EOR/Heavy Oil Survey: 2010 worldwide EOR survey, Volume 108, Issue 14, published April 19, 2010.
98. Capital expenditures can be split into two categories—maintenance and development—with development expenditures allocated to the development of new fields that have not yet reached peak production.
99. Source for 2011 CP capital expenditures—*Petroleum News*, "Eagle Ford Could Nudge Alaska for COP" (May 8, 2011); source for 2001 CP capital expenditures—*Petroleum News*, "Sunrise or Sunset for ConocoPhillips in Alaska?" (October 27, 2002); source for 2001 and 2011 CP split in capital expenditures—*Petroleum News*, "Johansen: Urgency Lacking on Throughput" (October 16, 2011).
100. These figures were derived from the CP ownership shares of the Colville River, Kuparuk River, and Prudhoe Bay field units and from the oil production reports of the Alaska Department of Natural Resources—Oil and Gas Division.
101. The volume of water produced relative to the volume of oil produced is referred to as the "water cut."
102. U.S. Geological Survey, *Economics of Undiscovered Oil in Federal Lands on the National Petroleum Reserve—Alaska*, by Emil Attanasi, Open-File Report 03-44 (January 2003), Figures A-2 (Alpine Field) and A-3 (Kuparuk Field).
103. In fact, these decisions would have to be made some time before the 350,000-barrel-per-day threshold is reached so they would be ready for implementation either prior to reaching the threshold or when that threshold is reached.
104. The owners of TAPS and operators of the North Slope fields might not know either at this junction what these future costs might be for both operating TAPS and the North Slope fields as volumes decline; at best they have estimates that might or might not turn out to be true.
105. The assumption that all North Slope exploration activity would cease with the decommissioning of TAPS might not be entirely realistic because some offshore oil fields might be economic to develop using floating production, storage, and offloading facilities (FPSO). This would be especially true in the Chukchi Sea, which has much less of an ice pack problem during the winter than the Beaufort Sea.
106. Maintenance capital expenditures could also decline if the field operators determined that drilling more wells was unprofitable.
107. *Petroleum News*, "Who Produces Crude Oil in Alaska?" Vol. 16, No. 43 (October 23, 2011).
108. ExxonMobil, 2010 Financial & Operating Review, Table entitled: "Oil and Gas Exploration and Production Earnings," p. 70.
109. See also EIA, "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves," November 30, 2010, website www.eia.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html.
110. The further delineation of unproved resources into inferred reserves and undiscovered resources is not applicable to continuous resources since the extent of the formation is geologically known. For continuous resources, the USGS undiscovered technically recoverable resources are comparable to the EIA unproved resources. The USGS methodology for assessing continuous petroleum resources is at pubs.usgs.gov/ds/547/downloads/DS547.pdf.
111. "Tight oil" refers to crude oil and condensates produced from low-permeability sandstone, carbonate, and shale formations.
112. See shale gas map at www.eia.gov/oil_gas/rpd/shale_gas.pdf for basin locations.
113. Appalachian: pubs.usgs.gov/of/2011/1298/; Arkoma: pubs.usgs.gov/fs/2010/3043/; TX-LA-MS Salt and Western Gulf: pubs.usgs.gov/fs/2011/3020/; Anadarko: pubs.usgs.gov/fs/2011/3003/.
114. A well's estimated ultimate recovery (EUR) equals the cumulative production of that well over a 30-year productive life, using current technology without consideration of economic or operating conditions.
115. "Sweet spot" is an industry term for those select and limited areas within a shale or tight play where the well EURs are significantly greater than the rest of the play, sometimes as much as ten times greater than the lower production areas within a play.
116. USGS Fact Sheet FS-009-03. pubs.usgs.gov/fs/fs-009-03/FS-009-03-508.pdf.
117. A well's EUR equals the cumulative production of that well over a 30-year productive life, using current technology without consideration of economic or operating conditions.
118. USGS Fact Sheet 2011-3092, pubs.usgs.gov/fs/2011/3092/pdf/fs2011-3092.pdf.
119. USGS Open-File Report 2011-1298, pubs.usgs.gov/of/2011/1298/OF11-1298.pdf, page 2.
120. Well-level production from Pennsylvania is provided in two time intervals (annual and semi-annual). To estimate production on a comparable basis, well-level production is converted to an average daily rate by dividing gas quantity by gas production days. Because wells drilled before 2008 are vertical wells and do not reflect the technology currently being deployed, only wells drilled after 2007 are considered in the EUR evaluation. Well-level production for wells drilled in West Virginia is provided on a monthly basis.

Market trends

Projections by the U.S. Energy Information Administration (EIA) are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular case. The Reference case projection is a business-as-usual estimate, given known technology, as well as market, demographic, and technological trends. Most cases in the *Annual Energy Outlook 2012 (AEO2012)* generally assume that current laws and regulations are maintained throughout the projections. Such projections provide a baseline starting point that can be used to analyze policy initiatives. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, rates of technology progress, and policy changes.

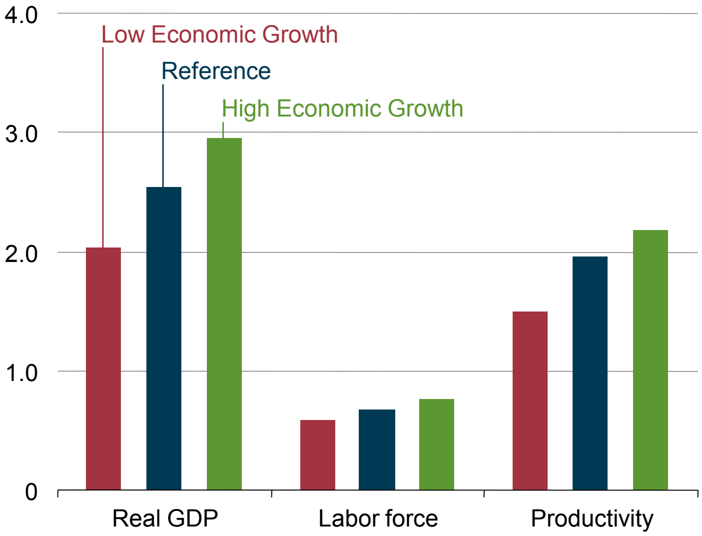
While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2012* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not as a substitute for, a complete and focused analysis of public policy initiatives.

Recovery in real gross domestic product growth continues at a modest rate

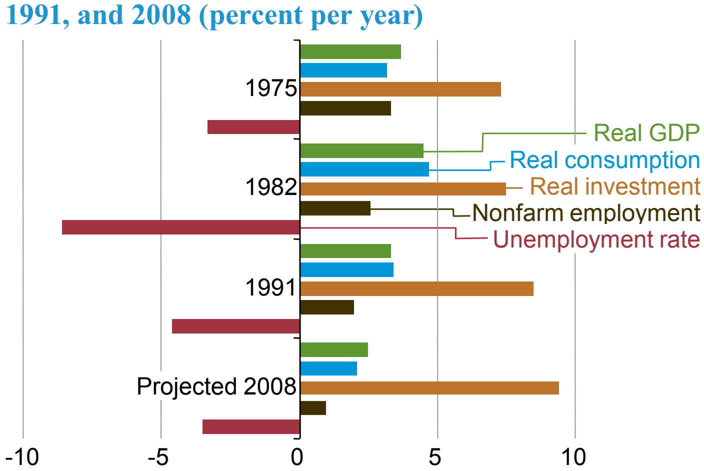
Figure 58. Average annual growth rates of real GDP, labor force, and nonfarm labor productivity in three cases, 2010-2035 (percent per year)



AEO2012 presents three views of U.S. economic growth (Figure 58). In 2011, the world economy experienced shocks that included turmoil in the Middle East and North Africa, a Greek debt crisis with financial impacts spreading to other Eurozone countries, and an earthquake in Japan, all leading to slower economic growth. U.S. growth projections in part reflect those world events.

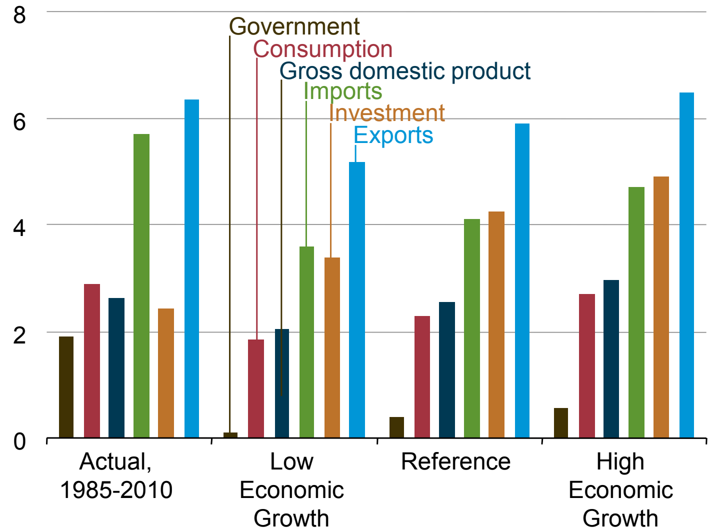
U.S. recovery from the 2007-2008 recession has been slower than past recoveries (Figure 59). A feature of economic recoveries since 1975 has been slowing employment gains, and, following the most recent recession, growth in nonfarm employment has been slower than in any other post-1960 recovery [*121*]. The average rates of growth are strong starting from the trough of the recessions.

Figure 59. Average annual growth rates over 5 years following troughs of U.S. recessions in 1975, 1982, 1991, and 2008 (percent per year)



Slow consumption growth, fast investment growth, and an ever-improving trade surplus

Figure 60. Average annual growth rates for real output and its major components in three cases, 2010-2035 (percent per year)



AEO2012 presents three economic growth cases: Reference, High, and Low. The High Economic Growth case assumes high growth and low inflation; the Low Economic Growth case assumes low growth and high inflation. Figure 60 compares the average annual growth rates for output and its major components in each of the three cases.

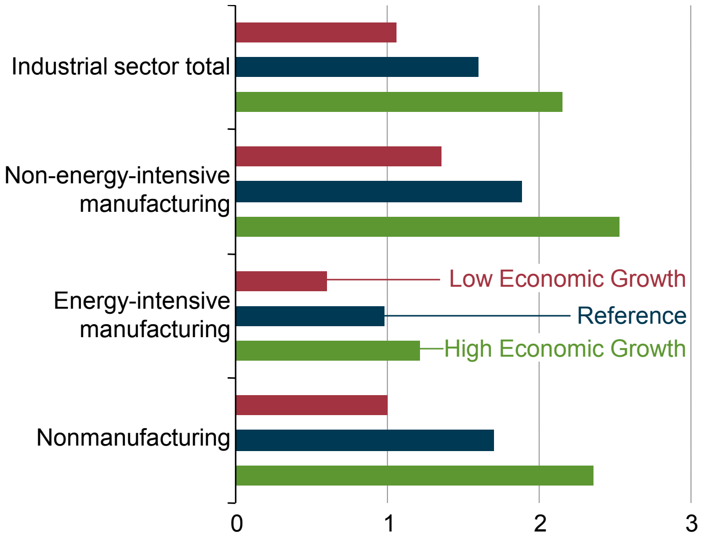
The short-term outlook (5 years) in each case represents current thinking about economic activity in the United States and the rest of the world; about the impacts of domestic fiscal and monetary policies; and about potential risks to economic activity. The long-term outlook projects smooth economic growth, assuming no shocks to the economy.

Differences among the Reference case and the High and Low Economic Growth cases reflect different expectations for growth in population (specifically, net immigration), labor force, capital stock, and productivity, which are above trend in the High Economic Growth case and below trend in the Low Economic Growth case. The average annual growth rate for real gross domestic product (GDP) from 2010 to 2035 in the Reference case is 2.5 percent, as compared with about 3.0 percent in the High Economic Growth case and about 2.0 percent in the Low Economic Growth case.

Compared with the 1985-2010 period, investment growth from 2010 to 2035 is faster in all three cases, whereas consumption, government expenditures, and imports grow more slowly in all three cases. Opportunities for trade are assumed to expand in each of the three cases, resulting in real trade surpluses by 2018 that continue through 2035.

Output growth for energy-intensive industries remains slow

Figure 61. Sectoral composition of industrial output growth rates in three cases, 2010-2035 (percent per year)

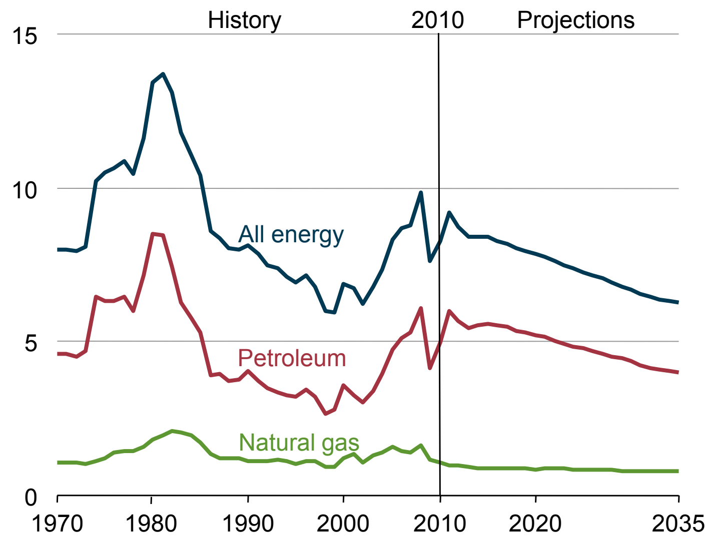


Industrial sector output has grown more slowly than the overall economy in recent decades, with imports meeting a growing share of demand for industrial goods, whereas the service sector has grown more rapidly [*122*]. In the *AEO2012* Reference case, real GDP grows at an average annual rate of 2.5 percent from 2010 to 2035, while both the industrial sector as a whole and its manufacturing component grow by 1.6 percent per year (Figure 61). As the economy recovers from the 2008-2009 recession, growth in U.S. manufacturing output in the Reference case accelerates from 2010 through 2020. After 2020, growth in manufacturing output slows due to increased foreign competition, slower expansion of domestic production capacity, and higher energy prices. These factors weigh heavily on the energy-intensive manufacturing sectors, which taken together grow at a slower rate of about 1.0 percent per year from 2010 to 2035, with variation by industry ranging from 0.8-percent annual growth for bulk chemicals to 1.5-percent annual growth for food processing.

A decline in U.S. dollar exchange rates, combined with modest growth in unit labor costs, stimulates U.S. exports, eventually improving the U.S. current account balance. From 2010 to 2035, real exports of goods and services grow by an average of 5.9 percent per year, and real imports of goods and services grow by an average of 4.1 percent per year. Strong growth in exports is an important component of projected growth in the transportation equipment, electronics, and machinery industries.

Energy expenditures decline relative to gross domestic product and gross output

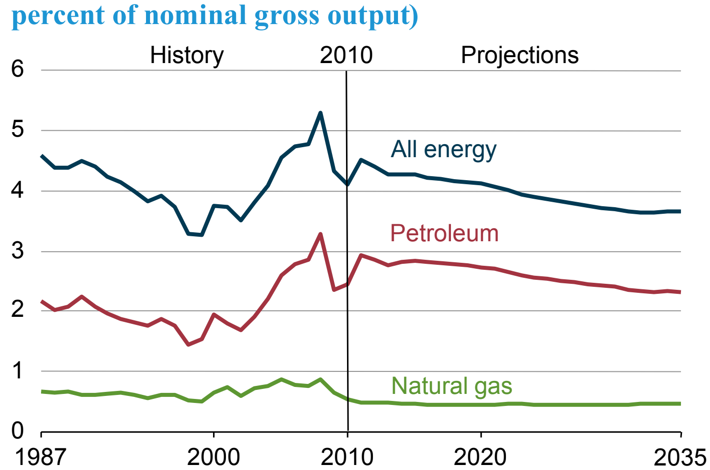
Figure 62. Energy end-use expenditures as a share of gross domestic product, 1970-2035 (nominal expenditures as percent of nominal GDP)



Total U.S. energy expenditures decline relative to GDP in the *AEO2012* Reference case (Figure 62) [*123*]. The projected share of energy expenditures falls from 2011 through 2035, averaging 7.5 percent from 2010 to 2035, which is below the historical average of 8.8 percent from 1970 to 2010.

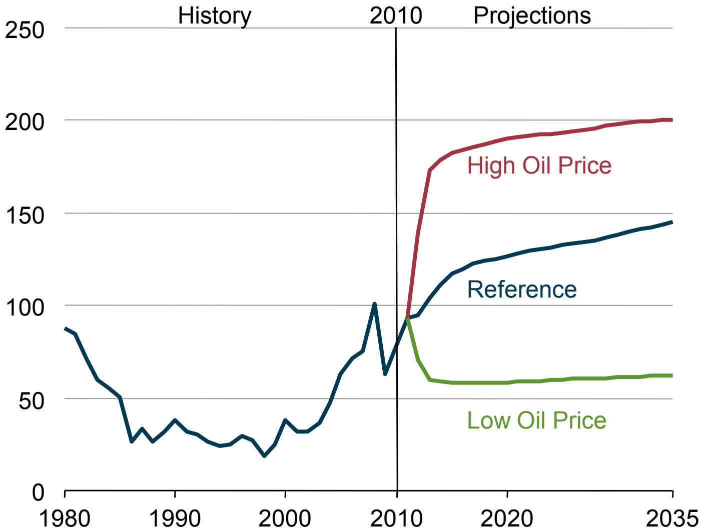
Gross output corresponds roughly to sales in the U.S. economy. Figure 63 provides an approximation of total energy expenditures relative to total sales. Energy expenditures as a share of gross output show roughly the same pattern as do energy expenditures as a share of GDP. The projected average shares of gross output relative to expenditures for total energy, petroleum, and natural gas are close to their historical averages, at 4.1 percent, 2.1 percent, and 0.5 percent, respectively.

Figure 63. Energy end-use expenditures as a share of gross output, 1987-2035 (nominal expenditures as percent of nominal gross output)



Oil price cases depict uncertainty in world oil markets

Figure 64. Average annual oil prices in three cases, 1980-2035 (2010 dollars per barrel)



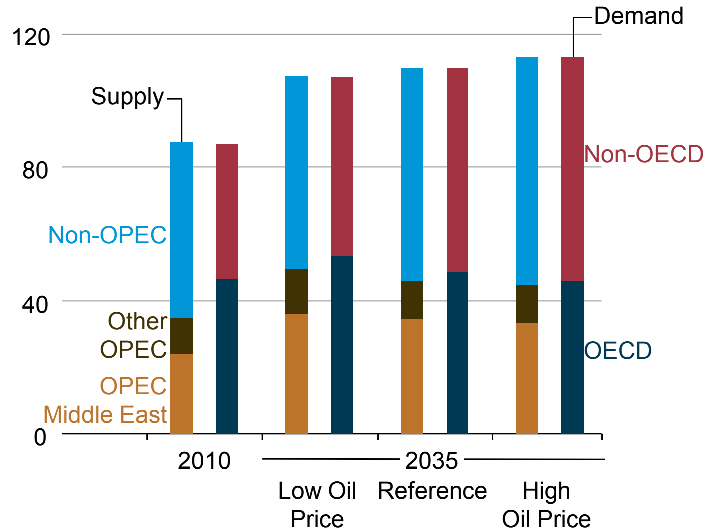
Oil prices in *AEO2012*, defined in terms of the average price of low-sulfur, light crude oil (West Texas Intermediate [WTI]) delivered to Cushing, Oklahoma, span a broad range that reflects the inherent volatility and uncertainty of oil prices (Figure 64). The *AEO2012* price paths are not intended to reflect absolute bounds for future oil prices but rather to provide a basis for analysis of the implications of world oil market conditions that differ from those assumed in the *AEO2012* Reference case. The Reference case assumes that the current price discount for WTI relative to similar "marker" crude oils (such as Brent and Louisiana Light Sweet) will fade when adequate pipeline capacity is built between Cushing and the Gulf of Mexico.

In the Low Oil Price case, GDP growth in countries outside the Organization of the Petroleum Exporting Countries (non-OPEC) is slower than in the Reference case, resulting in lower demand for petroleum and other liquids, and producing countries develop stable fiscal policies and investment regimes that encourage resource development. OPEC nations increase production, achieving approximately a 46-percent market share of total petroleum and other liquids production in 2035.

The High Oil Price case depicts a world oil market in which total GDP growth in countries outside the Organization for Economic Cooperation and Development (non-OECD) is faster than in the Reference case, driving up demand for petroleum and other liquids. Production of crude oil and natural gas liquids (NGL) is restricted by political decisions and limits on access to resources (such as the use of quotas and fiscal regimes) compared with the Reference case. Petroleum and other liquids production in the major producing countries is reduced (for example, the OPEC share averages 40 percent), and the consuming countries turn to more expensive production from other liquids sources to meet demand.

Trends in petroleum and other liquids markets are defined largely by the developing nations

Figure 65. World petroleum and other liquids supply and demand by region in three cases, 2010 and 2035 (million barrels per day)



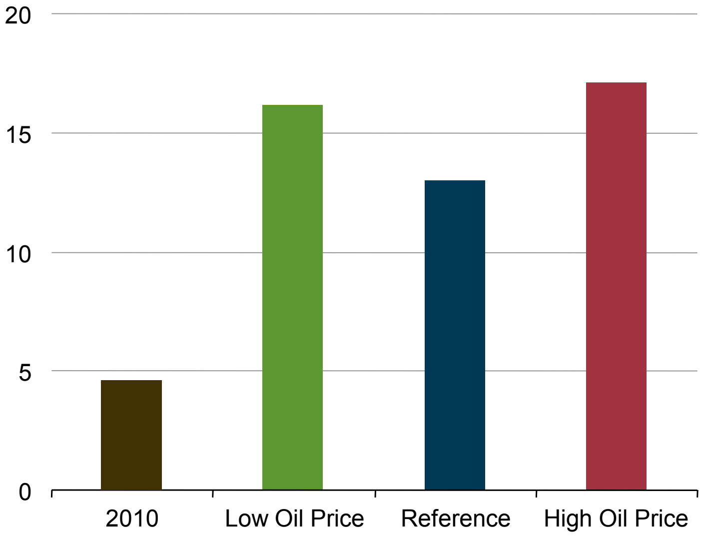
Total use of petroleum and other liquids in the *AEO2012* Reference, High Oil Price, and Low Oil Price cases in 2035 ranges from 107 to 113 million barrels per day (Figure 65). The alternative oil price cases reflect shifts in both supply and demand, with the result that total consumption and production levels do not vary widely. Although demand in the OECD countries is influenced primarily by price, demand in non-OECD regions—where future economic uncertainty is greatest—drives the price projections. That is, non-OECD petroleum and other liquids consumption is lower in the Low Oil Price case and higher in the High Oil Price case than it is in the Reference case.

OECD petroleum and other liquids use grows in the Reference case to 48 million barrels per day in 2035, while non-OECD use grows to 61 million barrels per day. In the Low Oil Price case, OECD petroleum and other liquids use in 2035 is higher than in the Reference case, at 53 million barrels per day, but demand in the slow-growing non-OECD economies in the Low Price case rises to only 54 million barrels per day. In the High Oil Price case the opposite occurs, with OECD consumption falling to 46 million barrels per day in 2035 and fast-growing non-OECD use—driven by higher GDP growth—increasing to 67 million barrels per day in 2035.

The supply response also varies across the price cases. In the Low Oil Price case, OPEC's ability to constrain market share is weakened, and low prices have a negative impact on non-OPEC crude oil supplies relative to the Reference case. Because non-crude oil technologies achieve much lower costs in the Low Price case, supplies of other liquids are more plentiful than in the Reference case. In the High Oil Price case, OPEC restricts production, non-OPEC resources become more economic, and high prices make other liquids more attractive.

Production from resources other than crude oil and natural gas liquids increases

Figure 66. Total world production of nonpetroleum liquids, bitumen, and extra-heavy oil in three cases, 2010 and 2035 (million barrels per day)



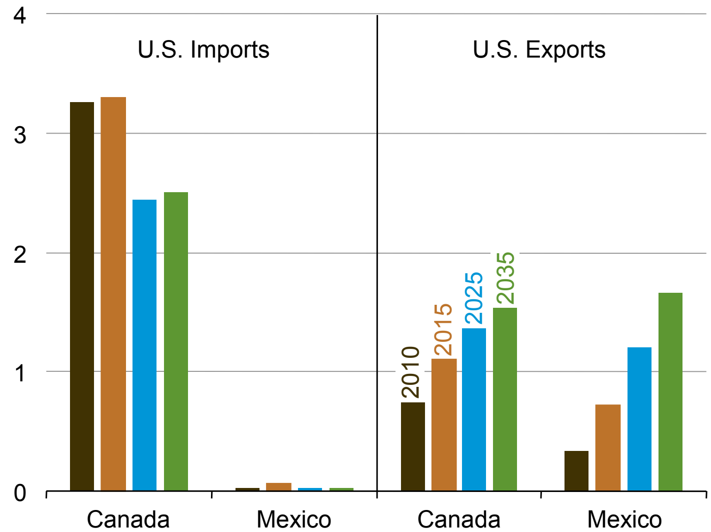
In 2010, world production of liquid fuels from resources other than crude oil and NGL totaled 4.6 million barrels per day, or about 5 percent of all petroleum and other liquids production. Production from those other sources grows to 13.0 million barrels per day (about 12 percent of total global production of petroleum and other liquids) in 2035 in the *AEO2012* Reference case, 16.2 million barrels per day (15 percent of the total) in the Low Oil Price case, and 17.1 million barrels per day (15 percent of the total) in the High Oil Price case (Figure 66). The higher levels of production from other resources result from declining technology costs in the Low Oil Price case and from higher oil prices in the High Oil Price case.

Assumptions about the development of other liquids resources differ across the three cases. In the Reference case, increasingly expensive projects become more economically competitive as a result of rising oil prices and advances in production technology. Bitumen in Canada and biofuels in the United States and Brazil are the most important components of production from sources other than crude oil and NGL. Excluding crude oil and NGL, U.S. and Brazilian biofuels and Canadian bitumen account for more than 70 percent of the total world increase in petroleum and other liquids production from 2010 to 2035 in the Reference case.

In the High Oil Price case, rising prices support increased development of nonpetroleum liquids, bitumen, and extra-heavy oil. A smaller increase is projected in the Low Oil Price case, which assumes significant declines in technology costs, particularly for extra-heavy oil production. Bitumen and biofuels continue to be the most important contributors to this supply category through 2035.

U.S. reliance on imported natural gas from Canada declines as exports grow

Figure 67. North American natural gas trade, 2010-2035 (trillion cubic feet)

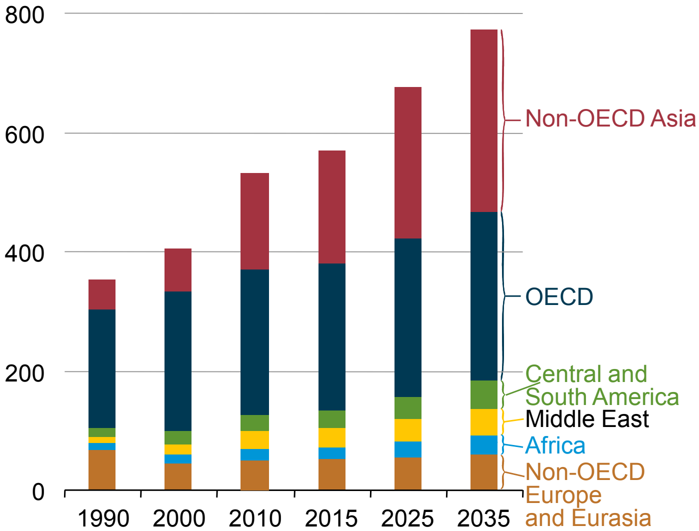


The energy markets of the three North American nations (United States, Canada, and Mexico) are well integrated, with extensive infrastructure that allows cross-border trade between the United States and both Canada and Mexico. The United States, which is by far the region's largest energy consumer, currently relies on Canada and Mexico for supplies of petroleum and other liquid fuels. Canada and Mexico were the largest suppliers of U.S. petroleum and other liquids imports in 2010, providing 2.5 and 1.3 million barrels per day, respectively. In addition, Canada supplies the United States with substantial natural gas supplies, exporting 3.3 trillion cubic feet to U.S. markets in 2010 (Figure 67).

In the *AEO2012* Reference case, energy trade between the United States and the two other North American countries continues. In 2035, the United States still imports 3.4 million barrels per day of petroleum and other liquid fuels from Canada in the Reference case, but imports from Mexico fall to 0.8 million barrels per day. With prospects for domestic U.S. natural gas production continuing to improve, the need for imported natural gas declines. U.S. imports of natural gas from Canada fall to 2.4 trillion cubic feet in 2025 in the Reference case and remain relatively flat through the end of the projection. On the other hand, U.S. natural gas exports to both Canada and Mexico increase. Canada's imports of U.S. natural gas grow from 0.7 trillion cubic feet in 2010 to 1.5 trillion cubic feet in 2035, and Mexico's imports grow from 0.3 trillion cubic feet in 2010 to 1.7 trillion cubic feet in 2035 in the *AEO2012* Reference case.

China and India account for half the growth in world energy use

Figure 68. World energy consumption by region, 1990-2035 (quadrillion Btu)



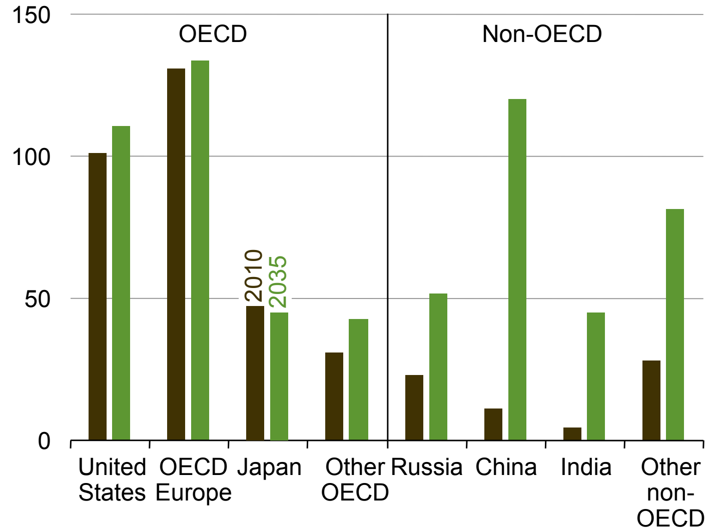
World energy consumption increases by 47 percent from 2010 through 2035 in the *AEO2012* Reference case (Figure 68). Most of the growth is projected for emerging economies outside the OECD, where robust economic growth is accompanied by increased demand for energy. Total non-OECD energy use grows by 72 percent, compared with an 18-percent increase in OECD energy use.

Energy consumption in non-OECD Asia, led by China and India, shows the most robust growth among the non-OECD regions, rising by 91 percent from 2010 to 2035. However, strong growth also occurs in much of the rest of the non-OECD regions: 69 percent in Central and South America, 65 percent in Africa, and 62 percent in the Middle East. The slowest growth among the non-OECD regions is projected for non-OECD Europe and Eurasia (including Russia), where substantial gains in energy efficiency are achieved through replacement of inefficient Soviet-era capital equipment.

Worldwide, the use of energy from all sources increases in the projection. Given expectations that oil prices will remain relatively high, petroleum and other liquids are the world's slowest-growing energy sources. High energy prices and concerns about the environmental consequences of greenhouse gas (GHG) emissions lead a number of national governments to provide incentives in support of the development of alternative energy sources, making renewables the world's fastest-growing source of energy in the outlook.

After Fukushima, prospects for nuclear power dim in Japan and Europe but not elsewhere

Figure 69. Installed nuclear capacity in OECD and non-OECD countries, 2010 and 2035 (gigawatts)



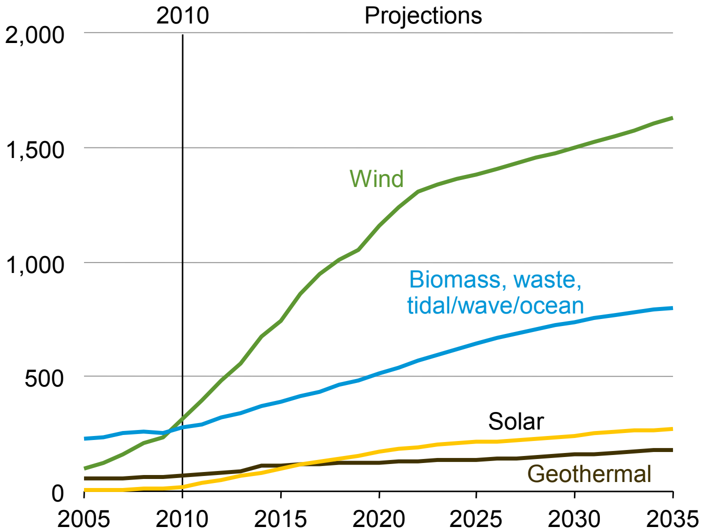
The earthquake and tsunami that hit northeastern Japan in March 2011 caused extensive loss of life and infrastructure damage, including severe damage to several reactors at the Fukushima Daiichi nuclear power plant. In the aftermath, governments in several countries that previously had planned to expand nuclear capacity—including Japan, Germany, Switzerland, and Italy—reversed course. Even China announced a temporary suspension of its approval process for new reactors pending a thorough safety review.

Before the Fukushima event, EIA had projected that all regions of the world with existing nuclear programs would expand their nuclear power capacity. Now, however, Japan's nuclear capacity is expected to contract by about 3 gigawatts from 2010 to 2035 (Figure 69). In OECD Europe, Germany's outlook has been revised to reflect a phaseout of all nuclear power by 2025. As a result, the projected net increase in OECD Europe's nuclear capacity in the *AEO2012* Reference case is only 3 gigawatts from 2010 to 2035.

Significant expansion of nuclear power is projected to continue in the non-OECD region as a whole, with total nuclear capacity more than quadrupling. From 2010 to 2035, nuclear power capacity increases by a net 109 gigawatts in China, 41 gigawatts in India, and 28 gigawatts in Russia, as strong growth in demand for electric power and concerns about security of energy supplies and the environmental impacts of fossil fuel use encourage further development of nuclear power in non-OECD countries.

Wind power leads rise in world renewable generation, solar power also grows rapidly

Figure 70. World renewable electricity generation by source, excluding hydropower, 2005-2035 (billion kilowatthours)



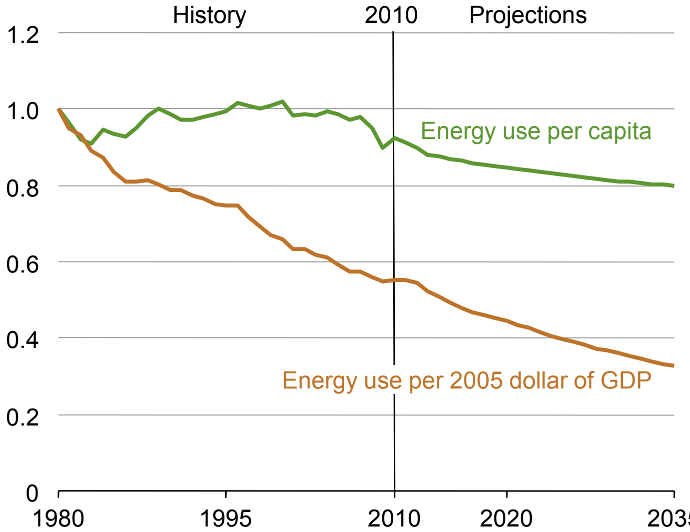
Renewable energy is the world's fastest-growing source of marketed energy in the *AEO2012* Reference case, increasing by an average of 3.0 percent per year from 2010 to 2035, compared to an average of 1.6 percent per year for total world energy consumption. In many parts of the world, concerns about the security of energy supplies and the environmental consequences of GHG emissions have spurred government policies that support rapid growth in renewable energy installations.

Hydropower is well-established worldwide, accounting for 83 percent of total renewable electricity generation in 2010. Growth in hydroelectric generation accounts for about one-half of the world increase in renewable generation in the Reference case. In Brazil and the developing nations of Asia, significant builds of mid- and large-scale hydropower plants are expected, and the two regions together account for two-thirds of the total world increase in hydroelectric generation from 2010 to 2035.

Solar power is the fastest-growing source of renewable energy in the outlook, with annual growth averaging 11.7 percent. However, because it currently accounts for only 0.4 percent of total renewable generation, solar remains a minor part of the renewable mix even in 2035, when its share reaches 3 percent. Wind generation accounts for the largest increment in nonhydropower renewable generation—60 percent of the total increase, as compared with solar's 12 percent (Figure 70). The rate of wind generation slows markedly after 2020 because most government wind goals are achieved and wind must then compete on the basis of economics with fossil fuels. Wind-powered generating capacity has grown swiftly over the past decade, from 18 gigawatts of installed capacity in 2000 to an estimated 179 gigawatts in 2010.

In the United States, average energy use per person declines from 2010 to 2035

Figure 71. Energy use per capita and per dollar of gross domestic product, 1980-2035 (index, 1980 = 1)



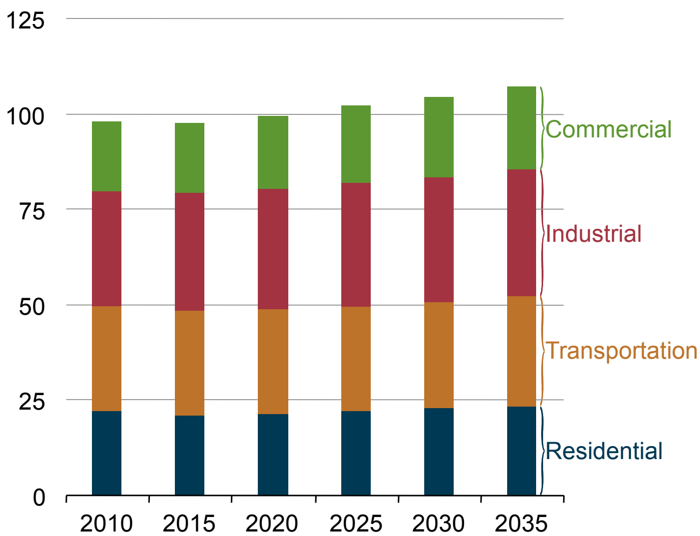
Growth in energy use is linked to population growth through increases in housing, commercial floorspace, transportation, and goods and services. These changes affect not only the level of energy use but also the mix of fuels consumed.

Changes in the structure of the economy and in the efficiency of the equipment deployed throughout the economy also have an impact on energy use per capita. The shift in the industrial sector away from energy-intensive manufacturing toward services is one reason for the projected decline in industrial energy intensity (energy use per dollar of GDP), but its impact on energy consumption per capita is less direct (Figure 71). From 1990 to 2007, the service sectors increased from a 69-percent share of total industrial output to a 75-percent share, but energy use per capita remained fairly constant, between 330 and 350 million British thermal units (Btu) per person, while energy use per dollar of GDP dropped from about 10,500 to 7,700 Btu. Increases in the efficiency of freight vehicles and the shift toward output from the service sectors are projected to continue through 2035, lowering energy use in relation to GDP. Energy use per dollar of GDP is projected to be about 4,400 Btu in 2035, or about one-third of the 1980 level.

Efficiency gains in household appliances and personal vehicles have a direct, downward impact on energy use per capita, as do efficiency gains in the electric power sector, as older, inefficient coal and other fossil steam electricity generating plants are retired in anticipation of lower electricity demand growth, changes in fuel prices, and new environmental regulations. As a result, U.S. energy use per capita declines to 274 million Btu in 2035.

Industrial and commercial sectors lead U.S. growth in primary energy use

Figure 72. Primary energy use by end-use sector, 2010-2035 (quadrillion Btu)



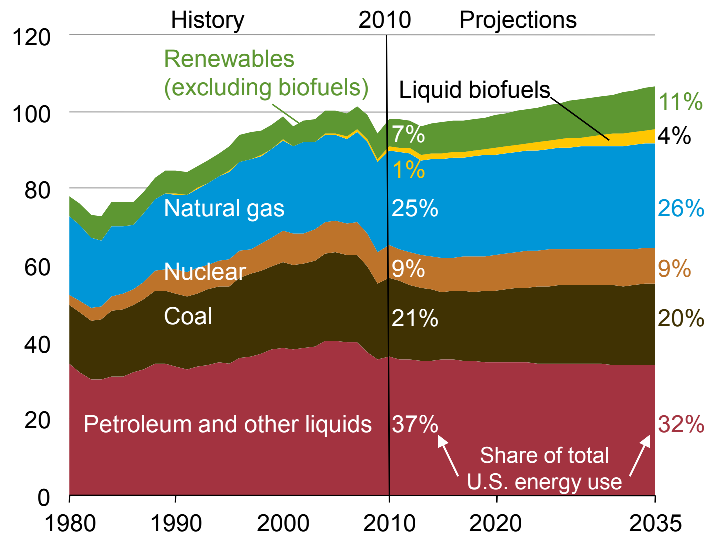
Total primary energy consumption, including fuels used for electricity generation, grows by 0.3 percent per year from 2010 to 2035, to 106.9 quadrillion Btu in 2035 in the *AEO2012* Reference case (Figure 72). The largest growth, 3.3 quadrillion Btu from 2010 to 2035, is in the commercial sector, which currently accounts for the smallest share of end-use energy demand. Even as standards for building shells and energy efficiency are being tightened in the commercial sector, the growth rate for commercial energy use, at 0.7 percent per year, is the highest among the end-use sectors, propelled by 1.0 percent average annual growth in commercial floorspace.

The industrial sector, which was more severely affected than the other end-use sectors by the 2008-2009 economic downturn, shows the second-largest increase in total primary energy use, at 3.1 quadrillion Btu from 2010 to 2035. The total increase in industrial energy consumption is 2.1 quadrillion Btu from 2008 to 2035, attributable to increased production of biofuels to meet the Energy Independence and Security Act of 2007 (EISA2007) renewable fuels standard (RFS) as well as increased use of natural gas in some industries, such as food and paper, to generate their own electricity.

Primary energy use in both the residential and transportation sectors grows by 0.2 percent per year, or by just over 1 quadrillion Btu each from 2010 to 2035. In the residential sector, increased efficiency reduces energy use for space heating, lighting, and clothes washers and dryers. In the transportation sector, light-duty vehicle (LDV) energy consumption declines after 2012 to 14.7 quadrillion Btu in 2023 (the lowest point since 1998) before increasing through 2035, when it is still 4 percent below the 2010 level.

Renewable energy sources lead rise in primary energy consumption

Figure 73. Primary energy use by fuel, 1980-2035 (quadrillion Btu)



With the exception of petroleum and other liquids, which falls through 2032 before increasing slightly in the last 3 years of the projection, consumption of all fuels increases in the *AEO2012* Reference case. In addition, coal consumption increases at a relatively weak average rate of less than 0.1 percent per year from 2010 to 2035, remaining below 2010 levels until after 2031. As a result, the aggregate fossil fuel share of total energy use falls from 83 percent in 2010 to 77 percent in 2035, while renewable fuel use grows rapidly (Figure 73). The renewable share of total energy use (including biofuels) increases from 8 percent in 2010 to 14 percent in 2035 in response to the Federal RFS, availability of Federal tax credits for renewable electricity generation and capacity, and State renewable portfolio standard (RPS) programs.

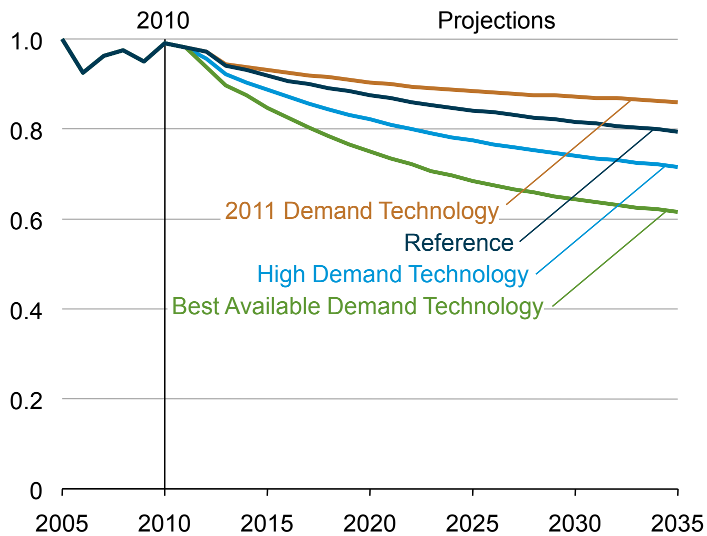
The petroleum and other liquids share of fuel use declines as consumption of other liquids increases. Almost all consumption of liquid biofuels is in the transportation sector. Biofuels, including biodiesel blended into diesel, E85, and ethanol blended into motor gasoline (up to 15 percent), account for 10 percent of all petroleum and other liquids consumption in 2035.

Natural gas consumption grows by about 0.4 percent per year from 2010 to 2035, led by the use of natural gas in electricity generation. Growing production from tight shale keeps natural gas prices below their 2005-2008 levels through 2035.

By the end of 2012, a total of 9.3 gigawatts of coal-fired power plant capacity currently under construction is expected to come online, and another 1.7 gigawatts is added after 2017 in the Reference case, including 0.9 gigawatts with carbon sequestration capability. Additional coal is consumed in the coal-to-liquids (CTL) process to produce heat and power, including electricity generation at CTL plants.

Residential energy use per household declines for a range of technology assumptions

Figure 74. Residential delivered energy intensity in four cases, 2005-2035 (index, 2005 = 1)



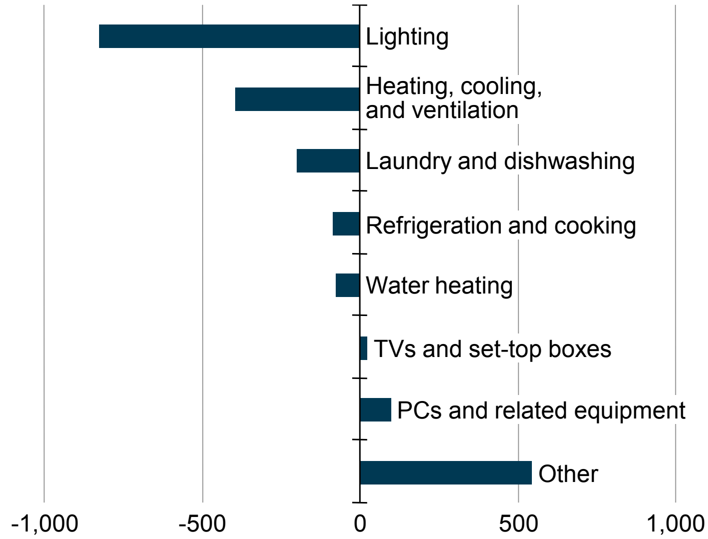
In the *AEO2012* Reference case, residential sector energy intensity, defined as average energy use per household per year, declines by 19.8 percent, to 81.9 million Btu per year in 2035 (Figure 74). Total delivered energy use in the residential sector remains relatively constant from 2010 to 2035, but a 27.5-percent growth in the number of households reduces the average energy intensity of each household. Most residential end-use services become less energy-intensive, with space heating accounting for more than one-half of the decrease. Population shifts to warmer and drier climates also contribute to a reduction in demand for space heating.

Three alternative cases show how different technology assumptions affect residential energy intensity. The 2011 Demand Technology case assumes no improvement in efficiency for end-use equipment or building shells beyond those available in 2011. The High Demand Technology case assumes higher efficiency, earlier availability, lower cost, and more frequent energy-efficient purchases for some advanced equipment. The Best Available Demand Technology case limits customers who purchase new and replacement equipment to the most efficient model available in the year of purchase—regardless of cost—and assumes that new homes are constructed to the most energy-efficient specifications.

From 2010 to 2035, household energy intensity declines by 27.7 percent in the High Demand Technology case and by 37.9 percent in the Best Available Demand Technology case. In the 2011 Demand Technology case, household energy intensity also falls as older appliances are replaced with 2011 vintage equipment. Without further gains in efficiency for residential equipment and building shells, the total decline from 2010 to 2035 is only 13.2 percent.

Electricity use increases with number of households despite efficiency improvement

Figure 75. Change in residential electricity consumption for selected end uses in the Reference case, 2010-2035 (kilowatthours per household)



Despite a decrease in electricity consumption per household, total delivered electricity use in the residential sector grows at an average rate of 0.7 percent per year in the *AEO2012* Reference case, while natural gas use and petroleum and other liquids use fall by 0.2 percent and 1.3 percent per year, respectively, from 2010 to 2035. The increase in efficiency, driven by new standards and improved technology, is not high enough to offset the growth in the number of households and electricity consumption in “other” uses.

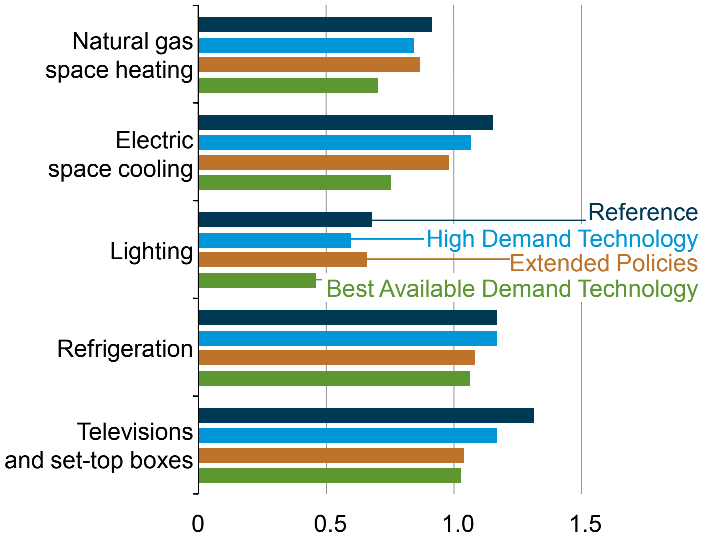
Portions of the Federal lighting standards outlined in EISA2007 went into effect on January 1, 2012. Over the next two years, general-service lamps that provide 310 to 2,600 lumens of light are required to consume about 30 percent less energy than typical incandescent bulbs. High-performance incandescent, compact fluorescent, and light-emitting diode (LED) lamps continue to replace low-efficacy incandescent lamps. In 2035, delivered energy for lighting per household in the Reference case is 827 kilowatthours per household lower, or 47 percent below the 2010 level (Figure 75).

Electricity consumption for three groups of electricity end uses increases on a per-household basis in the Reference case. Electricity use for televisions and set-top boxes grows by an average of 1.1 percent per year, accounting for 7.3 percent of total delivered electricity consumption in 2035. Personal computers (PCs) and related equipment account for 4.6 percent of residential electricity consumption in 2035, averaging 1.8-percent annual growth from their 2010 level. Electricity use by other household electrical devices, for which market penetration increases with little coverage by efficiency standards, increases by 1.8 percent annually and accounts for nearly one-fourth of total residential electricity consumption in 2035.

Residential sector energy demand

Residential consumption varies depending on efficiency assumptions

Figure 76. Ratio of residential delivered energy consumption for selected end uses (ratio, 2035 to 2010)



The *AEO2012* Reference case and three alternative cases demonstrate opportunities for improved energy efficiency to reduce energy consumption in the residential sector. The Reference, High Demand Technology, and Best Available Demand Technology cases include different levels of efficiency improvement without anticipating the enactment of new appliance standards. The Extended Policies case assumes the enactment of new rounds of standards, generally based on improvements seen in current ENERGY STAR equipment.

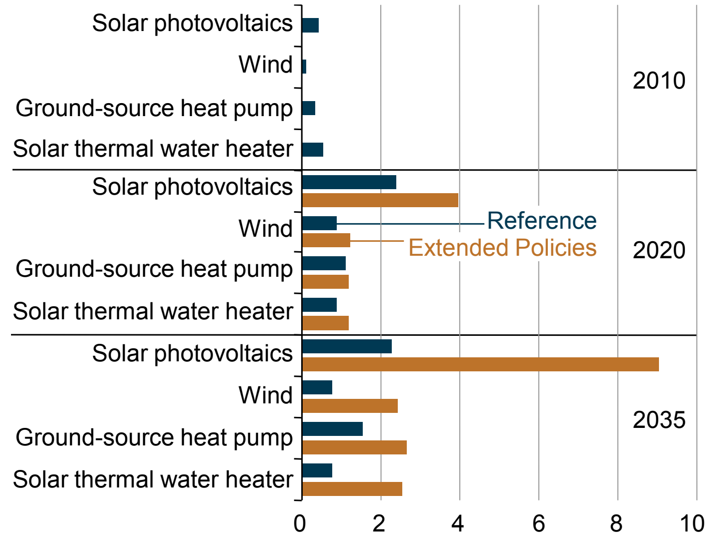
Despite continued growth in the number of households and number of appliances, energy consumption for some end uses is lower in 2035 than in 2010, implying that improved energy efficiency offsets the growth in service demand. In the case of natural gas space heating, population shifts towards warmer and drier climates also reduce consumption; the opposite is true for electric space cooling.

In the Extended Policies case, the enactment of new standards is based on the U.S. Department of Energy's multi-year schedule. For lighting, which already has an EISA2007-based standard that is scheduled to go into effect in 2020, future standards are not assumed until 2026. Among electric end uses, lighting has the largest percentage decline in energy use (more than 50 percent) in the Best Available Demand Technology case from 2010 to 2035 (Figure 76).

Televisions and set-top boxes, which are not currently covered by Federal standards, are assumed to have new standards in 2016 and 2018, respectively, in the Extended Policies case. The enactment of these new standards holds energy use for televisions and set-top boxes at or near their 2010 levels through 2035.

Tax credits could spur growth in renewable energy equipment in the residential sector

Figure 77. Residential market penetration by renewable technologies in two cases, 2010, 2020, and 2035 (percent of households)



Consistent with current law, existing investment tax credits (ITCs) expire at the end of 2016 in the *AEO2012* Reference case. The current credits can offset 30 percent of installed costs for a variety of distributed generation (DG) technologies, fostering their adoption. Installations slow dramatically after the ITCs expire, and in several cases their overall market penetration falls because growth in households exceeds the rise in new renewable installations (Figure 77). In the *AEO2012* Extended Policies case, the ITCs are extended through 2035, and penetration rates for all renewable technologies continue to rise.

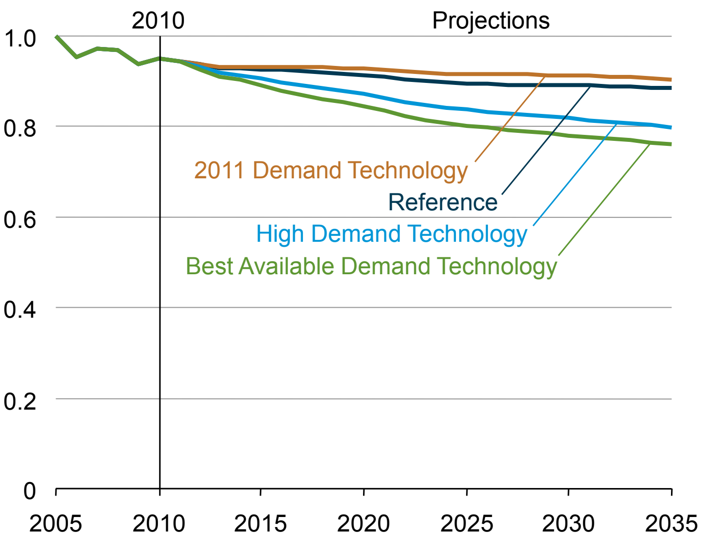
In the Reference case, photovoltaic (PV) and wind capacities grow by average rates of 10.8 percent and 9.2 percent per year, respectively, from 2010 to 2035. In the Extended Policies case, residential PV capacity increases to 54.6 gigawatts in 2035, with annual growth averaging 18.1 percent, and wind capacity grows to 11.0 gigawatts in 2035, averaging 15.9 percent per year.

The ITCs also affect the penetration of renewable space-conditioning and water-heating equipment. Ground-source heat pumps reach a 2.6-percent market share in 2035 in the Extended Policies case, after adding nearly 3.5 million units. In the Reference case, without the ITC extension, their market penetration is only 1.5 percent in 2035, with 1.6 million fewer installations than in the Extended Policies case.

Market penetration of solar water heaters in the Extended Policies case is 2.5 percent in 2035, more than triple the Reference case share. In the Reference case, installations increase by 2.5 percent annually from 2010 to 2035, compared with 7.5 percent annually in the Extended Policies case.

For commercial buildings, pace of decline in energy intensity depends on technology

Figure 78. Commercial delivered energy intensity in four cases, 2005-2035 (index, 2005 = 1)



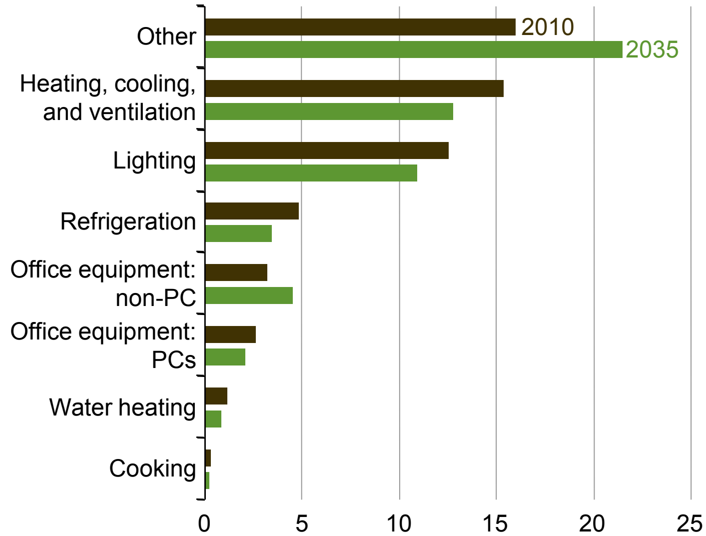
In the *AEO2012* Reference case, average delivered energy use per square foot of commercial floorspace declines by 7.0 percent from 2010 to 2035 (Figure 78). Growth in commercial floorspace (26.9 percent) leads to an increase in delivered energy use (18.1 percent), but efficiency improvements in equipment and building shells reduce energy intensity in commercial buildings. Space heating, space cooling, and lighting contribute most to the decrease in intensity, with space heating accounting for significantly more than cooling and lighting combined.

Three alternative cases show the potential impact of energy-efficient technologies on energy intensity in commercial buildings. The 2011 Demand Technology case limits equipment and building shell technologies in later years to the options available in 2011. The High Demand Technology case assumes higher efficiencies for equipment and building shells, lower costs, earlier availability of some advanced equipment, and decisions by commercial customers that place greater importance on future energy savings. The Best Available Technology case assumes more efficient buildings shells for new and existing buildings than in the High Demand Technology case and also requires commercial customers to choose among the most efficient models for each technology when replacing old or purchasing new equipment.

From 2010 to 2035, the intensity of commercial energy use in the 2011 Technology Demand case declines by 5.0 percent, to 101.9 thousand Btu per square foot of commercial floorspace in 2035. In comparison, intensity decreases faster in the High Demand Technology case (16.0 percent) and fastest in the Best Available Demand Technology case (20.0 percent).

Efficiency standards reduce electric energy intensity in commercial buildings

Figure 79. Energy intensity of selected commercial electric end uses, 2010 and 2035 (thousand Btu per square foot)



Electricity, which accounted for 52 percent of total commercial delivered energy use in 2010, increases to 56 percent in 2035 in the *AEO2012* Reference case, as commercial floorspace grows at an average annual rate of 1 percent and new electric end uses become more prevalent. Despite such growth, improved efficiency of commercial equipment slows the growth of purchased electricity over the projection period.

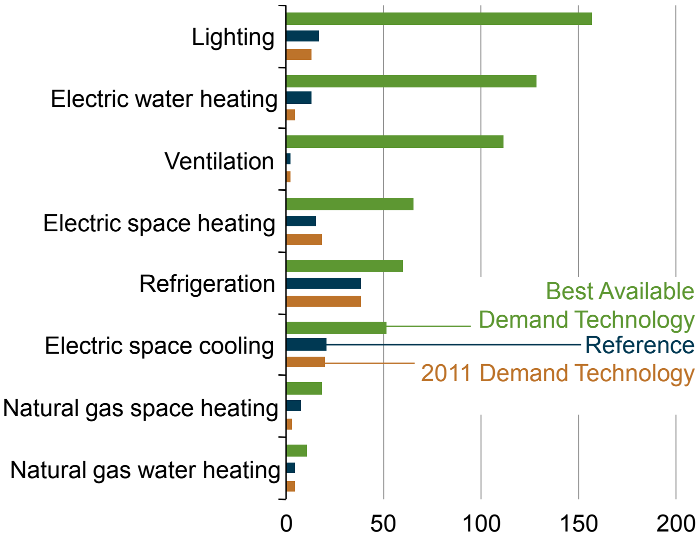
Commercial energy intensity in this figure, defined as the ratio of energy consumption in these appliances to floorspace, decreases for most electric end uses from 2010 to 2035 in the Reference case (Figure 79). Electricity intensity decreases by 1.3 percent annually for both cooking and refrigeration, by 0.5 percent annually for lighting, and by 0.7 percent annually for space conditioning (heating, cooling, and ventilation).

End uses such as space heating and cooling, water heating, refrigeration, and lighting are covered by Federal efficiency standards that act to limit growth in energy consumption to less than the growth in commercial floorspace. "Other" electric end uses, some of which are not subject to standards, account for much of the growth in commercial electricity consumption in the Reference case. Electricity consumption for "other" electrical end uses—including video displays and medical devices—increases by an average of 2.2 percent per year and in 2035 accounts for 38 percent of total commercial electricity consumption. Energy consumption for "other" office equipment—including servers and mainframe computers—increases by 2.3 percent per year from 2010 to 2035, as demand for high-speed networks and internet connectivity continues to grow.

Commercial sector energy demand

Technologies for major energy applications lead efficiency gains in commercial sector

Figure 80. Efficiency gains for selected commercial equipment in three cases, 2035 (percent change from 2010 installed stock efficiency)



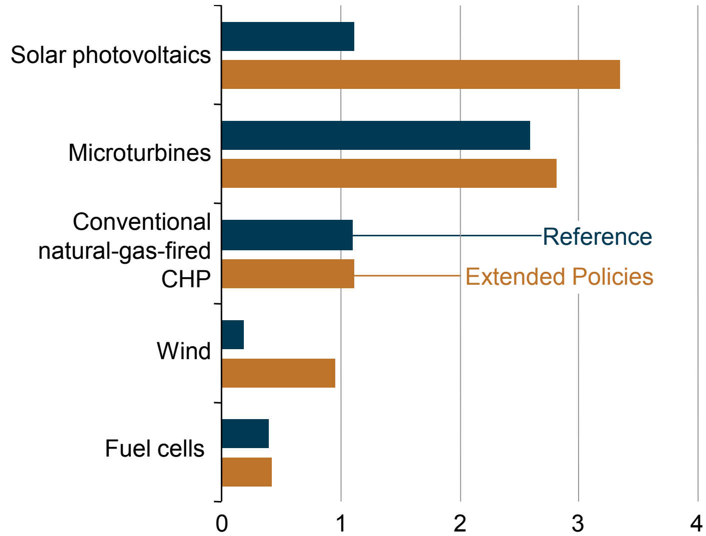
Delivered energy consumption for space heating, ventilation, air conditioning, water heating, lighting, cooking, and refrigeration uses in the commercial sector grows by an average of 0.2 percent per year from 2010 to 2035 in the *AEO2012* Reference case, compared with 1.0-percent annual growth in commercial floorspace. The core end uses, which frequently have been the focus of energy efficiency standards, accounted for just over 60 percent of commercial delivered energy demand in 2010. In 2035, their share falls to 53 percent. Energy consumption for all the remaining end uses grows by 1.3 percent per year, led by office equipment other than computers and other electric end uses.

The percentage gains in efficiency in the Reference case are highest for refrigeration, as a result of provisions in the Energy Policy Act of 2005 and EISA2007. Electric space cooling shows the next-largest percentage improvement, followed by lighting and electric space heating (Figure 80).

The Best Available Demand Technology case demonstrates significant potential for further improvement—especially in electric equipment, led by lighting, water heating, and ventilation. In the Best Available Demand Technology case, the share of total commercial delivered energy use in the core end uses falls to 49 percent in 2035, with significant efficiency gains coming from high-efficiency variable air volume ventilation systems, LED lighting, ground-source heat pumps, high-efficiency rooftop heat pumps, centrifugal chillers, and solar water heaters. Those technologies are relatively costly, however, and thus unlikely to gain wide adoption in commercial applications without improved economics. Additional efficiency improvements could also come from an expansion of standards to include some of the rapidly growing miscellaneous electric applications.

Investment tax credits could increase distributed generation in commercial sector

Figure 81. Additions to electricity generation capacity in the commercial sector in two cases, 2010-2035 (gigawatts)



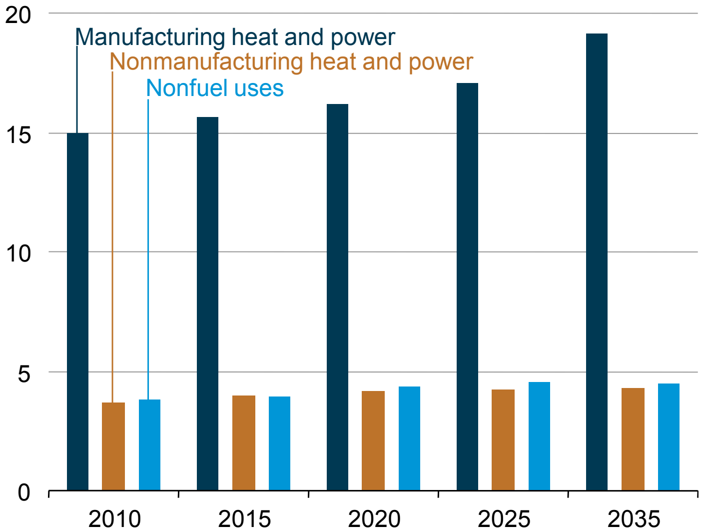
ITCs have a major impact on the growth of renewable DG in the commercial sector. Although most ITCs are set to expire at the end of 2016, the tax credit for solar PV installations reverts from 30 percent to 10 percent and continues indefinitely. Commercial PV capacity increases by 2.7 percent annually from 2010 through 2035 in the *AEO2012* Reference Case. Extending the ITCs to all DG technologies through 2035 in the *AEO2012* Extended Policies case causes PV capacity to increase at an average annual rate of 5.7 percent (Figure 81).

Growth in small-scale wind capacity more than doubles in the Extended Policies case relative to the Reference case, increasing at an average annual rate of 11.4 percent from 2010 to 2035. Wind accounts for 9.2 percent of the 11.1 gigawatts of total commercial DG capacity in 2035 in the Extended Policies case, and PV accounts for 40.6 percent. In the Extended Policies case, renewable energy accounts for 53 percent of all commercial DG capacity, compared with about 37 percent in the Reference case.

Although ITCs affect the rate of adoption of renewable DG by offsetting a portion of capital costs, their potential effects on nonrenewable DG technologies are offset by rising natural gas prices. In the Reference case, microturbine capacity using natural gas grows by an average of 18.1 percent per year from 42 megawatts in 2010 to 2.6 gigawatts in 2035, and the growth rate in the Extended Policies case is only slightly higher, at 18.4 percent. In the Extended Policies case, the microturbine share of total DG capacity in 2035 is 25.6 percent, as compared with 33.4 percent in the Reference case.

Manufacturing heat and power energy consumption increases modestly

Figure 82. Industrial delivered energy consumption by application, 2010-2035 (quadrillion Btu)



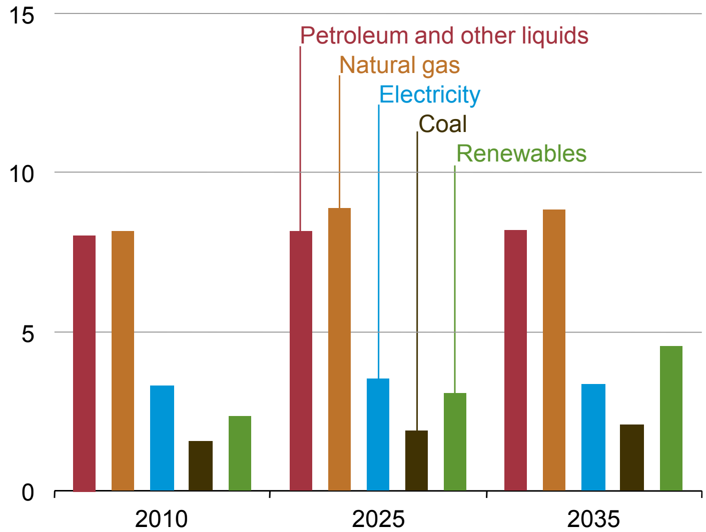
Despite a 49-percent increase in industrial shipments, industrial delivered energy consumption increases by only 15 percent from 2010 to 2035 in the *AEO2012* Reference case, reflecting a shift in the share of shipments from energy-intensive manufacturing industries (which include bulk chemicals, petroleum refineries, paper products, iron and steel, food products, aluminum, cement, and glass) to other, less energy-intensive industries, such as plastics, computers, and transportation equipment. Although energy use for most of the energy-intensive industries continues to grow after 2012, with the stronger growth in refining, declines in the energy intensity of heat and power production offset some the growth in their energy use.

The share of industrial delivered energy consumption used for heat and power in manufacturing increases from 64 percent in 2010 to 71 percent in 2035 (Figure 82). The increase in heat and power energy consumption in manufacturing in the Reference case is primarily a result of a large increase (2 quadrillion Btu) in total energy use in the petroleum refining industry, including production increases for CTL, coal- and biomass-to-liquids (CBTL), and biomass pyrolysis oil production.

Heat and power consumption in the nonmanufacturing industries (agriculture, mining, and construction) is flat in the Reference case projection, accounting for about 16 percent of total industrial energy consumption over the 2010-2035 period. The remaining consumption consists of nonfuel uses of energy—primarily, feedstocks for chemical manufacturing and asphalt for construction. The share of total industrial energy consumption represented by nonfuel use increases by 1.6 percent from 2010 to 2020 as a result of increased shipments of organic chemicals, then declines as competition from foreign producers slows the growth of domestic production.

Reliance on natural gas and natural gas liquids rises as industrial energy use grows

Figure 83. Industrial energy consumption by fuel, 2010, 2025 and 2035 (quadrillion Btu)



Led by increasing use of natural gas, total delivered industrial energy consumption grows at an annual rate of 0.6 percent from 2010 through 2035 in the Reference case. The mix of fuels changes slowly, reflecting limited capability for fuel switching with the current capital stock (Figure 83).

Industrial natural gas use grows by 8 percent from 2010 to 2035, reflecting relatively low natural gas prices. As a result, 33 percent of delivered industrial energy consumption is met with natural gas in 2035. The second-largest share is met by petroleum and other liquids (30 percent) and the remainder by renewables, electricity, and coal (37 percent). NGL, an increasingly valuable liquid component of natural gas processing, are consumed as a feedstock in the bulk chemicals industry and also are used for heat in other sectors. Industrial use of all petroleum and other liquids increases slightly from 2010 to 2035, and in 2035 the chemical industries use nearly one-half of the total as feedstock.

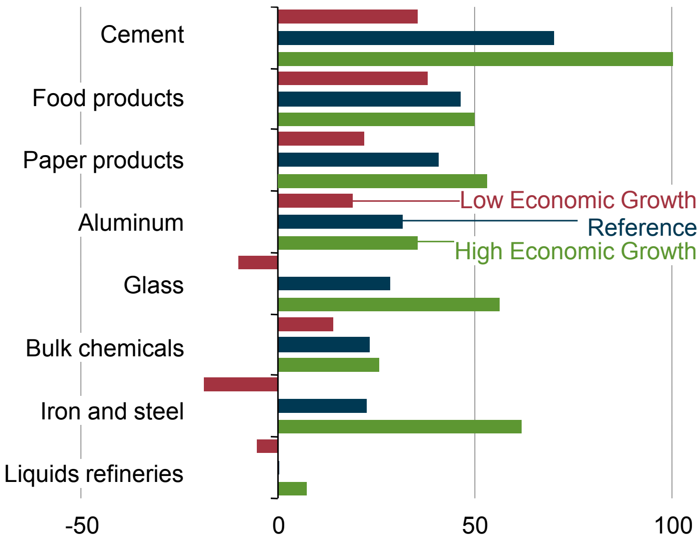
Coal use in the industrial sector for boilers and for smelting in steelmaking declines as more boilers are fired with natural gas and less metallurgical coal is used for steelmaking. After 2016, increased use of coal for CTL and CBTL production fully offsets the decline in the steel industry and boiler fuel use.

A decline in the electricity share of industrial energy consumption reflects modest growth in combined heat and power (CHP), which offsets purchased electricity requirements, as well as efficiency improvements across industries, primarily as a result of rising standards for motor efficiency. With growth in lumber, paper, and other industries that consume biomass-based byproducts, the renewable share of industrial energy use expands.

Industrial sector energy demand

Iron and steel and cement industries are most sensitive to economic growth rate

Figure 84. Cumulative growth in value of shipments from energy-intensive industries in three cases, 2010-2035 (percent)



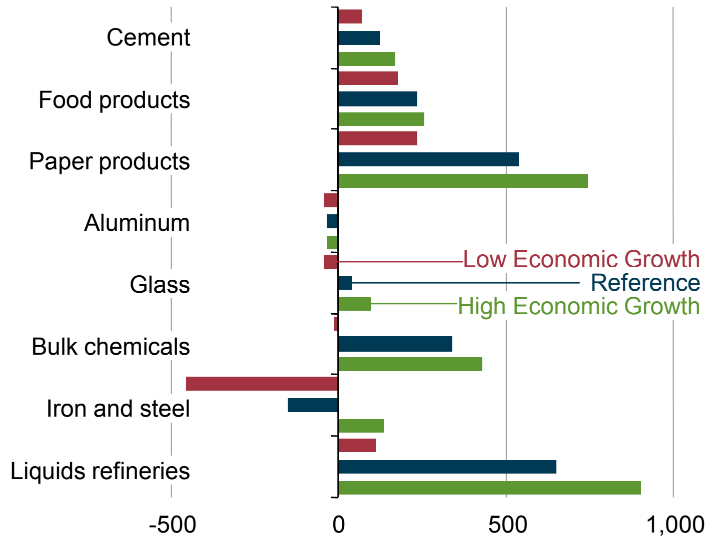
Total shipments from the energy-intensive industries grow by an average of 1 percent per year from 2010 to 2035 in the Reference case, as compared with 0.6 percent in the Low Economic Growth case and 1.2 percent in the High Economic Growth case. The post-recession recovery in shipments is uneven among the industrial subsectors. Paper, bulk chemicals, aluminum, and cement all show strong short-term recoveries from 2010 levels, while shipments from the liquids refinery industry lag. The iron and steel and glass industries show flat to moderate growth in the near term.

Among the energy-intensive industries, the value of shipments in the bulk chemicals, paper, and aluminum take less than 10 years to return to their 2006-2007 pre-recession levels. Others, including cement, iron and steel, and glass, take longer. Shipments from the liquids refinery industry do not reach pre-recession levels by 2035, because demand for transportation fuels is moderated by increasing vehicle efficiencies. Food shipments, which grow in proportion to population and are resistant to recessions, have not shown the same recession-related decline as the other industries. Shipments of bulk chemicals, especially organic chemicals, grow sharply from 2012 to 2025 with the increased use of NGL as feedstock. After 2025, shipments from the bulk chemical industry level off as a result of foreign competition.

The energy-intensive iron and steel and cement industries show the greatest variability in shipments across the three cases (Figure 84), because they supply downstream industries that are sensitive to GDP growth. Construction is a downstream industry for both iron and steel and cement, and the metal-based durables industry is a downstream industry for iron and steel. Shipments in the metal durables industry levels off after 2020, following a decline in iron and steel shipments.

Energy use reflects output and efficiency trends in energy-intensive industries

Figure 85. Change in delivered energy for energy-intensive industries in three cases, 2010-2035 (trillion Btu)



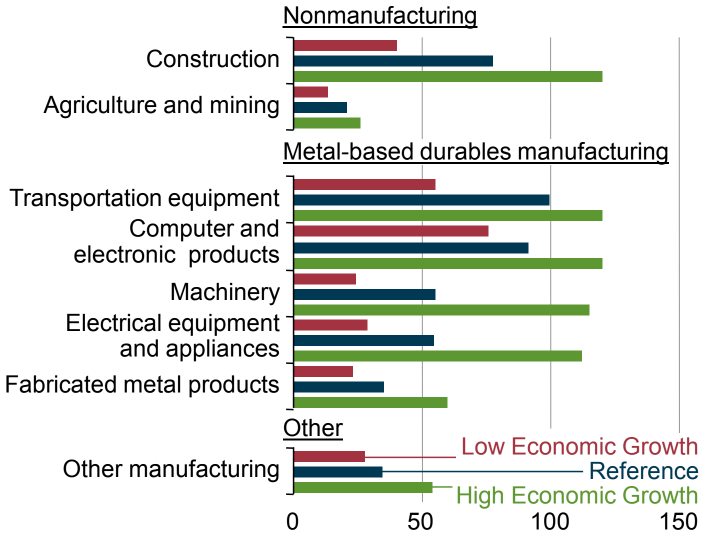
Changes in energy consumption from 2010 to 2035 in the energy-intensive industries ranges from almost nothing in the Low Economic Growth case to 0.8 percent per year or 5 quadrillion Btu in the High Economic Growth case (Figure 85). Changes in energy consumption by the industrial subsector largely reflect the corresponding changes in gross shipments. Energy efficiency improvements and changes in manufacturing methods and requirements, however, also affect energy consumption.

Starting from low levels of economic activity in 2010, shipments from all industries grow over the projection period. For example, steel industry shipments grow by 23 percent in the *AEO2012* Reference case from 2010 to 2035, but energy use declines by 12 percent due to a shift from the use of blast furnace steel production to the use of recycled products and electric arc furnaces. The continued decline of primary aluminum production and concurrent rise in less energy-intensive secondary production lead to a similar decline in aluminum industry energy use despite an increase in shipments. The paper industry shows a far less noticeable improvement in energy efficiency because of greater demand for more energy-intensive products such as paperboard by consumers.

The only industrial subsector that shows an increase in energy intensity is refining. In each of the three Economic Growth cases (Reference, Low Growth, and High Growth), the increase in liquids refinery industry energy consumption exceeds the growth in shipments over the projection period as a result of increased use of coal after 2015 for CTL and CBTL production. Production of alternative fuels is inherently more energy-intensive than production of traditional fuels, because they are refined from solids with relatively low energy densities.

Transportation equipment shows strongest growth in non-energy-intensive shipments

Figure 86. Cumulative growth in value of shipments from non-energy-intensive industries in three cases, 2010-2035 (percent)



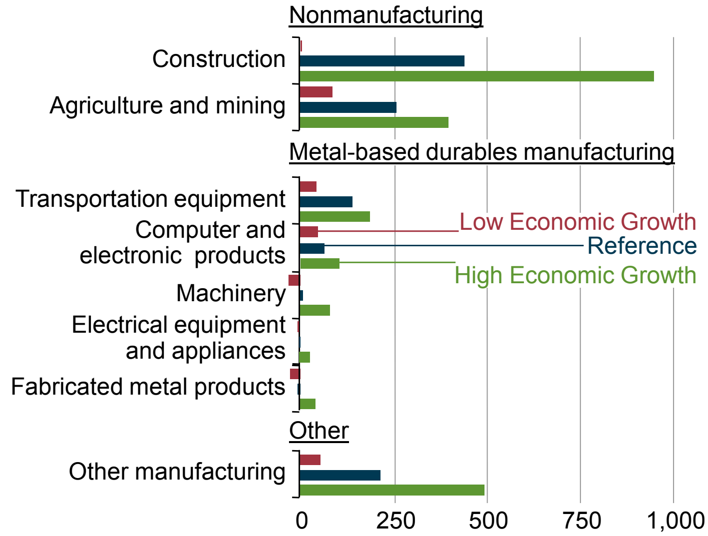
In 2035, non-energy-intensive manufacturing and nonmanufacturing industrial subsectors account for $6.7 trillion (2005 dollars) in shipments in the Reference case—a 57-percent increase from 2010. From 2010 to 2035, growth in those shipments averages 1.2 percent per year in the Low Economic Growth case and 2.5 percent in the High Economic Growth case, compared with 1.8 percent in the Reference case (Figure 86). Non-energy-intensive manufacturing and nonmanufacturing are segments of the industrial sector that primarily consume fuels for thermal or electrical needs, not as raw materials or feedstocks.

In the three cases, shipments from the two subsectors grow at roughly twice the annual rate projected for energy-intensive manufacturing, based on production of high-tech, high-value goods and strong supply chain linkages between energy-intensive manufacturing and many non-energy-intensive manufacturing industries (such as machinery and transportation equipment produced for the metals industries). Recovery in the two subsectors from 2010 to 2015 is rapid because of increased U.S. competiveness in the transportation equipment and machinery industries, as well as a recovering construction industry, which saw residential starts bottom out in 2010. After 2015, the growth is more moderate.

In the Reference case, shipments from the non-energy-intensive manufacturing and nonmanufacturing industries generally exceed pre-recession levels by 2017, reflecting a slow and extended economic recovery. Pre-recession shipment levels are exceeded in 2015 and 2024 in the High Economic Growth and Low Economic Growth cases, respectively.

Nonmanufacturing and transportation equipment lead energy efficiency gains

Figure 87. Change in delivered energy for non-energy-intensive industries in three cases, 2010-2035 (trillion Btu)



From 2010 to 2035, total energy consumption in the non-energy-intensive manufacturing and nonmanufacturing industrial subsectors changes by 2 percent or 178 trillion Btu in the Low Economic Growth case, 15 percent or 1,134 trillion Btu in the Reference case, and 30 percent or 2,282 trillion Btu in the High Economic Growth case (Figure 87). In each of the three cases, those industries together account for more than 40 percent of the projected increase in total industrial natural gas consumption.

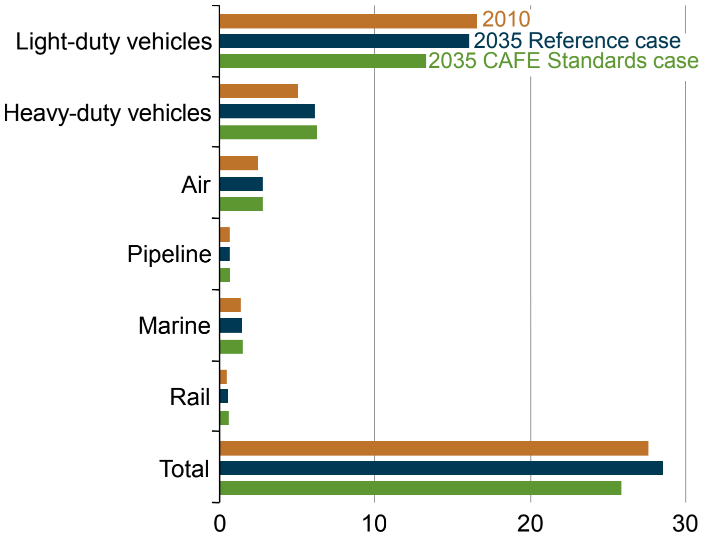
The transportation equipment and construction industries account for roughly 20 percent of the projected increase in energy use but approximately 40 percent of the projected growth in total industrial shipments in all cases. The transportation equipment industry, in particular, shows a rapid decline in energy intensity from 2010 to 2035. Energy consumption increases by 37 percent from 2010 to 2035 and production doubles, yielding an annualized decline in energy intensity of 1.3 percent per year in the transportation equipment industry over the projection period in the *AEO2012* Reference case.

Overall, the combined energy intensity of the non-energy-intensive manufacturing and nonmanufacturing industries declines by 25 percent in the Low Economic Growth case and 29 percent in the High Economic Growth case. The more rapid decline in the High Economic Growth case is consistent with an expectation that energy intensity will fall more rapidly when stronger economic growth facilitates additional investment in more energy-efficient equipment.

Transportation sector energy demand

Transportation energy use grows slowly in comparison with historical trend

Figure 88. Delivered energy consumption for transportation by mode in two cases, 2010 and 2035 (quadrillion Btu)



Transportation sector energy consumption grows at an average annual rate of 0.1 percent from 2010 to 2035 (from 27.6 quadrillion Btu to 28.6 quadrillion Btu), much slower than the 1.2-percent average from 1975 to 2010. The slower growth results primarily from improvement in fuel economy for both LDVs and heavy-duty vehicles (HDVs), as well as relatively modest growth in demand for personal travel.

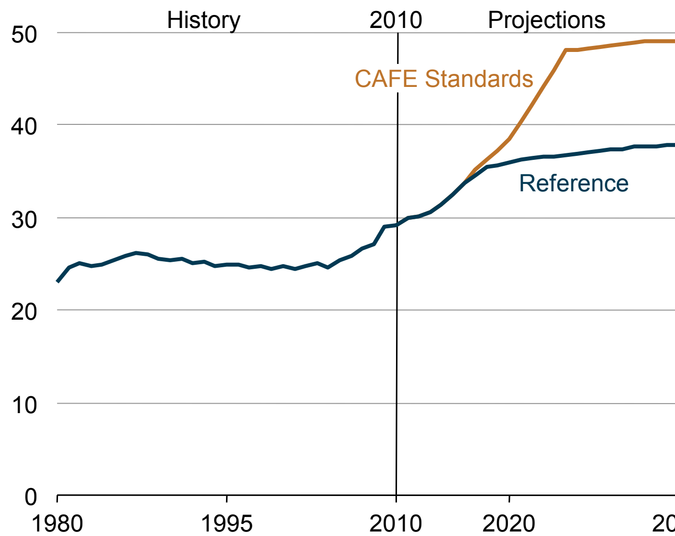
LDV energy demand falls by 3.2 percent (0.5 quadrillion Btu) from 2010 to 2035 (Figure 88). Personal travel demand rises more slowly than in recent history, with the increase more than offset by existing GHG standards for model year (MY) 2012 to 2016 and by EISA2007 fuel economy standards for MY 2017 to 2020. Inclusion of the proposed standards for MY 2017-2025, which are not included in the Reference case, reduce LDV energy demand by 20.0 percent (3.2 quadrillion Btu) from 2010 to 2035.

Energy demand for HDVs (including tractor trailers, buses, vocational vehicles, and heavy-duty pickups and vans) increases by 21 percent, or 1.1 quadrillion Btu, from 2010 to 2035, as a result of increases in vehicle miles traveled (VMT) as economic output recovers. Fuel efficiency and GHG emissions standards temper growth in energy demand even as more miles are traveled overall.

Energy demand for aircraft increases by 11 percent, or 0.3 quadrillion Btu from 2010 to 2035. Higher incomes and moderate growth in fuel costs encourage more personal air travel, the resulting increase in energy use offset by gains in aircraft fuel efficiency. Air freight use of energy grows as a result of export growth. Energy consumption for marine and rail travel also increases, as industrial output grows and more coal is transported. Energy use for pipelines also increases, even though more natural gas production occurs closer to end-use markets.

CAFE and greenhouse gas emissions standards boost vehicle fuel economy

Figure 89. Average fuel economy of new light-duty vehicles in two cases, 1980-2035 (miles per gallon)



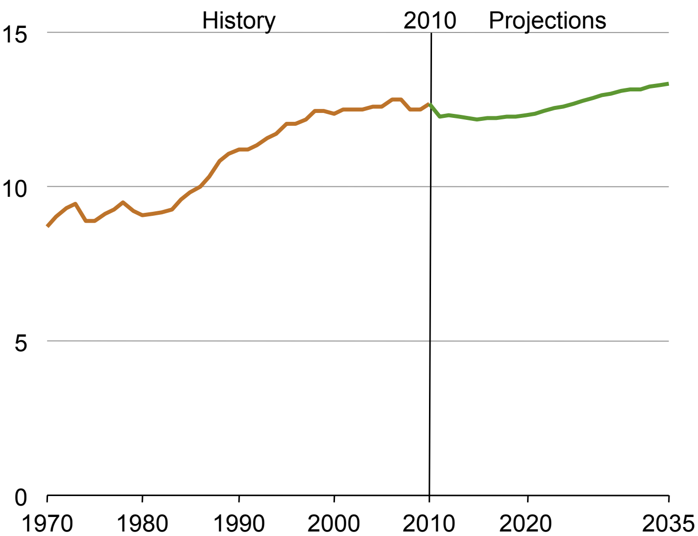
The introduction of Corporate Average Fuel Economy (CAFE) standards for LDVs in 1978 resulted in an increase in fuel economy from 19.9 miles per gallon (mpg) in 1978 to 26.2 mpg in 1987. Over the two decades that followed, despite improvements in LDV technology, fuel economy fell to between 24 and 26 mpg as sales of light-duty trucks increased from 20 percent of new LDV sales in 1980 to almost 55 percent in 2004 [*124*]. The subsequent rise in fuel prices and reduction in sales of light-duty trucks, coupled with tighter CAFE standards for light-duty trucks starting with MY 2008, led to a rise in LDV fuel economy to 29.2 mpg in 2010.

The National Highway Traffic Safety Administration (NHTSA) introduced attribute-based CAFE standards for MY 2011 LDVs in 2009 and, together with the U.S. Environmental Protection Agency (EPA), in 2010 announced CAFE and GHG emissions standards for MY 2012 to MY 2016. EISA2007 further requires that LDVs achieve an average fuel economy of 35 mpg by MY 2020 [*125*]. In the *AEO2012* Reference case, the fuel economy of new LDVs [*126*] rises to 30.0 mpg in 2011, 33.8 mpg in 2016, and 35.9 mpg in 2020 (Figure 89). After 2020, CAFE standards remain constant, with LDV fuel economy increasing moderately to 37.9 mpg in 2035 as a result of more widespread adoption of fuel-saving technologies.

In December 2011, NHTSA and EPA proposed more stringent attribute-based CAFE and GHG emissions standards for MYs 2017 to 2025 [*127*]. The proposal calls for a projected average LDV CAFE of 49.6 mpg by 2025 together with a GHG standard equivalent to 54.5 mpg. With the inclusion of the proposed LDV CAFE standards, LDV fuel economy in the CAFE Standards case increases by nearly 30 percent in 2035 compared to the Reference case.

Travel demand for personal vehicles increases more slowly than in the past

Figure 90. Vehicle miles traveled per licensed driver, 1970-2035 (thousand miles)



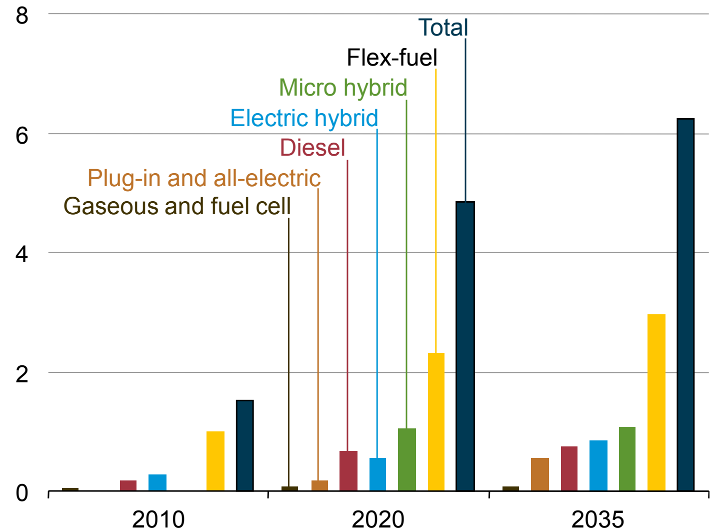
Personal vehicle travel demand, measured as VMT per licensed driver, grew at an average annual rate of 1.1 percent from 1970 to 2007, from about 8,700 miles per driver in 1970 to 12,800 miles per driver in 2007. Increased travel was supported by rising incomes, declining costs of driving per mile (determined by fuel economy and fuel price), and demographic changes (such as women entering the workforce). Between 2007 and 2010, VMT per licensed driver declined to around 12,700 miles per driver because of a spike in the cost of driving per mile and the economic downturn. In the *AEO2012* Reference case, VMT per licensed driver grows by an average of 0.2 percent per year, to 13,350 miles per driver in 2035 (Figure 90).

Although the real price of motor gasoline in the transportation sector increases by 48 percent from 2010 to 2035 in the Reference case, VMT per licensed driver still grows as real disposable personal income climbs by 81 percent. Faster growth in income than in fuel prices ensures that travel demand continues to rise by reducing the percentage of income spent on fuel. In addition, the effect of rising fuel costs is moderated by a 30-percent improvement in new vehicle fuel economy following the implementation of more stringent GHG and CAFE standards for LDVs.

Several demographic forces play a role in moderating the growth in VMT per licensed driver despite the rise in real disposable income. Although LDV sales increase through 2035, the number of vehicles per licensed driver remains relatively constant (at just over 1 per licensed driver). Also, unemployment remains above pre-recession levels in the Reference case until later in the projection, further tempering the increase in personal travel demand.

Sales of alternative fuel, fuel flexible, and hybrid vehicles rise

Figure 91. Sales of light-duty vehicles using non-gasoline technologies by fuel type, 2010, 2020, and 2035 (million vehicles sold)



LDVs that use diesel, other alternative fuels, hybrid-electric, or all-electric systems play a significant role in meeting more stringent GHG emissions and fuel economy standards, as well as offering fuel savings in the face of higher fuel prices. Sales of such vehicles increase from 14 percent of all new LDV sales in 2010 to 35 percent in 2035 in the *AEO2012* Reference case. Sales would be even higher with consideration of the proposed fuel economy standards covering MYs 2017 through 2025 that are not included in the Reference case (see discussion in "Issues in focus").

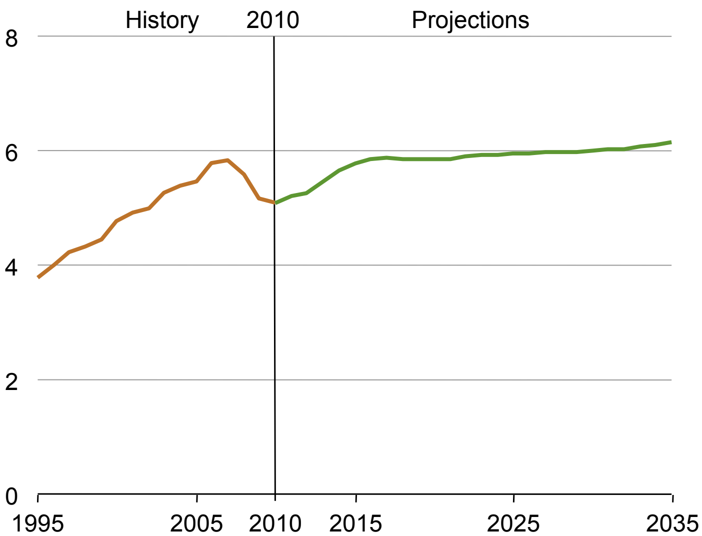
Flex-fuel vehicles (FFVs), which can use blends of ethanol up to 85 percent, represent the largest share of vehicles, at 17 percent of all new vehicle sales. Manufacturers selling FFVs currently receive incentives in the form of fuel economy credits earned for CAFE compliance through MY 2016. FFVs also play a critical role in meeting the RFS for biofuels.

Sales of hybrid electric and all-electric vehicles that use stored electric energy grow considerably in the Reference case (Figure 91). Micro hybrids, which use start/stop technology to manage engine operation while at idle, account for 6 percent of total LDV sales in 2035, which is the largest share for vehicles that use electric storage. Gasoline-electric and diesel-electric hybrid vehicles account for 5 percent of total LDV sales in 2035; and plug-in and all-electric hybrid vehicles account for 3 percent of LDV sales and 9 percent of sales of vehicles using diesel, alternative fuels, hybrid, or all-electric systems.

Sales of diesel vehicles also increase, to 4 percent of total LDV sales in 2035. Light-duty gaseous and fuel cell vehicles account for less than 0.5 percent of new vehicle sales throughout the projection because of the limited availability of a fueling infrastructure and their high incremental cost.

Heavy-duty vehicle energy demand continues to grow but slows from historical rates

Figure 92. Heavy-duty vehicle energy consumption, 1995-2035 (quadrillion Btu)



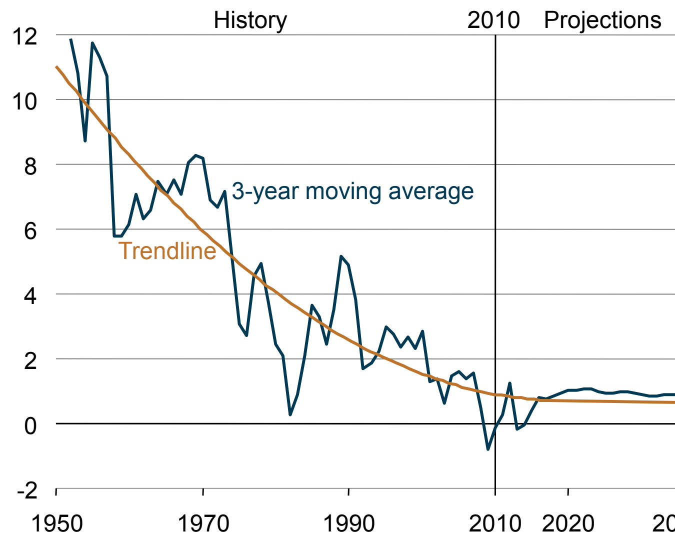
Energy demand for HDVs—including tractor trailers, vocational vehicles, heavy-duty pickups and vans, and buses—increases from 5.1 quadrillion Btu in 2010 to 6.2 quadrillion Btu in 2035, at an average annual growth rate of 0.8 percent, which is the highest among transportation modes. Still, the increase in energy demand for HDVs is lower than the 2-percent annual average from 1995 to 2010, as increases in VMT are offset by improvements in fuel economy following the recent introduction of new standards for HDV fuel efficiency and GHG emissions.

The total number of miles traveled annually by all HDVs grows by 48 percent from 2010 to 2035, from 234 billion miles to 345 billion miles, for an average annual increase of 1.6 percent. The rise in VMT is supported by rising economic output over the projection period and an increase in the number of trucks on the road, from 8.9 million in 2010 to 12.5 million in 2035.

Higher fuel economy for HDVs partially offsets the increase in their VMT, as average new vehicle fuel economy increases from 6.6 mpg in 2010 to 8.2 mpg in 2035. The gain in fuel economy is primarily a consequence of the new GHG emissions and fuel efficiency standards enacted by EPA and NHTSA that begin in MY 2014 and reach the most stringent levels in MY 2018 [*128*]. Fuel economy continues to improve moderately after 2018, as fuel-saving technologies continue to be adopted for economic reasons (Figure 92).

Residential and commercial sectors dominate electricity demand growth

Figure 93. U.S. electricity demand growth, 1950-2035 (percent, 3-year moving average)



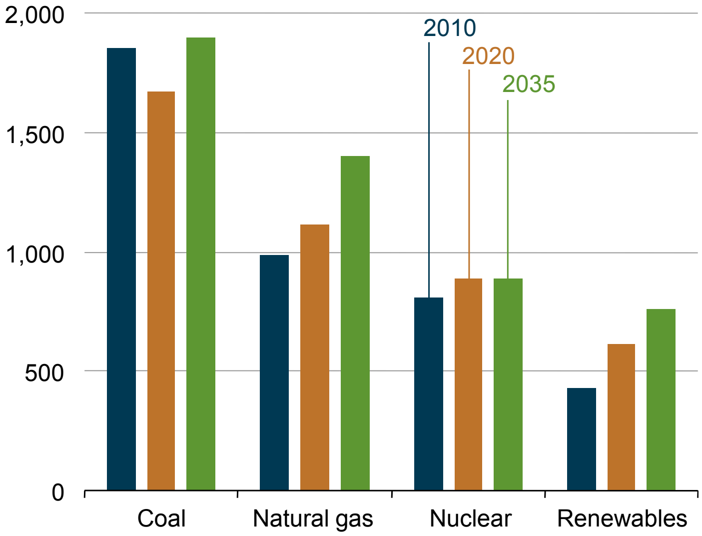
Electricity demand (including retail sales and direct use) growth has slowed in each decade since the 1950s, from a 9.8-percent annual rate of growth from 1949 to 1959 to only 0.7 percent per year in the first decade of the 21st century. In the *AEO2012* Reference case, electricity demand growth rebounds somewhat from those low levels but remains relatively slow, as growing demand for electricity services is offset by efficiency gains from new appliance standards and investments in energy-efficient equipment (Figure 93).

Electricity demand grows by 22 percent in the *AEO2012* Reference case, from 3,877 billion kilowatthours in 2010 to 4,716 billion kilowatthours in 2035. Residential demand grows by 18 percent over the same period, to 1,718 billion kilowatthours in 2035, spurred by population growth, rising disposable income, and continued population shifts to warmer regions with greater cooling requirements. Commercial sector electricity demand increases by 28 percent, to 1,699 billion kilowatthours in 2035, led by demand in the service industries. In the industrial sector, electricity demand has been generally declining since 2000, and it grows by only 2 percent from 2010 to 2035, slowed by increased competition from overseas manufacturers and a shift of U.S. manufacturing toward consumer goods that require less energy to produce. Electricity demand in the transportation sector is small, but it is expected to more than triple from 7 billion kilowatthours in 2010 to 22 billion kilowatthours in 2035 as sales of electric plug-in LDVs increase.

Average annual electricity prices (in 2010 dollars) increase by 3 percent from 2010 to 2035 in the Reference case, generally falling through 2020 in response to lower fuel prices used to generate electricity. After 2020, rising fuel costs more than offset lower costs for transmission and distribution.

Coal-fired plants continue to be the largest source of U.S. electricity generation

Figure 94. Electricity generation by fuel, 2010, 2020, and 2035 (billion kilowatthours)



Coal remains the dominant fuel for electricity generation in the *AEO2012* Reference case (Figure 94), but its share declines significantly. In 2010, coal accounted for 45 percent of total U.S. generation; in 2020 and 2035 its projected share of total generation is 39 percent and 38 percent, respectively. Competition from natural gas and renewables is a key factor in the decline. Overall, coal-fired generation in 2035 is 2 percent higher than in 2010 but still 6 percent below the 2007 pre-recession level.

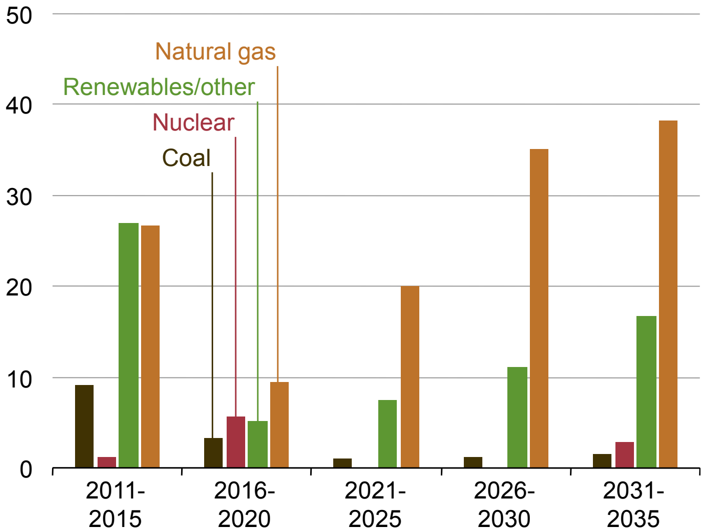
Generation from natural gas grows by 42 percent from 2010 to 2035, and its share of total generation increases from 24 percent in 2010 to 28 percent in 2035. The relatively low cost of natural gas makes the dispatching of existing natural gas plants more competitive with coal plants and, in combination with relatively low capital costs, makes natural gas the primary choice to fuel new generation capacity.

Generation from renewable sources grows by 77 percent in the Reference case, raising its share of total generation from 10 percent in 2010 to 15 percent in 2035. Most of the growth in renewable electricity generation comes from wind and biomass facilities, which benefit from State RPS requirements, Federal tax credits, and, in the case of biomass, the availability of low-cost feedstocks and the RFS.

Generation from U.S. nuclear power plants increases by 10 percent from 2010 to 2035, but the share of total generation declines from 20 percent in 2010 to 18 percent in 2035. Although new nuclear capacity is added by new reactors and uprates of older ones, total generation grows faster and the nuclear share falls. Nuclear capacity grows from 101 gigawatts in 2010 to 111 gigawatts in 2035, with 7.3 gigawatts of additional uprates and 8.5 gigawatts of new capacity between 2010 and 2035. Some older nuclear capacity is retired, which reduces overall nuclear generation.

Most new capacity additions use natural gas and renewables

Figure 95. Electricity generation capacity additions by fuel type, including combined heat and power, 2011-2035 (gigawatts)



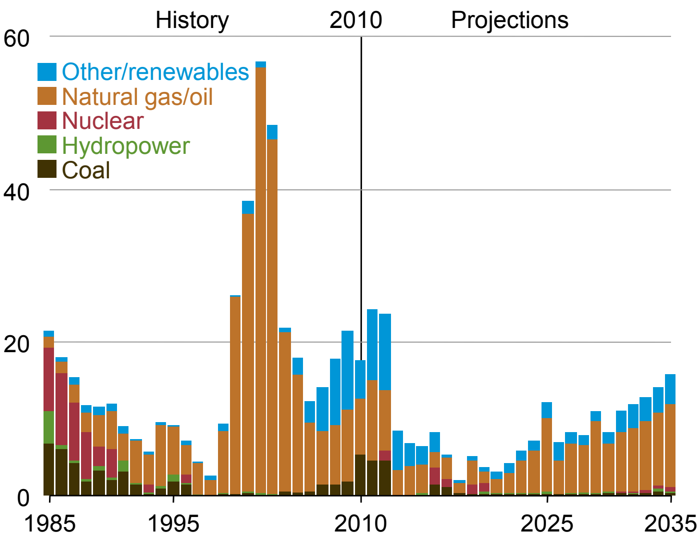
Decisions to add capacity, and the choice of fuel for new capacity, depend on a number of factors [*129*]. With growing electricity demand and the retirement of 88 gigawatts of existing capacity, 235 gigawatts of new generating capacity (including end-use combined heat and power) are projected to be added between 2011 and 2035 (Figure 95).

Natural-gas-fired plants account for 60 percent of capacity additions between 2011 and 2035 in the Reference case, compared with 29 percent for renewables, 7 percent for coal, and 4 percent for nuclear. Escalating construction costs have the largest impact on capital-intensive technologies, which include nuclear, coal, and renewables. However, Federal tax incentives, State energy programs, and rising prices for fossil fuels increase the competitiveness of renewable and nuclear capacity. Current Federal and State environmental regulations also affect fossil fuel use, particularly coal. Uncertainty about future limits on GHG emissions and other possible environmental programs also reduces the competitiveness of coal-fired plants (reflected in *AEO2012* by adding 3 percentage points to the cost of capital for new coal-fired capacity).

Uncertainty about demand growth and fuel prices also affects capacity planning. Total capacity additions from 2011 to 2035 range from 166 gigawatts in the Low Economic Growth case to 305 gigawatts in the High Economic Growth case. In the *AEO2012* Low Tight Oil and Shale Gas Resource case, natural gas prices are higher than in the Reference case and new natural gas fired capacity from 2011 to 2035 accounts for 102 gigawatts, which represents 47 percent of total additions. In the High Tight Oil and Shale Gas Resource case, delivered natural gas prices are lower than in the Reference case and natural gas-fired capacity additions by 2035 are 155 gigawatts, or 66 percent of total new capacity.

Additions to power plant capacity slow after 2012 but accelerate beyond 2020

Figure 96. Additions to electricity generating capacity, 1985-2035 (gigawatts)



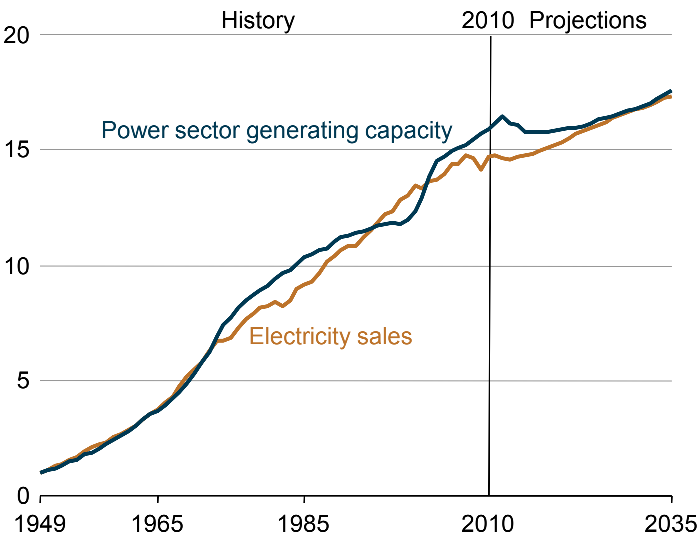
Typically, investments in electricity generation capacity have gone through "boom and bust" cycles. Periods of slower growth have been followed by strong growth in response to changing expectations for future electricity demand and fuel prices, as well as changes in the industry, such as restructuring (Figure 96). A construction boom in the early 2000s saw capacity additions averaging 35 gigawatts a year from 2000 to 2005, much higher than had been seen before. Since then, average annual builds have dropped to 17 gigawatts per year from 2006 to 2010.

In the *AEO2012* Reference case, capacity additions between 2011 and 2035 total 235 gigawatts, including new plants built not only in the power sector but also by end-use generators. Annual additions in 2011 and 2012 remain relatively high, averaging 24 gigawatts per year [*130*]. Of those early builds, about 40 percent are renewable plants built to take advantage of Federal tax incentives and to meet State renewable standards.

Annual builds drop significantly after 2012 and remain below 9 gigawatts per year until 2025. During that period, existing capacity is adequate to meet growth in demand in most regions, given the earlier construction boom and relatively slow growth in electricity demand after the economic recession. Between 2025 and 2035, average annual builds increase to 11 gigawatts per year, as excess capacity is depleted and the rate of total capacity growth is more consistent with electricity demand growth. More than 70 percent of the capacity additions from 2025 to 2035 are natural gas fired, given the higher construction costs for other capacity types and uncertainty about the prospects for future limits on GHG emissions.

Growth in generating capacity parallels rising demand for electricity

Figure 97. Electricity sales and power sector generating capacity, 1949-2035 (index, 1949 = 1.0)



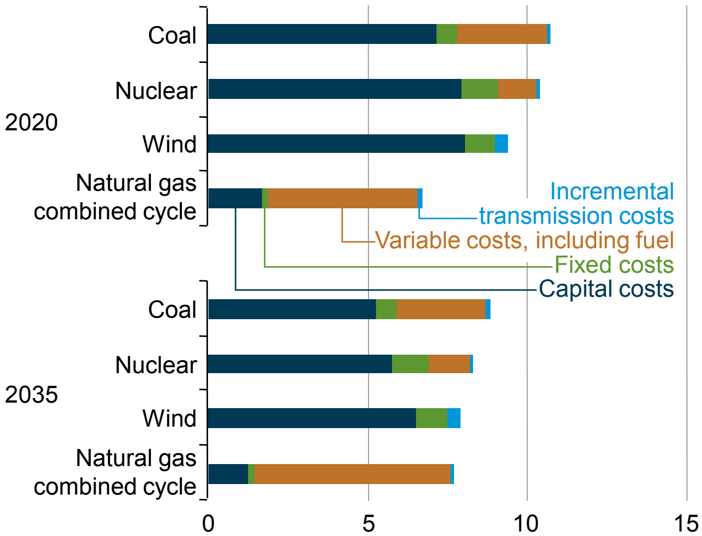
Over the long term, growth in electricity generating capacity parallels the growth in end-use demand for electricity. However, unexpected shifts in demand or dramatic changes affecting capacity investment decisions can cause imbalances that can take years to work out.

Figure 97 shows indexes summarizing relative changes in total generating capacity and electricity demand. During the 1950s and 1960s, the capacity and demand indexes tracked closely. The energy crises of the 1970s and 1980s, together with other factors, slowed electricity demand growth, and capacity growth outpaced demand for more than 10 years thereafter, as planned units continued to come on line. Demand and capacity did not align again until the mid-1990s. Then, in the late 1990s, uncertainty about deregulation of the electricity industry caused a downturn in capacity expansion, and another period of imbalance followed, with growth in electricity demand exceeding capacity growth.

In 2000, a boom in construction of new natural gas fired plants began, quickly bringing capacity back into balance with demand and, in fact, creating excess capacity. Construction of new intermittent wind capacity that sometimes needs backup capacity also began to grow after 2000. More recently, the 2008-2009 economic recession caused a significant drop in electricity demand, which has recovered only partially in the post-recession period. In combination with slow near-term growth in electricity demand, the slow economic recovery creates excess generating capacity in the *AEO2012* Reference case. Capacity currently under construction is completed in the Reference case, but only a limited amount of additional capacity is built before 2025, while older capacity is retired. In 2025, capacity growth and demand growth are in balance again, and they grow at similar rates through 2035.

Costs and regulatory uncertainties vary across options for new capacity

Figure 98. Levelized electricity costs for new power plants, excluding subsidies, 2020 and 2035 (2010 cents per kilowatthour)



Technology choices for new generating capacity are based largely on capital, operating, and transmission costs. Coal, nuclear, and renewable plants are capital-intensive (Figure 98), whereas operating (fuel) expenditures make up most of the costs for natural gas capacity [*131*]. Capital costs depend on such factors as equipment costs, interest rates, and cost recovery periods. Fuel costs vary with operating efficiency, fuel price, and transportation costs.

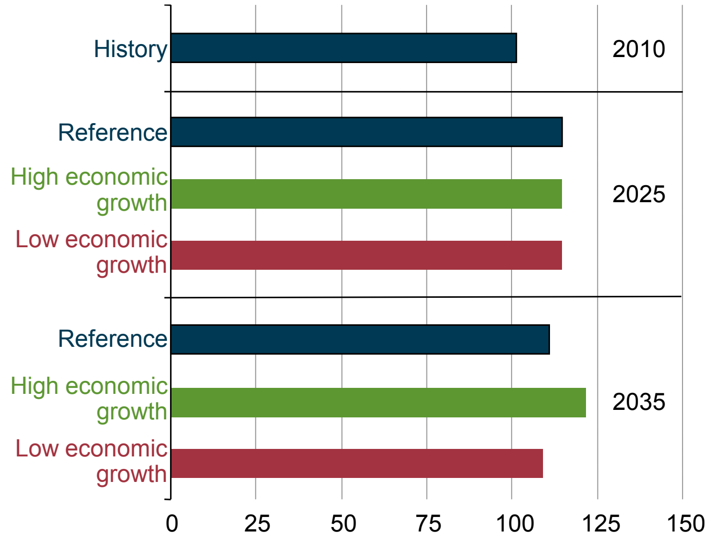
In addition to considerations of levelized costs [*132*], some technologies and fuels receive subsidies, such as production tax credits and ITCs. Also, new plants must satisfy local and Federal emissions standards and must be compatible with the utility's load profile.

Regulatory uncertainty also affects capacity planning. New coal plants may require carbon control and sequestration equipment, resulting in higher material, labor, and operating costs. Alternatively, coal plants without carbon controls could incur higher costs for siting and permitting. Because nuclear and renewable power plants (including wind plants) do not emit GHGs, their costs are not directly affected by regulatory uncertainty in this area.

Capital costs can decline over time as developers gain technology experience, with the largest rate of decline in new technologies. In the *AEO2012* Reference case, the capital costs of new technologies are adjusted upward initially to compensate for the optimism inherent in early estimates of project costs, then decline as project developers gain experience. The decline continues at a progressively slower rate as more units are built. Operating efficiencies also are assumed to improve over time, resulting in reduced variable costs unless increases in fuel costs exceed the savings from efficiency gains.

Nuclear power plant capacity grows slowly through uprates and new builds

Figure 99. Electricity generating capacity at U.S. nuclear power plants in three cases, 2010, 2025, and 2035 (gigawatts)



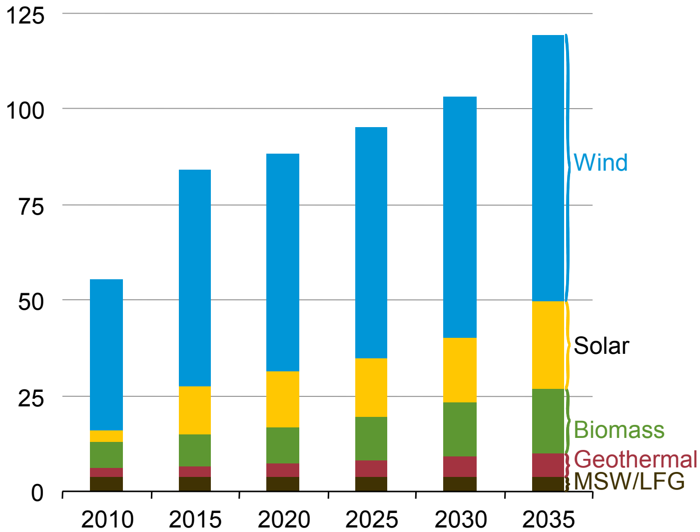
In the *AEO2012* Reference case, nuclear power capacity increases from 101.2 gigawatts in 2010 to a high of 114.7 gigawatts in 2025, before declining to 110.9 gigawatts in 2035 (Figure 99), largely as a result of plant retirements. The capacity increase through 2025 includes 7.3 gigawatts of expansion at existing plants and 6.8 gigawatts of new capacity, which includes completion of two conventional reactors at the Watts Bar and Bellefonte sites. Four advanced reactors, reported as under construction, are also assumed to be brought online by 2020 and to be eligible for Federal financial incentives. High construction costs for nuclear plants, especially relative to natural gas fired plants, make additional options for new nuclear capacity uneconomical until the later years of the projection, when an additional 1.8 gigawatts is added. Nuclear capacity additions vary with assumptions about overall demand for electricity. Across the Economic Growth cases, nuclear capacity additions from 2011 to 2035 range from 6.8 gigawatts in the Low Economic Growth case to 19.2 gigawatts in the High Economic Growth case.

One nuclear unit, Oyster Creek, is expected to be retired at the end of 2019, as announced by Exelon in December 2010. An additional 5.5 gigawatts of nuclear capacity is assumed to be retired by 2035. All other existing nuclear units continue to operate through 2035 in the Reference case, which assumes that they will apply for and receive operating license renewals, including in some cases a second 20-year extension after 60 years of operation (for more discussion, see "Issues in focus"). With costs for natural gas fired generation rising in the Reference case and uncertainty about future regulation of GHG emissions, the economics of keeping existing nuclear power plants in operation are favorable.

Renewable capacity

Wind dominates renewable capacity growth, but solar and biomass gain market share

Figure 100. Nonhydropower renewable electricity generation capacity by energy source, including end-use capacity, 2010-2035 (gigawatts)



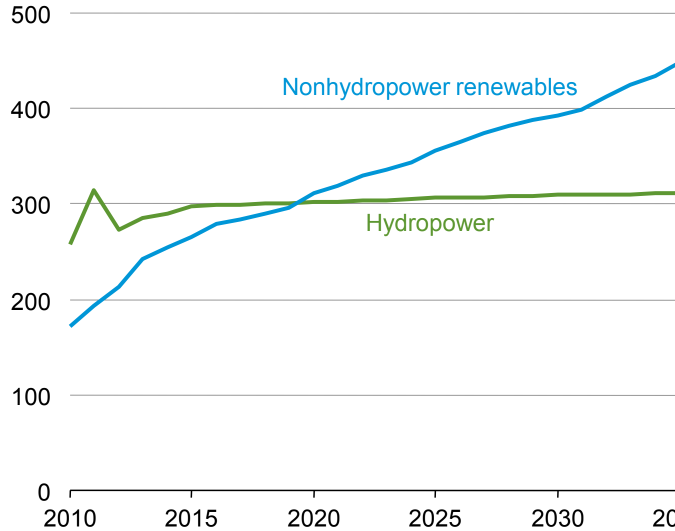
From 2010 to 2035, total nonhydropower renewable generating capacity more than doubles in the *AEO2012* Reference case (Figure 100). Wind accounts for the largest share of that new capacity, increasing from 39 gigawatts in 2010 to 70 gigawatts in 2035. Both solar capacity and biomass capacity grow at faster rates than wind capacity, but they start from smaller levels.

Excluding new projects already under construction, PV accounts for nearly all solar capacity additions both in the end-use sectors (where 11 gigawatts of PV capacity is added from 2010 to 2035) and in the electric power sector (8 gigawatts added from 2010 to 2035). While end-use solar capacity grows throughout the projection, the growth of solar capacity in the electric power sector is concentrated primarily in the last decade of the projection period (2025-2035) when the technology becomes more cost-competitive. Geothermal capacity nearly triples over the projection period, but in 2035 it still accounts for only about 5 percent of total nonhydropower renewable generating capacity.

Renewable capacity additions are supported by State RPS programs, the Federal RFS, and Federal tax credits. Total renewable capacity—particularly, wind and solar—grows rapidly in the near term in the *AEO2012* Reference case. There is, however, relatively little projected need for new generation capacity of any type, including renewables, for the remainder of the current decade, primarily because there is an abundance of existing natural gas fired capacity that can be operated at higher capacity factors. After 2020 there is a need for new generation capacity in the Reference case, resulting in a resurgence in renewable capacity growth.

Nonhydropower renewable generation surpasses hydropower by 2020

Figure 101. Hydropower and other renewable electricity generation, including end-use generation, 2010-2035 (billion kilowatthours)



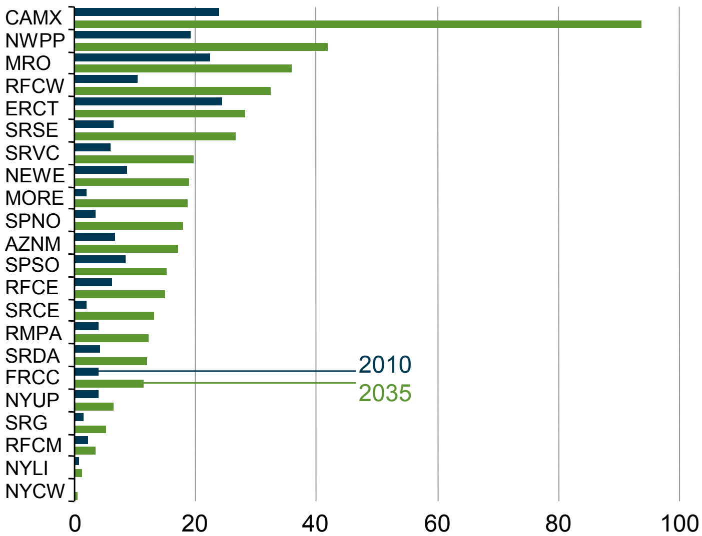
In the *AEO2012* Reference case, nonhydropower renewable generation grows at an average annual rate of 3.9 percent, nearly tripling from 2010 to 2035. Generation from nonhydropower renewable sources has been small historically in comparison with hydroelectric generation; however, nonhydropower renewable generation surpasses hydroelectric generation in 2020 in the Reference case (Figure 101).

The share of the total electricity generation accounted for by nonhydropower renewable generation increases from about 4 percent in 2010 to 9 percent in 2035. Although wind remains the largest source of nonhydropower renewable generation through 2035, both solar and biomass generation grow at faster annual rates. Solar generation increases by an average of nearly 10 percent per year, and biomass generation increases by 6 percent per year.

Both solar and wind energy are intermittent resources, and as a result their contributions to the generation mix are less than their contribution to the capacity mix. Biomass-fired generation, on the other hand, is dispatchable and grows to levels approaching wind generation by the end of the projection, at 145 billion kilowatthours in 2035, as compared with 194 billion kilowatthours for wind-powered generation. Most of the growth in biomass generation comes from CHP units used in the production of biomass-based liquid fuels, primarily in response to the Federal RFS. Biomass co-firing and end-use generation play an important role in satisfying State RPS mandates, particularly from 2010 to 2020, when overall capacity growth is modest.

State renewable portfolio standards increase renewable electricity generation

Figure 102. Regional growth in nonhydropower renewable electricity generation, including end-use generation, 2010-2035 (billion kilowatthours)



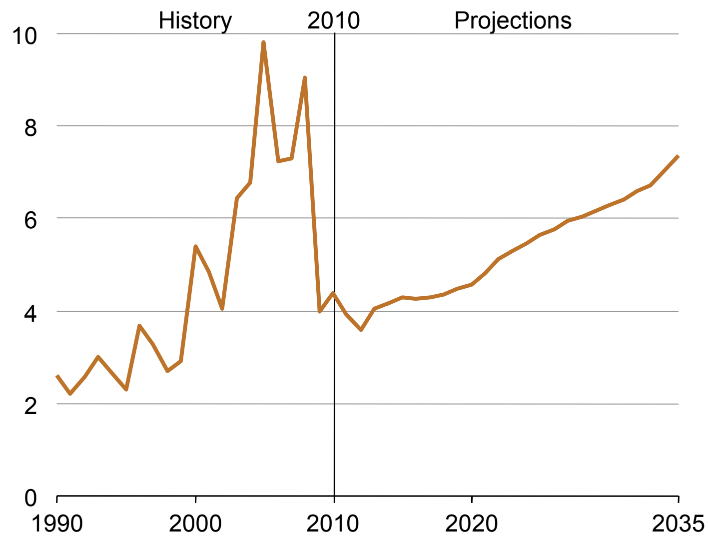
Regional growth in renewable electricity generation is based largely on two factors: availability of renewable energy resources and the existence of State RPS programs that require the use of renewable generation. After a period of robust RPS enactments in several States, the past few years have been relatively quiet in terms of State program expansions, primarily due to the subdued economic climate.

The highest level of nonhydroelectric renewable generation in 2035, 93.9 billion kilowatthours, occurs in the WECC California (CAMX) region (Figure 102), whose area approximates the California State boundaries. (For a map of the electricity regions presented, see Appendix F.) The three largest contributors to the total are wind, solar, and geothermal generation. The region encompassing the Pacific Northwest has more overall renewable generation, the vast majority of which comes from hydroelectric sources.

Although the Western and Southwestern States have the most projected solar installations, State RPS programs heavily influence the growth of solar capacity in the eastern States, where both the Reliability First Corporation/East (RFCE) and the Reliability First Corporation/West (RFCW) regions have large amounts of end-use solar generation, with 1.7 billion kilowatthours and 1.9 billion kilowatthours, respectively. The two regions are not known for a strong solar resource base, and the installations are in response to the ITC as well as solar requirements embedded in State RPS programs. Most biomass capacity—confined largely to the end-use sectors—is built at the sites of cellulosic ethanol plants, many of which are in the Southeast.

Natural gas prices are expected to rise with the marginal cost of production

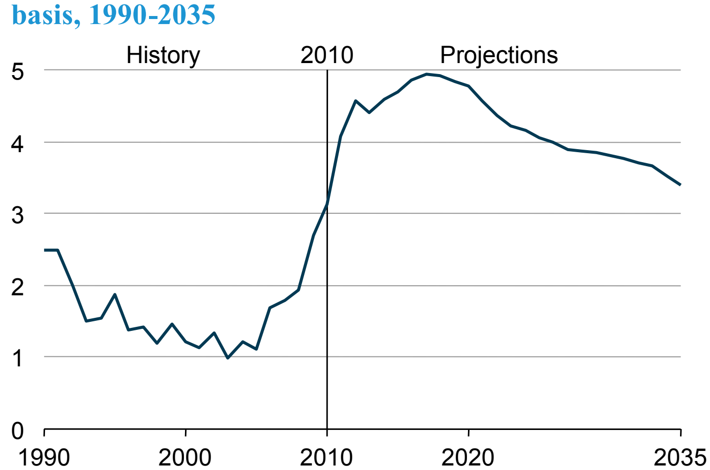
Figure 103. Annual average Henry Hub spot natural gas prices, 1990-2035 (2010 dollars per million Btu)



U.S. natural gas prices are determined largely by supply and demand conditions in North American markets. At current (2012) price levels, natural gas prices are below average replacement cost. However, over time natural gas prices rise with the cost of developing incremental production capacity (Figure 103). After 2017, natural gas prices rise in the *AEO2012* Reference case more rapidly than crude oil prices, but oil prices remain at least three times higher than natural gas prices through the end of the projection (Figure 104).

As of January 1, 2010, total proved and unproved natural gas resources are estimated at 2,203 trillion cubic feet. Development costs for natural gas wells are expected to grow slowly. Henry Hub spot prices for natural gas rise by 2.1 percent per year from 2010 through 2035 in the Reference case, to an annual average of $7.37 per million Btu (2010 dollars) in 2035.

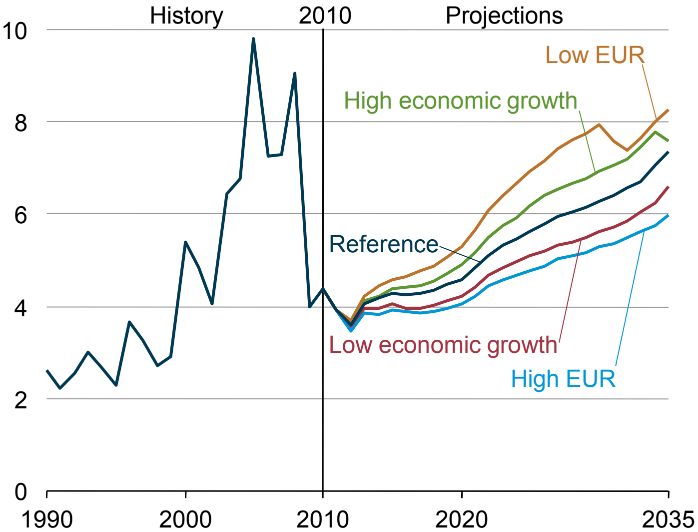
Figure 104. Ratio of low-sulfur light crude oil price to Henry Hub natural gas price on energy equivalent basis, 1990-2035



Natural gas production

Natural gas prices vary with economic growth and shale gas well recovery rates

Figure 105. Annual average Henry Hub spot natural gas prices in five cases, 1990-2035 (2010 dollars per million Btu)



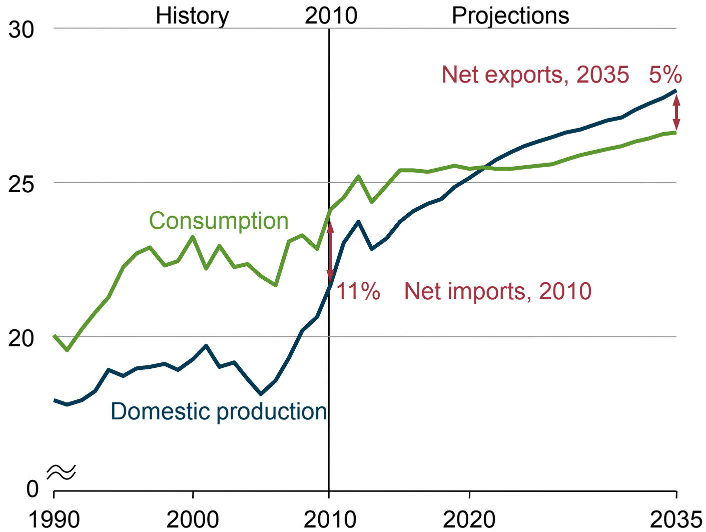
The rate at which natural gas prices change in the future can vary, depending on a number of factors. Two important factors are the future rate of macroeconomic growth and the expected cumulative production of shale gas wells over their lifetimes—the estimated ultimate recovery (EUR) per well. Alternative cases with different assumptions for these factors are shown in Figure 105.

Higher rates of economic growth lead to increased consumption of natural gas, causing more rapid depletion of natural gas resources and a more rapid increase in the cost of developing new incremental natural gas production. Conversely, lower rates of economic growth lead to lower levels of natural gas consumption and, ultimately, a slower increase in the cost of developing new production.

In the High and Low EUR cases, the EUR per shale gas well is increased and decreased by 50 percent, respectively. Future shale gas well recovery rates are an important determinant of future prices. Changes in well recovery rates affect the long-run marginal cost of shale gas production, which in turn affects both natural gas prices and the volumes of new shale gas production developed (further analysis and discussion are included in the "Issues in focus" section of this report). In the Low EUR case, an Alaska gas pipeline starts operating in 2031, accompanied by a dip in natural gas prices. A recent proposal to build a natural gas pipeline along the route of the Alyeska oil pipeline with an LNG export facility could speed up construction. In the High Economic Growth case, the pipeline begins operation in 2035, with a similar effect on prices.

With rising domestic production, the United States become a net exporter of natural gas

Figure 106. Total U.S. natural gas production, consumption, and net imports, 1990-2035 (trillion cubic feet)



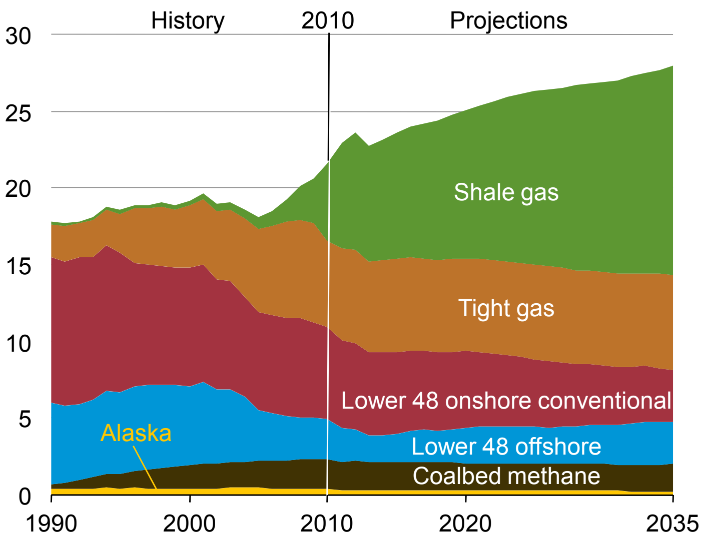
The United States consumed more natural gas than it produced in 2010, importing 2.6 trillion cubic feet from other countries. In the *AEO2012* Reference case, domestic natural gas production grows more quickly than consumption. As a result, the United States becomes a net exporter of natural gas by around 2022, and in 2035 net exports of natural gas from the United States total about 1.4 trillion cubic feet (Figure 106).

U.S. natural gas consumption grows at a rate of 0.4 percent per year from 2010 to 2035 in the Reference case, or by a total of 2.5 trillion cubic feet, to 26.6 trillion cubic feet in 2035. Growth in domestic natural gas consumption depends on many factors, including the rate of economic growth and the delivered prices of natural gas and other fuels. Natural gas consumption in the commercial and industrial sectors grows by less than 0.5 percent per year through 2035, and consumption for electric power generation grows by 0.8 percent per year. Residential natural gas consumption declines over the same period, by a total of 0.3 trillion cubic feet from 2010 to 2035.

U.S. natural gas production grows by 1.0 percent per year, to 27.9 trillion cubic feet in 2035, more than enough to meet domestic needs for consumption, which allows for exports. The prospects for future U.S. natural gas exports are highly uncertain and depend on many factors that are difficult to anticipate, such as the development of new natural gas production capacity in foreign countries, particularly from deepwater reservoirs, shale gas deposits, and the Arctic.

Shale gas provides largest source of growth in U.S. natural gas supply

Figure 107. Natural gas production by source, 1990-2035 (trillion cubic feet)



The increase in natural gas production from 2010 to 2035 in the *AEO2012* Reference case results primarily from the continued development of shale gas resources (Figure 107). Shale gas is the largest contributor to production growth; there is relatively little change in production levels from tight formations, coalbed methane deposits, and offshore fields.

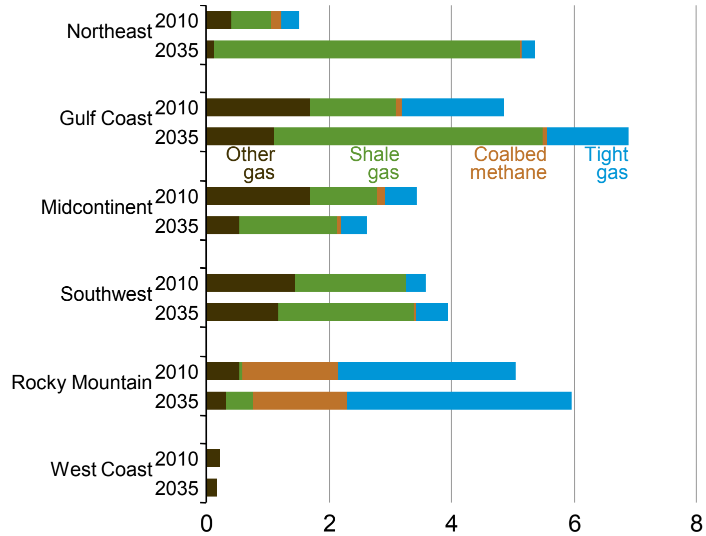
Shale gas accounts for 49 percent of total U.S. natural gas production in 2035, more than double its 23-percent share in 2010. In the Reference case, estimated proved and unproved shale gas resources amount to a combined 542 trillion cubic feet, out of a total U.S. resource of 2,203 trillion cubic feet. Estimates of shale gas resources and well productivity remain uncertain (see "Issues in focus" for discussion).

Tight gas produced from low permeability sandstone and carbonate reservoirs is the second-largest source of domestic supply in the Reference case, averaging 6.1 trillion cubic feet of production per year from 2010 to 2035. Coalbed methane production remains relatively constant throughout the projection, averaging 1.8 trillion cubic feet per year.

Offshore natural gas production declines by 0.8 trillion cubic feet from 2010 through 2014, following the 2010 moratorium on offshore drilling, as exploration and development activities in the Gulf of Mexico focus on oil-directed activity. After 2014 offshore production continues to rise throughout the remainder of the projection period.

In most U.S. regions, natural gas production growth is led by shale gas development

Figure 108. Lower 48 onshore natural gas production by region, 2010 and 2035 (trillion cubic feet)



Shale gas production, which more than doubles from 2010 to 2035, is the largest contributor to the projected growth in total U.S. natural gas production in the Reference case. Regional production growth largely reflects expected increases in production from shale beds. See Figure F4 in Appendix F for a map of U.S. natural gas supply regions.

In the Northeast, natural gas production grows by an average of 5.2 percent per year, or a total of 3.9 trillion cubic feet from 2010 to 2035 (Figure 108). The Marcellus shale, which accounts for 3.0 trillion cubic feet of the expected increase, is particularly attractive for development because of its large resource base, its proximity to major natural gas consumption markets, and the extensive pipeline infrastructure that already exists in the Northeast.

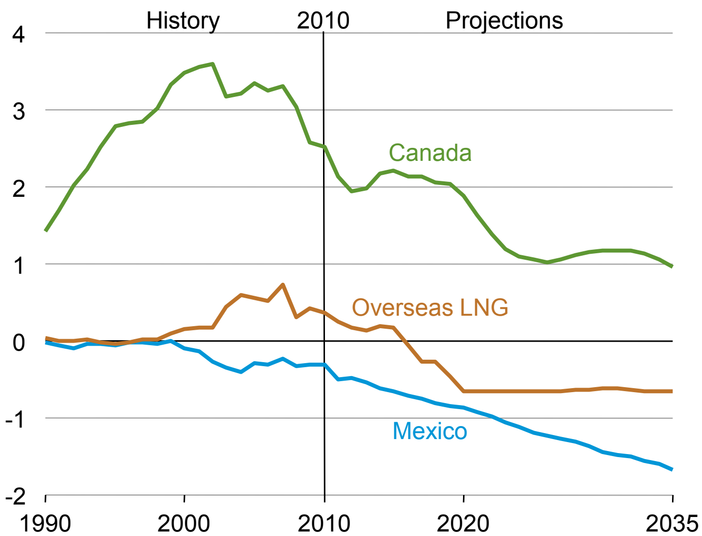
In the Gulf Coast region, natural gas production grows by 2.0 trillion cubic feet from 2010 to 2035, at an average rate of 1.4 percent per year. Natural gas production from the Haynesville/Bossier and Eagle Ford formations increases by 2.8 trillion cubic feet over the period, but declines in production from other natural gas fields in the region offset some of the gains, so that the net increase in production for the region as a whole is only about 2 trillion cubic feet.

In the Rocky Mountain region, natural gas production grows by 0.9 trillion cubic feet from 2010 through 2035, with tight sandstone and carbonate production increasing by 0.8 trillion cubic feet and shale gas production by 0.4 trillion cubic feet. As in the Gulf Coast region, production growth in the Rocky Mountain region is offset in part by production declines in the region's other natural gas fields.

Petroleum and other liquids consumption

The U.S. becomes a net natural gas exporter

Figure 109. U.S. net imports of natural gas by source, 1990-2035 (trillion cubic feet)



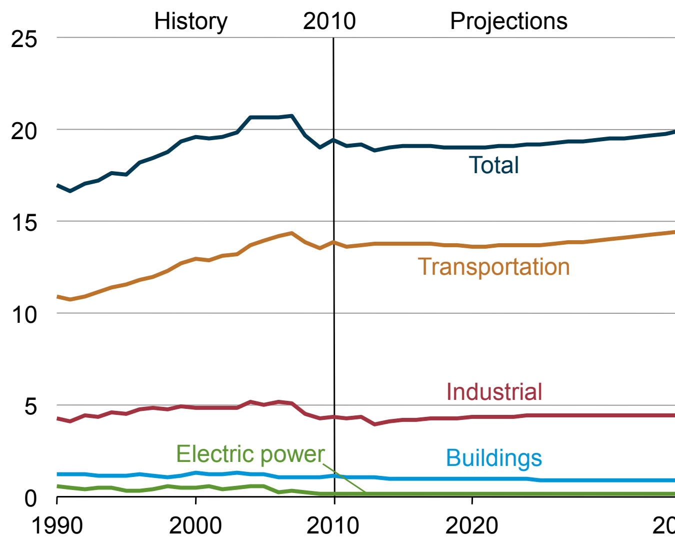
In 2010, the United States imported 11 percent of its total natural gas supply. In the *AEO2012* Reference case, U.S. natural gas production grows faster than consumption, so that early in the next decade exports exceed imports. In 2035, U.S. net natural gas exports are about 1.4 trillion cubic feet (about 4 billion cubic feet per day), half of which is exported overseas as liquefied natural gas (LNG). The other half is transported by pipelines, primarily to Mexico.

U.S. LNG exports supplied from lower 48 natural gas production are assumed to start when LNG export capacity of 1.1 billion cubic feet per day goes into operation in 2016. An additional 1.1 billion cubic feet per day of capacity is expected to come on line in 2019. At full capacity, the facilities could ship 0.8 trillion cubic feet of LNG to overseas consumers per year. Net U.S. LNG exports are somewhat lower than those figures imply, however, because LNG imports to the New England region are projected to continue. In general, future U.S. exports of LNG depend on a number of factors that are difficult to anticipate and thus are highly uncertain.

Net natural gas imports from Canada decline over the next decade in the Reference case and then stabilize at about 1.1 trillion cubic feet per year (Figure 109), when natural gas prices in the U.S. lower 48 States become high enough to motivate Canadian producers to expand their production of shale gas and tight gas. In Mexico, natural gas consumption shows robust growth through 2035, while Mexico's production grows at a slower rate. As a result, increasing volumes of imported natural gas from the United States fill the growing gap between Mexico's production and consumption.

Transportation uses lead growth in consumption of petroleum and other liquids

Figure 110. Consumption of petroleum and other liquids by sector, 1990-2035 (million barrels per day)



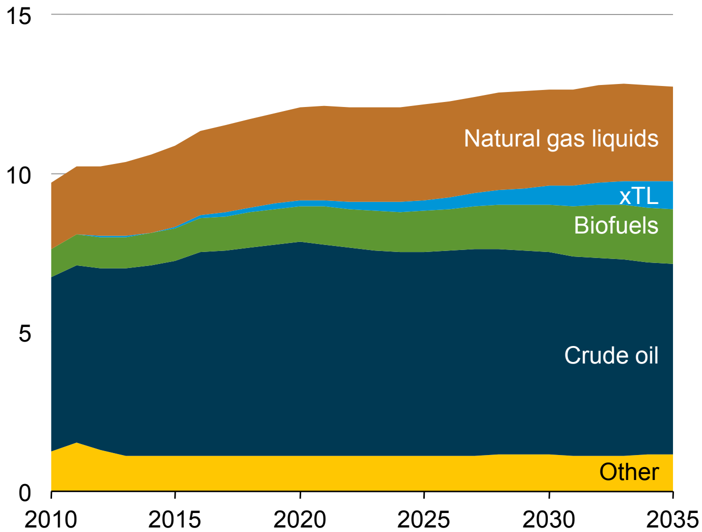
U.S. consumption of petroleum and other liquids totals 19.9 million barrels per day in 2035 in the *AEO2012* Reference case, an increase of 0.7 million barrels per day over the 2010 total (Figure 110). With the exception of the transportation sector, where consumption grows by about 0.6 million barrels per day from 2010 through 2035, petroleum and other liquids consumption remains relatively flat. The transportation sector accounts for 72 percent of total petroleum and other liquids consumption in 2035. Proposed fuel economy standards covering MYs 2017 through 2025 that are not included in the Reference case would further reduce projected petroleum use (see "Issues in focus").

Motor gasoline, ultra-low-sulfur diesel fuel, and jet fuel are the primary transportation fuels, supplemented by biofuels such as ethanol and biodiesel. Petroleum-based motor gasoline consumption drops by approximately 0.9 million barrels per day from 2010 to 2035 in the Reference case, displaced by increased ethanol use in the form of higher blends in gasoline and by E85 consumption, which increases from virtually zero in 2010 to 0.8 million barrels per day in 2035. Diesel fuel consumption increases from 3.3 million barrels per day in 2010 to 4.1 million barrels per day in 2035.

Biodiesel and a number of next-generation biofuels account for a large share of the increase in petroleum and other liquids consumption (excluding ethanol) for transportation from 2010 to 2035 (about 0.7 million barrels per day). The growth in biofuels consumption (including ethanol) is attributable to the EISA2007 RFS mandates, as well as high crude oil prices. The growth in diesel fuel use results primarily from increased sales of light-duty diesel vehicles needed to meet more stringent CAFE standards, with a corresponding increase in domestic production of diesel fuel.

Biofuels and natural gas liquids lead growth in total petroleum and other liquids supply

Figure 111. U.S. production of petroleum and other liquids by source, 2010-2035 (million barrels per day)

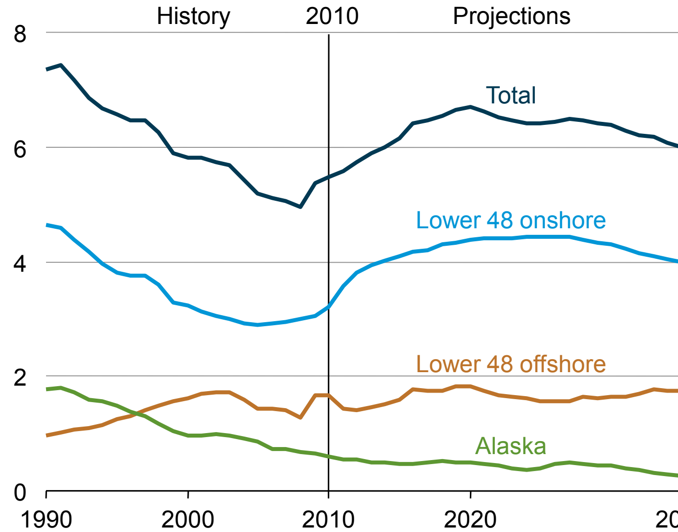


In the *AEO2012* Reference case, domestic production of petroleum and other liquids grows by 3.1 million barrels per day from 2010 to 2035 (Figure 111). Total production grows rapidly, from 9.7 million barrels per day in 2010 to 12.1 million barrels per day in 2020, as production of crude oil and NGL from tight oil formations (including shale plays) increases sharply. After 2020, total U.S. production of petroleum and other liquids grows more slowly, to 12.7 million barrels per day in 2035, as tight oil production levels off despite continued increases in crude oil prices. As production of other liquid fuels increases, the crude oil share of total domestic petroleum and other liquids production declines from 56 percent in 2010 to 47 percent in 2035. NGL production increases by more than 0.9 million barrels per day, to 3.0 million barrels per day in 2035, mainly as a result of strong growth in production of both tight oil and shale gas, which contain significant volumes of NGLs.

Biofuels production grows by 0.8 million barrels per day from 2010 to 2035 as a result of the EISA2007 RFS, with ethanol and biodiesel accounting for 0.7 and 0.1 million barrels per day, respectively, of the increase in the Reference case. The increase in domestic ethanol production reduces consumption of petroleum-based motor gasoline components by about 6 percent in 2035 on an energy-equivalent basis. In the early years of the projection, ethanol is used primarily for blending in E10 (motor gasoline blends containing up to 10 percent ethanol) and E15 (15 percent ethanol). In 2035, 37 percent of domestic ethanol production is used in E85 (85 percent ethanol) and 63 percent in E10 and E15 blends. In addition, growth in next-generation "xTL" production, which includes both biomass-to-liquids and CTL, contributes significantly to the growth in total U.S. petroleum and other liquids production, particularly after 2020, adding about 0.6 and 0.3 million barrels per day of production, respectively, from 2010 to 2035.

U.S. crude oil production increases, led by lower 48 onshore production

Figure 112. Domestic crude oil production by source, 1990-2035 (million barrels per day)



As world oil prices increase in the *AEO2012* Reference case, U.S. production of tight oil (liquid oil embedded in low-permeable sandstone, carbonate, and shale rock) and production using carbon dioxide-enhanced oil recovery (CO_2-EOR) techniques add to the projected increase in domestic crude oil production from 2010 to 2035 (Figure 112). Growth in lower 48 onshore crude oil production comes primarily from the continued development of tight oil resources, mostly from the Bakken and Eagle Ford formations. Tight oil production surpasses 1.3 million barrels per day in 2027 and then declines to about 1.2 million barrels per day in 2035 as "sweet spots" are depleted. *AEO2012* also includes six other tight formations in the projections for tight oil production: the Austin Chalk, Avalon/Bone Springs, Monterey, Niobrara, Spraberry, and Woodford formations. Additional tight oil resources are likely to be identified in the future as more work is completed to identify currently producing reservoirs that may be better categorized as tight formations, and as new tight oil plays are identified and incorporated (see next column).

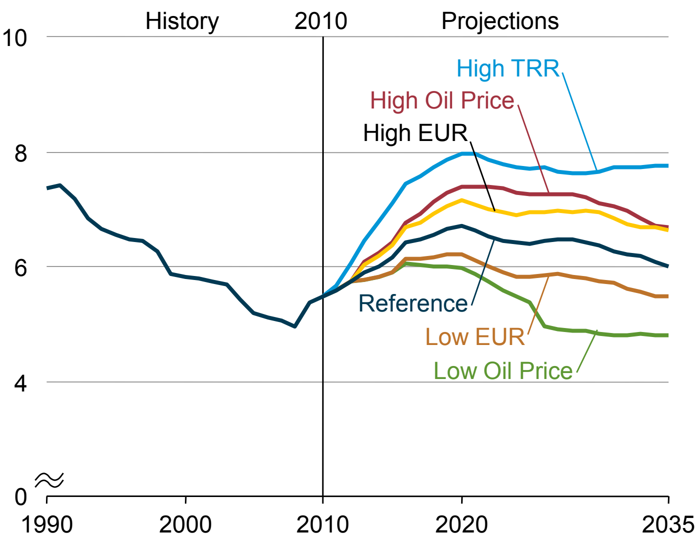
Crude oil production using CO_2-EOR increases significantly after 2020, when oil prices are higher, the more profitable tight oil deposits are depleted, and affordable anthropogenic sources of carbon dioxide (CO_2) are available. It plateaus at about 650,000 barrels per day from 2032 to 2035, when its profitability is limited by reservoir quality and CO_2 availability. From 2011 through 2035, CO_2-EOR production exceeds 4 billion barrels of oil.

Lower 48 offshore oil production remains relatively constant in the Reference case. The decline in currently producing fields is offset primarily by exploration and development of new fields in the deep waters of the Gulf of Mexico and, after 2029, in the Pacific Outer Continental Shelf.

Petroleum and other liquids supply

U.S. crude oil production varies with price and resource assumptions

Figure 113. Total U.S. crude oil production in six cases, 1990-2035 (million barrels per day)

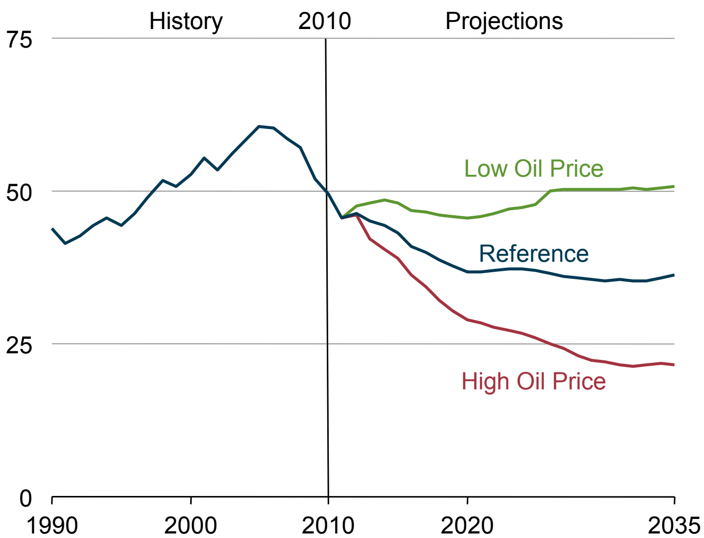


U.S. crude oil production varies with changes in assumptions about the extent of productivity improvement and well spacing in emerging tight oil resources examined in the High Technically Recoverable Resources (TRR) case and in the High and Low EUR cases (see discussion in "Issues in focus") and with changes in assumptions about crude oil prices in the Low and High Crude Oil Price cases (Figure 113). In the High TRR case, assumptions for tight oil allow for more rapid growth in crude oil production in the short and long term than in the Reference case, with production reaching nearly 8 million barrels per day in 2020. In the Low EUR case there is very little growth in domestic crude oil production over the projection period.

Higher oil prices lead to an increase in the level of investment in new oil projects. However, the returns from increased investment diminish as the average size and quality of available reservoirs decline. For example, in the High Oil Price case tight oil production is, on average, 225,000 barrels per day higher from 2020 to 2030 than in the Reference case but returns to Reference case levels in 2035. In contrast, low oil prices result in less investment in new oil projects and encourage producers to plug and abandon existing fields at earlier dates. For example, in the Low Oil Price case, oil production from the Alaska North Slope is shut down by around 2025, when the projected operating costs exceed wellhead production revenues (see "Issues in focus"). From 2020 to 2035, tight oil production is, on average, roughly 300,000 barrels per day lower in the Low Oil Price case than in the Reference case.

U.S. net imports of petroleum and other liquids fall in the Reference case

Figure 114. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2035 (percent)



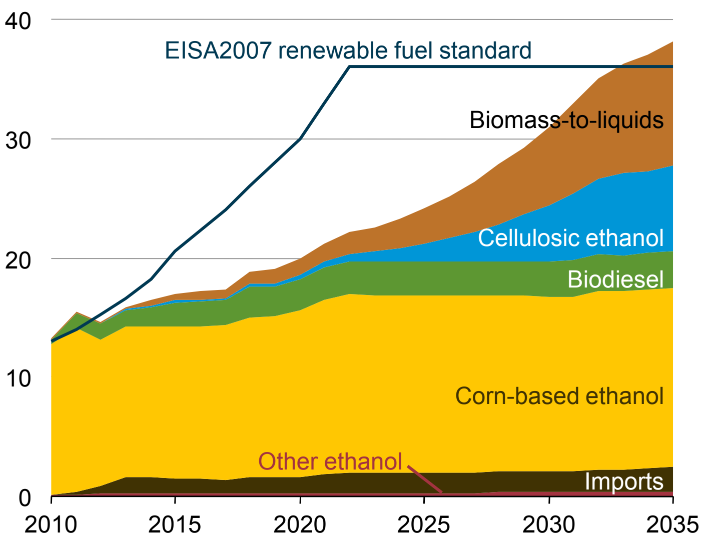
U.S. imports of petroleum and other liquids (including crude oil, petroleum liquids, and liquids derived from nonpetroleum sources) grew steadily from the mid-1980s to 2005 but have declined since then. In the *AEO2012* Reference and High Oil Price cases, U.S. imports of petroleum and other liquids continue to decline from 2010 to 2035, even as they provide a major part of total U.S. supply. Tighter fuel efficiency standards, increased use of biofuels, and greater production of domestic petroleum and other liquids contribute to the decrease in the share of imports. The combination of higher prices and renewable fuel mandates leads to more domestic production of petroleum and biofuels, which, combined with declines in the petroleum share of finished products after 2015, results in sustained net product exports.

The net import share of U.S. petroleum and other liquids consumption, which fell from 60 percent in 2005 to 50 percent in 2010, continues to decline in the Reference case, with the net import share falling to 36 percent in 2035 (Figure 114). In the High Oil Price case, the net import share falls even lower to a 22-percent share in 2035. In the Low Oil Price case, the net import share remains flat in the near term but rises to 51 percent in 2035, as domestic demand increases and imports become cheaper than crude oil produced domestically.

As a result of increased domestic production and slow growth in consumption, the United States becomes a net exporter of petroleum products, with net exports in the Reference case increasing from 0.18 million barrels per day in 2011 to 0.34 million barrels per day in 2035. In the High Oil Price case, net exports of petroleum products increase to 0.9 million barrels per day in 2035.

U.S. consumption of cellulosic biofuels exceeds renewable fuels standard in 2035

Figure 115. EISA2007 RFS credits earned in selected years, 2010-2035 (billion credits)



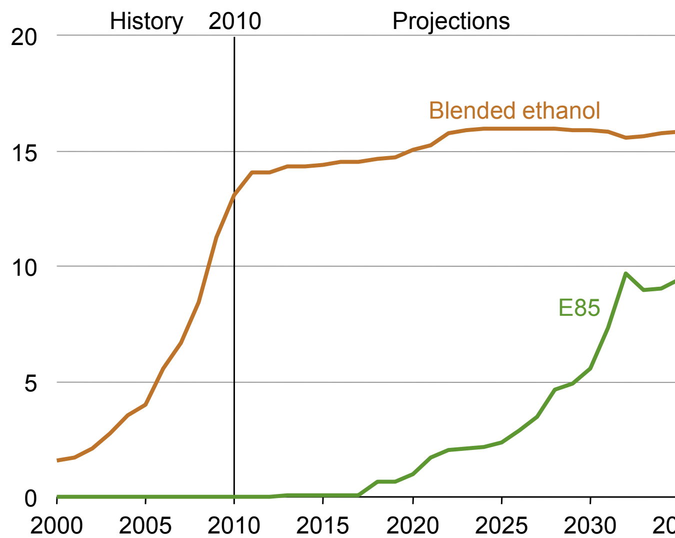
Although biofuel production increases substantially in the *AEO2012* Reference case, it does not meet the mandated RFS of 36 billion gallons in 2022 (Figure 115). Financial and technological hurdles delay the start of many advanced biofuel projects, particularly cellulosic biofuel projects. Three consecutive years of substantial reductions in the cellulosic biofuels mandate [*133*, *134*, *135*] have significantly reduced the possibility that the original RFS levels mandated in EISA2007 will be reached by 2022.

Between 2012 and 2022, it is expected that the EPA will evaluate the status of biofuel capacity annually and revise the production mandates for the following year, according to provisions in the RFS [*136*]. In 2011, after the EPA reduced the cellulosic biofuel mandate for both 2010 and 2011 from 100 million and 250 million gallons, respectively, to approximately 6 million gallons in both years, it also reduced the 2012 mandate from 500 million gallons to about 8 million gallons. Taking into account those modifications and anticipated future changes, only 22.1 billion of RFS credits are generated in 2022 in the Reference case, with 15 billion gallons of credits coming from domestic production of corn-based ethanol.

In the Reference case, the remainder of the biofuel supply consists of imported ethanol, biodiesel, cellulosic ethanol, and smaller volumes of next-generation biofuels. U.S. consumption of cellulosic ethanol grows from 0.6 billion gallons in 2022 to 7.2 billion gallons in 2035, when imports of ethanol and biodiesel total 2.2 billion gallons and 0.2 billion gallons, respectively.

Infrastructure hurdles limit near-term growth in consumption of E15 and E85 fuels

Figure 116. U.S. ethanol use in blended gasoline and E85, 2000-2035 (billion gallons per year)



A number of factors have recently limited the amount of ethanol that can be consumed domestically. Currently, given the limited availability of E85, the primary use of ethanol is as a blendstock for gasoline. With rapid growth in ethanol capacity and production in recent years, ethanol consumption in 2010 approached the legal gasoline blending limit of 10 percent (E10). As of January 2011, the EPA increased the blending limit to 15 percent for vehicles built in 2001 and later [*137*]. Once the final requirements are put in place, blenders will no longer be prohibited from blending beyond 10 percent for the general stock; however, a number of issues are expected to limit the rate at which terminals and retail outlets choose to take advantage of the option.

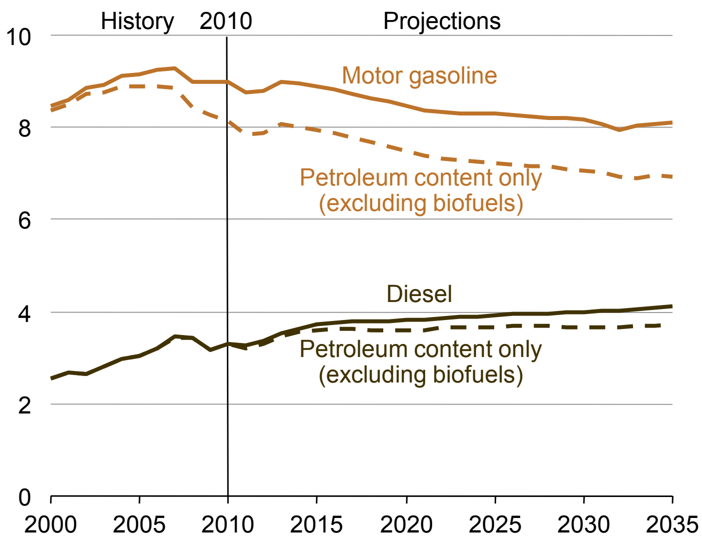
Liability from potential misfueling and infrastructure problems is one of the top concerns expected to slow the widespread adoption of E15. Retailers are hesitant to sell E15, even with the EPA's warning label, if they are not relieved of responsibility for damage to consumers' vehicles that may result from misfueling with the higher ethanol blend or from malfunctions of storage equipment or infrastructure. Consumer acceptance of the new fuel blend will also play a part, and warning labels may deter customers from risking potential damage from the use of E15, which potentially could void vehicle warranties.

In light of those potential issues, ethanol blending in gasoline increases slowly in the Reference case, from 13.2 billion gallons in 2010 (about 9 percent of the gasoline pool) to 15.0 billion gallons in 2020 (about 11 percent) and 15.8 billion gallons in 2035 (12.5 percent). Given the blending limitations, the remaining growth in ethanol use is in E85, which grows from about 0.6 billion gallons in 2018 to 9.5 billion gallons in 2035 (Figure 116).

Coal production

Shifts in fuel consumption guide future investment decisions for refiners

Figure 117. U.S. motor gasoline and diesel fuel consumption, 2000-2035 (million barrels per day)



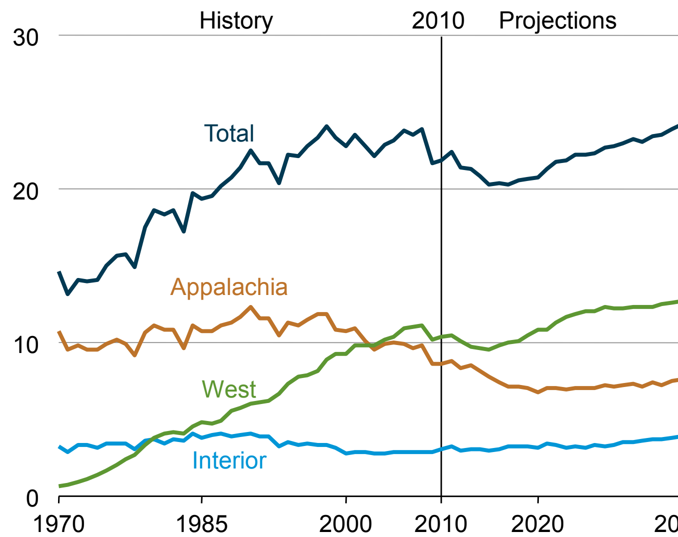
Tighter vehicle efficiency standards for LDVs require new LDVs to average 35 mpg by 2020, and newly issued regulations require increased use of ethanol. The Reference case does not include the proposed fuel economy standards covering MYs 2017 through 2025 that would raise vehicle efficiency standards even higher. Demand for motor gasoline declines in the Reference case. In combination with a tighter market for diesel fuel, the decrease in gasoline consumption leads to a shift in refinery outputs and investments. As some smaller and less integrated refineries begin to idle capacity as a result of higher costs, new refinery projects are focused on shifting production from gasoline to distillate fuels. The restructuring results in a net reduction in refinery capacity of 2.4 million barrels per day over the projection period.

In the Reference case, new capacity that was planned before the economic downturn of 2008-2009 comes on line early in the projection period, adding approximately 400,000 barrels per day of new refining distillation capacity from 2010 to 2015. As a result of refinery economics and concerns about the potential for enactment of legislation that could constrain carbon emissions, raise refiners' costs, and limit the growth in demand for petroleum and other liquids, no additional refinery capacity is built after 2015 until around 2030. Total refining capacity in the United States declines gradually after 2015 as additional capacity is idled.

Motor gasoline consumption and diesel fuel consumption (either including or excluding biofuels) trend in opposite directions in the Reference case (Figure 117). Consumption of diesel fuel increases by approximately 0.8 million barrels per day from 2010 to 2035, while motor gasoline consumption falls by 0.9 million barrels per day.

Early declines in coal production are more than offset by growth after 2015

Figure 118. Coal production by region, 1970-2035 (quadrillion Btu)



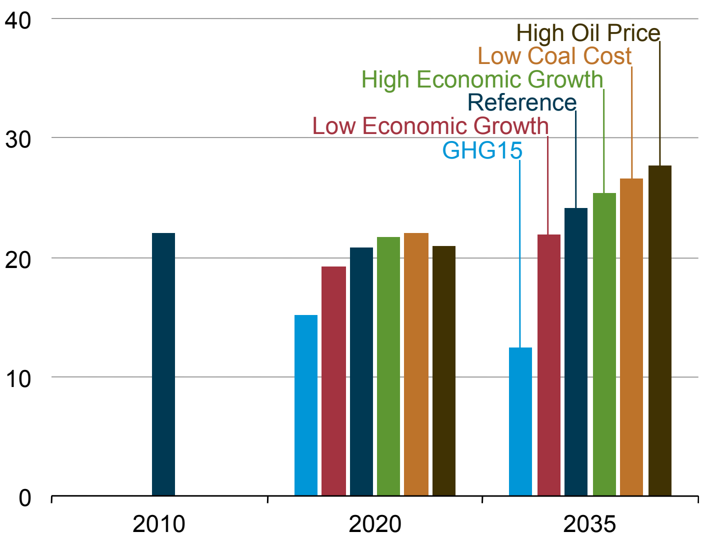
Although higher coal exports provide some support in 2011, U.S. coal production declines for four years thereafter as a result of low natural gas prices, rising coal prices, lack of growth in electricity demand, and increasing generation from renewables. In addition, new requirements to control emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), and air toxics (such as mercury and acid gases), result in the retirement of some coal-fired generating capacity, contributing to the reduction in demand for coal. After 2015, coal production grows at an average annual rate of 1.0 percent through 2035, with coal use for electricity generation increasing as electricity demand grows and natural gas prices rise.More coal is also used for production of synthetic liquids, and coal exports increase.

Western coal production grows through 2035 (Figure 118) but at a much slower rate than in the past, as demand growth continues to slow. Low-cost supplies of coal from the West satisfy much of the additional need for fuel at coal-fired power plants east of the Mississippi River and supply most of the coal used at new CTL and CBTL plants.

Coal production in the Interior region, which has trended downward slightly since the early 1990s, recovers to near historic highs in the *AEO2012* Reference case. Additional production from the Interior region originates from mines tapping into the substantial reserves of mid- and high-sulfur bituminous coal in Illinois, Indiana, and western Kentucky and from lignite mines in Texas and Louisiana. Appalachian coal production declines substantially from current levels, as coal produced from the extensively mined, higher cost reserves of Central Appalachia is supplanted by lower cost coal from other supply regions. An expected increase in production from the northern part of the Appalachia basin, however, moderates the overall production decline in Appalachia.

U.S. coal production is affected by actions to cut GHG emissions from existing power plants

Figure 119. U.S. total coal production in six cases, 2010, 2020, and 2035 (quadrillion Btu)



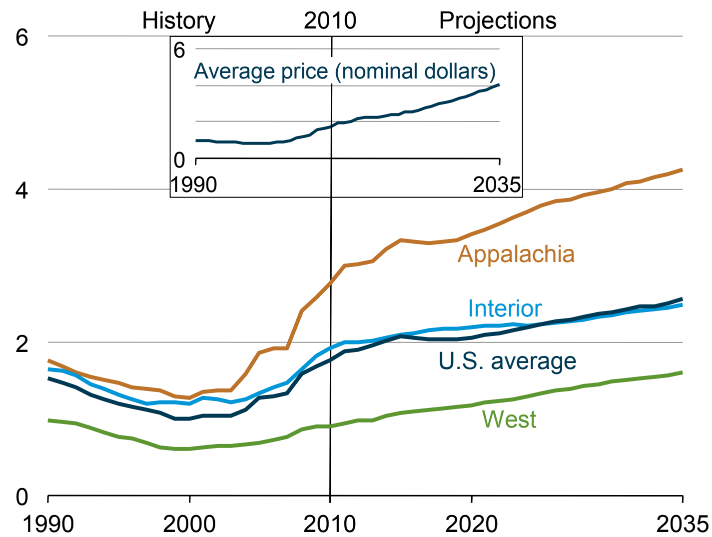
U.S. coal production varies across the *AEO2012* cases, reflecting different assumptions about the costs of producing and transporting coal, the outlook for economic growth, the outlook for world oil prices, and possible restrictions on GHG emissions (Figure 119). As shown in the GHG15 case, where a CO_2 emissions price that grows to $44 per metric ton in 2035 is assumed, actions to restrict or reduce GHG emissions can significantly affect the outlook for U.S. coal production.

Assumptions about economic growth primarily affect the projections for overall electricity demand, which in turn determine the need for coal-fired electricity generation. In contrast, assumptions about the costs of producing and transporting coal primarily affect the choice of technologies for electricity generation, with coal capturing a larger share of the U.S. electricity market in the Low Coal Cost case. In the High Oil Price case, higher oil prices stimulate the demand for coal-based synthetic liquids, leading to more coal use at CTL and CBTL plants. Production of coal-based synthetic liquids totals 1.3 million barrels per day in 2035 in the High Oil Price case, more than four times the amount in the Reference case.

From 2010 to 2035, changes in total annual coal production across the cases (excluding the GHG case) range from a decrease of 1 percent to an increase of 26 percent. In the earlier years of the projections, coal production is lower than in 2010 in most cases, as other sources of electricity generation displace coal-fired generation. From 2010 to 2020, changes in coal production across the cases (excluding the GHG case) range from a decline of 13 percent to virtually no change, with a 6-percent decline projected in the *AEO2012* Reference case.

Average minemouth price continues to rise, but at a slower pace than in recent years

Figure 120. Average annual minemouth coal prices by region, 1990-2035 (2010 dollars per million Btu)



In the *AEO2012* Reference case, the average real minemouth price for U.S. coal increases by 1.5 percent per year, from $1.76 per million Btu in 2010 to $2.56 in 2035, continuing the upward trend in coal prices that began in 2000 (Figure 120). A key factor underlying the higher coal prices in the projection is an expectation that coal mining productivity will continue to decline, but at slower rates than during the 2000s.

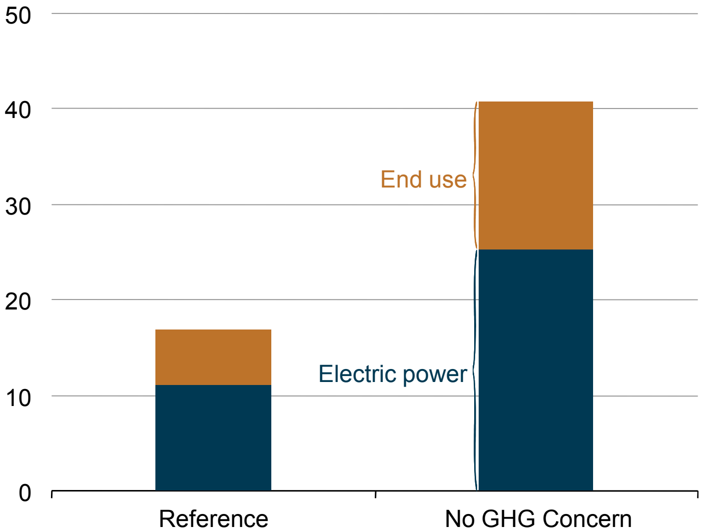
In the Appalachian region, the average minemouth coal price increases by 1.7 percent per year from 2010 to 2035. In addition to continued declines in coal mining productivity, the higher price outlook for the Appalachian region reflects a shift to higher-value coking coal, resulting from the combination of growing exports of coking coal and declining shipments of steam/thermal coal to domestic markets. Recent increases in the average price of Appalachian coal, from $1.28 per million Btu in 2000 to $2.77 per million Btu in 2010, in part a result of significant declines in mining productivity over the past decade, have substantially reduced the competitiveness of Appalachian coal with coal from other regions.

In the Western and Interior coal supply regions, declines in mining productivity, combined with increasing production, lead to increases in the real minemouth price of coal, averaging 2.3 percent per year for the Western region and 1.0 percent per year for the Interior region from 2010 to 2035.

Emissions from energy use

Concerns about future GHG policies affect investments in emissions-intensive capacity

Figure 121. Cumulative coal-fired generating capacity additions by sector in two cases, 2011-2035 (gigawatts)

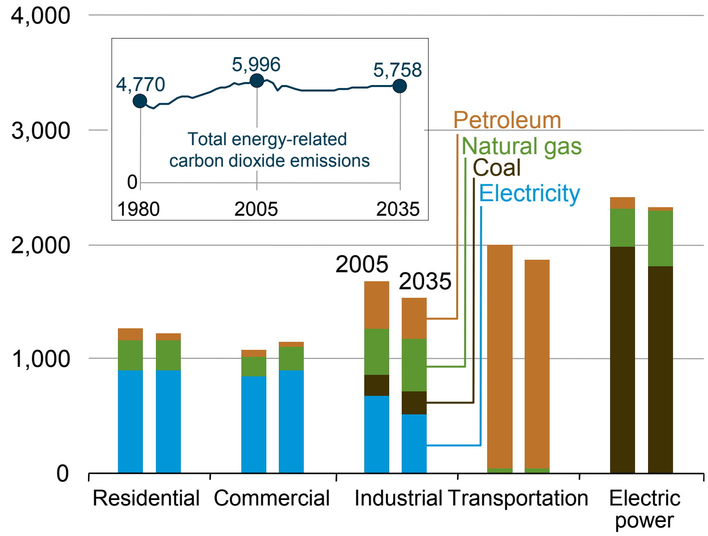


In the *AEO2012* Reference case, the cost of capital for investments in GHG-intensive technologies—including new coal-fired power plants without carbon capture and storage (CCS), new CTL and CBTL plants, and capital investment projects at existing coal-fired power plants (excluding CCS)—is increased by 3 percentage points to reflect the behavior of utilities, other energy companies, and regulators concerning the possible enactment of GHG legislation that could require owners to purchase emissions allowances, invest in CCS, or invest in other projects to offset their emissions in the future. The No GHG Concern case illustrates the potential impact on energy investments when the additional 3 percentage points added to the cost of capital for GHG-intensive technologies is removed.

In the No GHG Concern case, the lower cost of capital leads to 40 gigawatts of new coal-fired capacity additions from 2011 to 2035, up from 17 gigawatts in the Reference case (Figure 121). As a result, additions of both natural gas and renewable generating capacity are lower in the No GHG Concern case than in the Reference case. In the end-use sectors, all new coal-fired capacity additions in the No GHG Concern case are at CTL and CBTL plants, where part of the electricity is used to produce synthetic liquids and the remaining portion is sold to the grid. As a result, production of coal-based synthetic liquids totals 0.7 million barrels per day in 2035, compared with 0.3 million barrels per day in the Reference case. Total coal consumption (including coal converted to synthetic fuels) increases to 24.3 quadrillion Btu in 2035 in the No GHG Concern case, 2.6 quadrillion Btu (12 percent) higher than in the Reference case. Energy-related CO_2 emissions in 2035 are 5,900 million metric tons in the No GHG Concern case, about 2 percent higher than in the Reference case and 2 percent lower than their 2005 level.

Projected energy-related carbon dioxide emissions remain below their 2005 level

Figure 122. U.S. energy-related carbon dioxide emissions by sector and fuel, 2005 and 2035 (million metric tons)



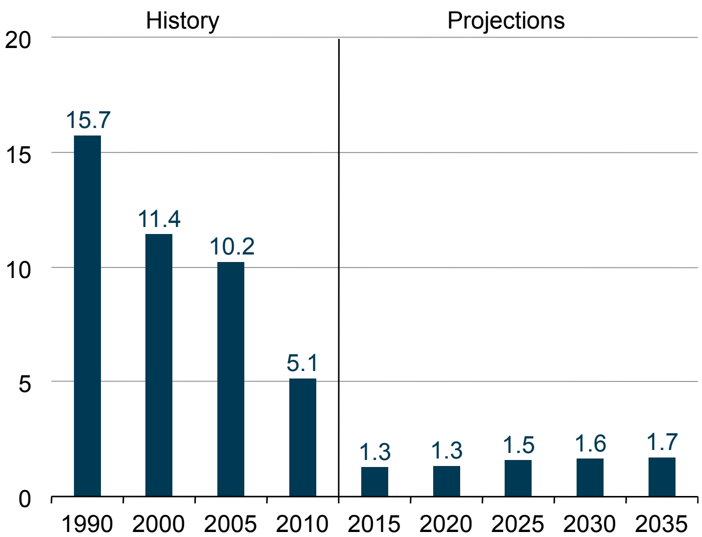
On average, energy-related CO_2 emissions in the *AEO2012* Reference case decline by 0.1 percent per year from 2005 to 2035, as compared with an average increase of 0.9 percent per year from 1980 to 2005. Reasons for the decline include an expected slow and extended recovery from the recession of 2008-2009, growing use of renewable technologies and fuels, efficiency improvements, slower growth in electricity demand, and more use of natural gas, which is less carbon-intensive than other fossil fuels. In the Reference case, energy-related CO_2 emissions remain below 2005 levels through 2035, when they total 5,758 million metric tons—238 million metric tons (4.0 percent) below their 2005 level (Figure 122).

Petroleum remains the largest source of U.S. CO_2 emissions over the projection period, but its share falls to 40 percent in 2035 from 44 percent in 2005. CO_2 emissions from petroleum use, mainly in the transportation sector, were at relatively low levels in 2009. Although they increase somewhat from 2025 to 2035, emissions from petroleum use remain fairly stable, as improvements in transportation fuel economy and the expanded use of ethanol and other biofuels outweigh expected increases in travel demand. CO_2 emissions from petroleum would be even lower if proposed fuel economy standards covering MYs 2017 through 2025 were included in the Reference case.

Emissions from coal, the second largest source of CO_2 emissions, remain below 2005 levels through 2035 in the Reference case. Coal's share of total U.S. CO_2 emissions remains relatively unchanged through 2035, because the percentage decline in emissions from coal combustion is roughly the same as the percentage decline in total CO_2 emissions over the period. The natural gas share of CO_2 emissions increases from just under 20 percent in 2005 to 25 percent in 2035 as the use of natural gas to fuel electricity generation and industrial applications increases.

Power plant emissions of sulfur dioxide are reduced by further environmental controls

Figure 123. Sulfur dioxide emissions from electricity generation, 1990-2035 (million short tons)



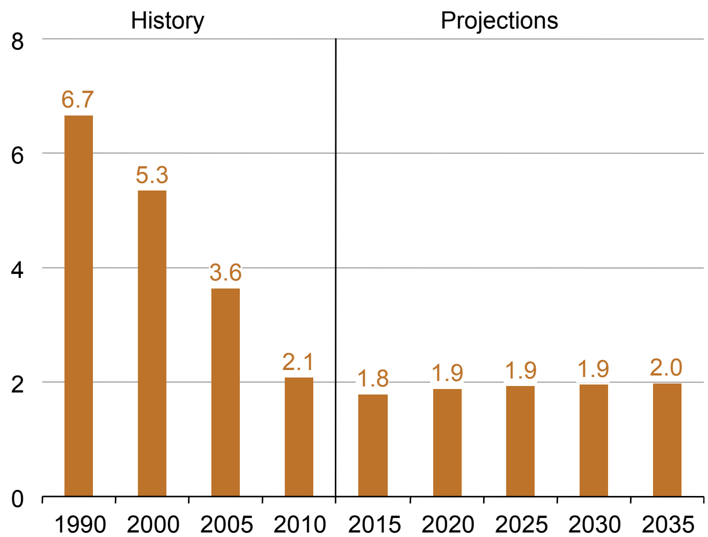
In the *AEO2012* Reference case, SO_2 emissions from the U.S. electric power sector fall from 5.1 million short tons in 2010 to a range of 1.3 to 1.7 million short tons in the 2015-2035 projection period. The reduction occurs in response to the EPA's Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS) [*138*]. Although SO_2 is not directly regulated by the MATS, the reductions are achieved as a result of the technology requirements for acid gas and non-mercury metal controls on coal-fired power plants. *AEO2012* assumes that, in order to continue operating, coal plants must have either flue gas desulfurization (FGD) or dry sorbent injection (DSI) systems installed by 2015. Both technologies, which are used to reduce acid gas emissions, also reduce SO_2 emissions.

EIA assumes a 95-percent SO_2 removal efficiency for FGD units and a 70-percent SO_2 removal efficiency for DSI systems. DSI systems can achieve 70-percent efficiency when they include a baghouse filter, which also is assumed to be needed for compliance with the non-mercury metal component of the MATS.

From 2010 to 2035, approximately 48 gigawatts of coal-fired capacity is retrofitted with FGD units in the Reference case, and another 58 gigawatts is retrofitted with DSI systems. By 2015, all operating coal-fired power plants are assumed to have either DSI or FGD systems installed on units larger than 25 megawatts. As a result, after a 75-percent decrease from 2010 to 2015, SO_2 emissions increase slowly from 2016 to 2035 (Figure 123), as total electricity generation from coal-fired power plants increases.

Nitrogen oxide emissions show little change from 2010 to 2035 in the Reference case

Figure 124. Nitrogen oxide emissions from electricity generation, 1990-2035 (million short tons)



Annual emissions of NO_X from the electric power sector, which totaled 2.1 million short tons in 2010, range between 1.8 and 2.0 million short tons from 2015 to 2035 (Figure 124). Annual NO_X emissions from electricity generation dropped by 43 percent from 2005 to 2010 due to implementation of the Clean Air Interstate Rule (CAIR), which led to the installation of additional NO_X pollution control equipment.

In the *AEO2012* Reference case, NO_X emissions are 5 percent below 2010 levels in 2035, despite a 2-percent increase in coal-fired electricity generation over the same period. The drop in emissions is a result primarily of CSAPR [*139*], which includes both annual and seasonal cap-and-trade systems for NO_X in 28 States. A slight rise in NO_X emissions after 2015 corresponds to a recovery in coal-fired generation as natural gas prices rise in the later years of the projection period.

The MATS does not have a direct effect on NO_X emissions, because none of the potential technologies required to comply with MATS has a significant impact on NO_X emissions. However, because MATS contributes to a reduction in coal-fired generation overall, it indirectly reduces NO_X emissions in the power sector in States without CSAPR where coal- and oil-fired units are used.

Coal-fired power plants can be retrofitted with one of three types of NO_X control technologies: selective catalytic reduction (SCR), selective noncatalytic reduction (SNCR), or low-NO_X burners. The type of retrofit used depends on the specific characteristics of the plant, including the boiler configuration and the type of coal used. From 2010 to 2035, 28 gigawatts of coal-fired capacity is retrofitted with NO_X controls in the Reference case: 69 percent with SCR, 3 percent with SNCR, and 29 percent with low-NO_X burners.

Endnotes for Market trends

Links current as of June 2012

121. In the recessions highlighted in Figure 46, percentage changes in annual GDP relative to the previous year were negative.

122. The industrial sector includes manufacturing, agriculture, construction, and mining. The energy-intensive manufacturing sectors include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.

123. Energy expenditures relative to GDP are not the energy share of GDP, because they include energy as an intermediate product. The energy share of GDP corresponds to the share of value added by domestic energy-producing sectors, excluding the value of energy as an intermediate product.

124. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 30*, ORNL-6986 (Oak Ridge, TN: June 2011), Chapter 4, "Light Vehicles and Characteristics," website cta.ornl.gov/data/index.shtml.

125. The *AEO2012* Reference case does not include the proposed LDV GHG and fuel economy standards published by the EPA and NHTSA in December 2011. (See "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards," website www.nhtsa.gov/fuel-economy.)

126. LDV fuel economy includes AFVs and banked credits toward compliance.

127. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Proposed Rule," Federal Register, Vol. 76, No. 231 (Washington, DC, December 1, 2011), website www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/2017-25_CAFE_NPRM.pdf. 49 CFR Parts 523, 531, 533, 536, and 537.

128. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," Federal Register, Vol. 76, No. 179 (Washington, DC: September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.

129. The factors that influence decisionmaking on capacity additions include electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different generation options, fuel prices, State RPS programs, and the availability of Federal tax credits for some technologies.

130. The 24 gigawatts include the 1.12 gigawatt Watts Bar 2 unit in 2012 that was subsequently delayed by TVA until 2015 due to cost overruns; www.tva.gov/news/releases/aprjun12/0426_board.htm.

131. Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and CHP capacity. Costs reflect the average of regional costs.

132. For detailed discussion of levelized costs, see U.S. Energy Information Administration, "Levelized Cost of New Generation Resources in the Annual Energy Outlook 2012," website www.eia.gov/forecasts/aeo/electricity_generation.cfm.

133. U.S. Environmental Protection Agency, "EPA Finalizes Regulations for the National Renewable Fuel Standard Program for 2010 and Beyond," EPA-420-F-10-007 (Washington, DC: February 2010), website www.epa.gov/otaq/renewablefuels/420f10007.pdf.

134. U.S. Environmental Protection Agency, "EPA Finalizes 2011 Renewable Fuel Standards," EPA-420-F-10-056 (Washington, DC: November 2010), website www.epa.gov/oms/fuels/renewablefuels/420f10056.pdf.

135. U.S. Environmental Protection Agency, "EPA Finalizes 2012 Renewable Fuel Standards," EPA-420-F-11-044 (Washington, DC: December 2011), website www.epa.gov/otaq/fuels/renewablefuels/documents/420f11044.pdf.

136. EISA2007, Section 211(o)(7) of the Clean Air Act.

137. U.S. Environmental Protection Agency, "E15 (a blend of gasoline and ethanol)," website www.epa.gov/otaq/regs/fuels/additive/e15.

138. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," website www.epa.gov/mats.

139. U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)," website epa.gov/airtransport.

Comparison with other projections

Energy Information Administration (EIA) and other contributors have endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives. None of the EIA or any of the other contributors shall be responsible for any loss sustained due to reliance on the information included in this report.

Only IHS Global Insight (IHSGI) produces a comprehensive energy projection with a time horizon similar to that of the *Annual Energy Outlook 2012 (AEO2012)*. Other organizations, however, address one or more aspects of the U.S. energy market. The most recent projection from IHSGI, as well as others that concentrate on economic growth, international oil prices, energy consumption, electricity, natural gas, petroleum, and coal, are compared here with the *AEO2012* Reference case.

1. Economic growth

The range of projected economic growth in the outlooks included in the comparison tends to be wider over the first 5 years of the projection period than over a longer period, because the group of variables—such as population, productivity, and labor force growth—that are used to influence long-run economic growth is smaller than the group of variables that affect projections of short-run growth. The average annual rate of growth of real gross domestic product (GDP) from 2010 to 2015 (in 2005 dollars) ranges from 2.4 percent to 3.4 percent (Table 22). From 2010 to 2020, the 10-year average annual growth rate ranges from 2.5 percent to 3.1 percent.

From 2010 to 2015, real GDP is projected to grow at a 2.5-percent average annual rate in the *AEO2012* Reference case, lower than projected by the Office of Management and Budget (OMB), Congressional Budget Office (CBO), Blue Chip Consensus (Blue Chip), Social Security Administration (in *The 2011 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds*), ExxonMobil, and the Interindustry Forecasting Project at the University of Maryland (INFORUM) and higher than projected by Strategic Energy and Economic Research, Inc. (SEER). The *AEO2012* projection of GDP growth is similar to the IHSGI average annual rate of 2.5 percent over the same period.

The average annual GDP growth of 2.5 percent in the *AEO2012* Reference case from 2010 to 2020 is at the low end of the range of outlooks, with OMB, INFORUM, and the Social Security Administration projecting the strongest recovery from the 2008-2009 recession. INFORUM projects average annual GDP growth of 3.1 percent from 2010 to 2020, while OMB and the Social Security Administration project annual average growth of 3.0 percent over the same period. The CBO, ExxonMobil, Blue Chip, the International Energy Agency's (IEA) November 2011 *World Energy Outlook* Current Policies Scenario, and SEER also project higher growth than the *AEO2012* Reference case from 2010 to 2020, ranging between 2.6 and 2.8 percent per year over the next 10 years.

There are few public or private projections of GDP growth for the United States that extend to 2035. The *AEO2012* Reference case projects 2.5-percent average annual GDP growth from 2010 to 2035, consistent with trends in labor force and productivity growth. IHSGI, ExxonMobil, and the Social Security Administration project GDP growth averaging 2.5 percent per year from 2010 to 2035, and INFORUM (at 2.7 percent) and SEER (at 2.8 percent) project higher GDP growth than in the *AEO2012* Reference Case over the same period. IEA projects a slightly lower rate of 2.4 percent per year from 2010 to 2035.

2. Oil prices

In the *AEO2012* Reference case, oil prices [West Texas Intermediate (WTI)] rise from $79 per barrel in 2010 to about $117 per barrel in 2015 and $127 per barrel in 2020 (Table 23). From the 2020 level, prices increase slowly to $145 per barrel in 2035. This price trend is slightly higher than the trend shown in last year's *AEO2011* Reference case.

Table 22. Projections of average annual economic growth, 2010-2035

	Average annual percentage growth rates			
Projection	2010-2015	2010-2020	2020-2035	2010-2035
AEO2012 (Reference case)	2.5	2.5	2.6	2.5
AEO2011 (Reference case)	3.0	2.8	2.6	2.7
IHSGI (November 2011)	2.5	2.5	2.5	2.5
OMB (January 2012)[a]	3.1	3.0	--	--
CBO (January 2012)[a]	2.7	2.8	--	--
INFORUM (January 2012)	3.4	3.1	2.4	2.7
Social Security Administration (August 2011)	3.3	3.0	2.1	2.5
IEA (2011)[b]	--	2.6	2.4	2.4
Blue Chip Consensus (October 2011)[a]	2.6	2.6	--	--
ExxonMobil	2.7	2.7	2.3	2.5
SEER	2.4	2.7	2.8	2.8

-- = not reported.
[a]OMB, CBO, and Blue Chip forecasts end in 2022, and growth rates cited are for 2010-2022.
[b]IEA publishes U.S. growth rates for certain intervals: 2009-2020 growth is 2.6 percent, and 2009-2035 growth rate is 2.4 percent.

Market volatility and different assumptions about the future of the world economy are reflected in the range of price projections for both the short term and the long term; however, most projections show prices rising over the entire course of the projection period. The projections range from $82 per barrel to $117 per barrel in 2015 (a span of $35 per barrel) and from $98 per barrel to $145 per barrel in 2035 (a span of $47 per barrel). The wide range underscores the uncertainty inherent in the projections. The range of the projections is encompassed in the range of the *AEO2012* Low and High Oil Price cases, from $58 per barrel to $182 per barrel in 2015 and from $62 per barrel to $200 per barrel in 2035.

The measure of oil prices is, by and large, comparable across projections. EIA reports the price of low-sulfur, light crude oil, approximately the same as the WTI price widely cited in the trade press. The only series that do not report projections in WTI terms are IEA, with prices in the Current Policies Scenario expressed as the price of imported crude oil, and INFORUM, with prices expressed as the average U.S. refiner acquisition cost (RAC) of imported crude oil.

3. Total energy consumption

Five projections by other organizations—INFORUM, IHSGI, ExxonMobil, IEA, and BP—include energy consumption by sector. To allow comparison with the IHSGI projection, the *AEO2012* Reference case was adjusted to remove coal-to-liquids (CTL) heat and power, biofuels heat and co-products, and natural gas feedstock use. To allow comparison with the ExxonMobil projection, electricity consumption in each sector was removed from the *AEO2012* Reference case projections. To allow comparison with the IEA and BP projections, the *AEO2012* Reference case projections for the residential and commercial sectors were combined to produce a buildings sector projection. BP does not include the electric power sector in its projection for total energy consumption; however, it does include conversion losses that allow comparison on the basis of total energy consumption. The IEA projections have a base year of 2009, as opposed to 2010 in the other projections, and BP's projections extend only through 2030, not 2035.

Total energy consumption is higher in all projection years in both the IHSGI and INFORUM projections than in the *AEO2012* Reference case. ExxonMobil, IEA, and BP show lower total energy consumption in all years (Table 24). ExxonMobil and BP include a cost for carbon dioxide (CO_2) emissions in their outlooks, which helps to explain the lower level of consumption in those outlooks. While the IEA reference case also includes a cost for CO_2 emissions, the IEA Current Policies Scenario (which assumes that no new policies are added to those in place in mid-2011) was used for comparison in this analysis, because it corresponds better with the assumptions in *AEO2012*.

The INFORUM projection of total energy consumption in 2035 is almost 8 quadrillion Btu higher than the *AEO2012* Reference case projection, with the industrial and electric power sectors each about 2 quadrillion Btu higher and the transportation sector about 3 quadrillion Btu higher. For the transportation sector, the difference appears to result from a higher number of light-duty vehicle miles traveled in the INFORUM results, which offsets slightly higher motor gasoline prices in the INFORUM projection. Vehicle efficiency is essentially the same in the INFORUM and *AEO2012* projections. INFORUM also projects higher revenue passenger-miles for air travel than *AEO2012*. Diesel prices are lower in the INFORUM projection, which leads to higher demand (about 1 quadrillion Btu) than in *AEO2012*. In the industrial sector, INFORUM projects industrial shipments in 2035 that are approximately 1.5 times the level of those in the *AEO2012* Reference case, which helps to explain the higher level of industrial energy consumption in the INFORUM projection relative to *AEO2012*.

IHSGI projects significantly higher electricity consumption for all sectors than in the *AEO2012* Reference case, which helps to explain much of the difference in total energy consumption between the two projections. In the IHSGI projection, the electric power sector consumes 13 quadrillion Btu more energy in 2035 than in the *AEO2012* Reference case. The greater use of electricity in the IHSGI projection, including 300 trillion Btu used by electric vehicles, also results in higher electricity prices than in the *AEO2012* Reference case.

Table 23. Projections of oil prices, 2015-2035 (2010 dollars per barrel)

Projection	2015	2020	2025	2030	2035
AEO2012 (Reference case)	116.91	126.68	132.56	138.49	144.98
AEO2011 (Reference case)	95.41	109.05	118.57	124.17	126.03
EVA	82.24	84.75	89.07	94.78	102.11
IEA (Current Policies Scenario)	106.30	118.10	127.30	134.50	140.00
INFORUM	91.78	105.84	113.35	117.83	116.76
IHSGI	99.16	72.89	87.19	95.65	98.08
Purvin & Gertz	98.75	103.77	106.47	107.37	107.37
SEER	94.20	101.57	107.13	111.26	121.94

Although there are differences in energy consumption by sector between the ExxonMobil and BP projections, in both cases total energy consumption declines from 2010 levels and is lower than in the *AEO2012* Reference case. The difference appears to result primarily from the inclusion of a tax on CO_2 emissions in both the ExxonMobil and BP projections, which is not considered in the *AEO2012* projection. Energy consumption in the transportation sector declines from 2010 levels in both the ExxonMobil and BP projections, driven by policy changes and technology improvement; however, BP projects a much larger drop in transportation energy consumption, a total of 4 quadrillion Btu (or four times the decline in the ExxonMobil projection) between 2010 and 2030.

Although energy consumption in all sectors in the IEA projection is higher in 2035 than in 2010, energy consumption in the transportation and industrial sectors declines from 2020 to 2030, by less than 1 quadrillion Btu in each sector.

IEA projects little change for energy use in those two sectors from 2030 to 2035, with industrial energy consumption declining very slowly and transportation energy consumption increasing very slightly. IEA projects total energy consumption that is higher than BP in 2030 and higher than ExxonMobil in 2035 but considerably lower than in the *AEO2012* Reference case.

4. Electricity

Table 25 compares summary results for the electric power sector from the *AEO2012* Reference case with projections by Energy Ventures Analysis (EVA), IHSGI, and INFORUM. In 2015, total electricity sales range from a low of 3,753 billion kilowatthours in the *AEO2012* Reference case to a high of 4,173 billion kilowatthours in the IHSGI projection. IHSGI shows higher sales across

Table 24. Projections of energy consumption by sector, 2010-2035 (quadrillion Btu)

Sector	*AEO2012* Reference	INFORUM	IHSGI	ExxonMobil	IEA	BP
			2010			
Residential	11.7	11.4	11.2	--	--	--
Residential excluding electricity	6.7	6.5	6.2	6.0	--	--
Commercial	8.7	8.5	8.6	--	--	--
Commercial excluding electricity	4.2	3.9	4.0	4.0	--	--
Buildings sector	20.4	20.0	19.8	10.0	19.1[a]	21.8
Industrial	23.4	23.1	--	--	22.9[a]	23.0
Industrial excluding electricity	20.1	19.9	--	20.0	--	--
Losses[b]	0.8	--	--	--	--	--
Natural gas feedstocks	0.5	--	--	--	--	--
Industrial removing losses and feedstocks	22.0	--	21.4	--	--	--
Transportation	27.6	27.4	26.6	27.0	22.9[a]	22.8
Electric power	39.6	40.1	40.8	37.0	35.6[a]	--
Less: electricity demand[c]	12.8	12.8	12.8	--	14.3[a]	--
Electric power losses	26.8	27.3	--	--	--	23.1
Total primary energy	**98.2**	**97.8**	**--**	**94.0**	**85.7[a]**	**90.7**
Excluding losses[b] and feedstocks	**96.8**	**--**	**95.8**	**--**	**--**	**--**
			2020			
Residential	11.4	11.2	11.8	--	--	--
Residential excluding electricity	6.4	6.4	5.8	6.0	--	--
Commercial	9.2	9.5	9.5	--	--	--
Commercial excluding electricity	4.3	4.3	4.0	4.0	--	--
Buildings sector	20.5	20.7	21.3	9.0	20.4	21.9
Industrial	24.6	27.4	--	--	24.8	23.4
Industrial excluding electricity	21.2	23.9	--	20.0	--	--
Losses[b]	1.2	--	--	--	--	--
Natural gas feedstocks	0.5	--	--	--	--	--
Industrial removing losses and feedstocks	22.9	--	22.5	--	--	--
Transportation	27.3	29.0	27.4	28.0	23.8	21.0
Electric power	40.2	41.6	48.6	39.0	39.3	--
Less: electricity demand[c]	13.3	13.6	15.7	--	16.4	--
Electric power losses	26.9	28.0	--	--	--	23.7
Total primary energy	**99.3**	**105.1**	**--**	**96.0**	**91.4**	**90.1**
Excluding losses[b] and feedstocks	**97.6**	**--**	**104.1**	**--**	**--**	**--**

-- = not reported.
See notes at end of table.

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all sectors in 2015 in comparison with the other projections. Total electricity sales in 2035 in the IHSGI projection (5,652 billion kilowatthours) are higher than in the others: 4,415 billion kilowatthours in the *AEO2012* Reference case, 4,483 billion kilowatthours in the INFORUM projection, and 4,726 billion kilowatthours in the EVA projection. Although IHSGI projects higher electricity sales in all sectors in 2035, the largest percentage differences between the IHSGI and other projections are in the industrial sector. Electricity sales in the industrial sector in 2035 in the IHSGI projection are 1,387 billion kilowatthours, as compared with 977 billion kilowatthours in the *AEO2012* Reference case, 941 billion kilowatthours in the EVA projection, and 968 billion kilowatthours in the INFORUM projection.

Table 24. Projections of energy consumption by sector, 2010-2035 (quadrillion Btu) (continued)

Sector	*AEO2012* Reference	INFORUM	IHSGI	ExxonMobil	IEA	BP
			2030			
Residential	11.7	11.6	12.6	--	--	--
Residential excluding electricity	6.2	6.3	5.7	5.0	--	--
Commercial	9.9	10.6	10.4	--	--	--
Commercial excluding electricity	4.4	4.5	4.0	4.0	--	--
Buildings sector	21.6	22.1	23.0	9.0	22.0	23.0
Industrial	26.1	28.8	--	--	24.1	23.2
Industrial excluding electricity	22.7	25.3	--	19.0	--	--
Losses[b]	2.4	--	--	--	--	--
Natural gas feedstocks	0.5	--	--	--	--	--
Industrial removing losses and feedstocks	23.3	--	23.0	--	--	--
Transportation	27.9	30.7	27.5	26.0	22.9	18.5
Electric power	43.2	45.0	54.3	41.0	41.6	--
Less: electricity demand[c]	14.5	14.8	18.1	--	17.9	--
Electric power losses	28.7	30.1	--	--	--	24.1
Total primary energy	**104.3**	**111.8**	**--**	**94.0**	**92.3**	**88.9**
Excluding losses[b] and feedstocks	**101.5**	**--**	**109.7**	**--**	**--**	**--**
			2035			
Residential	11.9	11.7	13.0	--	--	--
Residential excluding electricity	6.1	6.2	5.5	5.0	--	--
Commercial	10.3	11.1	10.8	--	--	--
Commercial excluding electricity	4.5	4.6	4.0	3.0	--	--
Buildings sector	22.2	22.8	23.8	8.0	22.9	--
Industrial	26.9	29.1	--	--	23.9	--
Industrial excluding electricity	23.6	25.7	--	18.0	--	--
Losses[b]	3.2	--	--	--	--	--
Natural gas feedstocks	0.4	--	--	--	--	--
Industrial removing losses and feedstocks	23.3	--	23.3	--	--	--
Transportation	28.6	31.9	27.8	25.0	23.1	--
Electric power	44.2	46.2	57.2	40.0	42.5	--
Less: electricity demand[c]	15.1	15.3	19.3	--	18.6	--
Electric power losses	29.2	30.8	--	--	--	--
Total primary energy	**106.9**	**114.7**	**--**	**92.0**	**93.4**	**--**
Excluding losses[b] and feedstocks	**103.3**	**--**	**112.7**	**--**	**--**	**--**

-- = not reported.

[a]IEA data are for 2009.

[b]Losses in CTL and biofuel production.

[c]Energy consumption in the sectors includes electricity demand purchases from the electric power sector, which are subtracted to avoid double counting in deriving total primary energy consumption.

Table 25. Comparison of electricity projections, 2015, 2025, and 2035 (billion kilowatthours, except where noted)

Projection	2010	AEO2012 Reference case	Other projections: EVA	IHSGI	INFORUM
			2015		
Average end-use price (2010 cents per kilowatthour)[a]	9.8	9.7	--	10.2	--
Residential	11.5	11.8	12.8	12.0	10.5
Commercial	10.1	9.9	11.5	10.7	9.3
Industrial	6.7	6.5	7.9	7.0	6.2
Total generation plus imports	**4,152**	**4,181**	**4,053**	**4,611**	**--**
Coal	1,851	1,581	1,591	1,905	--
Petroleum	37	28	--	45	--
Natural gas[b]	982	1,130	1,090	1,223	--
Nuclear	807	830	827	839	--
Hydroelectric/other[c]	449	583	515	576	--
Net imports	26	29	29	24	--
Electricity sales	3,749	3,753	3,921	4,173	3,854
Residential	1,451	1,392	1,481	1,563	1,365
Commercial/other[d]	1,336	1,354	1,414	1,489	1,438
Industrial	962	1,008	1,025	1,121	1,051
Capacity, including CHP (gigawatts)[e]	1,036	1,042	1,094	1,101	--
Coal	318	286	289	309	--
Oil and natural gas	459	464	514	491	--
Nuclear	101	104	106	104	--
Hydroelectric/other[f]	158	188	185	197	--
			2025		
Average end-use price (2010 cents per kilowatthour)[a]	9.8	9.7	--	10.9	--
Residential	11.5	11.6	13.2	12.8	10.5
Commercial	10.1	9.9	11.7	11.4	9.3
Industrial	6.7	6.7	8.0	7.4	6.2
Total generation plus imports	**4,152**	**4,578**	**4,514**	**5,417**	**--**
Coal	1,851	1,786	1,653	1,774	--
Petroleum	37	29	--	45	--
Natural gas[b]	982	1,140	1,335	1,760	--
Nuclear	807	917	870	918	--
Hydroelectric/other[c]	449	683	629	896	--
Net imports	26	22	27	25	--
Electricity sales	3,749	4,090	4,298	4,942	4,167
Residential	1,451	1,533	1,650	1,887	1,468
Commercial/other[d]	1,336	1,525	1,679	1,793	1,660
Industrial	962	1,032	969	1,261	1,039
Capacity, including CHP (gigawatts)[e]	1,036	1,091	1,119	1,274	--
Coal	318	282	267	283	--
Oil and natural gas	459	493	518	566	--
Nuclear	101	115	110	114	--
Hydroelectric/other[f]	158	201	224	312	--

-- = not reported.
See notes at end of table.

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Only IHSGI and the *AEO2012* Reference case provide average electricity price projections through 2035. Average electricity prices in the *AEO2012* Reference case are 9.8 cents per kilowatthour in 2010 and 9.7 cents per kilowatthour in 2015 and 2025 before reaching 10.1 cents per kilowatthour in 2035. In the IHSGI projection, the average electricity price rises continuously (with the exception of a small decrease from 2017 to 2018), from 9.8 cents per kilowatthour in 2010 to 10.2 cents in 2015, 10.9 cents in 2025, and 12.1 cents per kilowatthour in 2035.

In all the projections, average electricity prices by sector follow patterns similar to changes in the weighted average electricity price across all sectors (including transportation services). The lowest prices by sector in 2015 are in the INFORUM projection (10.5 cents per kilowatthour in the residential sector, 9.3 cents per kilowatthour in the commercial sector, and 6.2 cents per kilowatthour in the industrial sector). The highest average electricity prices by sector in 2015 are in the EVA projection (12.8 cents per kilowatthour in the residential sector, 11.5 cents per kilowatthour in the commercial sector, and 7.9 cents per kilowatthour in the industrial sector).

In the *AEO2012* Reference case, electricity prices for the residential sector are 11.8 cents per kilowatthour in both 2015 and 2035, electricity prices for the commercial sector increase from 9.9 cents per kilowatthour in 2015 to 10.1 cents per kilowatthour in 2035, and electricity prices for the industrial sector increase from 6.5 cents per kilowatthour in 2015 to 7.1 cents per kilowatthour in 2035. When compared with the *AEO2012* Reference case prices in 2035, the largest difference is with the IHSGI projection. The IHSGI price projections are much higher than those in the *AEO2012* Reference case. IHSGI shows real electricity prices rising to 14.3 cents per kilowatthour for the residential sector, 12.5 cents per kilowatthour for the commercial sector, and 8.1 cents per kilowatthour for the industrial sector in 2035.

Table 25. Comparison of electricity projections, 2015, 2025, and 2035 (billion kilowatthours, except where noted) (continued)

			Other projections		
Projection	2010	*AEO2012* Reference case	EVA	IHSGI	INFORUM
			2035		
Average end-use price (2010 cents per kilowatthour)[a]	9.8	10.1	--	12.1	--
Residential	11.5	11.8	12.9	14.3	10.5
Commercial	10.1	10.1	11.3	12.5	9.3
Industrial	6.7	7.1	7.6	8.1	6.2
Total generation plus imports	**4,152**	**5,004**	**--**	**6,199**	**--**
Coal	1,851	1,897	--	1,618	--
Petroleum	37	30	--	45	--
Natural gas[b]	982	1,398	--	2,354	--
Nuclear	807	887	--	1,030	--
Hydroelectric/other[c]	449	780	--	1,124	--
Net imports	26	12	--	28	--
Electricity sales	3,749	4,415	4,726	5,652	4,483
Residential	1,451	1,718	1,778	2,178	1,611
Commercial/other[d]	1,336	1,721	2,008	2,088	1,904
Industrial	962	977	941	1,387	968
Capacity, including CHP (gigawatts)[e]	1,036	1,190	--	1,450	--
Coal	318	285	--	262	--
Oil and natural gas	459	568	--	665	--
Nuclear	101	111	--	128	--
Hydroelectric/other[f]	158	226	--	396	--

-- = not reported.

[a]Average end-use price includes the transportation sector.

[b]Includes supplemental gaseous fuels. For EVA, represents total oil and natural gas.

[c]"Other" includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, solar and wind power, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, petroleum coke, and miscellaneous technologies.

[d]"Other" includes sales of electricity to government and other transportation services.

[e]EIA capacity is net summer capacity, including CHP plants.

[f]"Other" includes conventional hydro, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, wind power, pumped storage, and fuel cells.

Total electricity generation plus imports in 2015 ranges from a low of 4,053 billion kilowatthours in the EVA projection to a high of 4,611 billion kilowatthours in the IHSGI projection, compared with 4,181 billion kilowatthours in the *AEO2012* Reference case. Although coal represents the largest share of generation in 2015 in all the projections, the natural gas share of total generation grows from 2015 to 2035 in all the projections, particularly IHSGI. In the IHSGI projection, coal has a 33-percent share of total generation in 2025, and the natural gas share is 32 percent. IHSGI shows natural gas overtaking coal as a share of total generation by 2035 as a result of the carbon tax assumed in the IHSGI projection and the need to replace existing units that are uneconomical or are being retired for various regulatory or environmental reasons. In 2035, the coal share in the IHSGI projection is 26 percent of total generation, and the natural gas share is 38 percent. In the *AEO2012* Reference case, which does not include a carbon tax, the coal share also decreases but only to 38 percent of total generation, while the natural gas share increases to 28 percent.

Nuclear generation in 2015 ranges from a low of 827 billion kilowatthours in the EVA projection to a high of 839 billion kilowatthours in the IHSGI projection. From 2015 to 2025, EVA projects a 5-percent increase in nuclear generation, to 870 billion kilowatthours. IHSGI and *AEO2012* project increases of 9 percent and 10 percent, respectively. In the IHSGI projection, nuclear generation totals 1,030 billion kilowatthours in 2035, a 12-percent increase from 2025. The *AEO2012* Reference case shows nuclear generation declining to 887 billion kilowatthours in 2035, a 3-percent decrease from 2025, as units are retired when they reach the end of their useful generation lifetimes.

Total generating capacity by fuel in 2015 is relatively similar across the projections, ranging from 1,042 gigawatts in the *AEO2012* Reference case to 1,101 gigawatts in the IHSGI projection, but IHSGI shows a much larger decrease in capacity in 2025. IHSGI projects more aggressive growth in total generating capacity, due to what appears to be a much higher demand projection. Natural gas and oil-fired capacity grows to 566 gigawatts in 2025 in the IHSGI projection, compared with 493 gigawatts in *AEO2012* and 518 gigawatts in the EVA projections. Hydroelectric/other capacity grows to 312 gigawatts in 2025 in the IHSGI projection, higher than the 201 gigawatts in *AEO2012*. The faster growth in natural gas and hydroelectric/other capacity in the IHSGI projection continues through 2035. Natural gas and oil-fired capacity grows to 665 gigawatts in 2035, and hydroelectric/other capacity grows to 396 gigawatts in 2035 in the IHSGI projection. By comparison, natural gas and oil-fired capacity grows to 568 gigawatts and hydroelectric/other capacity grows to 226 gigawatts in the *AEO2012* Reference case in 2035.

5. Natural gas

The projections of natural gas consumption, production, imports, and prices (Table 26) vary significantly as a result of differences in assumptions. For example, the *AEO2012* Reference case assumes that current laws and regulations remain unchanged throughout the projection period (including the implication that laws which include sunset dates do, in fact, become ineffective at the time of those sunset dates), whereas the other projections may include anticipated policy developments over the next 25 years. In particular, the *AEO2012* Reference case does not assume changes in CO_2 emissions policies.

Each of the projections shows an increase in overall natural gas consumption from 2010 to 2035, with the IHSGI projection showing the largest increase, 39 percent. The ExxonMobil projection includes an increase of around 20 percent. The EVA projection shows an increase of 26 percent from 2010 to 2030 (EVA does not extend to 2035). Total natural gas consumption in the *AEO2012*, Deloitte, and SEER projections increases from 2010 to 2035, with total natural gas consumption growing from 4 to 31 percent. IHSGI shows the largest increase and INFORUM the smallest. The IHSGI projection for total natural gas consumption in 2035 is 36 percent higher than the INFORUM projection. In the *AEO2012* Reference case, total natural gas consumption grows by 5 percent from 2015 to 2035.

The IHSGI and ExxonMobil projections for natural gas consumption by electricity generators are much higher than the other projections shown in Table 26. In 2035, natural gas consumption by electricity generators in the IHGSI projection is more than double the consumption projected by INFORUM, and the ExxonMobil projection is 77 percent higher than the INFORUM projection. The *AEO2012* Reference case, SEER, and INFORUM projections show similar levels of natural gas consumption in the electricity generation sector in 2035, with average annual growth of 1 percent or less across the projection period, while consumption grows by an average of 3 percent in the ExxonMobil and IHSGI projections. The slower rate of growth in the *AEO2012* Reference case reflects relatively slower growth in electricity consumption and faster growth in renewable energy consumption than in the other projections.

Industrial natural gas consumption is similar across the projections, but with more rapid growth projected by EVA, Deloitte, and INFORUM. Natural gas consumption increases by 23 percent from 2010 to 2030 in the EVA projection and by 23 percent and 11 percent, respectively, from 2010 to 2035 in the INFORUM and Deloitte projections. All of the growth in industrial natural gas consumption in the Deloitte and INFORUM projections is between 2010 and 2015. In the *AEO2012* Reference case, in contrast, industrial natural gas consumption grows by 6 percent from 2010 to 2035. In the ExxonMobil projection, industrial natural gas consumption remains constant over the projection period; in the IHSGI projection industrial natural gas consumption falls from 2010 to 2035; and in the INFORUM, SEER, and Deloitte projections, after an initial increase, industrial natural gas consumption declines from 2015 to 2035.

The levels of commercial sector natural gas consumption are similar across the projections, but projections for the residential sector vary significantly [*140*]. Three of the seven projections (INFORUM, Deloitte, and EVA) show similar growth in residential consumption through 2030, and INFORUM and Deloitte are similar through 2035; however, the IHSGI and *AEO2012* projections show larger declines in residential consumption of natural gas from 2010 to 2035 (11 percent and 6 percent, respectively). The SEER projection for residential natural gas consumption shows a decrease of 4 percent from 2015 to 2025, then a partial recovery by 2035.

Table 26. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted)

Projection	2010	*AEO2012* Reference case	Other projections: IHSGI	EVA	Deloitte	SEER	ExxonMobil	INFORUM
					2015			
Dry gas production[a]	21.58	23.65	23.81	23.80	24.52	23.66	24.00	24.29
Net imports	**2.58**	**1.73**	**1.62**	**2.20**	**1.30**	**1.73**	**1.20**	**--**
Pipeline	2.21	1.56	--	1.80	1.22	1.56	--	--
LNG	0.37	0.16	--	0.40	0.08	0.16	--	--
Consumption	**24.13**	**25.39**	**25.52**	**26.60**	**24.07[b]**	**26.05**	**25.00[c]**	**23.61[b]**
Residential	4.94	4.85	4.64	4.90	4.86	4.91	8.00[d]	4.87
Commercial	3.20	3.33	3.10	3.20	3.23	3.41	--	3.43
Industrial[e]	6.60	7.01	6.64	7.00	7.51	7.64	8.00	8.19
Electricity generators[f]	7.38	8.08	9.02	9.30	8.46	8.06	9.00	7.12
Others[g]	2.01	2.12	2.11	2.20	--	2.04	--	--
Henry Hub spot market price (2010 dollars per million Btu)	4.39	4.29	4.75	4.07	4.25	4.28	--	--
End-use prices (2010 dollars per thousand cubic feet)								
Residential	11.36	10.56	11.82	--	--	11.68	--	--
Commercial	9.32	8.82	9.88	--	--	8.31	--	--
Industrial[h]	5.65	5.00	6.95	--	--	4.63	--	--
Electricity generators	5.25	4.65	5.20	--	--	5.17	--	--
					2025			
Dry gas production[a]	21.58	26.28	27.23	26.70	27.32	25.88	27.00	27.57
Net imports	**2.58**	**-0.79**	**2.13**	**1.30**	**0.38**	**0.29**	**1.50**	**--**
Pipeline	2.21	-0.13	--	0.90	0.29	1.03	--	--
LNG	0.37	-0.66	--	0.40	0.09	-0.74	--	--
Consumption	**24.13**	**25.53**	**29.39**	**29.00**	**26.36[b]**	**27.10**	**29.00[c]**	**23.43[b]**
Residential	4.94	4.76	4.53	5.00	5.05	4.71	8.00[d]	4.90
Commercial	3.20	3.44	3.15	3.30	3.46	3.53	--	3.60
Industrial[e]	6.60	7.14	6.52	7.70	7.58	7.47	8.00	8.20
Electricity generators[f]	7.38	7.87	12.78	10.50	10.27	9.27	13.00	6.74
Others[g]	2.01	2.31	2.42	2.50	--	2.12	--	--
Henry Hub spot market price (2010 dollars per million Btu)	4.39	5.63	4.82	6.47	5.80	6.29	--	--
End-use prices (2010 dollars per thousand cubic feet)								
Residential	11.36	12.33	11.70	--	--	14.40	--	--
Commercial	9.32	10.27	9.81	--	--	10.68	--	--
Industrial[h]	5.65	6.19	6.99	--	--	6.96	--	--
Electricity generators	5.25	5.73	5.28	--	--	7.47	--	--

-- = not reported.
See notes at end of table.

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With the exception of ExxonMobil, which shows a decline in U.S. production of domestic natural gas between 2030 and 2035, all the projections show increasing U.S. production of domestic natural gas over the projection period, although at different rates. The highest level of natural gas production is projected by IHSGI, exceeding the ExxonMobil projection by 21 percent in 2035. Coupled with a significant decline in net pipeline imports, SEER, INFORUM, and the *AEO2012* Reference case project a strong increase in the share of total U.S. natural gas supply accounted for by domestic production. The other projections show relatively stable and similar percentages for the contribution of domestic natural gas production to total supply, with the exception of IHSGI, which shows a notable increase in net imports after 2015. In all the projections, with the exception of EVA, net LNG imports remain below the 2010 level of 0.4 trillion cubic feet throughout the projection period. In all the projections, however, net pipeline imports decline from 2010 levels, with *AEO2012*, SEER, and Deloitte projecting more severe declines than EVA (only through 2030 since EVA does not show 2035).

The *AEO2012* Reference case and SEER show similar levels of natural gas production and Henry Hub spot prices, both with increasing production and prices over time. EVA shows similar levels of natural gas production as the *AEO2012* Reference case through 2025, but higher Henry Hub spot prices. IHSGI projects a larger increase in natural gas production but at relatively stable prices. In 2015, the Henry Hub spot price in the IHSGI projection is 11 percent higher than the price in the SEER projection; however, the SEER Henry Hub spot price quickly surpasses the IHSGI price, and it is 50 percent higher in 2035. Deloitte, ExxonMobil, and INFORUM did not include price projections.

Only IHSGI and SEER included delivered natural gas prices that can be compared with those in the *AEO2012* Reference case [*141*]. However, there appear to be definitional differences in the projections, based on an examination of 2010 price levels. In particular,

Table 26. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted) (continued)

Projection	2010	*AEO2012* Reference case	Other projections: IHSGI	EVA	Deloitte	SEER	ExxonMobil	INFORUM
		2035						
Dry gas production[a]	21.58	27.93	31.35	--	27.87	27.00	26.00	30.71
Net imports	2.58	**-1.36**	**2.36**	**--**	**0.14**	**-0.46**	**2.50**	**--**
Pipeline	2.21	-0.70	--	--	0.07	0.28	--	--
LNG	**0.37**	-0.66	--	--	0.08	-0.74	--	--
Consumption	24.13	**26.63**	**33.54**	**--**	**27.30[b]**	**27.24**	**29.00[c]**	**24.66[b]**
Residential	4.94	4.64	4.38	--	5.03	4.80	7.00[d]	4.83
Commercial	3.20	3.60	3.18	--	3.60	3.64	--	3.83
Industrial[e]	6.60	7.00	6.35	--	7.31	7.30	8.00	8.09
Electricity generators[f]	7.38	8.96	16.90	--	11.37	9.37	14.00	7.90
Others[g]	2.01	2.43	2.72	--	--	2.13	--	--
Henry Hub spot market price (2010 dollars per million Btu)	4.39	7.37	5.13	7.26	6.63	7.70	--	--
End-use prices (2010 dollars per thousand cubic feet)								
Residential	11.36	14.33	11.81	--	--	17.15	--	--
Commercial	9.32	11.93	9.99	--	--	13.09	--	--
Industrial[h]	5.65	7.73	7.22	--	--	9.20	--	--
Electricity generators	5.25	7.37	5.62	--	--	9.75	--	--

-- = not reported.
[a]Does not include supplemental fuels.
[b]Does not includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[c]Does not includes lease, plant, and pipeline fuel.
[d]Natural gas consumed in the residential and commercial sectors.
[e]Includes consumption for industrial combined heat and power (CHP) plants and a small number of industrial electricity-only plants, and natural gas-to-liquids heat/power production; excludes consumption by nonutility generators.
[f]Includes consumption of energy by electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators.
[g]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[h]The 2010 industrial natural gas price for IHSGI is $6.53.

the IHSGI industrial delivered natural gas price is difficult to compare. The industrial delivered natural gas price for 2010 in the IHSGI projection is $0.88 higher than the industrial price for 2010 in the *AEO2012* Reference case and $1.13 higher than the 2010 industrial price in the SEER projection (all prices in 2010 dollars per thousand cubic feet). From 2010 to 2035, the delivered price for electricity generators increases by 7 percent in the IHSGI projection, by 40 percent in the *AEO2012* Reference case, and by 86 percent in the SEER projection. The SEER projection also shows the largest increases in residential and commercial delivered prices, at 51 percent and 40 percent, respectively, over the same period. IHSGI shows the smallest increases in residential and commercial delivered prices over the projection period, at 4 percent and 7 percent, respectively. The *AEO2012* Reference case projects a 26-percent increase in residential delivered natural gas prices and a 28-percent increase in commercial prices.

6. Liquid fuels

In the *AEO2012* Reference case, the U.S. RAC for imported crude oil (in 2010 dollars) increases to $113.97 per barrel in 2015, $121.21 per barrel in 2025, and $132.95 per barrel in 2035 (Table 27). Prices are lower in the INFORUM projection, ranging from $91.78 per barrel in 2015 to $116.76 per barrel in 2035. BP, EVA, and Purvin & Gertz (P&G) did not report projections of RAC prices.

Domestic crude oil production increases from about 5.5 million barrels per day in 2010 to a peak of 6.7 million barrels per day in 2020, then declines to about 6.0 million barrels per day in 2035 in the *AEO2012* Reference case. Overall, the production level in 2035 is more than 9 percent higher than the 2010 level. The INFORUM projection shows a steady increase in production, to 5.8 million barrels per day in 2035. Domestic crude oil production decreases to 3.2 million barrels per day in 2035 in the P&G projection.

Supply from renewable sources increases to about 1.1 million barrels per day in 2015, almost 1.5 million barrels per day in 2025 (38.5 percent higher than the 2015 level), and more than 2.3 million barrels per day in 2035 (120.2 percent higher than the 2015 level) in the *AEO2012* Reference case. In the BP projection, supplies from renewable sources, on an energy-equivalent basis, increase by 49.5 percent from 2015 to 2025. BP does not report supplies from renewable sources in 2035, and it is not included in the projections by EVA, INFORUM, and P&G.

Prices for both transportation diesel fuel and gasoline increase through 2035 in the *AEO2012* projection, with diesel prices higher than gasoline prices. INFORUM projects rising gasoline prices from 2015 levels but decreasing diesel prices, with the gasoline price consistently higher than the diesel price. The BP, EVA, and P&G projections do not include delivered fuel prices.

7. Coal

Projections from EVA, IHSGI, INFORUM, IEA, ExxonMobil, and BP offer some opportunity to compare other coal outlooks with the *AEO2012* Reference case. Although many of the assumptions used in the other projections are unknown, ExxonMobil does assume a carbon tax, and EVA assumes some additional regulations affecting coal use that are not included in current laws. Such assumptions

Table 27. Comparison of liquids projections, 2015, 2025, and 2035 (million barrels per day, except where noted)

Projection	2010	*AEO2012* Reference case	Other projections BP[a]	EVA	INFORUM	P&G
		2015				
Average U.S. imported RAC (2010 dollars per barrel)	75.87	113.97	--	--	91.78	--
Average WTI price (2010 dollars per barrel)	79.39	116.91	--	82.24	--	98.75
Domestic production	**7.55**	**8.71**	**8.56**	**9.60**	**--**	**7.92**
Crude oil	5.47	6.15	--	6.90	5.43	5.43
Alaska	0.60	0.46	--	0.40	--	0.54
NGL	2.07	2.56	--	2.70	--	2.49
Total net imports	**9.56**	**8.27**	**8.20**	**--**	**9.81**	**--**
Crude oil	9.17	8.52	--	--	8.59	9.69
Products	0.39	-0.25	--	--	1.22	--
Liquids consumption	19.17	19.10	18.26	--	20.04[b]	17.69
Net petroleum import share of liquids supplied (percent)	50	43	45	--	--	--
Supply from renewable sources	0.90	1.05	1.24	--	--	--
Transportation product prices (2010 dollars per gallon)						
Gasoline	2.76	3.54	--	--	3.85	--
Diesel	3.00	3.78	--	--	3.60	--

-- = not reported.
See notes at end of table.

(continued on next page)

probably contribute to lower coal consumption levels compared with historical levels and the *AEO2012* Reference case. BP, EVA, ExxonMobil, and IHSGI have the most pessimistic views of coal use, with consumption declining over their respective projection horizons. In contrast, both the *AEO2012* and INFORUM projections show rising coal consumption after an initial decline. INFORUM's projection for coal consumption in 2035 is the highest—12 percent higher than in the *AEO2012* Reference case (Table 28).

Because most coal consumed in the United States is used for electricity generation, the outlooks with the largest declines in total coal consumption also show similar declines in coal use for electric power generation. The *AEO2012* Reference case has the most pessimistic outlook for coal consumption in the power sector in 2015; however, while coal use in the electric power sector recovers after 2015 in the *AEO2012* Reference case, it continues to decline in the EVA, IHSGI, ExxonMobil, and BP projections. ExxonMobil—which includes a carbon tax—shows the largest decline in coal use for electricity generation compared with the other projections,

Table 27. Comparison of liquids projections, 2015, 2025, and 2035 (million barrels per day, except where noted) (continued)

Projection	2010	*AEO2012* Reference case	Other projections: BP[a]	EVA	INFORUM	P&G
		2025				
Average U.S. imported RAC (2010 dollars per barrel)	75.87	121.21	--	--	113.35	--
Average WTI price (2010 dollars per barrel)	79.39	132.56	--	89.07	--	106.47
Domestic production	**7.55**	**9.41**	**9.20**	**11.10**	**--**	**7.37**
Crude oil	5.47	6.40	--	7.10	5.74	4.26
Alaska	0.60	0.40	--	0.00	--	0.45
NGL	2.07	3.01	--	4.00	--	3.11
Total net imports	**9.56**	**7.12**	**5.87**	**--**	**9.89**	**--**
Crude oil	9.17	7.24	--	--	8.31	10.71
Products	0.39	-0.12	--	--	1.58	--
Liquids consumption	19.17	19.20	17.30	--	20.38[b]	17.39
Net petroleum import share of liquids supplied (percent)	50	37	34	--	--	--
Supply from renewable sources	0.90	1.45	1.85	--	--	--
Transportation product prices (2010 dollars per gallon)						
Gasoline	2.76	3.85	--	--	4.36	--
Diesel	3.00	4.17	--	--	3.46	--
		2035				
Average U.S. imported RAC (2010 dollars per barrel)	75.87	132.95	--	--	116.76	--
Average WTI price (2010 dollars per barrel)	79.39	144.98	--	102.11	--	107.37
Domestic production	**7.55**	**9.00**	**--**	**--**	**--**	**--**
Crude oil	5.47	5.99	--	--	5.80	3.23
Alaska	0.60	0.27	--	--	--	0.41
NGL	2.07	3.01	--	--	--	--
Total net imports	**9.56**	**7.18**	**--**	**--**	**10.36**	**--**
Crude oil	9.17	7.52	--	--	8.49	11.68
Products	0.39	-0.34	--	--	1.88	--
Liquids consumption	19.17	19.90	--	--	21.31[b]	17.38
Net petroleum import share of liquids supplied (percent)	50	36	--	--	--	--
Supply from renewable sources	0.90	2.31	--	--	--	--
Transportation product prices (2010 dollars per gallon)						
Gasoline	2.76	4.03	--	--	4.49	--
Diesel	3.00	4.44	--	--	3.30	--

-- = not reported.

[a]For BP, liquids production data were converted from million metric tons to barrels at 8.067817 barrels per metric ton, and liquids demand data were converted at 8.162674 barrels per metric ton. One metric ton equals 1,000 kilograms.

[b]For INFORUM, liquids demand data were converted from quadrillion Btus to barrels at 187.84572 million barrels per quadrillion Btu.

and coal consumption in the BP outlook also declines from 2010 levels. The EVA projection for coal consumption in the electric power sector in 2030 is 13 percent lower than the 2010 level, whereas coal consumption returns to 2010 levels in 2030 in the *AEO2012* Reference case. The IEA projection for coal consumption in the electric power sector in 2035, at 19.2 quadrillion Btu, is similar to the *AEO2012* Reference case projection.

EVA, IHSGI, and the *AEO2012* Reference case all project declining use of coal at coking plants through 2030, with EVA including the most pessimistic outlook. INFORUM's industrial coal consumption figure, which appears to include both coking coal consumption

Table 28. Comparison of coal projections, 2015, 2025, 2030, and 2035 (million short tons, except where noted)

		AEO2012 Reference case		Other projections					
				EVA[a]	IHSGI	INFORUM	IEA[b]	Exxon-Mobil[c]	BP[b]
Projection	2010	(million short tons)	(quadrillion Btu)	(million short tons)			(quadrillion Btu)		
					2015				
Production	**1,084**	**993**	**20.24**	**1,017**	**1,144**	**970**	**--**	**--**	**22.00**
East of the Mississippi	446	407	--	411	--	--	--	--	--
West of the Mississippi	638	586	--	606	--	--	--	--	--
Consumption									
Electric power	975	839	16.15	871	1,002	--	--	17.00	18.68
Coke plants	21	22	--	20	21	--	--	--	--
Coal-to-liquids	0	0	--	--	--	--	--	--	--
Other industrial/buildings	55	53	1.66[d]	42	50	1.81[d]	--	--	--
Total consumption (quadrillion Btu)[e]	**20.76**	**--**	**17.80**	**--**	**--**	**--**	**--**	**19.00**	**20.53**
Total consumption (million short tons)	**1,051**	**914**	**--**	**933**	**1,073**	**916[f]**	**--**	**--**	**--**
Net coal exports	**64**	**95**	**2.38**	**100**	**70**	**54**	**--**	**--**	**1.48**
Exports	82	110	2.73	104	89	70	--	--	1.48
Imports	18	15	0.35	4	19	16	--	--	0.00[g]
Minemouth price									
2010 dollars per ton	35.61	42.08	--	--	--	32.80	--	--	--
2010 dollars per Btu	1.76	2.08	--	--	--	--	--	--	--
Average delivered price to electricity generators									
2010 dollars per ton	44.27	45.17	--	--	--	42.72	--	--	--
2010 dollars per Btu	2.26	2.35	--	--	2.39	--	--	--	--
					2025				
Production	**1,084**	**1,118**	**22.25**	**995**	**1,038**	**1,114**	**--**	**--**	**19.40**
East of the Mississippi	446	383	--	403	--	--	--	--	--
West of the Mississippi	638	735	--	592	--	--	--	--	--
Consumption									
Electric power	975	952	18.06	847	927	--	--	15.00	16.16
Coke plants	21	19	--	17	19	--	--	--	--
Coal-to-liquids	0	38	--	--	--	--	--	--	--
Other industrial/buildings	55	55	1.63[d]	33	39	2.07[d]	--	--	--
Total consumption (quadrillion Btu)[e]	**20.76**	**--**	**20.02**	**--**	**--**	**--**	**--**	**15.00**	**17.70**
Total consumption (million short tons)	**1,051**	**1,063**	**--**	**897**	**986**	**1,072[f]**	**--**	**--**	**--**
Net coal exports	**64**	**71**	**1.79**	**113**	**53**	**42**	**--**	**--**	**1.70**
Exports	82	115	2.82	118	73	75	--	--	1.70
Imports	18	44	1.03	4	20	33	--	--	0.00[g]
Minemouth price									
2010 dollars per ton	35.61	44.05	--	--	--	33.43	--	--	--
2010 dollars per Btu	1.76	2.23	--	--	--	--	--	--	--
Average delivered price to electricity generators									
2010 dollars per ton	44.27	48.13	--	--	--	43.58	--	--	--
2010 dollars per Btu	2.26	2.54	--	--	2.48	--	--	--	--

-- = not reported.
See notes at end of table.

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Table 28. Comparison of coal projections, 2015, 2025, 2030, and 2035 (million short tons, except where noted) (continued)

Projection	2010	*AEO2012* Reference case (million short tons)	*AEO2012* Reference case (quadrillion Btu)	Other projections: EVA[a] (million short tons)	IHSGI (million short tons)	INFORUM (million short tons)	IEA[b] (quadrillion Btu)	Exxon-Mobil[c] (quadrillion Btu)	BP[b] (quadrillion Btu)
2030									
Production	**1,084**	**1,166**	**23.22**	**992**	**984**	**1,177**	**--**	**--**	**17.99**
East of the Mississippi	446	409	--	396	--	--	--	--	--
West of the Mississippi	638	757	--	596	--	--	--	--	--
Consumption									
Electric power	975	975	18.55	847	885	--	19.2	13.00	14.76
Coke plants	21	18	--	16	19	--	--	--	--
Coal-to-liquids	0	51	--	--	--	--	--	--	--
Other industrial/buildings	55	55	1.60[d]	31	35	2.37[d]	1.1[b]	--	--
Total consumption (quadrillion Btu)[e]	**20.76**	**--**	**20.59**	**--**	**--**	**--**	**--**	**13.00**	**16.18**
Total consumption (million short tons)	**1,051**	**1,099**	**--**	**894**	**938**	**1,156[f]**	**--**	**--**	**--**
Net coal exports	**64**	**83**	**2.08**	**113**	**47**	**41**	**--**	**--**	**1.81**
Exports	82	117	2.85	118	68	74	--	--	1.81
Imports	18	33	0.77	5	20	53	--	--	0.00[g]
Minemouth price									
2010 dollars per ton	35.61	47.28	--	--	--	33.21	--	--	--
2010 dollars per Btu	1.76	2.39	--	--	--	--	--	--	--
Average delivered price to electricity generators									
2010 dollars per ton	44.27	50.56	--	--	--	43.31	--	--	--
2010 dollars per Btu	2.26	2.66	--	--	2.52	--	--	--	--
2035									
Production	**1,084**	**1,212**	**24.14**	**--**	**926**	**1,284**	**--**	**--**	**--**
East of the Mississippi	446	431	--	--	--	--	--	--	--
West of the Mississippi	638	781	--	--	--	--	--	--	--
Consumption									
Electric power	975	998	19.03	--	837	--	19.2	11.00	--
Coke plants	21	17	--	--	18	--	--	--	--
Coal-to-liquids	0	67	--	--	--	--	--	--	--
Other industrial/buildings	55	56	1.58[d]	--	31	2.70[d]	1.1	--	--
Total consumption (quadrillion Btu)[e]	**20.76**	**--**	**21.15**	**--**	**--**	**--**	**--**	**11.00**	**--**
Total consumption (million short tons)	**1,051**	**1,137**	**--**	**--**	**886**	**1,277[f]**	**--**	**--**	**--**
Net coal exports	**64**	**94**	**2.31**	**--**	**42**	**8**	**--**	**--**	**--**
Exports	82	129	3.13	--	63	71	--	--	--
Imports	18	36	0.82	--	20	64	--	--	--
Minemouth price									
2010 dollars per ton	35.61	50.52	--	--	--	33.06	--	--	--
2010 dollars per Btu	1.76	2.56	--	--	--	--	--	--	--
Average delivered price to electricity generators									
2010 dollars per ton	44.27	53.31	--	--	--	43.13	--	--	--
2010 dollars per Btu	2.26	2.80	--	--	2.54	--	--	--	--

-- = not reported.

[a]Regulations known to be accounted for in the EVA projections include MATS, CSAPR, regulations for cooling-water intake structures under Section 316(b) of the Clean Water Act, and regulations for coal combustion residuals under authority of the Resource Conservation and Recovery Act.

[b]For IEA and BP, data were converted from millions of tons oil equivalent (toe) at 39.683 million Btu per toe.

[c]ExxonMobil projections include a carbon tax.

[d]Coal consumption in quadrillion Btu. INFORUM's value appears to include coal consumption at coke plants. To facilitate comparison the *AEO2012* value also includes coal consumption at coke plants.

[e]For *AEO2012*, excludes coal converted to coal-based synthetic liquids.

[f]Calculated as consumption = (production - exports + imports).

[g]Calculated as imports = (consumption – production + exports).

and coal use at industrial steam plants, is higher than projected in the *AEO2012* Reference case. EVA and IHSGI show declines in coal use in the industrial/buildings sector (excluding the coking sector), whereas the *AEO2012* outlook is more stable. According to ExxonMobil's projection, coal is consumed only for electricity generation after 2015, as implied consumption in all other sectors drops to zero. The *AEO2012* Reference case appears to be the only projection that includes coal use in CTL production.

Only EVA provides regional production information for comparison with the *AEO2012* Reference case. Despite much lower total coal consumption than in *AEO2012*, EVA's estimate of coal production east of the Mississippi is similar to that in the *AEO2012* Reference case. The differences in coal production are primarily in basins west of the Mississippi, where *AEO2012* projects 161 million more tons of coal production in 2030 than projected by EVA.

With respect to exports, two broad consensus groups are identifiable among the projections. The most optimistic projections are EVA and *AEO2012*, which show exports remaining above 100 million tons through 2030. However, EVA and *AEO2012* do differ, in that the *AEO2012* Reference case projects stronger growth for coking coal exports, and EVA projects stronger growth for thermal coal exports. The second group of projections, including BP, INFORUM, and IHSGI, shows a less optimistic outlook for U.S. coal exports. Coal exports in 2030 in the *AEO2012* Reference case are 1.0 quadrillion Btu higher than projected by BP. If BP's average heat rate for exports is assumed to be similar to that in *AEO2012*, BP's projected coal exports in 2030 are about 70 million tons, similar to the INFORUM and IHSGI projections for the same year. IHSGI's projection of exports is the lowest of this group, peaking in 2025 and then falling to 63 million tons in 2035.

The outlook for coal imports varies considerably across the projections, with little consensus. In the EVA projection, imports drop to a negligible 4 million tons early on and remain at that level for the balance of the projection; and in the BP projection, there are no coal imports to the United States after 2015. In the IHSGI projection, coal imports vary little through 2035. In 2035, coal imports in the *AEO2012* Reference case are just over one-half those in the INFORUM outlook.

Coal price comparisons can be made only for the *AEO2012*, IHSGI, and INFORUM projections. *AEO2012* includes the highest minemouth coal prices, which rise by 42 percent from 2010 to 2035. IHSGI and the *AEO2012* Reference case do project similar delivered coal prices to the electricity sector through 2020, but after 2020 IHSGI's prices change little, whereas prices in the *AEO2012* Reference case continue to rise. The difference may indicate that IHSGI's more pessimistic coal consumption outlook has less to do with high coal prices than with other factors. Similarly, INFORUM's delivered coal price to the electricity sector falls and then remains constant at around 2015 levels through 2035, lower than the price in 2010.

Endnotes for Comparison with other projections

Links current as of June 2012

140. ExxonMobil's projection for residential consumption includes commercial consumption.
141. SEER's prices include a carbon tax.

List of acronyms

AB	Assembly Bill
AB32	California Assembly Bill 32
ACI	Activated carbon injection
AEO	*Annual Energy Outlook*
AEO2012	*Annual Energy Outlook 2012*
ANWR	Arctic National Wildlife Refuge
ARRA2009	American Recovery and Reinvestment Act of 2009
ASHRAE	American Society of Heating, Refrigerating, and Air-Conditioning Engineers
Blue Chip	Blue Chip Consensus
BTL	Biomass-to-liquids
Btu	British thermal unit
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CARB	California Air Resources Board
CBO	Congressional Budget Office
CBTL	Coal- and biomass-to-liquids
CCS	Carbon capture and storage
CHP	Combined heat and power
CI	Carbon intensity
CMM	Coal Market Module
CNG	Compressed natural gas
CO_2	Carbon dioxide
CO_2-EOR	Carbon dioxide-enhanced oil recovery
CSAPR	Cross-State Air Pollution Rule
CTL	Coal-to-liquids
DG	Distributed generation
dge	Diesel gallon equivalent
DOE	U.S. Department of Energy
DSI	Direct sorbent injection
E10	Motor gasoline blend containing up to 10 percent ethanol
E15	Motor gasoline blend containing up to 15 percent ethanol
E85	Motor fuel containing up to 85 percent ethanol
EERE	Energy Efficiency and Renewable Energy
EIA	U.S. Energy Information Administration
EIEA2008	Energy Improvement and Extension Act of 2008
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPACT05	Energy Policy Act of 2005
EUR	Estimated ultimate recovery
EV	Electric vehicle
EVA	Energy Ventures Analysis
FEMP	Federal Energy Management Program
FFV	Flex-fuel vehicle
FGD	Flue gas desulfurization
GDP	Gross domestic product
GHG	Greenhouse gas
GTL	Gas-to-liquids
GVWR	Gross vehicle weight rating
HAP	Hazardous air pollutant
HB	House Bill
HCl	Hydrogen chloride
HD	Heavy-duty
HDV	Heavy-duty vehicle
HEV	Hybrid electric vehicle
Hg	Mercury
ICE	Internal combustion engine
IDM	Industrial Demand Module
IEA	International Energy Agency
IECC2006	2006 International Energy Conversion Code
IEM	International Energy Module
IHSGI	IHS Global Insight
INFORUM	Interindustry Forecasting Project at the University of Maryland
IOU	Invester-owned utility
IREC	Interstate Renewable Energy Council
ITC	Investment tax credit
LCFS	Low Carbon Fuel Standard
LDV	Light-duty vehicle
LED	Light-emitting diode
LFMM	Liquid Fuels Market Module
LNG	Liquefied natural gas
MATS	Mercury and Air Toxics Standards
MAM	Macroeconomic Activity Module
mmt	Million metric tons
$MMTCO_2e$	Million metric tons carbon dioxide equivalent
mpg	Miles per gallon
MSRP	Manufacturer's suggested retail price
MY	Model year
NAICS	North American Industry Classification System
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NGL	Natural gas liquids
NGPL	Natural gas plant liquids
NGTDM	Natural Gas Transmission and Distribution Module
NGV	Natural gas vehicle
NHTSA	National Highway Traffic Safety Administration
NO_x	Nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
OECD	Organization for Economic Cooperation and Development
OMB	Office of Management and Budget
OPEC	Organization of the Petroleum Exporting Countries
P&G	Purvin & Gertz
PADD	Petroleum Administration for Defense District
PCs	Personal computers
PHEV	Plug-in hybrid electric vehicle
PM	Particulate matter
$PM_{2.5}$	Particulate matter less than 2.5 microns diameter
PMM	Petroleum Market Module
PTC	Production tax credit
PV	Solar photovoltaic
RAC	U.S. Refiner Acquisition Cost
RECS	Residential Energy Consumption Survey
RFM	Renewable Fuels Module
RFS	Renewable fuel standard
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable portfolio standard
SB	Senate Bill
SCR	Selective catalytic reduction
SEER	Strategic Energy and Economic Research, Inc.
SEIA	Solar Energy Industries Association
SNCR	Selective noncatalytic reduction
SO_2	Sulfur dioxide
STEO	Short-Term Energy Outlook
TAPS	Trans-Alaska Pipeline System
TRR	Technically recoverable resource
UEC	Unit energy consumption
UPS	Uninterruptible power supply
USGS	United States Geological Survey
VIUS	Vehicle Inventory and Use Survey
VMT	Vehicle miles traveled
WTI	West Texas Intermediate

Notes and sources

Table notes and sources

Table 1. HD National Program vehicle regulatory categories: U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles: Final Rule," *Federal Register*, Vol. 76, No. 179 (Washington, DC: September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.

Table 2. HD National Program standards for combination tractor greenhouse gas emissions and fuel consumption: U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, *Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles*, 49 CFR Parts 523, 534, and 535, RIN 2060-AP61; 2127-AK74, Federal Register Notice Vol. 76, No. 179, Thursday, September 15, 2011.

Table 3. HD National Program standards for vocational vehicle greenhouse gas emissions and fuel consumption: U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, *Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles*, 49 CFR Parts 523, 534, and 535, RIN 2060-AP61; 2127-AK74, Federal Register Notice Vol. 76, No. 179, Thursday, September 15, 2011.

Table 4. Renewable portfolio standards in the 30 States with current mandates: U.S. Energy Information Administration, Office of Energy Analysis. Based on a review of enabling legislation and regulatory actions from the various States of policies identified by the Database of States Incentives for Renewable Energy as of January 1, 2012, website www.dsireuse.org.

Table 5. Key analyses of interest from "Issues in focus" in recent *AEO*s: U.S. Energy Information Administration, *Annual Energy Outlook 2011*, DOE/EIA-0383(2011) (Washington, DC, April 2011); U.S. Energy Information Administration, *Annual Energy Outlook 2010*, DOE/EIA-0383(2010) (Washington, DC, April 2010); and U.S. Energy Information Administration, *Annual Energy Outlook 2009*, DOE/EIA-0383(2009) (Washington, DC, March 2009).

Table 6. Key assumptions for the residential sector in the *AEO2012* Integrated Demand Technology case: Projections: AEO2012 National Energy Modeling System, runs FROZTECH.D030812A, HIGHTECH.D032812A, and BESTTECH.D032812A.

Table 7. Key assumptions for the commercial sector in the *AEO2012* Integrated Demand Technology case: Projections: AEO2012 National Energy Modeling System, runs FROZTECH.D030812A, HIGHTECH.D032812A, and BESTTECH.D032812A.

Table 8. Estimated average fuel economy and greenhouse gas emissions standards proposed for light-duty vehicles, model years 2017-2025: U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards: Proposed Rule," *Federal Register*, Vol. 76, No. 231 (Washington, DC: December 1, 2011), website www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/2017-25_CAFE_NPRM.pdf.

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Figure 118. Coal production by region, 1970-2035: History (short tons): 1970-1990: U.S. Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 2002). **1991-2000:** U.S. Energy Information Administration, *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2010:** U.S. Energy Information Administration, *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011), and previous issues. **History (conversion to quadrillion Btu): 1970-2010: Estimation Procedure:** Estimates of average heat content by region and year are based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu, published in EIA's *Annual Energy Review*. **Sources:** U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Annual Coal Production and Preparation Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; Form EIA-923, "Power Plant Operations Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C. Note: For 1989-2035, coal production includes waste coal.

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Figure 120. Average annual minemouth coal prices by region, 1990-2035: History (dollars per short ton): 1990-2000: U.S. Energy Information Administration, *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2010:** U.S. Energy Information Administration, *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011), and previous issues. **History (conversion to dollars per million Btu): 1970-2009: Estimation Procedure:** Estimates of average heat content by region and year based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu published in EIA's *Annual Energy Review*. **Sources:** U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Annual Coal Production and Preparation Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; and Form EIA-920, "Combined Heat and Power Plant

Report"; Form EIA-923, "Power Plant Operations Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C. **Note:** Includes reported prices for both open-market and captive mines.

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Figure 122. U.S. energy-related carbon dioxide emissions by sector and fuel, 2005 and 2035: AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 123. Sulfur dioxide emissions from electricity generation, 1990-2035: 1990, 2000, 2005: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA-454/R-00-002 (Washington, DC, March 2000); U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, website ampd.epa.gov/ampd/. **2010 and Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 124. Nitrogen oxide emissions from electricity generation, 1990-2035: History: 1990, 2000, 2005: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA-454/R-00-002 (Washington, DC, March 2000); U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, website ampd.epa.gov/ampd/. **2010 and Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C.

Reference case

Table A1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Production								
Crude oil and lease condensate	11.35	11.59	13.23	14.40	13.77	13.71	12.89	0.4%
Natural gas plant liquids	2.57	2.78	3.33	3.79	3.93	3.98	3.94	1.4%
Dry natural gas	21.09	22.10	24.22	25.69	26.91	27.58	28.60	1.0%
Coal[1]	21.63	22.06	20.24	20.74	22.25	23.22	24.14	0.4%
Nuclear / uranium[2]	8.36	8.44	8.68	9.28	9.60	9.56	9.28	0.4%
Hydropower	2.67	2.51	2.90	2.95	2.99	3.02	3.04	0.8%
Biomass[3]	3.72	4.05	4.45	5.26	6.26	7.60	9.07	3.3%
Other renewable energy[4]	1.11	1.34	1.99	2.04	2.22	2.41	2.81	3.0%
Other[5]	0.47	0.64	0.60	0.64	0.69	0.79	0.91	1.4%
Total	**72.97**	**75.50**	**79.64**	**84.80**	**88.61**	**91.87**	**94.67**	**0.9%**
Imports								
Crude oil	19.70	20.14	18.87	16.00	16.23	16.04	16.90	-0.7%
Liquid fuels and other petroleum[6]	5.40	5.02	4.32	4.03	4.08	4.04	4.14	-0.8%
Natural gas[7]	3.85	3.81	3.73	3.49	2.75	3.00	2.84	-1.2%
Other imports[8]	0.61	0.52	0.44	0.72	1.07	0.78	0.81	1.8%
Total	**29.56**	**29.49**	**27.37**	**24.25**	**24.14**	**23.86**	**24.69**	**-0.7%**
Exports								
Liquid fuels and other petroleum[9]	4.20	4.81	5.00	4.39	4.46	4.67	4.95	0.1%
Natural gas[10]	1.08	1.15	1.93	3.09	3.51	3.86	4.17	5.3%
Coal	1.51	2.10	2.73	2.36	2.82	2.85	3.13	1.6%
Total	**6.79**	**8.06**	**9.66**	**9.84**	**10.79**	**11.38**	**12.25**	**1.7%**
Discrepancy[11]	**1.04**	**-1.23**	**-0.08**	**-0.10**	**-0.03**	**0.04**	**0.18**	**- -**
Consumption								
Liquid fuels and other petroleum[12]	36.50	37.25	36.72	36.38	36.58	36.99	37.70	0.0%
Natural gas	23.43	24.71	26.00	26.07	26.14	26.72	27.26	0.4%
Coal[13]	19.62	20.76	17.80	18.73	20.02	20.59	21.15	0.1%
Nuclear / uranium[2]	8.36	8.44	8.68	9.28	9.60	9.56	9.28	0.4%
Hydropower	2.67	2.51	2.90	2.95	2.99	3.02	3.04	0.8%
Biomass[14]	2.72	2.88	3.04	3.58	4.17	4.78	5.44	2.6%
Other renewable energy[4]	1.11	1.34	1.99	2.04	2.22	2.41	2.81	3.0%
Other[15]	0.32	0.29	0.30	0.29	0.28	0.25	0.24	-0.6%
Total	**94.71**	**98.16**	**97.43**	**99.32**	**101.99**	**104.32**	**106.93**	**0.3%**
Prices (2010 dollars per unit)								
Petroleum (dollars per barrel)								
Low sulfur light crude oil	62.37	79.39	116.91	126.68	132.56	138.49	144.98	2.4%
Imported crude oil[16]	59.72	75.87	113.97	115.74	121.21	126.51	132.95	2.3%
Natural gas (dollars per million Btu)								
at Henry hub	4.00	4.39	4.29	4.58	5.63	6.29	7.37	2.1%
at the wellhead[17]	3.75	4.06	3.84	4.10	5.00	5.56	6.48	1.9%
Natural gas (dollars per thousand cubic feet)								
at the wellhead[17]	3.85	4.16	3.94	4.19	5.12	5.69	6.64	1.9%
Coal (dollars per ton)								
at the minemouth[18]	33.62	35.61	42.08	40.96	44.05	47.28	50.52	1.4%
Coal (dollars per million Btu)								
at the minemouth[18]	1.68	1.76	2.08	2.06	2.23	2.39	2.56	1.5%
Average end-use[19]	2.32	2.38	2.56	2.58	2.70	2.81	2.94	0.9%
Average electricity (cents per kilowatthour)	9.9	9.8	9.7	9.6	9.7	9.8	10.1	0.1%

Table A1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Prices (nominal dollars per unit)								
Petroleum (dollars per barrel)								
Low sulfur light crude oil	61.65	79.39	125.97	148.87	170.09	197.10	229.55	4.3%
Imported crude oil[16]	59.04	75.87	122.81	136.02	155.52	180.06	210.51	4.2%
Natural gas (dollars per million Btu)								
at Henry hub	3.95	4.39	4.62	5.39	7.23	8.95	11.67	4.0%
at the wellhead[17]	3.71	4.06	4.14	4.81	6.42	7.92	10.26	3.8%
Natural gas (dollars per thousand cubic feet)								
at the wellhead[17]	3.80	4.16	4.24	4.93	6.57	8.11	10.51	3.8%
Coal (dollars per ton)								
at the minemouth[18]	33.24	35.61	45.34	48.13	56.52	67.28	80.00	3.3%
Coal (dollars per million Btu)								
at the minemouth[18]	1.66	1.76	2.24	2.42	2.86	3.41	4.05	3.4%
Average end-use[19]	2.30	2.38	2.76	3.03	3.47	4.01	4.66	2.7%
Average electricity (cents per kilowatthour)	9.8	9.8	10.4	11.3	12.5	13.9	16.0	2.0%

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that is later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Weighted average price delivered to U.S. refiners.
[17]Represents lower 48 onshore and offshore supplies.
[18]Includes reported prices for both open market and captive mines.
[19]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 natural gas wellhead price: U.S. Department of the Interior, Office of Natural Resources Revenue; and EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2009 and 2010 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011). 2010 petroleum supply values and 2009 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). Other 2009 petroleum supply values: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). 2009 and 2010 low sulfur light crude oil price: EIA, Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” Other 2009 and 2010 coal values: *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011). Other 2009 and 2010 values: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Energy consumption								
Residential								
Liquefied petroleum gases	0.51	0.56	0.51	0.50	0.50	0.51	0.51	-0.4%
Kerosene	0.03	0.03	0.02	0.02	0.02	0.02	0.02	-1.7%
Distillate fuel oil	0.60	0.63	0.55	0.48	0.43	0.38	0.35	-2.3%
Liquid fuels and other petroleum subtotal	1.14	1.22	1.08	1.01	0.95	0.91	0.87	-1.3%
Natural gas	4.90	5.06	4.97	4.95	4.88	4.84	4.76	-0.2%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-1.1%
Renewable energy[1]	0.43	0.42	0.43	0.43	0.43	0.43	0.43	0.1%
Electricity	4.66	4.95	4.75	4.96	5.23	5.55	5.86	0.7%
Delivered energy	**11.13**	**11.66**	**11.24**	**11.36**	**11.51**	**11.73**	**11.93**	**0.1%**
Electricity related losses	9.80	10.39	9.58	10.01	10.52	10.95	11.35	0.4%
Total	**20.93**	**22.05**	**20.81**	**21.36**	**22.02**	**22.68**	**23.28**	**0.2%**
Commercial								
Liquefied petroleum gases	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.3%
Motor gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.4%
Kerosene	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.7%
Distillate fuel oil	0.41	0.43	0.35	0.34	0.33	0.33	0.32	-1.2%
Residual fuel oil	0.08	0.08	0.08	0.08	0.08	0.08	0.08	-0.0%
Liquid fuels and other petroleum subtotal	0.68	0.72	0.62	0.62	0.62	0.62	0.62	-0.5%
Natural gas	3.20	3.28	3.41	3.51	3.53	3.60	3.69	0.5%
Coal	0.07	0.06	0.06	0.06	0.06	0.06	0.06	-0.0%
Renewable energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.0%
Electricity	4.46	4.54	4.59	4.88	5.16	5.48	5.80	1.0%
Delivered energy	**8.51**	**8.70**	**8.80**	**9.18**	**9.48**	**9.87**	**10.28**	**0.7%**
Electricity related losses	9.39	9.52	9.27	9.85	10.38	10.82	11.23	0.7%
Total	**17.90**	**18.22**	**18.06**	**19.03**	**19.86**	**20.69**	**21.50**	**0.7%**
Industrial[4]								
Liquefied petroleum gases	2.00	2.00	1.83	2.06	2.17	2.18	2.15	0.3%
Motor gasoline[2]	0.24	0.25	0.28	0.30	0.30	0.30	0.30	0.8%
Distillate fuel oil	1.11	1.16	1.25	1.18	1.19	1.17	1.18	0.1%
Residual fuel oil	0.11	0.12	0.09	0.08	0.08	0.08	0.08	-1.3%
Petrochemical feedstocks	0.90	0.94	1.01	1.20	1.29	1.31	1.30	1.3%
Other petroleum[5]	3.57	3.59	3.44	3.18	3.11	3.09	3.19	-0.5%
Liquid fuels and other petroleum subtotal	7.93	8.05	7.89	7.99	8.13	8.13	8.21	0.1%
Natural gas	6.32	6.76	7.19	7.26	7.32	7.21	7.18	0.2%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[6]	1.31	1.37	1.43	1.55	1.57	1.59	1.63	0.7%
Natural gas subtotal	7.63	8.14	8.62	8.80	8.89	8.80	8.81	0.3%
Metallurgical coal	0.40	0.55	0.57	0.48	0.49	0.46	0.43	-1.0%
Other industrial coal	0.94	1.01	1.03	1.04	1.08	1.08	1.08	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.26	0.36	0.48	0.60	- -
Net coal coke imports	-0.02	-0.01	-0.01	-0.02	-0.03	-0.04	-0.06	9.3%
Coal subtotal	1.32	1.56	1.59	1.76	1.90	1.98	2.06	1.1%
Biofuels heat and coproducts	0.82	0.84	0.81	0.96	1.27	1.92	2.57	4.6%
Renewable energy[7]	1.37	1.50	1.61	1.67	1.82	1.87	1.95	1.1%
Electricity	3.13	3.28	3.44	3.46	3.52	3.44	3.33	0.1%
Delivered energy	**22.20**	**23.37**	**23.96**	**24.64**	**25.53**	**26.14**	**26.94**	**0.6%**
Electricity related losses	6.59	6.89	6.94	6.97	7.09	6.80	6.46	-0.3%
Total	**28.79**	**30.26**	**30.90**	**31.61**	**32.61**	**32.93**	**33.39**	**0.4%**

Table A2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Transportation								
Liquefied petroleum gases	0.05	0.04	0.04	0.04	0.04	0.05	0.05	0.5%
E85[8]	0.00	0.00	0.01	0.13	0.30	0.72	1.22	27.0%
Motor gasoline[2]	16.84	16.91	16.13	15.31	14.90	14.69	14.53	-0.6%
Jet fuel[9]	2.98	3.07	3.03	3.09	3.19	3.27	3.33	0.3%
Distillate fuel oil[10]	5.53	5.77	6.55	6.80	7.03	7.20	7.44	1.0%
Residual fuel oil	0.81	0.90	0.91	0.92	0.93	0.93	0.94	0.2%
Other petroleum[11]	0.16	0.17	0.17	0.17	0.17	0.17	0.17	0.0%
Liquid fuels and other petroleum subtotal	26.36	26.88	26.83	26.46	26.57	27.02	27.67	0.1%
Pipeline fuel natural gas	0.61	0.65	0.68	0.67	0.67	0.68	0.69	0.2%
Compressed / liquefied natural gas	0.04	0.04	0.06	0.09	0.11	0.14	0.16	5.7%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	0.02	0.02	0.03	0.03	0.04	0.06	0.07	4.8%
Delivered energy	**27.04**	**27.59**	**27.60**	**27.25**	**27.40**	**27.90**	**28.60**	**0.1%**
Electricity related losses	0.05	0.05	0.05	0.06	0.08	0.11	0.14	4.5%
Total	**27.09**	**27.63**	**27.65**	**27.32**	**27.49**	**28.01**	**28.75**	**0.2%**
Delivered energy consumption for all sectors								
Liquefied petroleum gases	2.69	2.75	2.51	2.74	2.86	2.88	2.86	0.2%
E85[8]	0.00	0.00	0.01	0.13	0.30	0.72	1.22	27.0%
Motor gasoline[2]	17.13	17.21	16.46	15.66	15.25	15.04	14.88	-0.6%
Jet fuel[9]	2.98	3.07	3.03	3.09	3.19	3.27	3.33	0.3%
Kerosene	0.04	0.04	0.03	0.03	0.03	0.03	0.03	-1.2%
Distillate fuel oil	7.65	7.99	8.69	8.81	8.99	9.08	9.29	0.6%
Residual fuel oil	0.99	1.11	1.08	1.08	1.09	1.09	1.11	0.0%
Petrochemical feedstocks	0.90	0.94	1.01	1.20	1.29	1.31	1.30	1.3%
Other petroleum[12]	3.72	3.76	3.61	3.34	3.27	3.26	3.36	-0.4%
Liquid fuels and other petroleum subtotal	36.10	36.87	36.43	36.08	36.28	36.68	37.38	0.1%
Natural gas	14.46	15.15	15.64	15.81	15.85	15.79	15.79	0.2%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[6]	1.31	1.37	1.43	1.55	1.57	1.59	1.63	0.7%
Pipeline natural gas	0.61	0.65	0.68	0.67	0.67	0.68	0.69	0.2%
Natural gas subtotal	16.38	17.17	17.75	18.03	18.09	18.06	18.11	0.2%
Metallurgical coal	0.40	0.55	0.57	0.48	0.49	0.46	0.43	-1.0%
Other coal	1.01	1.08	1.09	1.10	1.14	1.14	1.15	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.26	0.36	0.48	0.60	- -
Net coal coke imports	-0.02	-0.01	-0.01	-0.02	-0.03	-0.04	-0.06	9.3%
Coal subtotal	1.39	1.62	1.65	1.82	1.96	2.04	2.12	1.1%
Biofuels heat and coproducts	0.82	0.84	0.81	0.96	1.27	1.92	2.57	4.6%
Renewable energy[13]	1.91	2.03	2.15	2.21	2.36	2.41	2.50	0.8%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	12.27	12.79	12.81	13.33	13.96	14.53	15.06	0.7%
Delivered energy	**68.87**	**71.32**	**71.59**	**72.43**	**73.92**	**75.64**	**77.75**	**0.3%**
Electricity related losses	25.83	26.84	25.84	26.89	28.07	28.67	29.18	0.3%
Total	**94.71**	**98.16**	**97.43**	**99.32**	**101.99**	**104.32**	**106.93**	**0.3%**
Electric power[14]								
Distillate fuel oil	0.07	0.08	0.08	0.09	0.09	0.09	0.09	0.5%
Residual fuel oil	0.32	0.30	0.21	0.21	0.22	0.22	0.23	-1.1%
Liquid fuels and other petroleum subtotal	0.39	0.38	0.29	0.30	0.31	0.31	0.32	-0.7%
Natural gas	7.04	7.54	8.25	8.05	8.04	8.66	9.16	0.8%
Steam coal	18.23	19.13	16.15	16.91	18.06	18.55	19.03	-0.0%
Nuclear / uranium[15]	8.36	8.44	8.68	9.28	9.60	9.56	9.28	0.4%
Renewable energy[16]	3.77	3.85	4.96	5.40	5.75	5.87	6.22	1.9%
Electricity imports	0.12	0.09	0.10	0.09	0.08	0.05	0.04	-2.9%
Total[17]	**38.10**	**39.63**	**38.64**	**40.22**	**42.03**	**43.20**	**44.24**	**0.4%**

Table A2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Total energy consumption								
Liquefied petroleum gases	2.69	2.75	2.51	2.74	2.86	2.88	2.86	0.2%
E85[8]	0.00	0.00	0.01	0.13	0.30	0.72	1.22	27.0%
Motor gasoline[2]	17.13	17.21	16.46	15.66	15.25	15.04	14.88	-0.6%
Jet fuel[9]	2.98	3.07	3.03	3.09	3.19	3.27	3.33	0.3%
Kerosene	0.04	0.04	0.03	0.03	0.03	0.03	0.03	-1.2%
Distillate fuel oil	7.72	8.07	8.78	8.89	9.07	9.17	9.38	0.6%
Residual fuel oil	1.32	1.41	1.29	1.29	1.31	1.32	1.34	-0.2%
Petrochemical feedstocks	0.90	0.94	1.01	1.20	1.29	1.31	1.30	1.3%
Other petroleum[12]	3.72	3.76	3.61	3.34	3.27	3.26	3.36	-0.4%
Liquid fuels and other petroleum subtotal	36.50	37.25	36.72	36.38	36.58	36.99	37.70	0.0%
Natural gas	21.51	22.69	23.89	23.85	23.89	24.45	24.94	0.4%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[6]	1.31	1.37	1.43	1.55	1.57	1.59	1.63	0.7%
Pipeline natural gas	0.61	0.65	0.68	0.67	0.67	0.68	0.69	0.2%
Natural gas subtotal	23.43	24.71	26.00	26.07	26.14	26.72	27.26	0.4%
Metallurgical coal	0.40	0.55	0.57	0.48	0.49	0.46	0.43	-1.0%
Other coal	19.23	20.21	17.24	18.01	19.20	19.69	20.18	-0.0%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.26	0.36	0.48	0.60	- -
Net coal coke imports	-0.02	-0.01	-0.01	-0.02	-0.03	-0.04	-0.06	9.3%
Coal subtotal	19.62	20.76	17.80	18.73	20.02	20.59	21.15	0.1%
Nuclear / uranium[15]	8.36	8.44	8.68	9.28	9.60	9.56	9.28	0.4%
Biofuels heat and coproducts	0.82	0.84	0.81	0.96	1.27	1.92	2.57	4.6%
Renewable energy[18]	5.68	5.88	7.11	7.61	8.11	8.29	8.71	1.6%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity imports	0.12	0.09	0.10	0.09	0.08	0.05	0.04	-2.9%
Total	**94.71**	**98.16**	**97.43**	**99.32**	**101.99**	**104.32**	**106.93**	**0.3%**
Energy use and related statistics								
Delivered energy use	68.87	71.32	71.59	72.43	73.92	75.64	77.75	0.3%
Total energy use	94.71	98.16	97.43	99.32	101.99	104.32	106.93	0.3%
Ethanol consumed in motor gasoline and E85	0.96	1.11	1.22	1.35	1.55	1.82	2.15	2.7%
Population (millions)	307.84	310.83	326.16	342.01	358.06	374.09	390.09	0.9%
Gross domestic product (billion 2005 dollars)	12703	13088	14803	16740	19185	21725	24539	2.5%
Carbon dioxide emissions (million metric tons)	5424.8	5633.6	5407.2	5434.4	5552.5	5647.3	5757.9	0.1%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (15 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[15]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[17]Includes non-biogenic municipal waste not included above.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2011. 2009 and 2010 carbon dioxide emissions: EIA, *Monthly Energy Review, October 2011* DOE/EIA-0035(2011/10) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A3. Energy prices by sector and source
(2010 dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Residential								
Liquefied petroleum gases	24.84	27.02	30.70	31.07	32.27	33.29	34.64	1.0%
Distillate fuel oil	18.35	21.21	27.26	28.81	30.15	31.42	32.73	1.8%
Natural gas	11.95	11.08	10.31	10.84	12.03	12.76	13.98	0.9%
Electricity	34.01	33.69	34.59	33.87	34.08	34.06	34.58	0.1%
Commercial								
Liquefied petroleum gases	21.76	23.52	27.42	27.78	28.97	29.96	31.30	1.1%
Distillate fuel oil	16.16	20.77	23.98	25.49	26.86	27.98	29.18	1.4%
Residual fuel oil	13.66	11.07	16.18	17.60	18.24	19.04	18.90	2.2%
Natural gas	9.82	9.10	8.60	8.98	10.02	10.60	11.64	1.0%
Electricity	30.06	29.73	29.03	28.69	29.00	28.68	29.48	-0.0%
Industrial[1]								
Liquefied petroleum gases	20.05	21.80	27.43	27.76	29.24	30.48	32.18	1.6%
Distillate fuel oil	16.74	21.32	24.20	25.73	27.22	28.39	29.53	1.3%
Residual fuel oil	12.16	10.92	19.21	20.53	21.23	21.71	21.65	2.8%
Natural gas[2]	5.33	5.51	4.88	5.12	6.04	6.57	7.54	1.3%
Metallurgical coal	5.49	5.84	7.22	7.58	8.11	8.61	9.11	1.8%
Other industrial coal	2.99	2.71	3.27	3.30	3.38	3.50	3.64	1.2%
Coal to liquids	- -	- -	1.26	2.05	2.08	2.22	2.38	- -
Electricity	20.05	19.63	18.91	18.95	19.60	19.81	20.78	0.2%
Transportation								
Liquefied petroleum gases[3]	25.84	26.88	31.93	32.21	33.38	34.37	35.74	1.1%
E85[4]	20.76	25.21	29.03	29.91	28.81	30.75	31.96	1.0%
Motor gasoline[5]	19.52	22.70	29.26	30.77	32.10	33.03	33.61	1.6%
Jet fuel[6]	12.75	16.22	23.74	25.26	26.45	27.58	29.13	2.4%
Diesel fuel (distillate fuel oil)[7]	18.02	21.87	27.56	28.98	30.42	31.38	32.40	1.6%
Residual fuel oil	10.61	10.42	18.32	19.58	20.62	20.76	20.95	2.8%
Natural gas[8]	14.17	13.20	12.40	12.50	13.29	13.68	14.51	0.4%
Electricity	35.71	32.99	30.50	29.74	31.53	32.54	33.82	0.1%
Electric power[9]								
Distillate fuel oil	14.54	18.73	22.77	24.18	25.35	26.43	27.80	1.6%
Residual fuel oil	8.98	11.89	23.00	24.38	25.40	25.55	25.72	3.1%
Natural gas	4.85	5.14	4.55	4.72	5.60	6.21	7.21	1.4%
Steam coal	2.22	2.26	2.35	2.41	2.54	2.66	2.80	0.9%
Average price to all users[10]								
Liquefied petroleum gases	16.13	17.28	22.99	23.06	24.19	25.23	26.63	1.7%
E85[4]	20.76	25.21	29.03	29.91	28.81	30.75	31.96	1.0%
Motor gasoline[5]	19.47	22.59	29.26	30.77	32.10	33.03	33.61	1.6%
Jet fuel	12.75	16.22	23.74	25.26	26.45	27.58	29.13	2.4%
Distillate fuel oil	17.73	21.65	26.87	28.36	29.81	30.87	31.91	1.6%
Residual fuel oil	10.51	10.82	19.01	20.31	21.31	21.53	21.68	2.8%
Natural gas	7.37	7.16	6.45	6.77	7.74	8.30	9.30	1.1%
Metallurgical coal	5.49	5.84	7.22	7.58	8.11	8.61	9.11	1.8%
Other coal	2.26	2.29	2.41	2.47	2.59	2.71	2.85	0.9%
Coal to liquids	- -	- -	1.26	2.05	2.08	2.22	2.38	- -
Electricity	29.02	28.68	28.38	28.09	28.54	28.65	29.56	0.1%
Non-renewable energy expenditures by sector (billion 2010 dollars)								
Residential	240.88	251.69	246.72	251.77	266.75	280.17	298.72	0.7%
Commercial	177.13	179.08	177.92	187.57	201.89	212.88	231.98	1.0%
Industrial	184.40	198.98	223.88	239.75	261.92	268.58	282.31	1.4%
Transportation	479.66	573.78	746.84	770.94	803.52	829.88	856.65	1.6%
Total non-renewable expenditures	1082.08	1203.54	1395.36	1450.04	1534.08	1591.52	1669.66	1.3%
Transportation renewable expenditures	0.07	0.08	0.25	3.77	8.74	22.00	38.86	28.2%
Total expenditures	**1082.15**	**1203.62**	**1395.61**	**1453.81**	**1542.81**	**1613.52**	**1708.52**	**1.4%**

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Residential								
Liquefied petroleum gases	24.55	27.02	33.08	36.51	41.41	47.38	54.86	2.9%
Distillate fuel oil	18.14	21.21	29.38	33.86	38.68	44.72	51.82	3.6%
Natural gas	11.82	11.08	11.11	12.74	15.43	18.16	22.14	2.8%
Electricity	33.62	33.69	37.27	39.80	43.72	48.47	54.76	2.0%
Commercial								
Liquefied petroleum gases	21.51	23.52	29.54	32.65	37.17	42.65	49.56	3.0%
Distillate fuel oil	15.97	20.77	25.83	29.95	34.47	39.82	46.20	3.2%
Residual fuel oil	13.51	11.07	17.43	20.68	23.41	27.10	29.93	4.1%
Natural gas	9.70	9.10	9.27	10.56	12.86	15.08	18.43	2.9%
Electricity	29.71	29.73	31.28	33.71	37.21	40.82	46.67	1.8%
Industrial[1]								
Liquefied petroleum gases	19.82	21.80	29.56	32.63	37.51	43.38	50.95	3.5%
Distillate fuel oil	16.55	21.32	26.08	30.24	34.93	40.40	46.76	3.2%
Residual fuel oil	12.02	10.92	20.70	24.13	27.24	30.89	34.28	4.7%
Natural gas[2]	5.27	5.51	5.26	6.02	7.75	9.35	11.93	3.1%
Metallurgical coal	5.43	5.84	7.78	8.91	10.40	12.26	14.42	3.7%
Other industrial coal	2.96	2.71	3.52	3.87	4.34	4.98	5.77	3.1%
Coal to liquids	- -	- -	1.36	2.41	2.67	3.16	3.78	- -
Electricity	19.83	19.63	20.38	22.27	25.15	28.20	32.90	2.1%
Transportation								
Liquefied petroleum gases[3]	25.55	26.88	34.41	37.85	42.83	48.91	56.59	3.0%
E85[4]	20.52	25.21	31.28	35.15	36.97	43.77	50.61	2.8%
Motor gasoline[5]	19.29	22.70	31.53	36.17	41.19	47.01	53.22	3.5%
Jet fuel[6]	12.61	16.22	25.58	29.68	33.94	39.25	46.12	4.3%
Diesel fuel (distillate fuel oil)[7]	17.82	21.87	29.69	34.06	39.03	44.66	51.29	3.5%
Residual fuel oil	10.49	10.42	19.74	23.01	26.45	29.55	33.18	4.7%
Natural gas[8]	14.01	13.20	13.36	14.69	17.05	19.47	22.97	2.2%
Electricity	35.31	32.99	32.86	34.95	40.46	46.31	53.55	2.0%
Electric power[9]								
Distillate fuel oil	14.37	18.73	24.53	28.42	32.52	37.61	44.02	3.5%
Residual fuel oil	8.88	11.89	24.78	28.66	32.59	36.37	40.73	5.0%
Natural gas	4.80	5.14	4.90	5.55	7.19	8.84	11.42	3.2%
Steam coal	2.19	2.26	2.53	2.83	3.25	3.78	4.43	2.7%

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Average price to all users[10]								
Liquefied petroleum gases	15.94	17.28	24.78	27.10	31.04	35.90	42.17	3.6%
E85[4]	20.52	25.21	31.28	35.15	36.97	43.77	50.61	2.8%
Motor gasoline[5]	19.25	22.59	31.53	36.16	41.19	47.01	53.22	3.5%
Jet fuel	12.61	16.22	25.58	29.68	33.94	39.25	46.12	4.3%
Distillate fuel oil	17.53	21.65	28.96	33.33	38.24	43.94	50.52	3.4%
Residual fuel oil	10.39	10.82	20.48	23.87	27.34	30.64	34.33	4.7%
Natural gas	7.28	7.16	6.95	7.96	9.93	11.81	14.73	2.9%
Metallurgical coal	5.43	5.84	7.78	8.91	10.40	12.26	14.42	3.7%
Other coal	2.23	2.29	2.60	2.90	3.32	3.86	4.51	2.8%
Coal to liquids	- -	- -	1.36	2.41	2.67	3.16	3.78	- -
Electricity	28.68	28.68	30.58	33.01	36.62	40.77	46.80	2.0%
Non-renewable energy expenditures by sector (billion nominal dollars)								
Residential	238.13	251.69	265.85	295.89	342.26	398.75	472.99	2.6%
Commercial	175.11	179.08	191.71	220.43	259.04	302.97	367.31	2.9%
Industrial	182.29	198.98	241.24	281.75	336.06	382.26	447.01	3.3%
Transportation	474.19	573.78	804.75	906.02	1030.98	1181.11	1356.41	3.5%
Total non-renewable expenditures	1069.72	1203.54	1503.55	1704.09	1968.35	2265.08	2643.72	3.2%
Transportation renewable expenditures	0.07	0.08	0.27	4.43	11.21	31.31	61.53	30.6%
Total expenditures	**1069.78**	**1203.62**	**1503.82**	**1708.52**	**1979.56**	**2296.40**	**2705.26**	**3.3%**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2009 residential and commercial natural gas delivered prices: EIA,*Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 and 2010 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and estimated State taxes, Federal taxes, and dispensing costs or charges. 2010 transportation sector natural gas delivered prices are model results. 2009 and 2010 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2010/09) (Washington, DC, September 2010). 2009 and 2010 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2010 and April 2011, Table 4.2, and EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2009 and 2010 coal prices based on: EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011) and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. 2009 and 2010 electricity prices: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A4. Residential sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Key indicators								
Households (millions)								
Single-family	81.73	82.11	85.49	89.94	94.26	98.56	102.54	0.9%
Multifamily	25.41	25.52	26.98	29.31	31.47	33.70	35.96	1.4%
Mobile homes	6.65	6.56	6.25	6.56	6.86	7.04	7.14	0.3%
Total	**113.78**	**114.19**	**118.73**	**125.82**	**132.60**	**139.30**	**145.64**	**1.0%**
Average house square footage	**1646**	**1653**	**1684**	**1705**	**1725**	**1743**	**1759**	**0.2%**
Energy intensity								
(million Btu per household)								
Delivered energy consumption	97.8	102.1	94.6	90.3	86.8	84.2	81.9	-0.9%
Total energy consumption	184.0	193.1	175.3	169.8	166.1	162.8	159.9	-0.8%
(thousand Btu per square foot)								
Delivered energy consumption	59.4	61.8	56.2	52.9	50.3	48.3	46.6	-1.1%
Total energy consumption	111.8	116.8	104.1	99.6	96.3	93.4	90.9	-1.0%
Delivered energy consumption by fuel								
Electricity								
Space heating	0.28	0.30	0.28	0.30	0.31	0.33	0.34	0.5%
Space cooling	0.81	1.08	1.01	1.06	1.12	1.18	1.24	0.6%
Water heating	0.44	0.45	0.47	0.50	0.52	0.53	0.53	0.7%
Refrigeration	0.38	0.37	0.37	0.38	0.39	0.41	0.43	0.6%
Cooking	0.11	0.11	0.11	0.12	0.13	0.14	0.15	1.4%
Clothes dryers	0.19	0.19	0.19	0.18	0.18	0.17	0.18	-0.3%
Freezers	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.3%
Lighting	0.70	0.69	0.52	0.48	0.46	0.46	0.47	-1.5%
Clothes washers[1]	0.03	0.03	0.03	0.03	0.02	0.02	0.02	-1.2%
Dishwashers[1]	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.4%
Color televisions and set-top boxes	0.32	0.33	0.32	0.34	0.37	0.40	0.43	1.1%
Personal computers and related equipment	0.17	0.17	0.19	0.22	0.24	0.26	0.27	1.8%
Furnace fans and boiler circulation pumps	0.14	0.13	0.14	0.14	0.14	0.15	0.15	0.4%
Other uses[2]	0.90	0.92	0.92	1.03	1.16	1.31	1.44	1.8%
Delivered energy	**4.66**	**4.95**	**4.75**	**4.96**	**5.23**	**5.55**	**5.86**	**0.7%**
Natural gas								
Space heating	3.31	3.50	3.39	3.34	3.27	3.24	3.19	-0.4%
Space cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.3%
Water heating	1.32	1.29	1.31	1.33	1.33	1.31	1.27	-0.1%
Cooking	0.22	0.22	0.22	0.22	0.22	0.23	0.23	0.3%
Clothes dryers	0.05	0.06	0.06	0.06	0.06	0.06	0.07	0.7%
Delivered energy	**4.90**	**5.06**	**4.97**	**4.95**	**4.88**	**4.84**	**4.76**	**-0.2%**
Distillate fuel oil								
Space heating	0.50	0.53	0.48	0.42	0.38	0.34	0.31	-2.1%
Water heating	0.10	0.10	0.07	0.06	0.05	0.04	0.04	-3.9%
Delivered energy	**0.60**	**0.63**	**0.55**	**0.48**	**0.43**	**0.38**	**0.35**	**-2.3%**
Liquefied petroleum gases								
Space heating	0.26	0.30	0.26	0.25	0.24	0.23	0.22	-1.1%
Water heating	0.08	0.07	0.05	0.04	0.04	0.04	0.03	-3.0%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.02	-0.9%
Other uses[3]	0.14	0.16	0.17	0.18	0.20	0.21	0.22	1.3%
Delivered energy	**0.51**	**0.56**	**0.51**	**0.50**	**0.50**	**0.51**	**0.51**	**-0.4%**
Marketed renewables (wood)[4]	0.43	0.42	0.43	0.43	0.43	0.43	0.43	0.1%
Other fuels[5]	0.04	0.04	0.03	0.03	0.03	0.03	0.03	-1.6%

Table A4. Residential sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Delivered energy consumption by end use								
Space heating	4.81	5.08	4.86	4.78	4.67	4.60	4.52	-0.5%
Space cooling	0.81	1.08	1.01	1.06	1.12	1.18	1.24	0.6%
Water heating	1.94	1.91	1.90	1.92	1.94	1.91	1.88	-0.1%
Refrigeration	0.38	0.37	0.37	0.38	0.39	0.41	0.43	0.6%
Cooking	0.35	0.35	0.36	0.37	0.38	0.39	0.40	0.5%
Clothes dryers	0.25	0.25	0.25	0.25	0.24	0.24	0.25	-0.0%
Freezers	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.3%
Lighting	0.70	0.69	0.52	0.48	0.46	0.46	0.47	-1.5%
Clothes washers[1]	0.03	0.03	0.03	0.03	0.02	0.02	0.02	-1.2%
Dishwashers[1]	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.4%
Color televisions and set-top boxes	0.32	0.33	0.32	0.34	0.37	0.40	0.43	1.1%
Personal computers and related equipment	0.17	0.17	0.19	0.22	0.24	0.26	0.27	1.8%
Furnace fans and boiler circulation pumps	0.14	0.13	0.14	0.14	0.14	0.15	0.15	0.4%
Other uses[6]	1.04	1.08	1.09	1.21	1.36	1.52	1.67	1.8%
Delivered energy	**11.13**	**11.66**	**11.24**	**11.36**	**11.51**	**11.73**	**11.93**	**0.1%**
Electricity related losses	**9.80**	**10.39**	**9.58**	**10.01**	**10.52**	**10.95**	**11.35**	**0.4%**
Total energy consumption by end use								
Space heating	5.41	5.70	5.42	5.37	5.29	5.24	5.17	-0.4%
Space cooling	2.52	3.34	3.06	3.19	3.36	3.51	3.65	0.4%
Water heating	2.87	2.85	2.85	2.93	2.98	2.96	2.90	0.1%
Refrigeration	1.17	1.15	1.11	1.14	1.18	1.23	1.28	0.4%
Cooking	0.58	0.58	0.59	0.61	0.64	0.67	0.69	0.7%
Clothes dryers	0.65	0.65	0.64	0.62	0.59	0.58	0.60	-0.4%
Freezers	0.26	0.26	0.25	0.26	0.26	0.26	0.26	0.1%
Lighting	2.18	2.13	1.58	1.45	1.39	1.37	1.37	-1.7%
Clothes washers[1]	0.10	0.10	0.10	0.08	0.07	0.07	0.07	-1.4%
Dishwashers[1]	0.31	0.31	0.30	0.30	0.30	0.31	0.33	0.2%
Color televisions and set-top boxes	1.00	1.02	0.98	1.03	1.10	1.18	1.26	0.9%
Personal computers and related equipment	0.53	0.53	0.57	0.65	0.72	0.76	0.79	1.6%
Furnace fans and boiler circulation pumps	0.42	0.42	0.42	0.43	0.44	0.44	0.44	0.2%
Other uses[6]	2.94	3.01	2.96	3.29	3.70	4.10	4.47	1.6%
Total	**20.93**	**22.05**	**20.81**	**21.36**	**22.02**	**22.68**	**23.28**	**0.2%**
Nonmarketed renewables[7]								
Geothermal heat pumps	0.00	0.01	0.01	0.02	0.02	0.02	0.03	6.4%
Solar hot water heating	0.01	0.01	0.02	0.02	0.02	0.02	0.02	2.4%
Solar photovoltaic	0.00	0.00	0.04	0.05	0.05	0.06	0.06	10.7%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	9.1%
Total	**0.02**	**0.02**	**0.08**	**0.10**	**0.10**	**0.11**	**0.11**	**6.9%**
Heating degree days[8]	**4408**	**4382**	**4208**	**4172**	**4136**	**4101**	**4067**	**-0.3%**
Cooling degree days[8]	**1279**	**1498**	**1392**	**1409**	**1426**	**1443**	**1459**	**-0.1%**

[1]Does not include water heating portion of load.
[2]Includes small electric devices, heating elements, and motors not listed above. Electric vehicles are included in the transportation sector.
[3]Includes such appliances as outdoor grills and mosquito traps.
[4]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2005*.
[5]Includes kerosene and coal.
[6]Includes all other uses listed above.
[7]Represents delivered energy displaced.
[8]See Table A5 for regional detail.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A5. Commercial sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Key indicators								
Total floorspace (billion square feet)								
Surviving	78.0	79.3	82.4	87.0	91.9	96.2	100.7	1.0%
New additions	2.3	1.8	1.7	2.0	2.0	2.0	2.3	1.0%
Total	**80.3**	**81.1**	**84.1**	**89.1**	**93.9**	**98.2**	**103.0**	**1.0%**
Energy consumption intensity (thousand Btu per square foot)								
Delivered energy consumption	106.0	107.3	104.6	103.1	101.0	100.6	99.8	-0.3%
Electricity related losses	117.0	117.3	110.2	110.6	110.6	110.2	109.0	-0.3%
Total energy consumption	223.0	224.5	214.8	213.7	211.5	210.7	208.8	-0.3%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating[1]	0.18	0.18	0.16	0.16	0.16	0.16	0.16	-0.6%
Space cooling[1]	0.47	0.56	0.50	0.50	0.51	0.52	0.53	-0.2%
Water heating[1]	0.09	0.09	0.09	0.09	0.09	0.09	0.08	-0.4%
Ventilation	0.50	0.51	0.53	0.56	0.58	0.61	0.63	0.9%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.3%
Lighting	1.03	1.01	1.00	1.03	1.06	1.10	1.13	0.4%
Refrigeration	0.40	0.39	0.35	0.34	0.34	0.34	0.35	-0.4%
Office equipment (PC)	0.22	0.21	0.19	0.19	0.20	0.21	0.21	0.0%
Office equipment (non-PC)	0.25	0.26	0.31	0.37	0.40	0.44	0.46	2.3%
Other uses[2]	1.29	1.30	1.43	1.62	1.80	2.00	2.22	2.2%
Delivered energy	**4.46**	**4.54**	**4.59**	**4.88**	**5.16**	**5.48**	**5.80**	**1.0%**
Natural gas								
Space heating[1]	1.61	1.65	1.69	1.73	1.70	1.68	1.64	-0.0%
Space cooling[1]	0.03	0.04	0.04	0.04	0.03	0.03	0.03	-1.1%
Water heating[1]	0.43	0.44	0.48	0.51	0.52	0.53	0.54	0.8%
Cooking	0.17	0.18	0.19	0.20	0.21	0.22	0.22	0.9%
Other uses[3]	0.95	0.98	1.01	1.04	1.07	1.14	1.25	1.0%
Delivered energy	**3.20**	**3.28**	**3.41**	**3.51**	**3.53**	**3.60**	**3.69**	**0.5%**
Distillate fuel oil								
Space heating[1]	0.16	0.14	0.12	0.11	0.10	0.10	0.09	-1.7%
Water heating[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.9%
Other uses[4]	0.22	0.26	0.20	0.20	0.20	0.20	0.19	-1.2%
Delivered energy	**0.41**	**0.43**	**0.35**	**0.34**	**0.33**	**0.33**	**0.32**	**-1.2%**
Marketed renewables (biomass)	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.0%
Other fuels[5]	0.33	0.34	0.33	0.34	0.34	0.35	0.36	0.2%
Delivered energy consumption by end use								
Space heating[1]	1.95	1.97	1.98	2.00	1.96	1.93	1.89	-0.2%
Space cooling[1]	0.50	0.60	0.54	0.54	0.54	0.55	0.57	-0.2%
Water heating[1]	0.55	0.56	0.60	0.63	0.64	0.65	0.66	0.7%
Ventilation	0.50	0.51	0.53	0.56	0.58	0.61	0.63	0.9%
Cooking	0.20	0.20	0.21	0.23	0.23	0.24	0.24	0.8%
Lighting	1.03	1.01	1.00	1.03	1.06	1.10	1.13	0.4%
Refrigeration	0.40	0.39	0.35	0.34	0.34	0.34	0.35	-0.4%
Office equipment (PC)	0.22	0.21	0.19	0.19	0.20	0.21	0.21	0.0%
Office equipment (non-PC)	0.25	0.26	0.31	0.37	0.40	0.44	0.46	2.3%
Other uses[6]	2.90	2.99	3.09	3.30	3.53	3.80	4.13	1.3%
Delivered energy	**8.51**	**8.70**	**8.80**	**9.18**	**9.48**	**9.87**	**10.28**	**0.7%**

Table A5. Commercial sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Electricity related losses	**9.39**	**9.52**	**9.27**	**9.85**	**10.38**	**10.82**	**11.23**	**0.7%**
Total energy consumption by end use								
Space heating[1]	2.34	2.35	2.31	2.33	2.28	2.24	2.19	-0.3%
Space cooling[1]	1.50	1.77	1.54	1.55	1.57	1.58	1.60	-0.4%
Water heating[1]	0.75	0.75	0.78	0.80	0.81	0.82	0.82	0.4%
Ventilation	1.56	1.57	1.60	1.69	1.75	1.81	1.84	0.6%
Cooking	0.25	0.25	0.26	0.27	0.27	0.28	0.29	0.5%
Lighting	3.21	3.14	3.01	3.12	3.21	3.27	3.32	0.2%
Refrigeration	1.24	1.21	1.06	1.02	1.02	1.02	1.04	-0.6%
Office equipment (PC)	0.67	0.66	0.57	0.58	0.59	0.61	0.63	-0.2%
Office equipment (non-PC)	0.77	0.81	0.95	1.10	1.21	1.30	1.36	2.1%
Other uses[6]	5.62	5.71	5.98	6.56	7.15	7.75	8.42	1.6%
Total	**17.90**	**18.22**	**18.06**	**19.03**	**19.86**	**20.69**	**21.50**	**0.7%**
Nonmarketed renewable fuels[7]								
Solar thermal	0.03	0.03	0.03	0.03	0.03	0.04	0.04	1.4%
Solar photovoltaic	0.00	0.01	0.01	0.01	0.01	0.01	0.01	2.8%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.3%
Total	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**1.7%**
Heating Degree Days								
New England	6649	5944	6349	6351	6355	6358	6360	0.3%
Middle Atlantic	5798	5453	5588	5587	5586	5585	5583	0.1%
East North Central	6542	6209	6215	6215	6215	6215	6215	0.0%
West North Central	6837	6585	6456	6461	6463	6466	6468	-0.1%
South Atlantic	2839	3183	2728	2703	2677	2651	2625	-0.8%
East South Central	3599	4003	3474	3480	3485	3491	3496	-0.5%
West South Central	2198	2503	2156	2149	2143	2137	2131	-0.6%
Mountain	4852	4808	4780	4749	4713	4677	4641	-0.1%
Pacific	3188	3202	3130	3135	3138	3140	3143	-0.1%
United States	**4408**	**4382**	**4208**	**4172**	**4136**	**4101**	**4067**	**-0.3%**
Cooling Degree Days								
New England	363	655	518	518	517	517	516	-0.9%
Middle Atlantic	587	997	783	783	783	784	784	-1.0%
East North Central	547	978	779	780	780	781	781	-0.9%
West North Central	720	1123	976	975	974	973	973	-0.6%
South Atlantic	2047	2289	2103	2118	2134	2149	2165	-0.2%
East South Central	1491	1999	1668	1665	1662	1658	1655	-0.8%
West South Central	2582	2755	2602	2607	2611	2615	2619	-0.2%
Mountain	1551	1489	1578	1595	1617	1637	1658	0.4%
Pacific	967	746	891	888	887	885	883	0.7%
United States	**1279**	**1498**	**1392**	**1409**	**1426**	**1443**	**1459**	**-0.1%**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[7]Represents delivered energy displaced.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A6. Industrial sector key indicators and consumption

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Key indicators								
Value of shipments (billion 2005 dollars)								
Manufacturing	4052	4260	4857	5260	5745	6023	6285	1.6%
Nonmanufacturing	1615	1578	1873	2103	2228	2305	2407	1.7%
Total	**5667**	**5838**	**6730**	**7363**	**7973**	**8328**	**8692**	**1.6%**
Energy prices								
(2010 dollars per million Btu)								
Liquefied petroleum gases	20.05	21.80	27.43	27.76	29.24	30.48	32.18	1.6%
Motor gasoline	16.79	16.77	29.20	30.72	32.06	33.01	33.55	2.8%
Distillate fuel oil	16.74	21.32	24.20	25.73	27.22	28.39	29.53	1.3%
Residual fuel oil	12.16	10.92	19.21	20.53	21.23	21.71	21.65	2.8%
Asphalt and road oil	6.59	5.59	9.30	9.94	10.37	10.45	10.69	2.6%
Natural gas heat and power	4.59	4.78	4.16	4.41	5.33	5.88	6.89	1.5%
Natural gas feedstocks	6.16	6.32	5.68	5.93	6.83	7.36	8.33	1.1%
Metallurgical coal	5.49	5.84	7.22	7.58	8.11	8.61	9.11	1.8%
Other industrial coal	2.99	2.71	3.27	3.30	3.38	3.50	3.64	1.2%
Coal for liquids	- -	- -	1.26	2.05	2.08	2.22	2.38	- -
Electricity	20.05	19.63	18.91	18.95	19.60	19.81	20.78	0.2%
(nominal dollars per million Btu)								
Liquefied petroleum gases	19.82	21.80	29.56	32.63	37.51	43.38	50.95	3.5%
Motor gasoline	16.60	16.77	31.46	36.10	41.14	46.98	53.12	4.7%
Distillate fuel oil	16.55	21.32	26.08	30.24	34.93	40.40	46.76	3.2%
Residual fuel oil	12.02	10.92	20.70	24.13	27.24	30.89	34.28	4.7%
Asphalt and road oil	6.52	5.59	10.02	11.68	13.30	14.87	16.93	4.5%
Natural gas heat and power	4.54	4.78	4.49	5.19	6.84	8.37	10.91	3.4%
Natural gas feedstocks	6.09	6.32	6.12	6.96	8.77	10.48	13.18	3.0%
Metallurgical coal	5.43	5.84	7.78	8.91	10.40	12.26	14.42	3.7%
Other industrial coal	2.96	2.71	3.52	3.87	4.34	4.98	5.77	3.1%
Coal for liquids	- -	- -	1.36	2.41	2.67	3.16	3.78	- -
Electricity	19.83	19.63	20.38	22.27	25.15	28.20	32.90	2.1%
Energy consumption (quadrillion Btu)[1]								
Industrial consumption excluding refining								
Liquefied petroleum gases heat and power	0.45	0.41	0.36	0.39	0.41	0.41	0.40	-0.0%
Liquefied petroleum gases feedstocks	1.54	1.58	1.45	1.65	1.75	1.76	1.74	0.4%
Motor gasoline	0.24	0.25	0.28	0.30	0.30	0.30	0.30	0.8%
Distillate fuel oil	1.11	1.15	1.25	1.18	1.19	1.17	1.18	0.1%
Residual fuel oil	0.10	0.11	0.09	0.08	0.08	0.08	0.08	-1.1%
Petrochemical feedstocks	0.90	0.94	1.01	1.20	1.29	1.31	1.30	1.3%
Petroleum coke	0.28	0.16	0.20	0.19	0.15	0.12	0.13	-1.1%
Asphalt and road oil	0.87	0.88	1.00	1.00	0.98	0.94	0.94	0.3%
Miscellaneous petroleum[2]	0.38	0.52	0.14	0.12	0.12	0.11	0.12	-5.8%
Petroleum subtotal	5.87	6.00	5.78	6.11	6.27	6.20	6.19	0.1%
Natural gas heat and power	4.48	4.84	5.23	5.22	5.27	5.23	5.23	0.3%
Natural gas feedstocks	0.47	0.48	0.48	0.51	0.50	0.47	0.44	-0.3%
Lease and plant fuel[3]	1.31	1.37	1.43	1.55	1.57	1.59	1.63	0.7%
Natural gas subtotal	6.25	6.69	7.14	7.27	7.34	7.29	7.31	0.4%
Metallurgical coal and coke[4]	0.38	0.55	0.56	0.46	0.46	0.42	0.38	-1.5%
Other industrial coal	0.88	0.95	0.97	0.98	1.02	1.02	1.02	0.3%
Coal subtotal	1.26	1.50	1.53	1.44	1.47	1.44	1.40	-0.3%
Renewables[5]	1.37	1.50	1.61	1.67	1.82	1.87	1.95	1.1%
Purchased electricity	2.94	3.09	3.24	3.26	3.33	3.24	3.12	0.0%
Delivered energy	**17.69**	**18.78**	**19.30**	**19.75**	**20.23**	**20.04**	**19.97**	**0.2%**
Electricity related losses	6.19	6.47	6.55	6.58	6.69	6.39	6.04	-0.3%
Total	**23.88**	**25.25**	**25.84**	**26.33**	**26.92**	**26.44**	**26.01**	**0.1%**

Table A6. Industrial sector key indicators and consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Refining consumption								
Liquefied petroleum gases heat and power	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.4%
Distillate fuel oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Residual fuel oil	0.01	0.01	0.00	0.00	0.00	0.00	0.00	- -
Petroleum coke	0.52	0.52	0.53	0.49	0.49	0.51	0.53	0.1%
Still gas	1.50	1.50	1.55	1.36	1.34	1.39	1.45	-0.1%
Miscellaneous petroleum[2]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	1.2%
Petroleum subtotal	2.05	2.05	2.11	1.89	1.86	1.93	2.02	-0.1%
Natural gas heat and power	1.38	1.44	1.48	1.53	1.55	1.51	1.51	0.2%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas subtotal	1.38	1.44	1.48	1.53	1.55	1.51	1.51	0.2%
Other industrial coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.0%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.26	0.36	0.48	0.60	- -
Coal subtotal	0.06	0.06	0.06	0.32	0.42	0.54	0.66	10.0%
Biofuels heat and coproducts	0.82	0.84	0.81	0.96	1.27	1.92	2.57	4.6%
Purchased electricity	0.19	0.20	0.20	0.20	0.19	0.20	0.21	0.3%
Delivered energy	**4.51**	**4.60**	**4.66**	**4.89**	**5.30**	**6.10**	**6.97**	**1.7%**
Electricity related losses	0.40	0.41	0.39	0.39	0.39	0.40	0.41	0.0%
Total	**4.91**	**5.01**	**5.05**	**5.28**	**5.69**	**6.50**	**7.39**	**1.6%**
Total industrial sector consumption								
Liquefied petroleum gases heat and power	0.46	0.42	0.38	0.41	0.42	0.42	0.41	-0.0%
Liquefied petroleum gases feedstocks	1.54	1.58	1.45	1.65	1.75	1.76	1.74	0.4%
Motor gasoline	0.24	0.25	0.28	0.30	0.30	0.30	0.30	0.8%
Distillate fuel oil	1.11	1.16	1.25	1.18	1.19	1.17	1.18	0.1%
Residual fuel oil	0.11	0.12	0.09	0.08	0.08	0.08	0.08	-1.3%
Petrochemical feedstocks	0.90	0.94	1.01	1.20	1.29	1.31	1.30	1.3%
Petroleum coke	0.80	0.68	0.73	0.68	0.64	0.63	0.66	-0.1%
Asphalt and road oil	0.87	0.88	1.00	1.00	0.98	0.94	0.94	0.3%
Still gas	1.50	1.50	1.55	1.36	1.34	1.39	1.45	-0.1%
Miscellaneous petroleum[2]	0.40	0.54	0.17	0.14	0.14	0.13	0.14	-5.3%
Petroleum subtotal	7.93	8.05	7.89	7.99	8.13	8.13	8.21	0.1%
Natural gas heat and power	5.86	6.28	6.71	6.75	6.82	6.74	6.74	0.3%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas feedstocks	0.47	0.48	0.48	0.51	0.50	0.47	0.44	-0.3%
Lease and plant fuel[3]	1.31	1.37	1.43	1.55	1.57	1.59	1.63	0.7%
Natural gas subtotal	7.63	8.14	8.62	8.80	8.89	8.80	8.81	0.3%
Metallurgical coal and coke[4]	0.38	0.55	0.56	0.46	0.46	0.42	0.38	-1.5%
Other industrial coal	0.94	1.01	1.03	1.04	1.08	1.08	1.08	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.26	0.36	0.48	0.60	- -
Coal subtotal	1.32	1.56	1.59	1.76	1.90	1.98	2.06	1.1%
Biofuels heat and coproducts	0.82	0.84	0.81	0.96	1.27	1.92	2.57	4.6%
Renewables[5]	1.37	1.50	1.61	1.67	1.82	1.87	1.95	1.1%
Purchased electricity	3.13	3.28	3.44	3.46	3.52	3.44	3.33	0.1%
Delivered energy	**22.20**	**23.37**	**23.96**	**24.64**	**25.53**	**26.14**	**26.94**	**0.6%**
Electricity related losses	6.59	6.89	6.94	6.97	7.09	6.80	6.46	-0.3%
Total	**28.79**	**30.26**	**30.90**	**31.61**	**32.61**	**32.93**	**33.39**	**0.4%**

Table A6. Industrial sector key indicators and consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Energy consumption per dollar of shipments (thousand Btu per 2005 dollar)								
Liquid fuels and other petroleum	1.40	1.38	1.17	1.09	1.02	0.98	0.94	-1.5%
Natural gas	1.35	1.39	1.28	1.20	1.11	1.06	1.01	-1.3%
Coal	0.23	0.27	0.24	0.24	0.24	0.24	0.24	-0.5%
Renewable fuels[5]	0.39	0.40	0.36	0.36	0.39	0.45	0.52	1.0%
Purchased electricity	0.55	0.56	0.51	0.47	0.44	0.41	0.38	-1.5%
Delivered energy	**3.92**	**4.00**	**3.56**	**3.35**	**3.20**	**3.14**	**3.10**	**-1.0%**
Industrial combined heat and power								
Capacity (gigawatts)	25.08	25.64	30.38	35.48	40.71	48.10	55.79	3.2%
Generation (billion kilowatthours)	130.57	141.07	168.00	201.40	235.62	287.62	341.40	3.6%

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 prices for motor gasoline and distillate fuel oil are based on: U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2009 and 2010 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2009 and 2010 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011) and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. 2009 and 2010 electricity prices: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 natural gas prices are based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 refining consumption values are based on: *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). 2010 refining consumption based on: *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). Other 2009 and 2010 consumption values are based on: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 shipments: IHS Global Insight, Global Insight Industry model, August 2011. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A7. Transportation sector key indicators and delivered energy consumption

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Key indicators								
Travel indicators								
(billion vehicle miles traveled)								
Light-duty vehicles less than 8,501 pounds	2625	2662	2710	2881	3111	3363	3583	1.2%
Commercial light trucks[1]	58	64	70	76	83	88	92	1.5%
Freight trucks greater than 10,000 pounds	240	234	273	297	317	330	345	1.6%
(billion seat miles available)								
Air	964	999	1028	1075	1120	1164	1208	0.8%
(billion ton miles traveled)								
Rail	1532	1559	1503	1662	1782	1826	1871	0.7%
Domestic shipping	477	522	549	587	604	617	627	0.7%
Energy efficiency indicators								
(miles per gallon)								
New light-duty vehicle CAFE standard[2]	25.4	25.7	32.4	35.0	35.2	35.3	35.3	1.3%
New car[2]	28.2	28.2	37.0	39.9	39.9	39.9	39.9	1.4%
New light truck[2]	23.0	23.4	27.9	29.2	29.2	29.2	29.2	0.9%
Compliance new light-duty vehicle[3]	29.3	29.2	32.5	35.9	36.8	37.4	37.9	1.0%
New car[3]	34.0	33.8	37.4	40.3	41.3	42.2	42.9	1.0%
New light truck[3]	25.4	25.5	27.7	30.6	31.0	31.2	31.5	0.8%
Tested new light-duty vehicle[4]	28.2	28.3	31.5	35.9	36.8	37.4	37.9	1.2%
New car[4]	33.2	33.3	36.4	40.3	41.2	42.2	42.8	1.0%
New light truck[4]	24.2	24.3	26.7	30.6	31.0	31.2	31.5	1.0%
On-road new light-duty vehicle[5]	23.0	22.9	25.6	29.2	30.0	30.5	30.9	1.2%
New car[5]	27.4	27.3	29.9	33.1	33.9	34.7	35.2	1.0%
New light truck[5]	19.5	19.6	21.6	24.7	24.9	25.2	25.4	1.0%
Light-duty stock[6]	20.4	20.4	21.5	23.6	25.6	27.1	28.2	1.3%
New commercial light truck[1]	15.6	15.7	16.7	18.8	18.9	19.0	19.1	0.8%
Stock commercial light truck[1]	14.3	14.4	15.2	16.7	18.0	18.7	19.0	1.1%
Freight truck	6.7	6.7	6.8	7.3	7.7	8.0	8.1	0.8%
(seat miles per gallon)								
Aircraft	62.0	62.3	62.8	63.8	65.2	67.0	69.3	0.4%
(ton miles per thousand Btu)								
Rail	3.4	3.4	3.5	3.5	3.5	3.5	3.5	0.1%
Domestic shipping	2.4	2.4	2.4	2.5	2.5	2.5	2.5	0.2%
Energy use by mode (quadrillion Btu)								
Light-duty vehicles	15.89	16.06	15.39	14.84	14.73	15.05	15.46	-0.2%
Commercial light trucks[1]	0.51	0.55	0.58	0.57	0.58	0.59	0.61	0.4%
Bus transportation	0.21	0.25	0.26	0.27	0.29	0.30	0.31	0.9%
Freight trucks	4.95	4.82	5.51	5.57	5.66	5.69	5.84	0.8%
Rail, passenger	0.04	0.05	0.05	0.06	0.06	0.06	0.06	1.2%
Rail, freight	0.36	0.45	0.43	0.48	0.51	0.52	0.53	0.6%
Shipping, domestic	0.17	0.22	0.23	0.24	0.25	0.25	0.25	0.5%
Shipping, international	0.77	0.86	0.87	0.87	0.88	0.88	0.89	0.1%
Recreational boats	0.24	0.25	0.26	0.26	0.27	0.28	0.29	0.5%
Air	2.44	2.52	2.55	2.63	2.71	2.76	2.79	0.4%
Military use	0.71	0.77	0.66	0.64	0.66	0.70	0.74	-0.1%
Lubricants	0.13	0.14	0.13	0.14	0.14	0.14	0.14	0.1%
Pipeline fuel	0.61	0.65	0.68	0.67	0.67	0.68	0.69	0.2%
Total	**27.04**	**27.59**	**27.60**	**27.25**	**27.40**	**27.90**	**28.60**	**0.1%**

Table A7. Transportation sector key indicators and delivered energy consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Energy use by mode (million barrels per day oil equivalent)								
Light-duty vehicles	8.50	8.63	8.30	8.05	8.05	8.31	8.64	0.0%
Commercial light trucks[1]	0.26	0.28	0.30	0.29	0.30	0.30	0.31	0.4%
Bus transportation	0.10	0.12	0.13	0.13	0.14	0.14	0.15	0.9%
Freight trucks	2.39	2.32	2.65	2.68	2.72	2.74	2.81	0.8%
Rail, passenger	0.02	0.02	0.02	0.03	0.03	0.03	0.03	1.2%
Rail, freight	0.17	0.22	0.21	0.23	0.24	0.25	0.25	0.6%
Shipping, domestic	0.08	0.10	0.11	0.11	0.11	0.11	0.12	0.5%
Shipping, international	0.34	0.38	0.38	0.38	0.38	0.39	0.39	0.1%
Recreational boats	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.5%
Air	1.18	1.22	1.23	1.27	1.31	1.33	1.35	0.4%
Military use	0.34	0.37	0.32	0.31	0.32	0.34	0.36	-0.1%
Lubricants	0.06	0.07	0.06	0.06	0.07	0.07	0.07	0.1%
Pipeline fuel	0.29	0.31	0.32	0.32	0.32	0.32	0.32	0.2%
Total	**13.87**	**14.17**	**14.17**	**14.01**	**14.14**	**14.48**	**14.95**	**0.2%**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]CAFE standard based on projected new vehicle sales.
[3]Includes CAFE credits for alternative fueled vehicle sales and credit banking.
[4]Environmental Protection Agency rated miles per gallon.
[5]Tested new vehicle efficiency revised for on-road performance.
[6]Combined"on-the-road" estimate for all cars and light trucks.
CAFE = Corporate average fuel economy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010); EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011); Federal Highway Administration, *Highway Statistics 2009* (Washington, DC, April 2011); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 30 and Annual* (Oak Ridge, TN, 2011); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 28, 2010); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2008 (Part II - User and Fuel Data), April 2010; EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010/2009* (Washington, DC, December 2010); EIA, *Fuel Oil and Kerosene Sales 2009*, DOE/EIA-0535(2009) (Washington, DC, February 2011); and United States Department of Defense, Defense Fuel Supply Center, Fact Book (January, 2010). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A8. Electricity supply, disposition, prices, and emissions
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Generation by fuel type								
Electric power sector[1]								
Power only[2]								
Coal	1712	1799	1531	1604	1710	1757	1803	0.0%
Petroleum	32	32	25	26	26	27	27	-0.6%
Natural gas[3]	723	776	903	874	882	983	1074	1.3%
Nuclear power	799	807	830	887	917	914	887	0.4%
Pumped storage/other[4]	2	2	2	2	2	2	2	-1.2%
Renewable sources[5]	384	390	504	544	579	594	630	1.9%
Distributed generation (natural gas)	0	0	0	1	2	3	4	- -
Total	**3651**	**3806**	**3796**	**3937**	**4118**	**4279**	**4427**	**0.6%**
Combined heat and power[6]								
Coal	29	32	30	30	31	31	31	-0.1%
Petroleum	4	3	1	1	1	1	1	-5.2%
Natural gas	118	122	126	124	124	124	123	0.0%
Renewable sources	5	5	4	5	5	5	4	-0.7%
Total	**159**	**165**	**160**	**160**	**161**	**160**	**159**	**-0.1%**
Total electric power sector generation	**3810**	**3971**	**3956**	**4097**	**4279**	**4439**	**4586**	**0.6%**
Less direct use	14	16	13	13	13	13	13	-0.7%
Net available to the grid	**3796**	**3955**	**3942**	**4084**	**4265**	**4426**	**4572**	**0.6%**
End-use sector[7]								
Coal	15	20	20	38	46	54	63	4.7%
Petroleum	3	3	2	2	2	2	2	-0.7%
Natural gas	80	84	101	113	132	160	198	3.5%
Other gaseous fuels[8]	10	11	16	16	15	15	15	1.2%
Renewable sources[9]	31	34	55	65	78	103	125	5.4%
Other[10]	4	4	3	3	3	3	3	-0.8%
Total end-use sector generation	**143**	**155**	**197**	**237**	**277**	**338**	**406**	**3.9%**
Less direct use	107	112	149	180	208	243	288	3.8%
Total sales to the grid	**36**	**43**	**48**	**57**	**69**	**95**	**118**	**4.1%**
Total electricity generation by fuel								
Coal	1756	1851	1581	1671	1786	1841	1897	0.1%
Petroleum	39	37	28	28	29	29	30	-0.8%
Natural gas	921	982	1130	1113	1140	1270	1398	1.4%
Nuclear power	799	807	830	887	917	914	887	0.4%
Renewable sources[5,9]	420	429	562	614	662	702	760	2.3%
Other[11]	19	21	21	21	21	21	21	-0.0%
Total electricity generation	**3953**	**4126**	**4152**	**4334**	**4556**	**4777**	**4992**	**0.8%**
Net generation to the grid	**3832**	**3998**	**3990**	**4141**	**4335**	**4521**	**4691**	**0.6%**
Net imports	**34**	**26**	**29**	**26**	**22**	**14**	**12**	**-2.9%**
Electricity sales by sector								
Residential	1364	1451	1392	1454	1533	1626	1718	0.7%
Commercial	1307	1329	1346	1431	1513	1607	1699	1.0%
Industrial	917	962	1008	1013	1032	1009	977	0.1%
Transportation	7	7	8	9	12	16	22	4.8%
Total	**3596**	**3749**	**3753**	**3907**	**4090**	**4258**	**4415**	**0.7%**
Direct use	121	128	162	193	221	256	302	3.5%
Total electricity use	**3717**	**3877**	**3915**	**4100**	**4311**	**4514**	**4716**	**0.8%**

Table A8. Electricity supply, disposition, prices, and emissions (continued)
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
End-use prices								
(2010 cents per kilowatthour)								
Residential	11.6	11.5	11.8	11.6	11.6	11.6	11.8	0.1%
Commercial	10.3	10.1	9.9	9.8	9.9	9.8	10.1	-0.0%
Industrial	6.8	6.7	6.5	6.5	6.7	6.8	7.1	0.2%
Transportation	12.2	11.3	10.4	10.1	10.8	11.1	11.5	0.1%
All sectors average	**9.9**	**9.8**	**9.7**	**9.6**	**9.7**	**9.8**	**10.1**	**0.1%**
(nominal cents per kilowatthour)								
Residential	11.5	11.5	12.7	13.6	14.9	16.5	18.7	2.0%
Commercial	10.1	10.1	10.7	11.5	12.7	13.9	15.9	1.8%
Industrial	6.8	6.7	7.0	7.6	8.6	9.6	11.2	2.1%
Transportation	12.0	11.3	11.2	11.9	13.8	15.8	18.3	2.0%
All sectors average	**9.8**	**9.8**	**10.4**	**11.3**	**12.5**	**13.9**	**16.0**	**2.0%**
Prices by service category								
(2010 cents per kilowatthour)								
Generation	6.1	5.9	5.6	5.7	6.0	6.1	6.4	0.3%
Transmission	1.0	1.0	1.1	1.1	1.1	1.1	1.1	0.3%
Distribution	2.9	2.9	3.0	2.8	2.7	2.6	2.6	-0.5%
(nominal cents per kilowatthour)								
Generation	6.0	5.9	6.0	6.7	7.7	8.7	10.2	2.2%
Transmission	1.0	1.0	1.2	1.3	1.4	1.6	1.8	2.2%
Distribution	2.8	2.9	3.3	3.3	3.4	3.7	4.1	1.4%
Electric power sector emissions[1]								
Sulfur dioxide (million short tons)	5.72	5.11	1.26	1.31	1.55	1.62	1.71	-4.3%
Nitrogen oxide (million short tons)	1.99	2.06	1.79	1.87	1.92	1.94	1.96	-0.2%
Mercury (short tons)	36.25	34.70	6.44	6.74	7.24	7.51	7.86	-5.8%

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The U.S. Energy Information Administration estimates that in 2010 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[5]Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
[6]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes refinery gas and still gas.
[9]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.
[10]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[11]Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 electric power sector generation; sales to the grid; net imports; electricity sales; and electricity end-use prices: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011), and supporting databases. 2009 and 2010 emissions: U.S. Environmental Protection Agency, Clean Air Markets Database. 2009 and 2010 electricity prices by service category: EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. **Projections**: EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A9. Electricity generating capacity
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Electric power sector[2]								
Power only[3]								
Coal	305.9	308.1	276.7	269.8	269.8	269.9	270.4	-0.5%
Oil and natural gas steam[4]	109.1	107.4	90.0	89.4	88.9	88.0	87.2	-0.8%
Combined cycle	167.7	171.7	187.4	187.7	197.6	218.3	246.0	1.4%
Combustion turbine/diesel	133.1	134.8	138.7	145.6	152.7	158.6	169.0	0.9%
Nuclear power[5]	101.1	101.2	103.6	111.2	114.7	114.3	110.9	0.4%
Pumped storage	22.2	22.2	22.2	22.2	22.2	22.2	22.2	0.0%
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7%
Renewable sources[6]	120.3	125.2	144.4	145.8	151.2	156.1	169.3	1.2%
Distributed generation[7]	0.0	0.0	0.2	0.5	0.8	1.3	2.1	- -
Total	**959.5**	**970.6**	**963.2**	**972.1**	**997.8**	**1028.7**	**1077.0**	**0.4%**
Combined heat and power[8]								
Coal	5.3	5.2	4.8	4.8	4.8	4.8	4.8	-0.3%
Oil and natural gas steam[4]	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0%
Combined cycle	25.8	26.3	26.3	26.3	26.3	26.3	26.3	-0.0%
Combustion turbine/diesel	2.8	2.8	2.8	2.8	2.8	2.8	2.8	-0.0%
Renewable sources[6]	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.2%
Total	**35.4**	**35.9**	**35.5**	**35.5**	**35.5**	**35.5**	**35.5**	**-0.0%**
Cumulative planned additions[9]								
Coal	0.0	0.0	9.3	9.3	9.3	9.3	9.3	- -
Oil and natural gas steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combined cycle	0.0	0.0	14.3	14.3	14.3	14.3	14.3	- -
Combustion turbine/diesel	0.0	0.0	5.0	5.0	5.0	5.0	5.0	- -
Nuclear power	0.0	0.0	1.1	6.8	6.8	6.8	6.8	- -
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[6]	0.0	0.0	14.0	14.0	14.0	14.0	14.0	- -
Distributed generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total	**0.0**	**0.0**	**43.7**	**49.3**	**49.3**	**49.3**	**49.3**	**- -**
Cumulative unplanned additions[9]								
Coal	0.0	0.0	0.0	0.9	0.9	1.0	1.7	- -
Oil and natural gas steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combined cycle	0.0	0.0	1.4	1.9	11.8	32.5	60.2	- -
Combustion turbine/diesel	0.0	0.0	5.2	12.9	23.2	30.2	41.5	- -
Nuclear power	0.0	0.0	0.0	0.0	0.0	0.1	1.8	- -
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[6]	0.0	0.0	5.7	7.0	12.4	17.4	30.5	- -
Distributed generation[7]	0.0	0.0	0.2	0.5	0.8	1.3	2.1	- -
Total	**0.0**	**0.0**	**12.4**	**23.2**	**49.1**	**82.5**	**137.8**	**- -**
Cumulative electric power sector additions	**0.0**	**0.0**	**56.1**	**72.5**	**98.5**	**131.8**	**187.1**	**- -**
Cumulative retirements[10]								
Coal	0.0	0.0	41.0	48.9	48.9	48.9	49.0	- -
Oil and natural gas steam[4]	0.0	0.0	17.4	18.0	18.5	19.4	20.3	- -
Combined cycle	0.0	0.0	0.0	0.2	0.2	0.2	0.2	- -
Combustion turbine/diesel	0.0	0.0	6.4	7.2	10.4	11.4	12.4	- -
Nuclear power	0.0	0.0	0.0	0.6	0.6	1.1	6.1	- -
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[6]	0.0	0.0	0.4	0.4	0.4	0.4	0.4	- -
Total	**0.0**	**0.0**	**65.2**	**75.2**	**78.9**	**81.4**	**88.4**	**- -**
Total electric power sector capacity	**994.9**	**1006.5**	**998.7**	**1007.6**	**1033.3**	**1064.2**	**1112.5**	**0.4%**

Table A9. Electricity generating capacity (continued)
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
End-use generators[11]								
Coal	3.6	4.3	4.2	6.6	7.7	8.8	9.9	3.4%
Petroleum	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.3%
Natural gas	14.7	14.7	17.7	19.8	22.9	27.4	33.2	3.3%
Other gaseous fuels[12]	1.8	1.7	2.5	2.5	2.5	2.5	2.5	1.5%
Renewable sources[6]	6.7	7.6	17.6	21.1	23.4	27.1	30.6	5.7%
Other[13]	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0%
Total	**28.0**	**29.6**	**43.3**	**51.3**	**57.8**	**67.1**	**77.5**	**3.9%**
Cumulative capacity additions[9]	**0.0**	**0.0**	**13.7**	**21.7**	**28.2**	**37.4**	**47.9**	**- -**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Nuclear capacity includes 7.3 gigawatts of uprates through 2035.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[9]Cumulative additions after December 31, 2010.
[10]Cumulative retirements after December 31, 2010.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[12]Includes refinery gas and still gas.
[13]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 capacity and projected planned additions: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A10. Electricity trade

(billion kilowatthours, unless otherwise noted)

Electricity trade	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Interregional electricity trade								
Gross domestic sales								
Firm power	232.1	237.5	139.1	104.4	47.1	24.2	24.2	-8.7%
Economy	231.9	137.0	206.3	211.9	235.4	230.1	235.8	2.2%
Total	**464.0**	**374.4**	**345.3**	**316.3**	**282.5**	**254.3**	**260.0**	**-1.4%**
Gross domestic sales (million 2010 dollars)								
Firm power	13923.7	14244.9	8341.5	6259.9	2824.5	1450.4	1450.4	-8.7%
Economy	9065.6	6611.0	8320.2	10576.4	14143.6	13529.2	14541.9	3.2%
Total	**22989.2**	**20855.9**	**16661.8**	**16836.3**	**16968.1**	**14979.5**	**15992.2**	**-1.1%**
International electricity trade								
Imports from Canada and Mexico								
Firm power	19.3	13.7	24.3	17.1	5.2	0.4	0.4	-13.3%
Economy	33.1	31.4	24.7	27.7	34.7	31.0	28.2	-0.4%
Total	**52.4**	**45.1**	**49.0**	**44.8**	**39.9**	**31.4**	**28.6**	**-1.8%**
Exports to Canada and Mexico								
Firm power	3.3	3.7	3.0	2.1	0.6	0.0	0.0	- -
Economy	14.7	15.7	16.9	16.7	17.0	17.0	16.5	0.2%
Total	**18.1**	**19.4**	**19.9**	**18.8**	**17.6**	**17.0**	**16.5**	**-0.7%**

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports. Firm power sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 2009 and 2010 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 2007; NERC, 2011 Summer Reliability Assessment (May 2011); and NERC, Winter Reliability Assessment 2011/2012 (November 2011). 2009 and 2010 Mexican electricity trade data: U.S. Energy Information Administration (EIA), *Electric Power Annual 2010* DOE/EIA-0348(2010) (Washington, DC, November 2011). 2009 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2009*. 2010 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2010*. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A11. Liquid fuels supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Crude oil								
Domestic crude production[1]	5.36	5.47	6.15	6.70	6.40	6.37	5.99	0.4%
Alaska	0.65	0.60	0.46	0.49	0.40	0.44	0.27	-3.2%
Lower 48 states	4.72	4.87	5.69	6.21	6.00	5.94	5.72	0.6%
Net imports	8.97	9.17	8.52	7.15	7.24	7.14	7.52	-0.8%
Gross imports	9.01	9.21	8.56	7.19	7.27	7.17	7.55	-0.8%
Exports	0.04	0.04	0.03	0.04	0.03	0.03	0.03	-1.1%
Other crude supply[2]	0.01	0.08	0.00	0.00	0.00	0.00	0.00	- -
Total crude supply	**14.34**	**14.72**	**14.67**	**13.85**	**13.64**	**13.52**	**13.51**	**-0.3%**
Other petroleum supply	**3.59**	**3.50**	**3.25**	**3.73**	**3.80**	**3.70**	**3.52**	**0.0%**
Natural gas plant liquids	1.91	2.07	2.56	2.91	3.01	3.05	3.01	1.5%
Net product imports	0.75	0.39	-0.25	-0.12	-0.12	-0.25	-0.34	- -
Gross refined product imports[3]	1.27	1.23	0.78	0.73	0.79	0.78	0.82	-1.6%
Unfinished oil imports	0.68	0.61	0.64	0.54	0.51	0.50	0.50	-0.8%
Blending component imports	0.72	0.74	0.66	0.64	0.65	0.65	0.66	-0.5%
Exports	1.92	2.19	2.32	2.03	2.07	2.17	2.31	0.2%
Refinery processing gain[4]	0.98	1.07	0.95	0.94	0.91	0.89	0.85	-0.9%
Product stock withdrawal	-0.04	-0.03	0.00	0.00	0.00	0.00	0.00	- -
Other non-petroleum supply	**0.81**	**1.00**	**1.22**	**1.52**	**1.86**	**2.36**	**2.96**	**4.4%**
Supply from renewable sources	0.75	0.87	1.05	1.22	1.48	1.89	2.37	4.1%
Ethanol	0.73	0.85	0.94	1.04	1.19	1.40	1.65	2.7%
Domestic production	0.72	0.88	0.94	1.04	1.17	1.37	1.59	2.4%
Net imports	0.01	-0.02	0.00	0.00	0.02	0.03	0.06	- -
Biodiesel	0.02	0.01	0.09	0.12	0.12	0.13	0.13	9.2%
Domestic production	0.03	0.02	0.09	0.12	0.12	0.13	0.13	7.9%
Net imports	-0.01	-0.01	0.00	0.00	0.00	0.00	-0.00	- -
Other biomass-derived liquids[5]	0.00	0.00	0.03	0.06	0.16	0.36	0.59	23.2%
Liquids from gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from coal	0.00	0.00	0.00	0.12	0.17	0.22	0.28	- -
Other[6]	0.05	0.13	0.17	0.19	0.21	0.25	0.31	3.6%
Total primary supply[7]	**18.74**	**19.22**	**19.14**	**19.10**	**19.29**	**19.57**	**19.99**	**0.2%**
Liquid fuels consumption								
by fuel								
Liquefied petroleum gases	2.13	2.27	1.94	2.11	2.21	2.22	2.21	-0.1%
E85[8]	0.00	0.00	0.01	0.09	0.21	0.49	0.83	27.0%
Motor gasoline[9]	9.00	8.99	8.88	8.48	8.29	8.17	8.09	-0.4%
Jet fuel[10]	1.39	1.43	1.46	1.49	1.54	1.58	1.61	0.5%
Distillate fuel oil[11]	3.63	3.80	4.19	4.24	4.33	4.38	4.48	0.7%
Diesel	3.18	3.32	3.71	3.81	3.92	3.99	4.11	0.9%
Residual fuel oil	0.51	0.54	0.56	0.56	0.57	0.57	0.58	0.3%
Other[12]	2.15	2.14	2.06	2.04	2.06	2.06	2.10	-0.1%
by sector								
Residential and commercial	1.05	1.12	1.00	0.96	0.94	0.92	0.91	-0.9%
Industrial[13]	4.24	4.31	4.17	4.31	4.41	4.41	4.44	0.1%
Transportation	13.54	13.82	13.80	13.62	13.71	14.00	14.41	0.2%
Electric power[14]	0.17	0.17	0.13	0.13	0.14	0.14	0.14	-0.7%
Total	**18.81**	**19.17**	**19.10**	**19.02**	**19.20**	**19.47**	**19.90**	**0.1%**
Discrepancy[15]	**-0.07**	**0.05**	**0.05**	**0.09**	**0.10**	**0.10**	**0.09**	**- -**

Table A11. Liquid fuels supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Domestic refinery distillation capacity[16]	17.7	17.6	17.5	15.8	15.5	15.4	15.2	-0.6%
Capacity utilization rate (percent)[17]	83.0	86.0	85.9	89.8	90.1	89.6	90.8	0.2%
Net import share of product supplied (percent)	51.9	49.6	43.2	36.8	37.0	35.4	36.2	-1.2%
Net expenditures for imported crude oil and petroleum products (billion 2010 dollars)	206.18	243.07	373.00	322.55	344.58	353.03	389.97	1.9%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol and ethers blended into gasoline.
[10]Includes only kerosene type.
[11]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[13]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[15]Balancing item. Includes unaccounted for supply, losses, and gains.
[16]End-of-year operable capacity.
[17]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 product supplied based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). Other 2009 data: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). Other 2010 data: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A12. Petroleum product prices
(2010 dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Crude oil prices (2010 dollars per barrel)								
Low sulfur light	62.37	79.39	116.91	126.68	132.56	138.49	144.98	2.4%
Imported crude oil[1]	59.72	75.87	113.97	115.74	121.21	126.51	132.95	2.3%
Delivered sector product prices								
Residential								
Liquefied petroleum gases	2.10	2.29	2.60	2.63	2.73	2.82	2.93	1.0%
Distillate fuel oil	2.54	2.94	3.78	4.00	4.18	4.36	4.54	1.8%
Commercial								
Distillate fuel oil	2.23	2.87	3.30	3.51	3.70	3.85	4.02	1.4%
Residual fuel oil	2.04	1.66	2.42	2.63	2.73	2.85	2.83	2.2%
Residual fuel oil (2010 dollars per barrel)	85.89	69.58	101.70	110.65	114.70	119.73	118.85	2.2%
Industrial[2]								
Liquefied petroleum gases	1.70	1.85	2.32	2.35	2.48	2.58	2.73	1.6%
Distillate fuel oil	2.31	2.93	3.32	3.53	3.74	3.90	4.05	1.3%
Residual fuel oil	1.82	1.63	2.88	3.07	3.18	3.25	3.24	2.8%
Residual fuel oil (2010 dollars per barrel)	76.47	68.62	120.80	129.07	133.47	136.47	136.12	2.8%
Transportation								
Liquefied petroleum gases	2.19	2.28	2.70	2.73	2.83	2.91	3.03	1.1%
Ethanol (E85)[3]	1.98	2.40	2.77	2.85	2.75	2.93	3.05	1.0%
Ethanol wholesale price	1.59	1.71	2.23	2.54	2.33	2.29	2.16	0.9%
Motor gasoline[4]	2.38	2.76	3.54	3.71	3.86	3.97	4.03	1.5%
Jet fuel[5]	1.72	2.19	3.21	3.41	3.57	3.72	3.93	2.4%
Diesel fuel (distillate fuel oil)[6]	2.47	3.00	3.78	3.97	4.17	4.30	4.44	1.6%
Residual fuel oil	1.59	1.56	2.74	2.93	3.09	3.11	3.14	2.8%
Residual fuel oil (2010 dollars per barrel)	66.71	65.53	115.15	123.09	129.62	130.52	131.73	2.8%
Electric power[7]								
Distillate fuel oil	2.02	2.60	3.16	3.35	3.52	3.67	3.86	1.6%
Residual fuel oil	1.34	1.78	3.44	3.65	3.80	3.83	3.85	3.1%
Residual fuel oil (2010 dollars per barrel)	56.46	74.77	144.60	153.30	159.70	160.65	161.71	3.1%
Refined petroleum product prices[8]								
Liquefied petroleum gases	1.37	1.46	1.95	1.95	2.05	2.14	2.26	1.7%
Motor gasoline[4]	2.37	2.74	3.54	3.71	3.85	3.97	4.03	1.6%
Jet fuel[5]	1.72	2.19	3.21	3.41	3.57	3.72	3.93	2.4%
Distillate fuel oil	2.44	2.97	3.69	3.89	4.09	4.23	4.38	1.6%
Residual fuel oil	1.57	1.62	2.85	3.04	3.19	3.22	3.25	2.8%
Residual fuel oil (2010 dollars per barrel)	66.10	68.00	119.50	127.68	133.95	135.33	136.32	2.8%
Average	**2.17**	**2.53**	**3.32**	**3.46**	**3.60**	**3.72**	**3.83**	**1.7%**

Table A12. Petroleum product prices (continued)
(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Crude oil prices (nominal dollars per barrel)								
Low sulfur light	61.65	79.39	125.97	148.87	170.09	197.10	229.55	4.3%
Imported crude oil[1]	59.04	75.87	122.81	136.02	155.52	180.06	210.51	4.2%
Delivered sector product prices								
Residential								
Liquefied petroleum gases	2.08	2.29	2.80	3.09	3.51	4.01	4.65	2.9%
Distillate fuel oil	2.52	2.94	4.07	4.70	5.36	6.20	7.19	3.6%
Commercial								
Distillate fuel oil	2.20	2.87	3.56	4.12	4.75	5.48	6.36	3.2%
Residual fuel oil	2.02	1.66	2.61	3.10	3.50	4.06	4.48	4.1%
Residual fuel oil (nominal dollars per barrel)	84.91	69.58	109.59	130.04	147.17	170.40	188.19	4.1%
Industrial[2]								
Liquefied petroleum gases	1.68	1.85	2.50	2.76	3.18	3.67	4.31	3.5%
Distillate fuel oil	2.28	2.93	3.58	4.15	4.80	5.55	6.42	3.2%
Residual fuel oil	1.80	1.63	3.10	3.61	4.08	4.62	5.13	4.7%
Residual fuel oil (nominal dollars per barrel)	75.59	68.62	130.16	151.68	171.25	194.23	215.53	4.7%
Transportation								
Liquefied petroleum gases	2.16	2.28	2.91	3.21	3.63	4.14	4.79	3.0%
Ethanol (E85)[3]	1.96	2.40	2.98	3.35	3.52	4.17	4.82	2.8%
Ethanol wholesale price	1.57	1.71	2.40	2.98	2.99	3.25	3.42	2.8%
Motor gasoline[4]	2.35	2.76	3.81	4.36	4.95	5.64	6.39	3.4%
Jet fuel[5]	1.70	2.19	3.45	4.01	4.58	5.30	6.23	4.3%
Diesel fuel (distillate fuel oil)[6]	2.44	3.00	4.07	4.67	5.35	6.12	7.03	3.5%
Residual fuel oil	1.57	1.56	2.95	3.44	3.96	4.42	4.97	4.7%
Residual fuel oil (nominal dollars per barrel)	65.95	65.53	124.07	144.66	166.32	185.76	208.57	4.7%
Electric power[7]								
Distillate fuel oil	1.99	2.60	3.40	3.94	4.51	5.22	6.11	3.5%
Residual fuel oil	1.33	1.78	3.71	4.29	4.88	5.44	6.10	5.0%
Residual fuel oil (nominal dollars per barrel)	55.81	74.77	155.81	180.16	204.91	228.64	256.05	5.0%
Refined petroleum product prices[8]								
Liquefied petroleum gases	1.35	1.46	2.10	2.30	2.63	3.04	3.57	3.6%
Motor gasoline[4]	2.35	2.74	3.81	4.36	4.95	5.64	6.39	3.4%
Jet fuel[5]	1.70	2.19	3.45	4.01	4.58	5.30	6.23	4.3%
Distillate fuel oil	2.41	2.97	3.97	4.57	5.25	6.03	6.93	3.4%
Residual fuel oil	1.56	1.62	3.07	3.57	4.09	4.59	5.14	4.7%
Residual fuel oil (nominal dollars per barrel)	65.34	68.00	128.77	150.05	171.87	192.61	215.84	4.7%
Average	**2.14**	**2.53**	**3.57**	**4.06**	**4.62**	**5.29**	**6.06**	**3.6%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2009 and 2010 imported crude oil price: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2009 and 2010 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2009 and 2010 electric power prices based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/09) (Washington, DC, September 2011). 2009 and 2010 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2009 and 2010 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A13. Natural gas supply, disposition, and prices
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Production								
Dry gas production[1]	20.58	21.58	23.65	25.09	26.28	26.94	27.93	1.0%
Supplemental natural gas[2]	0.07	0.07	0.06	0.06	0.06	0.06	0.06	-0.2%
Net imports	**2.68**	**2.58**	**1.73**	**0.35**	**-0.79**	**-0.89**	**-1.36**	**- -**
Pipeline[3]	2.26	2.21	1.56	1.01	-0.13	-0.27	-0.70	- -
Liquefied natural gas	0.42	0.37	0.16	-0.66	-0.66	-0.62	-0.66	- -
Total supply	**23.32**	**24.22**	**25.45**	**25.50**	**25.55**	**26.11**	**26.63**	**0.4%**
Consumption by sector								
Residential	4.78	4.94	4.85	4.83	4.76	4.72	4.64	-0.2%
Commercial	3.12	3.20	3.33	3.43	3.44	3.52	3.60	0.5%
Industrial[4]	6.17	6.60	7.01	7.08	7.14	7.03	7.00	0.2%
Natural-gas-to-liquids heat and power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas to liquids production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electric power[7]	6.87	7.38	8.08	7.87	7.87	8.47	8.96	0.8%
Transportation[8]	0.04	0.04	0.06	0.08	0.11	0.14	0.16	5.9%
Pipeline fuel	0.60	0.63	0.67	0.66	0.66	0.66	0.67	0.2%
Lease and plant fuel[9]	1.28	1.34	1.39	1.51	1.53	1.55	1.60	0.7%
Total	**22.85**	**24.13**	**25.39**	**25.47**	**25.53**	**26.10**	**26.63**	**0.4%**
Discrepancy[10]	**0.47**	**0.10**	**0.05**	**0.04**	**0.02**	**0.01**	**-0.00**	**- -**
Natural gas prices								
(2010 dollars per million Btu)								
Henry hub spot price	4.00	4.39	4.29	4.58	5.63	6.29	7.37	2.1%
Average lower 48 wellhead price[11]	3.75	4.06	3.84	4.10	5.00	5.56	6.48	1.9%
(2010 dollars per thousand cubic feet)								
Average lower 48 wellhead price[11]	3.85	4.16	3.94	4.19	5.12	5.69	6.64	1.9%
Delivered prices								
(2010 dollars per thousand cubic feet)								
Residential	12.25	11.36	10.56	11.11	12.33	13.08	14.33	0.9%
Commercial	10.06	9.32	8.82	9.21	10.27	10.86	11.93	1.0%
Industrial[4]	5.47	5.65	5.00	5.25	6.19	6.73	7.73	1.3%
Electric power[7]	4.97	5.25	4.65	4.83	5.73	6.35	7.37	1.4%
Transportation[12]	14.52	13.53	12.71	12.81	13.62	14.02	14.87	0.4%
Average[13]	**7.55**	**7.33**	**6.60**	**6.93**	**7.93**	**8.50**	**9.52**	**1.1%**

Table A13. Natural gas supply, disposition, and prices (continued)
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Natural gas prices								
(nominal dollars per million Btu)								
Henry hub spot price	3.95	4.39	4.62	5.39	7.23	8.95	11.67	4.0%
Average lower 48 wellhead price[11]	3.71	4.06	4.14	4.81	6.42	7.92	10.26	3.8%
(nominal dollars per thousand cubic feet)								
Average lower 48 wellhead price[11]	3.80	4.16	4.24	4.93	6.57	8.11	10.51	3.8%
Delivered prices								
(nominal dollars per thousand cubic feet)								
Residential	12.11	11.36	11.38	13.06	15.82	18.61	22.69	2.8%
Commercial	9.95	9.32	9.50	10.82	13.18	15.46	18.89	2.9%
Industrial[4]	5.40	5.65	5.39	6.17	7.94	9.58	12.23	3.1%
Electric power[7]	4.92	5.25	5.01	5.67	7.35	9.03	11.67	3.2%
Transportation[12]	14.36	13.53	13.70	15.06	17.48	19.95	23.54	2.2%
Average[13]	**7.46**	**7.33**	**7.11**	**8.15**	**10.17**	**12.10**	**15.08**	**2.9%**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[8]Natural gas used as vehicle fuel.
[9]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[10]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2009 and 2010 values include net storage injections.
[11]Represents lower 48 onshore and offshore supplies.
[12]Natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[13]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 supply values; and lease, plant, and pipeline fuel consumption: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 supply values; lease, plant, and pipeline fuel consumption; and wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). Other 2009 and 2010 consumption based on: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 wellhead price: U.S. Department of the Interior, Office of Natural Resources Revenue; and EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2009 residential and commercial delivered prices: EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 and 2010 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2010 and April 2011, Table 4.2, and EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2009 and 2010 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and estimated state taxes, federal taxes, and dispensing costs or charges. 2010 transportation sector delivered prices are model results. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A14. Oil and gas supply

Production and supply	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Crude oil								
Lower 48 average wellhead price[1] (2010 dollars per barrel)	**57.46**	**80.46**	**117.84**	**124.44**	**130.30**	**130.74**	**137.55**	**2.2%**
Production (million barrels per day)[2]								
United States total	5.36	5.47	6.15	6.70	6.40	6.37	5.99	0.4%
Lower 48 onshore	3.04	3.21	4.09	4.38	4.43	4.29	3.99	0.9%
Tight oil[3]	0.25	0.37	0.97	1.20	1.29	1.32	1.23	4.9%
Carbon dioxide enhanced oil recovery	0.27	0.28	0.26	0.33	0.49	0.61	0.66	3.5%
Other	2.52	2.55	2.86	2.85	2.66	2.36	2.10	-0.8%
Lower 48 offshore	1.68	1.67	1.60	1.83	1.57	1.65	1.74	0.2%
Alaska	0.65	0.60	0.46	0.49	0.40	0.44	0.27	-3.2%
Lower 48 end of year reserves[2] (billion barrels)	**18.75**	**18.33**	**20.55**	**23.02**	**23.64**	**24.34**	**24.23**	**1.1%**
Natural gas								
Lower 48 average wellhead price[1] (2010 dollars per million Btu)								
Henry hub spot price	4.00	4.39	4.29	4.58	5.63	6.29	7.37	2.1%
Average lower 48 wellhead price[1]	3.75	4.06	3.84	4.10	5.00	5.56	6.48	1.9%
(2010 dollars per thousand cubic feet)								
Average lower 48 wellhead price[1]	3.85	4.16	3.94	4.19	5.12	5.69	6.64	1.9%
Dry production (trillion cubic feet)[4]								
United States total	20.58	21.58	23.65	25.09	26.28	26.94	27.93	1.0%
Lower 48 onshore	17.50	18.66	21.48	22.48	23.64	24.11	24.97	1.2%
Associated-dissolved[5]	1.40	1.40	1.52	1.54	1.41	1.18	1.00	-1.3%
Non-associated	16.10	17.26	19.96	20.94	22.23	22.93	23.97	1.3%
Tight gas	6.40	5.68	6.08	6.06	6.17	6.07	6.14	0.3%
Shale gas	2.91	4.99	8.24	9.69	11.26	12.42	13.63	4.1%
Coalbed methane	1.99	1.99	1.83	1.79	1.77	1.74	1.76	-0.5%
Other	4.80	4.59	3.82	3.40	3.03	2.70	2.44	-2.5%
Lower 48 offshore	2.70	2.56	1.88	2.34	2.38	2.58	2.72	0.3%
Associated-dissolved[5]	0.70	0.71	0.55	0.75	0.67	0.70	0.73	0.1%
Non-associated	2.00	1.85	1.33	1.59	1.71	1.88	2.00	0.3%
Alaska	0.37	0.36	0.29	0.27	0.25	0.25	0.23	-1.8%
Lower 48 end of year dry reserves[4] (trillion cubic feet)	**263.40**	**260.50**	**274.79**	**290.32**	**299.77**	**307.17**	**311.58**	**0.7%**
Supplemental gas supplies (trillion cubic feet)[6]	**0.07**	**0.07**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**-0.2%**
Total lower 48 wells drilled (thousands)	**34.31**	**43.19**	**49.79**	**53.80**	**59.42**	**60.21**	**65.59**	**1.7%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[4]Marketed production (wet) minus extraction losses.
[5]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[6]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2009 and 2010 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). 2009 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2009) (Washington, DC, November 2010). 2009 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2009 natural gas lower 48 average wellhead price: U.S. Department of the Interior, Office of Natural Resources Revenue; and EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). Other 2009 and 2010 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A15. Coal supply, disposition, and prices
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Production[1]								
Appalachia	343	336	300	262	271	282	291	-0.6%
Interior	147	156	151	159	163	181	198	1.0%
West	585	592	542	613	684	703	722	0.8%
East of the Mississippi	450	446	407	377	383	409	431	-0.1%
West of the Mississippi	625	638	586	657	735	757	781	0.8%
Total	**1075**	**1084**	**993**	**1034**	**1118**	**1166**	**1212**	**0.4%**
Waste coal supplied[2]	**14**	**14**	**15**	**15**	**16**	**17**	**19**	**1.4%**
Net imports								
Imports[3]	21	18	15	28	44	33	36	2.8%
Exports	59	82	110	95	115	117	129	1.8%
Total	**-38**	**-64**	**-95**	**-67**	**-71**	**-83**	**-94**	**- -**
Total supply[4]	**1050**	**1034**	**914**	**982**	**1064**	**1100**	**1138**	**0.4%**
Consumption by sector								
Residential and commercial	3	3	3	3	3	3	3	-0.3%
Coke plants	15	21	22	18	19	18	17	-1.0%
Other industrial[5]	45	52	50	51	52	52	53	0.0%
Coal-to-liquids heat and power	0	0	0	13	19	26	34	- -
Coal to liquids production	0	0	0	12	18	25	32	- -
Electric power[6]	934	975	839	885	952	975	998	0.1%
Total	**997**	**1051**	**914**	**982**	**1063**	**1099**	**1137**	**0.3%**
Discrepancy and stock change[7]	**53**	**-17**	**-0**	**-0**	**1**	**0**	**0**	**- -**
Average minemouth price[8]								
(2010 dollars per short ton)	33.62	35.61	42.08	40.96	44.05	47.28	50.52	1.4%
(2010 dollars per million Btu)	1.68	1.76	2.08	2.06	2.23	2.39	2.56	1.5%
Delivered prices (2010 dollars per short ton)[9]								
Coke plants	144.66	153.59	189.11	198.45	212.18	225.36	238.32	1.8%
Other industrial[5]	65.62	59.28	70.14	70.89	72.77	75.43	78.53	1.1%
Coal to liquids	- -	- -	18.65	40.67	39.03	40.20	41.54	- -
Electric power								
(2010 dollars per short ton)	43.83	44.27	45.17	45.98	48.13	50.56	53.31	0.7%
(2010 dollars per million Btu)	2.22	2.26	2.35	2.41	2.54	2.66	2.80	0.9%
Average	**46.41**	**47.17**	**49.95**	**49.99**	**51.90**	**54.09**	**56.48**	**0.7%**
Exports[10]	102.61	120.41	140.89	155.03	163.43	172.39	177.66	1.6%

Table A15. Coal supply, disposition, and prices (continued)
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Average minemouth price[8]								
(nominal dollars per short ton)	33.24	35.61	45.34	48.13	56.52	67.28	80.00	3.3%
(nominal dollars per million Btu)	1.66	1.76	2.24	2.42	2.86	3.41	4.05	3.4%
Delivered prices (nominal dollars per short ton)[9]								
Coke plants	143.01	153.59	203.77	233.22	272.25	320.74	377.36	3.7%
Other industrial[5]	64.87	59.28	75.58	83.31	93.37	107.35	124.34	3.0%
Coal to liquids	- -	- -	20.09	47.80	50.08	57.22	65.77	- -
Electric power								
(nominal dollars per short ton)	43.33	44.27	48.68	54.03	61.76	71.96	84.40	2.6%
(nominal dollars per million Btu)	2.19	2.26	2.53	2.83	3.25	3.78	4.43	2.7%
Average	**45.88**	**47.17**	**53.83**	**58.74**	**66.60**	**76.98**	**89.43**	**2.6%**
Exports[10]	101.44	120.41	151.81	182.19	209.70	245.35	281.30	3.5%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
[8]Includes reported prices for both open market and captive mines.
[9]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[10]F.a.s. price at U.S. port of exit.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011); EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011); and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A16. Renewable energy generating capacity and generation
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Electric power sector[1]								
Net summer capacity								
Conventional hydropower	78.01	78.03	78.55	79.13	80.14	80.66	81.25	0.2%
Geothermal[2]	2.37	2.37	2.86	3.57	4.45	5.48	6.30	4.0%
Municipal waste[3]	3.20	3.30	3.36	3.36	3.36	3.36	3.36	0.1%
Wood and other biomass[4]	2.43	2.45	2.72	2.72	2.72	2.72	2.89	0.7%
Solar thermal	0.47	0.47	1.36	1.36	1.36	1.36	1.36	4.3%
Solar photovoltaic[5]	0.15	0.38	2.02	2.03	2.30	2.97	8.18	13.0%
Wind	34.52	39.05	54.26	54.31	57.57	60.29	66.65	2.2%
Offshore wind	0.00	0.00	0.20	0.20	0.20	0.20	0.20	- -
Total electric power sector capacity	**121.16**	**126.06**	**145.34**	**146.68**	**152.10**	**157.05**	**170.19**	**1.2%**
Generation (billion kilowatthours)								
Conventional hydropower	271.50	255.32	295.43	300.54	305.00	307.40	310.08	0.8%
Geothermal[2]	15.01	15.67	18.68	24.41	31.53	39.89	46.54	4.5%
Biogenic municipal waste[6]	16.10	16.56	14.66	14.67	14.67	14.67	14.67	-0.5%
Wood and other biomass	10.74	11.51	21.28	51.60	63.90	57.08	49.28	6.0%
Dedicated plants	9.68	10.15	10.13	13.16	13.30	11.81	10.37	0.1%
Cofiring	1.06	1.36	11.15	38.44	50.60	45.27	38.92	14.4%
Solar thermal	0.74	0.82	2.86	2.86	2.86	2.86	2.86	5.1%
Solar photovoltaic[5]	0.16	0.46	3.61	3.62	4.37	6.16	20.19	16.4%
Wind	73.88	94.49	150.22	150.34	160.73	169.64	189.92	2.8%
Offshore wind	0.00	0.00	0.75	0.75	0.75	0.75	0.75	- -
Total electric power sector generation	**388.11**	**394.82**	**507.49**	**548.78**	**583.81**	**598.46**	**634.30**	**1.9%**
End-use sectors[7]								
Net summer capacity								
Conventional hydropower[8]	0.34	0.33	0.33	0.33	0.33	0.33	0.33	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal waste[9]	0.36	0.35	0.35	0.35	0.35	0.35	0.35	0.0%
Biomass	4.56	4.56	5.73	6.68	8.44	11.31	13.81	4.5%
Solar photovoltaic[5]	1.22	2.05	8.98	11.19	11.69	12.41	13.33	7.8%
Wind	0.18	0.36	2.25	2.57	2.60	2.65	2.74	8.5%
Total end-use sector capacity	**6.66**	**7.65**	**17.64**	**21.12**	**23.41**	**27.05**	**30.57**	**5.7%**
Generation (billion kilowatthours)								
Conventional hydropower[8]	1.94	1.76	1.75	1.75	1.75	1.75	1.75	-0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal waste[9]	2.07	2.02	2.79	2.79	2.79	2.79	2.79	1.3%
Biomass	25.31	26.10	33.30	39.53	52.34	76.03	96.17	5.4%
Solar photovoltaic[5]	1.93	3.21	13.88	17.40	18.22	19.40	20.91	7.8%
Wind	0.24	0.47	2.88	3.31	3.36	3.44	3.56	8.5%
Total end-use sector generation	**31.48**	**33.56**	**54.59**	**64.77**	**78.45**	**103.40**	**125.17**	**5.4%**

Table A16. Renewable energy generating capacity and generation (continued)
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Total, all sectors								
Net summer capacity								
Conventional hydropower	78.35	78.36	78.88	79.46	80.47	80.99	81.58	0.2%
Geothermal	2.37	2.37	2.86	3.57	4.45	5.48	6.30	4.0%
Municipal waste	3.57	3.65	3.71	3.71	3.71	3.71	3.71	0.1%
Wood and other biomass[4]	6.99	7.00	8.45	9.40	11.16	14.03	16.71	3.5%
Solar[5]	1.85	2.90	12.37	14.58	15.35	16.74	22.87	8.6%
Wind	34.70	39.41	56.72	57.07	60.37	63.15	69.59	2.3%
Total capacity, all sectors	**127.83**	**133.70**	**162.98**	**167.80**	**175.51**	**184.10**	**200.76**	**1.6%**
Generation (billion kilowatthours)								
Conventional hydropower	273.44	257.08	297.18	302.28	306.75	309.15	311.83	0.8%
Geothermal	15.01	15.67	18.68	24.41	31.53	39.89	46.54	4.5%
Municipal waste	18.16	18.59	17.45	17.46	17.46	17.46	17.46	-0.3%
Wood and other biomass	36.05	37.61	54.58	91.13	116.24	133.11	145.45	5.6%
Solar[5]	2.82	4.48	20.35	23.87	25.44	28.42	43.96	9.6%
Wind	74.12	94.95	153.85	154.40	164.84	173.83	194.23	2.9%
Total generation, all sectors	**419.59**	**428.38**	**562.08**	**613.55**	**662.25**	**701.85**	**759.46**	**2.3%**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity generation and is only available after 2025.
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2009, EIA estimates that as much as 245 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2009, plus an additional 558 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011), Table 10.9 (annual PV shipments, 1989-2009). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[6]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2010 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Represents own-use industrial hydroelectric power.
[9]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 capacity: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2009 and 2010 generation: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A17. Renewable energy consumption by sector and source
(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Marketed renewable energy[1]								
Residential (wood)	**0.43**	**0.42**	**0.43**	**0.43**	**0.43**	**0.43**	**0.43**	**0.1%**
Commercial (biomass)	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.0%**
Industrial[2]	**2.19**	**2.34**	**2.42**	**2.63**	**3.09**	**3.79**	**4.52**	**2.7%**
Conventional hydroelectric	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.0%
Municipal waste[3]	0.16	0.17	0.18	0.18	0.18	0.18	0.18	0.1%
Biomass	1.19	1.31	1.42	1.48	1.62	1.68	1.76	1.2%
Biofuels heat and coproducts	0.82	0.84	0.81	0.96	1.27	1.92	2.57	4.6%
Transportation	**0.99**	**1.14**	**1.45**	**1.72**	**2.16**	**2.88**	**3.75**	**4.9%**
Ethanol used in E85[4]	0.00	0.00	0.01	0.08	0.20	0.47	0.80	27.0%
Ethanol used in gasoline blending	0.95	1.10	1.21	1.27	1.35	1.35	1.34	0.8%
Biodiesel used in distillate blending	0.04	0.03	0.18	0.23	0.24	0.25	0.26	9.2%
Liquids from biomass	0.00	0.00	0.03	0.11	0.33	0.78	1.31	- -
Renewable diesel and gasoline[5]	0.00	0.01	0.03	0.03	0.03	0.03	0.03	6.2%
Electric power[6]	**3.77**	**3.85**	**4.96**	**5.40**	**5.75**	**5.87**	**6.22**	**1.9%**
Conventional hydroelectric	2.65	2.49	2.88	2.93	2.98	3.00	3.03	0.8%
Geothermal	0.15	0.15	0.18	0.24	0.31	0.39	0.45	4.5%
Biogenic municipal waste[7]	0.07	0.08	0.09	0.09	0.09	0.09	0.09	0.6%
Biomass	0.17	0.19	0.27	0.60	0.73	0.64	0.56	4.4%
Dedicated plants	0.16	0.17	0.16	0.21	0.22	0.18	0.16	-0.1%
Cofiring	0.01	0.02	0.11	0.39	0.52	0.46	0.40	11.8%
Solar thermal	0.01	0.01	0.03	0.03	0.03	0.03	0.03	5.1%
Solar photovoltaic	0.00	0.00	0.04	0.04	0.04	0.06	0.20	16.4%
Wind	0.72	0.92	1.47	1.47	1.58	1.66	1.86	2.8%
Total marketed renewable energy	**7.49**	**7.87**	**9.37**	**10.29**	**11.54**	**13.09**	**15.03**	**2.6%**
Sources of ethanol								
from corn and other starch	0.94	1.14	1.20	1.32	1.39	1.39	1.46	1.0%
from cellulose	0.00	0.00	0.01	0.03	0.13	0.40	0.61	56.6%
Net imports	0.02	-0.03	0.00	0.00	0.03	0.04	0.08	- -
Total	**0.95**	**1.11**	**1.22**	**1.35**	**1.55**	**1.82**	**2.15**	**2.7%**

Table A17. Renewable energy consumption by sector and source (continued)
(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Nonmarketed renewable energy[8]								
Selected consumption								
Residential	**0.02**	**0.02**	**0.08**	**0.10**	**0.10**	**0.11**	**0.11**	**6.9%**
Solar hot water heating	0.01	0.01	0.02	0.02	0.02	0.02	0.02	2.4%
Geothermal heat pumps	0.00	0.01	0.01	0.02	0.02	0.02	0.03	6.4%
Solar photovoltaic	0.00	0.00	0.04	0.05	0.05	0.06	0.06	10.7%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	9.1%
Commercial	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**1.7%**
Solar thermal	0.03	0.03	0.03	0.03	0.03	0.04	0.04	1.4%
Solar photovoltaic	0.00	0.01	0.01	0.01	0.01	0.01	0.01	2.8%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.3%

[1]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A2.
[2]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Excludes motor gasoline component of E85.
[5]Renewable feedstocks for the on-site production of diesel and gasoline.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, geothermal, solar, and wind. Consumption at hydroelectric, geothermal, solar, and wind facilities determined by using the fossil fuel equivalent of 9,760 Btu per kilowatthour.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2010 approximately 0.3 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[8]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The U.S. Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 ethanol: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2009 and 2010 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A18. Energy-related carbon dioxide emissions by sector and source
(million metric tons, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Residential								
Petroleum	81	85	74	69	65	61	59	-1.5%
Natural gas	259	267	264	263	259	257	252	-0.2%
Coal	1	1	1	1	1	1	1	-1.3%
Electricity[1]	819	879	746	769	816	862	907	0.1%
Total residential	**1159**	**1232**	**1084**	**1101**	**1141**	**1181**	**1218**	**-0.0%**
Commercial								
Petroleum	49	51	44	44	44	44	44	-0.6%
Natural gas	169	173	181	186	187	191	196	0.5%
Coal	6	6	6	6	6	6	6	0.0%
Electricity[1]	785	805	721	757	806	852	897	0.4%
Total commercial	**1009**	**1035**	**952**	**993**	**1043**	**1093**	**1142**	**0.4%**
Industrial[2]								
Petroleum	339	344	364	350	351	351	358	0.2%
Natural gas[3]	383	408	445	454	459	455	456	0.4%
Coal	128	157	154	170	183	190	197	0.9%
Electricity[1]	551	583	540	536	550	535	516	-0.5%
Total industrial	**1401**	**1492**	**1503**	**1509**	**1542**	**1531**	**1527**	**0.1%**
Transportation								
Petroleum[4]	1818	1836	1825	1785	1778	1791	1814	-0.0%
Natural gas[5]	34	36	39	40	42	44	45	0.9%
Electricity[1]	4	4	4	5	7	9	12	4.2%
Total transportation	**1856**	**1876**	**1868**	**1831**	**1827**	**1843**	**1871**	**-0.0%**
Electric power[6]								
Petroleum	34	33	23	23	24	24	25	-1.1%
Natural gas	373	399	438	427	427	459	485	0.8%
Coal	1741	1828	1539	1606	1717	1763	1809	-0.0%
Other[7]	12	12	12	12	12	12	12	0.0%
Total electric power	**2159**	**2271**	**2011**	**2067**	**2179**	**2258**	**2330**	**0.1%**
Total by fuel								
Petroleum[3]	2320	2349	2329	2271	2261	2271	2300	-0.1%
Natural gas	1218	1283	1367	1370	1374	1405	1435	0.4%
Coal	1876	1990	1699	1781	1906	1959	2012	0.0%
Other[7]	12	12	12	12	12	12	12	0.0%
Total	**5425**	**5634**	**5407**	**5434**	**5552**	**5647**	**5758**	**0.1%**
Carbon dioxide emissions (tons per person)	**17.6**	**18.1**	**16.6**	**15.9**	**15.5**	**15.1**	**14.8**	**-0.8%**

[1]Emissions from the electric power sector are distributed to the end-use sectors.
[2]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes lease and plant fuel.
[4]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2009, international bunker fuels accounted for 90 to 126 million metric tons annually.
[5]Includes pipeline fuel natural gas and natural gas used as vehicle fuel.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.

Note: By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. See "Energy-Related Carbon Dioxide Emissions by End Use" for the emissions from biogenic energy sources as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration. Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review, October 2011* DOE/EIA-0035(2011/10) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A19. Energy-related carbon dioxide emissions by end use
(million metric tons)

Sector and end use	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Residential								
Space heating	280.90	298.51	277.05	272.48	267.41	264.17	259.97	-0.6%
Space cooling	142.72	191.18	159.32	164.10	174.13	183.61	192.21	0.0%
Water heating	160.15	159.68	151.53	154.46	157.58	156.73	154.55	-0.1%
Refrigeration	66.17	66.06	57.91	58.63	61.36	64.38	67.24	0.1%
Cooking	32.01	32.25	30.98	32.26	33.88	35.40	36.82	0.5%
Clothes dryers	36.78	37.23	33.43	31.76	30.86	30.58	31.50	-0.7%
Freezers	14.50	14.62	13.14	13.17	13.46	13.61	13.81	-0.2%
Lighting	123.36	122.27	81.97	74.77	72.02	71.52	72.33	-2.1%
Clothes washers[1]	5.87	5.79	4.96	4.18	3.86	3.64	3.74	-1.7%
Dishwashers[1]	17.70	17.75	15.48	15.32	15.33	16.16	17.28	-0.1%
Color televisions and set-top boxes	56.62	58.20	50.98	53.06	57.14	61.62	66.45	0.5%
Personal computers and related equipment	29.75	30.47	29.70	33.59	37.07	39.80	41.67	1.3%
Furnace fans and boiler circulation pumps	23.80	23.93	21.88	22.19	22.63	22.80	23.00	-0.2%
Other uses	167.37	173.46	155.66	171.03	194.05	216.69	237.60	1.3%
Discrepancy[2]	1.73	0.16	0.00	-0.00	0.00	0.00	0.00	- -
Total residential	**1159.44**	**1231.57**	**1083.99**	**1101.00**	**1140.80**	**1180.73**	**1218.17**	**-0.0%**
Commercial								
Space heating[3]	129.16	129.68	124.70	124.97	122.24	120.61	118.00	-0.4%
Space cooling[3]	84.66	101.34	80.33	79.94	81.20	82.60	84.17	-0.7%
Water heating[3]	41.32	41.44	41.47	42.83	43.45	44.00	44.04	0.2%
Ventilation	88.64	90.04	83.19	86.87	90.94	94.43	97.04	0.3%
Cooking	13.27	13.58	13.68	14.20	14.47	14.84	15.13	0.4%
Lighting	181.96	180.09	156.69	160.17	166.24	171.06	174.62	-0.1%
Refrigeration	70.13	69.16	55.15	52.64	52.71	53.53	54.79	-0.9%
Office equipment (PC)	38.00	37.69	29.68	29.85	30.75	32.11	33.19	-0.5%
Office equipment (non-PC)	43.86	46.44	49.41	56.62	62.87	67.77	71.49	1.7%
Other uses[4]	317.61	325.18	317.95	345.09	378.20	411.92	449.71	1.3%
Total commercial	**1008.62**	**1034.63**	**952.26**	**993.16**	**1043.07**	**1092.87**	**1142.18**	**0.4%**
Industrial								
Manufacturing								
Refining	261.44	265.88	268.04	278.94	288.94	303.58	322.94	0.8%
Food products	100.97	105.04	98.92	104.00	108.26	111.71	113.98	0.3%
Paper products	77.15	76.70	71.83	71.82	73.13	71.21	69.81	-0.4%
Bulk chemicals	221.74	234.55	213.65	229.11	233.13	225.47	215.77	-0.3%
Glass	18.92	18.59	19.05	20.00	21.33	21.21	20.50	0.4%
Cement manufacturing	25.91	25.67	33.19	35.70	37.08	36.48	37.41	1.5%
Iron and steel	91.87	116.74	117.01	110.23	114.88	107.91	99.25	-0.6%
Aluminum	27.63	30.89	28.68	27.66	26.37	24.89	23.14	-1.1%
Fabricated metal products	36.69	36.14	36.43	36.81	37.90	35.62	33.25	-0.3%
Machinery	22.80	23.76	24.75	24.32	26.46	25.49	23.73	-0.0%
Computers and electronics	30.67	33.07	32.16	33.69	36.48	36.57	36.74	0.4%
Transportation equipment	43.77	45.62	56.18	54.82	54.85	57.23	58.87	1.0%
Electrical equipment	7.86	8.17	8.23	8.25	9.10	8.85	8.55	0.2%
Wood products	16.74	16.90	19.68	19.99	20.46	19.14	18.50	0.4%
Plastics	37.47	38.26	34.96	35.35	34.86	34.29	33.32	-0.6%
Balance of manufacturing	142.01	142.62	133.94	136.85	138.25	133.50	129.25	-0.4%
Total manufacturing	1163.64	1218.60	1196.68	1227.54	1261.49	1253.14	1245.00	0.1%
Nonmanufacturing								
Agriculture	73.84	73.82	69.73	68.13	68.31	67.95	68.29	-0.3%
Construction	76.16	69.67	83.15	91.08	92.27	91.23	91.95	1.1%
Mining	43.45	46.03	44.37	44.16	43.79	43.23	42.83	-0.3%
Total nonmanufacturing	193.45	189.52	197.25	203.37	204.37	202.41	203.08	0.3%
Discrepancy[2]	43.83	83.41	108.76	78.58	76.09	74.99	78.94	-0.2%
Total industrial	**1400.92**	**1491.53**	**1502.69**	**1509.48**	**1541.94**	**1530.55**	**1527.02**	**0.1%**

Table A19. Energy-related carbon dioxide emissions by end use (continued)
(million metric tons)

Sector and end use	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Transportation								
Light-duty vehicles	1068.20	1060.96	1014.74	966.95	945.91	950.30	957.76	-0.4%
Commercial light trucks[5]	35.27	38.02	39.58	38.75	38.76	39.51	40.97	0.3%
Bus transportation	14.85	17.67	17.32	17.17	17.13	17.18	17.32	-0.1%
Freight trucks	356.16	348.09	389.50	391.24	396.52	398.85	409.21	0.6%
Rail, passenger	5.41	5.84	5.76	6.02	6.39	6.70	6.98	0.7%
Rail, freight	26.27	32.99	30.95	33.83	36.05	36.73	37.43	0.5%
Shipping, domestic	13.03	16.31	16.75	17.65	17.97	18.15	18.27	0.5%
Shipping, international	60.55	67.51	67.87	68.23	68.70	69.13	69.55	0.1%
Recreational boats	16.45	17.12	17.27	17.53	17.90	18.42	18.94	0.4%
Air	172.79	178.28	180.48	186.23	192.08	195.53	197.54	0.4%
Military use	50.94	54.70	47.05	45.77	47.13	49.65	52.56	-0.2%
Lubricants	4.71	5.19	5.00	5.10	5.19	5.24	5.28	0.1%
Pipeline fuel	32.53	34.34	36.23	35.81	35.79	35.99	36.36	0.2%
Discrepancy[2]	-1.34	-1.15	-0.21	0.45	1.14	1.81	2.39	- -
Total transportation	**1855.81**	**1875.88**	**1868.28**	**1830.73**	**1826.65**	**1843.20**	**1870.57**	**-0.0%**
Biogenic energy combustion[6]								
Biomass	178.16	190.68	208.91	245.80	271.80	268.87	268.81	1.4%
Electric power sector	15.83	18.00	25.42	56.39	68.61	60.49	52.72	4.4%
Other sectors	162.33	172.68	183.49	189.41	203.18	208.37	216.10	0.9%
Biogenic waste	6.56	7.10	8.20	8.21	8.21	8.21	8.21	0.6%
Biofuels heat and coproducts	77.06	79.11	75.91	89.81	119.14	179.75	241.23	4.6%
Ethanol	65.18	75.71	83.37	92.41	106.14	124.29	146.78	2.7%
Biodiesel	3.07	2.11	12.76	16.51	17.69	18.42	19.18	9.2%
Liquids from biomass	0.00	0.00	2.01	7.99	24.22	57.28	95.80	- -
Renewable diesel and gasoline	0.00	0.50	2.23	2.23	2.23	2.23	2.21	6.2%
Total	**330.03**	**355.21**	**393.39**	**462.96**	**549.43**	**659.05**	**782.23**	**3.2%**

[1]Does not include water heating portion of load.
[2]Represents differences between total emissions by end-use and total emissions by fuel as reported in Table A18. Emissions by fuel may reflect benchmarking and other modeling adjustments to energy use and the associated emissions that are not assigned to specific end uses.
[3]Includes emissions related to fuel consumption for district services.
[4]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus emissions from residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[5]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[6]By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. Accordingly, the emissions from biogenic energy sources are reported here as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review, October 2011* DOE/EIA-0035(2011/10) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A20. Macroeconomic indicators
(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	Reference case 2009	2010	2015	2020	2025	2030	2035	Annual growth 2010-2035 (percent)
Real gross domestic product	**12703**	**13088**	**14803**	**16740**	**19185**	**21725**	**24539**	**2.5%**
Components of real gross domestic product								
Real consumption	9037	9221	10218	11250	12697	14359	16220	2.3%
Real investment	1454	1715	2457	2888	3472	4063	4836	4.2%
Real government spending	2540	2557	2355	2407	2525	2667	2818	0.4%
Real exports	1494	1663	2289	3096	4235	5484	6953	5.9%
Real imports	1853	2085	2463	2800	3516	4461	5690	4.1%
Energy intensity (thousand Btu per 2005 dollar of GDP)								
Delivered energy	5.42	5.45	4.84	4.33	3.85	3.48	3.17	-2.1%
Total energy	7.46	7.50	6.58	5.93	5.32	4.80	4.36	-2.1%
Price indices								
GDP chain-type price index (2005=1.000)	1.097	1.110	1.196	1.304	1.424	1.580	1.758	1.9%
Consumer price index (1982-4=1.00)								
All-urban	2.15	2.18	2.42	2.67	2.95	3.30	3.72	2.2%
Energy commodities and services	1.93	2.12	2.62	2.94	3.36	3.86	4.37	2.9%
Wholesale price index (1982=1.00)								
All commodities	1.73	1.85	2.10	2.23	2.39	2.58	2.81	1.7%
Fuel and power	1.59	1.86	2.29	2.57	3.01	3.50	4.12	3.2%
Metals and metal products	1.87	2.08	2.43	2.50	2.57	2.61	2.64	1.0%
Industrial commodities excluding energy	1.76	1.83	2.04	2.13	2.22	2.32	2.43	1.1%
Interest rates (percent, nominal)								
Federal funds rate	0.16	0.18	3.26	4.07	4.29	4.52	4.30	- -
10-year treasury note	3.26	3.21	4.67	5.10	5.06	5.26	5.18	- -
AA utility bond rate	5.75	5.24	6.74	7.41	7.17	7.48	7.56	- -
Value of shipments (billion 2005 dollars)								
Service sectors	19996	20602	22469	24967	28029	30911	33430	2.0%
Total industrial	5667	5838	6730	7363	7973	8328	8692	1.6%
Nonmanufacturing	1615	1578	1873	2103	2228	2305	2407	1.7%
Manufacturing	4052	4260	4857	5260	5745	6023	6285	1.6%
Energy-intensive	1509	1595	1664	1786	1901	1973	2034	1.0%
Non-energy-intensive	2543	2664	3194	3474	3844	4050	4251	1.9%
Total shipments	**25664**	**26440**	**29199**	**32329**	**36002**	**39239**	**42122**	**1.9%**
Population and employment (millions)								
Population, with armed forces overseas	307.8	310.8	326.2	342.0	358.1	374.1	390.1	0.9%
Population, aged 16 and over	241.8	244.3	256.5	269.4	282.6	296.2	309.6	1.0%
Population, over age 65	39.7	40.4	47.1	55.1	64.2	72.3	77.7	2.6%
Employment, nonfarm	130.7	129.8	139.4	147.3	154.2	162.0	166.8	1.0%
Employment, manufacturing	11.8	11.5	12.1	11.9	11.4	10.3	9.2	-0.9%
Key labor indicators								
Labor force (millions)	154.2	153.9	158.0	163.6	168.6	174.5	181.7	0.7%
Nonfarm labor productivity (1992=1.00)	1.06	1.10	1.16	1.26	1.42	1.57	1.75	1.9%
Unemployment rate (percent)	9.28	9.63	7.51	6.47	5.54	5.40	5.54	- -
Key indicators for energy demand								
Real disposable personal income	9883	10062	11035	12472	14286	16268	18217	2.4%
Housing starts (millions)	0.60	0.63	1.75	1.92	1.96	1.90	1.89	4.5%
Commercial floorspace (billion square feet)	80.3	81.1	84.1	89.1	93.9	98.2	103.0	1.0%
Unit sales of light-duty vehicles (millions)	10.40	11.55	16.16	16.40	17.79	18.11	18.64	1.9%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2009 and 2010: IHS Global Insight, Global Insight Industry and Employment models, August 2011. **Projections:** U.S. Energy Information Administration, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A21. International liquids supply and disposition summary
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Crude oil prices (2010 dollars per barrel)								
Low sulfur light	62.37	79.39	116.91	126.68	132.56	138.49	144.98	2.4%
Imported crude oil[1]	59.72	75.87	113.97	115.74	121.21	126.51	132.95	2.3%
Crude oil prices (nominal dollars per barrel)								
Low sulfur light	61.65	79.39	125.97	148.87	170.09	197.10	229.55	4.3%
Imported crude oil[1]	59.04	75.87	122.81	136.02	155.52	180.06	210.51	4.2%
Petroleum liquids production[2]								
OPEC[3]								
Middle East	22.30	23.43	25.46	27.16	29.77	32.07	33.94	1.5%
North Africa	3.92	3.89	3.62	3.42	3.37	3.31	3.27	-0.7%
West Africa	4.16	4.45	5.09	5.35	5.40	5.31	5.26	0.7%
South America	2.43	2.29	2.13	1.97	1.92	1.79	1.72	-1.1%
Total OPEC petroleum production	**32.80**	**34.05**	**36.30**	**37.91**	**40.46**	**42.48**	**44.19**	**1.0%**
Non-OPEC								
OECD								
United States (50 states)	8.27	8.79	9.82	10.73	10.53	10.57	10.15	0.6%
Canada	1.96	1.91	1.79	1.82	1.82	1.81	1.78	-0.3%
Mexico and Chile	3.00	2.98	2.65	1.97	1.58	1.65	1.68	-2.3%
OECD Europe[4]	4.70	4.36	3.70	3.33	3.15	3.00	2.83	-1.7%
Japan	0.13	0.13	0.14	0.15	0.15	0.15	0.16	0.7%
Australia and New Zealand	0.65	0.62	0.55	0.54	0.54	0.53	0.53	-0.6%
Total OECD petroleum production	**18.71**	**18.80**	**18.65**	**18.54**	**17.78**	**17.72**	**17.14**	**-0.4%**
Non-OECD								
Russia	9.93	10.14	10.04	10.54	11.06	11.62	12.16	0.7%
Other Europe and Eurasia[5]	3.12	3.22	3.67	4.01	4.37	4.52	4.54	1.4%
China	3.99	4.27	4.29	4.46	4.79	4.93	4.70	0.4%
Other Asia[6]	3.67	3.77	3.79	3.55	3.38	3.17	3.00	-0.9%
Middle East	1.56	1.58	1.43	1.31	1.18	1.06	0.97	-1.9%
Africa	2.44	2.41	2.40	2.54	2.68	2.70	2.68	0.4%
Brazil	2.08	2.19	2.72	3.34	3.87	4.21	4.45	2.9%
Other Central and South America	1.90	2.01	2.29	2.32	2.47	2.67	2.65	1.1%
Total non-OECD petroleum production	**28.69**	**29.59**	**30.63**	**32.07**	**33.80**	**34.88**	**35.15**	**0.7%**
Total petroleum liquids production	**80.21**	**82.44**	**85.58**	**88.52**	**92.04**	**95.08**	**96.47**	**0.6%**
Other liquids production[7]								
United States (50 states)	0.75	0.90	1.05	1.34	1.62	2.08	2.59	4.3%
Other North America	1.69	1.93	2.51	3.08	3.75	4.46	5.16	4.0%
OECD Europe[4]	0.22	0.22	0.23	0.24	0.26	0.27	0.28	1.0%
Middle East	0.01	0.01	0.17	0.21	0.24	0.24	0.24	14.5%
Africa.	0.21	0.21	0.28	0.37	0.38	0.39	0.40	2.6%
Central and South America	1.14	1.20	1.78	2.31	2.61	2.90	3.17	3.9%
Other	0.12	0.13	0.16	0.28	0.61	0.92	1.18	9.1%
Total other liquids production	**4.14**	**4.61**	**6.18**	**7.82**	**9.47**	**11.27**	**13.02**	**4.2%**
Total production	**84.35**	**87.05**	**91.76**	**96.33**	**101.51**	**106.34**	**109.50**	**0.9%**

Table A21. International liquids supply and disposition summary (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Liquids consumption[8]								
OECD								
United States (50 states)	18.81	19.17	19.10	19.02	19.20	19.47	19.90	0.1%
United States territories	0.27	0.28	0.31	0.32	0.34	0.36	0.36	1.0%
Canada	2.16	2.21	2.15	2.21	2.25	2.29	2.35	0.2%
Mexico and Chile	2.35	2.34	2.39	2.43	2.50	2.60	2.68	0.5%
OECD Europe[4]	14.66	14.58	14.14	14.43	14.65	14.76	14.74	0.0%
Japan	4.39	4.45	4.51	4.60	4.62	4.51	4.42	-0.0%
South Korea	2.15	2.24	2.25	2.35	2.46	2.53	2.56	0.5%
Australia and New Zealand	1.16	1.13	1.11	1.14	1.17	1.21	1.23	0.3%
Total OECD consumption	**45.94**	**46.40**	**45.95**	**46.50**	**47.19**	**47.72**	**48.24**	**0.2%**
Non-OECD								
Russia	2.73	2.93	3.02	2.94	2.91	2.94	2.97	0.1%
Other Europe and Eurasia[5]	2.15	2.08	2.30	2.35	2.45	2.55	2.63	0.9%
China	8.33	9.19	12.10	14.36	16.03	17.65	18.50	2.8%
India	3.11	3.18	3.70	4.58	5.40	5.79	5.80	2.4%
Other non-OECD Asia[6]	6.43	6.73	7.28	7.95	8.85	9.40	9.89	1.5%
Middle East	6.84	7.35	7.78	7.69	8.16	8.98	9.49	1.0%
Africa	3.23	3.34	3.30	3.37	3.57	3.80	4.09	0.8%
Brazil	2.52	2.65	2.84	2.94	3.15	3.47	3.80	1.5%
Other Central and South America	3.07	3.19	3.49	3.66	3.81	4.05	4.09	1.0%
Total non-OECD consumption	**38.41**	**40.65**	**45.82**	**49.83**	**54.32**	**58.62**	**61.26**	**1.7%**
Total liquids consumption	**84.35**	**87.05**	**91.76**	**96.33**	**101.51**	**106.35**	**109.50**	**0.9%**
OPEC production[9]	33.34	34.58	37.30	39.23	41.91	44.05	45.89	1.1%
Non-OPEC production[9]	51.01	52.47	54.46	57.10	59.60	62.30	63.61	0.8%
Net Eurasia exports	10.25	10.53	11.11	12.60	13.94	14.85	15.54	1.6%
OPEC market share (percent)	39.5	39.7	40.7	40.7	41.3	41.4	41.9	- -

[1]Weighted average price delivered to U.S. refiners.
[2]Includes production of crude oil (including lease condensate and shale oil/tight oil), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, and refinery gains.
[3]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[4]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[5]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[6]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[7]Includes liquids produced from energy crops, natural gas, coal, extra-heavy oil, bitumen (oil sands), and kerogen (oil shale, not to be confused with shale oil/tight oil). Includes both OPEC and non-OPEC producers in the regional breakdown.
[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[9]Includes both petroleum and other liquids production.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2009 and 2010 imported crude oil price: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 quantities derived from: EIA, International Energy Statistics database as of November 2009. **2010 quantities and projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C and EIA, Generate World Oil Balance Model.

Appendix B

Economic growth case comparisons

Table B1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Production										
Crude oil and lease condensate	11.59	13.23	13.23	13.25	13.53	13.77	13.79	12.86	12.89	13.12
Natural gas plant liquids	2.78	3.33	3.33	3.33	3.91	3.93	3.93	3.93	3.94	3.95
Dry natural gas	22.10	24.02	24.22	24.28	26.17	26.91	27.64	27.48	28.60	30.05
Coal[1]	22.06	19.71	20.24	20.79	20.27	22.25	23.65	21.91	24.14	25.33
Nuclear / uranium[2]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.14	9.28	10.13
Hydropower	2.51	2.89	2.90	2.90	2.95	2.99	3.02	3.00	3.04	3.10
Biomass[3]	4.05	4.41	4.45	4.49	6.04	6.26	6.30	8.37	9.07	9.58
Other renewable energy[4]	1.34	2.08	1.99	2.18	2.21	2.22	2.42	2.44	2.81	3.64
Other[5]	0.64	0.60	0.60	0.60	0.68	0.69	0.71	0.83	0.91	0.93
Total	**75.50**	**78.96**	**79.64**	**80.50**	**85.36**	**88.61**	**91.06**	**89.95**	**94.67**	**99.83**
Imports										
Crude oil	20.14	18.34	18.87	19.43	15.20	16.23	17.55	15.30	16.90	18.50
Liquid fuels and other petroleum[6]	5.02	4.19	4.32	4.45	3.72	4.08	4.40	3.63	4.14	4.75
Natural gas[7]	3.81	3.67	3.73	3.76	2.61	2.75	2.89	2.74	2.84	2.86
Other imports[8]	0.52	0.34	0.44	0.47	0.97	1.07	0.95	0.73	0.81	0.96
Total	**29.49**	**26.54**	**27.37**	**28.11**	**22.50**	**24.14**	**25.79**	**22.40**	**24.69**	**27.07**
Exports										
Liquid fuels and other petroleum[9]	4.81	4.90	5.00	5.08	4.32	4.46	4.57	4.68	4.95	5.11
Natural gas[10]	1.15	1.93	1.93	1.92	3.55	3.51	3.48	4.29	4.17	4.07
Coal	2.10	2.73	2.73	2.73	2.78	2.82	2.82	3.09	3.13	3.18
Total	**8.06**	**9.57**	**9.66**	**9.74**	**10.66**	**10.79**	**10.87**	**12.06**	**12.25**	**12.37**
Discrepancy[11]	**-1.23**	**-0.03**	**-0.08**	**-0.09**	**-0.01**	**-0.03**	**-0.06**	**0.25**	**0.18**	**0.15**
Consumption										
Liquid fuels and other petroleum[12]	37.25	36.09	36.72	37.38	34.78	36.58	38.19	35.17	37.70	40.23
Natural gas	24.71	25.73	26.00	26.09	25.21	26.14	27.04	25.93	27.26	28.83
Coal[13]	20.76	17.17	17.80	18.36	18.23	20.02	21.30	19.16	21.15	22.43
Nuclear / uranium[2]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.14	9.28	10.13
Hydropower	2.51	2.89	2.90	2.90	2.95	2.99	3.02	3.00	3.04	3.10
Biomass[14]	2.88	3.01	3.04	3.06	3.95	4.17	4.21	4.96	5.44	5.78
Other renewable energy[4]	1.34	2.08	1.99	2.18	2.21	2.22	2.42	2.44	2.81	3.64
Other[15]	0.29	0.30	0.30	0.30	0.28	0.28	0.28	0.24	0.24	0.25
Total	**98.16**	**95.96**	**97.43**	**98.96**	**97.20**	**101.99**	**106.05**	**100.04**	**106.93**	**114.38**
Prices (2010 dollars per unit)										
Petroleum (dollars per barrel)										
Low sulfur light crude oil[16]	79.39	116.06	116.91	117.83	130.58	132.56	134.77	142.51	144.98	147.82
Imported crude oil[16]	75.87	113.12	113.97	114.90	118.61	121.21	124.15	130.33	132.95	136.68
Natural gas (dollars per million Btu)										
at Henry hub	4.39	4.06	4.29	4.36	5.10	5.63	6.17	6.60	7.37	7.58
at the wellhead[17]	4.06	3.64	3.84	3.91	4.54	5.00	5.46	5.83	6.48	6.66
Natural gas (dollars per thousand cubic feet)										
at the wellhead[17]	4.16	3.73	3.94	4.00	4.65	5.12	5.59	5.97	6.64	6.82
Coal (dollars per ton)										
at the minemouth[18]	35.61	42.70	42.08	41.92	44.24	44.05	44.48	50.92	50.52	51.36
Coal (dollars per million Btu)										
at the minemouth[18]	1.76	2.11	2.08	2.08	2.24	2.23	2.25	2.57	2.56	2.60
Average end-use[19]	2.38	2.55	2.56	2.57	2.68	2.70	2.73	2.90	2.94	3.03
Average electricity (cents per kilowatthour)	9.8	9.9	9.7	9.6	9.7	9.7	9.9	9.8	10.1	10.5

Table B1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Prices (nominal dollars per unit)										
Petroleum (dollars per barrel)										
Low sulfur light crude oil[16]	79.39	127.20	125.97	125.10	197.32	170.09	163.70	313.58	229.55	212.97
Imported crude oil[16]	75.87	123.98	122.81	121.98	179.23	155.52	150.79	286.76	210.51	196.92
Natural gas (dollars per million Btu)										
at Henry hub	4.39	4.45	4.62	4.63	7.70	7.23	7.50	14.52	11.67	10.92
at the wellhead[17]	4.06	3.99	4.14	4.15	6.86	6.42	6.63	12.82	10.26	9.59
Natural gas (dollars per thousand cubic feet)										
at the wellhead[17]	4.16	4.09	4.24	4.25	7.02	6.57	6.79	13.13	10.51	9.82
Coal (dollars per ton)										
at the minemouth[18]	35.61	46.80	45.34	44.50	66.85	56.52	54.03	112.04	80.00	74.00
Coal (dollars per million Btu)										
at the minemouth[18]	1.76	2.31	2.24	2.21	3.39	2.86	2.73	5.64	4.05	3.74
Average end-use[19]	2.38	2.79	2.76	2.73	4.05	3.47	3.32	6.37	4.66	4.36
Average electricity (cents per kilowatthour)	9.8	10.9	10.4	10.2	14.7	12.5	12.0	21.6	16.0	15.1

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that is later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas and natural gas used for liquefaction at export terminals.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Weighted average price delivered to U.S. refiners.
[17]Represents lower 48 onshore and offshore supplies.
[18]Includes reported prices for both open market and captive mines.
[19]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 natural gas supply values and natural gas wellhead price: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2010 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011). 2010 petroleum supply values: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). 2010 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2010 coal values: *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011). Other 2010 values: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System runs LM2012.D022412A, REF2012.D020112C, and HM2012.D022412A.

Table B2. Energy consumption by sector and source

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Energy consumption										
Residential										
Liquefied petroleum gases	0.56	0.51	0.51	0.51	0.49	0.50	0.52	0.48	0.51	0.54
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate fuel oil	0.63	0.55	0.55	0.55	0.43	0.43	0.43	0.35	0.35	0.35
Liquid fuels and other petroleum subtotal	1.22	1.08	1.08	1.08	0.94	0.95	0.97	0.85	0.87	0.91
Natural gas	5.06	4.96	4.97	5.00	4.77	4.88	5.04	4.50	4.76	5.08
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable energy[1]	0.42	0.42	0.43	0.43	0.42	0.43	0.45	0.41	0.43	0.47
Electricity	4.95	4.68	4.75	4.82	4.97	5.23	5.58	5.35	5.86	6.57
Delivered energy	**11.66**	**11.15**	**11.24**	**11.34**	**11.11**	**11.51**	**12.05**	**11.12**	**11.93**	**13.04**
Electricity related losses	10.39	9.43	9.58	9.75	10.03	10.52	11.17	10.47	11.35	12.72
Total	**22.05**	**20.59**	**20.81**	**21.09**	**21.13**	**22.02**	**23.22**	**21.59**	**23.28**	**25.76**
Commercial										
Liquefied petroleum gases	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.16
Motor gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Distillate fuel oil	0.43	0.35	0.35	0.35	0.33	0.33	0.33	0.32	0.32	0.32
Residual fuel oil	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Liquid fuels and other petroleum subtotal	0.72	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.63
Natural gas	3.28	3.43	3.41	3.42	3.56	3.53	3.51	3.70	3.69	3.71
Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.54	4.57	4.59	4.61	5.11	5.16	5.22	5.70	5.80	5.89
Delivered energy	**8.70**	**8.79**	**8.80**	**8.81**	**9.46**	**9.48**	**9.53**	**10.19**	**10.28**	**10.39**
Electricity related losses	9.52	9.21	9.27	9.32	10.30	10.38	10.44	11.15	11.23	11.40
Total	**18.22**	**18.00**	**18.06**	**18.13**	**19.76**	**19.86**	**19.97**	**21.34**	**21.50**	**21.79**
Industrial[4]										
Liquefied petroleum gases	2.00	1.80	1.83	1.83	2.06	2.17	2.18	2.01	2.15	2.20
Motor gasoline[2]	0.25	0.27	0.28	0.29	0.27	0.30	0.33	0.26	0.30	0.33
Distillate fuel oil	1.16	1.16	1.25	1.33	1.04	1.19	1.33	1.01	1.18	1.35
Residual fuel oil	0.12	0.09	0.09	0.09	0.08	0.08	0.09	0.08	0.08	0.09
Petrochemical feedstocks	0.94	1.00	1.01	1.01	1.22	1.29	1.29	1.21	1.30	1.33
Other petroleum[5]	3.59	3.29	3.44	3.60	2.81	3.11	3.45	2.80	3.19	3.60
Liquid fuels and other petroleum subtotal	8.05	7.61	7.89	8.15	7.48	8.13	8.68	7.36	8.21	8.89
Natural gas	6.76	7.04	7.19	7.34	6.81	7.32	7.62	6.49	7.18	7.84
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[6]	1.37	1.42	1.43	1.43	1.54	1.57	1.60	1.57	1.63	1.71
Natural gas subtotal	8.14	8.46	8.62	8.77	8.35	8.89	9.22	8.06	8.81	9.55
Metallurgical coal	0.55	0.55	0.57	0.59	0.41	0.49	0.54	0.34	0.43	0.53
Other industrial coal	1.01	1.01	1.03	1.05	1.02	1.08	1.12	1.01	1.08	1.14
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.11	0.36	0.37	0.31	0.60	0.61
Net coal coke imports	-0.01	-0.01	-0.01	-0.00	-0.03	-0.03	-0.03	-0.05	-0.06	-0.07
Coal subtotal	1.56	1.55	1.59	1.63	1.52	1.90	2.00	1.60	2.06	2.21
Biofuels heat and coproducts	0.84	0.80	0.81	0.82	1.26	1.27	1.27	2.39	2.57	2.69
Renewable energy[7]	1.50	1.59	1.61	1.63	1.67	1.82	1.91	1.74	1.95	2.10
Electricity	3.28	3.34	3.44	3.53	3.22	3.52	3.75	3.01	3.33	3.67
Delivered energy	**23.37**	**23.35**	**23.96**	**24.53**	**23.49**	**25.53**	**26.83**	**24.17**	**26.94**	**29.11**
Electricity related losses	6.89	6.73	6.94	7.15	6.50	7.09	7.50	5.89	6.46	7.10
Total	**30.26**	**30.08**	**30.90**	**31.68**	**29.99**	**32.61**	**34.33**	**30.06**	**33.39**	**36.21**

Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Transportation										
Liquefied petroleum gases	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.04	0.05	0.06
E85[8]	0.00	0.01	0.01	0.01	0.40	0.30	0.21	1.14	1.22	1.22
Motor gasoline[2]	16.91	16.00	16.13	16.29	14.26	14.90	15.49	13.43	14.53	15.38
Jet fuel[9]	3.07	3.01	3.03	3.04	3.15	3.19	3.24	3.25	3.33	3.42
Distillate fuel oil[10]	5.77	6.35	6.55	6.77	6.50	7.03	7.51	7.06	7.44	8.27
Residual fuel oil	0.90	0.91	0.91	0.91	0.92	0.93	0.93	0.93	0.94	0.95
Other petroleum[11]	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.18
Liquid fuels and other petroleum subtotal	26.88	26.48	26.83	27.22	25.43	26.57	27.60	26.03	27.67	29.47
Pipeline fuel natural gas	0.65	0.68	0.68	0.69	0.65	0.67	0.69	0.66	0.69	0.74
Compressed / liquefied natural gas	0.04	0.06	0.06	0.06	0.11	0.11	0.12	0.16	0.16	0.17
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.07	0.07	0.08
Delivered energy	**27.59**	**27.24**	**27.60**	**28.00**	**26.24**	**27.40**	**28.45**	**26.92**	**28.60**	**30.46**
Electricity related losses	0.05	0.05	0.05	0.05	0.08	0.08	0.09	0.13	0.14	0.15
Total	**27.63**	**27.30**	**27.65**	**28.05**	**26.32**	**27.49**	**28.54**	**27.05**	**28.75**	**30.62**
Delivered energy consumption for all sectors										
Liquefied petroleum gases	2.75	2.49	2.51	2.52	2.75	2.86	2.89	2.69	2.86	2.95
E85[8]	0.00	0.01	0.01	0.01	0.40	0.30	0.21	1.14	1.22	1.22
Motor gasoline[2]	17.21	16.32	16.46	16.63	14.58	15.25	15.87	13.75	14.88	15.77
Jet fuel[9]	3.07	3.01	3.03	3.04	3.15	3.19	3.24	3.25	3.33	3.42
Kerosene	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Distillate fuel oil	7.99	8.41	8.69	9.00	8.30	8.99	9.61	8.74	9.29	10.29
Residual fuel oil	1.11	1.07	1.08	1.08	1.08	1.09	1.10	1.09	1.11	1.12
Petrochemical feedstocks	0.94	1.00	1.01	1.01	1.22	1.29	1.29	1.21	1.30	1.33
Other petroleum[12]	3.76	3.45	3.61	3.76	2.97	3.27	3.62	2.97	3.36	3.77
Liquid fuels and other petroleum subtotal	36.87	35.80	36.43	37.07	34.48	36.28	37.87	34.86	37.38	39.90
Natural gas	15.15	15.49	15.64	15.83	15.25	15.85	16.29	14.85	15.79	16.80
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[6]	1.37	1.42	1.43	1.43	1.54	1.57	1.60	1.57	1.63	1.71
Pipeline natural gas	0.65	0.68	0.68	0.69	0.65	0.67	0.69	0.66	0.69	0.74
Natural gas subtotal	17.17	17.58	17.75	17.94	17.44	18.09	18.58	17.08	18.11	19.26
Metallurgical coal	0.55	0.55	0.57	0.59	0.41	0.49	0.54	0.34	0.43	0.53
Other coal	1.08	1.07	1.09	1.11	1.08	1.14	1.18	1.07	1.15	1.21
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.11	0.36	0.37	0.31	0.60	0.61
Net coal coke imports	-0.01	-0.01	-0.01	-0.00	-0.03	-0.03	-0.03	-0.05	-0.06	-0.07
Coal subtotal	1.62	1.62	1.65	1.70	1.58	1.96	2.06	1.67	2.12	2.28
Biofuels heat and coproducts	0.84	0.80	0.81	0.82	1.26	1.27	1.27	2.39	2.57	2.69
Renewable energy[13]	2.03	2.12	2.15	2.17	2.20	2.36	2.47	2.25	2.50	2.68
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.79	12.61	12.81	12.98	13.34	13.96	14.60	14.13	15.06	16.20
Delivered energy	**71.32**	**70.54**	**71.59**	**72.69**	**70.30**	**73.92**	**76.86**	**72.39**	**77.75**	**83.01**
Electricity related losses	26.84	25.42	25.84	26.27	26.91	28.07	29.20	27.65	29.18	31.37
Total	**98.16**	**95.96**	**97.43**	**98.96**	**97.20**	**101.99**	**106.05**	**100.04**	**106.93**	**114.38**
Electric power[14]										
Distillate fuel oil	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Residual fuel oil	0.30	0.21	0.21	0.22	0.21	0.22	0.23	0.22	0.23	0.24
Liquid fuels and other petroleum subtotal	0.38	0.29	0.29	0.30	0.30	0.31	0.32	0.31	0.32	0.34
Natural gas	7.54	8.15	8.25	8.15	7.77	8.04	8.46	8.84	9.16	9.58
Steam coal	19.13	15.56	16.15	16.67	16.65	18.06	19.24	17.50	19.03	20.15
Nuclear / uranium[15]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.14	9.28	10.13
Renewable energy[16]	3.85	5.05	4.96	5.15	5.66	5.75	5.91	5.75	6.22	7.14
Electricity imports	0.09	0.10	0.10	0.10	0.08	0.08	0.08	0.04	0.04	0.04
Total[17]	**39.63**	**38.03**	**38.64**	**39.25**	**40.25**	**42.03**	**43.80**	**41.78**	**44.24**	**47.57**

Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2010	Projections 2015 Low economic growth	2015 Reference	2015 High economic growth	2025 Low economic growth	2025 Reference	2025 High economic growth	2035 Low economic growth	2035 Reference	2035 High economic growth
Total energy consumption										
Liquefied petroleum gases	2.75	2.49	2.51	2.52	2.75	2.86	2.89	2.69	2.86	2.95
E85[8]	0.00	0.01	0.01	0.01	0.40	0.30	0.21	1.14	1.22	1.22
Motor gasoline[2]	17.21	16.32	16.46	16.63	14.58	15.25	15.87	13.75	14.88	15.77
Jet fuel[9]	3.07	3.01	3.03	3.04	3.15	3.19	3.24	3.25	3.33	3.42
Kerosene	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Distillate fuel oil	8.07	8.50	8.78	9.08	8.39	9.07	9.70	8.83	9.38	10.38
Residual fuel oil	1.41	1.28	1.29	1.30	1.29	1.31	1.33	1.31	1.34	1.36
Petrochemical feedstocks	0.94	1.00	1.01	1.01	1.22	1.29	1.29	1.21	1.30	1.33
Other petroleum[12]	3.76	3.45	3.61	3.76	2.97	3.27	3.62	2.97	3.36	3.77
Liquid fuels and other petroleum subtotal	37.25	36.09	36.72	37.38	34.78	36.58	38.19	35.17	37.70	40.23
Natural gas	22.69	23.64	23.89	23.97	23.02	23.89	24.74	23.70	24.94	26.38
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[6]	1.37	1.42	1.43	1.43	1.54	1.57	1.60	1.57	1.63	1.71
Pipeline natural gas	0.65	0.68	0.68	0.69	0.65	0.67	0.69	0.66	0.69	0.74
Natural gas subtotal	24.71	25.73	26.00	26.09	25.21	26.14	27.04	25.93	27.26	28.83
Metallurgical coal	0.55	0.55	0.57	0.59	0.41	0.49	0.54	0.34	0.43	0.53
Other coal	20.21	16.63	17.24	17.78	17.73	19.20	20.42	18.57	20.18	21.36
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.11	0.36	0.37	0.31	0.60	0.61
Net coal coke imports	-0.01	-0.01	-0.01	-0.00	-0.03	-0.03	-0.03	-0.05	-0.06	-0.07
Coal subtotal	20.76	17.17	17.80	18.36	18.23	20.02	21.30	19.16	21.15	22.43
Nuclear / uranium[15]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.14	9.28	10.13
Biofuels heat and coproducts	0.84	0.80	0.81	0.82	1.26	1.27	1.27	2.39	2.57	2.69
Renewable energy[18]	5.88	7.18	7.11	7.33	7.85	8.11	8.38	8.00	8.71	9.82
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity imports	0.09	0.10	0.10	0.10	0.08	0.08	0.08	0.04	0.04	0.04
Total	**98.16**	**95.96**	**97.43**	**98.96**	**97.20**	**101.99**	**106.05**	**100.04**	**106.93**	**114.38**
Energy use and related statistics										
Delivered energy use	71.32	70.54	71.59	72.69	70.30	73.92	76.86	72.39	77.75	83.01
Total energy use	98.16	95.96	97.43	98.96	97.20	101.99	106.05	100.04	106.93	114.38
Ethanol consumed in motor gasoline and E85	1.11	1.21	1.22	1.23	1.55	1.55	1.54	1.99	2.15	2.23
Population (millions)	310.83	325.23	326.16	327.19	354.23	358.06	362.48	382.76	390.09	398.74
Gross domestic product (billion 2005 dollars)	13088	14401	14803	15235	17676	19185	20538	21630	24539	27084
Carbon dioxide emissions (million metric tons)	5633.6	5298.2	5407.2	5503.9	5226.8	5552.5	5823.7	5355.8	5757.9	6117.5

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (15 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[17]Includes non-biogenic municipal waste not included above.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2011. 2010 carbon dioxide emissions: EIA, *Monthly Energy Review, October 2011* DOE/EIA-0035(2011/10) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System runs LM2012.D022412A, REF2012.D020112C, and HM2012.D022412A.

Table B3. Energy prices by sector and source
(2010 dollars per million Btu, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Residential										
Liquefied petroleum gases	27.02	30.48	30.70	30.86	31.69	32.27	32.91	33.94	34.64	35.27
Distillate fuel oil	21.21	27.00	27.26	27.52	29.17	30.15	30.64	32.01	32.73	33.99
Natural gas	11.08	10.10	10.31	10.39	11.46	12.03	12.61	13.16	13.98	14.38
Electricity	33.69	35.59	34.59	34.31	34.30	34.08	34.20	34.14	34.58	35.27
Commercial										
Liquefied petroleum gases	23.52	27.21	27.42	27.57	28.39	28.97	29.59	30.62	31.30	31.89
Distillate fuel oil	20.77	23.72	23.98	24.23	25.89	26.86	27.30	28.58	29.18	30.43
Residual fuel oil	11.07	16.02	16.18	16.35	17.82	18.24	18.62	18.61	18.90	19.61
Natural gas	9.10	8.40	8.60	8.67	9.51	10.02	10.52	10.92	11.64	11.91
Electricity	29.73	29.65	29.03	28.97	28.81	29.00	29.51	28.42	29.48	30.79
Industrial[1]										
Liquefied petroleum gases	21.80	27.12	27.43	27.66	28.44	29.24	30.12	31.26	32.18	32.98
Distillate fuel oil	21.32	23.95	24.20	24.45	26.23	27.22	27.61	28.93	29.53	30.79
Residual fuel oil	10.92	18.95	19.21	19.45	20.54	21.23	21.59	21.12	21.65	22.44
Natural gas[2]	5.51	4.68	4.88	4.94	5.58	6.04	6.51	6.89	7.54	7.74
Metallurgical coal	5.84	7.30	7.22	7.20	8.24	8.11	8.08	9.24	9.11	9.11
Other industrial coal	2.71	3.27	3.27	3.27	3.38	3.38	3.39	3.61	3.64	3.69
Coal to liquids	- -	1.27	1.26	1.26	2.27	2.08	2.14	2.34	2.38	2.42
Electricity	19.63	19.06	18.91	18.94	19.21	19.60	20.15	19.63	20.78	22.00
Transportation										
Liquefied petroleum gases[3]	26.88	31.71	31.93	32.09	32.80	33.38	34.04	35.02	35.74	36.31
E85[4]	25.21	28.85	29.03	29.26	27.92	28.81	31.30	31.02	31.96	33.04
Motor gasoline[5]	22.70	29.09	29.26	29.49	30.92	32.10	32.42	32.33	33.61	34.78
Jet fuel[6]	16.22	23.48	23.74	24.02	25.61	26.45	26.99	28.41	29.13	30.25
Diesel fuel (distillate fuel oil)[7]	21.87	27.28	27.56	27.83	29.18	30.42	30.85	31.53	32.40	33.80
Residual fuel oil	10.42	17.96	18.32	18.61	19.74	20.62	20.82	20.50	20.95	21.94
Natural gas[8]	13.20	12.17	12.40	12.51	12.51	13.29	13.86	13.42	14.51	14.87
Electricity	32.99	30.67	30.50	30.54	31.37	31.53	32.45	32.36	33.82	35.11
Electric power[9]										
Distillate fuel oil	18.73	22.50	22.77	23.04	24.44	25.35	25.88	27.17	27.80	29.02
Residual fuel oil	11.89	22.67	23.00	23.03	24.55	25.40	25.41	25.25	25.72	26.49
Natural gas	5.14	4.36	4.55	4.61	5.15	5.60	6.10	6.55	7.21	7.40
Steam coal	2.26	2.33	2.35	2.37	2.50	2.54	2.56	2.75	2.80	2.87
Average price to all users[10]										
Liquefied petroleum gases	17.28	22.78	22.99	23.18	23.62	24.19	24.91	25.96	26.63	27.37
E85[4]	25.21	28.85	29.03	29.26	27.92	28.81	31.30	31.02	31.96	33.04
Motor gasoline[5]	22.59	29.09	29.26	29.49	30.91	32.10	32.42	32.33	33.61	34.78
Jet fuel	16.22	23.48	23.74	24.02	25.61	26.45	26.99	28.41	29.13	30.25
Distillate fuel oil	21.65	26.61	26.87	27.14	28.65	29.81	30.23	31.09	31.91	33.27
Residual fuel oil	10.82	18.67	19.01	19.27	20.46	21.31	21.53	21.22	21.68	22.64
Natural gas	7.16	6.27	6.45	6.52	7.29	7.74	8.22	8.63	9.30	9.53
Metallurgical coal	5.84	7.30	7.22	7.20	8.24	8.11	8.08	9.24	9.11	9.11
Other coal	2.29	2.40	2.41	2.43	2.56	2.59	2.62	2.80	2.85	2.92
Coal to liquids	- -	1.27	1.26	1.26	2.27	2.08	2.14	2.34	2.38	2.42
Electricity	28.68	29.05	28.38	28.23	28.55	28.54	28.90	28.73	29.56	30.64
Non-renewable energy expenditures by sector (billion 2010 dollars)										
Residential	251.69	247.63	246.72	248.83	253.92	266.75	285.47	270.07	298.72	336.43
Commercial	179.08	179.38	177.92	178.42	197.28	201.89	208.21	220.10	231.98	244.34
Industrial	198.98	214.83	223.88	231.79	232.07	261.92	285.16	242.72	282.31	317.58
Transportation	573.78	731.18	746.84	764.56	736.46	803.52	848.96	777.83	856.65	950.17
Total non-renewable expenditures	1203.54	1373.02	1395.36	1423.60	1419.73	1534.08	1627.80	1510.72	1669.66	1848.51
Transportation renewable expenditures	0.08	0.24	0.25	0.26	11.22	8.74	6.44	35.33	38.86	40.34
Total expenditures	**1203.62**	**1373.26**	**1395.61**	**1423.86**	**1430.95**	**1542.81**	**1634.24**	**1546.05**	**1708.52**	**1888.85**

Table B3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Residential										
Liquefied petroleum gases	27.02	33.41	33.08	32.76	47.89	41.41	39.98	74.69	54.86	50.81
Distillate fuel oil	21.21	29.60	29.38	29.22	44.08	38.68	37.22	70.42	51.82	48.97
Natural gas	11.08	11.07	11.11	11.03	17.31	15.43	15.32	28.95	22.14	20.72
Electricity	33.69	39.01	37.27	36.43	51.84	43.72	41.53	75.12	54.76	50.81
Commercial										
Liquefied petroleum gases	23.52	29.82	29.54	29.27	42.91	37.17	35.94	67.37	49.56	45.95
Distillate fuel oil	20.77	26.00	25.83	25.73	39.13	34.47	33.15	62.88	46.20	43.85
Residual fuel oil	11.07	17.55	17.43	17.36	26.93	23.41	22.61	40.96	29.93	28.25
Natural gas	9.10	9.21	9.27	9.21	14.37	12.86	12.78	24.03	18.43	17.16
Electricity	29.73	32.49	31.28	30.75	43.53	37.21	35.84	62.54	46.67	44.37
Industrial[1]										
Liquefied petroleum gases	21.80	29.72	29.56	29.37	42.98	37.51	36.59	68.79	50.95	47.52
Distillate fuel oil	21.32	26.25	26.08	25.96	39.64	34.93	33.54	63.67	46.76	44.36
Residual fuel oil	10.92	20.77	20.70	20.64	31.03	27.24	26.22	46.48	34.28	32.33
Natural gas[2]	5.51	5.13	5.26	5.25	8.43	7.75	7.91	15.15	11.93	11.15
Metallurgical coal	5.84	8.00	7.78	7.64	12.45	10.40	9.81	20.34	14.42	13.13
Other industrial coal	2.71	3.59	3.52	3.47	5.11	4.34	4.12	7.95	5.77	5.32
Coal to liquids	- -	1.39	1.36	1.34	3.42	2.67	2.60	5.15	3.78	3.49
Electricity	19.63	20.89	20.38	20.11	29.03	25.15	24.47	43.20	32.90	31.70
Transportation										
Liquefied petroleum gases[3]	26.88	34.76	34.41	34.07	49.57	42.83	41.35	77.05	56.59	52.31
E85[4]	25.21	31.62	31.28	31.06	42.19	36.97	38.02	68.26	50.61	47.60
Motor gasoline[5]	22.70	31.88	31.53	31.31	46.72	41.19	39.38	71.14	53.22	50.11
Jet fuel[6]	16.22	25.74	25.58	25.50	38.70	33.94	32.78	62.51	46.12	43.58
Diesel fuel (distillate fuel oil)[7]	21.87	29.90	29.69	29.55	44.10	39.03	37.47	69.37	51.29	48.70
Residual fuel oil	10.42	19.69	19.74	19.76	29.83	26.45	25.28	45.11	33.18	31.60
Natural gas[8]	13.20	13.34	13.36	13.29	18.91	17.05	16.84	29.54	22.97	21.42
Electricity	32.99	33.62	32.86	32.42	47.41	40.46	39.41	71.19	53.55	50.59
Electric power[9]										
Distillate fuel oil	18.73	24.66	24.53	24.46	36.93	32.52	31.43	59.79	44.02	41.80
Residual fuel oil	11.89	24.85	24.78	24.45	37.10	32.59	30.87	55.56	40.73	38.16
Natural gas	5.14	4.78	4.90	4.90	7.78	7.19	7.41	14.41	11.42	10.66
Steam coal	2.26	2.56	2.53	2.51	3.78	3.25	3.12	6.05	4.43	4.13

Table B3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Average price to all users[10]										
Liquefied petroleum gases	17.28	24.97	24.78	24.61	35.69	31.04	30.26	57.13	42.17	39.44
E85[4]	25.21	31.62	31.28	31.06	42.19	36.97	38.02	68.26	50.61	47.60
Motor gasoline[5]	22.59	31.88	31.53	31.31	46.72	41.19	39.38	71.14	53.22	50.11
Jet fuel	16.22	25.74	25.58	25.50	38.70	33.94	32.78	62.51	46.12	43.58
Distillate fuel oil	21.65	29.16	28.96	28.81	43.29	38.24	36.72	68.42	50.52	47.93
Residual fuel oil	10.82	20.46	20.48	20.46	30.92	27.34	26.15	46.69	34.33	32.61
Natural gas	7.16	6.87	6.95	6.92	11.02	9.93	9.98	18.98	14.73	13.73
Metallurgical coal	5.84	8.00	7.78	7.64	12.45	10.40	9.81	20.34	14.42	13.13
Other coal	2.29	2.63	2.60	2.58	3.87	3.32	3.18	6.17	4.51	4.20
Coal to liquids	- -	1.39	1.36	1.34	3.42	2.67	2.60	5.15	3.78	3.49
Electricity	28.68	31.84	30.58	29.97	43.14	36.62	35.11	63.22	46.80	44.14
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	251.69	271.41	265.85	264.18	383.71	342.26	346.74	594.24	472.99	484.70
Commercial	179.08	196.61	191.71	189.42	298.11	259.04	252.89	484.30	367.31	352.03
Industrial	198.98	235.47	241.24	246.08	350.69	336.06	346.35	534.08	447.01	457.54
Transportation	573.78	801.41	804.75	811.72	1112.90	1030.98	1031.15	1711.49	1356.41	1368.93
Total non-renewable expenditures	1203.54	1504.89	1503.55	1511.41	2145.42	1968.35	1977.13	3324.10	2643.72	2663.20
Transportation renewable expenditures	0.08	0.27	0.27	0.27	16.95	11.21	7.82	77.73	61.53	58.11
Total expenditures	**1203.62**	**1505.16**	**1503.82**	**1511.69**	**2162.37**	**1979.56**	**1984.95**	**3401.83**	**2705.26**	**2721.31**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2010 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2010 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2010 transportation sector natural gas delivered prices are model results. 2010 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/09) (Washington, DC, September 2010). 2010 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2010 and April 2011, Table 4.2, and EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2010 coal prices based on: EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011) and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. 2010 electricity prices: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2012 National Energy Modeling System runs LM2012.D022412A, REF2012.D020112C, and HM2012.D022412A.

Table B4. Macroeconomic indicators
(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Real gross domestic product	**13088**	**14401**	**14803**	**15235**	**17676**	**19185**	**20538**	**21630**	**24539**	**27084**
Components of real gross domestic product										
Real consumption	9221	10007	10218	10510	11874	12697	13606	14594	16220	17889
Real investment	1715	2234	2457	2675	2956	3472	3982	3929	4836	5651
Real government spending	2557	2322	2355	2389	2420	2525	2601	2619	2818	2944
Real exports	1663	2243	2289	2322	3828	4235	4558	5846	6953	7979
Real imports	2085	2370	2463	2596	3258	3516	3909	5020	5690	6596
Energy intensity (thousand Btu per 2005 dollar of GDP)										
Delivered energy	5.45	4.90	4.84	4.77	3.98	3.85	3.74	3.35	3.17	3.06
Total energy	7.50	6.66	6.58	6.50	5.50	5.32	5.16	4.63	4.36	4.22
Price indices										
GDP chain-type price index (2005=1.000)	1.110	1.217	1.196	1.178	1.677	1.424	1.348	2.442	1.758	1.599
Consumer price index (1982-4=1)										
All-urban	2.18	2.47	2.42	2.36	3.53	2.95	2.78	5.38	3.72	3.36
Energy commodities and services	2.12	2.67	2.62	2.59	3.82	3.36	3.20	5.83	4.37	4.07
Wholesale price index (1982=1.00)										
All commodities	1.85	2.15	2.10	2.02	2.96	2.39	2.25	4.46	2.81	2.47
Fuel and power	1.86	2.31	2.29	2.27	3.41	3.01	2.92	5.44	4.12	3.85
Metals and metal products	2.08	2.45	2.43	2.45	2.85	2.57	2.53	3.39	2.64	2.56
Industrial commodities excluding energy	**1.83**	**2.08**	**2.04**	**2.02**	**2.63**	**2.22**	**2.12**	**3.47**	**2.43**	**2.24**
Interest rates (percent, nominal)										
Federal funds rate	0.17	3.31	3.26	2.50	5.75	4.29	3.58	7.56	4.30	3.59
10-year treasury note	3.21	6.62	4.67	4.09	8.03	5.06	4.49	8.22	5.18	4.47
AA utility bond rate	5.24	9.31	6.74	5.73	11.61	7.17	6.18	12.74	7.56	6.12
Value of shipments (billion 2005 dollars)										
Service sectors	20602	22047	22469	22970	26671	28029	29342	31392	33430	35331
Total industrial	5838	6407	6730	7072	7109	7973	8737	7606	8692	9954
Non-manufacturing	1578	1702	1873	2065	1885	2228	2554	2024	2407	2823
Manufacturing	4260	4705	4857	5008	5224	5745	6183	5583	6285	7131
Energy-intensive	1595	1633	1664	1692	1781	1901	1971	1854	2034	2155
Non-energy-intensive	2664	3072	3194	3316	3443	3844	4212	3729	4251	4976
Total shipments	**26440**	**28454**	**29199**	**30042**	**33780**	**36002**	**38079**	**38998**	**42122**	**45285**
Population and employment (millions)										
Population with armed forces overseas	310.8	325.2	326.2	327.2	354.2	358.1	362.5	382.8	390.1	398.7
Population, aged 16 and over	244.3	256.0	256.5	257.2	279.9	282.6	285.8	304.2	309.6	316.0
Population, over age 65	40.4	46.7	47.1	47.1	63.4	64.2	64.4	76.9	77.7	78.3
Employment, nonfarm	129.8	138.3	139.4	142.7	150.4	154.2	160.5	158.9	166.8	173.4
Employment, manufacturing	11.5	11.8	12.1	12.3	11.0	11.4	11.9	9.1	9.2	9.9
Key labor indicators										
Labor force (millions)	153.9	157.6	158.0	158.7	167.1	168.6	170.9	178.0	181.7	186.3
Non-farm labor productivity (1992=1.00)	1.10	1.14	1.16	1.18	1.33	1.42	1.47	1.55	1.75	1.85
Unemployment rate (percent)	9.63	8.11	7.51	7.10	6.04	5.54	5.05	6.15	5.54	5.09
Key indicators for energy demand										
Real disposable personal income	10062	10890	11035	11224	13862	14286	14978	17350	18217	19407
Housing starts (millions)	0.63	1.40	1.75	2.22	1.40	1.96	2.78	1.19	1.89	2.95
Commercial floorspace (billion square feet)	81.1	84.0	84.1	84.3	92.7	93.9	95.2	100.5	103.0	105.5
Unit sales of light-duty vehicles (millions)	11.55	15.34	16.16	16.69	16.20	17.79	18.85	15.31	18.64	20.55

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2010: IHS Global Insight, Global Insight Industry and Employment models, August 2011. **Projections:** U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs LM2012.D022412A, REF2012.D020112C, and HM2012.D022412A.

Appendix C
Price case comparisons

Table C1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Production										
Crude oil and lease condensate	11.59	12.66	13.23	13.79	11.57	13.77	15.60	10.29	12.89	14.37
Natural gas plant liquids	2.78	3.15	3.33	3.34	3.84	3.93	4.01	3.80	3.94	4.00
Dry natural gas	22.10	24.02	24.22	24.44	26.20	26.91	27.65	27.80	28.60	29.38
Coal[1]	22.06	20.76	20.24	19.80	22.39	22.25	23.45	23.59	24.14	27.73
Nuclear / uranium[2]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.42	9.28	9.26
Hydropower	2.51	2.90	2.90	2.90	2.99	2.99	2.98	3.05	3.04	3.04
Biomass[3]	4.05	4.52	4.45	4.67	6.14	6.26	7.14	7.92	9.07	11.33
Other renewable energy[4]	1.34	1.94	1.99	2.02	2.18	2.22	2.19	2.87	2.81	2.66
Other[5]	0.64	0.54	0.60	0.82	0.55	0.69	0.77	0.68	0.91	0.90
Total	**75.50**	**79.18**	**79.64**	**80.46**	**85.46**	**88.61**	**93.38**	**89.43**	**94.67**	**102.65**
Imports										
Crude oil	20.14	21.26	18.87	17.01	21.30	16.23	12.08	23.88	16.90	11.22
Liquid fuels and other petroleum[6]	5.02	4.97	4.32	3.89	5.08	4.08	3.43	5.40	4.14	3.26
Natural gas[7]	3.81	3.87	3.73	3.69	3.16	2.75	2.55	3.28	2.84	2.57
Other imports[8]	0.52	0.47	0.44	0.40	0.83	1.07	0.81	0.87	0.81	0.76
Total	**29.49**	**30.58**	**27.37**	**24.98**	**30.37**	**24.14**	**18.88**	**33.42**	**24.69**	**17.82**
Exports										
Liquid fuels and other petroleum[9]	4.81	5.16	5.00	4.95	4.51	4.46	4.58	4.89	4.95	5.02
Natural gas[10]	1.15	1.93	1.93	1.93	3.51	3.51	3.52	4.17	4.17	4.18
Coal	2.10	2.73	2.73	2.73	2.82	2.82	2.67	3.22	3.13	3.13
Total	**8.06**	**9.82**	**9.66**	**9.62**	**10.84**	**10.79**	**10.76**	**12.28**	**12.25**	**12.33**
Discrepancy[11]	**-1.23**	**0.04**	**-0.08**	**0.01**	**0.09**	**-0.03**	**-0.01**	**0.23**	**0.18**	**0.27**
Consumption										
Liquid fuels and other petroleum[12]	37.25	38.73	36.72	35.31	39.70	36.58	35.03	41.86	37.70	35.86
Natural gas	24.71	25.93	26.00	26.18	25.80	26.14	26.57	26.86	27.26	27.67
Coal[13]	20.76	18.35	17.80	17.30	20.17	20.02	20.39	21.05	21.15	22.69
Nuclear / uranium[2]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.42	9.28	9.26
Hydropower	2.51	2.90	2.90	2.90	2.99	2.99	2.98	3.05	3.04	3.04
Biomass[14]	2.88	3.06	3.04	3.13	4.19	4.17	4.48	4.98	5.44	6.45
Other renewable energy[4]	1.34	1.94	1.99	2.02	2.18	2.22	2.19	2.87	2.81	2.66
Other[15]	0.29	0.30	0.30	0.30	0.28	0.28	0.28	0.24	0.24	0.24
Total	**98.16**	**99.89**	**97.43**	**95.82**	**104.90**	**101.99**	**101.52**	**110.34**	**106.93**	**107.87**
Prices (2010 dollars per unit)										
Petroleum (dollars per barrel)										
Low sulfur light crude oil[16]	79.39	58.36	116.91	182.10	59.41	132.56	193.48	62.38	144.98	200.36
Imported crude oil[16]	75.87	55.41	113.97	179.16	48.84	121.21	180.29	53.10	132.95	187.04
Natural gas (dollars per million Btu)										
at Henry hub	4.39	4.21	4.29	4.26	5.61	5.63	5.60	7.36	7.37	7.17
at the wellhead[17]	4.06	3.78	3.84	3.81	4.98	5.00	4.97	6.47	6.48	6.31
Natural gas (dollars per thousand cubic feet)										
at the wellhead[17]	4.16	3.87	3.94	3.91	5.10	5.12	5.09	6.63	6.64	6.46
Coal (dollars per ton)										
at the minemouth[18]	35.61	39.93	42.08	44.26	41.50	44.05	45.62	47.24	50.52	51.12
Coal (dollars per million Btu)										
at the minemouth[18]	1.76	1.98	2.08	2.18	2.10	2.23	2.31	2.40	2.56	2.62
Average end-use[19]	2.38	2.42	2.56	2.68	2.51	2.70	2.81	2.73	2.94	3.07
Average electricity (cents per kilowatthour)	9.8	9.5	9.7	9.9	9.5	9.7	9.9	10.0	10.1	10.2

Table C1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Prices (nominal dollars per unit)										
Petroleum (dollars per barrel)										
Low sulfur light crude oil[165]	79.39	62.81	125.97	195.67	77.32	170.09	245.37	98.91	229.55	314.93
Imported crude oil[16]	75.87	59.64	122.81	192.52	63.56	155.52	228.64	84.19	210.51	294.00
Natural gas (dollars per million Btu)										
at Henry hub	4.39	4.54	4.62	4.57	7.30	7.23	7.10	11.67	11.67	11.26
at the wellhead[17]	4.06	4.07	4.14	4.10	6.48	6.42	6.30	10.26	10.26	9.91
Natural gas (dollars per thousand cubic feet)										
at the wellhead[17]	4.16	4.16	4.24	4.20	6.64	6.57	6.46	10.51	10.51	10.15
Coal (dollars per ton)										
at the minemouth[18]	35.61	42.97	45.34	47.56	54.01	56.52	57.86	74.91	80.00	80.35
Coal (dollars per million Btu)										
at the minemouth[18]	1.76	2.13	2.24	2.34	2.74	2.86	2.93	3.81	4.05	4.12
Average end-use[19]	2.38	2.61	2.76	2.88	3.27	3.47	3.56	4.33	4.66	4.83
Average electricity (cents per kilowatthour)	9.8	10.2	10.4	10.6	12.4	12.5	12.6	15.9	16.0	16.0

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that is later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas and natural gas used for liquefaction at export terminals.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Weighted average price delivered to U.S. refiners.
[17]Represents lower 48 onshore and offshore supplies.
[18]Includes reported prices for both open market and captive mines.
[19]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 natural gas supply values and natural gas wellhead price: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2010 coal minemouth and delivered coal prices: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 petroleum supply values: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). 2010 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude oil Acquisition Report." Other 2010 coal values: *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011). Other 2010 values: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System runs LP2012.D022112A, REF2012.D020112C, and HP2012.D022112A.

Table C2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Energy consumption										
Residential										
Liquefied petroleum gases	0.56	0.54	0.51	0.49	0.55	0.50	0.48	0.55	0.51	0.48
Kerosene	0.03	0.03	0.02	0.02	0.03	0.02	0.02	0.02	0.02	0.02
Distillate fuel oil	0.63	0.61	0.55	0.51	0.49	0.43	0.40	0.41	0.35	0.33
Liquid fuels and other petroleum subtotal	1.22	1.17	1.08	1.02	1.07	0.95	0.90	0.99	0.87	0.82
Natural gas	5.06	4.98	4.97	4.98	4.88	4.88	4.90	4.74	4.76	4.78
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable energy[1]	0.42	0.37	0.43	0.48	0.36	0.43	0.48	0.35	0.43	0.47
Electricity	4.95	4.78	4.75	4.71	5.27	5.23	5.20	5.90	5.86	5.83
Delivered energy	**11.66**	**11.31**	**11.24**	**11.19**	**11.58**	**11.51**	**11.48**	**11.98**	**11.93**	**11.91**
Electricity related losses	10.39	9.68	9.58	9.47	10.66	10.52	10.34	11.58	11.35	11.02
Total	**22.05**	**20.99**	**20.81**	**20.66**	**22.24**	**22.02**	**21.82**	**23.56**	**23.28**	**22.93**
Commercial										
Liquefied petroleum gases	0.14	0.16	0.14	0.12	0.18	0.15	0.13	0.19	0.16	0.14
Motor gasoline[2]	0.05	0.06	0.05	0.04	0.06	0.05	0.05	0.07	0.06	0.06
Kerosene	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.01	0.01
Distillate fuel oil	0.43	0.41	0.35	0.32	0.41	0.33	0.30	0.41	0.32	0.30
Residual fuel oil	0.08	0.13	0.08	0.06	0.14	0.08	0.06	0.14	0.08	0.07
Liquid fuels and other petroleum subtotal	0.72	0.76	0.62	0.55	0.79	0.62	0.56	0.81	0.62	0.57
Natural gas	3.28	3.42	3.41	3.42	3.51	3.53	3.55	3.64	3.69	3.72
Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.54	4.61	4.59	4.57	5.19	5.16	5.14	5.81	5.80	5.77
Delivered energy	**8.70**	**8.96**	**8.80**	**8.70**	**9.66**	**9.48**	**9.41**	**10.43**	**10.28**	**10.23**
Electricity related losses	9.52	9.34	9.27	9.18	10.50	10.38	10.21	11.41	11.23	10.90
Total	**18.22**	**18.30**	**18.06**	**17.89**	**20.16**	**19.86**	**19.62**	**21.84**	**21.50**	**21.13**
Industrial[4]										
Liquefied petroleum gases	2.00	1.86	1.83	1.80	2.22	2.17	2.13	2.23	2.15	2.11
Motor gasoline[2]	0.25	0.28	0.28	0.28	0.31	0.30	0.30	0.32	0.30	0.29
Distillate fuel oil	1.16	1.28	1.25	1.24	1.25	1.19	1.17	1.29	1.18	1.16
Residual fuel oil	0.12	0.12	0.09	0.09	0.13	0.08	0.07	0.14	0.08	0.07
Petrochemical feedstocks	0.94	1.01	1.01	1.01	1.30	1.29	1.28	1.32	1.30	1.29
Other petroleum[5]	3.59	3.82	3.44	3.23	3.82	3.11	2.89	4.10	3.19	2.83
Liquid fuels and other petroleum subtotal	8.05	8.39	7.89	7.65	9.03	8.13	7.83	9.40	8.21	7.76
Natural gas	6.76	7.17	7.19	7.21	7.19	7.32	7.38	7.18	7.18	7.29
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.07
Lease and plant fuel[6]	1.37	1.42	1.43	1.44	1.53	1.57	1.63	1.54	1.63	1.71
Natural gas subtotal	8.14	8.59	8.62	8.65	8.72	8.89	9.09	8.71	8.81	9.07
Metallurgical coal	0.55	0.58	0.57	0.56	0.48	0.49	0.49	0.44	0.43	0.43
Other industrial coal	1.01	1.03	1.03	1.02	1.04	1.08	1.08	1.05	1.08	1.09
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.10	0.36	1.12	0.10	0.60	2.74
Net coal coke imports	-0.01	-0.00	-0.01	-0.01	-0.03	-0.03	-0.03	-0.06	-0.06	-0.06
Coal subtotal	1.56	1.60	1.59	1.58	1.60	1.90	2.67	1.54	2.06	4.21
Biofuels heat and coproducts	0.84	0.85	0.81	0.86	1.19	1.27	1.73	1.99	2.57	3.63
Renewable energy[7]	1.50	1.63	1.61	1.63	1.90	1.82	1.75	2.10	1.95	1.87
Electricity	3.28	3.52	3.44	3.40	3.57	3.52	3.51	3.40	3.33	3.32
Delivered energy	**23.37**	**24.57**	**23.96**	**23.76**	**26.02**	**25.53**	**26.58**	**27.14**	**26.94**	**29.85**
Electricity related losses	6.89	7.11	6.94	6.84	7.21	7.09	6.98	6.68	6.46	6.27
Total	**30.26**	**31.69**	**30.90**	**30.60**	**33.24**	**32.61**	**33.56**	**33.82**	**33.39**	**36.12**

Table C2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Transportation										
Liquefied petroleum gases	0.04	0.04	0.04	0.05	0.04	0.04	0.05	0.05	0.05	0.05
E85[8]	0.00	0.01	0.01	0.37	0.02	0.30	1.49	0.20	1.22	2.63
Motor gasoline[2]	16.91	17.23	16.13	14.85	17.02	14.90	12.48	17.96	14.53	11.70
Jet fuel[9]	3.07	3.04	3.03	3.01	3.20	3.19	3.18	3.34	3.33	3.32
Distillate fuel oil[10]	5.77	6.71	6.55	6.45	7.08	7.03	7.14	7.58	7.44	7.57
Residual fuel oil	0.90	0.91	0.91	0.91	0.92	0.93	0.93	0.94	0.94	0.94
Other petroleum[11]	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Liquid fuels and other petroleum subtotal	26.88	28.11	26.83	25.81	28.45	26.57	25.44	30.24	27.67	26.40
Pipeline fuel natural gas	0.65	0.68	0.68	0.69	0.66	0.67	0.69	0.67	0.69	0.69
Compressed / liquefied natural gas	0.04	0.05	0.06	0.08	0.06	0.11	0.21	0.07	0.16	0.30
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.03	0.04	0.06	0.05	0.07	0.11
Delivered energy	**27.59**	**28.86**	**27.60**	**26.61**	**29.20**	**27.40**	**26.40**	**31.03**	**28.60**	**27.49**
Electricity related losses	0.05	0.05	0.05	0.06	0.07	0.08	0.12	0.10	0.14	0.20
Total	**27.63**	**28.92**	**27.65**	**26.67**	**29.27**	**27.49**	**26.52**	**31.12**	**28.75**	**27.69**
Delivered energy consumption for all sectors										
Liquefied petroleum gases	2.75	2.60	2.51	2.46	2.98	2.86	2.79	3.02	2.86	2.79
E85[8]	0.00	0.01	0.01	0.37	0.02	0.30	1.49	0.20	1.22	2.63
Motor gasoline[2]	17.21	17.57	16.46	15.17	17.39	15.25	12.82	18.35	14.88	12.05
Jet fuel[9]	3.07	3.04	3.03	3.01	3.20	3.19	3.18	3.34	3.33	3.32
Kerosene	0.04	0.04	0.03	0.03	0.04	0.03	0.03	0.04	0.03	0.03
Distillate fuel oil	7.99	9.01	8.69	8.52	9.24	8.99	9.02	9.69	9.29	9.36
Residual fuel oil	1.11	1.16	1.08	1.06	1.19	1.09	1.06	1.21	1.11	1.08
Petrochemical feedstocks	0.94	1.01	1.01	1.01	1.30	1.29	1.28	1.32	1.30	1.29
Other petroleum[12]	3.76	3.98	3.61	3.39	3.98	3.27	3.05	4.27	3.36	3.00
Liquid fuels and other petroleum subtotal	36.87	38.42	36.43	35.02	39.35	36.28	34.73	41.44	37.38	35.55
Natural gas	15.15	15.62	15.64	15.68	15.63	15.85	16.04	15.62	15.79	16.08
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.07
Lease and plant fuel[6]	1.37	1.42	1.43	1.44	1.53	1.57	1.63	1.54	1.63	1.71
Pipeline natural gas	0.65	0.68	0.68	0.69	0.66	0.67	0.69	0.67	0.69	0.69
Natural gas subtotal	17.17	17.72	17.75	17.81	17.82	18.09	18.43	17.83	18.11	18.55
Metallurgical coal	0.55	0.58	0.57	0.56	0.48	0.49	0.49	0.44	0.43	0.43
Other coal	1.08	1.09	1.09	1.08	1.11	1.14	1.15	1.11	1.15	1.16
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.10	0.36	1.12	0.10	0.60	2.74
Net coal coke imports	-0.01	-0.00	-0.01	-0.01	-0.03	-0.03	-0.03	-0.06	-0.06	-0.06
Coal subtotal	1.62	1.67	1.65	1.64	1.67	1.96	2.74	1.60	2.12	4.28
Biofuels heat and coproducts	0.84	0.85	0.81	0.86	1.19	1.27	1.73	1.99	2.57	3.63
Renewable energy[13]	2.03	2.10	2.15	2.22	2.37	2.36	2.34	2.56	2.50	2.45
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.79	12.94	12.81	12.71	14.07	13.96	13.91	15.16	15.06	15.02
Delivered energy	**71.32**	**73.71**	**71.59**	**70.26**	**76.47**	**73.92**	**73.87**	**80.58**	**77.75**	**79.48**
Electricity related losses	26.84	26.19	25.84	25.55	28.44	28.07	27.65	29.76	29.18	28.39
Total	**98.16**	**99.89**	**97.43**	**95.82**	**104.90**	**101.99**	**101.52**	**110.34**	**106.93**	**107.87**
Electric power[14]										
Distillate fuel oil	0.08	0.09	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09
Residual fuel oil	0.30	0.22	0.21	0.21	0.27	0.22	0.22	0.33	0.23	0.23
Liquid fuels and other petroleum subtotal	0.38	0.30	0.29	0.29	0.36	0.31	0.31	0.42	0.32	0.32
Natural gas	7.54	8.22	8.25	8.37	7.97	8.04	8.14	9.03	9.16	9.12
Steam coal	19.13	16.68	16.15	15.66	18.50	18.06	17.65	19.45	19.03	18.41
Nuclear / uranium[15]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.42	9.28	9.26
Renewable energy[16]	3.85	4.94	4.96	4.96	5.80	5.75	5.59	6.34	6.22	6.07
Electricity imports	0.09	0.10	0.10	0.10	0.08	0.08	0.08	0.04	0.04	0.04
Total[17]	**39.63**	**39.13**	**38.64**	**38.26**	**42.50**	**42.03**	**41.56**	**44.91**	**44.24**	**43.41**

Table C2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Total energy consumption										
Liquefied petroleum gases	2.75	2.60	2.51	2.46	2.98	2.86	2.79	3.02	2.86	2.79
E85[8]	0.00	0.01	0.01	0.37	0.02	0.30	1.49	0.20	1.22	2.63
Motor gasoline[2]	17.21	17.57	16.46	15.17	17.39	15.25	12.82	18.35	14.88	12.05
Jet fuel[9]	3.07	3.04	3.03	3.01	3.20	3.19	3.18	3.34	3.33	3.32
Kerosene	0.04	0.04	0.03	0.03	0.04	0.03	0.03	0.04	0.03	0.03
Distillate fuel oil	8.07	9.10	8.78	8.60	9.33	9.07	9.10	9.78	9.38	9.45
Residual fuel oil	1.41	1.38	1.29	1.27	1.46	1.31	1.28	1.55	1.34	1.31
Petrochemical feedstocks	0.94	1.01	1.01	1.01	1.30	1.29	1.28	1.32	1.30	1.29
Other petroleum[12]	3.76	3.98	3.61	3.39	3.98	3.27	3.05	4.27	3.36	3.00
Liquid fuels and other petroleum subtotal	37.25	38.73	36.72	35.31	39.70	36.58	35.03	41.86	37.70	35.86
Natural gas	22.69	23.84	23.89	24.05	23.60	23.89	24.17	24.65	24.94	25.20
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.07
Lease and plant fuel[6]	1.37	1.42	1.43	1.44	1.53	1.57	1.63	1.54	1.63	1.71
Pipeline natural gas	0.65	0.68	0.68	0.69	0.66	0.67	0.69	0.67	0.69	0.69
Natural gas subtotal	24.71	25.93	26.00	26.18	25.80	26.14	26.57	26.86	27.26	27.67
Metallurgical coal	0.55	0.58	0.57	0.56	0.48	0.49	0.49	0.44	0.43	0.43
Other coal	20.21	17.77	17.24	16.74	19.61	19.20	18.80	20.56	20.18	19.57
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.10	0.36	1.12	0.10	0.60	2.74
Net coal coke imports	-0.01	-0.00	-0.01	-0.01	-0.03	-0.03	-0.03	-0.06	-0.06	-0.06
Coal subtotal	20.76	18.35	17.80	17.30	20.17	20.02	20.39	21.05	21.15	22.69
Nuclear / uranium[15]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.42	9.28	9.26
Biofuels heat and coproducts	0.84	0.85	0.81	0.86	1.19	1.27	1.73	1.99	2.57	3.63
Renewable energy[18]	5.88	7.05	7.11	7.18	8.16	8.11	7.93	8.91	8.71	8.52
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity imports	0.09	0.10	0.10	0.10	0.08	0.08	0.08	0.04	0.04	0.04
Total	**98.16**	**99.89**	**97.43**	**95.82**	**104.90**	**101.99**	**101.52**	**110.34**	**106.93**	**107.87**
Energy use and related statistics										
Delivered energy use	71.32	73.71	71.59	70.26	76.47	73.92	73.87	80.58	77.75	79.48
Total energy use	98.16	99.89	97.43	95.82	104.90	101.99	101.52	110.34	106.93	107.87
Ethanol consumed in motor gasoline and E85	1.11	1.30	1.22	1.36	1.56	1.55	2.14	1.77	2.15	2.80
Population (millions)	310.83	326.16	326.16	326.16	358.06	358.06	358.06	390.09	390.09	390.09
Gross domestic product (billion 2005 dollars)	13088	14990	14803	14666	19146	19185	19380	24596	24539	24703
Carbon dioxide emissions (million metric tons)	5633.6	5592.8	5407.2	5251.2	5770.9	5552.5	5450.8	6049.1	5757.9	5737.1

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (15 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[17]Includes non-biogenic municipal waste not included above.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2011. 2010 carbon dioxide emissions: EIA, *Monthly Energy Review, October 2011* DOE/EIA-0035(2011/10) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System runs LP2012.D022112A, REF2012.D020112C, and HP2012.D022112A.

Table C3. Energy prices by sector and source
(2010 dollars per million Btu, unless otherwise noted)

Sector and source	2010	Projections 2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Residential										
Liquefied petroleum gases	27.02	22.54	30.70	39.69	22.18	32.27	40.42	23.49	34.64	42.03
Distillate fuel oil	21.21	16.55	27.26	38.29	17.27	30.15	39.23	18.46	32.73	40.00
Natural gas	11.08	10.22	10.31	10.30	11.96	12.03	12.02	13.97	13.98	13.86
Electricity	33.69	34.06	34.59	35.24	33.37	34.08	34.73	34.31	34.58	35.00
Commercial										
Liquefied petroleum gases	23.52	19.33	27.42	36.38	19.00	28.97	37.09	20.30	31.30	38.66
Distillate fuel oil	20.77	13.91	23.98	34.68	14.39	26.86	35.89	15.51	29.18	36.36
Residual fuel oil	11.07	5.99	16.18	27.80	6.25	18.24	28.32	6.90	18.90	28.11
Natural gas	9.10	8.52	8.60	8.59	9.98	10.02	10.01	11.66	11.64	11.49
Electricity	29.73	28.52	29.03	29.65	28.32	29.00	29.71	29.30	29.48	29.84
Industrial[1]										
Liquefied petroleum gases	21.80	16.98	27.43	38.87	16.33	29.24	39.62	17.95	32.18	41.60
Distillate fuel oil	21.32	14.50	24.20	34.82	14.95	27.22	36.32	16.19	29.53	36.60
Residual fuel oil	10.92	9.51	19.21	30.20	9.60	21.23	30.43	9.97	21.65	30.61
Natural gas[2]	5.51	4.78	4.88	4.88	5.99	6.04	6.01	7.52	7.54	7.38
Metallurgical coal	5.84	7.04	7.22	7.35	7.86	8.11	8.24	8.85	9.11	9.23
Other industrial coal	2.71	3.11	3.27	3.38	3.18	3.38	3.52	3.38	3.64	3.86
Coal to liquids	- -	1.17	1.26	1.32	2.02	2.08	2.26	2.26	2.38	2.64
Electricity	19.63	18.58	18.91	19.26	19.11	19.60	19.96	20.61	20.78	20.97
Transportation										
Liquefied petroleum gases[3]	26.88	23.86	31.93	40.71	23.47	33.38	41.43	24.77	35.74	43.04
E85[4]	25.21	18.16	29.03	38.11	17.18	28.81	41.93	16.59	31.96	39.01
Motor gasoline[5]	22.70	18.53	29.26	41.14	18.20	32.10	43.26	18.49	33.61	42.09
Jet fuel[6]	16.22	12.62	23.74	35.26	12.80	26.45	35.89	13.96	29.13	36.89
Diesel fuel (distillate fuel oil)[7]	21.87	17.99	27.56	38.22	18.14	30.42	39.66	19.15	32.40	39.63
Residual fuel oil	10.42	8.64	18.32	29.02	8.67	20.62	29.37	8.76	20.95	29.86
Natural gas[8]	13.20	12.28	12.40	12.45	13.05	13.29	13.41	14.26	14.51	14.47
Electricity	32.99	30.37	30.50	30.24	30.91	31.53	33.04	33.26	33.82	34.36
Electric power[9]										
Distillate fuel oil	18.73	12.06	22.77	33.56	12.54	25.35	34.16	13.56	27.80	35.05
Residual fuel oil	11.89	13.08	23.00	33.74	12.12	25.40	34.30	11.20	25.72	34.59
Natural gas	5.14	4.46	4.55	4.54	5.58	5.60	5.59	7.18	7.21	7.04
Steam coal	2.26	2.22	2.35	2.47	2.34	2.54	2.68	2.56	2.80	3.00
Average price to all users[10]										
Liquefied petroleum gases	17.28	14.64	22.99	32.23	13.90	24.19	32.57	15.28	26.63	34.20
E85[4]	25.21	18.16	29.03	38.11	17.18	28.81	41.93	16.59	31.96	39.01
Motor gasoline[5]	22.59	18.53	29.26	41.14	18.19	32.10	43.26	18.49	33.61	42.09
Jet fuel	16.22	12.62	23.74	35.26	12.80	26.45	35.89	13.96	29.13	36.89
Distillate fuel oil	21.65	17.16	26.87	37.56	17.45	29.81	39.04	18.54	31.91	39.12
Residual fuel oil	10.82	9.17	19.01	29.82	9.16	21.31	30.21	9.22	21.68	30.63
Natural gas	7.16	6.36	6.45	6.43	7.70	7.74	7.74	9.26	9.30	9.18
Metallurgical coal	5.84	7.04	7.22	7.35	7.86	8.11	8.24	8.85	9.11	9.23
Other coal	2.29	2.28	2.41	2.53	2.39	2.59	2.73	2.61	2.85	3.06
Coal to liquids	- -	1.17	1.26	1.32	2.02	2.08	2.26	2.26	2.38	2.64
Electricity	28.68	27.87	28.38	28.94	27.88	28.54	29.14	29.31	29.56	29.92
Non-renewable energy expenditures by sector (billion 2010 dollars)										
Residential	251.69	236.40	246.72	256.77	255.31	266.75	275.38	289.49	298.72	304.24
Commercial	179.08	171.63	177.92	184.03	193.67	201.89	208.38	225.40	231.98	235.90
Industrial	198.98	175.07	223.88	279.09	194.55	261.92	313.03	212.90	282.31	323.54
Transportation	573.78	489.96	746.84	998.67	491.22	803.52	976.23	537.61	856.65	958.30
Total non-renewable expenditures	1203.54	1073.06	1395.36	1718.56	1134.76	1534.08	1773.02	1265.39	1669.66	1821.97
Transportation renewable expenditures	0.08	0.18	0.25	14.01	0.39	8.74	62.29	3.32	38.86	102.69
Total expenditures	**1203.62**	**1073.25**	**1395.61**	**1732.58**	**1135.15**	**1542.81**	**1835.31**	**1268.71**	**1708.52**	**1924.66**

Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2010	Projections 2015 Low oil price	2015 Reference	2015 High oil price	2025 Low oil price	2025 Reference	2025 High oil price	2035 Low oil price	2035 Reference	2035 High oil price
Residential										
Liquefied petroleum gases	27.02	24.26	33.08	42.65	28.87	41.41	51.27	37.25	54.86	66.07
Distillate fuel oil	21.21	17.81	29.38	41.14	22.48	38.68	49.75	29.27	51.82	62.87
Natural gas	11.08	11.00	11.11	11.06	15.57	15.43	15.25	22.15	22.14	21.78
Electricity	33.69	36.66	37.27	37.86	43.43	43.72	44.05	54.40	54.76	55.02
Commercial										
Liquefied petroleum gases	23.52	20.80	29.54	39.09	24.73	37.17	47.04	32.18	49.56	60.77
Distillate fuel oil	20.77	14.97	25.83	37.27	18.73	34.47	45.51	24.59	46.20	57.15
Residual fuel oil	11.07	6.44	17.43	29.87	8.13	23.41	35.92	10.94	29.93	44.18
Natural gas	9.10	9.17	9.27	9.23	12.99	12.86	12.69	18.48	18.43	18.06
Electricity	29.73	30.70	31.28	31.86	36.86	37.21	37.68	46.46	46.67	46.91
Industrial[1]										
Liquefied petroleum gases	21.80	18.28	29.56	41.77	21.25	37.51	50.25	28.46	50.95	65.39
Distillate fuel oil	21.32	15.61	26.08	37.41	19.46	34.93	46.06	25.67	46.76	57.53
Residual fuel oil	10.92	10.23	20.70	32.45	12.49	27.24	38.59	15.80	34.28	48.11
Natural gas[2]	5.51	5.14	5.26	5.24	7.80	7.75	7.63	11.92	11.93	11.60
Metallurgical coal	5.84	7.57	7.78	7.90	10.23	10.40	10.45	14.04	14.42	14.51
Other industrial coal	2.71	3.35	3.52	3.63	4.13	4.34	4.46	5.36	5.77	6.06
Coal to liquids	- -	1.26	1.36	1.42	2.63	2.67	2.86	3.58	3.78	4.14
Electricity	19.63	19.99	20.38	20.69	24.87	25.15	25.31	32.68	32.90	32.96
Transportation										
Liquefied petroleum gases[3]	26.88	25.68	34.41	43.74	30.54	42.83	52.54	39.27	56.59	67.66
E85[4]	25.21	19.55	31.28	40.95	22.36	36.97	53.17	26.31	50.61	61.31
Motor gasoline[5]	22.70	19.94	31.53	44.21	23.68	41.19	54.86	29.32	53.22	66.16
Jet fuel[6]	16.22	13.59	25.58	37.89	16.66	33.94	45.51	22.13	46.12	57.99
Diesel fuel (distillate fuel oil)[7]	21.87	19.36	29.69	41.07	23.61	39.03	50.30	30.37	51.29	62.29
Residual fuel oil	10.42	9.30	19.74	31.18	11.28	26.45	37.25	13.89	33.18	46.93
Natural gas[8]	13.20	13.22	13.36	13.38	16.98	17.05	17.00	22.61	22.97	22.75
Electricity	32.99	32.69	32.86	32.50	40.22	40.46	41.90	52.74	53.55	54.01
Electric power[9]										
Distillate fuel oil	18.73	12.98	24.53	36.06	16.32	32.52	43.32	21.50	44.02	55.10
Residual fuel oil	11.89	14.07	24.78	36.26	15.77	32.59	43.50	17.77	40.73	54.38
Natural gas	5.14	4.80	4.90	4.88	7.27	7.19	7.09	11.38	11.42	11.06
Steam coal	2.26	2.39	2.53	2.65	3.04	3.25	3.40	4.06	4.43	4.72

Table C3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Average price to all users[10]										
Liquefied petroleum gases	17.28	15.75	24.78	34.64	18.08	31.04	41.30	24.23	42.17	53.76
E85[4]	25.21	19.55	31.28	40.95	22.36	36.97	53.17	26.31	50.61	61.31
Motor gasoline[5]	22.59	19.94	31.53	44.21	23.68	41.19	54.86	29.31	53.22	66.16
Jet fuel	16.22	13.59	25.58	37.89	16.66	33.94	45.51	22.13	46.12	57.99
Distillate fuel oil	21.65	18.47	28.96	40.36	22.71	38.24	49.51	29.39	50.52	61.50
Residual fuel oil	10.82	9.87	20.48	32.04	11.92	27.34	38.32	14.63	34.33	48.14
Natural gas	7.16	6.84	6.95	6.91	10.02	9.93	9.82	14.69	14.73	14.42
Metallurgical coal	5.84	7.57	7.78	7.90	10.23	10.40	10.45	14.04	14.42	14.51
Other coal	2.29	2.45	2.60	2.72	3.11	3.32	3.47	4.14	4.51	4.81
Coal to liquids	- -	1.26	1.36	1.42	2.63	2.67	2.86	3.58	3.78	4.14
Electricity	28.68	30.00	30.58	31.10	36.28	36.62	36.96	46.48	46.80	47.03
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	251.69	254.44	265.85	275.92	332.26	342.26	349.24	459.02	472.99	478.21
Commercial	179.08	184.73	191.71	197.75	252.04	259.04	264.27	357.40	367.31	370.80
Industrial	198.98	188.43	241.24	299.90	253.19	336.06	396.99	337.58	447.01	508.54
Transportation	573.78	527.35	804.75	1073.14	639.27	1030.98	1238.06	852.44	1356.41	1506.27
Total non-renewable expenditures	1203.54	1154.96	1503.55	1846.71	1476.75	1968.35	2248.56	2006.43	2643.72	2863.82
Transportation renewable expenditures	0.08	0.20	0.27	15.06	0.51	11.21	78.99	5.26	61.53	161.41
Total expenditures	**1203.62**	**1155.16**	**1503.82**	**1861.77**	**1477.26**	**1979.56**	**2327.55**	**2011.69**	**2705.26**	**3025.22**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2010 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2010 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2010 transportation sector natural gas delivered prices are model results. 2010 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/09) (Washington, DC, September 2010). 2010 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2010 and April 2011, Table 4.2, and EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2010 coal prices based on: EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011) and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. 2010 electricity prices: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2012 National Energy Modeling System runs LP2012.D022112A, REF2012.D020112C, and HP2012.D022112A.

Table C4. Liquid fuels supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil										
Domestic crude production[1]	5.47	5.88	6.15	6.41	5.38	6.40	7.25	4.79	5.99	6.68
Alaska	0.60	0.46	0.46	0.46	0.34	0.40	0.68	0.00	0.27	0.36
Lower 48 states	4.87	5.42	5.69	5.95	5.04	6.00	6.57	4.79	5.72	6.32
Net imports	9.17	9.63	8.52	7.64	9.58	7.24	5.32	10.74	7.52	4.91
Gross imports	9.21	9.66	8.56	7.67	9.61	7.27	5.36	10.77	7.55	4.95
Exports	0.04	0.03	0.03	0.03	0.03	0.03	0.04	0.03	0.03	0.04
Other crude supply[2]	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude supply	**14.72**	**15.52**	**14.67**	**14.05**	**14.96**	**13.64**	**12.56**	**15.53**	**13.51**	**11.59**
Other petroleum supply	**3.50**	**3.33**	**3.25**	**2.98**	**4.21**	**3.80**	**3.29**	**4.13**	**3.52**	**2.81**
Natural gas plant liquids	2.07	2.40	2.56	2.56	2.94	3.01	3.07	2.91	3.01	3.06
Net product imports	0.39	-0.01	-0.25	-0.50	0.33	-0.12	-0.62	0.31	-0.34	-0.94
Gross refined product imports[3]	1.23	0.97	0.78	0.61	1.06	0.79	0.51	1.14	0.82	0.55
Unfinished oil imports	0.61	0.74	0.64	0.56	0.67	0.51	0.38	0.74	0.50	0.26
Blending component imports	0.74	0.69	0.66	0.63	0.71	0.65	0.61	0.73	0.66	0.61
Exports	2.19	2.41	2.32	2.30	2.12	2.07	2.13	2.31	2.31	2.36
Refinery processing gain[4]	1.07	0.94	0.95	0.92	0.95	0.91	0.84	0.91	0.85	0.69
Product stock withdrawal	-0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other non-petroleum supply	**1.00**	**1.24**	**1.22**	**1.46**	**1.61**	**1.86**	**2.84**	**2.18**	**2.96**	**4.87**
Supply from renewable sources	0.87	1.11	1.05	1.20	1.42	1.48	2.01	1.92	2.37	3.24
Ethanol	0.85	1.00	0.94	1.05	1.20	1.19	1.64	1.36	1.65	2.15
Domestic production	0.88	0.99	0.94	0.99	1.18	1.17	1.47	1.35	1.59	1.96
Net imports	-0.02	0.01	0.00	0.06	0.02	0.02	0.17	0.01	0.06	0.19
Biodiesel	0.01	0.08	0.09	0.12	0.12	0.12	0.13	0.13	0.13	0.14
Domestic production	0.02	0.08	0.09	0.11	0.12	0.12	0.13	0.13	0.13	0.14
Net imports	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.00	-0.00
Other biomass-derived liquids[5]	0.00	0.02	0.03	0.03	0.10	0.16	0.24	0.44	0.59	0.95
Liquids from gas	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.06
Liquids from coal	0.00	0.00	0.00	0.00	0.05	0.17	0.52	0.05	0.28	1.27
Other[6]	0.13	0.14	0.17	0.26	0.15	0.21	0.24	0.20	0.31	0.30
Total primary supply[7]	**19.22**	**20.09**	**19.14**	**18.49**	**20.79**	**19.29**	**18.69**	**21.84**	**19.99**	**19.27**
Liquid fuels consumption										
by fuel										
Liquefied petroleum gases	2.27	2.00	1.94	1.90	2.30	2.21	2.15	2.32	2.21	2.15
E85[8]	0.00	0.01	0.01	0.25	0.02	0.21	1.02	0.14	0.83	1.80
Motor gasoline[9]	8.99	9.48	8.88	8.19	9.45	8.29	6.97	9.97	8.09	6.55
Jet fuel[10]	1.43	1.47	1.46	1.45	1.55	1.54	1.54	1.61	1.61	1.60
Distillate fuel oil[11]	3.80	4.34	4.19	4.10	4.45	4.33	4.34	4.67	4.48	4.51
Diesel	3.32	3.82	3.71	3.66	3.99	3.92	3.96	4.24	4.11	4.16
Residual fuel oil	0.54	0.60	0.56	0.55	0.63	0.57	0.56	0.67	0.58	0.57
Other[12]	2.14	2.23	2.06	1.97	2.38	2.06	1.95	2.51	2.10	1.94
by sector										
Residential and commercial	1.12	1.12	1.00	0.92	1.09	0.94	0.87	1.07	0.91	0.84
Industrial[13]	4.31	4.41	4.17	4.05	4.83	4.41	4.26	5.00	4.44	4.22
Transportation	13.82	14.47	13.80	13.31	14.69	13.71	13.26	15.64	14.41	13.90
Electric power[14]	0.17	0.14	0.13	0.13	0.16	0.14	0.14	0.19	0.14	0.14
Total	**19.17**	**20.14**	**19.10**	**18.41**	**20.77**	**19.20**	**18.53**	**21.90**	**19.90**	**19.12**
Discrepancy[15]	**0.05**	**-0.05**	**0.05**	**0.08**	**0.01**	**0.10**	**0.16**	**-0.06**	**0.09**	**0.15**

Table C4. Liquid fuels supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Domestic refinery distillation capacity[16]	17.6	17.6	17.5	17.1	16.8	15.5	14.6	17.1	15.2	13.8
Capacity utilization rate (percent)[17]	86.0	90.3	85.9	84.0	91.0	90.1	88.0	93.0	90.8	85.7
Net import share of product supplied (percent)	49.6	47.9	43.2	38.9	47.8	37.0	26.0	50.7	36.2	21.6
Net expenditures for imported crude oil and petroleum products (billion 2010 dollars)	243.07	207.99	373.00	523.15	189.41	344.58	384.81	226.36	389.97	363.97

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol and ethers blended into gasoline.
[10]Includes only kerosene type.
[11]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[13]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Balancing item. Includes unaccounted for supply, losses, and gains.
[16]End-of-year operable capacity.
[17]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 product supplied based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). Other 2010 data: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). **Projections:** EIA, AEO2012 National Energy Modeling System runs LP2012.D022112A, REF2012.D020112C, and HP2012.D022112A.

Table C5. Petroleum product prices
(2010 dollars per gallon, unless otherwise noted)

Sector and fuel	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (2010 dollars per barrel)										
Low sulfur light	79.39	58.36	116.91	182.10	59.41	132.56	193.48	62.38	144.98	200.36
Imported crude oil[1]	75.87	55.41	113.97	179.16	48.84	121.21	180.29	53.10	132.95	187.04
Delivered sector product prices										
Residential										
Liquefied petroleum gases	2.288	1.909	2.600	3.361	1.878	2.733	3.423	1.989	2.934	3.560
Distillate fuel oil	2.941	2.295	3.781	5.310	2.395	4.181	5.441	2.560	4.539	5.547
Commercial										
Distillate fuel oil	2.866	1.917	3.303	4.778	1.982	3.699	4.942	2.136	4.019	5.008
Residual fuel oil	1.657	0.896	2.421	4.161	0.935	2.731	4.240	1.033	2.830	4.207
Residual fuel oil (2010 dollars per barrel)	69.58	37.63	101.70	174.76	39.28	114.70	178.07	43.37	118.85	176.71
Industrial[2]										
Liquefied petroleum gases	1.846	1.438	2.323	3.292	1.383	2.476	3.355	1.520	2.725	3.523
Distillate fuel oil	2.932	1.991	3.322	4.780	2.053	3.737	4.986	2.223	4.054	5.025
Residual fuel oil	1.634	1.423	2.876	4.521	1.436	3.178	4.554	1.492	3.241	4.582
Residual fuel oil (2010 dollars per barrel)	68.62	59.77	120.80	189.87	60.33	133.47	191.28	62.65	136.12	192.45
Transportation										
Liquefied petroleum gases	2.276	2.021	2.704	3.447	1.987	2.827	3.508	2.097	3.026	3.645
Ethanol (E85)[3]	2.402	1.731	2.766	3.631	1.638	2.746	3.996	1.581	3.046	3.717
Ethanol wholesale price	1.712	2.356	2.228	2.622	2.215	2.333	2.741	1.985	2.159	2.571
Motor gasoline[4]	2.756	2.240	3.538	4.974	2.185	3.855	5.196	2.219	4.034	5.053
Jet fuel[5]	2.190	1.704	3.205	4.760	1.728	3.571	4.845	1.884	3.932	4.981
Diesel fuel (distillate fuel oil)[6]	2.998	2.465	3.776	5.237	2.486	4.168	5.435	2.624	4.439	5.430
Residual fuel oil	1.560	1.294	2.742	4.344	1.298	3.086	4.397	1.311	3.136	4.469
Residual fuel oil (2010 dollars per barrel)	65.53	54.33	115.15	182.43	54.50	129.62	184.67	55.06	131.73	187.70
Electric power[7]										
Distillate fuel oil	2.598	1.673	3.157	4.655	1.739	3.515	4.737	1.880	3.856	4.861
Residual fuel oil	1.780	1.957	3.443	5.051	1.814	3.802	5.135	1.677	3.850	5.178
Residual fuel oil (2010 dollars per barrel)	74.77	82.21	144.60	212.13	76.19	159.70	215.65	70.44	161.71	217.49
Refined petroleum product prices[8]										
Liquefied petroleum gases	1.464	1.239	1.947	2.729	1.177	2.049	2.758	1.294	2.255	2.896
Motor gasoline[4]	2.743	2.240	3.538	4.974	2.185	3.855	5.196	2.219	4.034	5.053
Jet fuel[5]	2.190	1.704	3.205	4.760	1.728	3.571	4.845	1.884	3.932	4.981
Distillate fuel oil	2.975	2.355	3.687	5.153	2.394	4.089	5.355	2.543	4.376	5.366
Residual fuel oil	1.619	1.372	2.845	4.464	1.371	3.189	4.523	1.381	3.246	4.585
Residual fuel oil (2010 dollars per barrel)	68.00	57.63	119.50	187.48	57.57	133.95	189.96	57.99	136.32	192.56
Average	**2.528**	**2.059**	**3.316**	**4.691**	**2.015**	**3.600**	**4.808**	**2.101**	**3.830**	**4.785**

Table C5. Petroleum product prices (continued)
(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (nominal dollars per barrel)										
Low sulfur light	79.39	62.81	125.97	195.67	77.32	170.09	245.37	98.91	229.55	314.93
Imported crude oil[1]	75.87	59.64	122.81	192.52	63.56	155.52	228.64	84.19	210.51	294.00
Delivered sector product prices										
Residential										
Liquefied petroleum gases	2.288	2.054	2.801	3.612	2.445	3.507	4.341	3.154	4.645	5.595
Distillate fuel oil	2.941	2.470	4.074	5.706	3.117	5.365	6.901	4.060	7.188	8.719
Commercial										
Distillate fuel oil	2.866	2.063	3.559	5.135	2.580	4.747	6.268	3.387	6.364	7.872
Residual fuel oil	1.657	0.964	2.609	4.471	1.217	3.504	5.377	1.637	4.481	6.613
Industrial[2]										
Liquefied petroleum gases	1.846	1.548	2.503	3.537	1.800	3.177	4.255	2.410	4.315	5.537
Distillate fuel oil	2.932	2.143	3.580	5.136	2.671	4.795	6.323	3.524	6.419	7.898
Residual fuel oil	1.634	1.532	3.099	4.858	1.869	4.077	5.776	2.365	5.132	7.202
Transportation										
Liquefied petroleum gases	2.276	2.175	2.914	3.704	2.586	3.627	4.449	3.326	4.792	5.729
Ethanol (E85)[3]	2.402	1.863	2.981	3.902	2.131	3.523	5.067	2.507	4.823	5.843
Ethanol wholesale price	1.712	2.535	2.400	2.818	2.883	2.994	3.477	3.147	3.419	4.041
Motor gasoline[4]	2.756	2.411	3.812	5.345	2.843	4.946	6.589	3.519	6.388	7.943
Jet fuel[5]	2.190	1.834	3.454	5.115	2.249	4.582	6.144	2.988	6.226	7.829
Diesel fuel (distillate fuel oil)[6]	2.998	2.653	4.069	5.628	3.235	5.348	6.893	4.161	7.029	8.535
Residual fuel oil	1.560	1.392	2.954	4.668	1.689	3.960	5.576	2.079	4.966	7.025
Electric power[7]										
Distillate fuel oil	2.598	1.801	3.402	5.002	2.263	4.510	6.008	2.982	6.105	7.641
Residual fuel oil	1.780	2.107	3.710	5.427	2.361	4.879	6.512	2.659	6.096	8.140
Refined petroleum product prices[8]										
Liquefied petroleum gases	1.464	1.334	2.098	2.933	1.531	2.629	3.498	2.052	3.571	4.552
Motor gasoline[4]	2.743	2.411	3.812	5.345	2.843	4.946	6.589	3.519	6.387	7.942
Jet fuel[5]	2.190	1.834	3.454	5.115	2.249	4.582	6.144	2.988	6.226	7.829
Distillate fuel oil	2.975	2.534	3.973	5.537	3.115	5.246	6.791	4.032	6.930	8.434
Residual fuel oil (nominal dollars per barrel)	68.00	62.03	128.77	201.46	74.93	171.87	240.90	91.95	215.84	302.67
Average	**2.528**	**2.216**	**3.573**	**5.041**	**2.623**	**4.620**	**6.097**	**3.331**	**6.064**	**7.520**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude oil Acquisition Report." 2010 imported crude oil price: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2010 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2010 electric power prices based on: *Monthly Energy Review*, DOE/EIA-0035(2011/09) (Washington, DC, September 2011). 2010 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2010 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2012 National Energy Modeling System runs LP2012.D022112A, REF2012.D020112C, and HP2012.D022112A.

Table C6. International liquids supply and disposition summary
(million barrels per day, unless otherwise noted)

Supply and disposition	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (2010 dollars per barrel)										
Low sulfur light	79.39	58.36	116.91	182.10	59.41	132.56	193.48	62.38	144.98	200.36
Imported crude oil[1]	75.87	55.41	113.97	179.16	48.84	121.21	180.29	53.10	132.95	187.04
Crude oil prices (nominal dollars per barrel)[1]										
Low sulfur light	79.39	62.81	125.97	195.67	77.32	170.09	245.37	98.91	229.55	314.93
Imported crude oil[1]	75.87	59.64	122.81	192.52	63.56	155.52	228.64	84.19	210.51	294.00
Petroleum liquids production[2]										
OPEC[3]										
Middle East	23.43	29.09	25.46	23.39	33.98	29.77	28.26	35.70	33.94	32.96
North Africa	3.89	4.01	3.62	3.48	3.66	3.37	3.41	3.12	3.27	3.28
West Africa	4.45	5.57	5.09	4.86	5.92	5.40	5.47	5.74	5.26	5.27
South America	2.29	2.37	2.13	2.05	2.06	1.92	1.94	1.63	1.72	1.72
Total OPEC petroleum production	**34.05**	**41.03**	**36.30**	**33.78**	**45.62**	**40.46**	**39.09**	**46.18**	**44.19**	**43.24**
Non-OPEC										
OECD										
United States (50 states)	8.79	9.36	9.82	10.15	9.42	10.53	11.40	8.81	10.15	10.72
Canada	1.91	1.79	1.79	1.82	1.77	1.82	1.85	1.75	1.78	1.87
Mexico	2.98	2.65	2.65	2.59	1.46	1.58	1.50	1.27	1.68	1.67
OECD Europe[4]	4.36	3.72	3.70	3.63	3.03	3.15	3.01	2.79	2.83	2.82
Japan	0.13	0.15	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.16
Australia and New Zealand	0.62	0.55	0.55	0.54	0.52	0.54	0.52	0.52	0.53	0.53
Total OECD petroleum production	**18.80**	**18.22**	**18.65**	**18.88**	**16.34**	**17.78**	**18.42**	**15.29**	**17.14**	**17.76**
Non-OECD										
Russia	10.14	9.74	10.04	9.79	9.73	11.06	10.38	8.96	12.16	12.02
Other Europe and Eurasia[5]	3.22	3.68	3.67	3.58	4.02	4.37	4.11	3.27	4.54	4.49
China	4.27	4.32	4.29	4.21	4.55	4.79	4.52	4.66	4.70	4.67
Other Asia[6]	3.77	3.80	3.79	3.73	3.23	3.38	3.22	2.97	3.00	2.99
Middle East	1.58	1.43	1.43	1.40	1.12	1.18	1.11	0.97	0.97	0.97
Africa	2.41	2.41	2.40	2.36	2.55	2.68	2.54	2.67	2.68	2.67
Brazil	2.19	2.73	2.72	2.66	3.47	3.87	3.64	3.32	4.45	4.40
Other Central and South America	2.01	2.30	2.29	2.26	2.36	2.47	2.35	2.64	2.65	2.63
Total non-OECD petroleum	**29.59**	**30.40**	**30.63**	**29.99**	**31.02**	**33.80**	**31.86**	**29.47**	**35.15**	**34.83**
Total petroleum liquids production	**82.44**	**89.66**	**85.58**	**82.65**	**92.98**	**92.04**	**89.37**	**90.93**	**96.47**	**95.83**
Other liquids production[7]										
United States (50 states)	0.90	1.10	1.05	1.14	1.45	1.62	2.42	1.96	2.59	4.38
Other North America	1.93	2.55	2.51	2.90	4.09	3.75	4.78	5.53	5.16	6.53
OECD Europe[3]	0.22	0.28	0.23	0.27	0.37	0.26	0.30	0.45	0.28	0.32
Middle East	0.01	0.13	0.17	0.14	0.23	0.24	0.21	0.22	0.24	0.22
Africa.	0.21	0.27	0.28	0.28	0.42	0.38	0.39	0.53	0.40	0.41
Central and South America	1.20	2.15	1.78	2.06	4.07	2.61	2.97	5.75	3.17	3.51
Other	0.13	0.21	0.16	0.24	0.81	0.61	1.15	1.75	1.18	1.69
Total other liquids production	**4.61**	**6.70**	**6.18**	**7.01**	**11.43**	**9.47**	**12.22**	**16.19**	**13.02**	**17.07**
Total production	**87.05**	**96.36**	**91.76**	**89.67**	**104.42**	**101.51**	**101.59**	**107.13**	**109.50**	**112.90**

Table C6. International liquids supply and disposition summary (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Liquids consumption[8]										
OECD										
United States (50 states)	19.17	20.14	19.10	18.41	20.77	19.20	18.53	21.90	19.90	19.12
United States territories	0.28	0.32	0.31	0.30	0.32	0.34	0.34	0.31	0.36	0.38
Canada	2.21	2.27	2.15	2.09	2.46	2.25	2.22	2.56	2.35	2.40
Mexico	2.34	2.50	2.38	2.30	2.78	2.50	2.32	3.20	2.68	2.43
OECD Europe[3]	14.58	14.86	14.14	13.69	15.97	14.65	13.85	16.10	14.74	13.93
Japan	4.45	4.80	4.51	4.35	5.14	4.62	4.33	4.92	4.42	4.14
South Korea	2.24	2.39	2.25	2.18	2.73	2.46	2.31	2.93	2.56	2.39
Australia and New Zealand	1.13	1.16	1.11	1.07	1.25	1.17	1.09	1.30	1.23	1.13
Total OECD consumption	**46.40**	**48.43**	**45.95**	**44.38**	**51.42**	**47.19**	**44.97**	**53.23**	**48.24**	**45.90**
Non-OECD										
Russia	2.93	3.14	3.02	2.96	2.88	2.91	2.93	2.71	2.97	3.12
Other Europe and Eurasia[5]	2.08	2.37	2.30	2.26	2.35	2.45	2.44	2.32	2.63	2.69
China	9.19	12.64	12.10	12.06	15.65	16.03	17.21	16.35	18.50	20.87
India	3.18	3.88	3.70	3.64	5.22	5.40	5.78	4.93	5.80	6.54
Other Asia	6.73	7.56	7.28	7.19	8.44	8.85	9.15	8.48	9.89	10.78
Middle East	7.35	8.26	7.78	7.72	8.35	8.16	8.51	9.03	9.49	10.46
Africa	3.34	3.44	3.30	3.24	3.43	3.57	3.57	3.47	4.09	4.21
Brazil	2.65	3.00	2.84	2.78	3.01	3.15	3.22	3.13	3.80	4.13
Other Central and South America	3.19	3.63	3.49	3.42	3.67	3.81	3.82	3.49	4.09	4.21
Total non-OECD consumption	**40.65**	**47.92**	**45.82**	**45.29**	**52.99**	**54.32**	**56.62**	**53.90**	**61.26**	**67.00**
Total liquids consumption	**87.05**	**96.36**	**91.76**	**89.67**	**104.42**	**101.51**	**101.59**	**107.13**	**109.50**	**112.90**
OPEC production[9]	34.58	42.18	37.30	34.88	47.89	41.91	40.63	49.42	45.89	45.01
Non-OPEC production[9]	52.47	54.18	54.46	54.79	56.52	59.60	60.97	57.71	63.61	67.89
Net Eurasia exports	10.53	10.64	11.11	10.81	12.00	13.94	12.75	10.52	15.54	15.10
OPEC market share (percent)	39.7	43.8	40.7	38.9	45.9	41.3	40.0	46.1	41.9	39.9

[1]Weighted average price delivered to U.S. refiners.
[2]Includes production of crude oil (including lease condensate and shale oil/tight oil), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, and refinery gains.
[3]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[4]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[5]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Slovenia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[6]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[7]Includes liquids produced from energy crops, natural gas, coal, extra-heavy oil, bitumen (oil sands), and kerogen (oil shale, not to be confused with shale oil/tight oil). Includes both OPEC and non-OPEC producers in the regional breakdown.
[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[9]Includes both petroleum and other liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude oil Acquisition Report." 2010 imported crude oil price: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **2010 quantities and projections:** EIA, AEO2012 National Energy Modeling System runs LP2012.D022112A, REF2012.D020112C, and HP2012.D022112A and EIA, Generate World Oil Balance Model.

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Table D1. Key results for residential and commercial sector technology cases

Energy consumption	2010	2015 Integrated 2011 Demand Technology	2015 Reference	2015 Integrated High Demand Technology	2015 Integrated Best Available Demand Technology	2025 Integrated 2011 Demand Technology	2025 Reference	2025 Integrated High Demand Technology	2025 Integrated Best Available Demand Technology
Residential									
Energy consumption (quadrillion Btu)									
Liquefied petroleum gases	0.56	0.52	0.51	0.51	0.50	0.52	0.50	0.48	0.48
Kerosene	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate fuel oil	0.63	0.56	0.55	0.54	0.53	0.46	0.43	0.41	0.39
Liquid fuels and other petroleum subtotal	1.22	1.10	1.08	1.07	1.05	1.00	0.95	0.91	0.88
Natural gas	5.06	5.03	4.97	4.83	4.63	5.12	4.88	4.51	4.00
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable energy[1]	0.42	0.43	0.43	0.42	0.41	0.47	0.43	0.41	0.37
Electricity	4.95	4.83	4.75	4.53	4.28	5.48	5.23	4.74	4.10
Delivered energy	**11.66**	**11.40**	**11.24**	**10.85**	**10.38**	**12.08**	**11.51**	**10.57**	**9.36**
Electricity related losses	10.39	9.75	9.58	9.09	8.52	10.98	10.52	9.53	8.17
Total	**22.05**	**21.15**	**20.81**	**19.95**	**18.90**	**23.07**	**22.02**	**20.10**	**17.53**
Delivered energy intensity (million Btu per household)	**102.1**	**96.0**	**94.6**	**91.4**	**87.4**	**91.1**	**86.8**	**79.7**	**70.6**
Nonmarketed renewables consumption (quadrillion Btu)	**0.02**	**0.08**	**0.08**	**0.08**	**0.09**	**0.10**	**0.10**	**0.11**	**0.13**
Commercial									
Energy consumption (quadrillion Btu)									
Liquefied petroleum gases	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15
Motor gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.43	0.35	0.35	0.35	0.35	0.33	0.33	0.32	0.32
Residual fuel oil	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Liquid fuels and other petroleum subtotal	0.72	0.62	0.62	0.62	0.62	0.62	0.62	0.61	0.61
Natural gas	3.28	3.42	3.41	3.39	3.41	3.53	3.53	3.48	3.56
Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.54	4.64	4.59	4.42	4.26	5.39	5.16	4.62	4.17
Delivered energy	**8.70**	**8.85**	**8.80**	**8.60**	**8.46**	**9.71**	**9.48**	**8.87**	**8.50**
Electricity related losses	9.52	9.38	9.27	8.88	8.48	10.79	10.38	9.29	8.30
Total	**18.22**	**18.24**	**18.06**	**17.48**	**16.94**	**20.50**	**19.86**	**18.16**	**16.80**
Delivered energy intensity (thousand Btu per square foot)	**107.3**	**105.3**	**104.6**	**102.2**	**100.6**	**103.4**	**101.0**	**94.5**	**90.5**
Commercial sector generation									
Net summer generation capacity (megawatts)									
Natural gas	711	843	865	900	914	1455	1955	2605	3066
Solar photovoltaic	1197	1251	1253	1254	1262	1490	1578	1753	2235
Wind	83	90	91	94	106	106	132	138	225
Electricity generation (billion kilowatthours)									
Natural gas	5.17	6.13	6.29	6.54	6.64	10.58	14.22	18.95	22.30
Solar photovoltaic	1.87	1.96	1.96	1.96	1.97	2.34	2.51	2.80	3.58
Wind	0.10	0.12	0.12	0.12	0.14	0.14	0.18	0.19	0.31
Nonmarketed renewables consumption (quadrillion Btu)	**0.03**	**0.04**	**0.04**	**0.05**	**0.05**	**0.04**	**0.04**	**0.07**	**0.08**

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System, runs FROZTECH.D030812A, REF2012.D020112C, HIGHTECH.D032812A, and BESTTECH.D032812A.

2035				Annual Growth 2010-2035 (percent)			
Integrated 2011 Demand Technology	Reference	Integrated High Demand Technology	Integrated Best Available Demand Technology	Integrated 2011 Demand Technology	Reference	Integrated High Demand Technology	Integrated Best Available Demand Technology
0.53	0.51	0.48	0.47	-0.2%	-0.4%	-0.6%	-0.7%
0.02	0.02	0.02	0.02	-1.2%	-1.7%	-2.1%	-2.4%
0.40	0.35	0.32	0.29	-1.8%	-2.3%	-2.7%	-3.1%
0.95	0.87	0.82	0.78	-1.0%	-1.3%	-1.6%	-1.8%
5.23	4.76	4.28	3.67	0.1%	-0.2%	-0.7%	-1.3%
0.01	0.01	0.00	0.00	-0.5%	-1.1%	-1.5%	-1.8%
0.50	0.43	0.39	0.34	0.6%	0.1%	-0.3%	-0.9%
6.23	5.86	5.26	4.45	0.9%	0.7%	0.2%	-0.4%
12.91	**11.93**	**10.75**	**9.24**	**0.4%**	**0.1%**	**-0.3%**	**-0.9%**
12.14	11.35	10.31	8.65	0.6%	0.4%	-0.0%	-0.7%
25.05	**23.28**	**21.06**	**17.89**	**0.5%**	**0.2%**	**-0.2%**	**-0.8%**
88.7	**81.9**	**73.8**	**63.4**	**-0.6%**	**-0.9%**	**-1.3%**	**-1.9%**
0.10	**0.11**	**0.14**	**0.19**	**6.4%**	**6.9%**	**7.7%**	**9.2%**
0.15	0.16	0.16	0.16	0.3%	0.3%	0.4%	0.4%
0.06	0.06	0.06	0.06	0.4%	0.4%	0.4%	0.4%
0.01	0.01	0.01	0.01	0.7%	0.7%	0.7%	0.7%
0.32	0.32	0.30	0.30	-1.2%	-1.2%	-1.4%	-1.5%
0.08	0.08	0.08	0.08	-0.1%	-0.0%	-0.0%	-0.0%
0.62	0.62	0.61	0.60	-0.6%	-0.5%	-0.7%	-0.7%
3.63	3.69	3.64	3.74	0.4%	0.5%	0.4%	0.5%
0.06	0.06	0.06	0.06	-0.0%	-0.0%	-0.0%	-0.0%
0.11	0.11	0.11	0.11	0.0%	0.0%	0.0%	0.0%
6.07	5.80	4.87	4.33	1.2%	1.0%	0.3%	-0.2%
10.49	**10.28**	**9.28**	**8.84**	**0.8%**	**0.7%**	**0.3%**	**0.1%**
11.82	11.23	9.54	8.41	0.9%	0.7%	0.0%	-0.5%
22.32	**21.50**	**18.82**	**17.25**	**0.8%**	**0.7%**	**0.1%**	**-0.2%**
101.9	**99.8**	**90.1**	**85.8**	**-0.2%**	**-0.3%**	**-0.7%**	**-0.9%**
2514	4795	6609	7235	5.2%	7.9%	9.3%	9.7%
1832	2311	3177	5546	1.7%	2.7%	4.0%	6.3%
178	270	269	375	3.1%	4.8%	4.8%	6.2%
18.29	34.88	48.08	52.63	5.2%	7.9%	9.3%	9.7%
2.88	3.74	5.17	9.02	1.7%	2.8%	4.2%	6.5%
0.24	0.38	0.38	0.53	3.5%	5.3%	5.3%	6.7%
0.04	**0.05**	**0.11**	**0.12**	**1.0%**	**1.7%**	**4.8%**	**5.1%**

Table D2. Key results for integrated technology cases

Consumption and emissions	2010	2015			2025			2035		
		Integrated 2011 Technology	Reference	Integrated High Technology	Integrated 2011 Technology	Reference	Integrated High Technology	Integrated 2011 Technology	Reference	Integrated High Technology
Energy consumption by sector (quadrillion Btu)										
Residential	11.66	11.39	11.24	10.87	12.08	11.51	10.60	12.90	11.93	10.80
Commercial	8.70	8.85	8.80	8.62	9.70	9.48	8.90	10.48	10.28	9.33
Industrial[1]	23.37	23.99	23.96	24.03	25.24	25.53	25.88	25.68	26.94	27.69
Transportation	27.59	27.61	27.60	27.48	27.45	27.40	26.80	28.57	28.60	27.64
Electric power[2]	39.63	39.09	38.64	37.46	43.38	42.03	39.08	46.11	44.24	40.45
Total	**98.16**	**98.00**	**97.43**	**96.02**	**103.43**	**101.99**	**98.25**	**108.09**	**106.93**	**102.23**
Energy consumption by fuel (quadrillion Btu)										
Liquid fuels and other petroleum[3]	37.25	36.77	36.72	36.54	36.67	36.58	35.84	37.67	37.70	36.52
Natural gas	24.71	26.02	26.00	25.69	26.77	26.14	25.13	28.64	27.26	25.23
Coal	20.76	18.14	17.80	16.64	20.73	20.02	17.87	21.89	21.15	18.45
Nuclear / uranium	8.44	8.68	8.68	8.68	9.60	9.60	9.34	9.14	9.28	9.55
Renewable energy[4]	6.72	8.10	7.92	8.17	9.38	9.38	9.80	10.48	11.29	12.24
Other[5]	0.29	0.30	0.30	0.30	0.28	0.28	0.27	0.26	0.24	0.24
Total	**98.16**	**98.00**	**97.43**	**96.02**	**103.43**	**101.99**	**98.25**	**108.09**	**106.93**	**102.23**
Energy intensity (thousand Btu per 2005 dollar of GDP)	**7.50**	**6.62**	**6.58**	**6.49**	**5.39**	**5.32**	**5.12**	**4.41**	**4.36**	**4.17**
Carbon dioxide emissions by sector (million metric tons)										
Residential	353	343	338	331	341	324	302	342	312	284
Commercial	229	231	231	230	237	237	233	242	246	242
Industrial[1]	909	964	963	962	993	992	983	1015	1011	995
Transportation	1872	1865	1864	1856	1829	1820	1772	1883	1859	1787
Electric power[6]	2271	2040	2011	1884	2268	2179	1942	2446	2330	1992
Total	**5634**	**5443**	**5407**	**5263**	**5668**	**5552**	**5232**	**5928**	**5758**	**5300**
Carbon dioxide emissions by fuel (million metric tons)										
Petroleum	2349	2332	2329	2315	2275	2261	2201	2327	2300	2208
Natural gas	1283	1368	1367	1350	1407	1374	1320	1508	1435	1327
Coal	1990	1731	1699	1586	1974	1906	1700	2081	2012	1753
Other[7]	12	12	12	12	12	12	12	12	12	12
Total	**5634**	**5443**	**5407**	**5263**	**5668**	**5552**	**5232**	**5928**	**5758**	**5300**
Carbon dioxide emissions (tons per person)	**18.1**	**16.7**	**16.6**	**16.1**	**15.8**	**15.5**	**14.6**	**15.2**	**14.8**	**13.6**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen.
[4]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; biogenic municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol component of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[5]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs LTRKITEN.D031312A, REF2012.D020112C, and HTRKITEN.D032812A.

Table D3. Key results for transportation sector light-duty vehicle efficiency cases

Consumption and indicators	2010	2015		2025		2035	
		Reference	CAFE Standards	Reference	CAFE Standards	Reference	CAFE Standards
Level of travel							
(billion vehicle miles traveled)							
Light-duty vehicles less than 8,501 pounds	2662	2710	2710	3111	3129	3583	3650
Commercial light trucks[1]	64	70	70	83	83	92	93
Freight trucks greater than 10,000 pounds	234	273	273	317	318	345	346
(billion seat miles available)							
Air	999	1028	1028	1120	1120	1208	1208
(billion ton miles traveled)							
Rail	1559	1503	1505	1782	1789	1871	1878
Domestic shipping	522	549	549	604	604	627	625
Energy efficiency indicators							
(miles per gallon)							
Tested new light-duty vehicle[2]	28.3	31.5	31.5	36.8	48.1	37.9	49.0
New car[2]	33.3	36.4	36.4	41.2	55.6	42.8	56.9
New light truck[2]	24.3	26.7	26.7	31.0	39.6	31.5	39.8
Light-duty stock[3]	20.4	21.5	21.5	25.6	27.5	28.2	34.5
New commercial light truck[1]	15.7	16.7	16.7	18.9	22.5	19.1	23.3
Stock commercial light truck[1]	14.4	15.2	15.2	18.0	19.0	19.0	22.5
Freight truck	6.7	6.8	6.8	7.7	7.7	8.1	8.1
(seat miles per gallon)							
Aircraft	62.3	62.8	62.8	65.2	65.2	69.3	69.3
(ton miles per thousand Btu)							
Rail	3.4	3.5	3.5	3.5	3.5	3.5	3.5
Domestic shipping	2.4	2.4	2.4	2.5	2.5	2.5	2.5
Energy use (quadrillion Btu)							
by mode							
Light-duty vehicles	16.06	15.39	15.39	14.73	13.78	15.46	12.84
Commercial light trucks[1]	0.55	0.58	0.58	0.58	0.55	0.61	0.52
Bus transportation	0.25	0.26	0.26	0.29	0.29	0.31	0.31
Freight trucks	4.82	5.51	5.51	5.66	5.67	5.84	5.87
Rail, passenger	0.05	0.05	0.05	0.06	0.06	0.06	0.06
Rail, freight	0.45	0.43	0.44	0.51	0.51	0.53	0.53
Shipping, domestic	0.22	0.23	0.23	0.25	0.25	0.25	0.25
Shipping, international	0.86	0.87	0.87	0.88	0.88	0.89	0.89
Recreational boats	0.25	0.26	0.26	0.27	0.27	0.29	0.29
Air	2.52	2.55	2.55	2.71	2.71	2.79	2.79
Military use	0.77	0.66	0.66	0.66	0.66	0.74	0.74
Lubricants	0.14	0.13	0.13	0.14	0.14	0.14	0.14
Pipeline fuel	0.65	0.68	0.68	0.67	0.67	0.69	0.68
Total	**27.59**	**27.60**	**27.60**	**27.40**	**26.44**	**28.60**	**25.92**
by fuel							
Liquefied petroleum gases	0.04	0.04	0.04	0.04	0.04	0.05	0.04
E85[4]	0.00	0.01	0.01	0.30	0.44	1.22	1.37
Motor gasoline[5]	16.91	16.13	16.13	14.90	13.81	14.53	11.82
Jet fuel[6]	3.07	3.03	3.03	3.19	3.19	3.33	3.33
Distillate fuel oil[7]	5.77	6.55	6.55	7.03	7.02	7.44	7.31
Residual fuel oil	0.90	0.91	0.91	0.93	0.93	0.94	0.94
Other petroleum[8]	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Liquid fuels and other petroleum	26.88	26.83	26.83	26.57	25.60	27.67	24.99
Pipeline fuel natural gas	0.65	0.68	0.68	0.67	0.67	0.69	0.68
Compressed/liquefied natural gas	0.04	0.06	0.06	0.11	0.11	0.16	0.15
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.04	0.05	0.07	0.09
Delivered energy	**27.59**	**27.60**	**27.60**	**27.40**	**26.44**	**28.60**	**25.92**
Electricity related losses	0.05	0.05	0.05	0.08	0.10	0.14	0.18
Total	**27.63**	**27.65**	**27.65**	**27.49**	**26.54**	**28.75**	**26.11**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[6]Includes only kerosene type.
[7]Diesel fuel for on- and off- road use.
[8]Includes aviation gasoline and lubricants.
CAFE = Corporate average fuel economy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs REF2012.D020112C and CAFEY.D032112A.

Table D4. Key results for HD NGV Potential case

Sales, consumption, and efficiency	2010	2015		2025		2035	
		Heavy Duty Vehicle Reference	Heavy Duty Natural Gas Vehicle Potential	Heavy Duty Vehicle Reference	Heavy Duty Natural Gas Vehicle Potential	Heavy Duty Vehicle Reference	Heavy Duty Natural Gas Vehicle Potential
Truck sales by size class (millions)	**0.36**	**0.56**	**0.56**	**0.65**	**0.65**	**0.80**	**0.81**
Medium	0.21	0.29	0.29	0.33	0.33	0.40	0.40
Diesel	0.13	0.20	0.20	0.24	0.20	0.28	0.21
Motor gasoline	0.07	0.08	0.08	0.08	0.07	0.10	0.08
Liquefied petroleum gases	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Natural gas	0.00	0.00	0.01	0.01	0.06	0.02	0.11
Heavy	0.15	0.27	0.27	0.32	0.32	0.40	0.40
Diesel	0.15	0.26	0.25	0.30	0.22	0.37	0.23
Motor gasoline	0.00	0.01	0.01	0.01	0.01	0.02	0.01
Liquefied petroleum gases	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas	0.00	0.00	0.01	0.00	0.08	0.01	0.16
Consumption by size class (quadrillion Btu)	**4.82**	**5.50**	**5.51**	**5.66**	**5.68**	**5.85**	**5.93**
Medium	0.83	1.03	1.03	1.12	1.12	1.15	1.16
Diesel	0.56	0.72	0.71	0.79	0.72	0.83	0.65
Motor gasoline	0.26	0.30	0.30	0.28	0.27	0.26	0.21
Liquefied petroleum gases	0.01	0.01	0.01	0.01	0.01	0.02	0.02
Natural gas	0.01	0.01	0.02	0.03	0.12	0.05	0.28
Heavy	3.99	4.47	4.48	4.55	4.56	4.71	4.77
Diesel	3.87	4.36	4.32	4.44	3.82	4.57	3.11
Motor gasoline	0.11	0.09	0.09	0.08	0.07	0.08	0.06
Liquefied petroleum gases	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Natural gas	0.00	0.01	0.06	0.02	0.66	0.05	1.59
New truck fuel efficiency by size class (gasoline equivalent miles per gallon)	**6.63**	**7.41**	**7.38**	**8.11**	**7.88**	**8.22**	**7.82**
Medium	11.92	13.42	13.34	15.06	14.32	15.43	14.12
Diesel	13.50	14.49	14.49	16.29	16.29	16.37	16.35
Motor gasoline	10.13	10.49	10.49	11.87	11.87	13.07	13.07
Liquefied petroleum gases	9.95	10.56	10.56	12.11	12.11	13.39	13.39
Natural gas	9.17	9.99	9.99	11.07	11.07	11.07	11.07
Heavy	5.79	6.82	6.80	7.46	7.29	7.58	7.29
Diesel	5.79	6.85	6.85	7.50	7.49	7.63	7.59
Motor gasoline	5.50	5.35	5.35	5.45	5.45	5.46	5.46
Liquefied petroleum gases	5.15	5.58	5.58	5.75	5.75	5.75	5.75
Natural gas	5.56	6.04	6.35	6.40	6.87	6.42	6.95
Stock fuel efficiency by size class (gasoline equivalent miles per gallon)	**6.66**	**6.83**	**6.82**	**7.72**	**7.61**	**8.12**	**7.81**
Medium	11.48	12.06	12.05	13.90	13.60	14.99	14.04
Diesel	13.87	13.89	13.89	15.54	15.49	16.27	16.23
Motor gasoline	9.23	9.66	9.66	10.82	10.79	12.35	12.30
Liquefied petroleum gases	8.67	9.59	9.59	11.31	11.31	12.87	12.86
Natural gas	8.69	9.32	9.49	10.85	10.95	11.05	11.06
Heavy	6.05	6.16	6.16	7.05	6.97	7.44	7.22
Diesel	6.07	6.19	6.18	7.09	7.04	7.50	7.44
Motor gasoline	5.36	5.34	5.34	5.38	5.38	5.44	5.44
Liquefied petroleum gases	5.43	5.43	5.43	5.62	5.62	5.71	5.71
Natural gas	5.51	5.75	6.06	6.31	6.79	6.41	6.92

[1]Includes lease condensate.
[2]Includes natural gas plant liquids, refinery processing gain, other crude oil supply, and stock withdrawals.
[3]Includes liquids, such as ethanol and biodiesel, derived from biomass, natural gas, and coal. Includes net imports of ethanol and biodiesel.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 data based on: Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 28 and Annual* (Oak Ridge, TN, 2009); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); Federal Highway Administration, *Highway Statistics 2007* (Washington, DC, October 2008); U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011); and EIA, AEO2012 National Energy Modeling System run RFNGV12.D050412A. **Projections:** EIA, AEO2012 National Energy Modeling System runs RFNGV12.D050412A and NOSUBNGV12.D050412A.

Table D5. Energy consumption and carbon dioxide emissions for extended policy cases

Consumption and emissions	2010	2015			2025			2035		
		Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies
Energy consumption by sector (quadrillion Btu)										
Residential	11.66	11.24	11.21	11.22	11.51	11.34	11.03	11.93	11.58	10.92
Commercial	8.70	8.80	8.79	8.78	9.48	9.49	9.20	10.28	10.31	9.79
Industrial[1]	23.37	23.96	23.95	23.96	25.53	25.73	25.42	26.94	26.99	26.60
Transportation	27.59	27.60	27.59	27.59	27.40	27.43	26.41	28.60	28.57	25.42
Electric power[2]	39.63	38.64	38.60	38.53	42.03	41.63	40.45	44.24	43.95	42.24
Total	**98.16**	**97.43**	**97.35**	**97.30**	**101.99**	**101.78**	**99.11**	**106.93**	**106.64**	**100.79**
Energy consumption by fuel (quadrillion Btu)										
Liquid fuels and other petroleum[3]	37.25	36.72	36.72	36.71	36.58	36.57	35.44	37.70	37.62	34.20
Natural gas	24.71	26.00	25.98	26.00	26.14	25.93	25.52	27.26	26.37	25.42
Coal	20.76	17.80	17.84	17.82	20.02	19.96	19.27	21.15	20.59	19.82
Nuclear / uranium	8.44	8.68	8.68	8.68	9.60	9.60	9.50	9.28	9.16	9.05
Renewable energy[4]	6.72	7.92	7.82	7.79	9.38	9.45	9.10	11.29	12.66	12.05
Other[5]	0.29	0.30	0.30	0.30	0.28	0.27	0.27	0.24	0.24	0.24
Total	**98.16**	**97.43**	**97.35**	**97.30**	**101.99**	**101.78**	**99.11**	**106.93**	**106.64**	**100.79**
Energy intensity (thousand Btu per 2005 dollar of GDP)	**7.50**	**6.58**	**6.58**	**6.58**	**5.32**	**5.30**	**5.16**	**4.36**	**4.35**	**4.11**
Carbon dioxide emissions by sector (million metric tons)										
Residential	353	338	337	338	324	322	319	312	307	293
Commercial	229	231	231	231	237	238	232	246	248	236
Industrial[1]	909	963	962	963	992	993	983	1011	1016	991
Transportation	1872	1864	1864	1863	1820	1813	1749	1859	1853	1642
Electric power[6]	2271	2011	2015	2012	2179	2161	2084	2330	2221	2133
Total	**5634**	**5407**	**5409**	**5407**	**5552**	**5526**	**5367**	**5758**	**5645**	**5295**
Carbon dioxide emissions by fuel (million metric tons)										
Petroleum	2349	2329	2329	2328	2261	2251	2180	2300	2289	2061
Natural gas	1283	1367	1366	1367	1374	1363	1341	1435	1387	1337
Coal	1990	1699	1702	1700	1906	1901	1835	2012	1957	1885
Other[7]	12	12	12	12	12	12	12	12	12	12
Total	**5634**	**5407**	**5409**	**5407**	**5552**	**5526**	**5367**	**5758**	**5645**	**5295**
Carbon dioxide emissions (tons per person)	**18.1**	**16.6**	**16.6**	**16.6**	**15.5**	**15.4**	**15.0**	**14.8**	**14.5**	**13.6**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen.
[4]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; biogenic municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol component of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[5]Includes non-biogenic municipal waste and net electricity imports.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs REF2012.D020112C, NOSUNSET.D032112A, and EXTENDED.D050612B.

Table D6. Electricity generation and generating capacity in extended policy cases
(gigawatts, unless otherwise noted)

Net summer capacity, generation, consumption, and emissions	2010	2015			2025			2035		
		Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies
Capacity	**1036.1**	**1042.0**	**1020.7**	**1011.3**	**1091.1**	**1088.5**	**1059.4**	**1190.0**	**1232.9**	**1167.6**
Electric power sector[1]	1006.5	998.7	977.3	967.6	1033.3	1004.8	976.6	1112.5	1098.0	1032.8
Pulverized coal	312.8	280.7	271.7	264.2	272.8	265.8	257.0	273.6	265.7	256.9
Coal gasification combined-cycle	0.5	0.9	0.9	0.9	1.8	1.8	1.7	1.7	1.7	1.5
Conventional natural gas combined-cycle	198.0	212.4	212.4	212.5	213.5	213.0	212.4	218.8	215.7	213.6
Advanced natural gas combined-cycle	0.0	1.2	1.0	1.3	10.3	4.7	2.4	53.4	20.5	8.4
Conventional combustion turbine	137.6	136.3	133.5	133.0	132.3	129.7	127.8	130.3	129.2	126.8
Advanced combustion turbine	0.0	5.2	3.7	4.0	23.2	11.7	6.8	41.5	24.9	10.2
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear / uranium	101.2	103.6	103.6	103.6	114.7	114.7	113.6	110.9	109.3	108.1
Oil and natural gas steam	108.1	90.7	85.2	84.2	89.6	83.3	81.4	87.9	83.1	80.6
Renewable sources	126.1	145.3	143.0	141.6	152.1	157.5	151.2	170.2	224.4	203.8
Pumped storage	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Distributed generation	0.0	0.2	0.1	0.1	0.8	0.5	0.3	2.1	1.3	0.5
Combined heat and power[2]	29.6	43.3	43.4	43.7	57.8	83.7	82.8	77.5	134.9	134.9
Fossil fuels / other	22.0	25.7	25.7	26.0	34.4	35.7	35.8	47.0	49.9	49.6
Renewable fuels	7.6	17.6	17.7	17.7	23.4	48.0	47.0	30.6	85.0	85.3
Cumulative additions	**0.0**	**69.8**	**65.8**	**65.3**	**126.7**	**140.0**	**124.8**	**235.0**	**290.9**	**240.4**
Electric power sector[1]	0.0	56.1	52.0	51.2	98.5	85.9	71.6	187.1	185.6	135.2
Pulverized coal	0.0	8.7	8.7	8.7	8.7	8.7	8.7	9.4	8.7	8.7
Coal gasification combined-cycle	0.0	0.6	0.6	0.6	1.5	1.5	1.5	1.5	1.5	1.5
Conventional natural gas combined-cycle	0.0	14.5	14.5	14.5	15.8	15.3	14.7	21.1	18.0	15.9
Advanced natural gas combined-cycle	0.0	1.2	1.0	1.3	10.3	4.7	2.4	53.4	20.5	8.4
Conventional combustion turbine	0.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Advanced combustion turbine	0.0	5.2	3.7	4.0	23.2	11.7	6.8	41.5	24.9	10.2
Nuclear / uranium	0.0	1.1	1.1	1.1	6.8	6.8	6.8	8.5	6.9	6.8
Renewable sources	0.0	19.6	17.3	15.9	26.4	31.8	25.5	44.5	98.7	78.1
Distributed generation	0.0	0.2	0.1	0.1	0.8	0.5	0.3	2.1	1.3	0.5
Combined heat and power[2]	0.0	13.7	13.8	14.1	28.2	54.1	53.2	47.9	105.3	105.3
Fossil fuels / other	0.0	3.7	3.8	4.1	12.4	13.7	13.9	25.0	27.9	27.6
Renewable fuels	0.0	10.0	10.0	10.0	15.8	40.3	39.3	22.9	77.4	77.7
Cumulative retirements	**0.0**	**65.2**	**82.5**	**91.4**	**78.9**	**94.9**	**108.8**	**88.4**	**101.3**	**116.2**
Generation by fuel (billion kilowatthours)	**4126**	**4152**	**4147**	**4142**	**4556**	**4559**	**4427**	**4992**	**5004**	**4813**
Electric power sector[1]	3971	3956	3950	3944	4279	4229	4106	4586	4498	4310
Coal	1831	1562	1565	1563	1741	1736	1673	1834	1781	1711
Petroleum	34	26	26	26	27	27	26	28	28	27
Natural gas	898	1028	1030	1030	1006	971	938	1196	1030	976
Nuclear / uranium	807	830	830	830	917	917	909	887	875	865
Renewable sources	395	508	498	493	584	574	557	634	780	728
Pumped storage	2	2	2	2	2	2	2	2	2	2
Distributed generation	0	0	0	0	2	1	1	4	2	1
Combined heat and power[2]	155	197	197	198	277	330	321	406	506	502
Fossil fuels / other	122	142	142	144	198	206	206	281	298	294
Renewable fuels	34	55	55	55	78	124	115	125	208	208
Average electricity price (cents per kilowatthour)	**9.8**	**9.7**	**9.8**	**9.8**	**9.7**	**9.6**	**9.6**	**10.1**	**9.9**	**9.6**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[2]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs REF2012.D020112C, NOSUNSET.D032112A, and EXTENDED.D050612B.

Table D7. Key results for advanced nuclear plant life cases
(gigawatts, unless otherwise noted)

Net summer capacity, generation, emissions, and fuel prices	2010	2015			2025			2035		
		Low Nuclear	Reference	High Nuclear	Low Nuclear	Reference	High Nuclear	Low Nuclear	Reference	High Nuclear
Capacity										
Coal steam	313.4	280.7	281.6	281.3	273.4	274.7	275.3	276.2	275.2	275.4
Oil and natural gas steam	108.1	88.2	90.7	91.0	87.0	89.6	89.4	84.5	87.9	86.9
Combined cycle	198.0	212.6	213.6	213.8	224.1	223.8	219.0	279.8	272.2	257.3
Combustion turbine / diesel	137.6	138.1	141.5	141.3	150.8	155.5	155.4	168.1	171.8	172.6
Nuclear / uranium	101.2	103.1	103.6	103.6	108.2	114.7	121.4	77.9	110.9	122.7
Pumped storage	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable sources	126.1	145.4	145.3	145.0	153.2	152.1	151.4	175.7	170.2	167.4
Distributed generation (natural gas)	0.0	0.1	0.2	0.2	0.7	0.8	0.8	1.7	2.1	2.1
Combined heat and power[1]	29.6	43.4	43.3	43.3	57.8	57.8	58.0	78.6	77.5	77.4
Total	**1036.1**	**1033.8**	**1042.0**	**1041.6**	**1077.4**	**1091.1**	**1093.0**	**1164.8**	**1190.0**	**1183.9**
Cumulative additions										
Coal steam	0.0	9.3	9.3	9.3	10.2	10.2	10.2	13.2	10.9	10.4
Oil and natural gas steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle	0.0	14.7	15.7	15.9	26.4	26.1	21.3	82.1	74.5	59.6
Combustion turbine / diesel	0.0	8.6	10.2	10.2	25.7	28.2	28.0	44.7	46.5	46.0
Nuclear / uranium	0.0	1.1	1.1	1.1	6.8	6.8	13.5	6.8	8.5	14.8
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable sources	0.0	19.7	19.6	19.3	27.5	26.4	25.7	50.0	44.5	41.7
Distributed generation	0.0	0.1	0.2	0.2	0.7	0.8	0.8	1.7	2.1	2.1
Combined heat and power[1]	0.0	13.8	13.7	13.7	28.2	28.2	28.4	49.0	47.9	47.7
Total	**0.0**	**67.2**	**69.8**	**69.7**	**125.5**	**126.7**	**127.9**	**247.5**	**235.0**	**222.4**
Cumulative retirements	**0.0**	**70.4**	**65.2**	**65.4**	**85.0**	**78.9**	**78.3**	**119.6**	**88.4**	**81.9**
Generation by fuel (billion kilowatthours)										
Coal	1831	1570	1562	1565	1760	1741	1727	1853	1834	1822
Petroleum	34	26	26	26	27	27	27	28	28	28
Natural gas	898	1022	1028	1026	1029	1006	972	1361	1196	1136
Nuclear / uranium	807	826	830	830	866	917	970	625	887	979
Pumped storage	2	2	2	2	2	2	2	2	2	2
Renewable sources	395	508	508	507	585	584	585	653	634	632
Distributed generation	0	0	0	0	2	2	2	3	4	4
Combined heat and power[1]	155	197	197	197	277	277	278	412	406	404
Total	**4124**	**4151**	**4152**	**4152**	**4547**	**4556**	**4562**	**4936**	**4992**	**5006**
Carbon dioxide emissions by the electric power sector (million metric tons)[2]										
Petroleum	33	23	23	23	24	24	24	24	25	25
Natural gas	399	436	438	437	435	427	415	545	485	467
Coal	1828	1547	1539	1543	1737	1717	1703	1823	1809	1798
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2271**	**2017**	**2011**	**2014**	**2207**	**2179**	**2154**	**2404**	**2330**	**2301**
Prices to the electric power sector[2] (2010 dollars per million Btu)										
Petroleum	13.32	22.93	22.93	22.94	25.38	25.38	25.38	26.53	26.31	26.13
Natural gas	5.14	4.52	4.55	4.54	5.70	5.60	5.46	8.03	7.21	7.00
Coal	2.26	2.36	2.35	2.35	2.54	2.54	2.53	2.81	2.80	2.78

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.

[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.

Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs LOWNUC12.D022312A, REF2012.D020112C, and HINUC12.D022312A.

Table D8. Key results for Low Renewable Technology Cost case

Capacity, generation, and emissions	2010	2015		2025		2035	
		Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost
Net summer capacity (gigawatts)							
Electric power sector[1]							
Conventional hydropower	78.03	78.55	78.76	80.14	81.34	81.25	84.36
Geothermal[2]	2.37	2.86	2.58	4.45	4.37	6.30	6.82
Municipal waste[3]	3.30	3.36	3.36	3.36	3.36	3.36	3.36
Wood and other biomass[4]	2.45	2.72	2.72	2.72	2.82	2.89	4.31
Solar thermal	0.47	1.36	1.36	1.36	1.36	1.36	1.36
Solar photovoltaic	0.38	2.02	2.05	2.30	5.12	8.18	34.27
Wind	39.05	54.46	61.41	57.77	65.59	66.85	105.87
Total	**126.06**	**145.34**	**152.25**	**152.10**	**163.96**	**170.19**	**240.35**
End-use sector[5]							
Conventional hydropower	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal waste[6]	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Wood and other biomass	4.56	5.73	5.89	8.44	10.52	13.81	17.21
Solar photovoltaic	2.05	8.98	9.19	11.69	14.29	13.33	23.29
Wind	0.36	2.25	3.18	2.60	4.06	2.74	5.26
Total	**7.65**	**17.64**	**18.95**	**23.41**	**29.55**	**30.57**	**46.43**
Generation (billion kilowatthours)							
Electric power sector[1]							
Coal	1831	1562	1547	1741	1731	1834	1780
Petroleum	34	26	26	27	27	28	28
Natural gas	898	1028	1018	1006	974	1196	1037
Total fossil	**2764**	**2616**	**2591**	**2774**	**2732**	**3058**	**2846**
Conventional hydropower	255.32	295.43	296.17	305.00	310.24	310.08	321.78
Geothermal	15.67	18.68	16.42	31.53	30.91	46.54	50.89
Municipal waste[7]	16.56	14.66	14.66	14.67	14.67	14.67	14.67
Wood and other biomass[4]	11.51	21.28	24.10	63.90	68.89	49.28	78.41
Dedicated plants	10.15	10.13	12.58	13.30	12.84	10.37	23.13
Cofiring	1.36	11.15	11.52	50.60	56.05	38.92	55.28
Solar thermal	0.82	2.86	2.86	2.86	2.86	2.86	2.86
Solar photovoltaic	0.46	3.61	3.68	4.37	11.91	20.19	84.04
Wind	94.49	150.97	174.49	161.49	188.46	190.67	310.55
Total renewable	**394.82**	**507.49**	**532.38**	**583.81**	**627.94**	**634.30**	**863.20**
End-use sector[5]							
Total fossil	**106**	**123**	**123**	**180**	**177**	**262**	**260**
Conventional hydropower[8]	1.76	1.75	1.75	1.75	1.75	1.75	1.75
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal waste[6]	2.02	2.79	2.79	2.79	2.79	2.79	2.79
Wood and other biomass	26.10	33.30	34.27	52.34	67.01	96.17	118.46
Solar photovoltaic	3.21	13.88	14.20	18.22	22.41	20.91	37.06
Wind	0.47	2.88	3.92	3.36	5.09	3.56	6.78
Total renewable	**33.56**	**54.59**	**56.92**	**78.45**	**99.05**	**125.17**	**166.82**
Carbon dioxide emissions by the electric power sector (million metric tons)[1]							
Coal	1828	1539	1525	1717	1706	1809	1754
Petroleum	33	23	23	24	24	25	25
Natural gas	399	438	434	427	416	485	435
Other[9]	12	12	12	12	12	12	12
Total	**2271**	**2011**	**1993**	**2179**	**2157**	**2330**	**2225**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes all municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Includes projections for energy crops after 2010.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[6]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities.
[8]Represents own-use industrial hydroelectric power.
[9]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs REF2012.D020112C, and LORENCST12.D041312A.

Table D9. Key results for environmental cases

Net summer capacity, generation, emissions, and fuel prices	2010	2035					
		Reference	Reference 05	High EUR	Low Gas Price 05	Greenhouse Gas $15	Greenhouse Gas $25
Capacity (gigawatts)							
Coal steam	313.4	275.2	261.6	268.3	254.2	124.3	39.1
Oil and natural gas steam	108.1	87.9	86.5	88.1	90.7	81.9	72.3
Combined cycle	198.0	272.2	276.2	273.1	285.6	298.0	312.7
Combustion turbine / diesel	137.6	171.8	173.9	181.5	178.4	154.7	142.9
Nuclear / uranium	101.2	110.9	111.1	109.3	109.3	160.5	225.0
Pumped storage	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Renewable sources	126.1	170.2	174.2	159.4	165.3	227.6	257.6
Distributed generation (natural gas)	0.0	2.1	2.0	5.2	5.6	0.3	0.2
Combined heat and power[1]	29.6	77.5	78.3	80.8	81.2	96.7	105.2
Total	**1036.1**	**1190.0**	**1186.0**	**1187.8**	**1192.5**	**1166.0**	**1177.3**
Cumulative additions (gigawatts)							
Coal steam	0.0	10.9	11.1	10.2	10.6	10.2	10.3
Combined cycle	0.0	74.5	78.4	75.4	87.9	100.3	115.0
Combustion turbine / diesel	0.0	46.5	43.4	52.1	48.0	38.9	24.7
Nuclear / uranium	0.0	8.5	8.7	6.9	6.9	58.1	122.7
Renewable sources	0.0	44.5	48.5	33.7	39.6	101.9	131.9
Distributed generation	0.0	2.1	2.0	5.2	5.6	0.3	0.2
Combined heat and power[1]	0.0	47.9	48.7	51.2	51.6	67.0	75.6
Total	**0.0**	**235.0**	**240.8**	**234.6**	**250.2**	**376.8**	**480.4**
Cumulative retirements (gigawatts)	**0.0**	**88.4**	**98.3**	**90.2**	**101.1**	**254.1**	**346.6**
Generation by fuel (billion kilowatthours)							
Coal	1831	1834	1752	1748	1664	699	102
Petroleum	34	28	27	29	28	24	21
Natural gas	898	1196	1253	1347	1404	1351	1306
Nuclear / uranium	807	887	889	875	875	1268	1782
Pumped storage	5	2	2	2	2	2	2
Renewable sources	395	634	642	601	618	888	876
Distributed generation	0	4	4	16	16	0	0
Combined heat and power[1]	155	406	410	426	428	512	545
Total	**4126**	**4992**	**4979**	**5044**	**5034**	**4743**	**4634**
Emissions by the electric power sector [2]							
Carbon dioxide (million metric tons)	2271	2330	2263	2310	2238	1228	555
Sulfur dioxide (million short tons)	5.11	1.71	1.68	1.54	1.57	0.61	0.15
Nitrogen oxides (million short tons)	2.06	1.96	1.93	1.93	1.93	0.85	0.42
Mercury (short tons)	34.70	7.86	7.57	7.49	7.15	3.40	0.91
Retrofits (gigawatts)							
Scrubber	0.00	47.57	19.91	52.97	18.31	30.07	25.69
Nitrogen oxide controls							
Combustion	0.00	7.97	6.08	4.16	1.51	2.38	2.38
Selective catalytic reduction post-combustion	0.00	19.17	10.29	13.44	6.10	7.67	5.91
Selective non-catalytic reduction post-combustion	0.00	0.71	0.71	0.71	0.71	0.70	2.50
Prices to the electric power sector[2] (2010 dollars per million Btu)							
Natural gas	5.14	7.21	7.35	6.03	6.14	9.37	11.10
Coal	2.26	2.80	2.77	2.73	2.70	6.64	9.45

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
EUR = Estimated ultimate recovery.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs REF2012.D020112C, REF12_R05.D030712A, HEUR12.D022212A, HEUR12_R05.D022312A, CO2FEE15.D031312A, and CO2FEE25.D031312A.

Table D10. Natural gas supply and disposition, oil and gas resource cases
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	2010	2015				2025				2035			
		Low EUR	Reference	High EUR	High TRR	Low EUR	Reference	High EUR	High TRR	Low EUR	Reference	High EUR	High TRR
Natural gas prices													
(2010 dollars per million Btu)													
Henry Hub spot price	4.39	4.58	4.29	3.94	3.10	6.93	5.63	4.77	3.45	8.26	7.37	5.99	4.25
Average lower 48 wellhead	4.06	4.10	3.84	3.54	2.80	6.11	5.00	4.26	3.11	7.24	6.48	5.31	3.81
(2010 dollars per thousand cubic feet)													
Average lower 48 wellhead	4.16	4.19	3.94	3.62	2.87	6.25	5.12	4.36	3.19	7.41	6.64	5.43	3.90
Dry gas production[2]	**21.58**	**22.80**	**23.65**	**24.38**	**26.54**	**24.25**	**26.28**	**27.81**	**30.85**	**26.11**	**27.93**	**30.07**	**34.15**
Lower 48 onshore	18.66	20.62	21.48	22.20	24.37	21.48	23.64	25.24	28.60	21.19	24.97	27.19	31.66
Associated-dissolved	1.40	1.47	1.52	1.58	1.70	1.31	1.41	1.50	1.60	0.90	1.00	1.13	1.29
Non-associated	17.26	19.15	19.96	20.62	22.68	20.17	22.23	23.74	27.00	20.28	23.97	26.07	30.37
Tight gas	5.68	6.13	6.08	6.01	5.88	6.40	6.17	6.02	5.86	6.30	6.14	5.93	5.76
Shale gas	4.99	7.35	8.24	8.99	11.24	8.88	11.26	12.98	16.44	9.74	13.63	16.01	20.53
Coalbed methane	1.99	1.85	1.83	1.80	1.74	1.84	1.77	1.73	1.69	1.80	1.76	1.70	1.66
Other	4.59	3.81	3.82	3.82	3.82	3.04	3.03	3.02	3.02	2.44	2.44	2.43	2.42
Lower 48 offshore	2.56	1.89	1.88	1.88	1.87	2.51	2.38	2.31	1.99	3.12	2.72	2.64	2.27
Associated-dissolved	0.71	0.55	0.55	0.55	0.55	0.71	0.67	0.67	0.59	0.84	0.73	0.71	0.60
Non-associated	1.85	1.34	1.33	1.33	1.32	1.81	1.71	1.65	1.40	2.28	2.00	1.93	1.67
Alaska	0.36	0.29	0.29	0.29	0.29	0.25	0.25	0.25	0.25	1.80	0.23	0.23	0.22
Supplemental natural gas[3]	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net imports	**2.58**	**1.77**	**1.73**	**1.65**	**1.42**	**-0.39**	**-0.79**	**-1.06**	**-1.62**	**-1.16**	**-1.36**	**-1.73**	**-2.35**
Pipeline[4]	2.21	1.61	1.56	1.49	1.27	0.22	-0.13	-0.40	-0.95	-0.50	-0.70	-1.07	-1.69
Liquefied natural gas	0.37	0.17	0.16	0.16	0.15	-0.61	-0.66	-0.66	-0.66	-0.66	-0.66	-0.66	-0.66
Total supply	**24.22**	**24.64**	**25.45**	**26.09**	**28.02**	**23.92**	**25.55**	**26.81**	**29.30**	**25.01**	**26.63**	**28.40**	**31.86**
Consumption by sector													
Residential	4.94	4.83	4.85	4.88	4.94	4.69	4.76	4.82	4.92	4.59	4.64	4.72	4.84
Commercial	3.20	3.30	3.33	3.37	3.47	3.32	3.44	3.54	3.71	3.50	3.60	3.75	3.97
Industrial[5]	6.60	6.99	7.01	7.07	7.20	6.96	7.14	7.26	7.51	6.85	7.00	7.24	7.61
Electric power[6]	7.38	7.40	8.08	8.56	10.07	6.74	7.87	8.78	10.54	7.67	8.96	10.13	12.62
Transportation[7]	0.04	0.06	0.06	0.06	0.06	0.11	0.11	0.12	0.12	0.15	0.16	0.17	0.18
Pipeline fuel	0.63	0.66	0.67	0.67	0.69	0.64	0.66	0.67	0.69	0.72	0.67	0.69	0.74
Lease and plant fuel[8]	1.34	1.35	1.39	1.43	1.55	1.44	1.53	1.60	1.78	1.54	1.60	1.70	1.91
Total	**24.13**	**24.59**	**25.39**	**26.04**	**27.97**	**23.90**	**25.53**	**26.79**	**29.28**	**25.01**	**26.63**	**28.40**	**31.87**
Discrepancy[9]	**0.10**	**0.05**	**0.05**	**0.05**	**0.05**	**0.02**	**0.02**	**0.02**	**0.02**	**-0.00**	**-0.00**	**-0.01**	**-0.01**
Lower 48 end of year reserves	**260.50**	**265.85**	**274.79**	**283.88**	**298.90**	**280.90**	**299.77**	**318.24**	**347.21**	**291.70**	**311.58**	**333.43**	**371.70**

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[4]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[5]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Natural gas used as a vehicle fuel.
[8]Represents natural gas used in field gathering and processing plant machinery.
[9]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2010 values include net storage injections.
EUR = Estimated ultimate recovery.
TRR = Technically recoverable resources.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 supply values; lease, plant, and pipeline fuel consumption; and wellhead price: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). Other 2010 consumption based on: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011).
Projections: EIA, AEO2012 National Energy Modeling System runs LEUR12.D022212A, REF2012.D020112C, HEUR12.D022212A., and HTRR12.D050412A

Table D11. Liquid fuels supply and disposition, oil and gas resource cases
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2010	2015				2025				2035			
		Low EUR	Reference	High EUR	High TRR	Low EUR	Reference	High EUR	High TRR	Low EUR	Reference	High EUR	High TRR
Prices													
(2010 dollars per barrel)													
Low sulfur light crude oil[1]	79.39	117.84	116.91	116.11	113.74	134.54	132.56	130.60	127.97	146.78	144.98	143.27	139.78
Imported crude oil[1]	75.87	114.90	113.97	113.17	110.80	123.99	121.21	118.63	115.77	135.38	132.95	131.20	127.55
Crude oil supply													
Domestic production[2]	5.47	5.91	6.15	6.38	7.09	5.82	6.40	6.95	7.69	5.49	5.99	6.62	7.76
Alaska	0.60	0.46	0.46	0.46	0.46	0.40	0.40	0.40	0.34	0.27	0.27	0.27	0.38
Lower 48 onshore	3.21	3.85	4.09	4.32	5.04	3.77	4.43	5.00	5.98	3.22	3.99	4.67	5.97
Lower 48 offshore	1.67	1.60	1.60	1.60	1.59	1.65	1.57	1.54	1.36	2.00	1.74	1.69	1.41
Net imports	9.17	8.80	8.52	8.28	7.57	7.87	7.24	6.68	5.89	8.12	7.52	6.90	5.65
Other crude oil supply	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude oil supply	**14.72**	**14.71**	**14.67**	**14.65**	**14.66**	**13.69**	**13.64**	**13.63**	**13.58**	**13.61**	**13.51**	**13.52**	**13.40**
Other petroleum supply	**3.50**	**3.17**	**3.25**	**3.33**	**3.40**	**3.66**	**3.80**	**3.94**	**4.13**	**3.40**	**3.52**	**3.73**	**4.02**
Natural gas plant liquids	2.07	2.43	2.56	2.68	2.97	2.67	3.01	3.27	3.91	2.66	3.01	3.33	4.04
Net product imports[3]	0.39	-0.20	-0.25	-0.30	-0.54	0.08	-0.12	-0.24	-0.69	-0.12	-0.34	-0.43	-0.89
Refinery processing gain[4]	1.07	0.94	0.95	0.94	0.97	0.90	0.91	0.91	0.91	0.86	0.85	0.83	0.86
Product stock withdrawal	-0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other non-petroleum supply	**1.00**	**1.22**	**1.22**	**1.22**	**1.22**	**1.87**	**1.86**	**1.86**	**1.85**	**2.91**	**2.96**	**2.87**	**2.81**
From renewable sources[5]	0.87	1.05	1.05	1.05	1.05	1.48	1.48	1.48	1.49	2.33	2.37	2.32	2.27
From non-renewable sources[6]	0.13	0.17	0.17	0.17	0.16	0.38	0.38	0.37	0.36	0.58	0.58	0.55	0.53
Total primary supply[7]	**19.22**	**19.10**	**19.14**	**19.20**	**19.27**	**19.21**	**19.29**	**19.42**	**19.56**	**19.91**	**19.99**	**20.11**	**20.23**
Refined petroleum products supplied													
Residential and commercial	1.12	1.00	1.00	1.00	1.00	0.93	0.94	0.94	0.95	0.90	0.91	0.91	0.92
Industrial[8]	4.31	4.17	4.17	4.19	4.19	4.38	4.41	4.44	4.46	4.41	4.44	4.46	4.47
Transportation	13.82	13.78	13.80	13.82	13.88	13.66	13.71	13.79	13.88	14.37	14.41	14.49	14.57
Electric power[9]	0.17	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.15	0.14
Total	**19.17**	**19.07**	**19.10**	**19.14**	**19.21**	**19.11**	**19.20**	**19.31**	**19.44**	**19.83**	**19.90**	**20.01**	**20.10**
Discrepancy[10]	**0.05**	**0.03**	**0.05**	**0.06**	**0.07**	**0.10**	**0.10**	**0.11**	**0.12**	**0.09**	**0.09**	**0.11**	**0.12**
Lower 48 end of year reserves (billion barrels)[2]	**18.33**	**19.39**	**20.55**	**21.66**	**23.49**	**21.36**	**23.64**	**25.77**	**27.83**	**22.68**	**24.23**	**26.27**	**29.06**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes ethanol (including imports), biodiesel (including imports), pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks for the production of green diesel and gasoline.
[6]Includes alcohols, ethers, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[9]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[10]Balancing item. Includes unaccounted for supply, losses and gains.
EUR = Estimated ultimate recovery.
TRR = Technically recoverable resources.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2010 data: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). **Projections:** EIA, AEO2012 National Energy Modeling System runs LEUR12.D022212A, REF2012.D020112C, HEUR12.D022212A, and HTRR.D050412A.

Table D12. Volumetric and mass representations of liquid fuels production cases
(volume in million barrels per day, mass in billion tons, unless otherwise noted)

Supply and disposition	2000		2011			2035		
	Volume	Mass	PMM Volume	LFMM Volume	LFMM Mass	PMM Volume	LFMM Volume	LFMM Mass
Primary feedstocks[1]								
Crude oil[2]	15.36	0.83	15.37	14.87	0.83	14.05	13.73	0.78
Natural gas[3]	0.00	0.00	0.00	0.00	0.00	0.00	2.95	0.03
Natural gas plant liquids[4]	1.91	0.07	2.16	1.21	0.09	3.01	0.30	0.11
Coal[5]	0.00	0.00	0.00	0.00	0.00	0.28	0.27	0.09
Biomass[6]	0.10	0.01	0.92	13.99	0.14	2.37	14.64	0.31
Total primary feedstocks	**17.37**	**0.91**	**18.45**	**- -**	**1.06**	**19.71**	**- -**	**1.32**
Refined products[1]								
Residual fuel oil	0.91	0.04	0.47	0.52	0.03	0.58	0.58	0.03
Middle distillates[7]	2.55	0.26	3.21	5.90	0.30	3.73	6.69	0.34
Biodiesel[8]	0.00	0.00	0.05	0.02	0.00	0.13	0.01	0.00
Gasoline blendstocks[9]	8.37	0.37	7.84	8.57	0.41	6.94	7.73	0.37
Ethanol[10]	0.10	0.00	0.86	0.95	0.05	1.65	1.61	0.08
Chemicals[11]	2.62	0.10	2.11	2.17	0.05	2.10	3.20	0.08
Solid products[12]	- -	0.05	- -	- -	0.07	- -	- -	0.08
Fuel consumption and other[13]	- -	0.10	- -	0.00	0.15	0.00	0.00	0.34
Total refined products	**14.55**	**0.91**	**14.54**	**18.13**	**1.06**	**15.13**	**19.82**	**1.32**
End use products								
Residual fuel oil	0.91	0.04	0.47	0.50	0.03	0.58	0.57	0.03
Heating oil[14]	1.17	0.03	0.62	0.53	0.03	0.37	0.37	0.02
Diesel fuel[15]	2.55	0.16	3.27	3.40	0.17	4.11	4.19	0.21
Jet fuel	1.73	0.08	1.44	1.51	0.08	1.61	1.67	0.08
Motor Gasoline[16]	8.47	0.38	8.76	9.29	0.44	8.09	8.32	0.40
E85[17]	0.00	0.00	0.00	0.00	0.00	0.83	0.84	0.04
Liquefied petroleum gases	2.43	0.02	2.26	0.46	0.01	2.21	0.74	0.01
Chemical feedstocks[18]	0.40	0.07	0.33	1.70	0.06	0.57	2.47	0.06
Agricultural products[19]	- -	0.00	- -	- -	0.05	- -	- -	0.06
Biomass heat and power[20]	- -	0.00	- -	- -	0.00	- -	- -	0.02
Other[21]	1.91	0.04	1.89	0.34	0.02	1.79	0.36	0.02
Total end use products	**19.57**	**0.82**	**19.04**	**17.73**	**0.89**	**20.16**	**19.53**	**0.95**

[1]Includes domestic production and net imports.
[2]Includes unfinished oils and lease condensate.
[3]Natural gas that remains after the liquefiable hydrocarbon portion has been removed from the gas stream at lease and/or plant separation facilities. Volume in billion cubic feet per day.
[4]Liquids in the natural gas production stream that stay in gaseous form at the surface and are separated at a gas processing plant. Once extracted, these liquids are separated into distinct products, or "fractions", such as propane, butane, and ethane.
[5]Coal input to the coal-to-liquids process. Volume in million barrels per day fuel oil equivalent.
[6]Biological material from living, or recently living organisms such as grain crops, sugars, cellulosic biomass, or renewable oils. Volume in million barrels per day fuel oil equivalent.
[7]Includes all fuels that meet ASTM D396 and D975 (#4 and lighter) and D1655/D6615, including those derived from fossil and renewable feedstock.
[8]Methyl ester based fuel produced from fatty acids in renewable oils.
[9]Includes all blendstocks that meet ASTM D4814, including those derived from fossil and renewable feedstock.
[10]Includes denaturant.
[11]Includes liquefied petroleum gases and petrochemical feestocks.
[12]Includes petroleum coke, distillers grains, sulfur, and asphalt sales.
[13]Includes fuels burned for internal use, heat and power sales, solid waste, and process emissions.
[14]A distillate fuel oil for use in atomizing type burners for domestic heating or for use in medium capacity commercial-industrial burner units.
[15]For on-road use.
[16]Includes ethanol and ethers blended into motor gasoline.
[17]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[18]Includes petrochemical feedstocks and chemicals from Fischer-Tropsch processes, such as coal-to-liquids, biomass-to-liquids, and natural gas-to-liquids.
[19]Non-liquid co-products for use in the agricultural sector. Includes dried distiller grains.
[20]Heat and power generated from the burning of residual biomass.
[21]Includes petroleum coke, asphalt, road oil, and still gas.
- - = Not applicable.
PMM = Petroleum market module.
LFMM = Liquid fuels market module.
Note: PMM and LFMM projections do not exactly match due to differences in accounting for additional materials and updated refinery stream representations. Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2000 crude oil production: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2000 data: EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000)/1 (Washington, DC, June 2001). **Projections:** EIA, AEO2012 National Energy Modeling System runs REF2012.D020112C, and REF_LFMM.D050312A.

Table D13. Key results for No GHG Concern case
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	2010	2015		2025		2035	
		Reference	No GHG Concern	Reference	No GHG Concern	Reference	No GHG Concern
Production[1]	**1084**	**993**	**1016**	**1118**	**1169**	**1212**	**1339**
Appalachia	336	300	301	271	263	291	301
Interior	156	151	156	163	173	198	216
West	592	542	558	684	733	722	822
Waste coal supplied[2]	**14**	**15**	**18**	**16**	**16**	**19**	**24**
Net imports[3]	**-64**	**-95**	**-97**	**-71**	**-57**	**-94**	**-88**
Total supply[4]	**1034**	**914**	**936**	**1064**	**1128**	**1138**	**1276**
Consumption by sector							
Residential and commercial	3	3	3	3	3	3	3
Coke plants	21	22	22	19	19	17	17
Other industrial[5]	52	50	50	52	52	53	53
Coal-to-liquids heat and power	0	0	0	19	47	34	90
Coal-to-liquids liquids production	0	0	0	18	44	32	85
Electric power[6]	975	839	861	952	962	998	1028
Total coal use	**1051**	**914**	**936**	**1063**	**1127**	**1137**	**1276**
Average minemouth price[7]							
(2010 dollars per short ton)	35.61	42.08	41.83	44.05	43.14	50.52	49.88
(2010 dollars per million Btu)	1.76	2.08	2.07	2.23	2.21	2.56	2.54
Delivered prices[8] (2010 dollars per short ton)							
Coke plants	153.59	189.11	188.05	212.18	212.06	238.32	237.86
Other industrial[5]	59.28	70.14	70.04	72.77	73.23	78.53	79.88
Coal to liquids	- -	18.65	18.62	39.03	36.06	41.54	43.46
Electric power[6]							
(2010 dollars per short ton)	44.27	45.17	44.94	48.13	48.40	53.31	55.05
(2010 dollars per million Btu)	2.26	2.35	2.34	2.54	2.55	2.80	2.87
Average	**47.17**	**49.95**	**49.60**	**51.90**	**51.28**	**56.48**	**56.89**
Exports[9]	120.41	140.89	140.22	163.43	163.15	177.66	176.61
Cumulative electricity generating capacity additions (gigawatts)[10]							
Coal	0.0	9.1	9.1	13.5	18.4	16.6	39.9
Conventional	0.0	8.7	8.7	8.7	9.1	9.4	21.8
Advanced without sequestration	0.0	0.6	0.6	0.6	0.7	0.6	2.0
Advanced with sequestration	0.0	0.0	0.0	0.9	0.9	0.9	0.9
End-use generators[11]	0.0	-0.1	-0.1	3.4	7.8	5.6	15.2
Petroleum	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Natural gas	0.0	29.1	28.0	63.3	61.4	141.6	128.9
Nuclear / uranium	0.0	1.1	1.1	6.8	6.8	8.5	7.4
Renewables [12]	0.0	29.6	29.3	42.2	41.3	67.4	58.2
Other	0.0	0.8	0.8	0.8	0.8	0.8	0.8
Total	**0.0**	**69.8**	**68.4**	**126.7**	**128.8**	**235.0**	**235.3**
Liquids from coal (million barrels per day)	0.00	0.00	0.00	0.17	0.38	0.28	0.73

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes reported prices for both open market and captive mines.
[8]Prices weighted by consumption tonnage; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[9]F.a.s. price at U.S. port of exit.
[10]Cumulative additions after December 31, 2010. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[12]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
- - = Not applicable.
Btu = British thermal unit.
GHG = Greenhouse gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011); EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011); and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.
Projections: EIA, AEO2012 National Energy Modeling System runs REF2012.D020112C and NOGHGCONCERN.D031212A.

Table D14. Key results for coal cost cases
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	2010	2020			2035			Annual growth 2010-2035 (percent)		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Production[1]	**1084**	**1096**	**1034**	**962**	**1336**	**1212**	**946**	**0.8%**	**0.4%**	**-0.5%**
Appalachia	336	281	262	253	309	291	261	-0.3%	-0.6%	-1.0%
Interior	156	168	159	159	194	198	202	0.9%	1.0%	1.0%
West	592	647	613	550	833	722	483	1.4%	0.8%	-0.8%
Waste coal supplied[2]	14	13	15	18	14	19	40	0.2%	1.4%	4.4%
Net imports[3]	-64	-78	-67	-73	-87	-94	-59	1.2%	1.5%	-0.3%
Total supply[4]	**1034**	**1031**	**982**	**907**	**1263**	**1138**	**927**	**0.8%**	**0.4%**	**-0.4%**
Consumption by sector										
Residential and commercial	3	3	3	3	3	3	3	-0.2%	-0.3%	-0.4%
Coke plants	21	19	18	18	17	17	16	-0.8%	-1.0%	-1.1%
Other industrial[5]	52	51	51	50	53	53	52	0.1%	0.0%	-0.0%
Coal-to-liquids heat and power	0	15	13	12	57	34	29	- -	- -	- -
Coal-to-liquids liquids production	0	14	12	11	54	32	27	- -	- -	- -
Electric power[6]	975	929	885	812	1079	998	800	0.4%	0.1%	-0.8%
Total coal use	**1051**	**1031**	**982**	**907**	**1263**	**1137**	**926**	**0.7%**	**0.3%**	**-0.5%**
Average minemouth price[7]										
(2010 dollars per short ton)	35.61	32.70	40.96	52.91	25.80	50.52	106.78	-1.3%	1.4%	4.5%
(2010 dollars per million Btu)	1.76	1.64	2.06	2.65	1.31	2.56	5.24	-1.2%	1.5%	4.5%
Delivered prices[8] (2010 dollars per short ton)										
Coke plants	153.59	165.27	198.45	239.32	136.73	238.32	413.77	-0.5%	1.8%	4.0%
Other industrial[5]	59.28	60.23	70.89	84.14	50.11	78.53	127.31	-0.7%	1.1%	3.1%
Coal to liquids	- -	34.43	40.67	49.20	25.22	41.54	68.76	- -	- -	- -
Electric power[6]										
(2010 dollars per short ton)	44.27	39.19	45.98	55.09	34.16	53.31	94.16	-1.0%	0.7%	3.1%
(2010 dollars per million Btu)	2.26	2.04	2.41	2.89	1.77	2.80	4.79	-1.0%	0.9%	3.0%
Average	**47.17**	**42.38**	**49.99**	**60.26**	**35.44**	**56.48**	**100.09**	**-1.1%**	**0.7%**	**3.1%**
Exports[9]	120.41	121.34	155.03	187.16	96.75	177.66	338.54	-0.9%	1.6%	4.2%
Cumulative electricity generating capacity additions (gigawatts)[10]										
Coal	0.0	12.9	12.5	12.2	30.7	16.6	14.5	- -	- -	- -
Conventional	0.0	8.7	8.7	8.7	19.8	9.4	8.7	- -	- -	- -
Advanced without sequestration	0.0	0.6	0.6	0.6	1.0	0.6	0.6	- -	- -	- -
Advanced with sequestration	0.0	0.9	0.9	0.9	0.9	0.9	0.9	- -	- -	- -
End-use generators[11]	0.0	2.7	2.3	2.1	9.0	5.6	4.3	- -	- -	- -
Petroleum	0.0	0.1	0.1	0.1	0.1	0.1	0.1	- -	- -	- -
Natural gas	0.0	36.6	39.7	43.1	128.1	141.6	131.7	- -	- -	- -
Nuclear / uranium	0.0	6.8	6.8	6.8	7.3	8.5	7.7	- -	- -	- -
Renewables[12]	0.0	34.2	34.5	41.0	67.9	67.4	65.9	- -	- -	- -
Other	0.0	0.8	0.8	0.8	0.8	0.8	0.8	- -	- -	- -
Total	**0.0**	**91.3**	**94.3**	**104.0**	**234.9**	**235.0**	**220.6**	**- -**	**- -**	**- -**
Liquids from coal (million barrels per day)	0.00	0.14	0.12	0.11	0.45	0.28	0.21	- -	- -	- -

Table D14. Key results for coal cost cases (continued)
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	2010	2020			2035			Annual growth 2010-2035 (percent)		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Cost indices										
(constant dollar index, 2010=1.000)										
Transportation rate multipliers										
Eastern railroads	1.000	0.970	1.067	1.170	0.780	1.044	1.300	-1.0%	0.2%	1.1%
Western railroads	1.000	0.870	0.963	1.050	0.750	0.999	1.250	-1.1%	-0.0%	0.9%
Mine equipment costs										
Underground	1.000	0.914	1.000	1.094	0.786	1.000	1.270	-1.0%	0.0%	1.0%
Surface	1.000	0.914	1.000	1.094	0.786	1.000	1.270	-1.0%	0.0%	1.0%
Other mine supply costs										
East of the Mississippi: all mines	1.000	0.914	1.000	1.094	0.786	1.000	1.270	-1.0%	0.0%	1.0%
West of the Mississippi: underground	1.000	0.914	1.000	1.094	0.786	1.000	1.270	-1.0%	0.0%	1.0%
West of the Mississippi: surface	1.000	0.914	1.000	1.094	0.786	1.000	1.270	-1.0%	0.0%	1.0%
Coal mining labor productivity										
(short tons per miner per hour)	5.55	6.29	4.92	3.67	8.06	3.88	1.68	1.5%	-1.4%	-4.7%
Average coal miner wage										
(2010 dollars per year)	77,466	84,135	92,285	100,436	78,164	99,537	124,954	0.0%	1.0%	1.9%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal to liquids process.
[6]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes reported prices for both open market and captive mines.
[8]Prices weighted by consumption tonnage; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[9]F.a.s. price at U.S. port of exit.
[10]Cumulative additions after December 31, 2010. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[12]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011); EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011); U.S. Department of Labor, Bureau of Labor Statistics, Average Hourly Earnings of Production Workers: Coal Mining, Series ID : ceu1021210008; and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. **Projections:** EIA, AEO2012 National Energy Modeling System runs LCCST12.D031312A, REF2012.D020112C, and HCCST12.D031312A.

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Appendix E
NEMS overview and brief description of cases

The National Energy Modeling System

Projections in the *Annual Energy Outlook 2012 (AEO2012)* are generated using the National Energy Modeling System (NEMS) [*142*], developed and maintained by the Office of Energy Analysis of the U.S. Energy Information Administration (EIA). In addition to its use in developing the *Annual Energy Outlook (AEO)* projections, NEMS is also used to complete analytical studies for the U.S. Congress, the Executive Office of the President, other offices within the U.S. Department of Energy (DOE), and other Federal agencies. NEMS is also used by other nongovernment groups, such as the Electric Power Research Institute, Duke University, Georgia Institute of Technology, and OnLocation, Inc. In addition, the *AEO* projections are used by analysts and planners in other government agencies and nongovernment organizations.

The projections in NEMS are developed with the use of a market-based approach, subject to regulations and standards. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS extends to 2035. To represent regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; 22 regions and subregions of the North American Electric Reliability Corporation for electricity; and the five Petroleum Administration for Defense Districts (PADDs) for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. The modular design also permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS executes each of the component modules to solve for prices of energy delivered to end users and the quantities consumed, by product, region, and sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to end users. The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. A solution is reached annually through the projection horizon. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence.

Each NEMS component represents the impacts and costs of legislation and environmental regulations that affect that sector. NEMS accounts for all combustion-related carbon dioxide (CO_2) emissions, as well as emissions of sulfur dioxide, nitrogen oxides, and mercury from the electricity generation sector.

The version of NEMS used for *AEO2012* generally represents current legislation and environmental regulations, including recent government actions, for which implementing regulations were available as of December 31, 2011, such as: the Mercury and Air Toxics Standards (MATS) [*143*] issued by the U.S. Environmental Protection Agency (EPA) in December 2011; the Cross-State Air Pollution Rule (CSAPR) [*144*] as finalized by the EPA in July 2011; the new fuel efficiency standards for medium- and heavy-duty vehicles (HDVs) published by the EPA and the National Highway Traffic Safety Administration (NHTSA) in September 2011 [*145*]; California's cap-and-trade program authorized by Assembly Bill (AB) 32, the Global Warming Solutions Act of 2006 [*146*]; the EPA policy memo regarding compliance of surface coal mining operations in Appalachia [*147*], issued on July 21, 2011; and the American Recovery and Reinvestment Act of 2009 (ARRA2009) [*148*], which was enacted in mid-February 2009.

The potential impacts of proposed Federal and State legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS. However, many pending provisions are examined in alternative cases included in *AEO2012* or in other analyses completed by EIA.

In general, the historical data presented with the *AEO2012* projections are based on EIA's *Annual Energy Review 2010*, published in October 2011 [*149*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2010. Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to the *AEO2012* appendix tables indicate the definitions and sources of historical data.

Where possible, the *AEO2012* projections for 2011 and 2012 incorporate short-term projections from EIA's December 2011 *Short-Term Energy Outlook (STEO).* For short-term energy projections, readers are referred to monthly updates of the *STEO* [*150*].

Component modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing prices or expenditures for energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) provides a set of macroeconomic drivers to the energy modules and receives energy-related indicators from the NEMS energy components as part of the macroeconomic feedback mechanism within NEMS.

Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, value of industrial shipments, new housing starts, sales of new light-duty vehicles (LDVs), interest rates, and employment. Key energy indicators fed back to the MAM include aggregate energy prices and costs. The MAM uses the following models from IHS Global Insight: Macroeconomic Model of the U.S. Economy, National Industry Model, and National Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to project regional economic drivers, and a Commercial Floorspace Model to project 13 floorspace types in 9 Census divisions. The accounting framework for industrial value of shipments uses the North American Industry Classification System (NAICS).

International Energy Module

The International Energy Module (IEM) uses assumptions of economic growth and expectations of future U.S. and world petroleum and other liquids production and consumption, by year, to project the interaction of U.S. and international petroleum and other liquids markets. The IEM computes world oil prices, provides a world crude-like liquids supply curve, generates a worldwide oil supply/demand balance for each year of the projection period, and computes initial estimates of crude oil and light and heavy petroleum product imports to the United States by PADD regions. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international petroleum and other liquids supply and demand, current investment trends in exploration and development, and long-term resource economics by country and territory. The oil production estimates include both conventional and other liquids supply recovery technologies.

In interacting with the rest of NEMS, the IEM changes the oil price—which is defined as the price of light, low-sulfur crude oil delivered to Cushing, Oklahoma (PADD 2)—in response to changes in expected production and consumption of crude oil and other liquids in the United States.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by Census division, housing type, and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and changes in the housing stock. The Commercial Demand Module projects energy consumption in the commercial sector by Census division, building type, and category of end use, based on delivered prices of energy, availability of renewable sources of energy, and changes in commercial floorspace.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, representations of renewable energy technologies, and the effects of both building shell and appliance standards. The modules also include projections of distributed generation. The Commercial Demand Module also incorporates combined heat and power (CHP) technology. Both modules incorporate changes to “normal” heating and cooling degree-days by Census division, based on a 10-year average and on State-level population projections. The Residential Demand Module projects an increase in the average square footage of both new construction and existing structures, based on trends in new construction and remodeling.

Industrial Demand Module

The Industrial Demand Module (IDM) projects the consumption of energy for heat and power, as well as the consumption of feedstocks and raw materials in each of 21 industry groups, subject to the delivered prices of energy and macroeconomic estimates of employment and the value of shipments for each industry. As noted in the description of the MAM, the representation of industrial activity in NEMS is based on the NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Of the eight energy-intensive manufacturing industries, seven are modeled in the IDM, including energy-consuming components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Energy demand for petroleum refining (the eighth energy-intensive manufacturing industry) is modeled in the Petroleum Market Module (PMM), as described below, but the projected consumption is reported under the industrial totals.

There are several updates and upgrades in the representations of select industries. The base year for the bulk chemical industry has been updated to 2006 in keeping with updates to EIA’s 2006 Manufacturing Energy Consumption Survey [*151*]. *AEO2012* also includes an upgraded representation for the cement and lime industries and agriculture. Instead of assuming that technological development for a particular process occurs on a predetermined (exogenous) path based on engineering judgment, these upgrades allow IDM technological change to be modeled endogenously, while using more detailed process representation. The upgrade allows for technological change, and therefore energy intensity, to respond to economic, regulatory, and other conditions. For subsequent *AEO*s, other industries represented in the IDM projections will be similarly upgraded.

A generalized representation of CHP is included. A revised methodology for CHP systems, implemented for *AEO2012*, simulates the utilization of installed CHP systems based on historical utilization rates and is driven by end-use electricity demand. To evaluate the economic benefits of additional CHP capacity, the model also includes an updated appraisal incorporating historical rather than assumed capacity factors and regional acceptance rates for new CHP facilities. The evaluation of CHP systems still uses a discount rate, which is equal to the projected 10-year Treasury bill rate plus a risk premium.

Transportation Demand Module

The Transportation Demand Module projects consumption of energy in the transportation sector—including petroleum products, electricity, methanol, ethanol, compressed natural gas (CNG), and hydrogen—by transportation mode, subject to delivered energy prices and macroeconomic variables such as disposable personal income, GDP, population, interest rates, and industrial shipments. The Transportation Demand Module includes legislation and regulations, such as the Energy Policy Act of 2005 (EPACT2005), the Energy Improvement and Extension Act of 2008 (EIEA2008), and the ARRA2009, which contain tax credits for the purchase of alternatively fueled vehicles. Fleet vehicles are also modeled, allowing for analysis of legislative proposals specific to those markets. Representations of LDV Corporate Average Fuel Economy (CAFE) and greenhouse gas (GHG) emissions standards, HDV fuel consumption and GHG emissions standards, and biofuels consumption in the module reflect standards enacted by NHTSA and the EPA, as well as provisions in the Energy Independence and Security Act of 2007 (EISA2007).

The air transportation component of the Transportation Demand Module explicitly represents air travel in domestic and foreign markets and includes the industry practice of parking aircraft in both domestic and international markets to reduce operating costs, as well as the movement of aging aircraft from passenger to cargo markets. For passenger travel and air freight shipments, the module represents regional fuel use in regional, narrow-body, and wide-body aircraft. An infrastructure constraint, which is also modeled, can potentially limit overall growth in passenger and freight air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

There are three primary submodules of the Electricity Market Module—capacity planning, fuel dispatching, and finance and pricing. The capacity expansion submodule uses the stock of existing generation capacity, the cost and performance of future generation capacity, expected fuel prices, expected financial parameters, expected electricity demand, and expected environmental regulations to project the optimal mix of new generation capacity that should be added in future years. The fuel dispatching submodule uses the existing stock of generation equipment types, their operation and maintenance costs and performance, fuel prices to the electricity sector, electricity demand, and all applicable environmental regulations to determine the least-cost way to meet that demand. The submodule also determines transmission and pricing of electricity. The finance and pricing submodule uses capital costs, fuel costs, macroeconomic parameters, environmental regulations, and load shapes to estimate generation costs for each technology.

All specifically identified options promulgated by the EPA for compliance with the Clean Air Act Amendments of 1990 are explicitly represented in the capacity expansion and dispatch decisions. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several States, primarily in the Northeast, have enacted air emission regulations for CO_2 that affect the electricity generation sector, and those regulations are represented in *AEO2012*. The *AEO2012* Reference case also imposes a limit on power sector CO_2 emissions for plants serving California, to represent the power sector impacts of California's AB 32. The *AEO2012* Reference case reflects the CSAPR as finalized by the EPA on July 6, 2011, requiring reductions in emissions from power plants that contribute to ozone and fine particle pollution in 28 States. Reductions in mercury emissions from coal- and oil-fired power plants also are reflected through the inclusion of the mercury and air toxics standards for power plants, finalized by the EPA on December 16, 2011.

Although currently there is no Federal legislation in place that restricts GHG emissions, regulators and the investment community have continued to push energy companies to invest in technologies that are less GHG-intensive. The trend is captured in the *AEO2012* Reference case through a 3-percentage-point increase in the cost of capital, when evaluating investments in new coal-fired power plants, new coal-to-liquids (CTL) plants without carbon capture and storage (CCS), and for pollution control retrofits.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (dedicated biomass plants and co-firing in existing coal plants), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and both onshore and offshore wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits (ITCs) for renewable fuels are incorporated, as currently enacted, including a permanent 10-percent ITC for business investment in solar energy (thermal nonpower uses as well as power uses) and geothermal power (available only to those projects not accepting the production tax credit [PTC] for geothermal power). In addition, the module reflects the increase in the ITC to 30 percent for solar energy systems installed before January 1, 2017. The extension of the credit to individual homeowners under EIEA2008 is reflected in the Residential and Commercial Demand Modules.

PTCs for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants also are represented. They provide a credit of up to 2.2 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2012*, new wind plants coming on line before January 1, 2013, are eligible to receive the PTC; other eligible plants must be in service before January 1, 2014. As part of the ARRA2009, plants eligible for the PTC may instead elect to receive a 30-percent ITC or an equivalent direct grant. *AEO2012* also accounts for new renewable energy capacity resulting from State renewable portfolio standard programs, mandates, and goals, as described in *Assumptions to the Annual Energy Outlook 2012* [*152*].

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply—onshore, offshore, and Alaska—by all production techniques, including natural gas recovery from coalbeds and low-permeability formations of sandstone and shale. The framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and natural gas production activities are modeled for 12 supply regions, including 6 onshore, 3 offshore, and 3 Alaskan regions.

The Onshore Lower 48 Oil and Gas Supply Submodule evaluates the economics of future exploration and development projects for crude oil and natural gas at the play level. Crude oil resources include conventional resources as well as highly fractured continuous zones, such as the Austin chalk and Bakken shale formations. Production potential from advanced secondary recovery techniques (such as infill drilling, horizontal continuity, and horizontal profile) and enhanced oil recovery (such as CO_2 flooding, steam flooding, polymer flooding, and profile modification) are explicitly represented. Natural gas resources include high-permeability carbonate and sandstone, tight gas, shale gas, and coalbed methane.

Domestic crude oil production quantities are used as inputs to the PMM in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are used as inputs to the Natural Gas Transmission and Distribution Module (NGTDM) for determining natural gas wellhead prices and domestic production.

Natural Gas Transmission and Distribution Module

The NGTDM represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting the domestic and foreign supply regions with 12 lower 48 U.S. demand regions. The 12 lower 48 regions align with the 9 Census divisions, with three subdivided, and Alaska handled separately. The flow of natural gas is determined for both a peak and off-peak period in the year, assuming a historically based seasonal distribution of natural gas demand. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. An algorithm is included to project the addition of CNG retail fueling capability. The module also accounts for foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, as well as liquefied natural gas (LNG) imports and exports. For *AEO2012*, LNG exports and re-exports were set exogenously and assumed to reach and maintain a total level of 903 billion cubic feet per year by 2020.

Petroleum Market Module

The PMM projects prices of petroleum products, crude oil and product import activity, and domestic refinery operations, subject to demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and biofuels—ethanol, biodiesel, biomass-to-liquids (BTL), CTL, gas-to-liquids (GTL), and coal-and-biomass-to-liquids (CBTL). Costs, performance, and first dates of commercial availability for the advanced other liquids technologies [*153*] are reviewed and updated annually.

The module represents refining activities in the five PADDs, as well as a less detailed representation of refining activities in the rest of the world. It models the costs of automotive fuels, such as conventional and reformulated gasoline, and includes production of biofuels for blending in gasoline and diesel. Fuel ethanol and biodiesel are included in the PMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent or less by volume (E10), 15 percent by volume (E15) in States that lack explicit language capping ethanol volume or oxygen content, and up to 85 percent by volume (E85) for use in flex-fuel vehicles.

The PMM includes representation of the Renewable Fuels Standard (RFS) included in EISA2007, which mandates the use of 36 billion gallons of ethanol equivalent renewable fuel by 2022. Both domestic and imported ethanol count toward the RFS. Domestic ethanol production is modeled for three feedstock categories: corn, cellulosic plant materials, and advanced feedstock materials. Starch-based ethanol plants are numerous (more than 190 are now in operation, with a total maximum sustainable nameplate capacity of more than 14 billion gallons annually), and they are based on a well-known technology that converts starch and sugar into ethanol. Ethanol from cellulosic sources is a new technology with only a few small pilot plants in operation. Ethanol from advanced feedstocks—defined as plants that ferment and distill grains other than corn and reduce GHG emissions by at least 50 percent—is also a new technology modeled in the PMM.

Fuels produced by Fischer-Tropsch synthesis and through a pyrolysis process are also modeled in the PMM, based on their economics relative to competing feedstocks and products. The five processes modeled are CTL, CBTL, GTL, BTL, and pyrolysis.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM by 41 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves respond to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of

U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by region and sector, environmental restrictions, and accounting for minemouth prices, transportation costs, and coal supply contracts. Over the projection horizon, coal transportation costs in the CMM vary in response to changes in the cost of rail investments.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports in the context of world coal trade, determining the pattern of world coal trade flows that minimizes production and transportation costs while meeting a specified set of regional world coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in 3 types of coal for 17 export regions and 20 import regions. U.S. coal production and distribution are computed for 14 supply regions and 16 demand regions.

Annual Energy Outlook 2012 cases

Table E1 provides a summary of the cases produced as part of *AEO2012*. For each case, the table gives the name used in *AEO2012*, a brief description of the major assumptions underlying the projections, and a reference to the pages in the body of the report and in this appendix where the case is discussed. The text sections following Table E1 describe the various cases. The Reference case assumptions for each sector are described in *Assumptions to the Annual Energy Outlook 2012* [*154*]. Regional results and other details of the projections are available at website www.eia.gov/aeo/supplement.

Macroeconomic growth cases

In addition to the *AEO2012* Reference case, Low Economic Growth and High Economic Growth cases were developed to reflect the uncertainty in projections of economic growth. The alternative cases are intended to show the effects of alternative growth assumptions on energy market projections. The cases are described as follows:

- In the Reference *case*, population grows by 0.9 percent per year, nonfarm employment by 1.0 percent per year, and labor productivity by 1.9 percent per year from 2010 to 2035. Economic output as measured by real GDP increases by 2.5 percent per year from 2010 through 2035, and growth in real disposable income per capita averages 1.5 percent per year.
- The Low Economic Growth case assumes lower growth rates for population (0.8 percent per year) and labor productivity (1.5 percent per year), resulting in lower nonfarm employment (0.8 percent per year), higher prices and interest rates, and lower growth in industrial output. In the Low Economic Growth case, economic output as measured by real GDP increases by 2.0 percent per year from 2010 through 2035, and growth in real disposable income per capita averages 1.3 percent per year.
- The High Economic Growth case assumes higher growth rates for population (1.0 percent per year) and labor productivity (2.2 percent per year), resulting in higher nonfarm employment (1.2 percent per year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the Reference case, and consequently economic output grows at a higher rate (3.0 percent per year) than in the Reference case (2.5 percent). Disposable income per capita grows by 1.6 percent per year, compared with 1.5 percent in the Reference case.

Oil price cases

The oil price in *AEO2012* is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and is similar to the price for light, sweet crude oil traded on the New York Mercantile Exchange, referred to as West Texas Intermediate (WTI). *AEO2012* also includes a projection of the U.S. annual average refiners' acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by domestic refiners.

The historical record shows substantial variability in oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2012* considers three oil price cases (Reference, Low Oil Price, and High Oil Price) to allow an assessment of alternative views on the future course of oil prices.

The Low and High Oil Price cases reflect a wide range of potential price paths, resulting from variation in demand by countries outside the Organization for Economic Cooperation and Development (OECD) for petroleum and other liquid fuels due to different levels of economic growth. The Low and High Oil Price cases also reflect different assumptions about decisions by members of the Organization of the Petroleum Exporting Countries (OPEC) regarding the preferred rate of oil production and about the future finding and development costs and accessibility of conventional oil resources outside the United States.

- In the Reference case, real oil prices rise from a $93 per barrel (2010 dollars) in 2011 to $145 per barrel in 2035. The Reference case represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources. It also assumes that OPEC producers will choose to maintain their share of the market and will schedule investments in incremental production capacity so that OPEC's conventional oil production will represent about 40 percent of the world's total petroleum and other liquids production over the projection period.
- In the Low Oil Price case, crude oil prices are only $62 per barrel (2010 dollars) in 2035, compared with $145 per barrel in the Reference case. In the Low Oil Price case, the low price results from lower demand for petroleum and other liquid fuels in the non-OECD nations. Lower demand is derived from lower economic growth relative to the Reference case. In this case, GDP growth in the non-OECD countries is reduced by 1.5 percentage points relative to Reference case in each projection year, beginning in 2015. The OECD projections are affected only by the price impact. On the supply side, OPEC countries increase

Table E1. Summary of the *AEO2012* cases

Case name	Description	Reference in text	Reference in Appendix E
Reference	Baseline economic growth (2.5 percent per year from 2010 through 2035), oil price, and technology assumptions. Complete projection tables in Appendix A. Light, sweet crude oil prices rise to about $145 per barrel (2010 dollars) in 2035. Assumes RFS target to be met as soon as possible.	--	--
Low Economic Growth	Real GDP grows at an average annual rate of 2.0 percent from 2010 to 2035. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	p. 72	p. 221
High Economic Growth	Real GDP grows at an average annual rate of 3.0 percent from 2010 to 2035. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	p. 72	p. 221
Low Oil Price	Low prices result from a combination of low demand for petroleum and other liquid fuels in the non-OECD nations and higher global supply. Lower demand is measured by lower economic growth relative to the Reference case. In this case, GDP growth in the non-OECD is reduced by 1.5 percentage points in each projection year relative to Reference case assumptions, beginning in 2015. On the supply side, OPEC increases its market share to 46 percent, and the costs of other liquids production technologies are lower than in the Reference case. Light, sweet crude oil prices fall to $62 per barrel in 2035. Partial projection tables in Appendix C.	p. 74	p. 221
High Oil Price	High prices result from a combination of higher demand for petroleum and other liquid fuels in the non-OECD nations and lower global supply. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth rates for China and India are raised by 1.0 percentage point relative to the Reference case in 2012 and decline to 0.3 percentage point above the Reference case in 2035. GDP growth rates for other non-OECD regions average about 0.5 percentage point above the Reference case. OPEC market share remains at about 40 percent throughout the projection, and non-OPEC petroleum production expands more slowly in the short to middle term relative to the Reference case. Light, sweet crude oil prices rise to $200 per barrel (2010 dollars) in 2035. Partial projection tables in Appendix C.	p. 74	p. 224
No Sunset	Begins with the Reference case and assumes extension of all existing energy policies and legislation that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs) and those that involve extensive regulatory analysis, such as CAFE improvements and periodic updates of efficiency standards. Partial projection tables in Appendix D.	p. 18	p.229
Extended Policies	Begins with the No Sunset case but excludes extension of tax credits for blenders and for other biofuels that were included in the No Sunset case. Assumes an increase in the capacity limitations on the ITC and extension of the program. The case includes additional rounds of efficiency standards for residential and commercial products, as well as new standards for products not yet covered, adds multiple rounds of national building codes by 2026, and increases LDV fuel economy standards in the transportation sector to 62 miles per gallon in 2035. Partial projection tables in Appendix D.	p. 18	p. 230
Transportation: CAFE Standards	Explores energy and market impacts assuming that LDV CAFE and GHG emissions standards proposed for model years 2017-2025 are enacted. Partial projection tables in Appendix D.	p. 29	p. 226
Transportation: High Technology Battery	Explores the impact of significant improvement in vehicle battery and non-battery system cost and performance on new LDV sales, energy consumption, and GHG emissions. Partial projection tables in Appendix D.	p. 31	p. 226
Transportation: HDV Reference	Incorporates revised CNG and LNG pricing assumptions and HDV market acceptance relative to the *AEO2012* Reference case. Partial projection tables in Appendix D.	p.40	p. 226
Transportation: HD NGV Potential	Using the HDV Reference case, explores energy and market issues associated with the assumed expansion of natural gas refueling infrastructure for the HDV market. Partial projection tables in Appendix D.	p. 39	p. 226

Table E1. Summary of the *AEO2012* cases (continued)

Case name	Description	Reference in text	Reference in Appendix E
Electricity: Low Nuclear	Assumes that all nuclear plants are limited to a 60-year life (31 gigawatts of retirements), uprates are limited to the 1 gigawatt that has been reported to EIA, and planned additions are the same as in the Reference case. Partial projection tables in Appendix D.	p. 51	p. 226
Electricity: High Nuclear	Assumes that all nuclear plants are life-extended beyond 60 years (except for one announced retirement), and uprates are the same as in the Reference case. New plants include those under construction and plants that have a scheduled U.S. Nuclear Regulatory Commission (NRC) or Atomic Safety and Licensing Board hearing and use a currently certified design (e.g., AP1000). Partial projection tables in Appendix D.	p. 52	p. 227
Electricity: Reference 05	Includes CSAPR and MATS as in the Reference case, with reduced 5-year environmental investment recovery. Partial projection tables in Appendix D.	p. 47	p. 227
Electricity: Low Gas Price 05	Includes CSAPR and MATS as in the Reference case, with reduced 5-year environmental investment recovery combined with the High Estimated Ultimate Recovery (EUR) case. Partial projection tables in Appendix D.	p. 47	p. 227
Renewable Fuels: Low Renewable Technology Cost	Costs for new nonhydropower renewable generating technologies start 20 percent lower in 2012 and decline to 40 percent lower than Reference case levels in 2035. Capital costs of renewable other liquid fuel technologies start 20 percent lower in 2012 and decline to approximately 40 percent lower than Reference case levels in 2035. Partial projection tables in Appendix D.	p. 208	p. 227
Petroleum: LFMM	Changes in the refining industry in the past and prospective future are discussed in the context of the development of the Liquid Fuels Market Module (LFMM) developed for NEMS. Provides overview of large-scale trends and highlights of specific issues that may require further analysis. Partial projection tables in Appendix D.	p. 43	p. 228
Oil and Gas: Low EUR	EUR per tight oil or shale gas well is 50 percent lower than in the Reference case.	p. 60	p. 227
Oil and Gas: High EUR	The EUR per tight oil and shale gas well is 50 percent higher than in the Reference case. Partial projection tables in Appendix D	p. 60	p. 227
Oil and Gas: High Technically Recoverable Resources (TRR)	The well spacing for all tight oil and shale gas plays is 8 wells per square mile (i.e., each well has an average drainage area of 80 acres), and the EUR for tight oil and shale gas wells is 50 percent higher than in the Reference case. Partial projection tables in Appendix D.	p. 60	p. 227
Coal: Low Coal Cost	Regional productivity growth rates for coal mining are approximately 2.8 percent per year higher than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates in 2035 are between 21 and 25 percent lower than in the Reference case. Partial projection tables in Appendix D.	p. 101	p. 228
Coal: High Coal Cost	Regional productivity growth rates for coal mining are approximately 2.8 percent per year lower than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates in 2035 are between 25 and 27 percent higher than in the Reference case. Partial projection tables in Appendix D.	p. 214	p. 228
Integrated 2011 Demand Technology	Referred to in text as "2011 Demand Technology." Assumes future equipment purchases in the residential and commercial sectors are based only on the range of equipment available in 2011. Energy efficiency of new industrial plant and equipment is held constant at the 2012 level over the projection period. Partial projection tables in Appendix D.	p. 27	p. 224
Integrated Best Available Demand Technology	Referred to in text as "Best Available Demand Technology." Assumes all future equipment purchases in the residential and commercial sectors are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. Partial projection tables in Appendix D.	p. 27	p. 225

Table E1. Summary of the *AEO2012* cases (continued)

Case name	Description	Reference in text	Reference in Appendix E
Integrated High Demand Technology	Referred to in text as "High Demand Technology." Assumes earlier availability, lower costs, and higher efficiencies for more advanced residential and commercial equipment. For new residential and commercial construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016. Industrial sector assumes earlier availability, lower costs, and higher efficiency for more advanced equipment and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes. In the transportation sector, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs. Freight trucks are assumed to see more rapid improvement in fuel efficiency for engine and emissions control technologies. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors. Partial projection tables in Appendix D.	p. 27	p. 225
Integrated 2011 Technology	Referred to in text as "2011 Technology." Combination of the Integrated 2011 Demand Technology case with the assumption that costs of new power plants do not improve from 2012 levels throughout the projection. Partial projection tables in Appendix D.	p. 202	p. 229
Integrated High Technology	Referred to in text as "High Technology." Combination of the Integrated High Demand Technology case and the Low Renewable Technology Cost case. Also assumes that costs for new nuclear and fossil-fired power plants are lower than Reference case levels, by 20 percent in 2012 and 40 percent in 2035. Partial projection tables in Appendix D.	p. 202	p. 229
No GHG Concern	No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy. Partial projection tables in Appendix D.	p. 102	p. 229
GHG15	Applies a price for CO_2 emissions throughout the economy, starting at $15 per metric ton in 2013 and rising by 5 percent per year through 2035. The price is set to target the same reduction in CO_2 emissions as in the *Annual Energy Outlook 2011 (AEO2011)* GHG Price Economywide case. Partial projection tables in Appendix D.	p. 46	p. 229
GHG25	Applies a price for CO_2 emissions throughout the economy, starting at $25 per metric ton in 2013 and rising by 5 percent per year through 2035. The price is set at the same dollar amount as in the *AEO2011* GHG Price Economywide case. Partial projection tables in Appendix D.	p. 46	p. 229

their conventional oil production to obtain a 46-percent share of total world petroleum and other liquids production, and oil resources outside the United States are more accessible and/or less costly to produce (as a result of technology advances, more attractive fiscal regimes, or both) than in the Reference case.

- In the High Oil Price case, oil prices reach about $200 per barrel (2010 dollars) in 2035. In the High Oil Price case, the high prices result from higher demand for petroleum and other liquid fuels in the non-OECD nations. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth in the non-OECD region is raised by 0.1 to 1.0 percentage point relative to the Reference case in each projection year, starting in 2012. GDP growth rates for China and India are raised by 1.0 percentage points relative to the Reference case in 2012, declining to 0.3 percentage point above the Reference case in 2035. GDP growth rates for most other non-OECD regions average about 0.5 percentage point above the Reference case in each projection year. The OECD projections are affected only by the price impact. On the supply side, OPEC countries are assumed to reduce their market share somewhat, and oil resources outside the United States are assumed to be less accessible and/or more costly to produce than in the Reference case.

Buildings sector cases

In addition to the *AEO2012* Reference case, three technology-focused cases using the Demand Modules of NEMS were developed to examine the effects of changes in technology. Buildings sector assumptions for the Integrated 2011 Demand Technology case and the Integrated High Demand Technology case are also used in the appropriate Integrated Technology cases.

Residential sector assumptions for the technology-focused cases are as follows:

- For the Integrated 2011 Demand Technology case it is assumed that all future residential equipment purchases are based only on the range of equipment available in 2011. Existing building shell efficiencies are assumed to be fixed at 2011 levels (no further improvements). For new construction, building shell technology options are constrained to those available in 2011.

- For the Integrated High Demand Technology case it is assumed that residential advanced equipment is available earlier, at lower costs, and/or at higher efficiencies [*155*]. For new construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016. Consumers evaluate investments in energy efficiency at a 7-percent real discount rate.
- For the Integrated Best Available Demand Technology case it is assumed that all future residential equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. For new construction, building shell efficiencies are assumed to meet the criteria for the most efficient components after 2011.

Commercial sector assumptions for the technology-focused cases are as follows:

- For the Integrated 2011 Demand Technology case it is assumed that all future commercial equipment purchases are based only on the range of equipment available in 2011. Building shell efficiencies are assumed to be fixed at 2011 levels.
- For the Integrated High Demand Technology case it is assumed that commercial advanced equipment is available earlier, at lower costs, and/or with higher efficiencies than in the Reference case [*156*]. Energy efficiency investments are evaluated at a 7-percent real discount rate. Building shell efficiencies for new and existing buildings in 2035 assume a 25-percent improvement relative to the Reference case.
- For the Integrated Best Available Demand Technology case it is assumed that all future commercial equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. Building shell efficiencies for new and existing buildings in 2035 assume a 50-percent improvement relative to the Reference case.

The Residential and Commercial Demand Modules of NEMS were also used to complete the Low Renewable Technology Cost case, which is discussed in more detail below, in the renewable fuels cases section. In combination with assumptions for electricity generation from renewable fuels in the electric power sector and industrial sector, this sensitivity case analyzes the impacts of changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- The Low Renewable Technology Cost case assumes greater improvements in residential and commercial PV and wind systems than in the Reference case. The assumptions for capital cost estimates are 20 percent below Reference case assumptions in 2012 and decline to at least 40 percent lower than Reference case costs in 2035.

The No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the Residential and Commercial Demand Modules of NEMS. The Extended Policies case builds on the No Sunset case and adds multiple rounds of appliance standards and building codes as described below.

- The No Sunset case assumes that selected policies with sunset provisions will be extended indefinitely rather than allowed to sunset as the law currently prescribes. For the residential sector, these extensions include: personal tax credits for selected end-use equipment, including furnaces, heat pumps, and central air conditioning; personal tax credits for PV installations, solar water heaters, small wind turbines, and geothermal heat pumps; and manufacturer tax credits for refrigerators, dishwashers, and clothes washers, passed on to consumers at 100 percent of the tax credit value. For the commercial sector, business ITCs for PV installations, solar water heaters, small wind turbines, geothermal heat pumps, and CHP are extended to the end of the projection. The business tax credit for solar technologies remains at the current 30-percent level without reverting to 10 percent as scheduled.
- The Extended Policies case includes updates to appliance standards, as prescribed by the timeline in DOE's multiyear plan, and introduces new standards for products currently not covered by DOE. Efficiency levels for the updated residential appliance standards are based on current ENERGY STAR guidelines. Residential end-use technologies subject to updated standards are not eligible for No Sunset incentives in addition to the standards. Efficiency levels for updated commercial equipment standards are based on the technology menu from the *AEO2012* Reference case and purchasing specifications for Federal agencies designated by the Federal Energy Management Program (FEMP). The case also adds national building codes to reach 30-percent improvement relative to the 2006 International Energy Conservation Code (IECC 2006) for residential households and to American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) Standard 90.1-2004 for commercial buildings by 2020, with additional rounds of improved codes in 2023 and 2026.

Industrial sector cases

In addition to the *AEO2012* Reference case, two technology-focused cases using the IDM of NEMS were developed that examine the effects of less rapid and more rapid technology change and adoption. The energy intensity changes discussed in this section exclude the refining industry, which is modeled separately from the IDM in the PMM. Different assumptions for the IDM were also used as part of the Integrated Low Renewable Technology Cost case, No Sunset case, and Extended Policies case, but each is structured on a set of the initial industrial assumptions used for the Integrated 2011 Demand Technology case and Integrated High Demand Technology case. For the industrial sector, assumptions for those two technology-focused cases are as follows:

- For the Integrated 2011 Demand Technology case, the energy efficiency of new industrial plant and equipment is held constant at the 2012 level over the projection period. Changes in aggregate energy intensity may result both from changing equipment and production efficiency and from changing composition of output within an individual industry. Because all *AEO2012* side cases are integrated runs, potential feedback effects from energy market interactions are captured. Hence, the level and composition of overall industrial output varies from the Reference case, and any change in energy intensity in the two technology side cases is attributable to process and efficiency changes and increased use of CHP, as well as changes in the level and composition of overall industrial output.

- For the Integrated High Demand Technology case, the IDM assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*157*] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes—i.e., 0.7 percent per year, as compared with 0.4 percent per year in the Reference case. The same assumption is incorporated in the Low Renewable Technology Cost case, which focuses on electricity generation. Although the choice of the 0.7-percent annual rate of improvement in byproduct recovery is an assumption in the High Demand Technology case, it is based on the expectation of higher recovery rates and substantially increased use of CHP in that case. Due to integration with other NEMS modules, potential feedback effects from energy market interactions are captured.

The industrial No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the IDM of NEMS. The Extended Policies case builds on the No Sunset case and modifies select industrial assumptions, which are as follows:

- The No Sunset case and Extended Policies case include an assumption for CHP that extends the existing industrial CHP ITC through the end of the projection period. Additionally, the Extended Policies case includes an increase in the capacity limitations on the ITC by increasing the cap on CHP equipment from 15 megawatts to 25 megawatts and eliminating the system-wide cap of 50 megawatts. These assumptions are based on the current proposals in H.R. 2750 and H.R. 2784 of the 112th Congress.

Transportation sector cases

In addition to the *AEO2012* Reference case, the NEMS Transportation Demand Module was used to examine the effects of advanced technology costs and efficiency improvement on technology adoption and vehicle fuel economy as part of the Integrated High Demand Technology case [*158*]. For the Integrated High Demand Technology case, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs. In the freight truck sector, the High Demand Technology case assumes more rapid incremental improvement in fuel efficiency and lower costs for engine and emissions control technologies. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors.

Three additional integrated cases were developed to examine the potential energy impacts associated with the implementation of proposed model year 2017 to 2025 LDV CAFE standards, the impact of the successful development of advanced batteries, and the impact of the penetration of HDVs using LNG. The specific cases include:

- The CAFE Standards case examines the energy, GHG, and vehicle market impacts of increasing LDV fuel economy standards to reflect those proposed by the EPA and NHTSA for model years 2017-2025. Fuel economy standards are assumed to remain constant after model year 2025.
- The High Technology Battery case examines the energy, GHG emissions, and sales impacts on new LDVs associated with rapid improvement in battery cost and non-battery systems performance.
- The HDV Reference case incorporates revised pricing assumptions for CNG and LNG highway fuels and HDV market acceptance.
- The HD NGV Potential case examines the energy and GHG impacts associated with assumed significant increases in LNG refueling infrastructure to enable market adoption of natural gas use by HDVs in long-haul corridors relative to the HDV Reference case.

Electricity sector cases

In addition to the Reference case, several integrated cases with alternative electric power assumptions were developed to support discussions in the “Issues in focus” section of *AEO2012*. Two alternative cases were run for nuclear power plants, to address uncertainties about the operating lives of existing reactors, the potential for new nuclear capacity, and capacity uprates at existing plants. These scenarios are discussed in the “Issues in focus” article, “Nuclear power in *AEO2012*.”

In addition, two alternative cases were run to analyze uncertainties related to the lifetimes of coal-fired power plants due to recent environmental regulations and potential GHG legislation in the future. Over the next few years, electricity generators will begin taking steps to comply with a number of new environmental regulations, primarily by adding environmental controls at existing coal-fired power plants. The additional cases examine the impacts of shorter economic recovery periods for the environmental controls, with the natural gas prices used in the *AEO2012* Reference case and lower natural gas prices.

Nuclear cases

- The Low Nuclear case assumes that all existing nuclear plants are retired after 60 years of operation. In the Reference case, existing plants are assumed to run as long as they continue to be economic, implicitly assuming that a second 20-year license renewal will be obtained for most plants that reach 60 years before 2035. The Low Nuclear case was run to analyze the impact of additional nuclear retirements, which could occur if the oldest plants do not receive a second license extension. In this case, 31 gigawatts of nuclear capacity is assumed to be retired by 2035. The Low Nuclear case assumes that no new nuclear capacity will be added throughout the projection, excluding capacity already planned or under construction. The case also assumes that only those capacity uprates reported to EIA will be completed (1 gigawatt). The Reference case assumes additional uprates based on NRC surveys and industry reports.

- The High Nuclear case assumes that all existing nuclear units will receive a second license renewal and operate beyond 60 years (excluding one announced retirement). In the Reference case, beyond the announced retirement of Oyster Creek, an additional 5.5 gigawatts of nuclear capacity is assumed to be retired through 2035, reflecting uncertainty about the impacts and/or costs of future aging. This case was run to provide a more optimistic outlook, with all licenses renewed and all plants continuing to operate economically beyond 60 years. The High Nuclear case also assumes that additional planned nuclear capacity is completed based on combined license applications issued by the NRC. The Reference case assumes that 6.8 gigawatts of planned capacity is added, compared with 13.5 gigawatts of planned capacity additions in the High Nuclear case.

Environmental Rules cases

- The Reference 05 case assumes that the economic recovery period for investments in new environmental controls in the electric power sector is reduced from 20 years to 5 years.
- The Low Gas Price 05 case uses more optimistic assumptions about future volumes of shale gas production, leading to lower natural gas prices, combined with the 5-year recovery period for new environmental controls in the electric power sector. The domestic shale gas resource assumption comes from the High EUR case.

Renewable fuels cases

In addition to the *AEO2012* Reference case, EIA developed a case with alternative assumptions about renewable fuels to examine the effects of more aggressive improvement in the cost of renewable technologies.

- In the Low Renewable Technology Cost case, the levelized costs of new nonhydropower renewable generating technologies are assumed to start at 20 percent below Reference case assumptions in 2012 and decline to 40 percent below the Reference case costs for the same resources in 2035. In general, lower costs are represented by reducing the capital costs of new plant construction. Biomass fuel supplies also are assumed to be 40 percent less expensive than for the same resource quantities used in the Reference case. Assumptions for other generating technologies are unchanged from those in the Reference case. In the Low Renewable Technology Cost case, the rate of improvement in recovery of biomass byproducts from industrial processes also is increased.
- In the No Sunset case and the Extended Policies case, expiring Federal tax credits targeting renewable electricity are assumed to be permanently extended. This applies to the PTC, which is a tax credit of 2.2 cents per kilowatthour available for the first 10 years of production by new generators using wind, geothermal, and certain biomass fuels, or a tax credit of 1.1 cents per kilowatthour available for the first 10 years of production by new generators using geothermal energy, certain hydroelectric technologies, and biomass fuels not eligible for the full credit of 2.2 cents per kilowatthour. This tax credit is scheduled to expire on December 31, 2012, for wind and 1 year later for other eligible technologies. The same schedule applies to the 30-percent ITC, which is available to new solar installations through December 31, 2016, and may also be claimed in lieu of the PTC for eligible technologies, expiring concurrently with the PTC expiration dates indicated above.

Oil and gas supply cases

The sensitivity of the *AEO2012* projections to changes in assumptions regarding technically recoverable tight oil and shale gas resources are examined in two cases:

- In the Low EUR case, the EUR per tight oil or shale gas well is assumed to be 50 percent lower than in the Reference case, increasing the per-unit cost of developing the resource. The total unproved TRR of tight oil is decreased to 17 billion barrels, and the shale gas resource is decreased to 241 trillion cubic feet, as compared with unproved resource estimates of 33 billion barrels of tight oil and 482 of shale gas in the Reference case as of January 1, 2010.
- In the High EUR case, the EUR per tight oil and shale gas well is assumed to be 50 percent higher than in the Reference case, decreasing the per-unit cost of developing the resource. The total unproved technically recoverable tight oil resource is increased to 50 billion barrels, and the shale gas resource is increased to 723 trillion cubic feet.
- In the High TRR case, the well spacing for all tight oil and shale gas plays is assumed to be 8 wells per square mile (i.e., each well has an average drainage area of 80 acres), and the EUR for tight oil and shale gas wells is assumed to be 50 percent higher than in the Reference case. The total unproved technically recoverable tight oil resource is increased to 89 billion barrels, and the shale gas resource is increased to 1,091 trillion cubic feet, more than twice the Reference case assumptions for tight oil and shale gas resources.

Petroleum market cases

Production of petroleum and other liquid fuels has evolved and changed significantly in recent years as a result of changes in the mix of feedstocks, production regions, technologies, regulation and policy, and international markets. To better reflect those changes, a new LFMM has been developed for use as part of NEMS. The intent is to use the LFMM in developing the *Annual Energy Outlook 2013 (AEO2013).* The LFMM was designed as a data-driven tool using a generalized algebraic modeling system. The LFMM uses nine types of crude oil (compared to five types in the current model). The LFMM configuration uses nine refining regions instead of the traditional five PADDs—eight domestic regions and one maritime Canada and Caribbean region that captures imports of refined products into the northeastern United States.

Market conditions and regulations have resulted in the implementation of new technologies using nonpetroleum feedstocks such as grains, biomass, pyrolysis oils, coal, biomass, and natural gas. The EISA2007 RFS mandates the use 36 billion gallons of renewable fuels by 2022, and the LFMM allows analysis of different renewable fuel capacities required to meet the mandate. Because the LFMM is a data-driven model, new technologies can be added easily to help in analysis of the RFS mandate. In addition, the LFMM has extensive representation of the RFS and other policies that affect its implementation. The technologies associated with the RFS have high development costs, and capital recovery is uncertain. That uncertainty can be analyzed by varying the market penetration rates for the technologies under different assumptions. Further, to accommodate evolving international markets, LFMM uses different approaches while interfacing with NEMS PMM. The new interface is able to work with newer crude types, as well as changes in prices for crude oil and petroleum products.

For *AEO2012*, an LFMM case was developed to test the new model and compare results with those produced by the PMM—which is the current model used for *AEO2012*—for the Reference, Low Economic Growth, High Economic Growth, Low Oil Price, and High Oil Price cases produced using the current version of the NEMS. The intent is to highlight areas where the two models produce significantly different results and explore the basis of those differences so that EIA will be able to ensure that the LFMM is ready for use as part of *AEO2013*.

Coal market cases

Two alternative coal cost cases examine the impacts on U.S. coal supply, demand, distribution, and prices that result from alternative assumptions about mining productivity, labor costs, mine equipment costs, and coal transportation rates. The alternative productivity and cost assumptions are applied in every year from 2012 through 2035. For the coal cost cases, adjustments to the Reference case assumptions for coal mining productivity are based on variation in the average annual productivity growth of 2.8 percent observed since 2000. Transportation rates are lowered (in the Low Coal Cost case) or raised (in the High Coal Cost case) from Reference case levels to achieve a 25-percent change in rates relative to the Reference case in 2035. The Low and High Coal Cost cases represent fully integrated NEMS runs, with feedback from the macroeconomic activity, international, supply, conversion, and enduse demand modules.

- In the Low Coal Cost case, the average annual growth rates for coal mining productivity are higher than those in the Reference case and are applied at the supply curve level. As an example, the average annual productivity growth rate for Wyoming's Southern Powder River Basin supply curve is increased from -1.8 percent in the Reference case for the years 2012 through 2035 to 0.8 percent in the Low Coal Cost case. Coal mining wages, mine equipment costs, and other mine supply costs all are assumed to be about 21 percent lower in 2035 in real terms in the Low Coal Cost case than in the Reference case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be 25 percent lower in 2035.
- In the High Coal Cost case, the average annual productivity growth rates for coal mining are lower than those in the Reference case and are applied as described in the Low Coal Cost case. Coal mining wages, mine equipment costs, and other mine supply costs in 2035 are assumed to be about 27 percent higher than in the Reference case, and coal transportation rates in 2035 are assumed to be 25 percent higher.

Additional details of the productivity, wage, mine equipment cost, and coal transportation rate assumptions for the Reference and alternative coal cost cases are provided in Appendix D.

Cross-cutting integrated cases

A series of cross-cutting integrated cases are used in *AEO2012* to analyze specific cases with broader sectoral impacts. For example, three integrated technology progress cases analyze the impacts of more rapid and slower technology improvement rates in the demand sector (partially described in the sector-specific sections above), and two other integrated technology cases examine the impacts of more rapid and slower technology improvement rates across both demand and supply/conversion sectors. In addition, two cases also were run with alternative assumptions about expectations of future regulation of GHG emissions.

Integrated technology cases

In the demand sectors (residential, commercial, industrial, and transportation), technology improvement typically means greater efficiency of energy use and/or reduced cost. In the energy supply/conversion sectors (electricity generation, natural gas and petroleum and other liquids supply, petroleum refining, etc.), technology improvement tends to mean greater availability of energy supplies and/or reduced cost of production (and ultimately prices). When alternative cases that examine the impacts of variation in the rate of technology improvement are completed, combining the demand and supply/conversion sectors, the impacts on energy markets are sometimes masked because of the offsetting nature of technology improvements in the two areas.

Two sets of alternative cases are used in *AEO2012* to examine the potential impacts of variation in the rate of technology improvement. The first set looks at impacts on the demand sector in isolation. The second set looks at the combined impacts of technology changes in both the demand and supply/conversion sectors. The three demand technology cases—Integrated 2011 Demand Technology, Integrated Best Available Demand Technology, and Integrated High Demand Technology—examine the impacts on the end-use demand sectors of variations in the rate of technology improvement, independent of the offsetting impacts of variations in technology improvement in the supply/conversion sectors.

EIA also completed two fully integrated technology cases that examine combined impacts on the demand and supply/conversion sectors. The Integrated 2011 Technology case combines the assumptions from the Integrated 2011 Demand Technology case with an assumption that the costs of new fossil, nuclear, and nonhydroelectric renewable power plants are fixed at 2012 levels and do not improve due to learning during the projection period. The Integrated High Technology case combines the assumptions from the Integrated High Demand Technology and the Low Renewable Technology Cost case with an assumption that the costs of new nuclear and fossil-fired power plants are lower than assumed in the Reference case, with costs 20 percent lower than Reference case levels in 2012 and 40 percent lower than Reference case levels in 2035.

Greenhouse gas cases

On May 13, 2010, the EPA promulgated standards for GHG emissions in the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" [*159*]. The rule sets up levels of CO_2-equivalent emissions at new and existing facilities that make major modifications that increase GHG emissions which trigger coverage of the facilities in the New Source Review and Title V permitting program. As a result of this and prior actions, regulators and the investment community are beginning to push energy companies to invest in less GHG-intensive technologies. To reflect the market reaction to potential future GHG regulation, a 3-percentage-point increase in the cost of capital is assumed for investments in new coal-fired power plants without CCS and new CTL plants without CCS in the Reference case and all other *AEO2012* cases except the No GHG Concern, GHG15, and GHG25 cases. Those assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs when a new plant begins operation.

The three alternative GHG cases are used to provide a range of potential outcomes, from no concern about future GHG legislation to the imposition of a specific economywide carbon allowance price. *AEO2012* includes two economywide CO_2 price cases, the GHG15 and GHG25 cases, which examine the impacts of economywide carbon allowance prices. In the GHG15 case, the price is set at $15 per metric ton CO_2 in 2013. In the GHG25 case, the price is set at $25 per metric ton CO_2 in 2013. In both cases the price begins to rise in 2014 at 5 percent per year. The GHG cases are intended to measure the sensitivity of the *AEO2012* assumptions to different CO_2 prices that are consistent with previously proposed legislation. At the time the *AEO2012* was completed, no legislation including a GHG price was pending, but the EPA is developing technology-based CO_2 standards for new coal-fired power plants. In the two GHG cases for *AEO2012*, no assumptions are made with regard to offsets, bonus allowances for CCS, or specific allocation of allowances.

The No GHG Concern case was run without any adjustment for concern about potential GHG regulations (without the 3-percentage-point increase in the cost of capital). In the No GHG Concern case, the same cost of capital is used to evaluate all new capacity builds, regardless of type.

No Sunset case

In addition to the *AEO2012* Reference case, a No Sunset case was run assuming that selected policies with sunset provisions—such as the PTC, ITC, and tax credits for energy-efficient equipment in the buildings and industrial sectors—will be extended indefinitely rather than allowed to sunset as the law currently prescribes.

For the residential sector, the extensions include: (a) personal tax credits for selected end-use equipment, including furnaces, heat pumps, and central air conditioning; (b) personal tax credits for PV installations, solar water heaters, small wind turbines, and geothermal heat pumps; (c) manufacturer tax credits for refrigerators, dishwashers, and clothes washers, passed on to consumers at 100 percent of the tax credit value.

For the commercial sector, business ITCs for PV installations, solar water heaters, small wind turbines, geothermal heat pumps, and CHP are extended to the end of the projection. The business tax credit for solar technologies remains at the current 30-percent level without reverting to 10 percent as scheduled.

In the industrial sector, the existing ITC for industrial CHP, which currently ends in 2016, is extended to 2035.

For the refinery sector, blending credits are extended; the $1.00 per gallon biodiesel tax credit is extended; the $0.54 per gallon tariff on imported ethanol is extended; and the $1.01 per gallon PTC for cellulosic biofuels is extended.

For renewables, the PTC of 2.2 cents per kilowatthour for wind, geothermal, and certain biomass and the PTC of 1.1 cents per kilowatthour for hydroelectric and landfill gas resources, which currently are set to expire at the end of 2012 for wind and the end of 2013 for other eligible resources, are extended to 2035; and the 30-percent solar power ITC, which currently is scheduled to revert to 10 percent in 2016, is extended indefinitely.

Extended Policies case

In the Extended Policies case, assumptions for tax credit extensions are the same as in the No Sunset case described above with the exception of the PTC extension for cellulosic biofuels and the tax credits for residential equipment subject to updated Federal efficiency standards, which are dropped. Further, updates to Federal appliance efficiency standards are assumed to occur at regular intervals, and new standards for products not currently covered by DOE are assumed to be introduced. Finally, proposed rules by NHTSA and the EPA for national tailpipe CO_2-equivalent emissions and fuel economy standards for LDVs, including both passenger cars and light-duty trucks, are harmonized and incorporated in this case.

Updates to appliance standards are assumed to occur as prescribed by the timeline in DOE's multi-year plan, and new standards for products currently not covered by DOE are introduced by 2019. The efficiency levels chosen for the updated residential appliance standards are based on current ENERGY STAR guidelines. Residential end-use technologies subject to updated standards are not eligible for No Sunset incentives in addition to the standards. The efficiency levels chosen for updated commercial equipment standards are based on the technology menu from the *AEO2011* Reference case and either FEMP-designated purchasing specifications for Federal agencies or ENERGY STAR guidelines. National building codes are added to reach 30-percent improvement relative to IECC 2006 for residential households and ASHRAE 90.1-2004 for commercial buildings by 2020, with additional rounds of improvements in 2023 and 2026.

In the industrial sector, the ITC for industrial CHP is further extended to cover all system sizes rather than applying only to systems under 50 megawatts; and the CHP equipment cap is increased from 15 megawatts to 25 megawatts. These extensions are consistent with previously proposed legislation (S. 1639) or pending legislation (H.R. 2750 and 2784).

For transportation, the Extended Policies case assumes that the standards are further increased, so that the minimum fuel economy standard achieved by LDVs continues to increase through 2035.

Endnotes for Appendix E

Links current as of April 2012

142. U.S. Energy Information Administration, *The National Energy Modeling System: An Overview 2009*, DOE/EIA-0581(2009) (Washington, DC: October 2009), website www.eia.gov/oiaf/aeo/overview.
143. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," website www.epa.gov/mats.
144. U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)," website epa.gov/airtransport. CSAPR was scheduled to begin on January 1, 2012; however, the U.S. Court of Appeals for the D.C. Circuit issued a stay delaying implementation while it addresses legal challenges to the rule that have been raised by several power companies and States. CSAPR is included in *AEO2012* despite the stay, because the Court of Appeals had not made a final ruling at the time *AEO2012* was published.
145. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *Federal Register*, Vol. 76, No. 179 (September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.
146. California Air Resources Board (ARB), "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms," Article 5 § 95800 to 96023, website www.arb.ca.gov/cc/capandtrade/capandtrade.htm.
147. U.S. Environmental Protection Agency, "July 21, 2011 Final Memorandum: Improving EPA Review of Appalachian Surface Coal Mining Operations Under the Clean Water Act, National Environmental Policy Act, and the Environmental Justice Executive Order," website water.epa.gov/lawsregs/guidance/wetlands/mining.cfm.
148. For the complete text of the American Recovery and Reinvestment Act of 2009, see website www.gpo.gov/fdsys/pkg/PLAW-111publ5/html/PLAW-111publ5.htm.
149. U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC: October 2011), website www.eia.gov/aer.
150. U.S. Energy Information Administration, "Short-Term Energy Outlook," website www.eia.gov/forecasts/steo. Portions of the preliminary information were also used to initialize the NEMS Petroleum Market Module projection.
151. U.S. Energy Information Administration, "Manufacturing Energy Consumption Survey," website www.eia.doe.gov/emeu/mecs.
152. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2012*, DOE/EIA-0554(2012) (Washington, DC: June 2012), website www.eia.gov/forecasts/aeo/assumptions.
153. Alternative other liquids technologies include all biofuels technologies plus CTL and GTL.
154. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2012*, DOE/EIA-0554(2012) (Washington, DC: June 2012), website www.eia.gov/forecasts/aeo/assumptions.
155. High technology assumptions for the residential sector are based on U.S. Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case* (Navigant Consulting, Inc. with SAIC, September 2011), and *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., September 2008).
156. High technology assumptions for the commercial sector are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case* (Navigant Consulting, Inc. with SAIC, September 2011), and *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., September 2008).
157. These assumptions are based in part on Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).
158. U.S. Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2003).
159. U.S. Environmental Protection Agency, "Final Rule: Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule," website www.epa.gov/nsr/documents/20100413fs.pdf.

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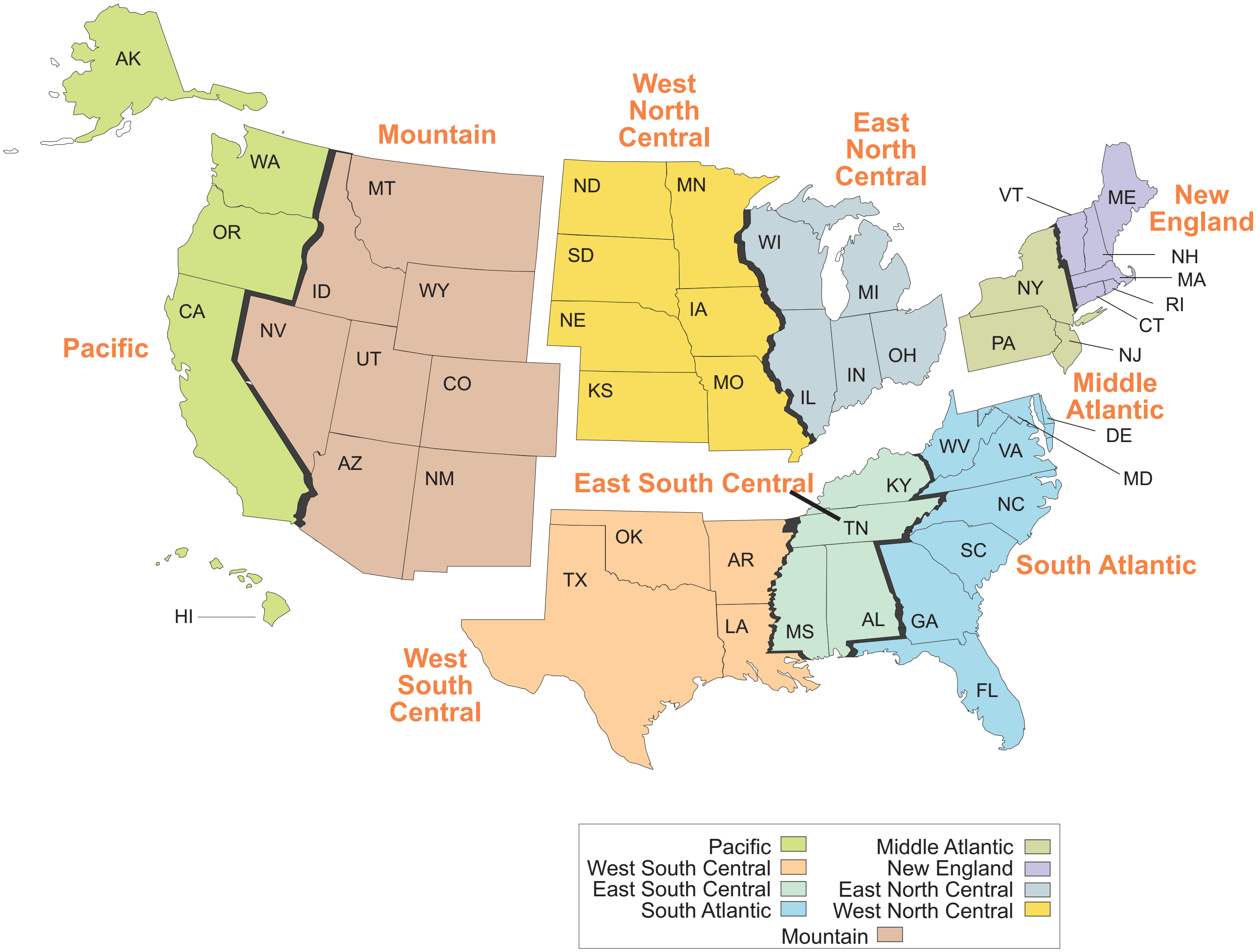
Regional Maps

Figure F1. United States Census Divisions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F1. United States Census Divisions (continued)

Division 1
New England

Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2
Middle Atlantic

New Jersey
New York
Pennsylvania

Division 3
East North Central

Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4
West North Central

Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5
South Atlantic

Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6
East South Central

Alabama
Kentucky
Mississippi
Tennessee

Division 7
West South Central

Arkansas
Louisiana
Oklahoma
Texas

Division 8
Mountain

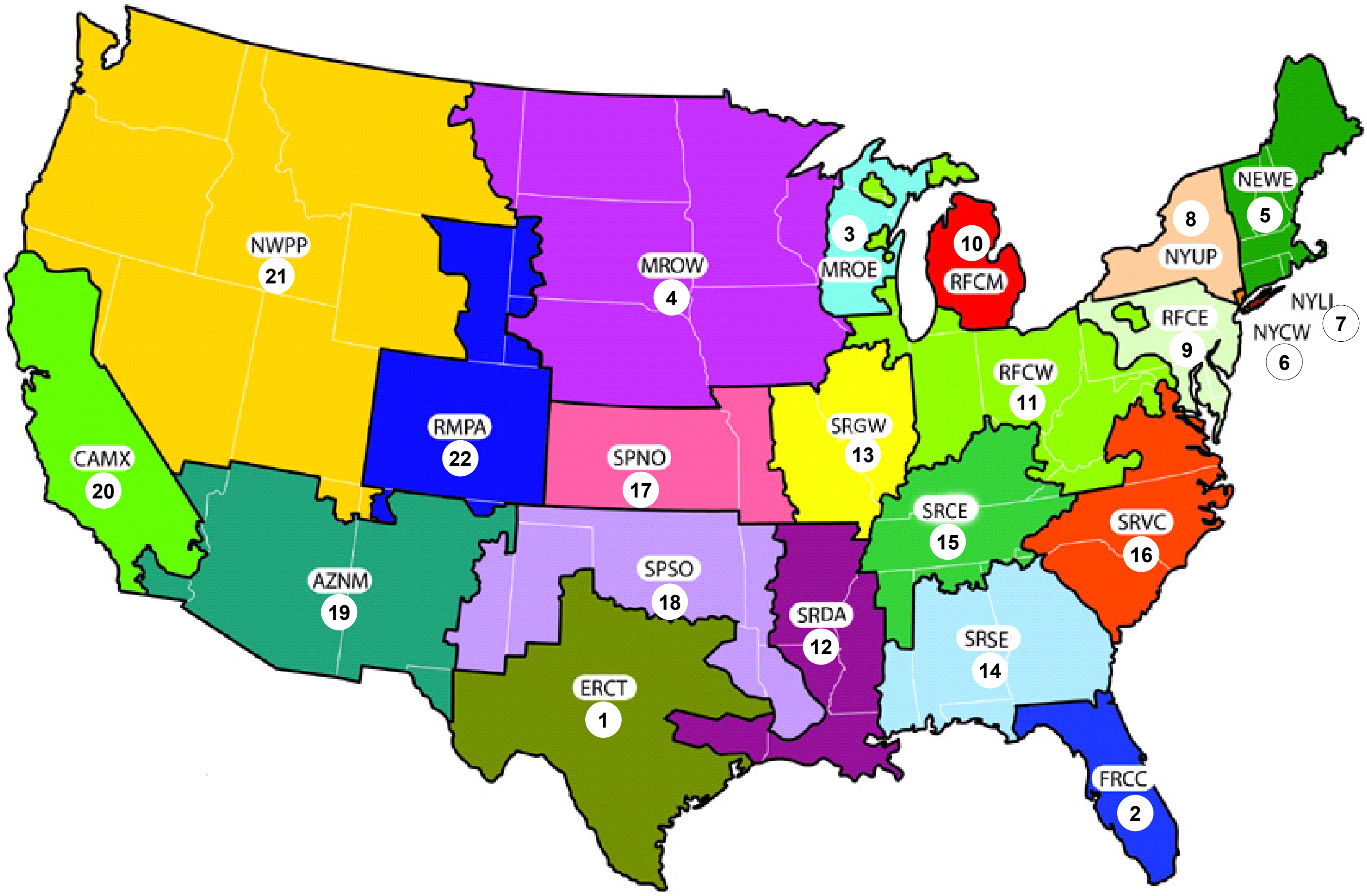
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9
Pacific

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Energy Analysis.

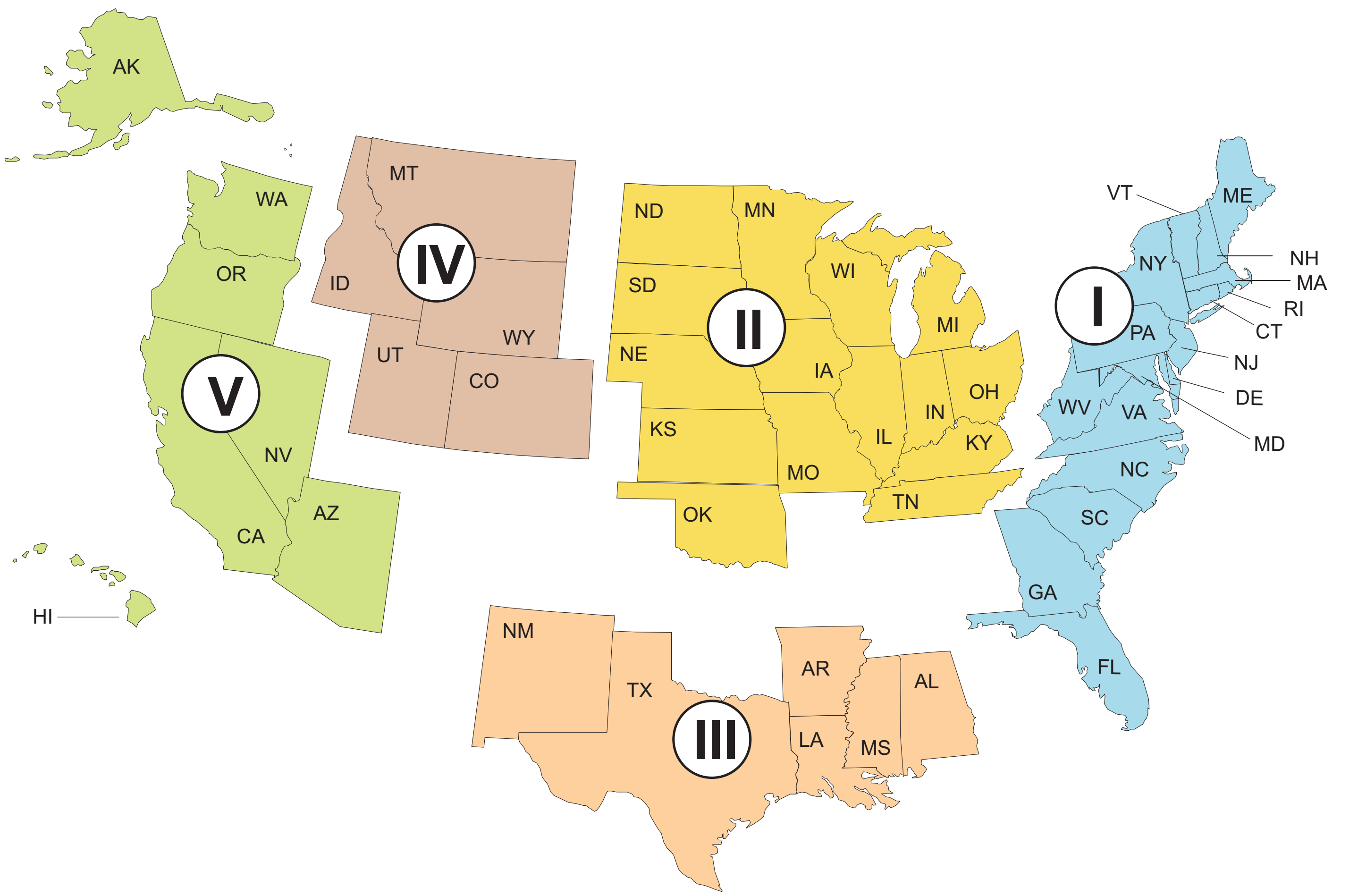
Figure F2. Electricity market module regions



1.	ERCT	TRE All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

Source: U.S. Energy Information Administration, Office of Energy Analysis.

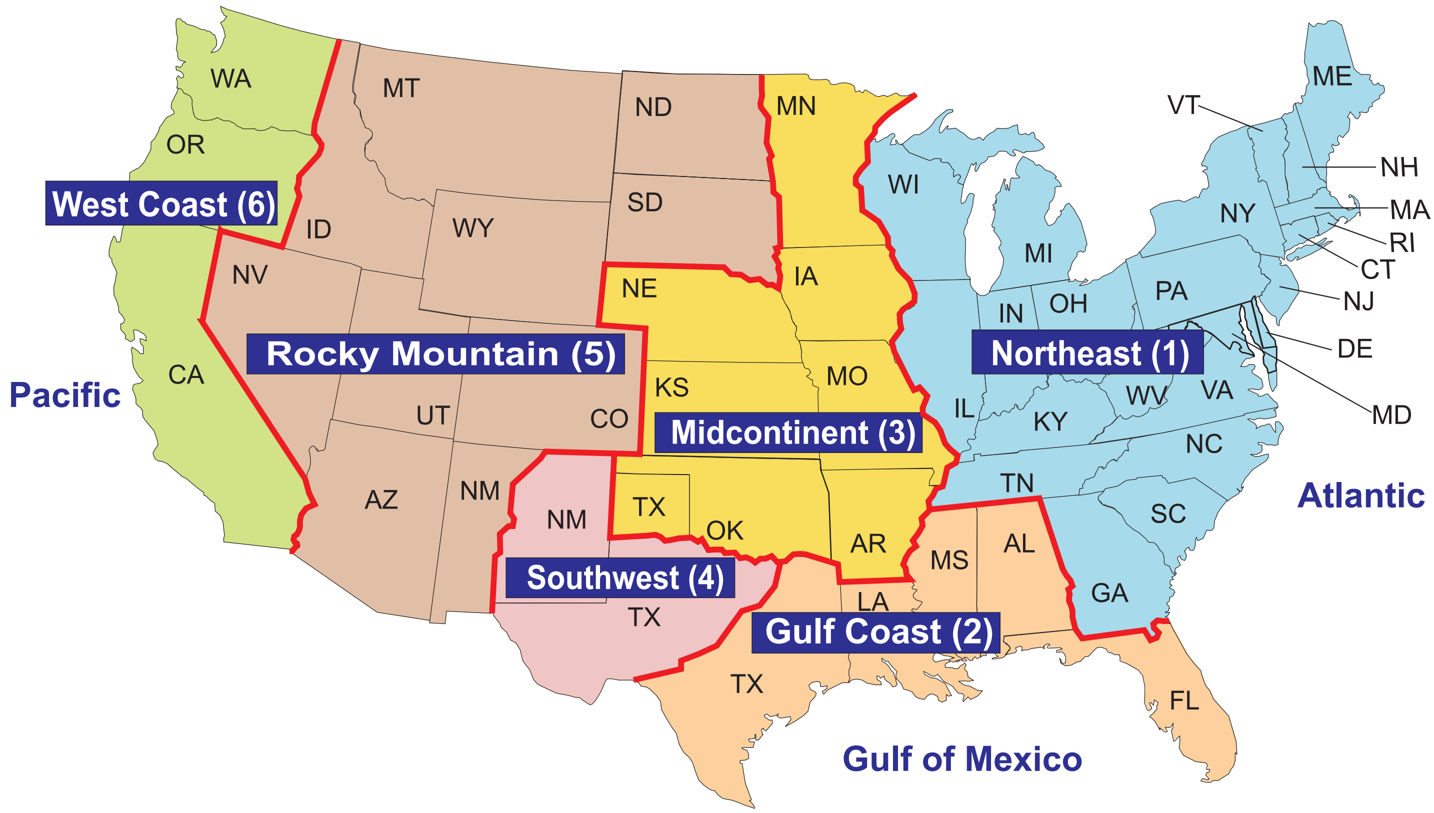
Figure F3. Petroleum Administration for Defense Districts



PAD District I - East Coast
PAD District II - Midwest
PAD District III - Gulf Coast
PAD District IV - Rocky Mountain
PAD District V - West Coast

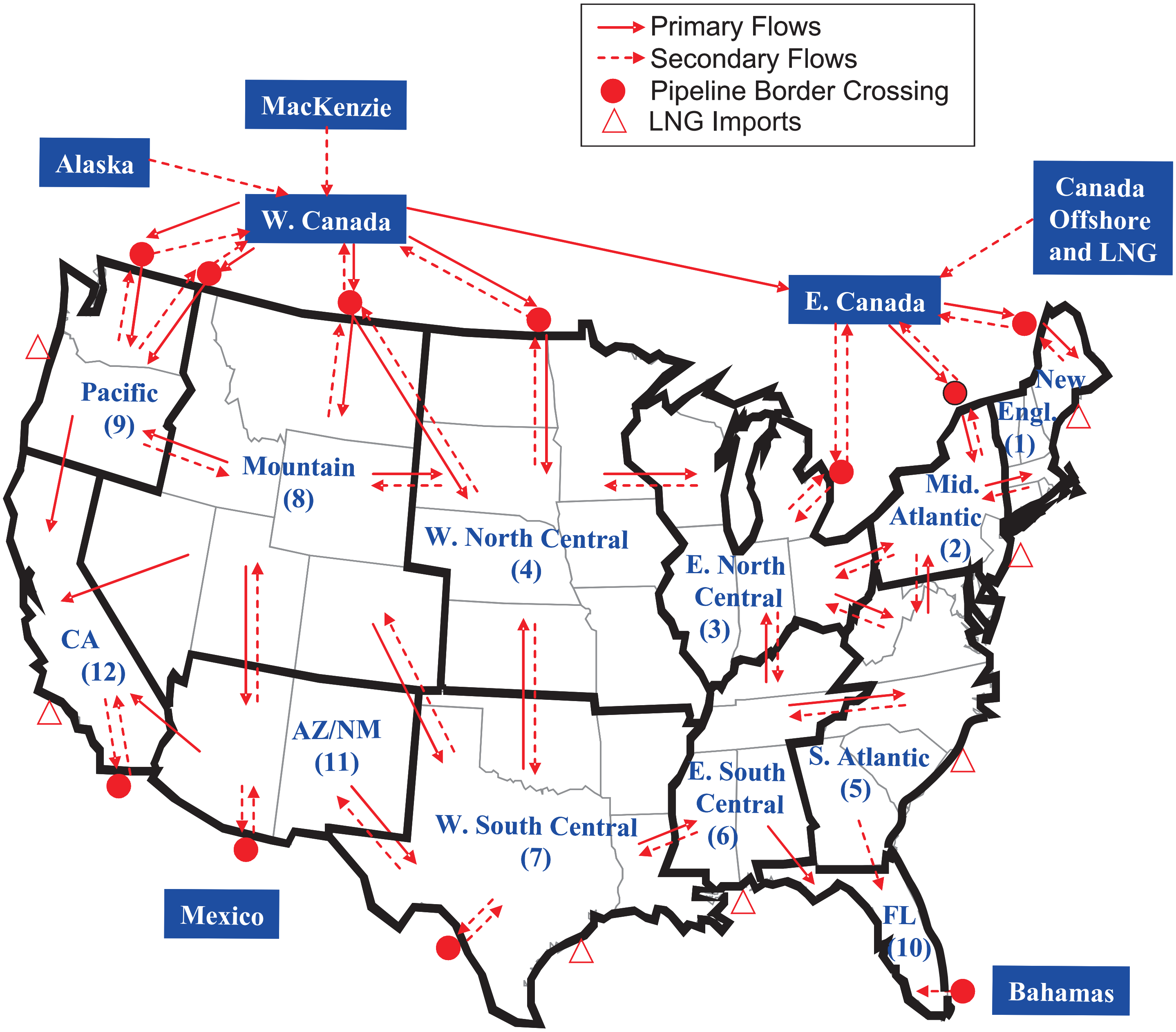
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F4. Oil and gas supply model regions



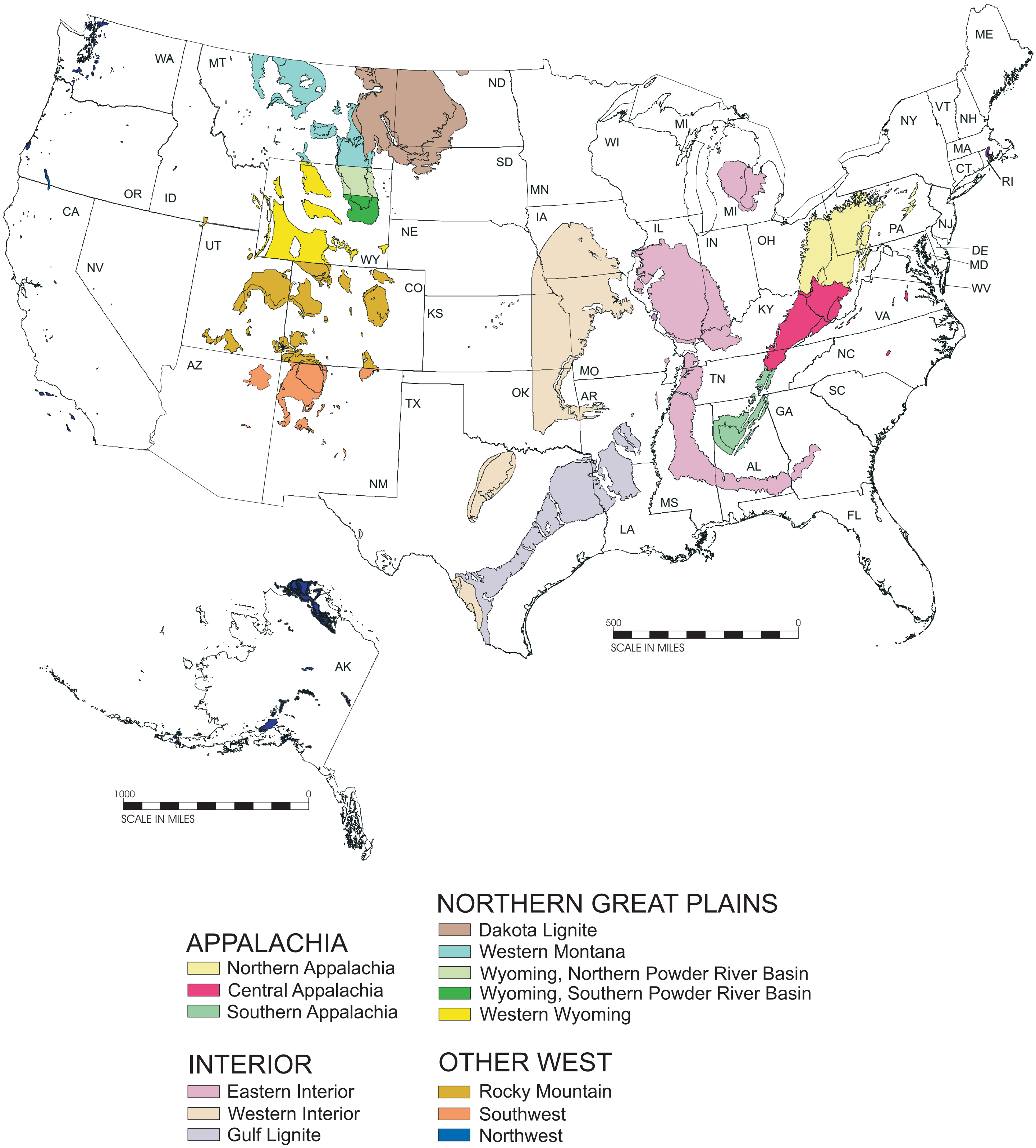
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F5. Natural gas transmission and distribution model regions



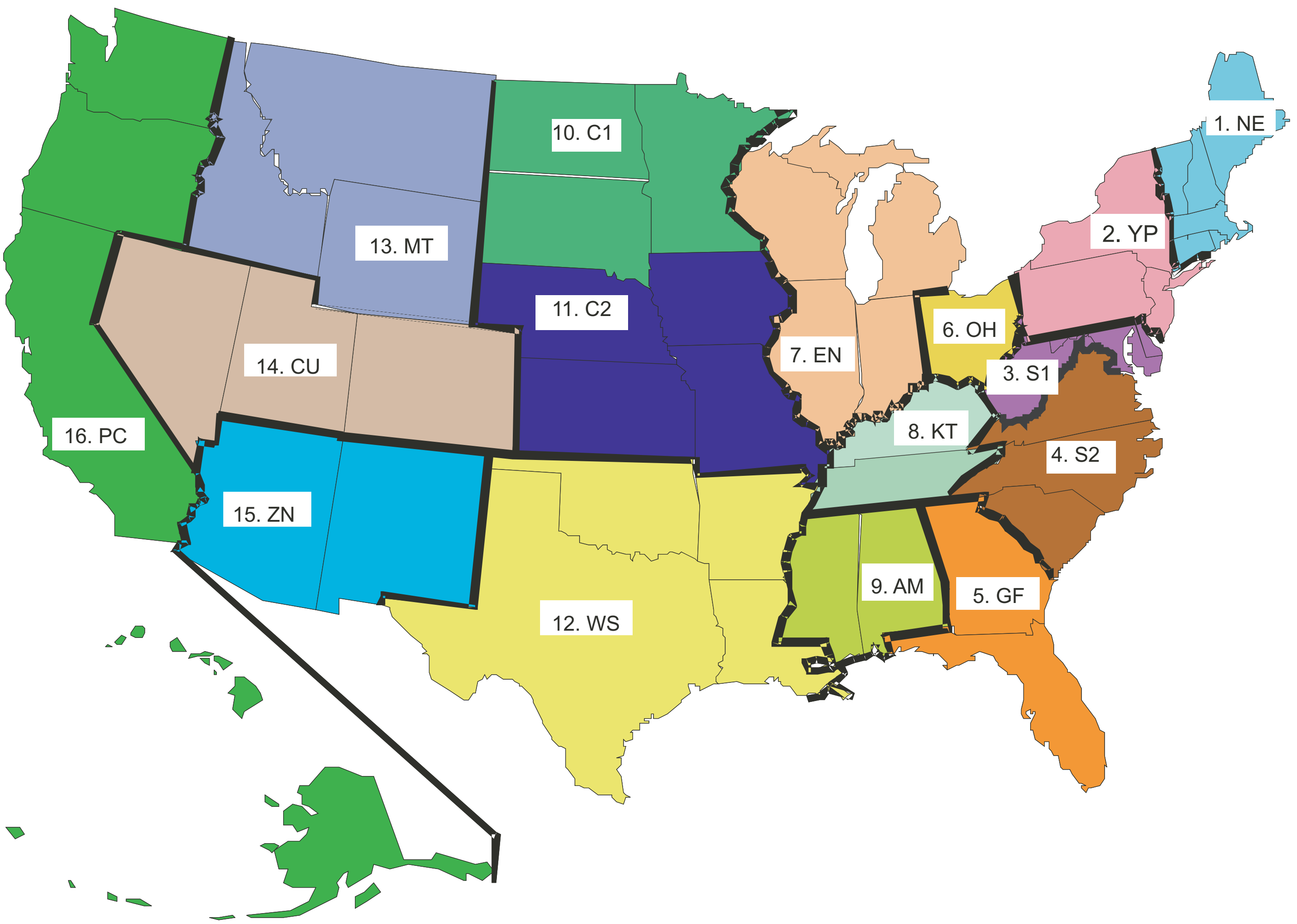
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F6. Coal supply regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F7. Coal demand regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. S1	WV,MD,DC,DE
4. S2	VA,NC,SC
5. GF	GA,FL
6. OH	OH
7. EN	IN,IL,MI,WI
8. KT	KY,TN

Region Code	Region Content
9. AM	AL,MS
10. C1	MN,ND,SD
11. C2	IA,NE,MO,KS
12. WS	TX,LA,OK,AR
13. MT	MT,WY,ID
14. CU	CO,UT,NV
15. ZN	AZ,NM
16. PC	AK,HI,WA,OR,CA

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Appendix G
Conversion factors

Table G1. Heat rates

Fuel	Units	Approximate heat content
Coal[1]		
Production	million Btu per short ton	20.192
Consumption	million Btu per short ton	19.847
Coke plants	million Btu per short ton	26.297
Industrial	million Btu per short ton	20.433
Residential and commercial	million Btu per short ton	21.188
Electric power sector	million Btu per short ton	19.623
Imports	million Btu per short ton	24.719
Exports	million Btu per short ton	25.698
Coal coke	million Btu per short ton	24.800
Crude oil		
Production	million Btu per barrel	5.800
Imports[1]	million Btu per barrel	5.989
Petroleum products and other liquids		
Consumption[1]	million Btu per barrel	5.254
Motor gasoline[1]	million Btu per barrel	5.100
Jet fuel	million Btu per barrel	5.670
Distillate fuel oil[1]	million Btu per barrel	5.771
Diesel fuel[1]	million Btu per barrel	5.762
Residual fuel oil	million Btu per barrel	6.287
Liquefied petroleum gases[1]	million Btu per barrel	3.557
Kerosene	million Btu per barrel	5.670
Petrochemical feedstocks[1]	million Btu per barrel	5.510
Unfinished oils	million Btu per barrel	6.118
Imports[1]	million Btu per barrel	5.337
Exports[1]	million Btu per barrel	5.851
Ethanol	million Btu per barrel	3.561
Biodiesel	million Btu per barrel	5.359
Natural gas plant liquids		
Production[1]	million Btu per barrel	3.674
Natural gas[1]		
Production, dry	Btu per cubic foot	1,024
Consumption	Btu per cubic foot	1,024
End-use sectors	Btu per cubic foot	1,025
Electric power sector	Btu per cubic foot	1,022
Imports	Btu per cubic foot	1,025
Exports	Btu per cubic foot	1,009
Electricity consumption	Btu per kilowatthour	3,412

[1]Conversion factor varies from year to year. The value shown is for 2010.
Btu = British thermal unit.
Sources: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011), and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

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Using GPCM® to Model LNG Exports from the US Gulf Coast

Robert Brooks, Ph.D., President, RBAC, Inc.

March 2, 2012

As the gas industry rolled into the 21st century, natural gas production was beginning to decline and the outlook for production looked rather bleak. A small upsurge due to the advent of coal-bed methane development had begun to play out and it looked like the future lay in LNG imports. Billions of dollars were spent in designing and getting permitted dozens of new LNG import terminals. Ten new terminals and two offshore receiving stations were actually built. As it turned out, the companies that lagged behind and didn't actually build these expensive terminals were the winners, because the industry as a whole did not predict an upstream revolution which was quietly occurring at the same time. A breakthrough in horizontal drilling combined with hydro-fracturing and advanced 3D imaging finally made it possible to economically develop the enormous gas and oil resources long known to exist in vast shale formations throughout much of North America.

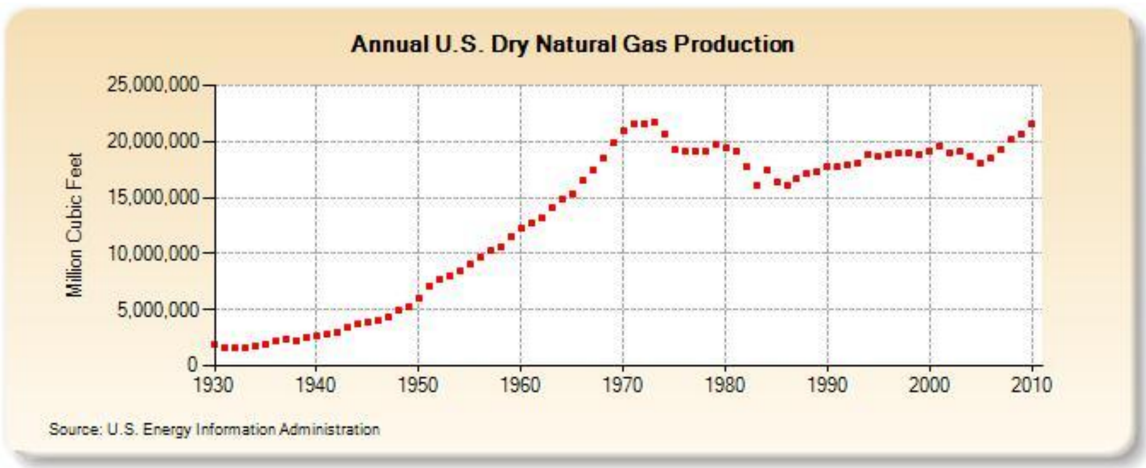


Figure 1: US Dry Natural Gas Production 1930-2010

A drilling boom began which completely turned the US production graph around. (See Figure 1.) All of a sudden there was more gas than could be easily absorbed in a recession-bound market. Natural gas prices began to erode, moving from the $6/mmbtu range to under $4/mmbtu (Figure 2), and the new challenge became "what are we going to do with all this gas?"

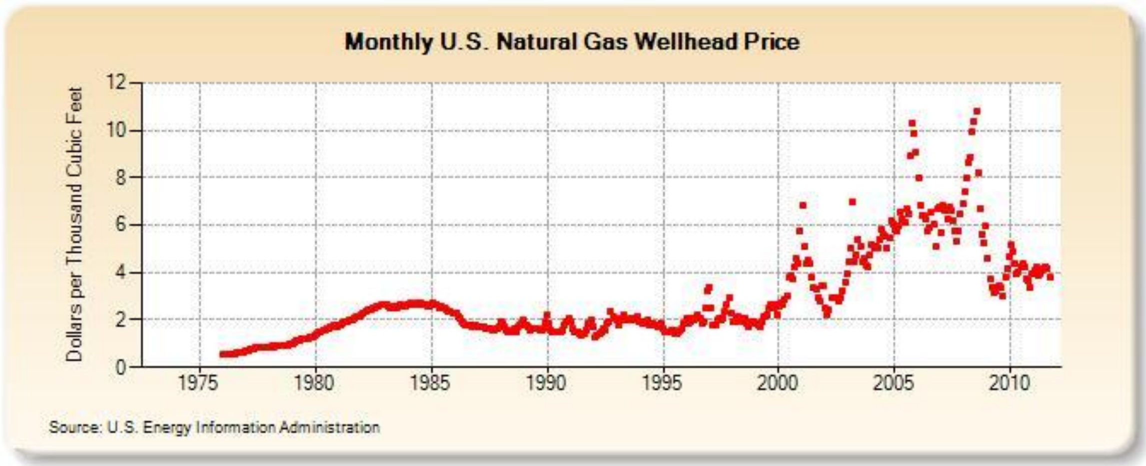


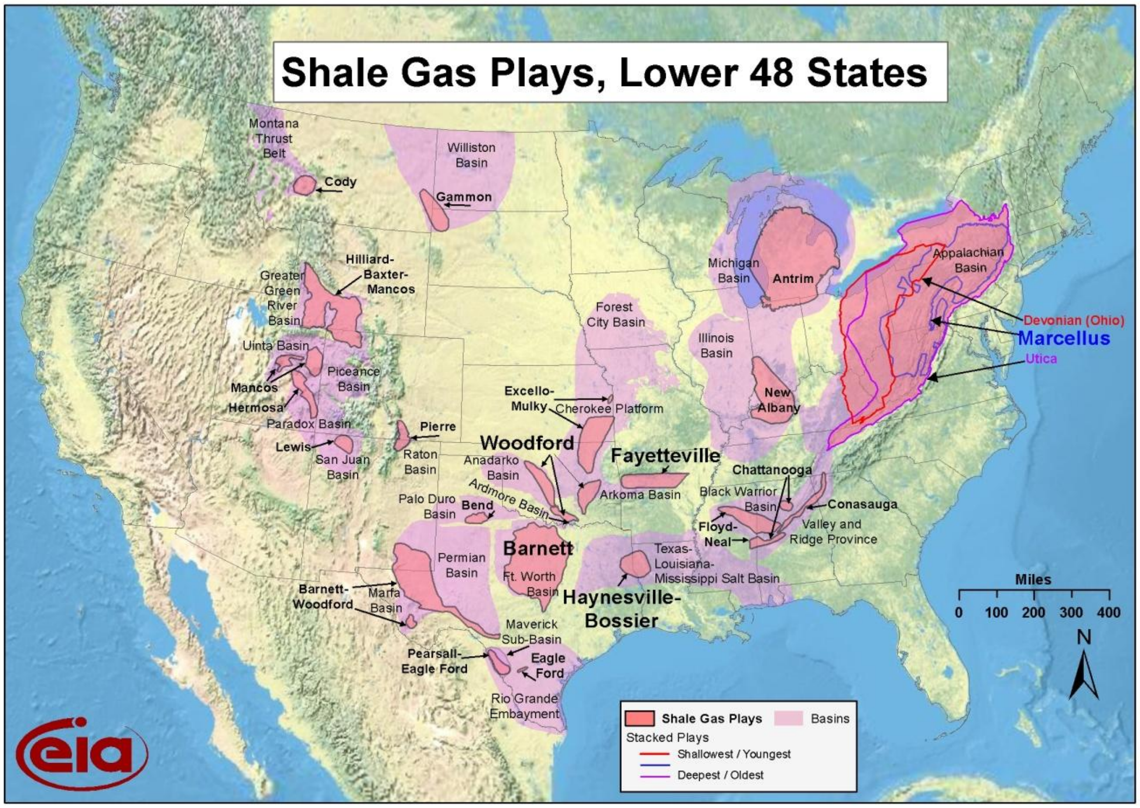
Figure 2: Monthly Natural Gas Wellhead Prices 1975-2010

Five answers have been put forward: redirect drilling from dry gas plays to plays having higher concentrations of more profitable natural gas liquids, replace coal with natural gas in electricity generation; build new fleets of natural gas powered trucks, buses, and cars; convert the gas into liquids for use in transportation; and, most recently, liquefy the gas and export it to other countries willing to pay much higher prices, notably Japan, China, Korea, and India.

As of year-end 2011 redirection to wetter gas plays has not solved the problem because the wetter gas plays have proven to be even more prolific gas producers than the dry gas plays drilled earlier. Replacing coal with gas in electricity production has been occurring but is a slow process which will take decades to unfold. Similarly, the natural gas vehicle market is growing, but from such a small base that it will take a very long time to have an impact on gas price, if ever. Gas-to-liquids is a mature technology, but is expensive, and its future in North America is still quite uncertain.

Up until very recently, the idea of liquefying excess North American natural gas and exporting it to overseas markets did not appear to be likely of success. That was before late 2011 when Cheniere Energy, owner of the Sabine Pass LNG terminal in Louisiana, announced the completion of agreements with UK-based BG Group and Spain’s Gas Natural Fenosa to export LNG to Europe and Latin America and with GAIL (India) Limited for similar exports to India. Each of these agreements is for 3.5 million tons of LNG per year. In January 2012, Cheniere and Korea Gas Corporation (KOGAS) announced a similar agreement for another 3.5 million tons per year. 14 million tons per year of LNG would require almost 2 billion cubic feet per day (bcf/day) of production.

Much or most of the gas to be liquefied into LNG would be produced out of the nearby Haynesville-Bossier Shale play of northern Louisiana and east Texas. Following upon these deals, Cheniere announced plans to convert its planned Corpus Christi LNG import terminal into a second liquefaction and export terminal, this one located near the prolific Eagle Ford Shale wet gas play in South Texas.



Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

Figure 3: Shale Gas Plays in the United States

Some concern has been expressed by end-users of natural gas that these export projects would increase natural gas prices in the United States. Cheniere estimated that exports of 2 bcf/day could raise gas prices by as much as 10%. DOE's Energy Information Administration was requested by Congress to make its own projection. DOE assumed a much more extreme range of exports between 6 and 12 bcf/day with two different ramp-up rates (1 bcf/day per year and 3 bcf/day per year). In their 6 bcf/day scenario with 2 year ramp-up, the so-called "low, rapid" scenario, EIA projected an average price increase at the Henry Hub in Southern Louisiana of $0.60 per million btu (mmbtu) over the period 2016-2035.

Using its WGM model with the assumption of a 6 bcf/day export volume, consultant Deloitte MarketPoint LLC projected an average increase of only $0.22 mmbtu at the Henry Hub in Southern Louisiana over the same time period as EIA. Deloitte attributed the tiny magnitude of this price impact to the ability of the North American gas market to quickly and efficiently adjust to the prospect of an export market.

Using the GPCM model RBAC has produced its own analysis to address this question. Starting with RBAC's GPCM 11Q3 Base Case released in October 2011, which assumed Gulf LNG exports of 0.7 bcf/day, we have created five new scenarios: 1) no LNG exports from the US lower-48 states, 2) 1 bcf/day, 3) 2 bcf/day, 4) 4 bcf/day, and 5) 6 bcf per day. Each of the

LNG scenarios took 3 years to ramp up to maximum by 2018 and continued at that level through 2035.

The following figures show the results from these scenarios and the impact of various volumes of LNG exports on prices at Henry Hub.

Figure 4 shows Henry Hub price forecasts for the five scenarios. Prices are expected to be in the sub-$4 range from 2012-2015 for all scenarios, varying from that point depending on the volume of LNG exports in each.

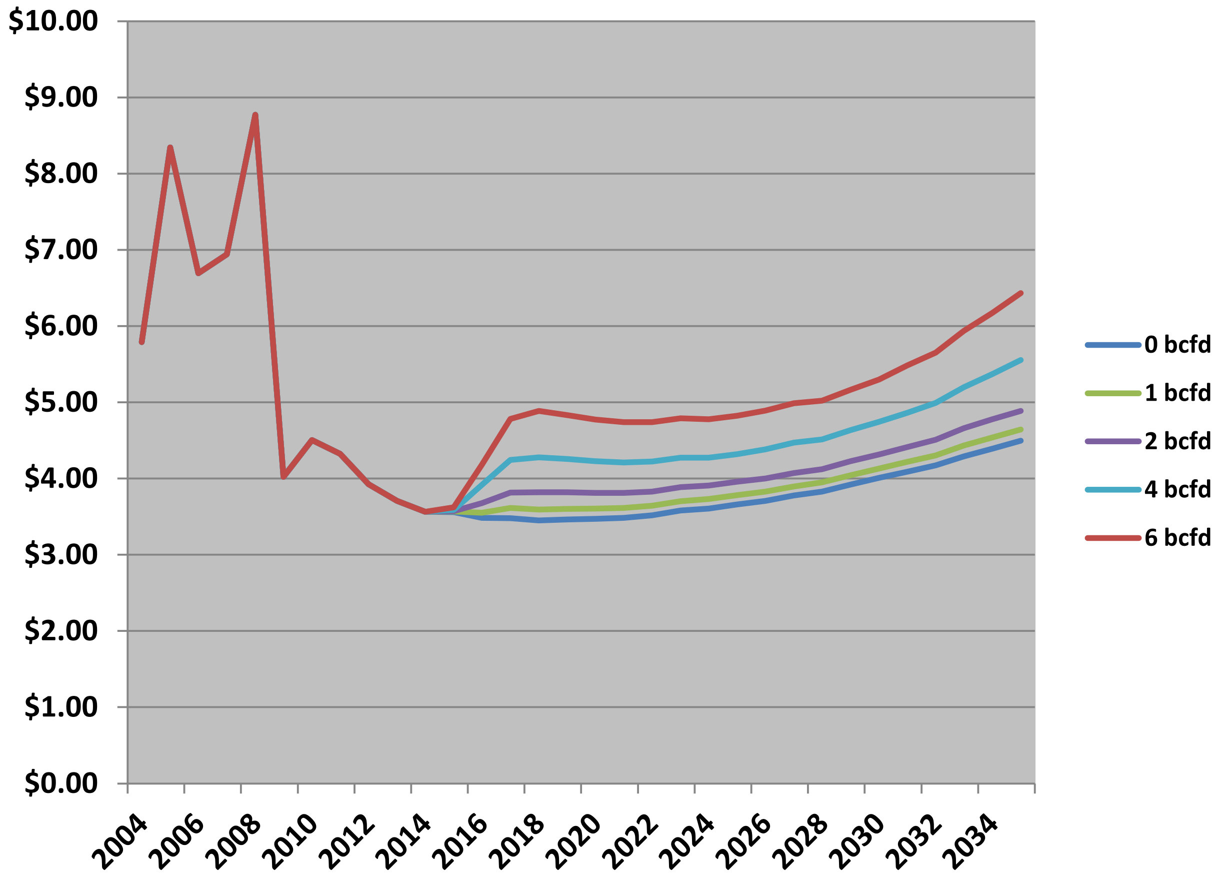


Figure 4: Annual Average Henry Hub Gas Price Forecast: 0, 1, 2, 4, and 6 bcf/day exports

Figure 5 shows the price difference between the no-LNG and the 1, 2, 4, and 6 bcf/day scenarios.

Figure 6 shows the average price impact over the 20 year 2016-2035 time period of each of the LNG export scenarios versus a zero-LNG export scenario.

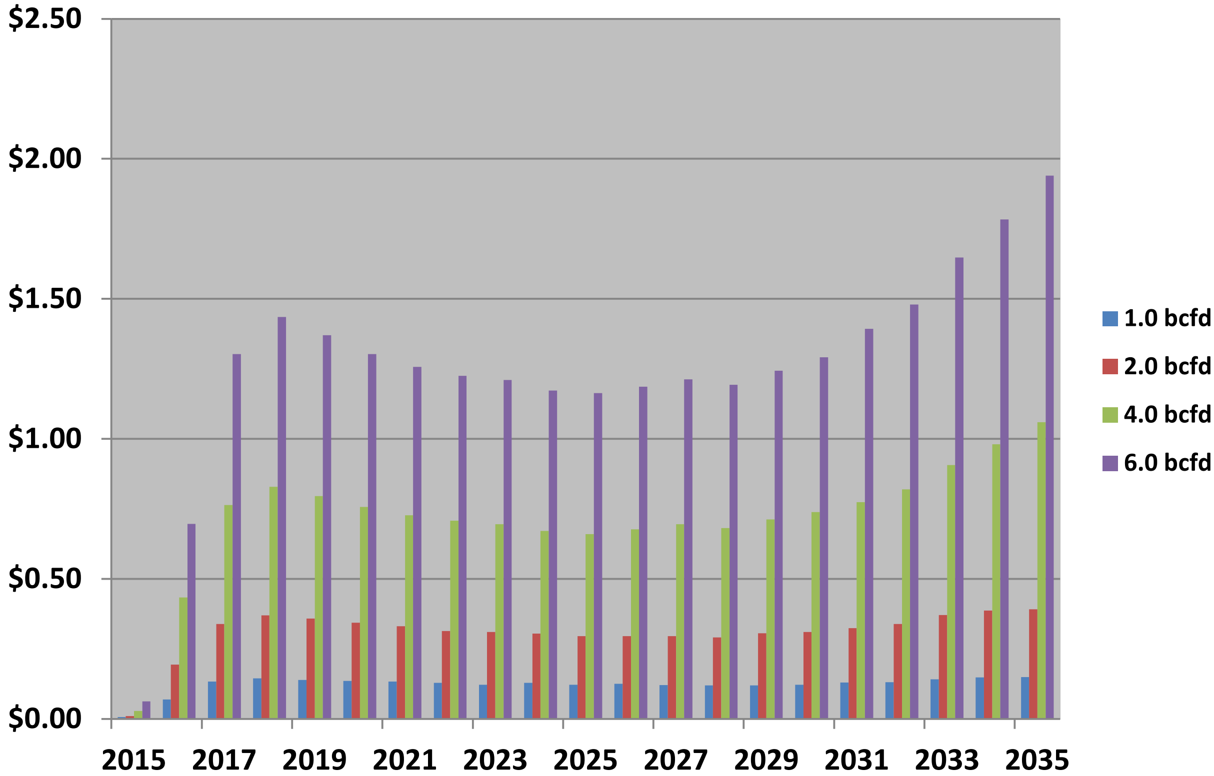


Figure 5: Price Impact at Henry Hub Due to Various Levels of Gulf Coast LNG Exports

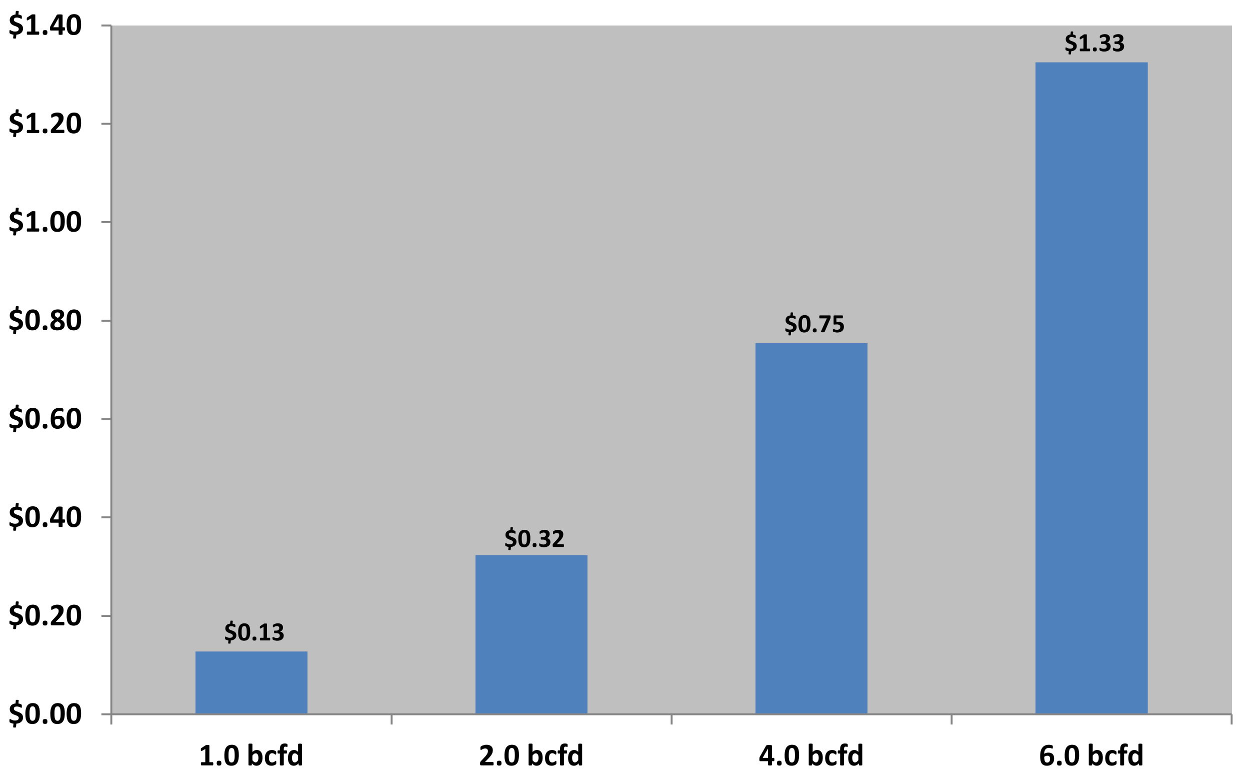


Figure 6: Average Price Impact at Henry Hub 2016-2035 of Different Gulf LNG Export Levels

The price impact of this level of LNG exports predicted using RBAC's GPCM model is about the same as Cheniere for the 2 bcf/day scenario ($0.32), but much greater for the more extreme 6 bcf/day scenario than that estimated by EIA ($0.60) or Deloitte ($0.22). It averages about $1.33 per mmbtu over the forecast horizon, a 30% increase at Henry Hub. RBAC's 6 bcf/day scenario does not forecast that the industry will respond with speed and efficiency with an insignificant gas-price increase as does the Deloitte model. The flexibility of the industry to respond to this large and sudden increase in demand comes at a price.

The following figure shows the effect of this extreme level of LNG exports and resulting higher prices on domestic gas deliveries.

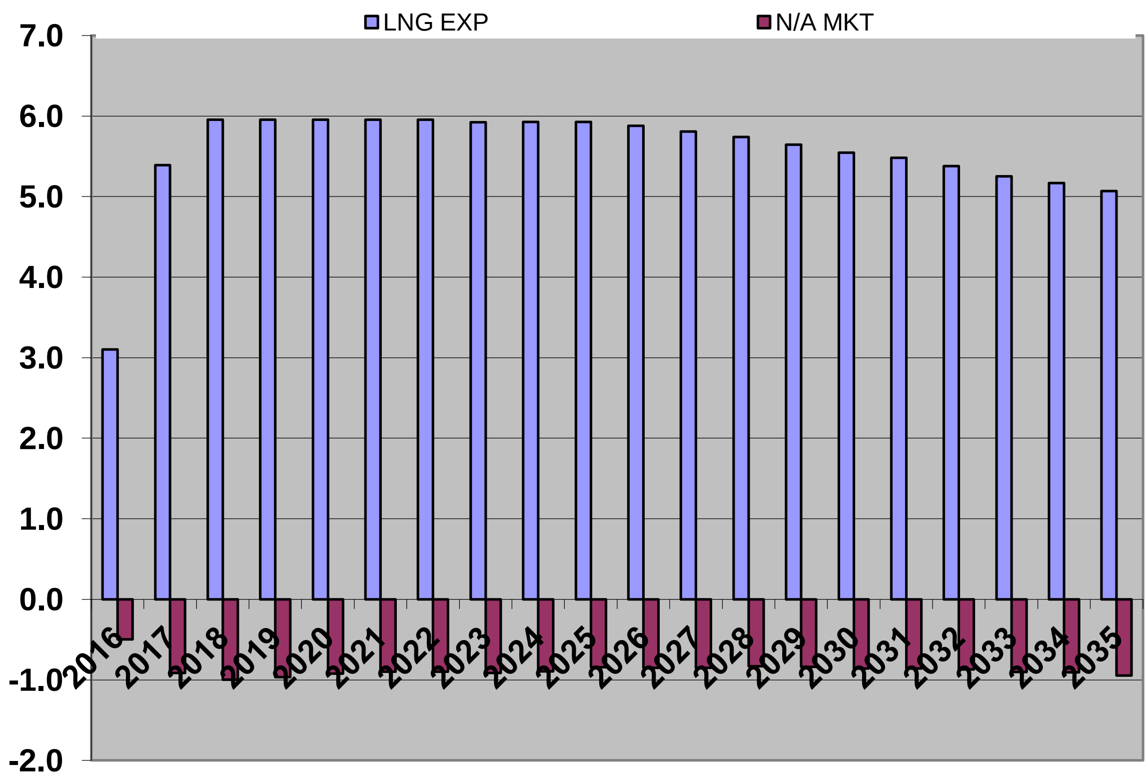


Figure 7: Impact of LNG Exports on Deliveries to the North American Market

First note that the scenario as designed ran into difficulty exporting 6 BCF/day after 2025. The amount available for export slowly fell to about 5 BCF/day by 2035. The 6 bcf/day scenario assumes 3 bcf/day from Louisiana and 3 bcf/day from Texas. In the longer run, it is more difficult to supply 3 bcf/day for LNG exports from Texas due to competition with Mexico. On average the LNG exports were about 5.5 BCF/day in this scenario.

The addition of 5.5 BCF/day LNG export demand raises prices enough to reduce deliveries to the domestic North American market by almost 0.8 BCF/day. Most of this reduction is felt by the industrial market, the most price sensitive sector in the US. Thus the net additional production required by the new LNG export market is about 4.7 BCF/day.

Perhaps one reason why EIA's price response is less than RBAC's is that EIA assumes an increase in production of only 3.8 bcf/day will be required to supply 6 bcf/day in exports. This surprising result comes about because EIA's result shows a 2.1 bcf/day decrease in gas available to consumers in the US. Their demand model is much more price-sensitive than RBAC's.

Figure 8 shows where the additional supply will originate in the 6 bcf/day RBAC scenario. About 10% of the required new supply comes from coal-bed methane and a small uptick in LNG imports. The latter is due to the fact that the Mexican market is dependent on imports from the US as well as LNG. With less pipeline gas available to Mexico from South Texas, more local gas must be produced and more LNG imported.

One surprise is that conventional sources will initially provide about 50% of the incremental supply needed for the net increase in demand with shale providing about 40%. However, as shale becomes the predominant source of production, it also takes over as the primary source of incremental supply for exports, reaching more than 60% by year 2035. This may be more a result of the fact that GPCM models physical gas flows. How gas is contracted could be quite different.

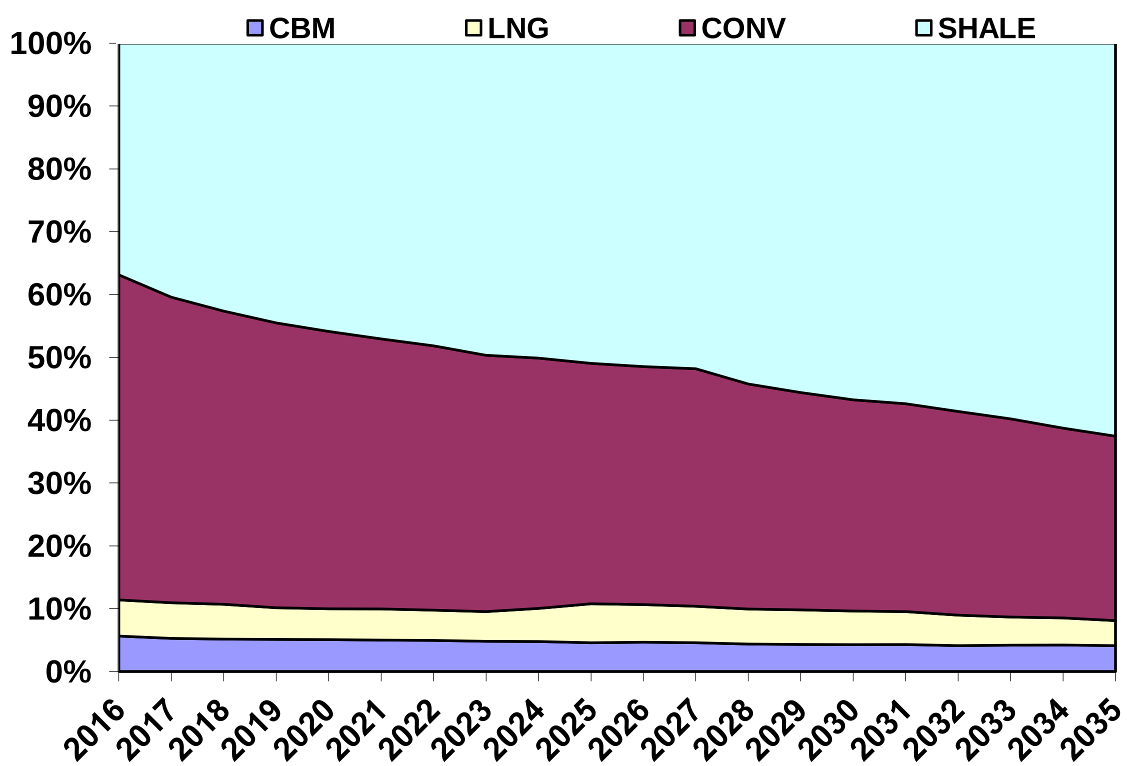


Figure 8: Share of New Supply Required in 6 bcf/day LNG Exports Scenario

Sensitivity of Results to Supply Assumptions

A sixth scenario was run to test the sensitivity of these results to the base case assumption of supply responsiveness to changes in demand. By raising price sensitivity of supply for prices higher than about $4/mmbtu, production capacity grows faster than in the original 6 bcf/day LNG exports scenario. By 2035 capacity is about 4 BCF/day (3%) higher for the same price.

Figure 9 shows the effect of this higher production sensitivity case on Henry Hub price.

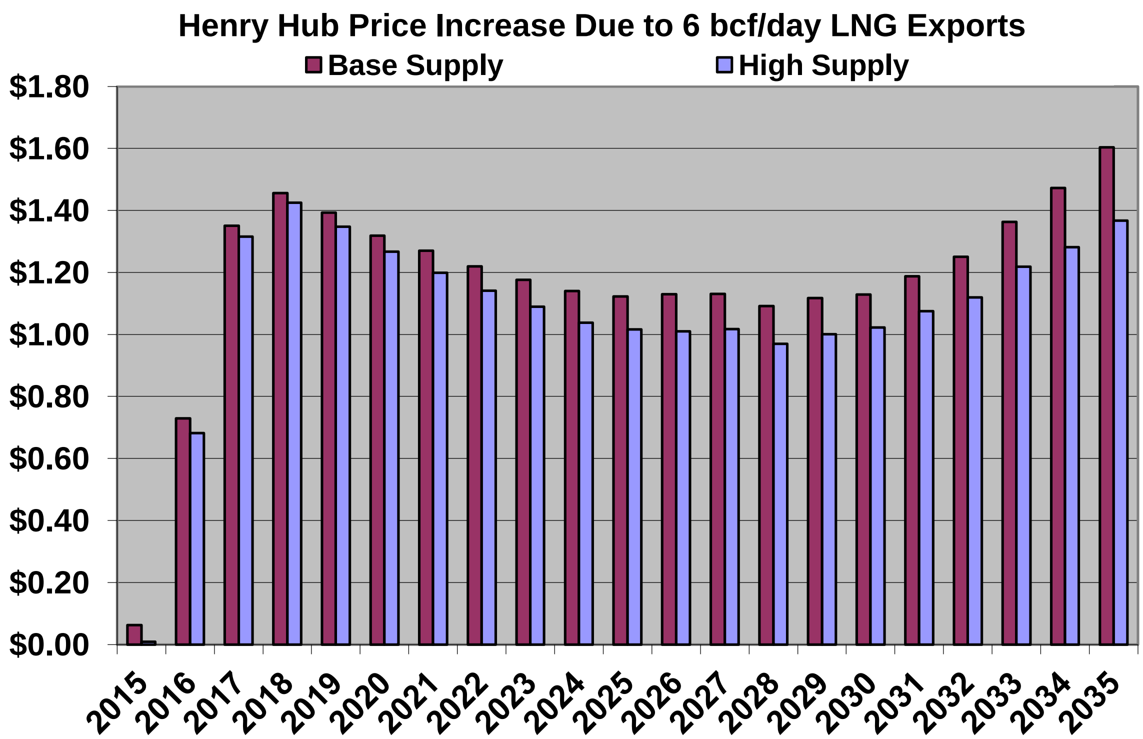


Figure 9: Sensitivity of Henry Hub Price Effect to Supply Capacity Growth

The price effect of LNG exports is reduced by about $0.05 in 2016 growing to almost $0.25 by 2035. The average price effect in the sensitivity case is $1.13, about $0.10 less than the original 6 bcf/day exports case. These results suggest that both EIA and Deloitte models may substantially underestimate the price effect of 6 bcf/day LNG exports of the magnitude reported in their studies. The adjustments which the industry makes to meet the challenge of this large new demand are not likely to be made so quickly and with so little impact on price.

Moore, Larine

From: Molinaro, Peter (PA) [molinapa@dow.com]
Sent: Thursday, January 24, 2013 1:59 PM
To: LNGStudy
Subject: 2012 LNG Export Study – Comments by The Dow Chemical Company
Attachments: 2012 LNG Export Study -- Dow Chemical Comments.pdf

Categories: Pink

Enclosed herewith are the comments of The Dow Chemical Company on the NERA Economic Consulting ("NERA") Report *Macroeconomic*
Impacts of Increased LNG Exports from the United States.

Peter

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Before the

UNITED STATES DEPARTMENT OF ENERGY

OFFICE OF FOSSIL ENERGY

2012 LNG Export Study	)))))	Request for Comments

COMMENTS OF THE DOW CHEMICAL COMPANY

January 24, 2013

I. INTRODUCTION

In accordance with the Department of Energy ("DOE"), Office of Fossil Energy's ("OFE") request for comments, The Dow Chemical Company ("Dow") is pleased to present these comments on the NERA Economic Consulting ("NERA") Report *Macroeconomic Impacts of Increased LNG Exports from the United States* (the "NERA Report" or the "Report").[1] OFE has sought comments to help inform the U.S. government's determination of the public interest in connection with requests for authorization to export LNG.

As a threshold matter, it is important to understand that even though the Report finds net economic benefits at the broadest economic level, these gains would be concentrated in the oil and gas industry sectors. All other sectors of the economy would, according to the Report, lose. The Report concludes that "[e]xpansion of LNG

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[1] *2012 LNG Export Study*, 77 Fed. Reg. 73,627 (Dec. 11, 2012).

exports has two major effects on income: it raises energy costs and, in the process, depresses both real wages and the return on capital in all other industries."[2]

While this finding is striking, the NERA Report is, on the whole, inadequate for assessing the macroeconomic impacts of LNG. The Report is fundamentally flawed due to its top-down modeling approach, outdated assumptions and data, and the lack of a robust peer review. Furthermore, the authors failed to account for a variety of important economic issues in their modeling exercise, such as regional or sectoral job losses and gains, the potential for increased gas prices and price volatility, the impacts of tighter environmental regulations on hydraulic fracturing and water disposal, and the likelihood for higher greenhouse gas ("GHG") emissions domestically and from the LNG value chain due to liquefaction, shipping, and regasification. Consequently, the NERA Report is not helpful in determining, and certainly should not be determinative of, the public interest with regard to increased LNG exports. More generally, the Report is not a reasonable basis for U.S. government policymaking or administrative action.

But it is not just the quantification of economic considerations that is inadequate. Even a sound macroeconomic assessment, important though it is, should be but one element of a public interest determination. The Report cannot and does not address, as a policy matter, the gross imbalances in harm and benefits that could inure from significantly higher LNG exports. In addition, as the Deputy Secretary of Energy has observed, a public interest evaluation needs to account for a variety of considerations, from environmental to international to energy security.

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[2] NERA Report at 7.

Despite its failings, the NERA Report has stimulated sufficient public attention and deliberation that OFE could readily obtain the necessary input for appropriate economic modeling through public comments on the general topic of macroeconomic considerations. This could be done in the context of a focused, short term rulemaking.

This is a matter of critical national significance. The importance and complexity of the issue requires a process that will allow for the reasoned consideration of myriad viewpoints on the question of whether additional exports of natural gas are in the public interest. For that reason, we see no adequate procedural alternative to a full administrative proceeding by OFE. Only through that process, including public hearings, can the government establish the appropriate criteria for making the statutorily required public interest determinations for LNG export authorizations.

II. DOW

Dow was founded in Michigan in 1897 and is one of the world's leading manufacturers of chemicals and plastics, supplying more than 5,000 products to customers in 160 countries, including hundreds of specialty chemicals, plastics, agricultural and pharmaceutical raw materials for products essential to life. About 25,000 of Dow's 52,000 employees are in the United States.

Dow is an energy intensive, trade exposed ("EITE") company. It uses energy resources, primarily natural gas and natural gas liquids ("NGL"), for energy and feedstocks to make products essential to the economy and quality of life. Energy is used to drive the chemical reactions necessary to turn feedstocks into useful products, many of which lead to net energy savings and lower carbon footprints.

Dow supports expanded trade and U.S. exports and has a long tradition of playing a constructive role in assisting with U.S. government evaluation of international energy and trade policy matters. Dow believes that with development and implementation of public interest criteria and metrics for LNG export applications, the system can achieve an appropriate balance of national interests. The goal should be to encompass the impact on the nation as a whole, from the American consumer to the various sectors of the economy and, at a minimum, to reflect income effects, job creation and value-added from production and investment.

III. EXECUTIVE SUMMARY

The NERA Report purports to be an assessment of the "potential macroeconomic impact" of LNG exports based on an "energy-economy model." On further scrutiny, two conclusions stand out. First, a variety of flaws in the authors' modeling approach make the NERA Report's findings unsound and incomplete. Second, neither the NERA Report nor any other macroeconomic assessment of LNG exports can address the range of public policy issues that should be considered in deciding the public interest.

NERA Report Is Fundamentally Flawed and Incomplete

Macroeconomic modeling can be used for assessing economy-wide energy and environmental policies, such as GHG policies, that have significant impacts on every sector of the economy. However, for narrower assessments such as LNG exports, the tool can be too blunt if incorrectly applied with outdated assumptions and without proper peer review. This is the case with the NERA Report, which leaves it a profoundly flawed economic analysis. It grossly underestimates gas price increases, price volatility and, in general, economic harm that could result from unchecked LNG exports. Some of the flaws in NERA's approach are summarized below.

Defects in Modeling of Demand

- The NERA modeling approach does not rest on valid projections of U.S. demand for natural gas. It is based on two-year old data (Annual Energy Outlook 2011), which do not account for scores of announced investment projects by energy-intensive industries that will require major volumes of natural gas. At minimum, NERA should have used the most up-to-date statistics, not only from EIA but also other public and subscription sources, and should have given consideration to the scores of industry investment announcements based on a presumption of a continued reasonable gas price.

- The Report fails to account for structural factors that would result in higher domestic gas prices. For example, the Report does not account for the impact of long-term "take or pay" commitments or oil-indexed contracts, which are common in international LNG contracts.

- The Report's underlying economic modeling relies on simplistic and flawed selection of demand elasticities. It uses the same elasticities to evaluate demand among all non-U.S. regions – an approach that cannot comport with reality.

Defects in Modeling of Supply

- The modeling approach does not account for the inability of U.S. supply to keep up with what would be skyrocketing export demand. The Report assumes relatively modest rates of gas production increases. In fact, unprecedented production increases would be required to meet the demand resulting from unchecked LNG exports if domestic natural gas demand were simultaneously to grow at all – which is very likely.

- The modeling approach does not address the possibility of new policy by federal and state agencies that could greatly hinder continued expansion of U.S. natural gas development utilizing hydraulic fracturing.

Defects in Modeling Price Effects

- The Report understates domestic gas price effects and fails to consider how increased LNG exports' true price impact affects industry and consumers.

- The NERA model by itself is incapable of assessing what would most probably be a spike in price volatility as a result of lifting constraints on LNG exports. Natural gas price volatility, and the increased uncertainty inherent in such volatility, would have a wide-ranging, disproportionately adverse effect on development and capital investment among U.S. gas-consuming industries.

Defects in Modeling Industry Impact

- The NERA model represents the industrial sector as an average of five sub-sectors, which mutes the impacts of LNG exports on critical, high employment sub-sectors such as the chemical industry. The chemical industry relies chiefly on natural gas and NGLs for its energy and feedstock needs. In 2011, energy and feedstock represented 42 percent of Dow's costs.

- NERA's modeling approach fails to account for the importance of manufacturing to the U.S. economy and the harm that would result when LNG exports undermine the U.S. manufacturing sector. In particular, the Report fails to adequately address the value added by manufactured goods as compared to the once-through value of natural gas when burned. It also fails to account for the loss of new investments (currently $95 billion announced) and the loss of new jobs (estimated at 5 million).

Other Modeling Defects

- The Report misapprehends the employment and trade-balance implications of higher LNG exports. The United States is enjoying an explosion in exports of energy-intensive manufactured goods, due largely to reasonable natural gas prices. Any reversal of that trend caused by higher natural gas prices would negate the balance-of-payments impact of higher gas exports.

- The Report wrongly assumes that foreign investment is playing and will play a minor role in the expansion of natural gas export infrastructure. In fact, quite the opposite is true.

Failure to Cover Other Relevant Economic Issues

- The NERA Report fails to address a number of important economic questions. NERA's brochure on its model confirms that not all results have been provided as part of its submission to OFE. More granular results on a regional and economic sector basis missing for each scenario include regional and sectoral analysis of:

  - Employment levels in "job-equivalents"
  - Employment income
  - Household income - demand and prices of fuel inputs and electricity
  - Welfare, GDP, investment, consumption, and output
  - GHG emissions.

In a recent letter, the Deputy Secretary of Energy confirmed that the U.S. government needs to evaluate issues like these as it determines whether increased LNG exports are in the public interest.

Dow urges that OFE ensure that the complete set of NERA's model results is released to the public.

Absence of Peer Review

- A peer review process was not completed on the NERA modeling approach and final results. While there is no government-wide rule for when and how to conduct peer reviews, there are established peer review processes within DOE for scientific programs. DOE should have applied a rigorous peer review of the Report as it could have a significant impact on energy policy decisions.

Given these flaws, U.S. officials should not consider basing policy judgments on the NERA Report. And the defects are so far-reaching that, by and large, they cannot be corrected through modeling adjustments.

Economic Modeling Cannot Provide Answers to All Relevant Policy Issues

As the government pursues LNG-export public interest analyses, it should also be borne in mind that neither the NERA Report nor any other economic analysis can be decisive on the range of factors that should bear on decision-making regarding U.S. LNG export policy. These include, for example,

- competitiveness of U.S. industries in international markets in light of, among other things, reciprocity among national policies or the lack thereof
- energy security and the broader national security
- U.S. foreign policy and other international considerations, including consistency with U.S. obligations under international trade rules
- environmental issues that are not susceptible to economic modeling.

Again, the Deputy Secretary of Energy has confirmed that public interest assessments should be broadly inclusive in this way.

By its terms, the NERA Report seeks merely to complete what is essentially an accounting exercise about whether, at the highest level of aggregation, benefits from increased LNG exports outweigh adverse implications. But U.S. policymaking has never been and should not be driven by this type of macroeconomic cost-benefit assessment. If it were, we would simply turn all policymaking over to a committee of economists.

Public interest determinations regarding LNG exports require a thoughtful, holistic assessment of LNG export policy informed by better economic analysis and other input from the broad spectrum of U.S. stakeholders. This will facilitate informed evaluations of implications for the full profile of U.S. values.

IV. COMMENTS

The NERA Report acknowledges that expanding LNG exports would "raise[] energy costs" and "depress[] both real wages and the return on capital in all other industries."[3] The authors contend that benefits to the oil and gas industry and its owners would offset these losses. While this alleged offset is inaccurate, one should not lose sight of what the Report itself is conveying. While the Report's price increase projections are significantly understated, even those understated price increases would have far-reaching negative impacts on the health and competitiveness of U.S. manufacturing and agriculture. The United States is enjoying an explosion in exports of energy-intensive manufactured goods, due largely to reasonable natural gas prices. Deceleration of growth in exports of manufactured goods caused by higher natural gas prices would overwhelm the balance-of-payments impact of higher gas exports.

[3] NERA Report at 7.

Beyond that, and as detailed below:

- The NERA Report's modeling is flawed and overly narrow. The actual modeling is defective in many ways, and it fails to account for a variety of important economic issues that the underlying model can be used to address.
- Neither the NERA Report nor any economic modeling can cover the range of policy issues that need to be evaluated for public interest determinations on LNG exports.

A. The NERA Report Is Fundamentally Flawed and Incomplete

1. Defects in Modeling Demand

a. Using Out-of-Date Data, Report Underestimates U.S. Demand for Natural Gas

The NERA Report bases its analysis on the U.S. Energy Information Administration ("EIA") Annual Energy Outlook from 2011 ("AEO 2011").[4] These two year-old data were not accurate when compiled in 2011, and they do not account at all for presently planned and underway capacity expansions in the manufacturing, transportation and power sectors.

The NERA Report highlights its reliance on these out-of-date statistics:

> NERA's modeling of shifts in natural gas price, production, and demand are built off an attempt to replicate EIA's price path. This was an important step to ensure that the NERA model output was consistent with the EIA's model. Of particular importance was the ability to replicate EIA's natural gas prices as closely as possible since it is a key driver of macroeconomic impacts.[5]

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[4] EIA, *2011 Annual Energy Outlook* (Dec. 16, 2010).

[5] NERA Report at 200.

As a threshold point, it is questionable for NERA to assume the same price path as EIA rather than modeling the price path itself. Moreover, far from strengthening the report, NERA's replication of AEO 2011's price path ensures that its modeling will not be useful and makes any related conclusions inaccurate and unreliable. Since the data omit a recent upsurge in investment, they lead NERA to produce modeling results that significantly underestimate demand for natural gas and hide actual anticipated domestic U.S. price consequences from LNG exports.

Further, since completion of AEO 2011, there has been a manufacturing renaissance with announcements of approximately 100 capital investments in manufacturing representing some $95 billion in new spending and millions of jobs driven largely by the supply and price outlook for natural gas.[6] These investments will add about 5 million new jobs and 6 bcf/d of industrial gas demand by 2020.[7] That is nearly a 30 percent increase in industrial demand relative to 2009, the baseline year for AEO 2011, and is simply unaccounted for in the NERA Report.

NERA, at page 60 of the Report, describes the manufacturing sector as a "modest consumer of natural gas." To the contrary, industry is the largest total natural gas consumer in the United States. Through direct use of natural gas, and indirect use of natural gas through the electric power sector, industry consumes 40 percent of the nation's natural gas.

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[6] See Exhibit 1.

[7] "Rising U.S. Exports–Plus Reshoring–could help create up to 5 million jobs by 2020," *BCG*, Press Release, http://www.bcg.com/media/pressreleasedetails.aspx?id=tcm:12-116389, Sept. 21, 2012 (last visited Jan 14, 2013).

Considering these new investments, as well as economic growth and production increases in all of industry, U.S. industrial gas demand could grow by as much as 11 bcf/d by 2035. This is more than double the demand predicted by the AEO 2011's high EUR case, which itself includes significantly higher demand than the reference case.

Industrial demand is not the only area where the demand data relied upon for the NERA Report are flawed. AEO 2011 sees a very modest level of increased demand for natural gas in transportation, shifting from 0.1 to 0.2 bcf/d over the 2013 – 2020 timeframe. Yet data from Wood Mackenzie, CERA and others indicate a potential increase from 0.2 to 1.5 bcf/d.[8] This is due largely to market-driven increases in fleet vehicles converting to LNG and compressed natural gas to replace other conventional fuels like diesel and gasoline.

With regard to power, AEO 2011 projected a decrease in power sector natural gas demand through the end of the decade. This view does not reflect even today's reality, let alone projections going forward, as more power plants rely on natural gas rather than coal as prices are low, coal regulations are increasing, and older coal plants are facing retirement. Data show a 14 percent increase in power sector demand growth by 2020, ultimately resulting in 24.7 bcf/d of power sector demand.[9] There are three main potential and powerful energy policy drivers in the future demand equation: (1) carbon policy, (2) renewables policy, and (3) nuclear policy. Each of these areas carries with it significant implications for increasing natural gas demand.

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[8] Dow analysis of internal data and proprietary data obtained from Wood Mackenzie and CERA.

[9] Dow analysis of internal data and proprietary data obtained from Wood Mackenzie and CERA.

Such a significant under-recognition of natural gas demand establishes that AEO 2011 is not a credible source for natural gas demand.

b. Report Fails to Account for Structural Factors That Would Increase LNG Exports

The Report assumes that once the gap between U.S. and foreign gas prices (stated on a delivered, apples-to-apples basis) is closed, exports of LNG from the United States will cease. The Report further assumes that if a foreign country gains access to cheaper gas resources – from third country exports, domestic gas projects, or both – the foreign country will cease purchases of U.S.-sourced LNG. These assumptions fail to account for the standard use of long-term (*e.g.*, twenty-year) "take or pay" contracts that inhibit the free flow of price signals in the gas market and lead to shipments beyond the expected margin.

Furthermore, the NERA Report calculates the price received for exports by assuming they will be based on Henry Hub pricing with an added tolling fee plus a 15 percent markup. While this may be true of some contracts, it certainly does not reflect the reality of how most LNG export projects will be structured. A Chevron company executive recently and candidly noted that linking LNG pricing to U.S. benchmark gas prices is not an economical strategy for most export projects.[10] Additionally, subsidized public lending entities would be expected to promote investments in infrastructure to facilitate trade in U.S. LNG.

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[10] "Chevron: Most LNG Prices to Remain Linked to Oil," *The Wall Street Journal*, U.S. Edition, Dec. 5, 2012, *available at* http://online.wsj.com/article/SB10001424127887324640104578160712548841932.html.

c. Report Uses Flawed Demand Elasticities

The Report employs the same demand elasticity for all regions outside of the United States.[11] It is unrealistic to assume that the price elasticity of demand for imported natural gas will be the same in gas-poor countries that rely heavily on gas to meet their domestic energy needs (e.g., Japan and Korea) and gas-rich countries (e.g., Russia and Canada). Gas-poor countries are desperate for imported energy because they either have little-to-no reserves or the reserves they have are not economically supported for development at current and expected gas prices. For example, Japan and Korea consumed 4.53 TCF of LNG or 47 percent of the world's LNG supply in 2010.[12] It is expected that the demand for LNG from Japan and Korea, along with other gas-poor countries will be extremely strong in the future. The chart below shows how much gas Japan and Korea consumed in 2010 as part of their total energy consumption. This chart does not include the increased Japanese gas consumption due to the Fukushima Daiichi nuclear disaster. Moving significantly away from gas in the near-to-medium term would be almost impossible for these countries, suggesting even lower elasticities than what NERA uses.

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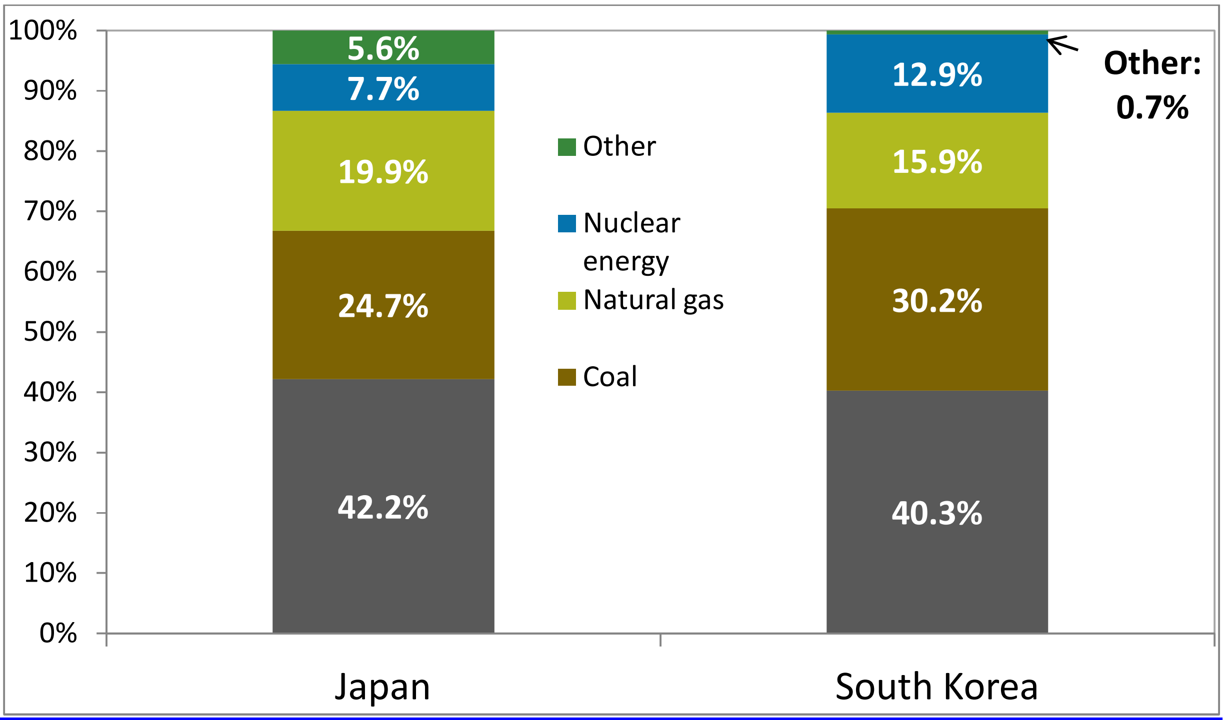
[11] NERA Report at 91.

[12] NERA Report, Figure 10 at 19.

Japan and Korea Energy Consumption by Fuel Type - 2010



Source: World Bank.

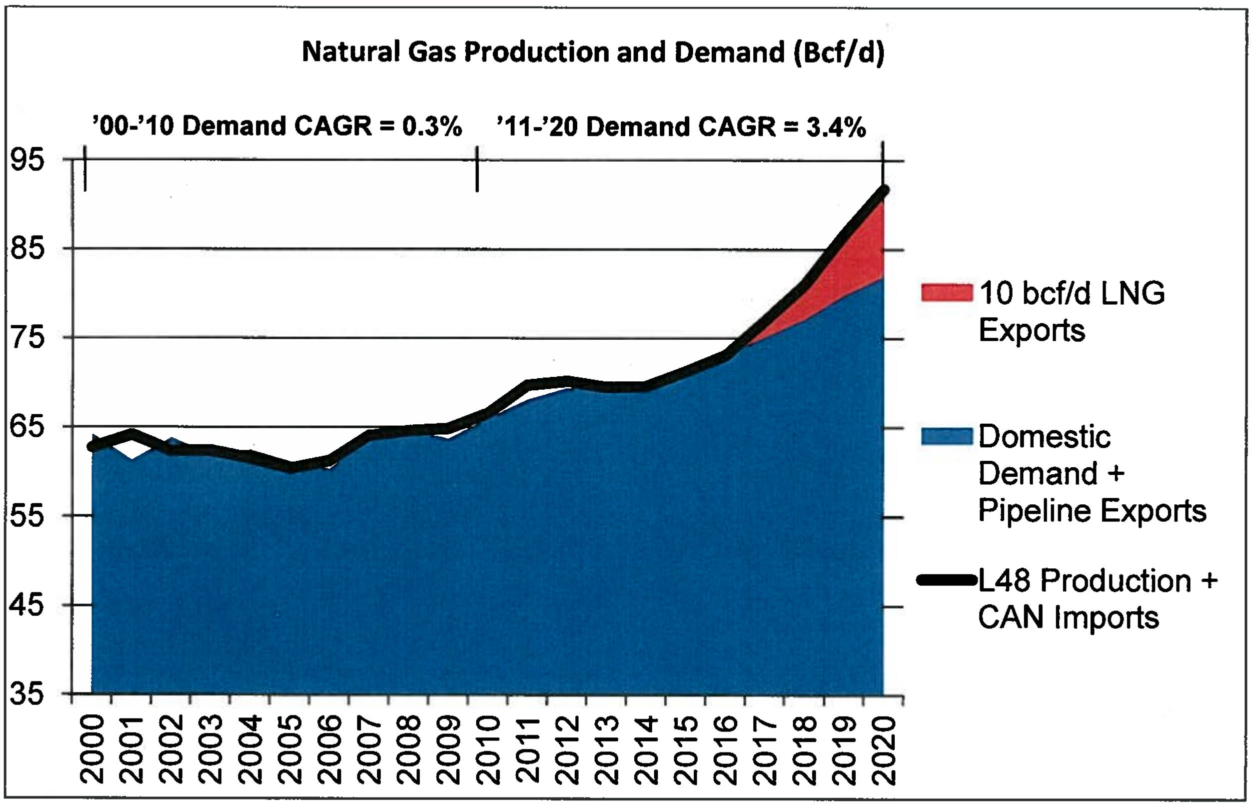
The same may not be true for Russia and Canada, which have extensive domestic reserves of natural gas. Use of the same, flawed demand elasticity for all foreign countries undoubtedly affected the modeling results and almost certainly led to a significant underestimation of demand for exported natural gas moving forward.

2. Defects in Modeling Supply

a. Domestic Gas Production Would Be Unable to Keep Up with Demand Required To Satisfy Unlimited LNG Exports

In stark contrast to its gross underestimation of natural gas demand, NERA tends to have an unduly optimistic and sanguine view regarding future natural gas supply increases. In fact, increasing the supply of natural gas involves lags and uncertainties similar to those on the demand side. Supply will not automatically emerge to meet demand. Critically, one-third of new shale gas production will be required simply to replace the decline in conventional gas production, which clearly exacerbates the supply challenge.

NERA's model indicates that 10 bcf/d in LNG exports would bring about inevitable, major gas price increases. In doing so, the model posits that rising exports will be offset by declining domestic demand for natural gas, such that overall demand for U.S. natural gas will go up by less than exports. It is wholly unrealistic to posit that domestic demand for natural gas is going to decline in the coming years, unless natural gas prices spike upwards. The underlying domestic demand for natural gas likely will increase significantly in the coming years, so higher domestic demand will supplement higher export demand. It is unproven and unlikely that natural gas production can consistently keep up with such increases in demand.



Source: Dow analysis of internal data and proprietary data obtained from Wood Mackenzie and CERA.

An export level of 10 bcf/d by 2020 would require U.S. production to increase to 86 bcf/d by 2020 (a 36 percent increase in production relative to 2011). It is unprecedented for U.S. production to grow by over 20 bcf/d in such a truncated time period. In fact, the last time 20 bcf/d was added it took the oil and gas industry 20 years to do so. Further, the bulk of demand growth will occur in 2017–2020, when production would have to be capable of sustaining an unprecedented growth rate year-to-year.

A level of production growth at that level presents two main problems for the economy. First, given the labor and capital requirements of meeting such an aggressive level of production growth, resources will necessarily be pulled out of the industrial and other sectors. There would need to be rapid deployment of new drilling rigs, increased steel pipe manufacturing and an expanded work force throughout the value chain to be able to service such unprecedented growth in production. With an already well-documented skills shortage in the labor market, basic supply and demand economics will prevail and drive labor prices higher, which would in turn have a chilling impact on investment in the manufacturing sector.

Second, because demand from new industrial projects and LNG facilities would come online in the 2017-2018 time frame, prices would rise dramatically followed by a potential crash due to stalled industrial growth. At this level of production growth in such a short time, it seems very unlikely that the supply response will be high and fast enough to accommodate demand growth without price spikes, particularly given the timing of when industrial projects and LNG facilities will come online. To accommodate these price shocks, the natural gas market will inevitably experience demand destruction to regain balance. That is, industrial demand for natural gas will be destroyed by price spikes. Such destruction of industrial natural gas demand will be felt most significantly in the EITE industries due to their gas price sensitivity, while LNG exports will continue relatively unabated due to the prevalence of long term, high-priced take or pay contracts. Thus, price spikes caused by supply shortages will both drive industry away from natural gas and hurt the profitability of the U.S. industrial base, especially that portion of the industrial base accounted for by EITE industries. Similar supply shortages drove up price levels and price volatility from 2000 through 2009 with the attendant loss of jobs in the industrial sector. In fact, if industry believes this is the likely outcome, then the entire $95 billion in new capital investments will be put at risk of being cancelled or delayed, along with all the attendant job creation. Clearly this will also be felt across the power sector and residential heating where prices will rise dramatically for consumers as oil-indexed global LNG prices drive U.S. domestic gas prices and the domestic manufacturing industry foregoes capital investment and job creation due to demand destruction.

A secondary challenge will also develop, and that is the capacity and locations of pipelines. Even if the natural gas industry can produce the gas at reasonable prices in the quantity desired, pipelines will need to be built to accommodate the new volumes. Such rapid expansion of pipeline infrastructure is hardly a certainty. In 2012, the Midwest Independent Transmission System Operator, Inc. ("MISO") concluded that, even today, 65 percent of the pipelines in the MISO region do not have adequate capacity going forward over the next five-to-six years.[13] The supply of natural gas

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[13] MISO, *Overview for Gas-Electric Infrastructure Workshop: 2011-2030*, MISO Region (Sept. 2012).

underground is one thing, but until the gas is removed from the ground and transported to where it is needed the supply is only theoretical, not actual.

b. Report Does Not Address Supply Security for the United States

The NERA Report does consider a low LNG production scenario. However it does **not** consider significant policy changes that could impact the level of natural gas production even further. For example, tax credits for energy production, which are highly valued by domestic oil and gas producers, continue to be targeted in federal budget negotiations and could expire under some tax reform scenarios. According to Wood Mackenzie, it is estimated that the expiration or elimination of those tax credits could result in a 5 percent decline in natural gas production and the loss of nearly 60,000 bpd of oil production.[14] Thus, tax policy changes behavior and should have been considered in the Report when modeling various scenarios.

In addition, the NERA Report appears to lack full consideration of the implications of future regulation of hydraulic fracturing, the process by which abundant shale gas resources have come into production in recent years. While the NERA Report does recognize the uncertainty of domestic supply, cost and regulation, it chooses the Low Shale EUR case as its low gas production scenario, which assumes lower recovery per well, but not extra cost due to regulation. There are currently a number of relevant regulatory proposals under consideration by several federal agencies, including the Department of the Interior and the Environmental Protection Agency, as well as by various state legislative and regulatory authorities. While effective regulation is

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[14] Wood Macenzie, *Evaluation of Proposed Tax Changes on the U.S. Oil and Gas Industry* 13 (Aug. 2010).

necessary to ensure that the environment will be protected and to assure the public that the natural gas industry adheres to a set of acceptable performance standards, it cannot simply be assumed that additional regulation will not curtail production beyond the levels already considered in the "low production scenario" and result in higher prices.

The prospect of new stringent environmental regulations can threaten future growth in production. Hydraulic fracturing has been used for over 60 years in the oil and natural gas industry. The process employs materials under high pressure to fracture the geologic formations holding in natural gas or crude oil, allowing it to flow to the surface. Without this technology, sources of oil and gas, like shale, would not be possible. Along with the significant success of hydraulic fracturing and the development of new vast sources of natural gas and crude oil has come an onslaught by activist environmental groups intent on curbing or even stopping this activity. In nearly all shale producing areas, activists have protested fracturing technology as allegedly being dangerous to the environment and in particular drinking water. Though most states have not changed policy in response to these groups, there is a continued threat of intervention that could hinder continued development activities.

Efforts of these groups could result in policy changes that substantially impede growth of U.S. natural gas production. Dow believes that hydraulic fracturing has a good overall track record and can be done safely. Dow also believes that the practice requires appropriate regulation to assure safe and environmentally sustainable production.

The nation's energy history is replete with instances where government policy constrained supply while driving up demand. It is more than plausible to believe that this condition could recur. In short, there are many uncertainties on the supply side of the equation.

3. Defects in Modeling Price Effects

a. Report Understates Price Effects and Does Not Convey True Price to Industry and Consumers of Increased LNG Exports

First, the NERA Report provides on page 2 that:

> Natural gas price increases at the time LNG exports could begin range from zero to \$0.33 (2010\$/mcf). The largest price increases that would be observed after 5 more years of potentially growing exports could range from \$0.22 to \$1.11 (2010\$/mcf).

Even if these estimated price increases were reasonably accurate, which is not the case for reasons explained elsewhere in these comments, NERA is indicating that price increases of up to 8 percent would occur immediately, and, after 5 years, percentage increases would range up to 28.1 percent. Dow respectfully submits that an average wellhead price increase of 28.1 percent or \$1.11/mcf would likely result in lost manufacturing jobs and cause significant damage to the U.S. economy.

Second, the NERA Report underestimates the impact of unconstrained LNG exports that would further increase costs to consumers:

> As seen in Figure 6, in no case does the U.S. wellhead price increase by more than \$1.09/mcf <u>**due to market-determined levels of exports**</u>. Even in cases in which no limits were placed on exports, <u>**competition between the US and competing suppliers of LNG exports and buyer resistance limits increases in both U.S. LNG exports and U.S. natural gas prices**</u>. (Emphasis added.)[15]

NERA's assertion that prices will never increase by more than \$1.11/mcf is founded on the proposition that natural gas exports – even unconstrained exports – will never rise

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[15] NERA Report at 10-11.

higher than 6.72 tcf/year or roughly 18.5 bcf/day by 2025. However, as of January 11, 2013 the U.S. government had already approved approximately 28 bcf/day in natural gas exports to FTA countries[16] and is considering authorizing far higher volumes of exports. NERA fails to consider what would happen if natural gas exports reached levels at or near the authorized levels under a "no constraint" scenario. If exports were to reach such levels, then domestic natural gas prices undoubtedly would spike upwards, and any valid economic model would demonstrate as much.

Third, the NERA Report observes at page 2 that:

> U.S. natural gas prices increase when the U.S. exports LNG. But the global market limits how high U.S. natural gas prices can rise under pressure of LNG exports because importers will not purchase U.S. exports if U.S. wellhead price rises above the cost of competing supplies.

While this arbitrage phenomenon makes general sense in most competitive markets, it does not make much sense in the global LNG market given the likely broad use of long-term "take-or-pay" contracts in that market. At no point in the NERA Report is this alleged effect illustrated in context with the other substantial cost and pricing data presented.

The NERA Report notes at page 12 that:

> In none of the scenarios analyzed in this study do U.S. wellhead prices become linked to oil prices in the sense of rising to oil price parity, even if the U.S. is exporting to regions where natural gas prices are linked to oil. The reason is that costs of liquefaction, transportation, and regasification keep U.S. prices well below those in importing regions.

NERA posits that natural gas prices will never reach parity with crude oil prices. That may or may not be true. However, even if that is true, it certainly does not mean that

[16] Department of Energy, *Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower 48 States*. http://www.fossil.energy.gov/programs/gasregulation/index.html

natural gas prices could not rise markedly as a result of LNG exports. To the contrary, the current gap between the domestic LNG price and the crude oil price is so large that gas prices could rise tremendously without reaching parity.

As indicated in the table below, even if NERA is correct about crude parity, the price netback from Japan-Korea could prompt natural gas prices to double as a result of unconstrained exports of LNG.

Analysis of LNG Netback to U.S. from Various Markets – 2015
(US$ per mmbtu)

	A	B	C = A - B	D	E = C/D
	Market Price	LNG Costs Adders[17]	Net Back	U.S. Wellhead	Wellhead Premium
Europe	10.97	6.3	4.67	3.83	122%
China-India	14.36	8.39	5.97	3.83	156%
Japan-Korea	15.8	7.14	8.66	3.83	226%

Source: NERA Report.

Thus, based on the high netback values, it seems clear that there is a very strong economic incentive for U.S. exports to these mostly non-FTA markets, and so long as U.S. exporters can achieve these results and DOE authorizations, U.S. gas will flow out of U.S. markets and U.S. domestic gas prices will spike upwards. Moreover, given that many of these contracts will involve non-U.S. parties, profits are likely to flow outside of the U.S. tax base as well.

[17] These adders include very significant regasification and pipeline from regasification to city gate costs, ranging from $1.40 to 2.38 per mmbtu. If the exported LNG is priced as delivered to the import terminal, the margins, and economic incentives could be even higher than shown here.

<u>In short, there is no basis to conclude that U.S. LNG exports will be severely constrained by competition among suppliers or buyer resistance. To the contrary, the economic realities are that U.S. LNG exporters have sufficient cost headroom to make significant profits even with higher U.S. domestic gas prices, likely even moving domestic U.S. gas prices much closer to world oil-indexed levels.</u>

There is also evidence of large, non-U.S. gas exporters attempting to create a cartel to further control natural gas exports and pricing, the consequences of which are also not anticipated or modeled by NERA but could have the same effect of dramatically raising U.S. natural gas prices.[18] That is, as the supply of LNG in the world export market is constrained by a cartel, demand for U.S. LNG would spike even higher than would otherwise be the case, leading to even higher volumes of U.S. exports and even greater increases in U.S. natural gas prices.

b. Report Disregards Exacerbated Gas Price Volatility

The NERA Report disregards injurious gas-price volatility that would result from unlimited LNG exports. According to NERA, the model it used "is a model of long run economic growth such that in any given year, prices, employment, or economic activity might fluctuate above or below projected levels."[19]

Apart from sustained higher prices, erratic pricing of inputs results in uncertainty, suspended investment plans and, ultimately, diminished growth and reduced employment among industries that rely on those inputs. History shows that high

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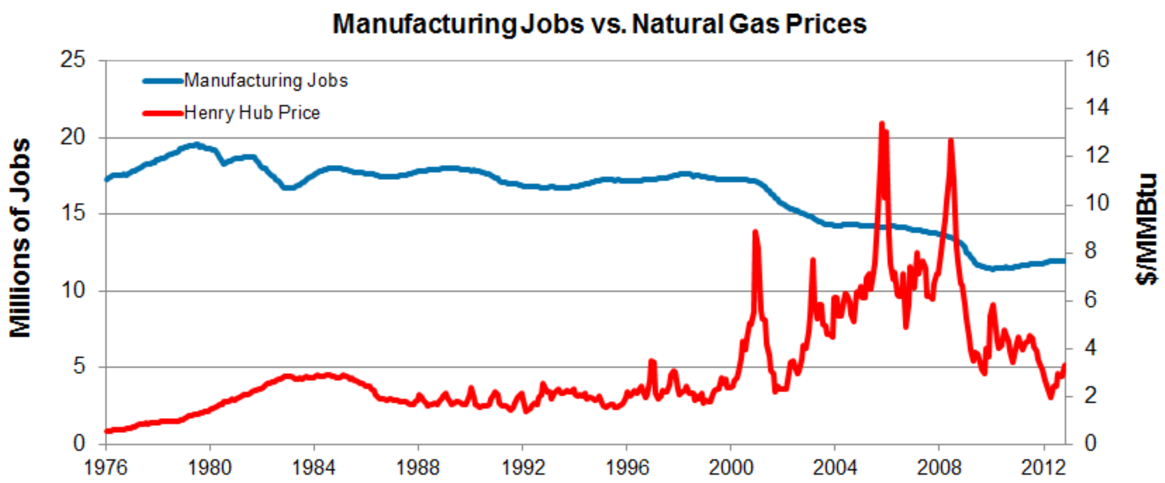
[18] "Natural gas exporting group seeks coordination over pricing," *Bloomberg*, Dec. 22, 2012, *available at* http://www.bloomberg.com/news/2012-12-22/natural-gas-exporting-group-seeks-coordination-over-pricing.html.

[19] NERA Report at 5.

volatility in U.S. natural gas prices can impact employment in manufacturing. Since 2000, higher gas prices and high volatility coincided with an industrial gas demand decrease of 24 percent or 5.4 bcf/d. This resulted in a loss of approximately 6 million U.S. manufacturing jobs from 2000-2009, or roughly one third of all manufacturing jobs. However, since January 2010 the manufacturing sector has added over 500,000 jobs. Billions of dollars worth of newly announced investments spurred by lower gas prices are expected to create millions more new jobs.



Source: Energy Information Administration; Bureau of Labor Statistics.

Looking forward, large increases in gas demand from LNG exports will tighten the U.S. supply-demand balance significantly. In natural gas markets, as in other energy commodity markets, periods of tight supply-demand balance are typically correlated with high price volatility. Higher volatility in natural gas prices is detrimental to both industrial and residential consumers, and these risks cannot be completely hedged away without costs.

In addition, price volatility is frequently driven by expectations rather than current reality. And expectations of increased demand often outpace expectations of increased supply since supply takes years to come online. Gas traders routinely count increased demand as soon as the contracts are signed, even though the contracts may run for years and the actual level of demand will not increase significantly until several years down the line. That is, expectations run far ahead of reality on the demand side. In contrast, traders and other market participants recognize that it will take years for new production and pipelines to come online and supply to increase. So, on the supply side, expectations and reality are more closely aligned. These dynamics exacerbate price volatility during inflection periods (i.e. periods of market change).

The NERA Report is acutely skeptical about demand increases (other than from exports) and profoundly optimistic about new supply (which seems to appear exactly when needed and in sufficient quantities and at low prices). Over the past decade when the natural gas market was in short supply market participants expected that the United States would need, at the margin, to buy LNG. The anticipated need for substantial import volumes drove the natural gas price up markedly. NERA ignores the impact of such a shortage mentality and the consequent price volatility. Natural gas volatility and attendant uncertainty would result in suspension or cancellation of major portions of the $95 billion in new capital investment by energy-intensive industries.[20]

Recent history has exhibited a "boom and bust" cycle of gas price volatility and similarly volatile LNG industry expansion and contraction. Generally, from 1990 to 2000, natural gas prices were low and not particularly volatile. Then, in the 2000 – 2009 period, as supply could not keep pace with demand there were ever increasing and highly volatile gas prices with feverish interest in importing LNG to address the supply-demand

[20] See, e.g., BIAC, *Thought Starter on Price Volatility in Energy Markets* (Jan. 2012).

imbalance. From 2009 to the present, with the supply influx of gas from shale, prices have been lower with less volatility, and a feverish rush to export LNG has arisen. The NERA Report would buttress and facilitate this rush to export by significantly underestimating domestic gas demand, finding abundant gas supplies from wherever, and simply missing the clear potential for one more "boom and bust" cycle of higher and more volatile domestic gas prices driven by oil-indexed global LNG pricing and domestic industrial demand destruction with seriously problematic employment and adverse domestic price consequences for residential heating and electricity consumers.

4. Defects in Modeling Industry Impact

a. Model Lacks Granularity and Fails to Address Industry-Specific Impacts

As evidenced by Figure 74 of the NERA Report, the Report aggregated sectors and did not perform industry-specific, granular analysis. Accordingly, NERA's results are not industry-specific and fail to take account of volatilities and hardships experienced on an industry-specific level, some of which may be pronounced. It is unrealistic to posit, as NERA does, that the impact of expanded natural gas exports will be the same within the chemical, paper and plastic industries, respectively.

NERA used its proprietary energy-economy model for its study. The model is a computable general equilibrium ("CGE") model that represents the economy through twelve sectors – eleven aggregated sectors and the electric sector, which is a detailed, bottom-up representation with considerable detail. The energy intensive sector ("EIS") is one of the eleven aggregated sectors, which includes the following five industries according to NERA's classification:

- Chemical manufacturing

- Paper and pulp manufacturing
- Glass manufacturing
- Cement manufacturing
- Primary metal manufacturing[21]

The NERA modeling approach is to bundle these five sectors into one sector and assume that average behavior is representative of all five industries. NERA mislabels Chemical manufacturing as NAICS code 326. NAICS code 326 actually refers to “Plastic and Rubber Products” while NAICS code 325 refers to “Chemical Products”. It is possible that NERA forgot to include chemical products in its EIS sector aggregation. If so, this would be another example of a fundamental flaw in NERA’s analysis that would further undermine its impact analysis of LNG exports on the chemical manufacturing industry.

By bundling these industries, NERA applies the same labor, capital, fuel, and other material inputs in the same way across industries. Such an aggregation mutes the true impact to the industries, especially the chemical products industry. The chemical products subsector varies significantly from the other four industries in terms of value added to the economy (GDP) and energy consumption by fuel source:

[21] NERA Report at 64.

Bureau of Economic Analysis Industry	2011 Value Added ($ Billion)	2011 Employment	Total Energy Consumption (Millions of Barrels of Oil Equivalent)				
			Natural Gas	LPG and NGL	Net Electricity	Coal	Other
Chemical products	253	785,000	10,130	13,360	3,000	1,060	2,320
Fabricated metal products	122	1,347,000	1,390	30	830	0	50
Plastics and rubber products	69	635,000	740	30	1,060	N/A	130
Paper products	53	388,000	2,750	30	1,430	1,280	8,160
Nonmetallic mineral products[22]	33	364,000	2,670	30	850	1,860	1,060

Source: Bureau of Economic Analysis, *Value Added by Industry, Gross Output by Industry, Intermediate Inputs by Industry, the Components of Value Added by Industry, and Employment by Industry 2011*; EIA 2006 *Manufacturing Energy Consumption Survey (*(2010 Survey Results Not Yet Available), rounded to the nearest 10).

In addition, the chemical manufacturing industry is composed of dozens of different business models with varying inputs and outputs. These outputs have different price points and thus different value added to the economy. Shoe horning the chemical industry into an aggregated EIS is not appropriate for studying the impact of LNG exports on the economy.

b. Report Fails to Account for Importance of Manufacturing and Harm to Manufacturing If LNG Exports Increase Domestic Natural Gas Prices

The NERA Report demonstrates virtually no understanding of industrial gas usage in a competitive cost environment and inexplicably fails to address at all the value added by manufactured goods versus the once-through value of natural gas when burned. The negative impacts of unreasonable levels of LNG exports on the manufacturing sector,

[22] Includes glass and cement manufacturing.

and by extension, the U.S. economy, are far worse than the Report anticipates. Using gas to make value-added products creates greater benefits, including ripple effects, for the U.S. economy than simply exporting raw BTUs. Moreover, the Report's analysis of global LNG pricing grossly underestimates U.S. incentives for LNG exports.

The Report reaches the misguided conclusion that there is little evidence that EITE industries are high value-added industries. The Report's reliance on this inaccurate understanding is another factor that independently undermines its credibility. NERA defines high value added industries to be those with high ratios of wages and profits to revenues.[23] In 2011, the chemical industry and the plastic and rubber industry both had higher value added ratios (i.e. higher ratios of wages and profits to revenues) than did manufacturing as a whole.[24] In addition, in 2011 the chemical industry had 46 percent more value added than did the oil and gas industry. Accordingly, NERA is incorrect to posit that EITE industries are not high value added industries.

The chemical industry alone is indicative. Industries accounting for more than 96 percent of all manufactured output utilize chemical industry products.[25] Unfortunately, it appears that the NERA model fails to account for how natural gas pricing impacts the wider economy, given that the Report states on page 70 that "it was not possible to model impacts on each of the potentially affected sectors."

Additionally, the NERA Report leans heavily on a study by a 2007 Interagency Task Force convened during the Waxman-Markey legislative debate to classify EITE

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[23] NERA Report at 68-69.

[24] Bureau of Economic Analysis, *Gross Domestic Product by Industry Data*, http://www.bea.gov/industry/gdpbyind_data.htm (last visited January 15, 2013).

[25] Bureau of Economic Analysis, *Benchmark Input-Output Data, 2002 Standard Mark and Use Data at the Sector Level*, http://www.bea.gov/industry/io_benchmark.htm (lasted visited January 16, 2013).

industries. The NERA Report uses this study to define a slice of the economy that will be negatively impacted by LNG exports, which equated to 780,000 workers as of 2009. More importantly, the findings of the Task Force also led Congress to conclude that it was unacceptable to raise energy prices on energy intensive manufacturers because of the adverse employment implications across the economy. While the NERA Report borrows heavily from those parts of the Waxman-Markey congressional debate that could support LNG exports, predictions of adverse employment impacts from the congressional process are absent from the Report.

Both the current NERA model and report overstate the positive economic outcomes for the U.S. economy while dramatically underestimating the negative outcomes, leading to a flawed risk/benefit outcome and related conclusions.

5. Other Modeling Defects

a. Report Understates Employment and Trade Balance Impact of Higher Natural Gas Exports

The economic model employed by NERA assumes full employment and full labor fungibility/mobility across sectors.[26] These assumptions are unrealistic, especially given the current state of the U.S. economy. NERA necessarily understates the economic dislocations and unemployment associated with increased natural gas exports.

EITE industries that will be significantly harmed by the higher natural gas prices associated with increased natural gas exports employ far more people than does the oil and gas industry, which is likely to benefit from such exports. In 2011, total employment in the oil and gas industry was 171,000, while the chemical industry employed 785,000

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[26] NERA Study at 110.

people, the plastic and rubber industry employed 635,000 people and the paper industry employed 388,000 people.[27]

In addition, NERA ignores the impact on the overall U.S. trade balance associated with the increase in natural gas exports it models. NERA estimates that natural gas exports will bring in up to $25 billion in additional U.S. export revenue by 2020.[28] Insofar as increased natural gas prices will adversely impact the international competitiveness of not only EITE industries but also the rest of the industrial and agricultural sectors, the overall level of exports outside of the natural gas sector is likely to drop. Even a modest percentage drop in those exports would overwhelm any increase in natural gas exports. Indeed, given that total U.S. exports outside of the oil and gas sector are in excess of a trillion dollars a year, it is quite plausible that the loss in exports by the agricultural and industrial sectors as a result of increased natural gas exports would be well in excess of $30 billion by 2020. Accordingly, recent improvements in the U.S. trade balance and desired future improvements in that balance would be significantly undercut by a pronounced increase in natural gas exports.

The United States is enjoying an explosion in exports of energy-intensive manufactured goods, due largely to reasonable natural gas prices.

As indicated in the chart below, the U.S. trade surplus in Basic Chemicals has grown from roughly $15 billion to roughly $35 billion as natural gas prices have dropped.

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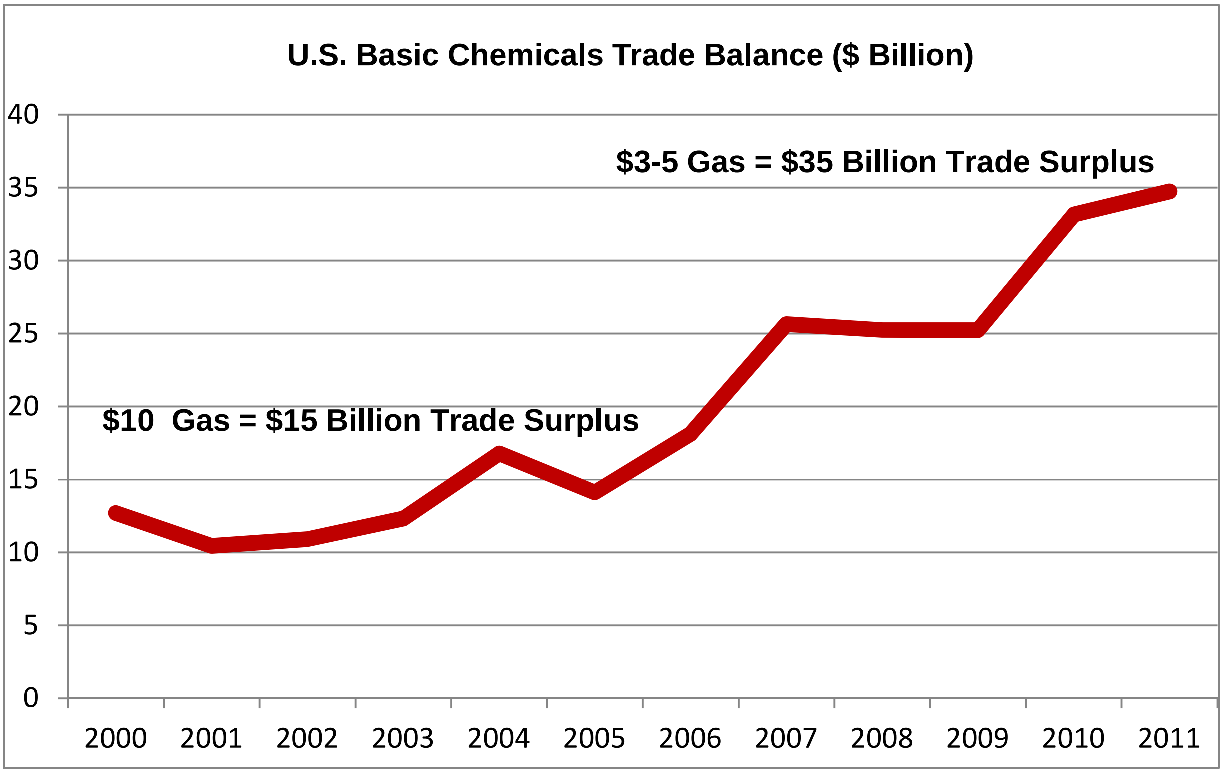
[27] Bureau of Economic Analysis, *Gross Domestic Product by Industry* Data, http://www.bea.gov/industry/gdpbyind_data.htm (last visited Jan. 15, 2013).

[28] NERA Report at 179 to 199.



Source: American Chemistry Council, Guide to the Business of Chemistry – 2012.

In addition, if a significant portion of the $95 billion in capital investment by EITE industries discussed above were delayed or cancelled as a result of increased natural gas prices and price volatility, there would be a larger negative effect on exports from value-added manufacturing industries.

b. Report Wrongly Assumes that Foreign Direct Investment Will Not Play a Major Role in Expansion of Natural Gas Export Infrastructure

The NERA Report assumes that all investment in natural gas production as well as liquefaction facilities will come strictly from U.S. entities, and it notes at page 211 that "macroeconomic effects could be different if these facilities and activities were financed by foreign direct investment." However, a number of foreign entities are already investing in natural gas production today, particularly on the gas exploration side.[29] China's CNOOC, France's Total, and Australia's BHP are just a few examples of foreign companies taking multi-billion dollar stakes in U.S. shale plays.[30] Thus, NERA's assumption of limited foreign direct investment is incorrect and, by NERA's own admission, renders the results of the Report flawed. Moreover, large investments in U.S. LNG export infrastructure by foreign interests will take profits outside the United States.

Furthermore, foreign direct investment in the natural gas sector by certain Asian countries (China in particular) may well be strategic, and could evidence an attempt to lock up supplies of natural gas for those energy-starved Asian markets.[31] Such strategic investments could result in exports that are not tied to microeconomic considerations of the sort referenced by NERA, but rather to strategic economic considerations tied to the well-being of the foreign investor's home market.

Finally, in addition to losing the tax base that would have come from additional manufacturing and value add in the United States, large overseas investments in U.S. LNG exports from companies and import/export banks will take profits outside the United States, further shifting the risk/reward balance against LNG exports **if** they came at the expense of domestic manufacturing.

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[29] See Exhibit 2

[30] See Exhibit 2.

[31] See, e.g., *China's Global Quest for Resources and Implications for the United States*, Testimony of Dr. Mikkal Herberg (Research Director, Asian Energy Security Program The National Bureau of Asian Research) before the U.S.-China Economic and Security Review Commission (Jan. 26, 2012); Stanley Reed, "Chinese Oil Executive learning from Experience," *The New York Times* Nov. 12, 2012, *available at* http://www.nytimes.com/2012/11/13/business/global/chinese-oil-executive-learning-from-experience.html.

c. Model Benefits are Concentrated and Overstated

Natural gas impacts the entire economy, from electricity to vehicles to consumer products, and lower natural gas prices have already had a positive impact on the U.S. economy. From lower costs for raw materials and feedstocks for manufacturers to reduced energy bills for consumers, abundant, affordable natural gas has been a critical factor in the economic recovery that is underway. Unfortunately, the NERA Report's conclusions raise a number of concerns related specifically to the impacts of LNG exports across the whole of the economy and on consumers.

To quote from page 7 of the Report:

> Expansion of LNG exports has two major effects on income: it raises energy costs and, in the process, depresses both real wages and the return on capital in all other industries, but it also creates two additional sources of income. First, additional income comes in the form of higher export revenues and wealth transfers from incremental LNG exports at higher prices paid by overseas purchasers. Second, U.S. households also benefit from higher natural gas resource income or rents.

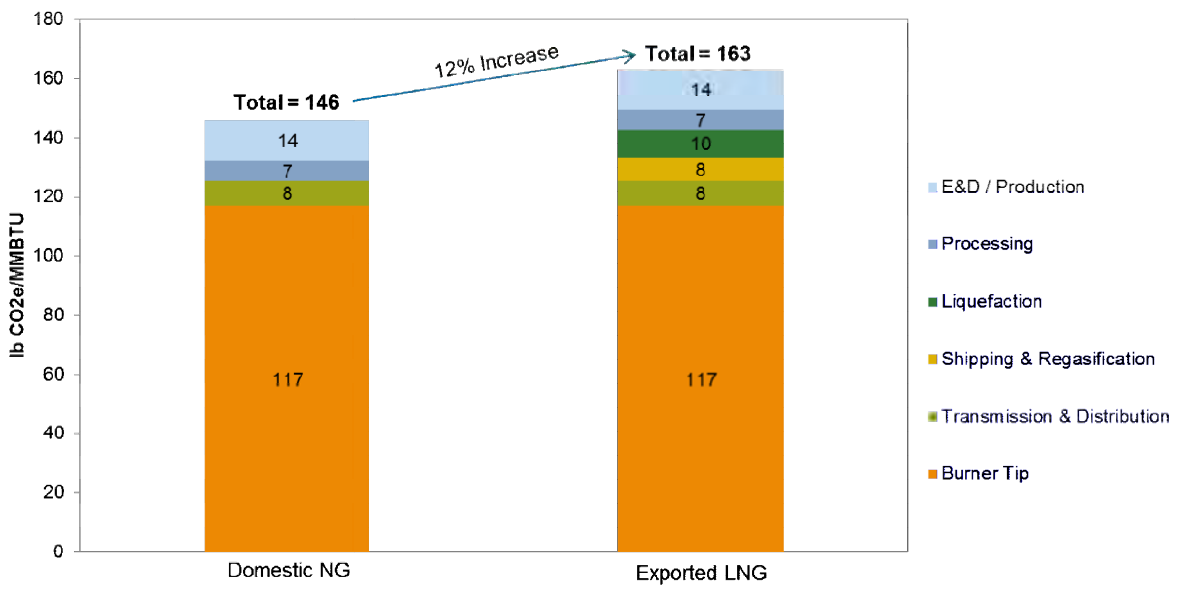
More specifically, in terms of the beneficiaries under each export scenario, the NERA Report provides that income from LNG exports will inure to companies involved in natural gas production and LNG operations, that consumers will benefit as their wealth increases through stock ownership and increases in retirement wealth (*e.g.*, pensions) as those companies increase in value, and that these incomes will offset the higher costs associated with higher energy prices. Unfortunately, this wealth increase is not even predicted to be broad-based. It would be concentrated among those few who own stock in or work for gas production and LNG companies, while the broader population would be negatively impacted by higher energy costs. Indeed, Figure 4 at page 9 of the NERA Report specifies that, excepting gas and to some very limited extent oil, **<u>all other</u>**

industries will see real wages and investments decline. Indeed, the NERA Report's section heading "Some Groups and Industries Will Experience Negative Effects of LNG Exports" is affirmatively misleading, as the NERA Report's own results indicate that virtually all groups and industries will experience harm as a result of increased LNG exports.

Figures 144 through 155 of the NERA Report provide the detailed modeling results found by NERA. Those figures indicate that increased natural gas exports would result in lower total demand for natural gas within the United States, and lower demand for natural gas in every sector of the United States. In agriculture and industry, such decreased demand for natural gas could occur for one or both of two reasons: the usage of natural gas per unit of production within each sector declines and the total production within each sector declines. NERA provides no evidence that increased exports of natural gas would reduce the natural gas intensity of the U.S. economy – i.e., the amount of natural gas needed to produce a unit of output – and there is no independent reason to believe that this would be the case. Moreover, if such a decline in natural gas intensity resulted from a shift to more use of coal, then there would be severe implications for the carbon intensity and CO_2 emissions of U.S. production. Moreover, the life-cycle emissions of LNG exports sent from the United States across the world are higher than domestically consumed gas (see Figure below), so claims that such exports would lower worldwide CO_2 emissions may not be true.

Indeed, U.S. GHG emissions likely will rise if LNG exports spike because higher prices for U.S. natural gas will lessen fuel switching from coal to natural gas in the power sector, thereby increasing GHG emissions above the level that would otherwise occur.

Life-Cycle Emissions Comparison of Domestic Natural Gas vs. LNG Combusted



Source: ICF International; Charles River Associates.

As to consumers, on page 8 the NERA Report provides that "households with income solely from wages or transfers, in particular, will not participate in these benefits." In other words, benefits will be quite regressive as higher prices of natural gas will raise energy bills which will disproportionally and negatively impact lower-income households and those supported by "wage earners," which is most of the population. A 2012 study found that lower-income households, which represent close to a quarter of all U.S. households, pay over 20 percent of their after-tax income for energy.[32] More than half of the homes in the United States use natural gas for heating, and many states in the Northeast are continuing to switch from fuel oil to natural gas for home heating, not to

[32] American Coalition for Clean Coal Electricity, *Energy Cost Impacts on American Families 2001-2012* (Feb. 2012).

mention that seniors on fixed-incomes are particularly vulnerable to energy price increases and that electric price increases caused by higher natural gas fuel costs affect everyone. In addition, natural gas provides roughly 30 percent of the electricity generated and used in this country.[33]

Natural gas is also a major household expenditure, primarily for home heating. To put the impact of LNG export-driven price increases in further perspective, we examined the additional natural gas costs that households would face under one of NERA's unchecked export scenarios.[34] As the figure below indicates, we found a wide disparity in costs on a state-by-state basis. For example, New York, New Jersey, and Upper Michigan residents would pay $800 more per year in 2025, while residents of Tennessee, Kentucky, South Carolina, and Florida would experience less than a $300 per year increase in their annual natural gas bills in 2025. These figures do not reflect higher costs of electric heating that would result from higher gas prices in an unchecked LNG export scenario. As more and more Americans switch from more expensive fuel oil to low-cost gas for home heating, unchecked LNG exports would result in something of a bait and switch, locking many Americans into higher-than-expected utility bills far into the future.

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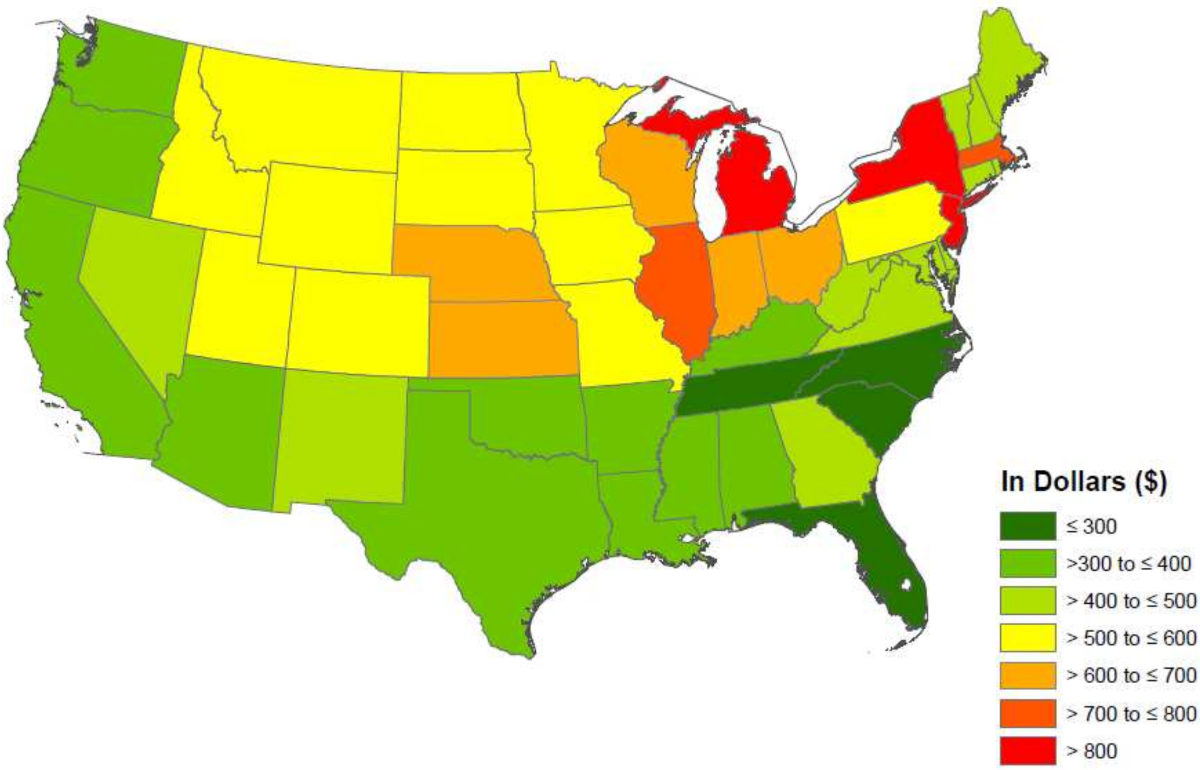
[33] EIA, *Electric Power Monthly*, Data for Oct. 2012, released Dec. 21, 2012, http://www.eia.gov/electicity/month/epm_table?grapher.cfm?t=epmt_1_01 (last visited Jan. 21, 2013).

[34] USREF_SD_NC scenario, which stands for reference case gas prices with an international supply/demand shock and unconstrained LNG exports.

Increased Household Natural Spending in 2025 by State in an Unconstrained Export Scenario[35]



Further, while the Report acknowledges that EITE industries will be harmed by LNG exports, it is not at all clear that the planned capital investments associated with building LNG capacity will be offset by the capital that will not be invested by manufacturers if natural gas prices rise again to unaffordable levels. Given the $95 billion of investments predicated on affordable natural gas that has been announced to date, analysis is

[35] Costs were calculated by taking the 2025 price differential between NERA's USREF_SD_NC scenario and its Reference Gas Price Scenario and multiplying by the state-level gas consumption from EIA's 2009 Residential Energy Consumption Survey.

needed of the opportunity cost related to employment and GDP if these investments do not go forward due to increased costs.

6. Failure to Cover Relevant Economic Issues

The NERA Report fails to address a number of important economic questions. NERA's on-line brochure regarding its model indicates that not all results have been provided as part of its submission to OFE.[36] More granular results on a national, regional and economic sector basis were not included, such as those for:

- Employment levels in "job-equivalents"
- Employment income
- Household income
- Demand and prices of fuel inputs and electricity
- Welfare, GDP, investment, consumption and output
- GHG emissions.

For a report that could have an enormous bearing on national policy, it is critical for all commenters to have the full set of modeling results for review. This would enable an open and transparent debate on the NERA modeling approach and analysis and possibly all future analyses that may arise. A fuller set of results would provide insights into the economic winners and losers of increased or unconstrained LNG exports on the American economy from a state, regional, household, and economic sector perspective. Dow urges that OFE ensure that the complete set of NERA's model results is released to the public.

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[36] NERA, *The NewERA Model At A Glance*, http://www.nera.com/67_7607.htm (last visited Jan. 21, 2013).

7. Peer Review

The NERA Report was not peer reviewed. A peer review, where independent reviewers use specified evaluation criteria, may have caught a number of the flaws in the modeling approach selected and implemented. Peer reviews are a common process within both the U.S. government broadly[37] and DOE in particular.[38] OFE, which handles science-related matters, should have applied the peer review process to the NERA economic analysis given the weight that such a study could have on national policy decisions.

B. <u>Economic Modeling Cannot Provide Answers to All Relevant Policy Issues</u>

As the government pursues LNG-export public interest analyses, it should also be borne in mind that neither the NERA Report nor any other economic analysis can be decisive on the range of issues that should bear on decision-making regarding U.S. LNG export policy. Policy considerations and the public interest extend far beyond macroeconomics. Much more input, analysis and judgment is needed to come to grips

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[37] The federal standard for peer review is set by the Office of Management and Budget's ("OMB") *Final Information Quality Bulletin for Peer Review*, published in 2004. That OMB Bulletin requires that certain information disseminated by federal agencies adhere to quality standards for peer review. The NERA Report should be considered "highly influential scientific information" subject to the highest standards outlined in the OMB Bulletin. http://www.whitehouse.gov/sites/default/files/omb/memoranda/fy2005/m05-03.pdf

[38] DOE has rigorous peer review and annual merit review ("AMR") process established for scientific programs. Examples of such peer review processes within DOE include the 2012 DOE Energy Storage Program Peer Review and Update Meeting (Sep. 2012), the Geothermal Technologies Program Peer Review Meeting (May 2012), the Hydrogen & Fuel Cells Program AMR (scheduled May 2013) and the Vehicle Technologies Program AMR (scheduled June 2014). *The Department of Energy's Peer Review Practices*, U.S. Department of Energy Office of Inspector General Office of Audit Services, Apr. 2008, at 1.

with all of the public policy and public interest considerations that bear upon LNG exports.

In a recent letter, the Deputy Secretary of Energy confirmed that the U.S. government intends to evaluate an expansive, comprehensive set of factors as it determines whether authorized LNG exports are in the public interest. In short, the government plans to examine any factor that bears on the public interest. In keeping with Deputy Secretary Poneman's letter, examples of factors for examination should include:

- competitiveness of U.S. industries in international markets in light of, among other things, reciprocity among national policies or the lack thereof
- energy security and the broader national security
- U.S. foreign policy and other international considerations, including consistency with U.S. obligations under international trade rules
- environmental issues that are not susceptible to economic modeling.

That factors like these do not necessarily lend themselves to economic or quantitative assessments does not mean that they should not play a role in public interest determinations.

By its terms, the NERA Report seeks merely to complete what is essentially an accounting exercise about whether, at the highest level of aggregation, benefits from increased LNG exports outweigh adverse implications. Even if aggregate benefits outweighed aggregate costs, this would still be only one of many considerations for a public interest assessment.

In this regard, U.S. policymaking has never been and should not be driven by this type of macroeconomic cost-benefit assessment. If it were, we would simply turn all policymaking over to a committee of economists.

Public interest determinations regarding LNG exports require a thoughtful, holistic assessment of LNG export policy informed by better economic analysis and other input from the broad spectrum of U.S. stakeholders. This will facilitate informed evaluations of implications for the full profile of U.S. values.

V. CONCLUSION

As shown above, the NERA Report is inadequate to serve as a basis for macroeconomic analysis needed for LNG export public interest determinations. At the same time, the NERA Report has stimulated sufficient public attention and deliberation that OFE could readily obtain the necessary input for appropriate economic modeling through public comments on the general topic of macroeconomic considerations. This could be done in the context of a focused, short term rulemaking.

This is a matter of critical national significance. The importance and complexity of the issue requires a process that will allow for the reasoned consideration of myriad viewpoints on the question of whether additional exports of natural gas are in the public interest. For that reason, we see no adequate procedural alternative to a full administrative proceeding by OFE. Only through that process, including public hearings, can the government establish the appropriate criteria for making the statutorily required public interest determinations for LNG export authorizations.

Dow supports expanded trade and U.S. exports and has a long tradition of playing a constructive role in assisting with U.S. government evaluation of international energy and trade policy matters. Dow believes that with development and implementation of public interest criteria and metrics for LNG export applications, the system can achieve an appropriate balance of national interests. The goal should be to encompass the impact on the nation as a whole, from the American consumer to the various sectors of the economy and, at a minimum, to reflect income effects, job creation and value-added from production and investment.

Respectfully Submitted,

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Dated: 24 January 2012

Exhibit 1

Industry to Invest $95 Billion In Manufacturing Renaissance

Total Industrial natural gas demand expected to grow by over 11bcf/day by 2035.
Newly announced investments below to exceed 6bcf/day.

Chemicals and Fertilizer

	Company	Location	Date Online	Project Type
1	Dow	St. Charles, LA	2012	Ethylene Restart
2	Dow	Freeport, TX	2017	New Ethylene
3	Westlake	Lake Charles, LA	2012	Ethylene Expansion
4	Williams Olefins	Geismar, LA	2013	Ethylene Expansion
5	INEOS	Chocolate Bayou, TX	2013	Ethylene Debottleneck
6	LyondellBasell	Laporte, TX	2014	Ethylene Expansion
7	Westlake	Lake Charles, LA	2014	Ethylene Expansion
8	Aither Chemicals	WV or PA or OH	2016	New Ethylene
9	Exxon Mobil	Baytown, TX	2016	New Ethylene
10	Chevron Phillips	Baytown, TX	2017	New Ethylene
11	Formosa	Point Comfort, TX	2017	New Ethylene
12	Braskem	WV	2017	New Ethylene
13	Sasol	Lake Charles, LA	2018	New Ethylene
14	Shell	PA	2018	New Ethylene
15	Eastman	Longview, TX	2012	Ethylene/Polypropylene Expansion
16	Indorama	Under Consideration	2018	New Ethylene
17	LyondellBasell	Channleview, TX	NA	Ethylene Expansion
18	Sabic	Under Consideration	NA	New Ethylene
19	Occidental/Mexichem JV	Ingleside, TX	2016	New Ethylene
20	PTT Global Chemical	Under Consideration	NA	New Ethylene
21	Orascom Construction	Beaumont, TX	2011	Ammonia Restart
22	Orascom Construction	Beumont, TX	2012	Methanol Restart
23	Orascom Construction	Lee County, IA	2015	New Fertilizer
24	Potash Corp	Geismar, LA	2013	Ammonia Restart
25	Potash Corp	Augusta, GA	2013	Ammonia Expansion
26	Rentech Nitrogen	East Dubuque, IL	2013	Ammonia Expansion
27	Austin Powder	Mosheim, TN	2014	Ammonia Expansion
28	LyondellBasell	Channelview, TX	2014	Methanol Restart
29	Methanex	Geismar, LA	2015	Methanol Migration
30	CF Industries	Donaldsonville, LA	2015	Ammonia Expansion
31	CF Industries	Port Neal, IA	2015	Ammonia Expansion
32	Incitec Pivot	Under Consideration	NA	Ammonia Migration
33	Koch Fertilizer	Various	NA	Ammonia Expansion
34	LSB Industries	Pryor, OK	NA	Ammonia Restart
35	Dyno Nobel	Waggaman, LA	2015	New Ammonia
36	Celanese	Clear Lake, TX	2015	New Methanol
37	CHS Inc.	ND	2016	New Ammonia
38	Agrium	Under Consideration	2017	New Fertilizer
39	Dakota Gas	Beulah, ND	2016	New Fertilizer
40	ND Corn Growers Association	ND	NA	New Fertilizer
41	Ohio Valley Resources	Rockport, IN	2016	New Ammonia
42	Mosaic	St. James Parish, LA	2016	Ammonia Expansion
43	Dow	Freeport, TX	2015	New Propylene
44	Dow	Freeport, TX	2018	New Propylene
45	Eastman	Under Consideration	2015	New Propylene
46	Formosa	Point Comfort, LA	2016	New Propylene
47	LyondellBasell	Channelview, TX	2014	New Propylene
48	Mitsui	Ohio	2012	Propylene Expansion
49	Enterprise	Mont Belvieu, TX	2013	Propylene Expansion
50	Enterprise	Mont Belvieu, TX	2015	New Propylene
51	Exxon Mobil	Baytown, TX	2016	2 New Polyethylenes
52	Chevron Phillips	Old Ocean, TX	2017	2 New Polyethylenes
53	Eastman	Longview, TX	2012	EthylHexanol Expansion
54	Chevron Phillips	Baytown, TX	2014	New Hexene
55	Huntsman Chemical	McIntosh, AL	NA	Epoxy Expansion
56	INEOS	Gulf Coast	NA	Ethylene oxide
57	Kuraray	Pasadena, CA	2014	EVOH Expansion
58	Lanxness	Orange, TX	NA	Nd-PBR
59	Lubrizol	Deer Park, TX	2015	Plastic Resins

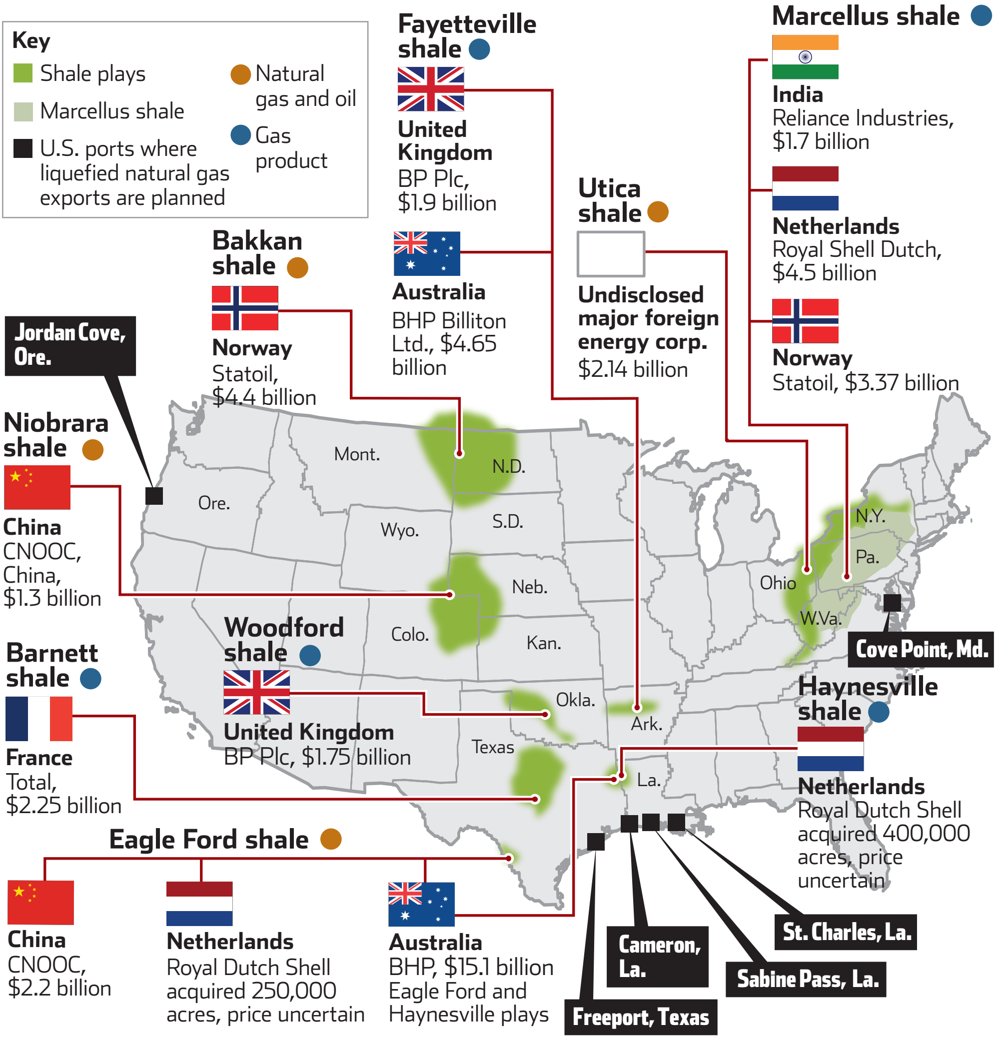
60	Honeywell Specialty materials	Mobile, AL	2012	Adsorbents; Catalysts
61	Westlake	Geismar, LA	2013	New Chlor-Alkali
62	Dow-Mitsui JV	Freeport, TX	2013	New Chlor Alkali
63	Molycorp	Mountain Pass, CA	NA	New Chlor-Alkali and rare earth metals mining
64	Formosa	Point Comfort, TX	2012	Chlorine/Caustic Soda
65	Formosa	Point Comfort, TX	2012	Ethylene Dichloride
66	Shintech	Plaquemine, LA	2012	VCM
67	Shintech	Plaquemine, LA	2012	Chlorine/Caustic Soda
68	Shintech	Plaquemine, LA	2012	PVC
69	Occidental	Jacksonville, TN	2013	Chlorine and Caustic Soda
70	Dow Agrosciences	Freeport, TX	NA	Herbicide
71	Mitsubishi Chemical Holdings Corp.	Freeport, TX	2017	Acrylic Resin
Steel & Aluminum				
72	Alcoa	Upper Burrell, PA	2012	Expansion
73	Alcoa	Lafayette, Indiana	2014	New
74	ArcelorMittal	Cleveland, OH	2012	Expansion
75	Carpenter Technology	Reading, PA	NA	Expansion
76	Carpenter Technology	Limestone County, AL	2013	New
77	Coilplus	North Carolina	2014	Expansion
78	Essar Steel	Nashwauk, MN	2015	New
79	Gerdau	St. Paul, MN	2014	New
80	Nucor	Blytheville, AK	2014	Expansion
81	Timken	Canton, OH	2014	Expansions
82	United States Steel	Lorain, OH	Completed 10/12	Expansions
83	United States Steel	Leipsic, OH	NA	New Steel
84	Metal-Matic	Middleton, OH	2012	Expansion
85	Vallourec and Mannesmann	Youngstown, OH	NA	New
86	Welspun	Little Rock, AK	NA	Expansion
87	Nucor	St. James Parish, LA	2013	New
88	Voestalpine	Under Consideration	NA	Iron
89	Borusan Mannesman	Under Consideration	2014	Steel Pipe
Tires				
90	Bridgestone	Aiken, SC	2014	New off-road radial tire / expansion passenger/light truck tire
91	Continental	Sumter, SC	2013 start / 2021 full capac.	Passenger and light truck tires
92	Michelin	Anderson, SC	2015	Earthmover tires (OTR)
93	Bridgestone	Bloomington, IL	2013	OTR Tires
Plastics				
94	M&G Group	Corpus Christi, TX	NA	New PET Plant
95	M&G Group	Corpus Christi, TX	NA	New PTA Plant
96	Huntington Foam	Greenville, MI	NA	Expansion
97	JM Eagle	Sunnyside, WA and Meadville, PA	NA	Polyethylene expansion
98	Springfield Plastics	Auburn, IL	2012	Polyethylene expansion
99	Kyowa America	Portland, TN	NA	Plastic Injection Molding
100	Lanxess	Gastonia, NC	Opened 9/12	Plastic
Natural Gas to Liquids				
101	Shell	LA or TX	NA	New
102	Sasol	LA	2018	New
103	Calumet Specialty Products Partners	Karns City, PA	2014	New
Glass				
104	Sage	Fairbaul, MN	Opened 9/12	Dynamic; Electrochromic Glass
Transportation &Transportation Equipment				
105	Caterpillar	Athens, GA	NA	Tractors and Excavators
106	Airbus	Mobile, AL	2015	Airplanes
107	Honda Motor Co.	Anna, OH	2012	Advanced Transmission Components

Packaging				
108	Abbott Laboratories	Tipp City, OH	2013	Aseptic Packages
Current as of January 2013				

Exhibit 2

Foreign flurry

These are some of the billion-dollar-plus foreign investments in natural gas and oil shale plays. Permit applications to export liquefied natural gas from six American port terminals have been filed with the Department of Energy. Only one, at Sabine Pass, La., has been approved so far.



Source: Tribune-Review research

BOB NEWELL | TRIBUNE-REVIEW

DEPARTMENT OF AGRICULTURAL, ENVIRONMENTAL AND DEVELOPMENT ECONOMICS

COLLEGE OF FOOD, AGRICULTURAL, AND ENVIRONMENTAL SCIENCES

The Economic Value of Shale Natural Gas in Ohio

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Department of Agricultural, Environmental and Development Economics

Swank Program Website: http://aede.osu.edu/programs/swank/

THE OHIO STATE UNIVERSITY EXTENSION — OARDC

Swank Program in Rural-Urban Policy Summary and Report
December 2011

Mark Partridge Short Biography

Dr. Mark Partridge is the Swank Chair of Rural-Urban Policy at Ohio State University. He is a Faculty Research Affiliate, City-Region Studies Centre, University of Alberta, an Affiliate of the Martin Prosperity Center at the University of Toronto, and an adjunct professor at the University of Saskatchewan. Professor Partridge is Managing Co-Editor of the *Journal of Regional Science* and is the Co-editor of new the *Springer Briefs in Regional Science* as well as serves on the editorial boards of *Annals of Regional Science, Growth and Change, Letters in Spatial and Resource Sciences, The Review of Regional Studies, and Region et Developpement*. He has published over 100 scholarly papers and coauthored the book *The Geography of American Poverty: Is there a Role for Place-Based Policy?* Dr. Partridge has consulted with OECD, Federal Reserve Bank of Chicago, Federal Reserve Bank of Cleveland, and various governments in the U.S. and Canada, and the European Commission. Professor Partridge has received funding from many sources including the Appalachian Regional Commission, Brookings Institution, European Commission, Infrastructure Canada, Lincoln Institute of Land Policy, U.S. National Science Foundation, U.S. National Oceanic and Atmospheric Administration, and Social Science and Humanities Research Council of Canada. His research includes investigating rural-urban interdependence and regional growth and policy. Dr. Partridge served as President of the Southern Regional Science Association in 2004-05 and is currently on the Executive Council of the Regional Science Association International (the international governing board).

Amanda Weinstein Short Biography

Amanda Weinstein is a PhD student in the Department of Agricultural, Environmental, and Development Economics at The Ohio State University. Her research as the C. William Swank Graduate Research Associate includes policy briefs about the employment effects of energy policies and general regional growth and policy issues. She is an OECD consultant advising on the economic impacts of alternative energy policies on rural communities. Her other research interests include women's role in economic development examining women's effect on regional productivity growth. She was awarded the Coca-Cola Critical Difference for Women Graduate Studies Grant to continue her work on gender issues in economics. She is also conducting research on the skills most valued during a recession and the impact of military service on intergenerational mobility. Before starting her PhD at OSU, she was a commissioned officer in the United States Air Force after graduating from the United States Air Force Academy. As a Scientific Analyst in the Air Force and then as a Sr. Management Analyst for BearingPoint, she advised Air Force leadership on various acquisition and logistics issues. She is currently an adjunct faculty member of Embry-Riddle University and DeVry.

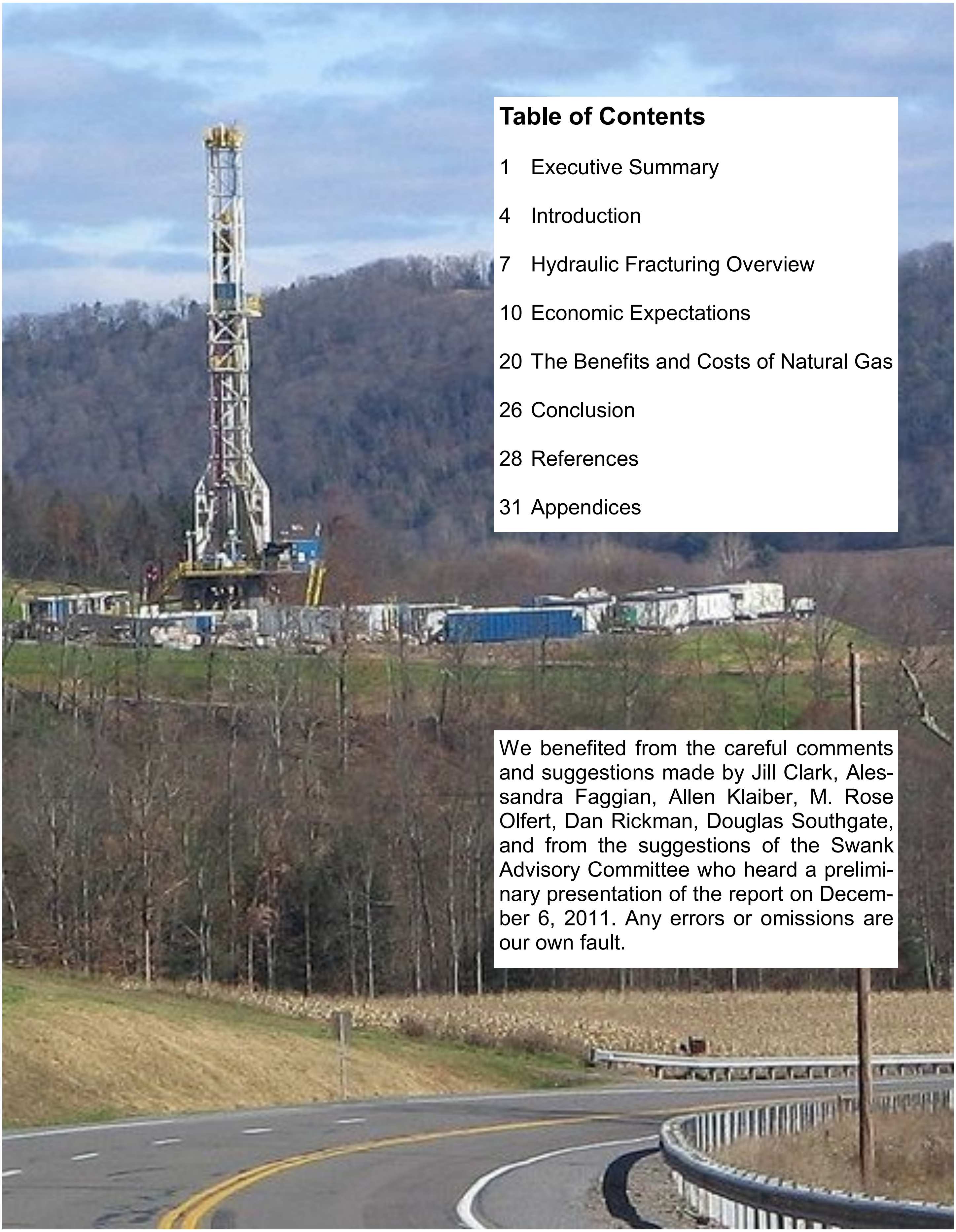


Table of Contents

We benefited from the careful comments and suggestions made by Jill Clark, Alessandra Faggian, Allen Klaiber, M. Rose Olfert, Dan Rickman, Douglas Southgate, and from the suggestions of the Swank Advisory Committee who heard a preliminary presentation of the report on December 6, 2011. Any errors or omissions are our own fault.

Tower for drilling horizontally into the Marcellus Shale Formation for natural gas in Lycoming County, Pennsylvania.

Executive Summary

Increased production of US natural gas in recent years has helped to meet the growing demands of American customers and has reduced natural gas imports. Natural gas is also a cleaner burning fuel when compared to its most realistic substitute, coal. This substantial increase in production has been attributed in large part due to the development of shale gas through a process called hydraulic fracturing. Hydraulic fracturing has enabled the expansion of natural gas extraction into new undeveloped areas. The Marcellus shale in Pennsylvania has experienced impressive growth in its natural gas industry and neighboring Ohio is beginning down the same path. Proponents argue that among the many purported advantages, natural gas production is associated with significant amounts of new economic activity.

Economists have 150 years of experience in examining energy booms and busts throughout the world to form their expectations of how energy development affects regional economies. Generally, economists find that energy development is associated with small or even negative long-run impacts. They refer to a "natural resources curse" phenomenon associated with the surprisingly poor performance of resource abundant economies. There appears to be more examples like Louisiana, West Virginia, Venezuela, and Nigeria of energy economies seemingly underperforming and few examples of places such as Alberta and Norway of relative over performance. This backdrop needs to be considered in forming good policy in Ohio in order to avoid being in the former group.

In supporting energy development, the natural gas industry has funded its own studies of economic performance. For example, utilizing assumptions derived from Pennsylvania economic impact studies, Kleinhenz & Associates (2011) estimate that the natural gas industry could help "create and support" over 200,000 jobs to Ohio and $14 billion in spending in the next four years. These figures are about the same size as those for Pennsylvania (in industry funded studies). As we outline in this report, impact studies such as those employed by the industry are typically flawed due to the following reasons:

1. Possible double counting economic effects from drilling activities and royalties/lease payments to landowners. Most important, these studies have multipliers well above what independent economists would normally expect.
2. Including unrealistic assumptions about the percentage of spending and hiring that will remain within the state.
3. Ignoring the costs of natural gas extraction on other sectors through higher wages, and land costs that will make them less competitive (e.g., Dutch Disease), as well as environmental damage that limits tourism and other activities. It will also displace coal mining—i.e. more natural gas jobs come at the expense of fewer jobs in coal mining.
4. Often employing out-of-date empirical methodologies that academic economists have long abandoned for better methodologies in terms of evaluation of economic effects.

Many of the same reasons why alternative energy has not been (will not be) a major job creator also applies to natural gas (Weinstein et al., 2010):

1. The energy industry and specifically the natural gas industry's employment share is small and by itself is not a major driver of job growth for an entire state the size of Ohio or Pennsylvania. During the one year span October 2010-October 2011, U.S. Bureau of Labor Statistics data reports that Ohio's unemployment rate fell from 9.7 to 9.0% or 0.7% (without shale development), while Pennsylvania's unemployment rate only fell from 8.5% to 8.1% or 0.4% (with shale development). Ohio also had faster job growth during the span (1.3% versus 1%), showing that shale development by itself is not shaping their growth.
2. It is a capital-intensive industry versus labor-intensive—or a dollar of output is associated with significantly fewer workers.

The costs of natural gas include the effects it has on other industries. Some of these effects include displacement of other forms of economic activity, the effects of pollution that drive out residents who are worried about its effects and the higher wages and land/housing costs that make other sectors less competitive. For example, the tourism industry will likely be adversely affected by fears of pollution and higher wages and costs as other sectors have to compete for workers with the higher paying natural gas sector. In Pennsylvania, for instance, the tourism industry employed approximately 400,000 in 2010 (though a much smaller number is immediately near the shale development) compared to only 26,000 in a broad definition of the natural gas industry (Barth, 2010; BLS). Similar concerns should also apply to Ohio across various sectors of the economy.

Our broad analysis shows the expected employment effects of natural gas are modest in comparison to Ohio's 5.1 million nonfarm employee economy. We show this through (1) an assessment of impact analysis, (2) comparison of drilling counties with similarly matched non-drilling counties in Pennsylvania, (3) statistical regressions on the entire state of Pennsylvania, (4) employment comparisons with North Dakota's Bakkan shale region, and (5) an examination of the employment life cycle effects of natural gas and coal per kilowatt of electricity. Specifically, we estimate that Pennsylvania gained about 20,000 direct, indirect, and induced jobs in the natural gas industry between 2004-2010, which is a far cry fewer than the over 100,000 jobs reported in industry-funded studies (and the 200,000 expected in Ohio by 2015). Given the anticipated size of the boom, Ohio is expected to follow the Pennsylvania's experience. We believe 20,000 jobs would be a more realistic starting point for what to expect in Ohio over the next four years and is in line with what other independent assessments have suggested. However, our 20,000 job estimate does not account for displacement losses in other industries such as tourism, and we also note that local economic effects could appear larger in heavily impacted areas. Moreover, we find that mining counties had considerably faster per-capita income growth than their non-drilling peers, which likely results from royalties/lease payments and the high wages in the industry. Thus, we expect the near-term boom to be associated with frothy increases in income but more temperate job effects.

There are several reasons why the industry-funded studies produce employment results that are considerably different from our estimates. Foremost, impact studies are not viewed as best practice by academic economists and would be rarely used in peer reviewed studies by urban and regional economists. Instead, best practice usually tries to identify a counterfactual of what would have happened <u>without</u> the natural gas industries and compare to what did happen (we adopt two of these approaches). One advantage of identifying the counterfactual is that the estimated effects use actual employment data and are not the estimated outcome of an impact computer model. Yet, like virtually every other economic event, there are winners (e.g., landowners or high-paid rig workers) and losers (e.g., those who can no longer afford the high rents in mining communities and communities dealing with excessive demands on their infrastructure). Moreover, the boom/bust history of the energy economy is that drilling activity usually begins with a wave of drilling and construction in the initial phases, followed by a significant slowdown in jobs as the production phase requires a much smaller number of permanent employees. Indeed Ohio has a long history of energy booms that illustrates that booms too often have few lasting effects. Ohioans need to be aware of this cycle if they are to make prudent decisions and try to gain sustainable gains after the boom has ended. The fundamental problem here is that the time distribution of jobs resulting from a new development is often ignored and it is important. For example it matters whether there are 1,000 jobs distributed as 1,000 for one year and then none, versus 100 additional jobs for 10 consecutive years, or 10 additional jobs for the next 100 years. Yet, 'impact' analysis such as that used by the energy industry typically does not differentiate among these scenarios and the whole topic is usually ignored by the media. Professional economists note that long-term regional economic development requires <u>permanent</u> jobs, and thus independent economists place considerably less weight on the initial construction phase associated with energy development. Policies need to be developed to ensure long-term success.

Natural gas extraction is also associated with potential environmental degradation. Pennsylvania and other areas have reported numerous incidents of water contamination; most notably in Dimock, PA, which was featured in the controversial documentary *Gasland*. Because hydraulic fracturing occurs at levels far below the aquifer level, it is most likely not to blame for contamination, but any contamination is instead likely caused by a casing/tubing failure or other part of the drilling process. Thus, the EPA exempted natural gas extraction using hydraulic fracturing from the Safe Drinking Water Act and Clean Water Act in 2005. However, recognizing increasing concerns over the impact on drinking water and ground water, in 2010 Congress directed the EPA to study the effects of hydraulic fracturing on the environment with results expected by the end of 2012. Until the federal government acts on this issue, state regulations are necessary to ensure natural gas extraction is performed in a safe manner protecting the environment and residents. Yet, coal mining is also associated with high localized environmental costs, indicating that if natural gas mining is not done, there will still be environmental problems that will need to be addressed because more coal mining will be required.

We argue that the focus on whether the industry creates jobs is misguided in assessing its true value and is not how economists typically evaluate the effectiveness of a program or policy. Rather, the focus should be placed on the true costs and benefits of natural gas especially compared to coal (its main substitute in electricity production). *Compared to coal, natural gas is cheaper and emits less carbon and both industries have their own inherent localized environmental costs in their production.* Independent economists would note that neither industry is associated with large numbers of jobs due to their capital-intensive nature. Making a true assessment of the costs and benefits will require qualified independent analysis. Likewise, ensuring that Ohioans benefit long after the energy boom requires innovative planning that unfortunately, most locations that have experienced such booms have failed to do over the last 150 years. These findings also illustrate that Ohio will need to continue to make economic reforms if it is to prosper in the long term because no one industry—in this case energy development—will be its long-term savior.

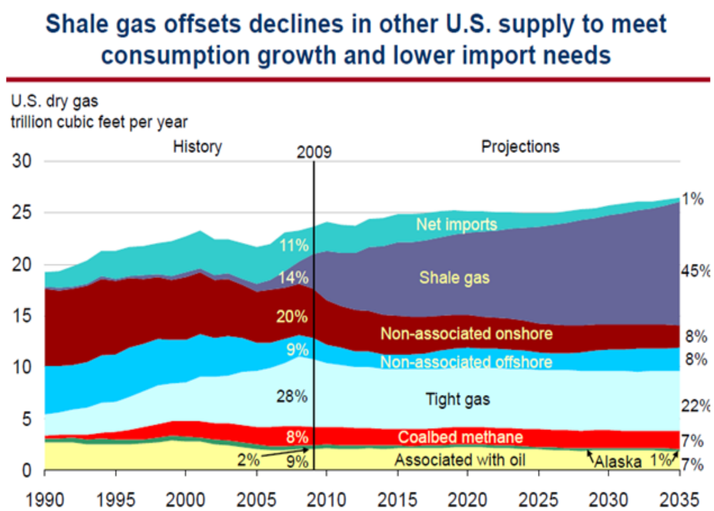
Introduction

With the US economy still struggling to recover from the Great Recession, many are looking for a quick fix to create jobs and generate income. Politicians often turn to the latest economic fad to solve unemployment problems, such as aiming to become the next Silicon Valley or, more recently, the next green energy hub. Employment effects are often overstated to justify various policies rather than having a real conversation about the true benefits and costs of a policy.[1] For example, the job creation benefits of green jobs were optimistically asserted while ignoring the high capital intensity of alternative energy and the displacement effect of jobs no longer needed in the fossil fuels industry, especially coal. In response, the fossil fuels energy industry has now put forward its own solution to unemployment and growing energy demands: natural gas from shale, which also provides its own set of environmental costs and benefits.

In their "Short-Term Energy Outlook," the US Energy Information Administration (EIA) expects that total natural gas consumption will grow by 1.8% in 2011. Despite the increase in consumption, recent increases in natural gas production have met these demands and reduced natural gas imports. Thus, shale gas proponents claim that newly accessible reserves could provide a new level of energy independence for the US. The 2010 EIA "Annual Energy Outlook" found that natural gas production reached its highest levels since 1973 at 21.9 trillion cubic feet (Tcf). This increase in production is mainly attributed to the increase in natural gas extraction from shale resources. From 2009 to 2010 shale gas production more than doubled from 63 billion cubic meters to 137.8 billion cubic meters. This trend in rising natural gas production, especially shale gas production, is likely to continue. Figure 1 below shows the increasing shale gas production the US has experienced, along with future expectations.

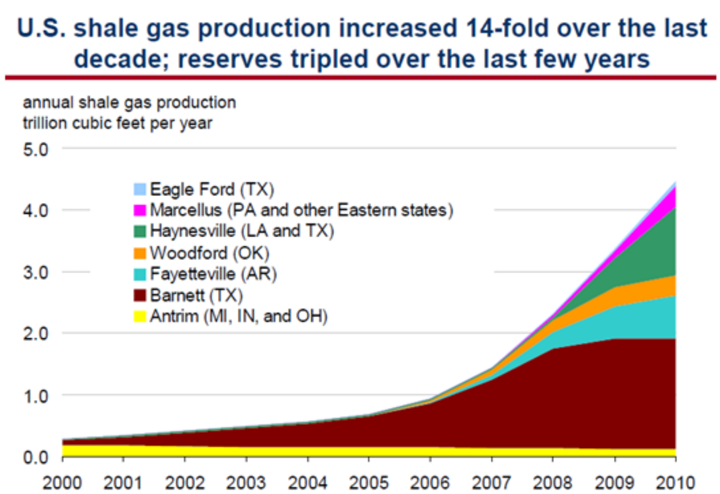
The dramatic increase in shale gas production since 2005 is shown below in Figure 2 separated by the area where shale gas has been developed. Recent technological advancements in a method called hydraulic fracturing, or "fracking", have made extracting natural gas from shale more efficient and cost effective. This has brought natural gas potential to new areas as evidenced by the increased drilling in Pennsylvania. Although still a small percentage compared to Texas, growth in shale gas production in Pennsylvania is growing rapidly and provides a roadmap for how production in Ohio will evolve.

With these innovations, shale gas potential is now growing in neighboring Ohio, which shares the same Marcellus shale with Pennsylvania. Many have already begun to speculate what this could mean in terms of the job benefits to Ohio. An industry-funded study by Kleinhenz & Associates (2011) suggests that new Ohio natural gas production could "create and support" over 200,000 jobs



Source: US EIA Annual Energy Outlook 2011

Figure 1: Shale Gas Prospects



Source: US EIA Annual Energy Outlook 2011

Figure 2: Shale Gas Areas of Production

1. Independent economists have long complained about hyped up numbers from various industry impact reports. For a tongue-in-cheek look see Leach (2011). http://www.theglobeandmail.com/report-on-business/economy/economy-lab/the-economists/who-needs-pipelines-the-oil-bucket-brigade-is-ready/article2268015/

and $14 billion injected into the state economy over the next 4 years (Gearino, 2011).[2] In this manner, Chesapeake Energy CEO Aubrey McClendon stated, "This will be the biggest thing in the state of Ohio since the plow" (Vardon, 2011). Obviously, there is considerable hype surrounding the economic effects of shale oil production

To see if these expectations are realistic, we examine the impacts that natural shale gas has had on Pennsylvania to draw comparisons to Ohio. Many industry funded studies of the economic impacts of the Marcellus shale development in Pennsylvania are consistent with the Kleinhenz & Associates (2011) predictions, which is reasonable in the sense that the early stages of Ohio's development is expected to mimic what happened in Pennsylvania.

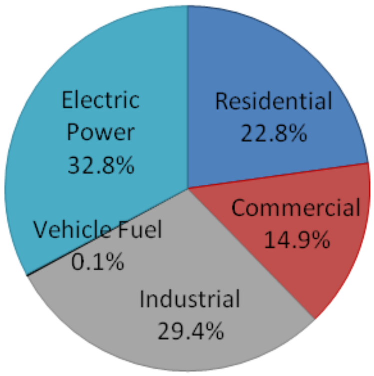
Unlike the industry funded reports, Barth (2010) doubts whether there is any net positive economic impact of drilling in Pennsylvania. She contends that previous industry-funded reports have focused on the benefits while ignoring the costs and risks associated with natural gas extraction. She claims industry funded studies haven't properly accounted for other impacts, including the costs of environmental degradation. Although replacing coal or oil with natural gas can significantly reduce carbon emissions, rising concerns have mounted, most notably in the controversial 2010 documentary *Gasland,* about the potential environmental impacts of natural gas mining on nearby water sources. This has become more of a concern as hydraulic fracturing and natural gas extraction occurs closer to both water sources and population centers in Pennsylvania and Ohio. These concerns have not yet been fully alleviated by the US EPA or the natural gas industry. In 2005, hydraulic fracturing methods were exempted from the Safe Drinking Water Act and Clean Water Act. However, recognizing increasing concerns over the impact on drinking water and ground water, in 2010 Congress directed the U.S. Environmental Protection Agency (EPA) to study the effects of hydraulic fracturing on the environment.

Barth (2010) also argues that previous industry-funded studies have not properly accounted for the impact on infrastructure, property values, and the "displacement" impact pollution can have on other industries such as tourism and fishing. In 2010, tourism employed approximately 400,000 people in Pennsylvania whereas the natural gas industry employed closer to 26,000 (Barth, 2010; BLS). If tourism suffers as a result of the natural gas industry, then a bigger industry could be put at risk from expansion of the natural gas industry, though we note that much of Pennsylvania's tourism industry is not near the mining activity.

Economists have long argued that energy development has limited overall impacts on the economy. There is a longstanding literature that refers to a "natural resources curse" that limits growth from energy development. One reason for the limited effects of energy development is Dutch Disease, which broadly refers to the higher taxes, wages, land rents, and other costs associated with energy development that make other sectors less competitive (including currency appreciation at the national level). These higher costs also reduce the likelihood new businesses will locate in the affected location. Previous research has found evidence of a natural resources curse and Dutch Disease suggesting that a natural resource boom can occur at the cost of other sectors and general long-run economic growth. For example, Papyrakis and Gerlagh (2007) found that US states with a higher degree of reliance on natural resources experience lower economic growth.[3] Kilkenny and Partridge (2009) and James and Aadland (2011) also found evidence of this resource curse at the US county level.

Figure 3 on the next page shows that most natural gas is still used to supply electricity. Thus, with rising electricity demands, increasing natural gas production will lower the need for electricity generation from coal—i.e., we will have more natural gas jobs that are offset by fewer coal jobs. Only 0.1% of natural gas is used as vehicle fuel, which is derived from oil as opposed to coal. Thus, new natural gas will not significantly decrease US reliance on foreign oil unless, as publicly suggested by T. Boone Pickens, the US considers converting more buses, trucks and other vehicles to natural gas. Thus, its effects on "energy security" are rather limited in the foreseeable future as increased electrical demand and the growing reliance on US natural gas will primarily be at the expense of US coal.[4]

2. Kleinhenz & Associates (2011) specify that over 200,000 jobs will be *created* or *supported* but they do not clearly define the difference between "created" and "supported" jobs. In terms of long-term economic development, permanent job creation would be necessary—or does natural gas development create more permanent jobs than what would have happened without the energy development? The latter counterfactual question is not addressed in that report.
3. Dutch Disease refers to natural gas development in the Netherlands in the 1960s and 1970s. The ensuing boom raised costs and appreciated the Dutch currency, rendering Dutch manufacturers less competitive on international markets. After the initial boom settled down, not only were there less employment in the natural gas industry, but Dutch manufactures found it hard to regain their market share on international markets, producing a permanent cost on their economy.
4. The recent expansion of shale development did reduce natural gas imports, but going forward, its main influence will be as a substitute for other sources of electricity, primarily coal.



Source: US EIA

Figure 3: 2010 Natural Gas Consumption by End Use

Even with a significant conversion of vehicles to natural gas, the energy sector as a whole has an employment share that is simply too small to significantly impact the high unemployment rates the US is experiencing. In 2010, the natural gas industry accounted for less than 0.4% of national employment, so even if the sector doubled in size—which is quite a stretch—overall U.S. employment would only be marginally effected (BLS).[5] This is not surprising as natural gas like much of the energy sector (including alternative energy) is quite capital intensive, which reduces the employment effects of natural gas compared to the broader economy.

The pursuit of economic fads is often justified by overpromising jobs while ignoring the displacement effects on other sectors of the economy as well as other costs on the economy. The benefits should be appropriately weighed against the costs, but this requires a better understanding of both the benefits and costs. It should not be based on the overblown hype of either side. Using previous experience from Pennsylvania, we will produce realistic estimates what Ohio should expect from shale gas development over the next four years. We find that although the employment advantages of shale gas have generally been overstated by the industry, there are clear benefits of natural gas production when compared to coal (which has its own environmental risks). The biggest advantages are that natural gas is more cost-effective than coal and can reduce carbon emissions. Coal forms the natural benchmark because in the medium term, natural gas production would displace coal production as the alternative source for electricity.

5. The calculation of total natural gas employees uses the methodology of IHS Global described in more detail in note 7 and we use U.S. Bureau of Labor Statistics Data to derive the employment figures.

Hydraulic Fracturing Overview

Innovations in hydraulic fracturing are the reasons natural gas extraction has recently been developing in the Marcellus shale regions in Pennsylvania and Ohio and now expanding to the Utica shale regions in Ohio. Before investigating the impacts of shale gas development, it is important to understand the hydraulic fracturing method that has made natural gas extraction from shale economically feasible.

Shale is a fine-grained sedimentary rock that can trap petroleum and natural gas well below the surface. Horizontal drilling and hydraulic fracturing now allow the energy industry to extract this trapped gas. Commercial hydraulic fracturing began in 1949, though it took decades of use for innovations to make shale gas extraction more cost effective. Horizontal drilling can cost 3 to 4 times more than conventional drilling, but has the potential of reaching substantially more reserves. Figure 4 from the EIA compares horizontal drilling and hydraulic fracturing to conventional methods of natural gas extraction. Figure 5, further depicts the hydraulic fracturing process.

Horizontal wells and hydraulic fracturing in conjunction with advances in micro-seismic technology aiding both exploration and the drilling process have allowed the energy industry to extract natural gas at greater depths. According to the EPA (Jun., 2010), horizontal wells are drilled to a depth between 8,000 and 10,000 feet. Hydraulic fracturing extracts natural gas from shale using a pressurized injection of fluid composed mostly of water and a small portion of sand and chemical additives that vary by site. This pressure causes the shale to fracture, requiring sand or other propping agents to keep the fissures open and allow gas to escape. Between 15 to 80% of the fluids are recovered from the well before the natural gas is collected. This water called "produced water" can be reused in other wells, but will need to be treated or disposed of at some point.

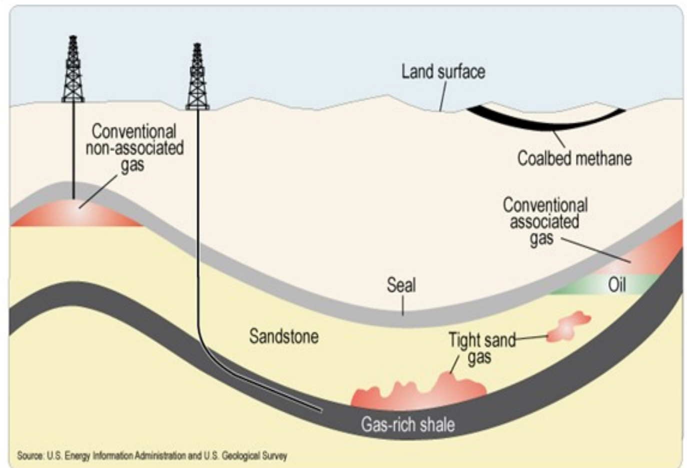
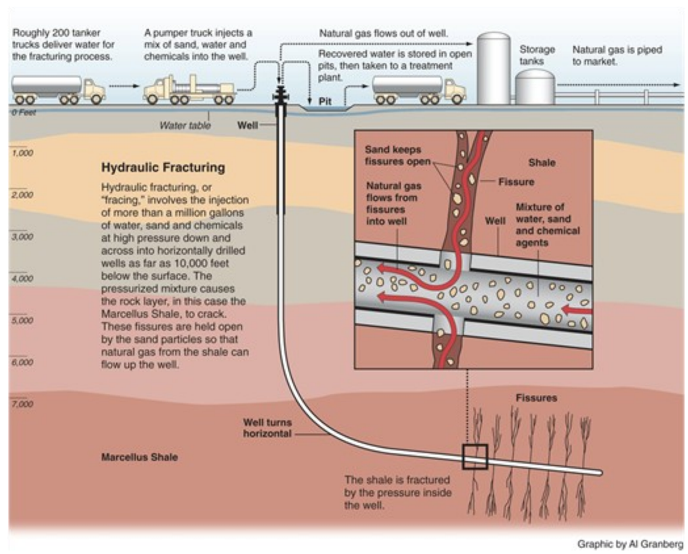


Figure 4: Natural Gas Mining Methods

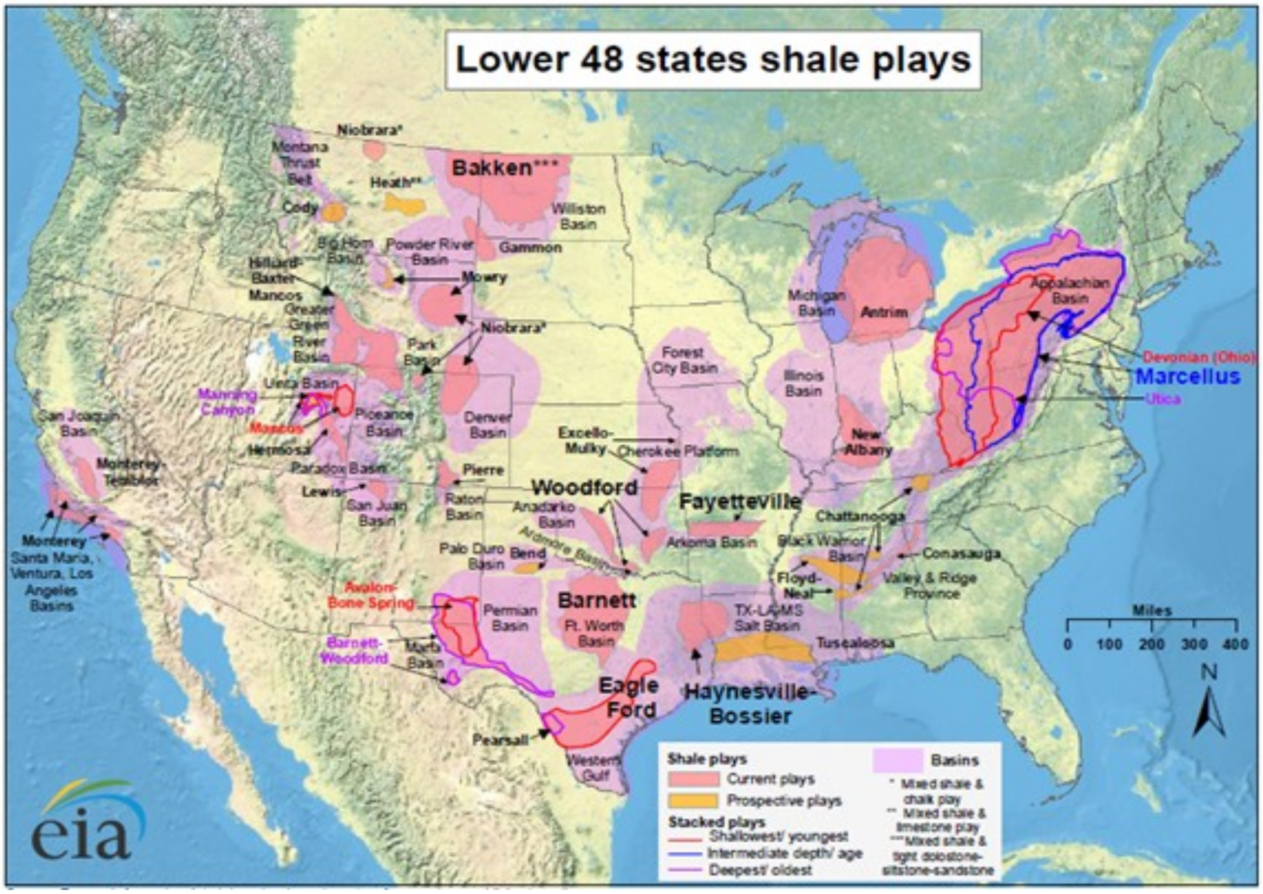


Source: ProPublica

Figure 5: Hydraulic Fracturing

Natural Gas Development in the US:

In the 1980s, the Barnett shale in Texas became the first natural gas producing shale. More than a decade of production from the Barnett shale in Texas has helped improve the hydraulic fracturing process, leading the way for it to be used in other areas such as the Marcellus shale in Pennsylvania and the Utica Shale in Ohio. The Marcellus shale is more than 60 million acres and is significantly larger than the Barnett. The EIA estimates that there are 410 Tcf of recoverable gas in the Marcellus shale alone. Figure 6 on the next page shows the location of US shale plays including the Barnett in Texas and the Marcellus and Utica in Pennsylvania and Ohio. Figure 6 clearly shows that shale natural gas is a national phenomenon that will dramatically alter natural gas availability and pricing nationally. Indeed, EIA data further documents that shale plays are a global phenomenon that will likely reduce world-wide natural gas prices.

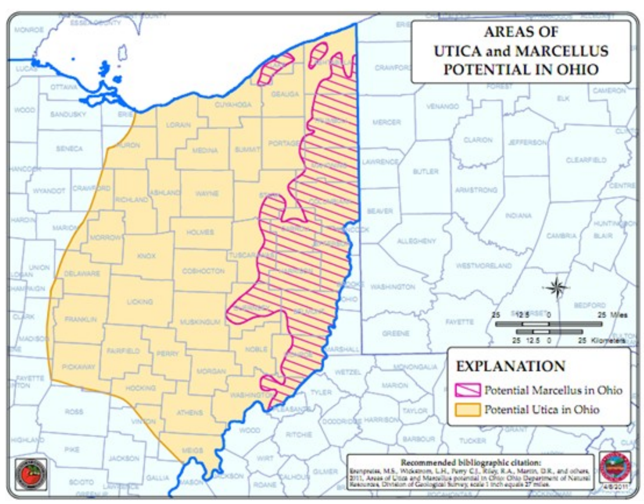


Source: US EIA

Figure 6: US Shale Resources

The large potential of the Marcellus shale, and more recently the Utica shale, has made Pennsylvania and Ohio highly attractive for mining of natural gas reserves. Figure 7 below provides a more detailed look at areas in Ohio that may be directly affected by natural gas resources. In an interview, Douglas Southgate of The Ohio State University's Subsurface Energy Resource Center states that shale resources in Ohio can provide a reliable, cheap, and local source of energy for Ohio. He explains that much of the attention has been on the Marcellus formation, though it is becoming clear that the Utica is more important. In the long term, the latter is expected to supply oil in significant quantities (Dezember and Lefebvre, 2011). It is also an important source of natural gas liquids (NGLs) such as ethane, which is converted into the ethylene used to manufacture a wide array of chemical products (American Chemistry Council, 2011). Thus, Southgate and others argue that shale deposits in and around Ohio are an important source of various hydrocarbons, not just the methane used to heat homes, generate electricity, and so forth.

Ohio shale development is just beginning. Figure 8 on the next page shows specific Marcellus and Utica well activity in Ohio from 2006 through August, 2011. It was recently reported that Chesapeake Energy has its first 4 active Utica shale wells in Ohio producing between 3 and 9.5 million cubic

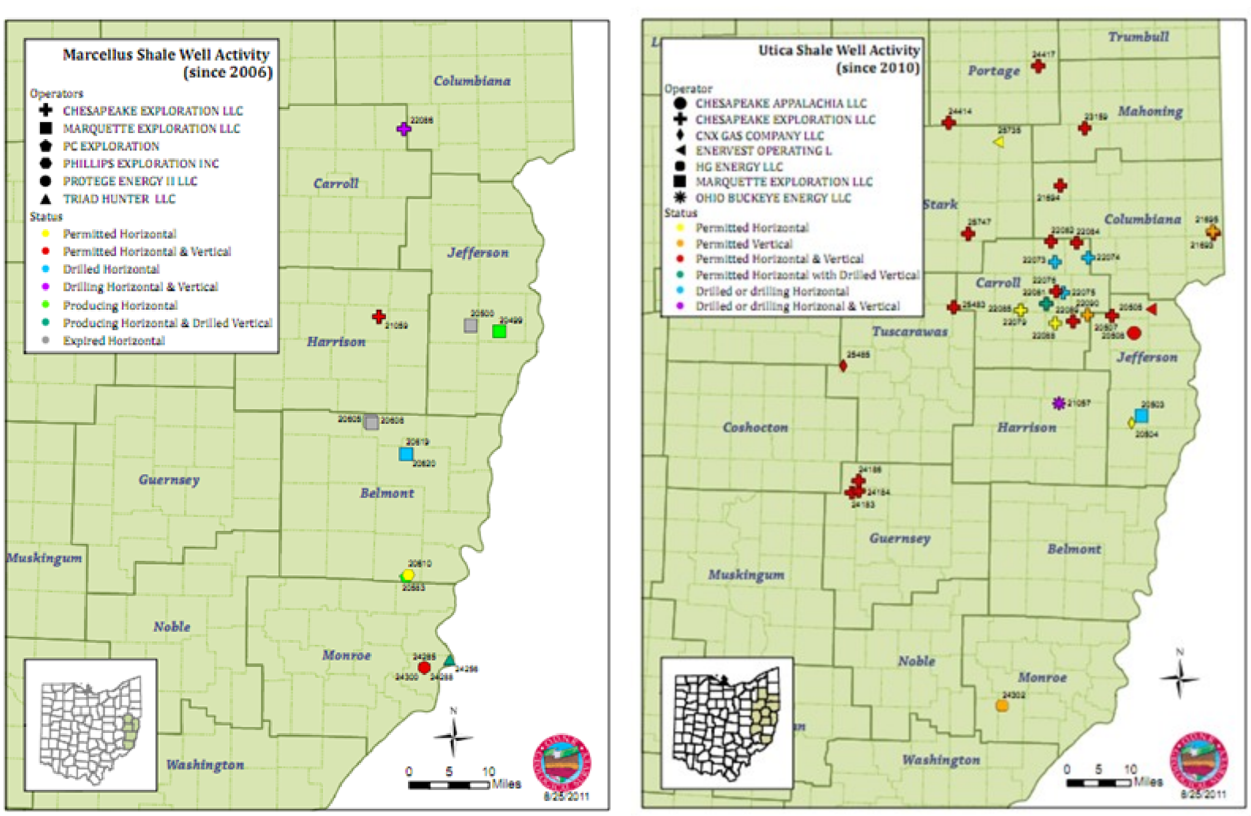


Source: ODNR

Figure 7: Ohio Shale Resources

feet of natural gas per day (Gearnino, 2011). A conventional well might produce between 100,000 and 500,000 cubic feet per day, but the Marcellus and Utica shale wells are expected to produce between 2 to 10 million cubic feet of natural gas per day. Chesapeake plans to increase the number of wells to 20 by the end of 2013.

Although shale development has already begun in Ohio, it is still nascent compared to Pennsylvania. The projected impacts on Ohio are still being debated. For example, Kleinhenz & Associates (2011) projected natural gas development in Ohio would lead to 200,000 jobs and $14 billion in spending. Much of their analysis uses assumptions derived from recent Pennsylvania impact studies such as Considine et al. (2009; 2010; 2011). Kleinhenz & Associates (2011) projected that 4,000 wells will be drilled in Ohio by 2015. Overall, they produced economic results that are similar to the industry-funded estimates for Pennsylvania.



Source: ODNR (Aug, 2011)

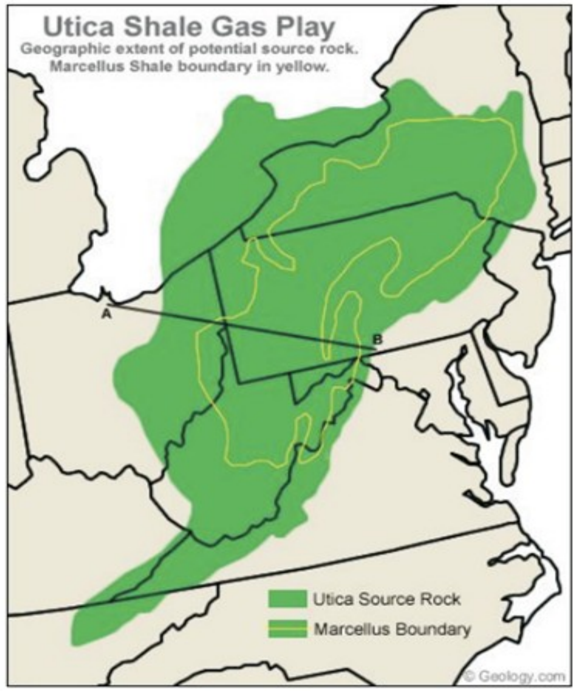
Figure 8: Marcellus and Utica Well Activity in Ohio

Economic Expectations

Pennsylvania is a particularly good gauge to predict what the impacts of shale gas will be on Ohio because they share much of the same natural resources. They are also very proximate and have similar economic structures. Figure 9 shows the Marcellus and Utica shale running through both states. Besides being neighbors, Pennsylvania and Ohio are the 6th and 7th most populous states. For both states, the shale resources are mainly located in rural areas, though there are larger population centers that are affected.

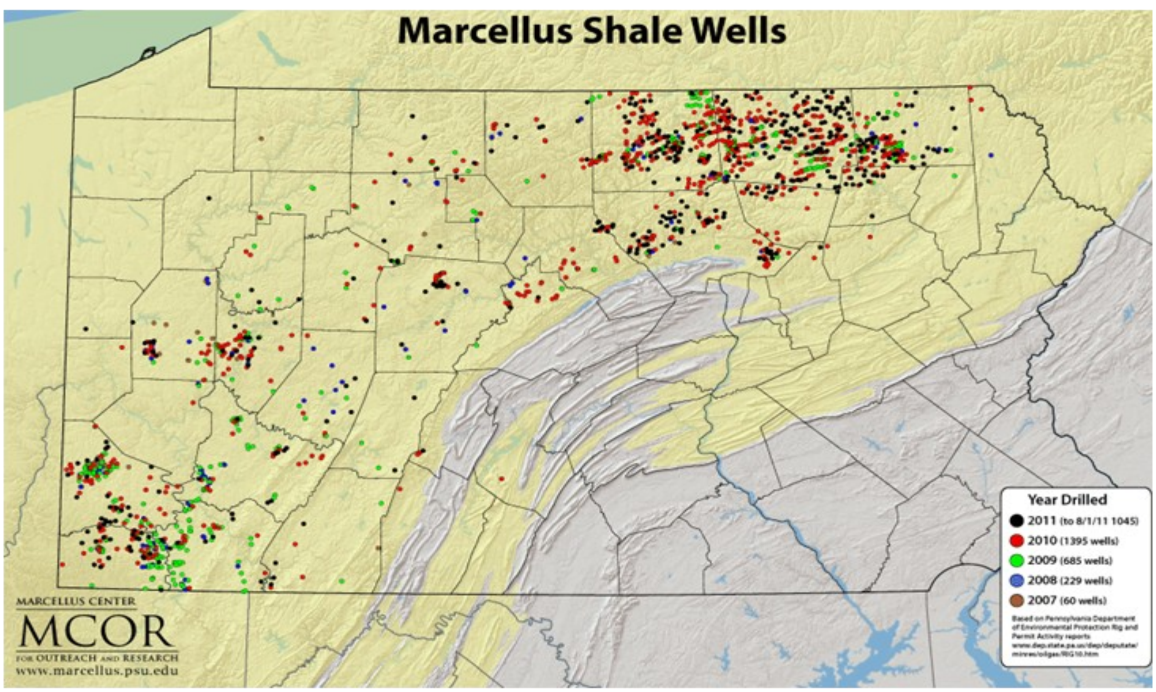
In 2005, the first well in the Marcellus shale in Pennsylvania began producing natural gas. Since then, most of the wells have been located in the northeast and southwest in Pennsylvania. Figure 10 shows the location of wells across the state by year. The number of shale wells drilled grew from 60 in 2007 to 1,395 in 2010. Considine (2010) finds that 36% of the 229 wells drilled in 2008 were horizontal and that percentage is expected to rise.

As the number of wells drilled dramatically increased, so did natural gas production in Pennsylvania, especially in the northeast region. Figure 11 on the next page shows the notable increase in production.



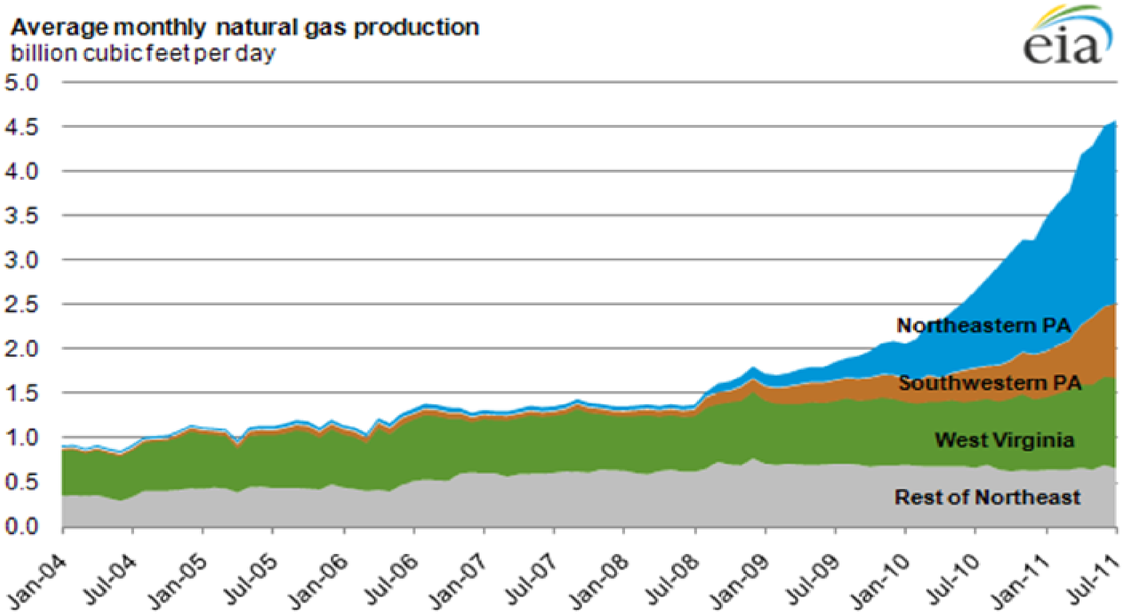
Source: Ohio EPA

Figure 9: Marcellus and Utica Shale Plays



Source: PSU

Figure 10: Marcellus Shale development 2007-2011



Source: US EIA

Figure 11: Northeast Natural Gas Production

Pennsylvania Natural Gas Employment:

Studies of natural gas's role in national and regional economies typically use impact studies (though this is not considered best practice for evaluating economic effects). Impact studies, such as the ones we describe, typically estimate three types of employment effects: (1) direct effects of the jobs directly employed in the activity (in this case natural gas mining); (2) indirect effects that would include inputs to the direct activity (such as pipeline construction); and (3) induced effects due to the added household income (e.g., workers purchasing items in the local economy) (see IMPLAN.com for more details). Summing across the three categories, if done correctly, would produce the total number of jobs "supported" by the industry (not new jobs created). As we describe below, estimating the number of new jobs created would need to assess what would have happened in the absence of natural gas mining—i.e., develop the counterfactual—which is not done in standard impact analysis.

One source of confusion is that impact studies do not produce continuous employment numbers. If an impact study says there are 200,000 jobs, this does not mean 200,000 workers are continuously employed on a permanent basis. For example, there are workers who do site preparation. Then there is another group who do the drilling followed by another group who maintains the well when it is in production. Finally, there is an entirely different group doing pipeline construction, and so on. So, while the public is likely more interested in continuous ongoing employment effects, impact studies are producing total numbers of supported jobs that occur in a more piecemeal fashion.

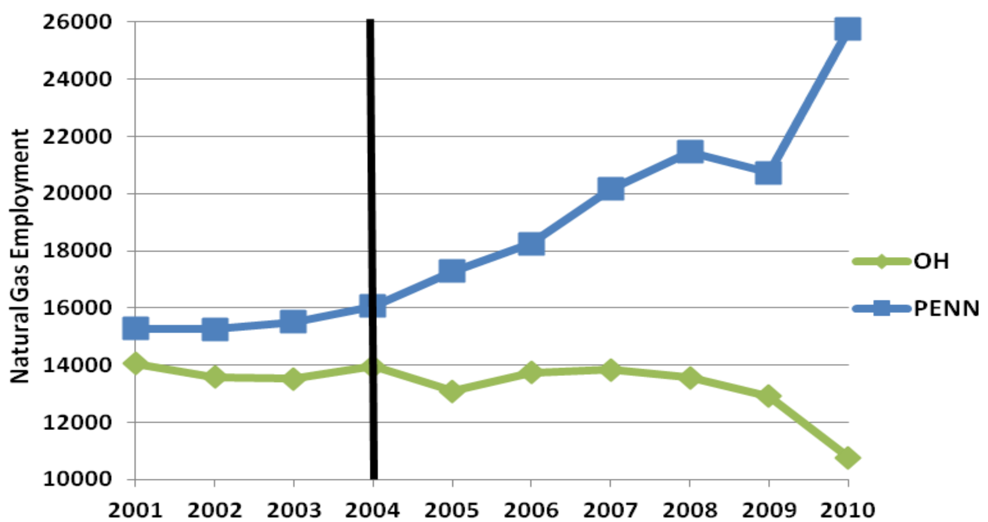
Impact analysis is usually based on an old input-output technology that is typically not used today by economists to estimate actual economic effects. Impact studies do not include various displacement effects and do not reflect the true counterfactual of comparing what would have happened without natural gas drilling. For example, oil and natural gas drilling would lead to higher local wages and land costs, which reduce employment that would have occurred elsewhere in the economy. Likewise, the environmental effects may reduce activity in the tourism sector and other residents may not want to live near such degrading activity. Finally, greater natural gas employment means that there are fewer jobs in coal that would have occurred without the increase in natural gas employment. As described below, best practice economics uses other approaches that try to adjust for displacement effects to derive more accurate estimates of actual effects (see Irwin et al. (2010) for a discussion of the weaknesses of impact studies).

Figure 12 on the next page shows the direct and much of the indirect employment in natural gas and other related sectors in Ohio and Pennsylvania.[6]

6. For the direct effect of natural gas mining, we also include some indirect suppliers that are related to natural gas drilling, which overstates the direct effects. However, not all of the indirect industries are included in Figure 12. When we use a multiplier below, because we already include some indirect effects, we would overstate the total number of supported jobs for the industry.

Since some of the sectors reported in Figure 12 include other sectors—primarily oil—we assume that all of the gain in Pennsylvania employment is due to new natural gas production. Also, we do not include "energy related" sectors in Figure 12 if they showed a large decrease in employment because we believe that would understate the importance of new natural gas production in Pennsylvania (those declines would likely be due to other factors). Thus, if anything, we believe that any measurement "errors" would work to overstate the importance of new gas production employment.[7] From Figure 12, with these assumptions, we assume that from 2004-2010, there was a gain of about 10,000 direct and indirect jobs in the natural gas industry in Pennsylvania.

The typical multiplier would take direct employment and multiply it by the multiplier to arrive at the total effects, including indirect and induced effects. Since the 10,000 number derived above includes some of indirect effects such as pipeline construction, using the standard multiplier would likely lead to an overstatement of the total employment effects of new production. Nonetheless, assuming the standard multiplier of 2 (which is on the high end), the natural gas industries would still have led to about 20,000 direct, indirect, and induced jobs from 2004 to 2010 in Pennsylvania, though this ignores employment losses in other sectors displaced by natural gas.[8] By comparison, Considine et al.'s (2011) industry funded study suggested that natural gas was associated with 140,000 Pennsylvania jobs during 2010.



Note: 21111-Oil and gas extraction 213111 - Drilling Oil and Gas Wells 213112 - Support Activities for Oil and Gas Operations 541360 - Geophysical Surveying and Mapping Services 238912 - Nonresidential Site Preparation Contractors 333132 - Oil and Gas Field Machinery and Equipment Manufacturing 486210 - Pipeline Transportation of Natural Gas 237120 - Oil and Gas Pipeline Construction

Source: BLS

Figure 12: Ohio and Pennsylvania Natural Gas Employment[9]

7. IHS Global Insight (2009) notes that employment in these sectors also includes employment in the oil sector and other sectors (not just natural gas). They calculate some national estimates of natural gas's share of overall employment in each sector. For example, they estimate natural gas's employment share for the following industries as follows: (1) 2111-Oil and gas extraction, 213111 - Drilling Oil and Gas Wells, and 213112 - Support Activities for Oil and Gas was 74% in 2008; (2) 237120 - Oil and Gas Pipeline Construction was 68% in 2008; (3) 333132 - Oil and Gas Field Machinery and Equipment Manufacturing was 65% in 2008 and (4) 238912 - Nonresidential Site Preparation Contractors was 16% in 2008). We could have used IHS Global Insight's shares in our calculations, but we believe this would **understate** the increase in the size of the natural gas sector in Pennsylvania because some of the gains would be attributed to other sectors.
8. Academic economists generally use a multiplier of 2 as an upper bound multiplier. For example, Stabler and Olfert (2002) describe a range of employment multipliers in the 1.1 to 1.5 range. Hughes (2003) describes that *output* multipliers above 2.5 are likely very questionable. Likewise, Kelsey et al. (2009) found an output multiplier for natural gas in Pennsylvania to be in the 1.86 to 1.90 range, further showing that our 2.0 multiplier is reasonable. Indeed, as the economy becomes more global, fewer employment gains are on-shore or local, which would reduce employment multiplier effects. Likewise, with outsourcing and increasingly fragmented supply chains, firms are further shifting their purchases outside the firm, which further reduces the amount purchased locally. Further, keep in mind that the energy sector is highly capital intensive which would work to reduce the employment effects and increase the output effects in a multiplier. Thus, we believe our use of an employment multiplier of 2 would be viewed as "generous" by independent academic economists.
9. The direct effects would commonly include the drilling and extraction activities while indirect effects would normally include inputs such as pipeline construction and field equipment manufacturing. Hence, this is why we state that we are already including some of the key inputs as direct employment in Figure 12.

We believe that independent and academic economists in regional and urban economics would view our 20,000 employment estimate as reasonable and some may view it on the high end of actual job creation.[10] For example, Barth (2010) notes that other studies found a multiplier for oil and gas as low as 1.4. She also notes that in similar input-output studies, other industries were found to have higher multipliers than oil and gas, with agriculture having one of the highest multipliers. If shale development adversely effects employment in (say) coal mining, agriculture, and tourism, then those numbers should be subtracted from these numbers to derive the actual employment effects (including any multiplier effects in those sectors). To be sure, we only calculate an impact style estimate to give a feel of the overestimated effects produced by industry consultants (and others who produce impact studies). There are much better approaches than impact studies to calculate actual effects, which we describe below.

One other issue is that proponents of natural gas expansion in Ohio often claim that lower natural gas prices will provide a major stimulus to overall employment, especially in manufacturing. While we will not assess whether natural gas prices are a sufficient share of a typical firm's cost structure to make a tangible difference, we do note that there are reasons to be skeptical of those claims (though we hope we are wrong). Foremost, to make a difference on Ohio's relative competitive edge compared to the rest of the United States and the rest of the world, it would have to be an event that helps Ohio's businesses much more than in the rest of the world. However, as we note in the discussion surrounding Figure 6, shale natural gas is a global phenomenon, meaning that falling natural gas prices will benefit a significant share of Ohio's global competitors. Thus, there is no "edge" given to Ohio's businesses that would make them tangibly more competitive than their national and international competitors.

Economists typically subject their forecasts to "smell tests" by making comparisons to similar events. In our case, comparing energy development around North Dakota's Bakken shale formation in the far northwestern part of the state is good benchmark to assess whether our 20,000 job forecast for Ohio makes sense. Specifically, development of North Dakota's Bakken shale region has been about the same magnitude as the energy development in Pennsylvania and should produce somewhat comparable job effects on both states.[11] During the October 2007-October 2011 period (or a four year period that corresponds to Kleinhenz & Associates' Ohio study), the entire state of North Dakota added about 39,000 jobs. It is highly unlikely that this is all due to energy as high commodity prices (for example) have supported North Dakota's relatively large farm economy. Further, we would expect that the Bismarck metropolitan area (which is relatively close to the mining activity) to be more impacted by the energy boom, while the Fargo and Grand Forks metropolitan areas that are hundreds of miles away on the Minnesota border to be considerably less affected. In this comparison, Bismarck added 4,600 jobs during this four-year period, while Fargo and Grand Forks metropolitan areas respectively added 4,400 and 1,600 jobs. These figures strongly suggest that North Dakota's relative prosperity is more widespread than just an energy boom in the Bakken region. So, even if all 39,000 North Dakota jobs were due to energy (which we have already shown is highly unlikely), this would be a far cry short of the 200,000 jobs that have been forecasted for Pennsylvania and Ohio despite the comparable size of the three states' energy booms.[12] Thus, our forecast of 20,000 jobs over the next four years is further supported as a reasonable forecast based on the North Dakota experience.

Although Pennsylvania's natural gas employment gains are impressive, they still represent just a small share of total state employment. From 2004 to 2010, the employment share of oil and natural gas related sectors shown in Figure 12 increased from 0.30% to 0.48% (see Figure 13). This small employment share is simply not enough to have a significant effect on total jobs and on unemployment for the state.[13] Despite the significant increase in natural gas jobs from 2009 to 2010,

10. For example, there are many factors affecting the actual employment number. If there are workers from out of state, Ohio's employment number would be lower. Conversely, if more landowners are in state compared to Pennsylvania, that would increase the employment number. Other factors are harder to predict such as mining's effect on agriculture and timber.
11. U.S. Bureau of Labor Statistics Data (Current Employment Statistics) suggests that between October 2007 and October 2011, mining employment (which is due to the direct energy production) increased by about 12,000 in both states. The other employment numbers referred to here are from the same source.
12. U.S. Bureau of Labor Statistics Data shows that North Dakota had an October 2011 unemployment rate of 3.5%, which seems quite low compared to the 9.0% national rate. However, North Dakota always has very low unemployment rates due to long-term structural reasons (Partridge and Rickman, 1997a, 1997b). For example, it was an even lower 3.0% in October 2001, well before the energy and commodity price boom of recent years, illustrating that the energy boom is only a partial reason for North Dakota's current low unemployment rate.
13. To give a further feel for the size of the natural gas sector in Pennsylvania, Barth (2010) finds that in January 2010 there were 48,777 Walmart employees in Pennsylvania (almost double that of the natural gas industry broadly defined) and approximately 400,000 jobs in the tourism industry.

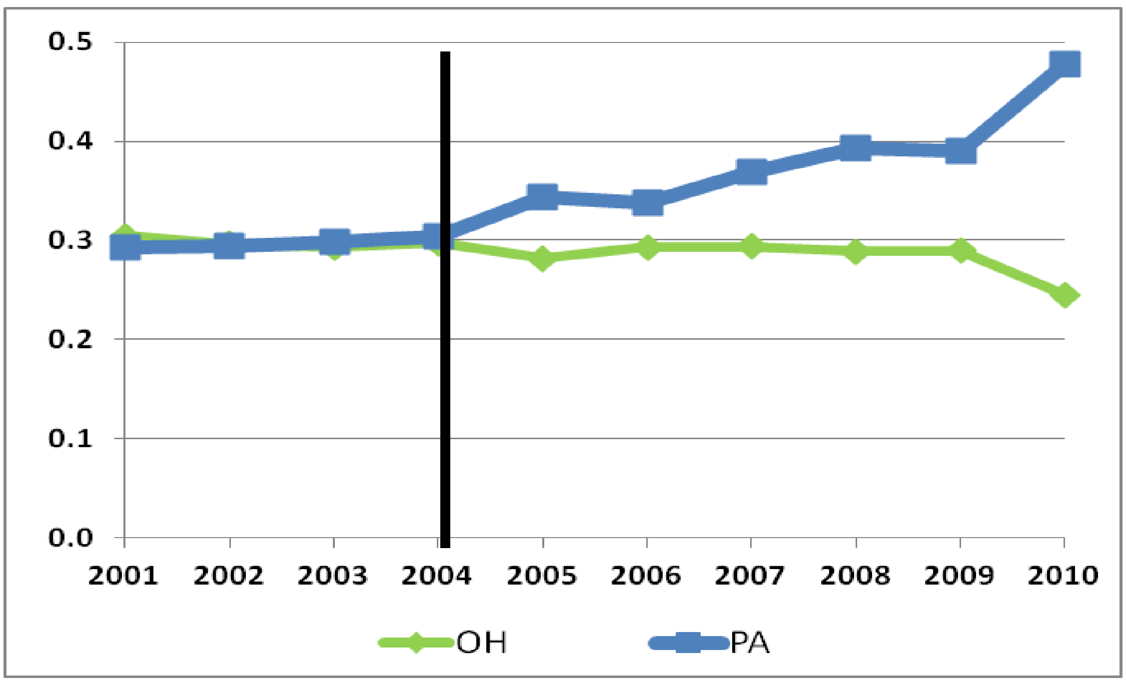
Pennsylvania's unemployment rate still increased from 8.0% to 8.7% during this time (BLS: U.S. Department of Labor, Bureau of Labor Statistics). At most, natural gas employment effects would be localized. Conversely, Ohio's unemployment rate remained unchanged at 10.1% from 2009 to 2010 (BLS) despite a loss in the energy sector jobs in Figure 12, illustrating that natural gas employment is not driving either state's economy.

Concerns with the Economic Impact Studies of Natural Gas Development:

Impact studies are typically associated with overstatements of the employment effects of new development. For example, the Considine et al. (2011) study appears to include indirect and induced jobs before applying the multiplier effect, which double-counts effects and blows up the estimated effects. Direct jobs should include those jobs directly associated with drilling the wells and extracting the natural gas. Indirect jobs include the jobs associated with various inputs required by the industry such as pipelines. Induced jobs should include those jobs and services required by the workers such as restaurants and entertainment.[14] The final two categories should be the outcome of the multiplier process.

Second, Considine et al. assumes that 95% of natural gas industry spending will occur in Pennsylvania. Kleinhenz & Associates assumes a slightly more conservative 90% of all spending will be spent in Ohio. In global economies in which state economies are integrated with national and international economies, such assumptions would not be credible for independent economists. Moreover, because the industry is relatively new and undeveloped, more of the inputs would be brought in from outside of the state, e.g., from Texas.[15]

There are other problems with impact studies because, in reality, more of the money leaks out. For example, Kelsey et al. (2011) found 37% of the Marcellus employment has gone to non-Pennsylvania residents and that landowners save or invest approximately 55% of the money they make from royalties/lease payments rather than spending it in the local economy. They use these



Source: BLS

Figure 13: Ohio and Pennsylvania Natural Gas Employment Shares of Total State Employment

14. Examples of jobs that should not be categorized as direct to natural gas mining are Finance & Insurance, Educational Services, Health, Arts & Entertainment, Hotel & Food Services, etc. By including these jobs as direct jobs, Considine et al. is essentially double counting the employment effects. While we do not have Considine et al.'s programming we believe one source of the double counting derives from how household spending from lease payments/royalties are treated. Even using the job estimates of Considine et al., it is still not a significant portion of the total employment in Pennsylvania.
15. We believe a more reasonable approach would have been to use the default state spending shares from the IMPLAN software (i.e., Considine et al. overruled IMPLAN's default numbers and incorporated 95%). In the absence of detailed and regional I-O data, other shortcuts have been used such as payroll to sales ratios (Oakland et al., 1971; Rioux and Schofield, 1990; Wilson, 1977) or Value-added to gross outlays by industry (Stabler and Olfert, 1994).

	Population 2005	Per Capita Income 2005	Employment Growth Rate 2001-2005	Employment Growth Rate 2005-2009	Income Growth Rate 2001-2005	Income Growth Rate 2005-2009
Non-Drilling Counties	255,508	$32,187	5.3%	-0.4%	12.6%	13.6%
Drilling Counties	124,928	$27,450	1.4%	-0.6%	12.8%	18.2%

Source: BEA

Table 1: Pennsylvania County Descriptive Statistics

more realistic findings to develop a better estimate of the economic impacts of shale development in Pennsylvania. Using IMPLAN, Kelsey et al. (2011) find that in 2009, Marcellus shale development economic impact was over 23,000 jobs and more than $3.1 billion. Our estimate of 20,000 jobs then closely corresponds to Kelsey et al.'s estimates (2011).

Finding Counterfactuals to Assess Growth:

The key problem with impact studies is that they do not estimate the actual number of jobs created by mining because of all of the displacement effects. They are not the true counterfactual and economists have not viewed them as best practice for decades (Irwin et al., 2010). Economists have developed other more credible approaches in developing a counterfactual, such as difference in difference approaches. One of these approaches is to match drilling counties to non-drilling counties that otherwise would have had similar employment patterns if there was no drilling. Thus, the goal is to find counties that would have looked similar to the drilling counties in the absence of drilling. We describe this approach below.

Although natural gas employment does not seem to have had a significant impact on the state as a whole, it may still have a sizeable impact on the specific counties, many of them rural. Table 1 presents data for Pennsylvania counties before and after drilling. Table 1 shows that before 2005, drilling counties are notably struggling more than non-drilling counties. Drilling counties on average are less populated, more rural, have lower per capita income and less employment growth. Natural gas leases also provide an additional source of income for landowners. Landowners that choose to lease their land to natural gas companies generally receive an upfront payment per acre and royalties on the gas produced from the well. Although the payout varies, it can be quite sizeable. From Table 2, it seems natural gas development is positively related to per capita income growth rates for drilling counties.

Table 1 highlights the fact that drilling counties on average look very different than most non-drilling counties. Thus, we look specifically at 3 significant high-drilling counties in the northeast (Tioga, Bradford, and Susquehanna) and 3 in the southwest (Washington, Greene, and Fayette).[16] We then match each of these two sets of mining counties to similar non-mining counties (as of 2009) based on population and similar employment and income dynamics *before* 2005 and the advent of shale drilling.[17] Figure 14 shows the mining and non-mining counties that were chosen. Figure 14 shows that the matches are divided into the Northeast quadrant of the state and the southern part of the state. The appendix provides additional graphs directly comparing each drilling county with its matched

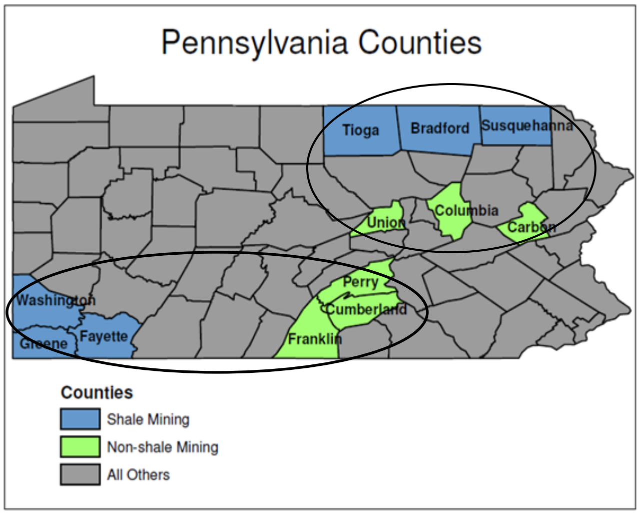


Figure 14: 2009 Matched Drilling and Non-drilling Counties

16. Drilling counties were matched to non-drilling counties on the basis of population and general urbanization as well as region (either north or south).
17. Matching studies can employ other mathematical approaches to finding matches. As will be apparent, our choice of non-drilling counties will appear to be good matches.

non-drilling county.

Using BEA employment and income data, the shale mining counties are compared to the non-mining counties with 2004 marking the point immediately before drilling activities began. One of the key features of the employment and income data is that both mining and non-mining counties are on similar growth paths prior to drilling, suggesting there they are good comparisons (see Figures 15-18 in the next pages). Figure 15 suggests that mining counties may have had faster job growth in the Southern region, but Figure 16 shows that the opposite applies in the Northeastern region. Overall, there are no clear employment effects for heavily drilled counties. We are not saying there are no drilling employment effects, but that they are not large enough to be detected in this commonly used matching approach. One reason may be that many of the new jobs may go to people outside the state who have previous experience in natural gas extraction.[18] Conversely, the positive impacts on incomes are more clear. Figures 17 and 18 show the per capita income impact of natural gas drilling appears to be positive in both Southern and Northeastern regions. While the effects may differ in longer-run periods, our four year window conforms to Kleinhenz & Associates' four year forecast for Ohio.

To be sure, there are many things happening in these county economies, but such efforts to form the true counterfactual are more in line with best economic practice than the impact studies that are often used by economic consultants. In particular, one especially appealing feature is that our approach is based on actual employment and income data and not based on the assumptions of computer software.

For further comprehensive analysis to appraise whether our previous matched results are correct, we now perform a statistical analysis on all counties within Pennsylvania. To control for county-specific effects, we use a difference-in-difference approach to find the impact of drilling on the change in employment after drilling compared to the change in employment before drilling. Details of the difference-in-difference methodology are provided in the appendix, but essentially we are examining whether having more natural gas wells is associated with more job and income growth, but this time we are considering all Pennsylvania counties. This approach accounts for the fact that drilling and non-drilling counties may have systematic differences (fixed effects) for a variety of reasons - and we are adjusting for these differences. Table 2 shows that the number of wells drilled since 2005 has no statistically significant effect on employment.[19] Overall, we believe that there have been modest employment effects in drilling counties, but they are not large enough to statistically ascertain (most likely due to some of the offsetting factors we just described). The upshot is decision makers who are interested in the actual job creation effects of natural gas need to take much more seriously the displacement effects throughout the economy.

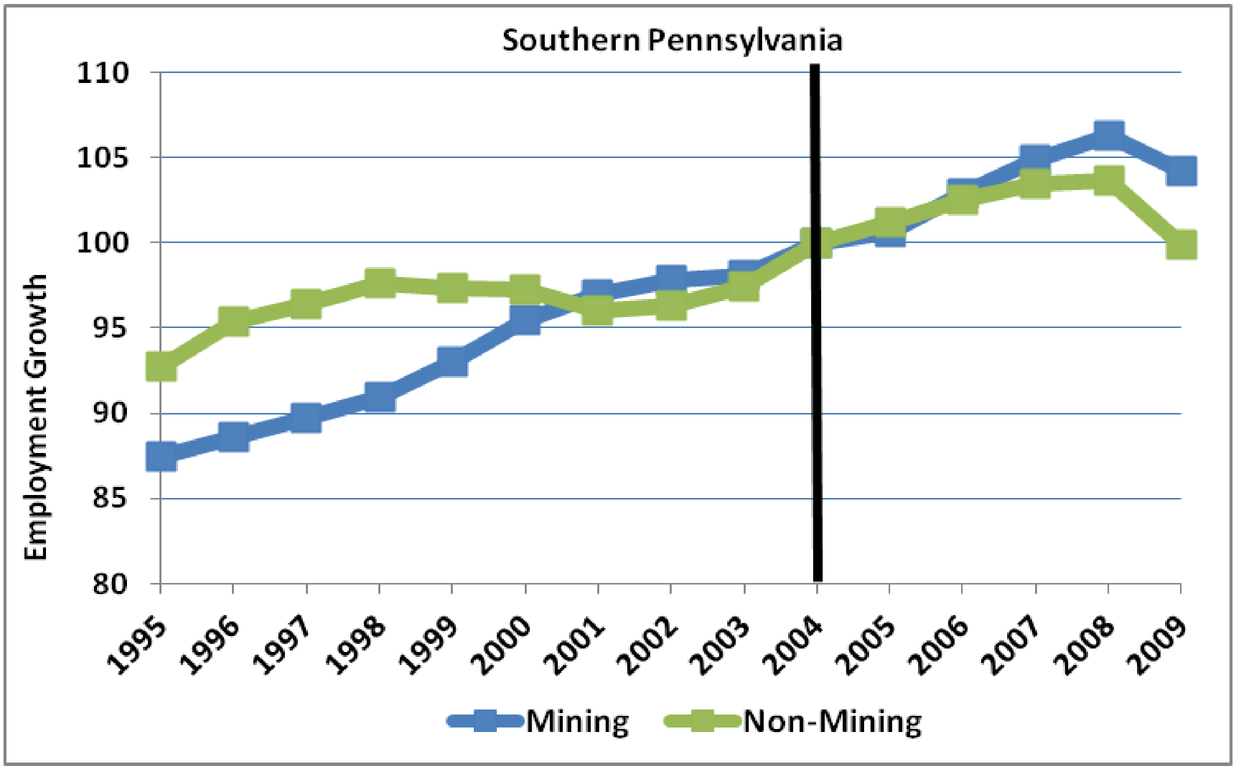
There are many important reasons why we would expect natural gas' impact on employment to be small or insignificant, which explains the findings in Figures 15 and 16 and in Table 2. Besides displacement, one reason is the production technology of natural gas. Like other fossil fuel energy industries, natural gas is rather capital intensive.

	Change in Percent Employment Growth 2005-2009 Compared to 2001-2005	
	Parameter Estimate	t-value
Total Wells 05-09	**1.769E-05**	**1.14**
2001 Log Population	0.023	2.64
2001 Log Per Capita Income	-0.096	-1.55
N	67	
R2	0.118	
Adjusted-R2	0.076	

Source: BEA and Pennsylvania DEP Data. See the appendix for more details.

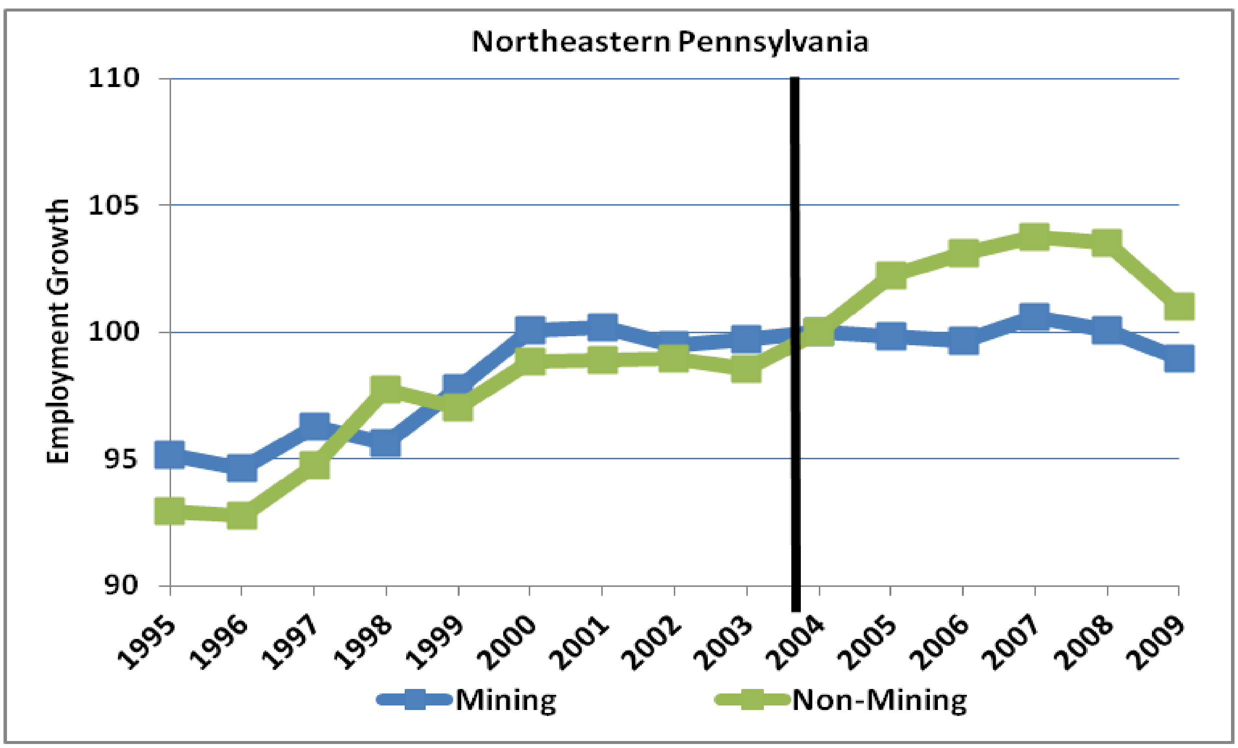
Table 2: Employment Effects of Drilling

18. Pennsylvania and Ohio residents may not have the skills and experience needed to meet the demands of the natural gas industry and royalty/lease monies may not be spent locally. Similarly with natural gas spending, Pennsylvania may not have the services and supply chain the energy industry requires initially. Along with other displacement effects, this may explain the lack of employment response.
19. We also considered that possibility that there are threshold effects (or other nonlinearities) in which drilling does not affect economic growth until a certain number of wells are drilled. We did this by adding a number of wells drilled squared term to the model. This variable's coefficient was negative and statistically insignificant in both the income and employment growth models, suggesting that there are no nonlinear effects. Additionally, these numbers don't account for people switching from part time to full time employment.



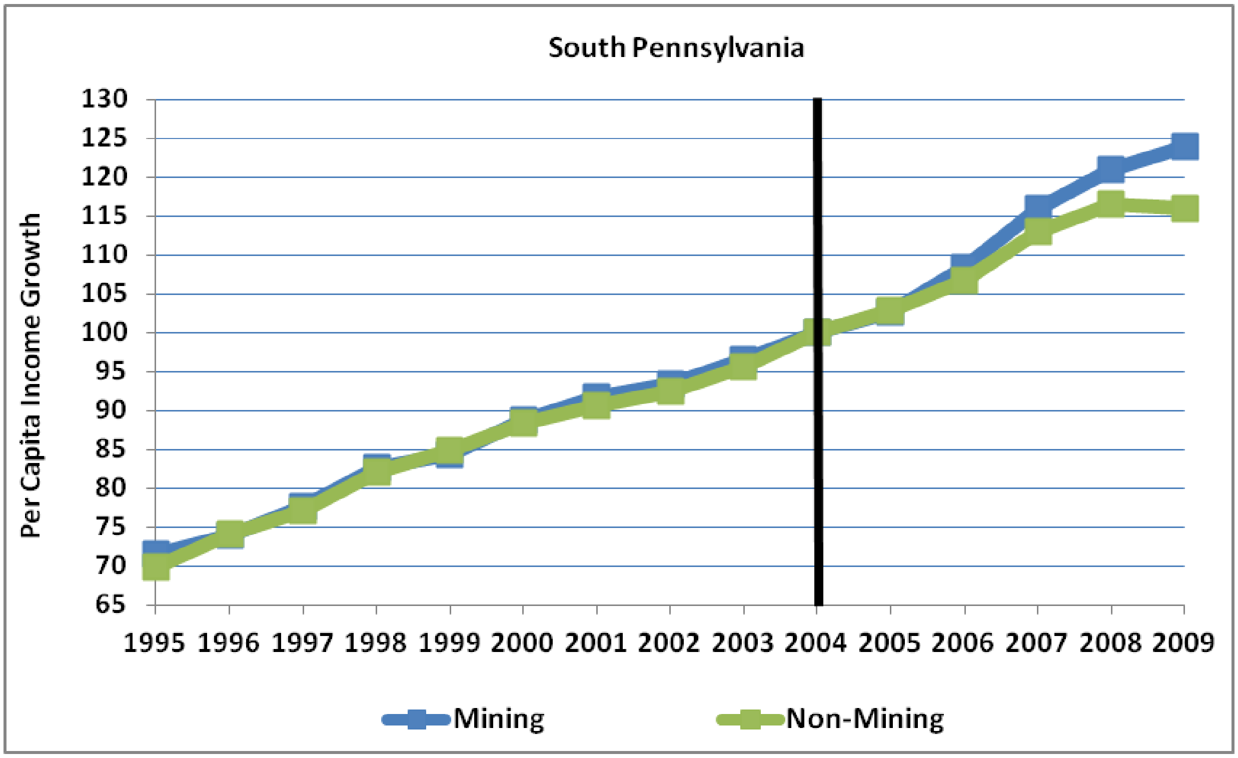
Source: BEA Mining counties (Washington, Greene, and Fayette) Non-mining counties (Perry, Franklin, Cumberland)

Figure 15: Drilling and Non-drilling Employment Comparison (2004=100)



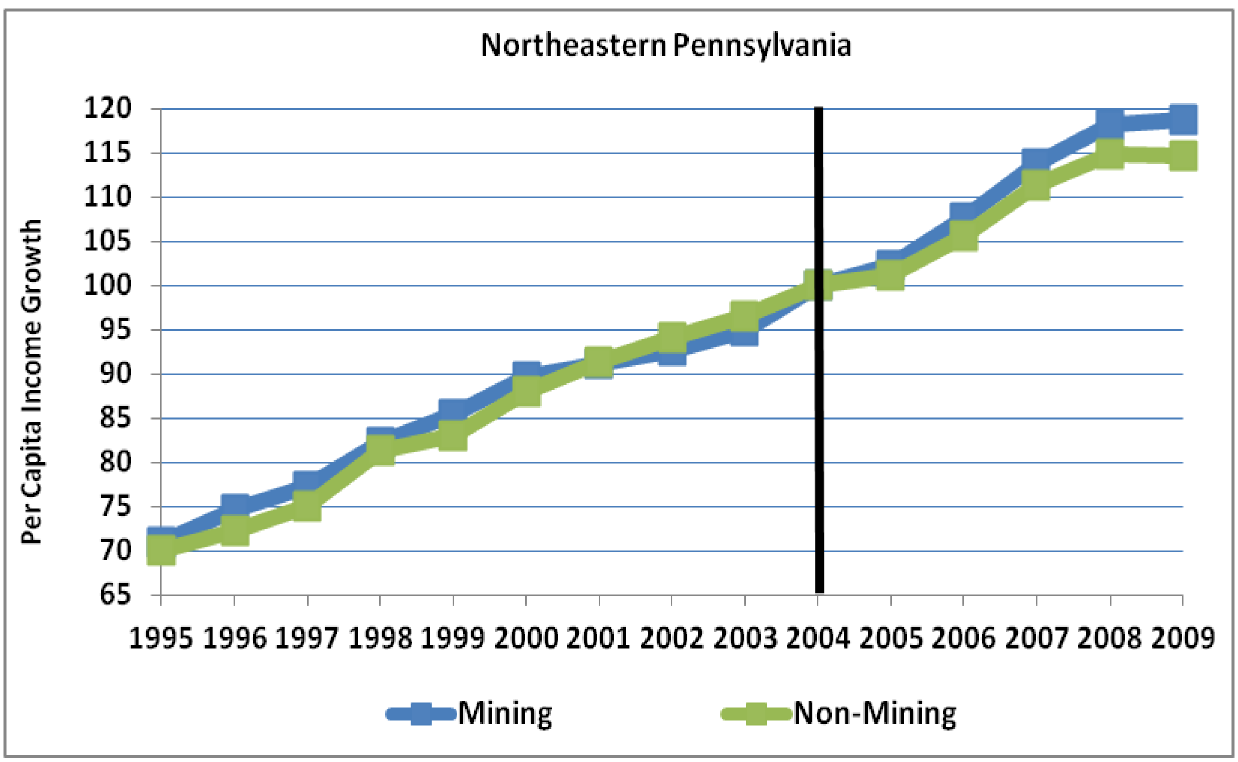
Source: BEA. Mining counties (Tioga, Bradford, and Susquehanna) Non-mining counties (Union, Columbia, Carbon)

Figure 16: Drilling and Non-drilling Employment Comparison (2004=100)



Source: BEA. Mining counties (Washington, Greene, and Fayette) Non-mining counties (Perry, Franklin, Cumberland)

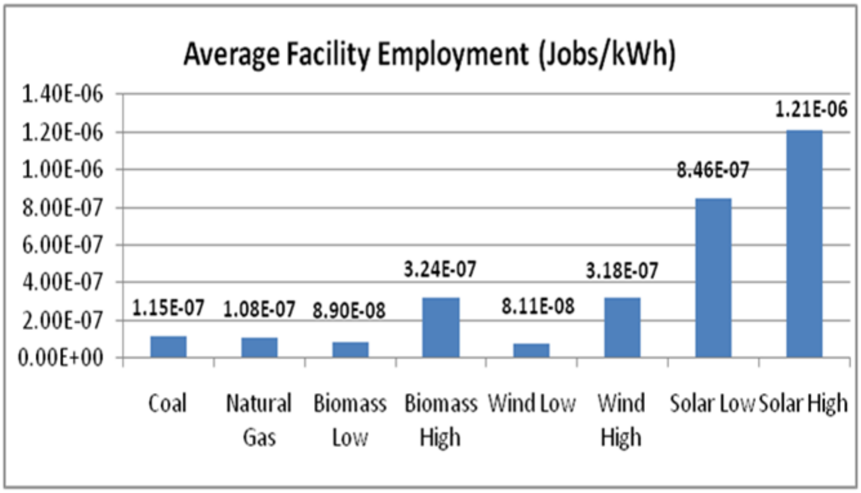
Figure 17: Drilling and Non-drilling Per Capita Income Comparison (2004=100)



Source: BEA. Mining counties (Tioga, Bradford, and Susquehanna) Non-mining counties (Union, Columbia, Carbon)

Figure 18: Drilling and Non-drilling Per Capita Income Comparison (2004=100)

Figure 19 shows the estimated number of jobs required to produce a kWh of electricity. Natural gas actually requires fewer jobs to produce a given amount of electricity than coal. The job requirements for natural gas electricity production are low because it is efficient at producing a kWh. In this case, fewer jobs created is actually a good thing for the overall competitiveness of the economy because that implies low-cost electricity, but it means that natural gas drilling has smaller employment impacts.



Source: Weinstein et al. (2010) chart using data from Kammen et al. (2004)

Figure 19: Jobs Requirements to Produce a kWh by Energy Source

As figure 3 shows, most natural gas resources (32.8%) are used for electricity. When switching from coal to natural gas, there will be significant displacement effects in addition to the effects of natural gas being more productive than coal in producing a kWh. Using the same technique shown in Weinstein et al. (2010), Table 3 shows the approximate employment effects of even large shifts (25% of the kWh produced from coal to kWh generated from natural gas) are rather small. In both cases, there are small employment losses with Ohio having more employment losses due to a higher percentage of electricity being generated from coal.

	Total kWh from Coal 2009	Change in Jobs	Change in Energy Costs (millions)	Change in Emissions (lbs)
Ohio	113,711,997,000	-195	-$491,804	-23,822,663,372
Pennsylvania	105,474,534,000	-181	-$456,177	-22,096,914,873

Source: EIA and Weinstein et al. (2010)

Table 3: Effects of Displacing Coal with Natural Gas

	Change in Percent income Growth	
	Parameter Estimate	t-value
Total Wells 05-09	**2.515E-05**	**2.11**
2001 Log Population	0.084	2.53
2001 Log Employment	-0.086	-2.76
N	67	
R2	0.205	
Adjusted-R2	0.167	

Source: BEA and Pennsylvania DEP Data

Table 4: Income Effects of Drilling

Table 4 shows the regression results for a difference-in-difference for county per-capita income. In this case, the income injected into the economy by the natural gas industry through leases and wages appears to have a significant positive effect on per capita income. These results, along with the employment regression results, verify our previous analysis using matched drilling and non-drilling counties. Drilling seems to have a positive and significant effect on income in drilling counties - but not on employment.

The Benefits and Costs of Natural Gas

Once the realistic expectations of the employment and income effects of shale natural gas development are properly assessed, these impacts can be included when weighing the benefits and costs of shale gas.

The Benefits of Natural Gas:

Other than the income effects and modest employment impacts, additional benefits to natural gas include lower energy prices, natural gas imports, and carbon emissions (especially compared to coal). First, Figure 20 below shows the average levelized cost to produce a kWh. As shown in Table 3, natural gas decreases electricity costs for end users. However, if natural gas prices are too low it will be less economical to pursue shale gas.[20]

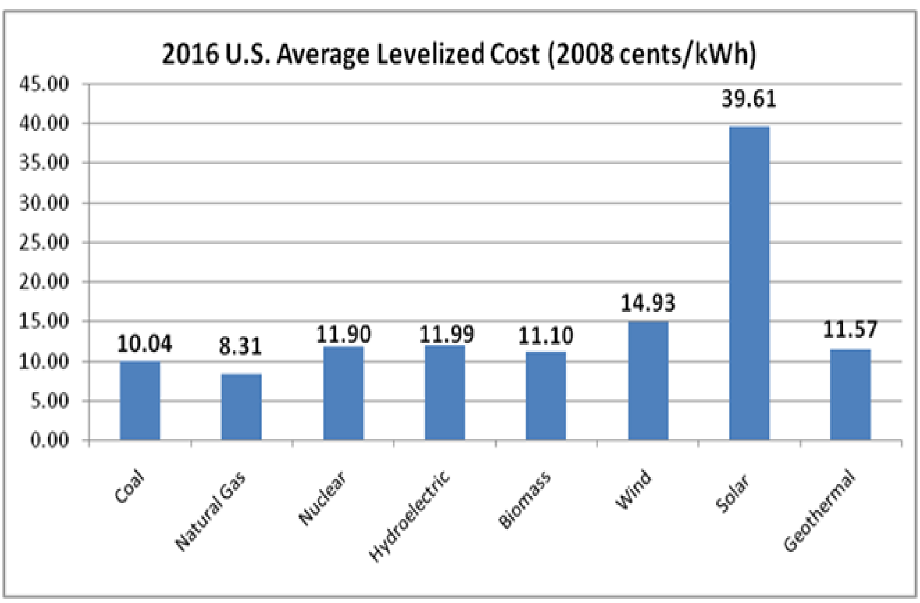
Pennsylvania and Ohio are also good locations to produce natural gas as there is significant natural gas infrastructure in the area and large population and industry centers that require natural gas as shown in Figure 21 on the next page. This proximity further decreases energy costs by reducing transportation costs.

Increasing domestic sources of natural resources are reducing the demand for foreign gas. The EIA reports that 87% of the natural gas consumed in 2009 was produced domestically. Figure 22 on the next page shows that since 2007, natural gas imports have been declining. However, as already noted, future increases in natural gas production will have very little effect on "energy security" as our largest problem relates to oil imports.

The potential benefits of natural gas have been touted by both the industry and the US EIA. However, the ability to supply the country's energy's needs may have been overstated. In the 2011 Annual Energy Outlook, the EIA estimates that 2,543 Tcf of potential natural gas resources could supply the U.S. for approximately 100 years at the 2010 level of annual consumption. However, this does not account for the increasing trends in consumption. Accounting for the trend in consumption from 1974 to 2010, this estimate falls to 65 years. Using a more recent trend from 1986 to 2010, the estimate falls to 52 years. Despite the significant reserves, natural gas energy strategies still suffer from typical fossil fuels problems such as nonrenewability.

The Environmental Benefits and Costs:

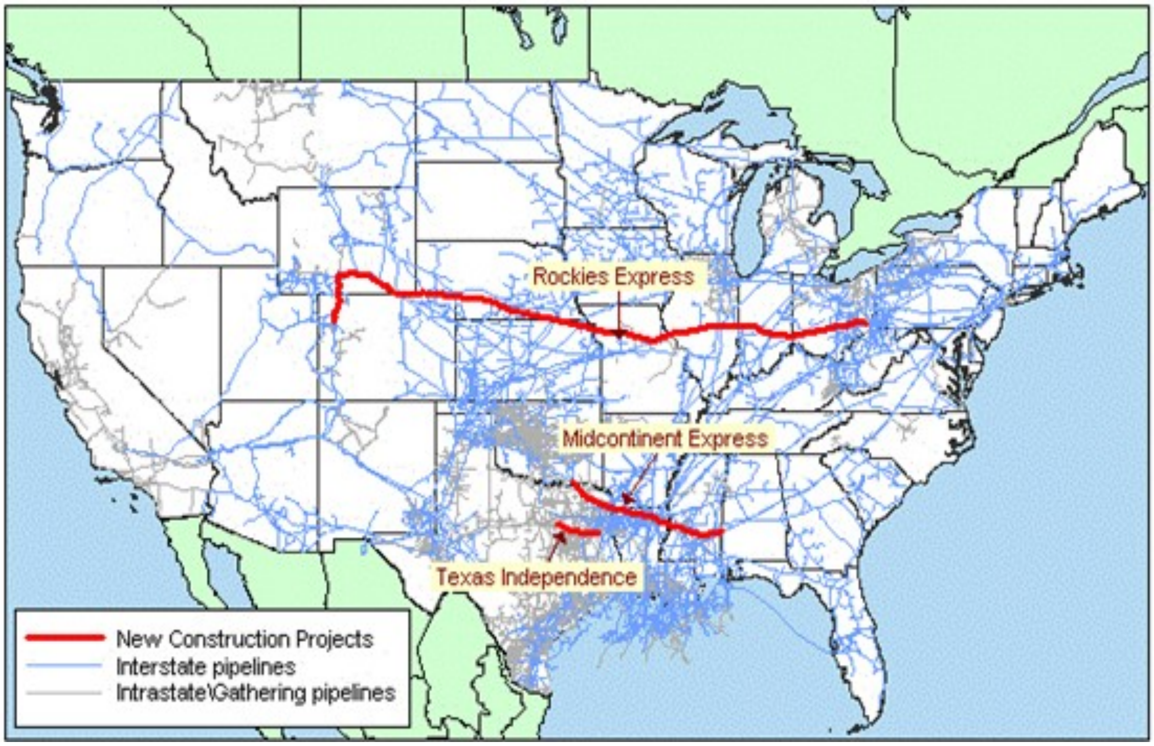
Natural gas is often viewed as a bridge between a reliance on carbon emitting fossil fuels and an energy industry comprised of some mix of alternative energy sources with far less reliance on foreign energy and carbon emitting energy sources. Figure 23 on page 22 shows the life cycle emissions rates for various sources of electricity generation. Although natural gas emits significantly more carbon than nuclear and alternative energy sources, it does emit far less than coal. Thus, as table 3 showed, switching from coal to natural gas will not only save money on energy costs it will also reduce carbon emissions. Natural gas combustion emits lower levels of carbon dioxide, nitrogen oxide, and sulfur dioxide than both coal and oil. Yet,



Source: Weinstein et al. (2010) using data from the EIA

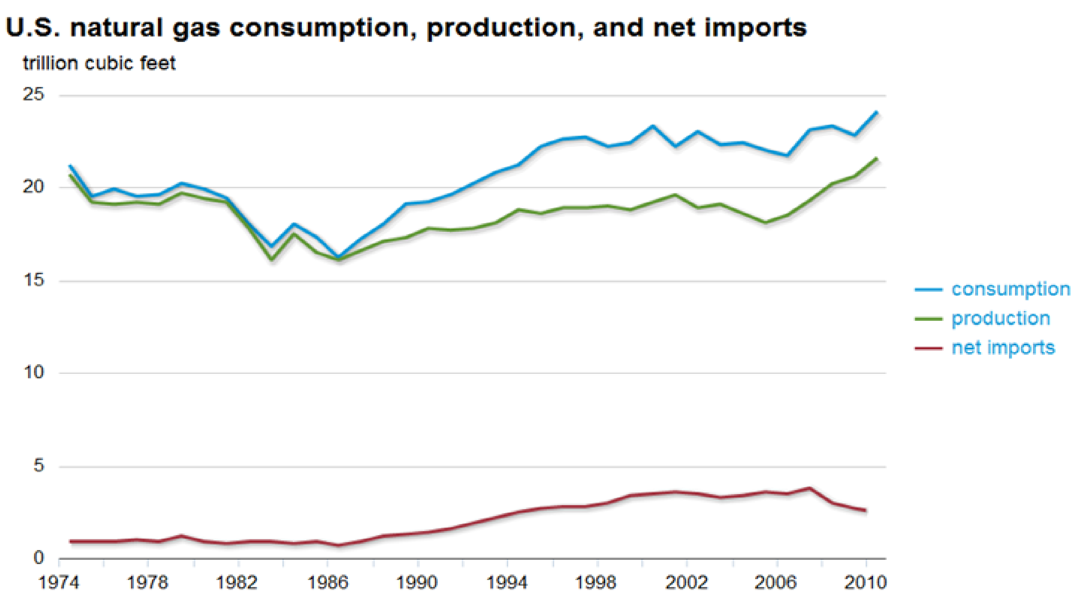
Figure 20: Energy production costs by energy source[21]

20. It should also be noted that a decoupling of natural gas prices from oil prices has realigned markets (Southgate and Daniels, 2011).
21. The average levelized cost is the present value of all costs including building and operating the plants.



Source: EIA, GasTran Natural Gas Transportation Information System.

Figure 21: Natural Gas Infrastructure



Source: EIA

Figure 22: Increasing Production Reduces Imports

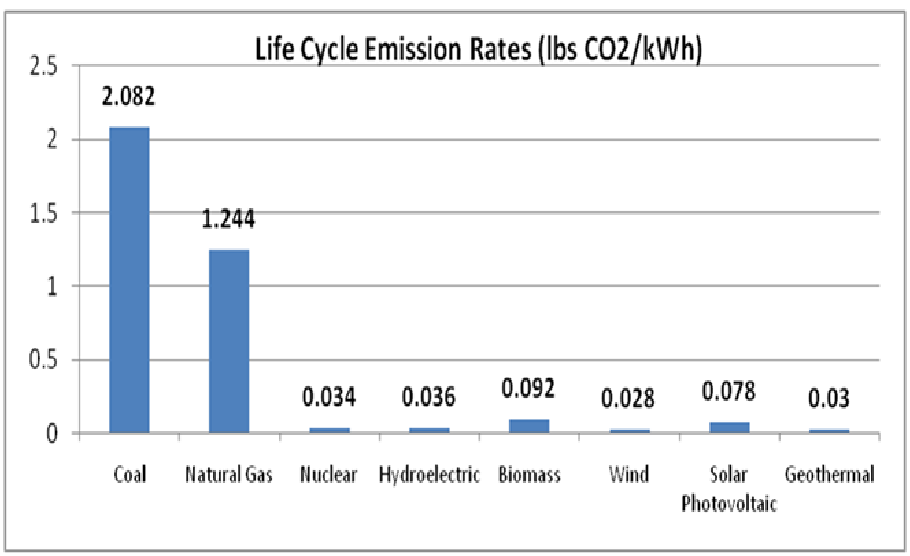
Howarth et al. (2011) find that the carbon emission benefits of natural gas are less when it extracted using hydraulic fracturing compared to conventional methods because of the water and wastewater transportation.

Despite the potential emissions advantages of natural gas, significant concerns have been raised about the environmental impact of natural gas extraction with a Duke University study finding elevated levels of methane in water near drilling sites (Osborn et al., 2011) and the EPA's recent announcement that hydraulic fracturing chemicals polluted water sources in Wyoming (The Associated Press).

The environmental concerns with natural gas have been focused on the hydraulic fracturing process and its impact on water sources. The importance of understanding the hydraulic fracturing process is essential in understanding its potential environmental effects. If cracks aren't able to be controlled or predicted during hydraulic fracturing or somehow disturb the ground, then natural gas or fracturing fluid containing toxic chemicals may shift or migrate to aquifers affecting drinking water. However, hydraulic fracturing typically occurs at depths well below the level of aquifers and drinking water. At thousands of feet below water sources, it is unlikely that hydraulic fracturing would contaminate water sources in Ohio. A 2004 EPA report found that, although fluids migrated unpredictably, hydraulic fracturing did not affect underground drinking water and posed no health risk. Representatives of the natural gas industry have made similar claims that hydraulic fracturing has never contaminated drinking water sources. These claims were used to exempt the natural gas industry from the Clean Water Act and the Safe Drinking Water Act when Congress enacted the 2005 Energy Policy Act.

Although the hydraulic fracturing method of injecting fluids deep below the aquifer level may not be a source of contamination, this level and aquifers themselves must be drilled through. Casing failures in the drilling process may cause fracturing fluids or natural gas to escape and pollute aquifers and local water sources. There are also concerns over spills that can occur during transport or impoundment failures. Thus, whether hydraulic fracturing has contaminated water sources becomes an issue of semantics as to whether the cause is the actual hydraulic fracturing or the drilling, extracting, and spills. Because of the potential impacts on water sources, it is important to be aware of the location of water sources compared to the location of shale resources. Figures 24 and 25 on the next page show the water resources of the US (aquifers are differentiated by various colors). US water resources and shale resources are clearly geographically overlapping though they are at different depths (including in Ohio and Pennsylvania).

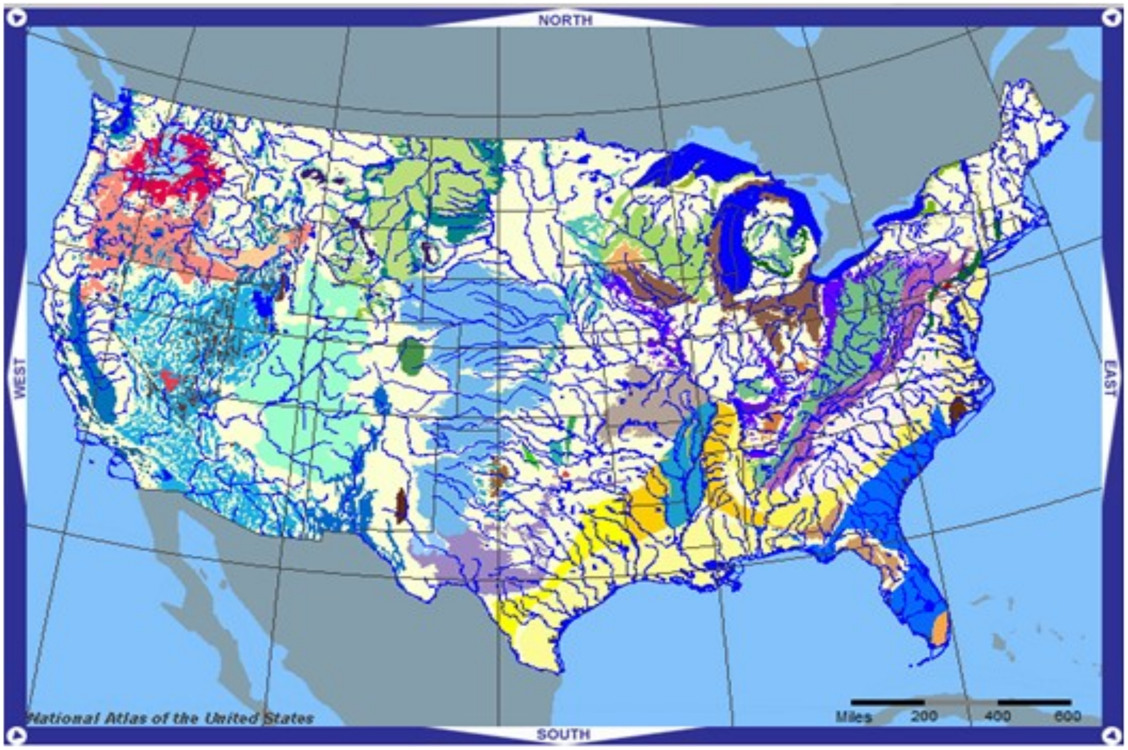
In addition to accidental contamination in the drilling and extraction process, water use and disposal are also concerns. The hydraulic fracturing method requires at least a million gallons of water per well that is combined with chemicals and sand. Sapien (2009) notes that approximately 9 million gallons of wastewater per day were produced from Pennsylvania wells in 2009, and this amount is expected to increase. This water byproduct contains elements and chemicals such as cadmium and benzene that are known to cause cancer. There may be other toxic chemicals in the hydraulic fracturing fluid mix though energy companies have continually refused to disclose these chemicals for proprietary reasons. Water byproducts also contain Total Dissolved Solids (TDS) that can make the water five times as salty as



Source: Weinstein et al. (2010) using data from Meier (2002)

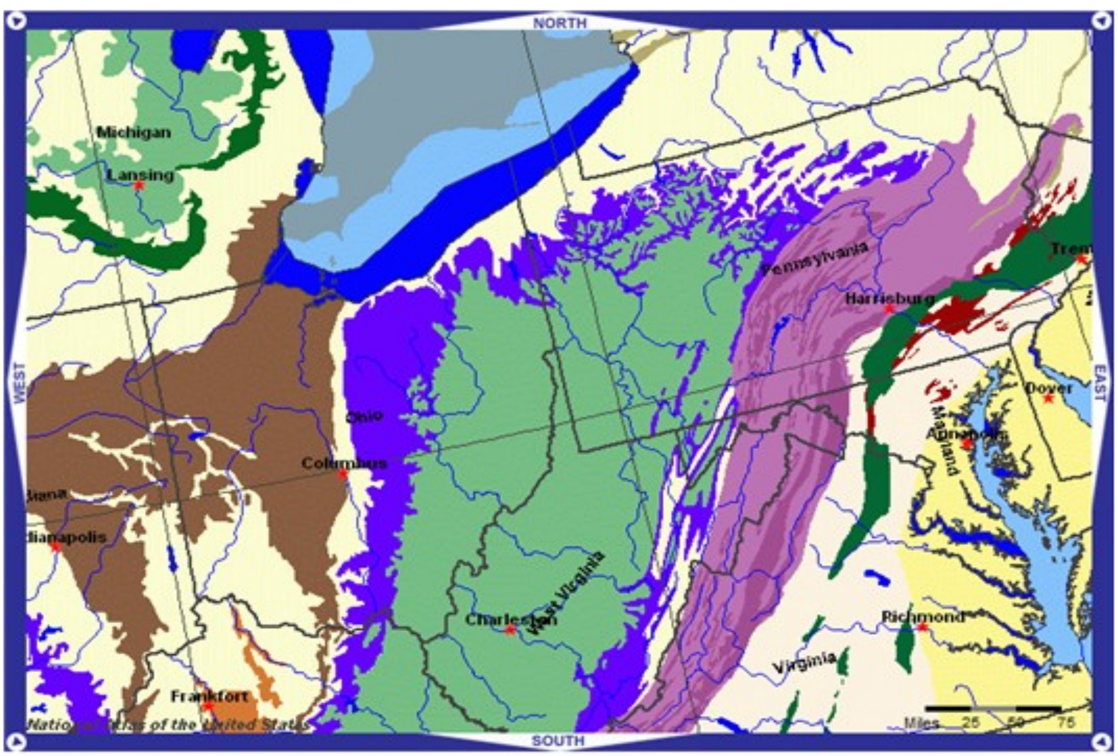
Figure 23: Carbon Emissions by Electricity Source[22]

22. Life cycle emissions rates include the total aggregated carbon emissions over the life cycle of the fuel, including extraction, production, distribution, and use.



Source: NationalAtlas.Gov

Figure 24: US Aquifer, Stream, and Waterbed Resources



Source: NationalAtlas.Gov

Figure 25: Ohio and Pennsylvania Aquifer, Stream, and Waterbed Resources

seawater. Although some of this water is left behind and some can be reused, there is still a significant amount that must be treated and disposed. Water byproducts must be stored in either open wells, closed containment wells, or injected back into the ground. Open wastewater wells can lead to air pollution as it evaporates and water contamination if the lining fails, but this method is less expensive than other methods. There are additional air pollution concerns with the increased traffic resulting from water transportation, flaring, etc.

There are also environmental costs in the form of noise pollution. Ohio residents may simply not want to look at or hear natural gas rigs in their backyard or heavy equipment driving through the countryside. Hydraulic fracturing does limit the number of rigs used compared to conventional methods.

The potential environmental impact of hydraulic fracturing on water in Ohio needs to be accounted for when estimating the economic costs of natural gas. Just as the employment and income effects for Ohio were estimated using Pennsylvania as a case study, the potential environmental impacts of hydraulic fracturing and natural gas drilling on Ohio can be approximated by examining incidents in Pennsylvania. Whether the source of contamination is from the migration of fluids and gas underground, drilling or extraction accidents, or improper disposal of water byproducts, it is important to understand what Pennsylvania residents have experienced. After gaining a better understanding of the environmental impacts, then it is important to determine the source of the contamination, how it can be prevented, and whether new regulations are needed to protect the Ohio environment and its drinking water.

Pennsylvania Environmental Concerns:

In 2008, Lustgarten noted that more than 1,000 cases of suspected contamination have been documented in Colorado, New Mexico, Alabama, Ohio, and Pennsylvania. Incidents of contamination have been most publicized in Dimock, PA. Dimock is located in Susquehanna County in northeastern Pennsylvania where natural gas development is most pronounced. Dimock is a struggling rural area with approximately 1,300 residents and nearly 1 in 7 is unemployed. Residents hoped the natural gas industry would turn their economy around. Instead, the controversial documentary *Gasland* contends it environmentally turned it upside down.[23] The documentary begins and ends in Dimock and includes footage of residents lighting their tap water on fire. After natural gas drilling began in Dimock, Lustgarten notes that several of the residents' wells have exploded. Affected residents now buy water from outside sources. The Pennsylvania Department of Environmental Protection (DEP) believes a casing failure is to blame for the drinking water contamination and is holding Cabot Oil responsible. Cabot Oil has agreed to supply clean water to some of the affected residents and has been required to pay compensation to many residents. In September of 2009, Cabot Oil spilled nearly 8,000 gallons of fracturing fluids that seeped into a nearby creek.

Evidence of fracturing fluid has now been found in drinking water sources including the Monongahela River. In response to these cases and others, the natural gas industry has been quick to label these events as unfortunate but highly unlikely implying that these cases are the result of just a few "bad apples." In some cases they claim methane has always existed in these water sources, but simply went unnoticed until now. Without conducting baseline water testing before drilling, the burden of proof required by the courts in many cases cannot be met to prove otherwise.

The *New York Times* publicized recent peer-reviewed research by Duke University showing an association between drinking water contamination and natural gas extraction. The study by Osborn et al. (2011) conducted research at 68 private water wells in Pennsylvania and New York finding that methane concentrations were 17 times higher for wells near active drilling, with some wells having methane levels requiring "immediate action." However, the study found no evidence of fracturing fluid contamination in these wells. The prevalence and commonality of these incidents, coupled with the devastating impacts, seem to suggest the need for caution. Some chemicals, particularly in the produced water, may be harder for residents to detect than methane, especially when the industry refuses to disclose all of the components of the fracturing fluid mixture. Regardless, it is clear that more information on the environmental impacts of natural gas is needed in deciding any need for further regulations.

Recent EPA Action:

Recognizing the need to further understand the true impacts of natural gas extraction, specifically hydraulic fracturing, Congress directed the EPA to

23. It should be noted that *Gasland* did not undergo the scientific scrutiny of a peer-reviewed journal article and because no baseline testing was conducted in *Gasland* or any research thus far, it is difficult to discern the source of contamination and whether it came from gas industry activity. Hopefully, US EPA research will answer these questions in 2012.

study the impact hydraulic fracturing has on drinking water and groundwater. The EPA (2011) identified seven case studies, three of which are in Pennsylvania, to examine the lifecycle of a well and whether hydraulic fracturing affects drinking water. The EPA will also collect information from computer modeling, laboratories, and other data from the industry, states, and communities. Initial results of this study are expected in late 2012. Hence, it is unlikely that there will be any national regulations in the near future, while Ohio hydraulic fracturing in the Marcellus and Utica has already begun. Until Congress or the EPA acts, the regulation of hydraulic fracturing is left to the states.[24]

Ohio Environmental Protection:

Because the EPA and Congress have essentially relegated any regulatory authority to the states, this increases the importance of the Ohio EPA and the Ohio Division of Mineral Resources Management (ODNR) for environmental regulations. The Ohio EPA (2011) states that ODNR has primary regulatory authority over natural gas drilling, including the treatment and disposal of wastewater in the hydraulic fracturing process. The Ohio EPA also has water quality certification requirements to help preserve wetlands, streams, rivers, and other water sources. The appendix includes a list of the regulatory authority between ODNR and the Ohio EPA.

The Ohio Farm Bureau's Dale Arnold contends that Ohio has better regulatory authority over the oil and gas industry compared to Pennsylvania. Although the Cuyahoga River fire in 1969 in Cleveland, OH was not associated with fracturing, Scott (2009) notes it was a catalyst not only for Ohio environmental regulations, but also the national Clean Water Act in 1972 and the creation of the US EPA (and Ohio EPA). Dale Arnold reckons that even before the Cuyahoga fire, Ohioans had built a "collective consciousness," learning from past oil and gas industry experiences, preparing themselves for future waves.

Ohio's collected experiences and advanced environmental regulations have certainly left the state better prepared to handle the wastewater produced from hydraulic fracturing than Pennsylvania. Much of the wastewater from Pennsylvania comes to Ohio injection wells. Hunt (2011) notes that in June of 2010, Ohio quadrupled out-of-state fees to limit brine coming in from Pennsylvania and other states while anticipating the increased disposal needs of Ohio's own burgeoning natural gas industry. Despite the increased prices, nearly half of the brine in Ohio injection wells came from Pennsylvania after its officials banned 27 treatment plants from dumping brine into streams. This highlights the importance of Ohio properly addressing the issue of wastewater.

Ohio has made strides in environmental regulations through the drilling permitting process. Permits or "frac tickets" are required for gas companies planning on using hydraulic fracturing to extract natural gas. A frac ticket requires that companies disclose the chemicals used in the fracturing fluid. If a spill or casing failure should occur, Ohio will know many of the possible contaminants for testing. Ohio's permitting also allows residents to more easily prove their water has been contaminated with fracturing fluid.

Because many of the residents that will be most affected by shale gas development are farmers, the Ohio Farm Bureau is advising farmers and residents on the leasing process and is recommending that residents establish independent baseline water and soil quality measures that have been so notably missing from Pennsylvania and elsewhere. In addition, it is now standard practice in Ohio for gas companies to do their own baseline testing on all residents' water within 3,000 yards of the drilling site.

Even with better regulations, accidents may happen. Lustgarten (2009) recounts a 2007 incident of a house explosion in Bainbridge, OH. In a later report, ODNR found that a faulty concrete casing failure from a nearby natural gas well caused methane to be pushed into an aquifer during hydraulic fracturing, which then found its way into the plumbing, building up in the basement of the house.

The Cuyahoga fire itself and other serious environmental incidents have a more profound impact than just on the environment. Congressmen Louis Stokes said in regards to the Cuyahoga fire, "It portrayed a totally different image of Cleveland than the image of a productive, progressive city that was making news of a progressive nature" (as quoted in Scott, 2009). The lessons of the Cuyahoga fire resonate for natural gas development. The negative impacts on the environment can affect communities in lasting ways that cannot be exactly quantified but still require consideration.

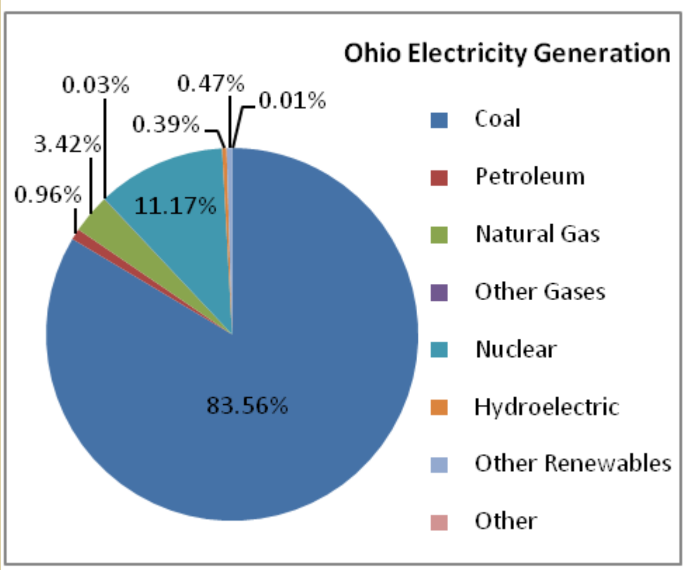
24. In 2009, members of Congress introduced the Fracturing Responsibility and Awareness of Chemicals Act, also called the "Frac Act," to undo the natural gas industry's exemption from the Safe Drinking Water Act and require the industry to disclose the chemicals used in the fracturing process. Though reintroduced in March of 2011, it is not expected to pass.

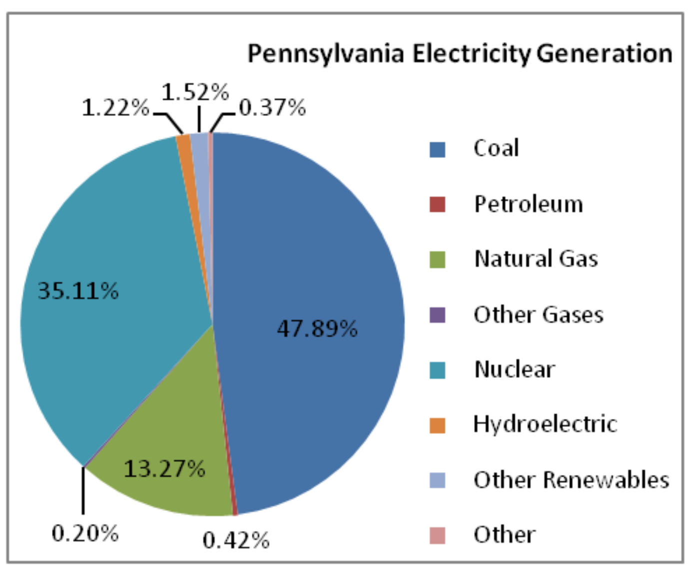
Conclusion

Hydraulic fracturing has made natural gas extraction possible and more productive in shale resources that were previously deemed uneconomical. This has brought a new wave of natural gas extraction to Ohio and other areas. However, recent experiences with hydraulic fracturing have also opened a new debate about the costs and benefits of natural gas extraction. Gary Walzer, Principle Engineer at EMTEC, states that natural gas has the potential to be a substantial source of domestic energy that is cleaner than coal with lower emissions. This has the potential to decrease US reliance on coal. Compared to Pennsylvania, Ohio clearly has a less diversified energy portfolio that relies heavily on carbon emitting coal. Based on electricity generation alone, Ohio is emitting significantly more carbon than Pennsylvania. Natural gas could be a significant first step for Ohio to diversify its energy portfolio and reduce carbon emissions.

Compared to coal, natural gas is not only cleaner but also less expensive to produce electricity. Producing energy in close proximity to where it is needed further lowers energy prices for consumers and industry. Unlike alternative energy, there are market forces pushing for the production of natural gas without the use of inefficient subsidies, though all of the social costs of natural gas (and coal) are not sufficiently priced. Low natural gas prices provide evidence that it is highly efficient for producing electricity. This efficiency is one reason why natural gas is associated with fewer jobs than coal—but the lower costs make the rest of the economy more competitive.

Does all of this also mean that natural gas will create significant numbers of job for Ohioans? Previous studies on the economic impacts of natural gas appear to have widely overstated the economic impacts. This is not surprising, as these studies are typically industry-funded and industry-funded studies are usually not the best sources of information for economic effects (regardless of the industry). One reason for the overstatement is the energy industry is generally very capital intensive. Alan Krueger, Chief Economist and Assistant Secretary for Economic Policy at the US Department of Treasury stated in 2009, “The oil and gas industry is about 10 times more capital intensive than the US economy as a whole… suggesting these tax subsidies are not effective means for domestic job creation” (US Department of Treasury). The energy industry as a whole also does not account for a significant share of employment. Even if the natural gas industry experiences significant job growth, its employment share is too small to have any significant effect on unemployment rates and on the economy (with the exception of remote rural areas such as in rural Western North Dakota). Previous studies on the economic impacts also fail to account for the displacement effects that the natural gas industry will have on other industries. Finally, from a national perspective greater natural gas production will displace other fossil fuels and their workers as they are no longer needed, in





Source: US EIA

Figure 26: 2009 Electricity Generation Profiles

particular coal.

We use Pennsylvania as a case study to estimate the employment effects of drilling that Ohio can realistically expect. Our analysis shows the employment effects of natural gas are modest given the size of the Ohio and Pennsylvania economy. We show this through (1) an assessment of impact analysis, (2) by comparing drilling counties with similarly matched non-drilling counties in Pennsylvania, (3) statistical regressions on the entire state of Pennsylvania, (4) employment comparisons with North Dakota's Bakkan shale region, and (5) an examination of the employment life cycle effects of natural gas and coal per kilowatt of electricity. Our results are not unexpected as the economic literature has long pointed to the adverse effects of natural resource development through phenomenon such as the "natural resources curse" and Dutch Disease. Likewise, a recent Cornell University study found similar overstatements by the oil industry in terms of job forecasts for the Keystone XL pipeline (Cornell University ILR School Global Labor Institute, 2011). On the other hand, our approaches suggest that natural gas activity will increase per-capita income. We expect this is primarily among landholders receiving royalties/lease payments and through higher wages in the industry. Thus, we expect a short-term infusion of income in affected economies.

As Christopherson and Rightor (2011) point out, it is important to realize these are fairly short-term estimates and may still not account for the cycle of the natural resource boom. The initial boom causes competition for labor in the short-term, bidding up wages. This makes the area less competitive and "crowds out" other sectors, especially those that rely on low cost labor such as agriculture and tourism. As housing prices are bid up, this will also further displace low-income workers. In the long-run, the business climate may suffer as there are fewer businesses that are unrelated to the oil and gas industry, which makes the local economy less diverse and more vulnerable to economic shocks. Our advice to counties experiencing drilling activity is to ensure they properly pay for infrastructure needs upfront, place monies in reserves for after the boom, and build up local assets such as schools in order to produce lasting benefits from energy development.

Finally, the environmental costs of natural gas need to be realistically addressed by the industry and regulators. Although natural gas can reduce carbon emissions compared to coal and other fossil fuels, there are concerns about its effect on drinking water. Because Ohio has been able to learn from Pennsylvania's experiences with the oil and gas industry, Ohio seems better prepared to deal with the environmental risks. Nevertheless, a realistic assessment of the environmental costs of natural gas should also include the environmental opportunity cost of natural gas. Natural gas mainly displaces coal, which emits even more carbon and also has additional environmental and safety concerns. A Clean Air Task Force report unequivocally states that "coal irreparably damages the environment." Coal poses significant health risks to both miners and nearby residents. Despite the number of years the US has been extracting coal, there are still significant issues with its waste products. Most recently on Oct. 31, 2011 a bluff collapse caused coal ash to be spilled into Lake Michigan (Jones and Behm, 2011). In 2008, the *New York Times* reported that experts called the Tennessee ash flood that dumped over 1.1 billion gallons of coal ash waste "one of the largest environmental disasters of its kind" (Dewan, 2008). We are not understating the environmental costs of natural gas, but rather putting it into perspective in relation to the environmental costs of coal, which is natural gas's main competitor.

Although we should not expect natural gas to be a big job creator, there are significant benefits to producing natural gas that are getting lost in the hype of job creation. Raising expectations that natural gas will not be able to meet is setting Ohio residents up to be disappointed. The true benefits of natural gas need to be highlighted while putting the costs into perspective. Likewise, Ohio needs to plan today about how to make some of the gains from the energy boom permanent. Among many things, this will require innovative policies and funding models to ensure that infrastructure is paid for today and there is adequate funding to maintain that infrastructure in the future.

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Appendix 1: County Comparison Mining (blue) vs. Non-Mining (green)

See notes to figures 15-18 for more details. Southern drilling counties include Washington, Greene, and Fayette. Southern non-drilling counties include Franklin, Perry, and Cumberland. Northeastern drilling counties include Tioga, Bradford, and Susquehanna. Northeastern non-drilling counties include Union, Columbia, and Carbon.

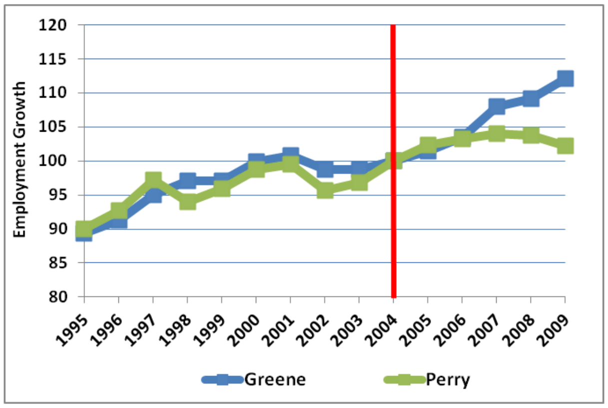

Figure 27: Employment Growth Comparison Greene vs. Perry

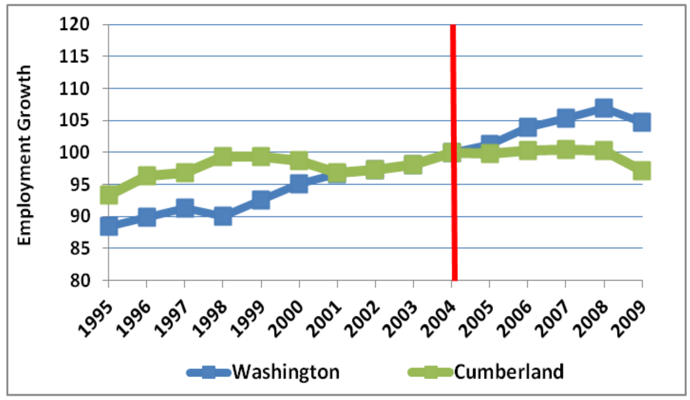

Figure 28: Employment Growth Comparison Washington vs. Cumberland

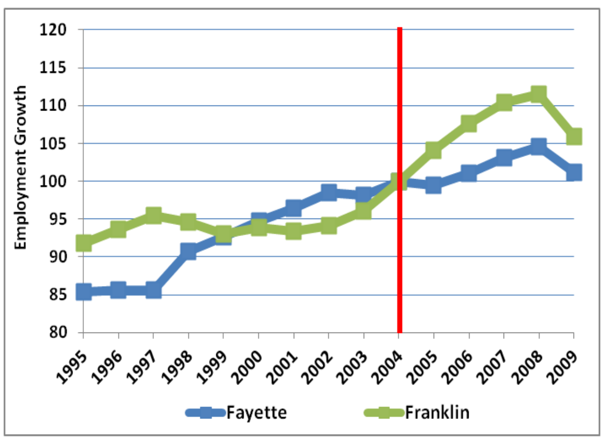

Figure 29: Employment Growth Comparison Fayette vs. Franklin

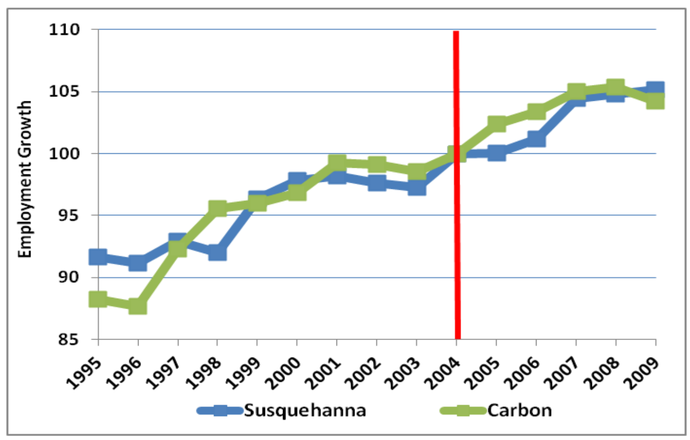

Figure 30: Employment Growth Comparison Susquehanna vs. Carbon

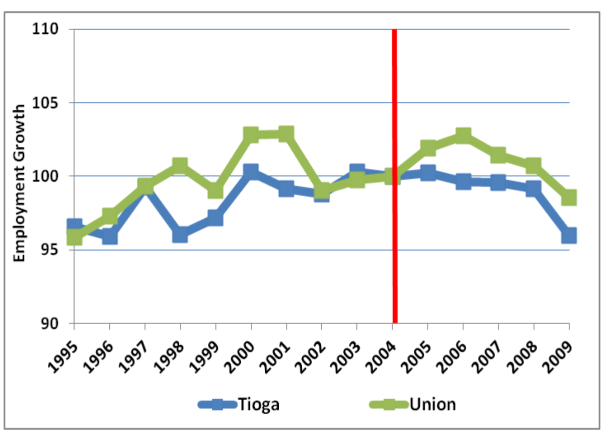

Figure 31: Employment Growth Comparison Tioga vs. Union

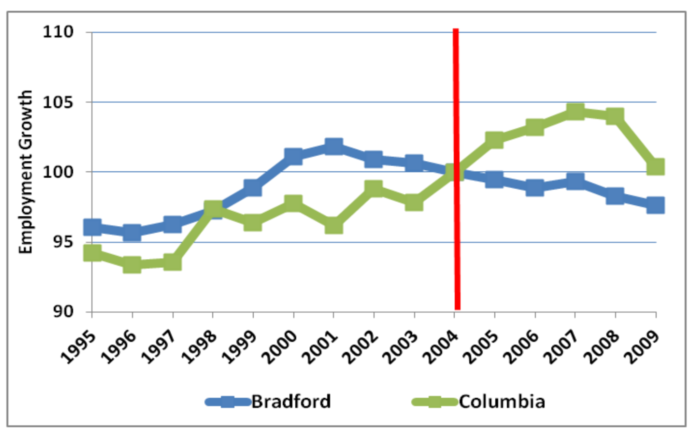

Figure 32: Employment Growth Comparison Bradford vs. Columbia

Appendix 1: County Comparison Mining (blue) vs. Non-Mining (green)

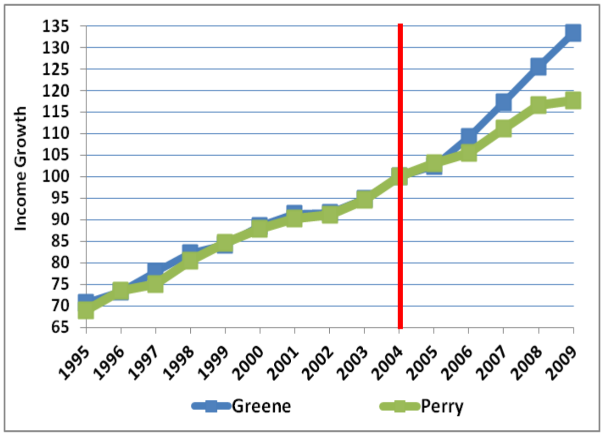

Figure 33: Per Capita Income Growth Comparison
Greene vs. Perry

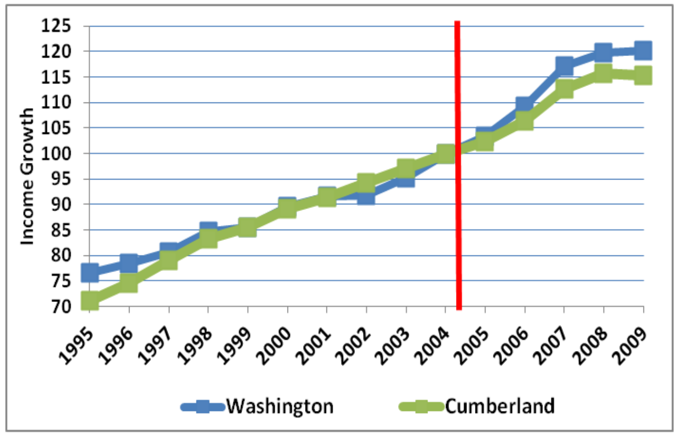

Figure 34: Per Capita Income Growth Comparison
Washington vs. Cumberland

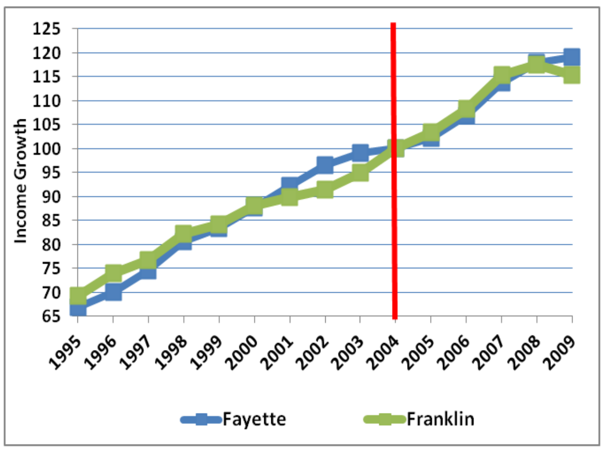

Figure 35: Per Capita Income Growth Comparison
Fayette vs. Franklin

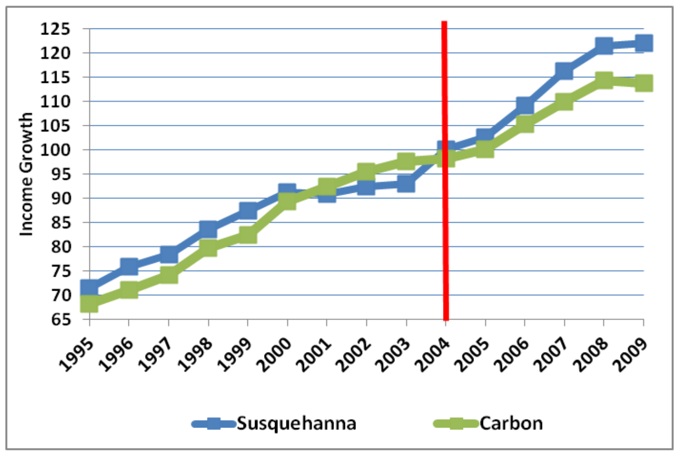

Figure 36: Per Capita Income Growth Comparison
Susquehanna vs. Carbon

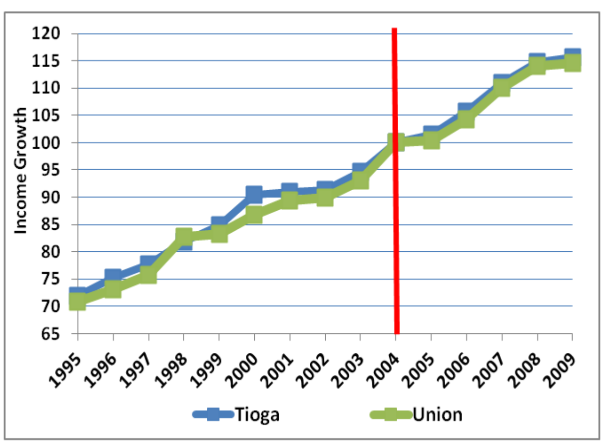

Figure 37: Per Capita Income Growth Comparison
Tioga vs. Union

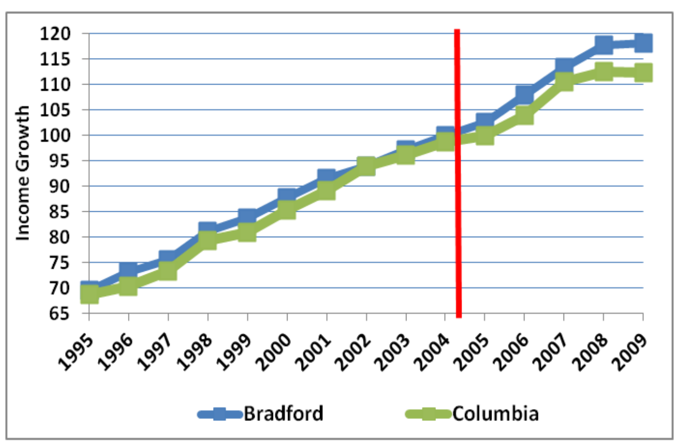

Figure 38: Per Capita Income Growth Comparison
Bradford vs. Columbia

Appendix 2: Statistical Methodology

In 2005, drilling began in Pennsylvania in a number of counties with natural gas potential due to the location of resources in the Marcellus shale. The choice of county to develop shale gas was based on the random occurrence of natural resources and not prior economic conditions. However, there may be other inherent county differences between drilling and non-drilling counties. For example, counties with drilling tend to be rural. Likewise, counties tend to have many factors that influence their economic growth such as the quality of its government, distance to urban centers, and educational and demographic attributes of the population. These factors are either constant or change very slowly. We treat these as county fixed effects on county growth.

We want to measure the economic impacts of drilling. Equation 2 shows the impact of the number of wells on the percent employment growth (Y_{i1}) for county i in period 1 (2005-2009). However, the empirical estimation of this impact would not be able to account for county fixed effects (C_i). This could bias the estimates of the impact of drilling by omitting relevant variables that differentiate drilling counties from non-drilling counties. Thus, equation 3 estimates the impact of drilling since 2005 on the difference in employment growth between period 1 and period 0 (2001-2005). The county fixed effect is differenced out and thus there should not be omitted variable bias.

Table 5 shows the results of this estimation using the total number of well drilled since 2005. We also include additional controls to better account for differences in the way larger or wealthier counties may have reacted to shale development, or more importantly, how wealthier or more urban counties were differentially affected by effects of the housing bubble/bust and the Great Recession. Using the total number of wells parameter estimate, Table 5 shows that drilling has a small and statistically insignificant impact on percent employment growth.

$$Y_{i0} = \beta_0 + \beta_1(\text{Number of Wells})_{i0} + C_i + \varepsilon_{i0} \quad (1)$$
$$Y_{i1} = \beta_0 + \beta_1(\text{Number of Wells})_{i1} + C_i + \varepsilon_{i1} \quad (2)$$
$$Y_{i1} - Y_{i0} = \beta_0 + \beta_1(\Delta \text{ Number of Wells}) + \varepsilon_i \quad (3)$$

A similar method is used to empirically estimate the impact of drilling on per capita income with results presented Table 6. In this case, drilling has a statistically significant impact on percent per capita income growth.

2005-09 Percent Employment Growth Minus 2001-05 Percent Employment Growth	Parameter Estimate	t-value
	Difference in Employment Change	
Total Wells 05-09	**1.769E-05**	**1.14**
2001 Log Population	0.023	2.64
2001 Log Per Capita Income	-0.096	-1.55
N	67	
R2	0.118	
Adjusted-R2	0.076	

Table 5: Impact of drilling on employment

2005-2009 Percent Income Growth Minus 2001-05 Percent Income Growth	Parameter Estimate	t-value
	Difference in Income Change	
Total Wells 05-09	**2.515E-05**	**2.11**
2001 Log Population	0.084	2.53
2001 Log Employment	-0.086	-2.76
N	67	
R2	0.205	
Adjusted-R2	0.167	

Table 6: Impact of drilling on income

Another method to develop a counterfactual to compare how drilling counties would have done if there was no drilling is to use a difference in difference approach. The difference in differences approach treats drilling as a treatment in a natural experiment. The difference in differences estimates the causal effect of the difference between the treatment and control group before and after treatment (drilling). This is shown below in equation 4 where i=0 represents non-drilling counties and i=1 represents drilling counties; t=0 is still the first time period (2001-2005) and t=1 is the second time period (2005-2009).

$$[E(Y_{11})-E(Y_{01})] - [E(Y_{10})-E(Y_{00})] \quad (4)$$

To measure the impact of drilling on the employment growth of county i in time period t (Y_{it}), a control group needs to be established (non-drilling counties). This is further expanded in equation (5). The main effect of

Appendix 2: Statistical Methodology

the treatment group, β_1 controls for the difference between the treatment and control in period 0. The main effect of the second period, β_2 controls for the difference between the effects of the second period compared to the first period. The parameter of interest, β_3 estimates equation 4: the impact of the number of wells had on counties since drilling began in 2005. Through asymptotics, it can be shown that the probability limit of the estimate of β_3 is equivalent to equation 4.

$$Y_{it} = \beta_0 + \beta_1(\text{Number of Wells}_{it}) + \beta_2 t + \beta_3(t*\text{Number of Wells}_{it}) + \varepsilon_i \qquad (5)$$

Table 7 shows the empirical estimation of equation 4 for employment growth. The results are similar to those in Table 5 with the impact of drilling on employment being small and statistically insignificant. Table 8 reports the estimates of equation 5 for per capita income growth. Similar to Table 6, it shows that drilling appears to have had a positive statistically significant impact on per capita income growth.

Percent Employment Growth	Parameter Estimate	t-value
Time Period*Total Wells	**1.763E-05**	**0.91**
Time Period	-0.05	-4.12
Total Wells	-3.240E-06	-0.23
Log Population	-0.005	-0.85
Log Per Capita Income	0.066	1.69
N	134	
R2	0.125	
Adjusted-R2	0.091	

Table 7: Impact of drilling on employment

Percent Income Growth	Parameter Estimate	t-value
Time Period*Total Wells	**3.119E-05**	**2.52**
Time Period	0.0253	3.51
Total Wells	-3.310E-06	-0.37
Log Population	0.009	0.55
Log Employment	-0.007	-0.43
N	134	
R2	0.205	
Adjusted-R2	0.167	

Table 8: Impact of drilling on income

Appendix 3: Ohio Environmental Regulatory Authority

Summary of ODNR and Ohio EPA regulatory authority over oil/gas drilling and production activities

	Ohio Department of Natural Resources	Ohio Environmental Protection Agency
Drilling in the shale deposits	✓ Issues permits for drilling oil/gas wells in Ohio. ✓ Sets requirements for proper location, design and construction of wells. ✓ Inspects and oversees drilling activity. ✓ Requires controls and procedures to prevent discharges and releases. ✓ Requires that wells no longer used for production are properly plugged. ✓ Requires registration for facility owners with the capacity to withdraw water at a quantity greater than 100,000 gallons per day.	✓ Requires drillers obtain authorization for construction activity where there is an impact to a wetland, stream, river or other water of the state. ✓ Requires drillers obtain an air permit to install and operate (PTIO) for units or activities that have emissions of air pollutants.
Wastewater and drill cutting management at drill sites	✓ Sets design requirements for on-site pits/lagoons used to store drill cuttings and brine/flowback water. ✓ Requires proper closure of on-site pits/lagoons after drilling is completed. ✓ Sets standards for managing drill cuttings and sediments left on-site.	✓ Requires proper management of solid wastes shipped off-site for disposal.
Brine/flowback water disposal	✓ Regulates the disposal of brine and oversees operation of Class II wells used to inject oil/gas-related waste fluids. ✓ Reviews specifications and issues permits for Class II wells. ✓ Sets design/construction requirements for Class II underground injection wells. ✓ Responds to questions/concerns from citizens regard safety of drinking water from private wells from oil/ natural gas drilling.	
Brine/flowback water hauling	✓ Registers transporters hauling brine and oil/gas drilling-related wastewater in Ohio.	
Pumping water to the drill site from a public water supply system		✓ Requires proper containment devices at the point of connection to protect the public water system.

Source: EPA (2011)

Working Paper Series

A Comprehensive Economic Impact Analysis of Natural Gas Extraction in the Marcellus Shale

April, 2011

The Economic Impact of Marcellus Shale Gas Drilling What Have We Learned? What are the Limitations?

David Kay[1]

Summary: What is the issue?

Several studies have projected large positive economic impacts of shale gas development in the Marcellus region. To make informed choices for their communities, policy makers need to understand the strengths and limitations of these studies. Most importantly, they need to understand that there is a tenuous relationship between positive economic impacts in the short run and long term economic development based on an extractive, exhaustible natural resource. In addressing the relationship, proactive policy can make a difference.

Keywords

Marcellus Shale, Economic Impact, Economic Development

Author

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Introduction

For several years, the prospects for energy development from gas deposits in tight shale formations have riveted the attention of natural gas industry boosters and detractors across the US. In southern and western shale-rich states, the shift towards shale gas production is definitively underway, if yet in its early stages. In New York in early 2011, unconventional shale gas drilling has remained on hold as debates over the pros and cons of a nascent 21st Century gas rush are fiercely engaged. In New York as well as in Pennsylvania, where shale gas drilling has only recently begun, the extensive Marcellus Shale formation is at the center of policy attention. Few natural resource issues have moved from obscurity to center stage in so dramatic a fashion and within such a short time frame.

Extractive natural resource development has frequently been described as transformative to regions that experience it (Bridge 2004; Power 1996; Sweeney 2010). Many citizens believe that the future of New York's economy, environment, character, and quality of life are at stake because of the geographic breadth of the Marcellus natural gas play and the anticipated scale and pace of its development. Environmental issues, especially those involving water, are currently being intensively scrutinized. However, in this brief we focus our attention on the economy.[2] Our primary goal is to review the existing research into the likely economic implications of shale gas development and to raise questions about what policy makers need to know.[3]

We highlight four key issues that have not been adequately addressed by existing economic impact models but which are critical to understanding the economic consequences of shale gas drilling.

- First: we examine existing studies of the economic impacts of shale gas operations, focusing on those that have been referenced in New York State's still evolving environmental impact assessment documents. Because these studies involve projections based on models, we look carefully at several central assumptions that qualify the applicability of the models.
- Second: we discuss the most critical factor that will affect the regional and local economy – the uncertain pace, scale and geographic pattern of drilling operations, and

the associated need to better understand oil and gas company decisions about where, when and how many wells to drill.[4]

• Third: we highlight the need to better understand the economic behavior of landowners who receive a significant fraction of the gas company local spending through leasing bonuses and royalties.

• Fourth: we review the long-term economic prospects for regions dependent on natural resource extraction industries. In particular, we consider the relevance of substantial research that points to the possibility of diminished long-term economic prospects for regions or communities that become overly dependent on natural resource extraction industries.

We conclude that existing evidence about the Marcellus shale gas operations is inadequate to make predictions about the numbers of jobs that will be created, business expansion, or revenue generation with high levels of confidence. Gas development will direct new money into the region, and the prospects for substantial short-term economic gain for some local businesses and property owners are real. Many economic development opportunities will also arise. On the other hand, mixed economic results are likely even in the short run. The rising tide is not likely to lift all boats: there will be losing constituencies among communities and individuals who are displaced or left behind. Moreover, the experience of many economies based on extractive industries is a warning that their short-term gains frequently fail to translate into lasting, community-wide economic development. Most alarmingly, in recent decades credible research evidence has grown showing that resource dependent communities can and often do end up worse off than they would have been without exploiting their extractive sector reserves. When the metaphorical economic waters recede, the flotsam left behind can in some circumstances be seen more as the aftermath of a flood than of a rising tide.

In the end, it seems clear that neither riches nor ruin are inevitable. The academic consensus is that the quality of policy and governance makes an important difference for realization of an extractive industry's long-term economic development potential. The prospects for positive economic impacts in the short run should not blind policy makers to the potential for long term harm to overall economic development outcomes, especially when responsibly proactive policies may reduce and even reverse this risk.

What is Economic Impact Analysis and How Do We Evaluate the Findings?

Based on the projected size of the resource and anticipated flow of new money into the region, a large positive economic significance of Marcellus shale gas for the region as well as for individual landowners and communities has tended to be taken for granted by policy makers and the press. Even somewhat critical coverage often starts with statements like, "Nearly everyone appreciates the economic benefits derived from the development of… the Marcellus".[5] Studies focused on the regional economic impacts of shale drilling in several producing states have reinforced this predilection by quantifying large positive impacts.[6]

Almost all existing studies employ a well-established method (input-output analysis) that measures changes in the level of product and service sales and how that translates into changes into new jobs (employment) and income (wages) (Miller and Blair 2009). The underlying objective of this method is to estimate the level of overall economic activity associated with increased regional production or sales of particular services or products (such as shale gas), calculating the difference from what would otherwise be expected if the increases did not occur. The term economic impact is thus typically used to refer to the economic contribution a given investment, policy or project may make to the existing local economy.[7]

Input-output analyses of the natural gas industry typically start with the observation that each well drilled is associated with an infusion of dollars to the regional economy. With each well, industry capitalizes on its earlier exploration and leasing expenditures by purchasing some of its drilling-related goods and services from local businesses and workers; eventually local expenditures pertaining to well production, reclamation and well closure will follow. Each producing well also prompts delivery of a stream of payments to government in taxes and of royalties to local landowners who (depending on assumptions) spend some or all of that money locally. Each of these infusions of funding in turn stimulates increased economic activity, or "multiplier" effects on spending, in industries outside the gas extraction sector itself.

Concerns relevant to all input-output studies

In assessing an economic impact model, we can't just look at the end result -- the jobs and revenue numbers that are produced by the model. We also need to pay careful attention to the assumptions underlying the model. Of course, all models have strengths and weaknesses in their assumptions, so we need to determine how severe the weaknesses are in a particular context to make a judgment about the model's usefulness or predictive ability. The strengths of economic impact analyses based on simple input-output modeling assumptions include:

- The relative simplicity, familiarity, and widespread use of the models that make them easy to use and to critique.

- The fact that input-output models are based on descriptive accounting "snapshots" of the economy at one particular point in time and have the related and important strength of reflecting the complex existing web of purchase and sales relationships, or input and output linkages, between all economic sectors.

The limitations of these models include:

- The constraints on the ability of basic input-output models to evaluate economic circumstances in which change in the economy has been or will be rapid and large. In the Marcellus Shale case, this is a particularly relevant concern because of the continuing evolution and application of new drilling technologies on the one hand and the likelihood that boom/bust effects will lead to localized and abrupt effects on prices in factor and input markets (eg. effects on lease prices, housing markets, labor markets as are already seen in Pennsylvania).

• Assumptions about the independence of impacts over time -- the economic effects of drilling activity that occurs in one year are assumed not to interact with those occurring in subsequent years; ie. overlapping or cumulative economic effects are ignored.

• The close tie between input-output modeling and the economic base theory of economic development which privileges exports as the engine of economic growth. This theoretical framework has been sharply and repeatedly challenged for its overly narrow formulation of growth dynamics, its limited prescriptions for policy, and its anemic ability to explain growth empirically.[8]

• Over-simplification of the economy such that certain (so called general equilibrium) economic relationships involving supply and demand effects are assumed away, leading to the result that any increase in drilling will lead to more growth as an inevitability rather than as an empirical proposition to be tested.

• The fact that several important "built-in" model parameters – most importantly those that indicate the proportion of goods and services in every economic sector that will be purchased locally – are costly-to-validate estimates. These estimates may incorporate significant estimation errors for a given industry, particularly in a regional or county level model.

• The difficulty, grounded largely in a lack of available data, of applying this type of analysis at the sub-county or individual community levels, a fact that exacerbates several of the other named limitations. This difficulty is of considerable significance in the case of the Marcellus shale where impacts are likely to be different and unevenly distributed across urban and rural localities.

Economic Impact Studies of the Marcellus Shale

In the next sections we look at several economic impact studies that have been influential in supporting the public perception that Marcellus gas will have large positive economic benefits for the regions in which drilling is occurring. To a greater or lesser extent, all the points we raised about the general strengths and weakness of economic impact models apply to the economic impact studies of the Marcellus shale.

The Broome County Marcellus Economic Impact Study

The Draft SGEIS released by New York State (NYSDEC 2009) features brief highlights of the only study of the possible impacts of shale development on the New York economy that was then available. This impact study was prepared for the Broome County Legislature in 2009 by two Texas based economists (Weinstein and Clower 2009). Noting that about 10-20% of the Marcellus formation lies within New York State, the authors restricted the scope of their analysis to the economic and fiscal impacts of Marcellus gas extraction anticipated in Broome County alone. Of the studies considered in this report, the Broome County Marcellus Economic Impact Study is the most dependent on "back-of-the-envelope" calculations and rough assumptions.

As suggested earlier, the most important factor to consider in a study of the impact of Marcellus Shale gas drilling is natural gas production rates. Whether simply assumed or based on sophisticated estimates or calculations, the quantity and timing of gas production must be specified as a first step in an impact analysis. Only after this step is completed are the results introduced into a model of the regional economy to determine how the entire regional economy is affected by changes in the natural gas sector. In this study, as in all the studies reviewed in this report, MIG's IMPLAN economic modeling system and data sets are used for the economy-wide economic analysis.

Two Scenarios Drive Analysis

The Broome County study authors proposed two basic drilling scenarios. First, they assumed that the entire area of the county would be available for drilling. Presuming that an average of six wells would be drilled per 640-acre (square mile) section, 4,296 wells were calculated to be "hypothetically" possible with blanket penetration. Noting that "downtown Binghamton or the town squares of other communities" are unlikely to host drilling operations, the authors rounded this number of wells downward slightly to 4,000. However, they softened this qualification by suggesting to readers in a footnote that horizontal drilling might make gas under urban centers accessible for extraction.

An essential further assumption was that the wells would all be drilled at a steady pace over an upcoming single decade, ie. 400 wells each year. With little information to go on, no effort was made to assess whether this density and pace of drilling would be politically, economically, environmentally, or technically feasible throughout the entire county. Aside from the "downtown" issue, for this scenario no opportunities or constraints were considered relating to leasing patterns, current land uses, regulatory regimes, corporate goals, landowner preferences, vertical versus horizontal well distribution and productivity, drilling rig capacities and availability, pipeline construction and rights of way, future gas prices, geologic and topographic variation or any other factors that are likely to affect the ten year drilling profile. However, a second scenario does assume without further discussion that just half that total number of wells (2,000) would be drilled. Both scenarios are appropriately presented as hypotheticals rather than as efforts at contingent prediction; little or no justification of either scenario or its likelihood was offered.[9]

To derive an economic value of the gas produced from the wells, the authors next estimated a value per well by multiplying projected prices of gas times the anticipated quantity of gas per well, resulting in ten-year gross revenues per well of $9.3 million, or revenues of $37.2 billion for 4,000 wells. Production and revenues beyond a ten-year time horizon are not considered. Though standard Energy Information Administration (EIA) sources for projections of future natural gas prices were used, no attempt was made to account for the inherent volatility and uncertainty of prices in this sector. It is worth noting in this context that current EIA natural gas price projections are significantly lower (by 9-14% between 2011 and 2020)[10] than those that were available at the time of the study. The overall revenue projections contrast with assumed expenditures of $3.5 million on average to complete each Marcellus well. This translates to total expenditures of $7 and $14 billion for the two drilling scenarios respectively. These figures are based on early drilling costs reported by a single firm (Chesapeake Energy). While not inconsistent with other early cost estimates, the implications of variations from this single estimate are not evaluated. In practice, costs will vary by company, type, length, and location of wells. Also important are timing and the related issues of where drillers are on their Marcellus "learning curve", plus the likely price pressures rapidly accelerated drilling would put on some factor (e.g. labor and land rent) and input (e.g. hydraulic fracturing services) markets.

How Economy-wide Impacts are Estimated

Both the gross revenue and drilling expenditure numbers just discussed were simulated as a stimulus to the Broome County economy using the MIG/IMPLAN derived input-output model. In the case of the expenditure impact, the entire reported expenditure of $3.5 million per well appears to be treated as though it is spent on Broome County businesses in the gas extraction sector. This is an assumption essential to the expenditure results shown. However, not enough detail is presented about the expenditures or the way they are introduced to the model to determine whether this assumed expenditure pattern can withstand closer scrutiny.

The initial impacts introduced into the model produce small "multiplier" effects on the economy county-wide. The modeling effort indicates that the total impact of $7.6/15.3 billion in economic activity over ten years and 813/1,627 jobs (averaged per year) is overwhelmingly attributable to the $7/14 billion of assumed expenditures by shale gas drilling enterprises in the County. The multiplier is very small (at 1.08, slightly greater than the minimum possible of 1.0) mostly because, as the authors note, of the absence of a supply chain or range of natural gas industry support companies in Broome County.[11] Instead, in the short run at least most expenditures on equipment and services would benefit those locations, such as Texas and Oklahoma, where support companies are concentrated. The authors imply that in the longer term the multiplier might increase as support company presence grew in Broome County. The extent of growth it might be realistic to expect would be subject to quite a few contingencies which are not addressed by the study.

This expenditure-based estimate of impacts appears to account for only the business-to-business purchases made directly, or stimulated indirectly, by the gas industry.[12] The authors also present a second set of impact estimates based on the revenues associated with the drilling levels they have assumed. The revenue estimates of impact are larger than the expenditure impacts because they include all the business-to-business expenditure effects plus additional effects associated with increased labor income, profits to local business owners, returns to corporate and real property owners (including interest, profits, rents, royalties, etc.) and others like government who have a claim on some share of total revenues. To reiterate this point: the impacts reported for the expenditure data are actually a portion of, and are again incorporated into, the larger-by-definition impacts reported for the revenue projections.

Among the revenue impacts reported for the two basic scenarios are $21/41 billion in economic activity over ten years and 2,190/4,380 jobs supported per year. The authors explicitly note that IMPLAN's default parameters for this model estimate that "about 15 percent of the spending associated with natural gas production activities will stay in the local economy". Presumably as a result of this small fraction, a very small overall multiplier effect is again in evidence, with economy-wide effects on economic activity projected to be only 11% higher than the assumed initial stimulus. Unfortunately, as noted earlier regarding the expenditures, no clear information is provided on how the initial stimulus is introduced into the model, or how this treatment might have differed between the initial revenue and expenditure impacts. This makes it difficult to assess the technical validity of the results. In any event, it is unlikely that a model based on historical industry averages adequately reflect the reality of a rapidly evolving industry over its first few years in a new location. This applies in particular to the treatment of bonus and royalty payments to landowners – a factor which proves to make an enormous difference to results in studies from other states.

Summary

In sum, these results are based on rough and ready assumptions and calculations. Simplistic assumptions about drilling rates thus serve as the foundation of the analysis, and are translated into initial economic impacts primarily through very early and hence tentative Marcellus well yield information. The resulting gas quantities are then combined with projections of gas prices over a decade. Although their treatment of lease and royalty payments to landowners is unclear, the study authors probably correctly estimate high "economic leakage" rates (low local expenditures by the industry). This makes sense for a newly developing industry in a single county economy. As a result, the multipliers are small and total results are overwhelming dominated by the assumptions about the numbers of wells that will be drilled over the decade.

Perhaps surprisingly, the Broome study authors do not take advantage of a key strength of input-output type models, namely their ability to highlight the distribution of impacts across different economic sectors or household income classes. In addition, aside from a minimal justification of the two drilling rate scenarios that drive the entire analysis, no effort was made to assess the sensitivity of the results to alternative assumptions.

Some of the limitations of this study were unavoidable given the fact that the analysis was done prior to the benefit of extensive experience with drilling in the Marcellus or related empirical data. Moreover, the analysis was presumably intended as a first cut exploration of economic impacts rather than the final word on the subject. Whatever functions it may have served when the study was undertaken, much has been learned since it was completed and it has only modest enduring usefulness for understanding the likely economic impacts of shale gas drilling on Broome County.

The "Emerging Giant" Study of the Pennsylvania Economy

Another economic impact study was briefly cited by the New York Draft SGEIS to substantiate the public benefit of shale gas drilling. Completed by economist Tim Considine and colleagues, the cited August 2009 "emerging giant" study of the Pennsylvania economy is one of a series of IMPLAN based economic impact analyses of Marcellus Shale gas development potential that has been produced by Considine since 2006. This study in particular stimulated significant controversy in both New York and Pennsylvania. However, the points of controversy regarding the study are largely unrelated to the quantitative results summarized in the Draft SGEIS.[13] In summary, these results are that "the Marcellus gas industry generated $2.3 billion in total value, added more than 29,000 jobs, and $240 million in state and local taxes in 2008. With a substantially higher pace of development expected in 2009, economic output will top $3.8 billion, state and local tax revenues will be more than $400 million, and total job creation will exceed 48,000."

Because drilling had already commenced in Pennsylvania in 2008, when the economic impact study was conducted, it begins with an effort to measure existing economic activity associated with Marcellus drilling. The primary source of economic data was a survey returned by seven of the 45 firms reported to have drilled in the Pennsylvania Marcellus (with more vertical than horizontal wells, however) at the time. The data for these firms indicated in part that the number of wells recorded by the state undercounted actual drilling activity by 18%. State and survey data combined to adjust for the undercount provide an estimate of 364 wells drilled during 2008.[14] The authors estimate that the seven responding firms were responsible for a large majority - nearly three-fifths (59%) - of all the wells drilled in that year.

The survey of the seven firms also collected data on company expenditures on payroll, purchases from vendors, payments to landowners, and payments to government, leading to an estimate of 2008 industry spending of just over $3 billion, or about $8.5 million per well. The data on location of purchases from the local economy showed that only three sectors (mining, construction, and wholesale trade) provided 86% of the product and service purchases from local businesses.

The survey results also indicated that 95% of total industry spending occurred within Pennsylvania, which seems extraordinarily high until an explanation emerges from closer inspection. About two-thirds of total reported industry spending in 2008 went directly to Pennsylvania landowners. This proportion reflects the importance of leasing activity at this stage in the cycle of the development of the Marcellus play. Lease and bonus payments also explain high per well costs. This expenditure pattern would be unlikely to be sustained over time. For example, after the leasing phase of the cycle tapers off, drilling ramps up and purchases from industry support businesses and royalty payments to landowners with productive wells accelerate. As mineral rights acquisition activity declines, so will overall front-end lease payments. These observations point to a general caution about the need to carefully attend to the patterns of drilling and related payments since they are likely to shift over the several stages of development of a play. Cost/revenue projections in particular (especially when calculated per drilled and/or producing well) need to consider that there will be changes over the full drilling/development cycle. Unfortunately, little empirical evidence about revenue pattern changes over the life of a play appears to be available.

Given the dominance of lease, bonus and royalty spending in overall gas company expenditures, the question of landowner economic behavior is of signal importance in interpreting the economic impacts predicted in the "Emerging Giant" study. The authors appropriately account for the fact that landowner receipts do not fully translate into disposable income that is available for consumers to spend. They use a regional average correction factor to adjust total income to disposable income. However, as discussed in more detail below in relation to a more recent three state study also authored by Considine, a more fundamental and less defensible assumption is that landowners treat this "windfall" of revenues like an increase in income rather than like an increase in wealth. This is very important, because many studies show that the propensity to consume out of wealth is much less than out of income, especially in the short term. However, it is also true that there is little more than anecdotal information about actual landowner/lessor spending behavior so far. Information is even thinner about how these windfalls might be managed differently over time as the large initial bonus and royalty payments dwindle over a short span of years to a much smaller and then negligible stream of incoming revenues.

To begin to address this lack of good information, a group of Pennyslvania State University researchers is currently engaged in conducting a study of the spending patterns of landowners who have leased gas rights. According to one of these researchers, their work has so far highlighted several further concerns that indicate the several Considine studies probably over-estimate the extent to which landowner revenues will benefit the local or even state economy. They raise the question, "Who owns the land, and thus who are the recipients of gas company payments?" Many owners of Pennsylvania gas rights are not, in fact, local or even necessarily Pennsylvania residents. Thus, royalty and other payments to landowners accrue to a) the state general fund for all drilling on state forest or game land, b) nonresident owners of many second homes and undeveloped land owned for recreational purposes, and c) nonlocal owners of mineral rights that have been severed from the surface rights over past decades or who have recently moved from their properties while retaining their mineral rights. Though these issues may well be important quantitatively in many local areas, the extent of severed rights in particular is very difficult to estimate empirically because of the lack of easily accessible records. [15]

The probable exaggeration of short-term landowner spending is important in the overall study for another reason. The study estimates that approximately $2.18 billion dollars are spent "directly" by industry on the local economy. Using a model of the state economy, the study then calculates that this direct spending stimulated an additional $2.05 billion of new output, equivalent to an overall impact multiplier of 1.94. Accounting for the strong possibility that landowners did not all spend their lease revenue portion of that $2.18 billion instate in the same way they spend their paychecks, there ought to be a corresponding (and almost certainly downward) adjustment to the $2.05 billion in additional output as well.

In further analysis by the study authors, economic impacts on the Pennsylvania economy were projected into the future, with an estimate that more than 1,000 wells would be drilled in 2010 with annual increases reaching over 2,800 per year by 2020. The study bases its projections on the relatively strong historical statistical relationship that was in evidence between drilling rates and natural gas prices in the Barnett Shale. Although there is little in the way of obviously better statistical evidence to go on for quantitative projections, there are several reasons for great caution in applying this relationship to the Marcellus, especially in the shorter term. Exploratory drilling in the Barnett began in the early 1980's, horizontal hydraulic fracturing in the late 1990's, with significant production from horizontal wells in about 2003. The study's estimated statistical relationship is based on the period 1993-2008 (14 data points), a period of rapid evolution and experimentation in drilling technology and effectiveness that may or may not appropriately reflect the Marcellus context.

More importantly, recently increasing attention has been paid to various drivers of the current drilling pace in Pennsylvania that are not directly related to current natural gas prices. They include the gas operator's need to initiate production or risk losing or having to renegotiate leases on less favorable terms ("hold by production"); the smoothing effects of futures markets for gas; production incentives related to joint venture agreements, the internationalization of capital investment in shale gas drilling, capitalization strategies that emphasize production over profit, and other aspects of the restructuring of industry ownership and diversification of some gas companies into natural gas liquids; and continuation of the exploratory phase of drilling as well drilling technology, Marcellus productivity, and regional geology continue to be assessed. All these explain higher drilling activity during a recession than the rock bottom market prices alone would predict.[16]

Finally, the "Emerging Giant" study, which was undertaken during a boom period, assumes relatively high gas prices and increases (eg. $6.7/mcf in 2010 including a 90 cent Marcellus location premium, "gradually rising thereafter"). These are higher prices than have been experienced in fact. Moreover, actual drilling rates are somewhat higher than predicted by the model (1,454 Marcellus wells actually drilled as of the end of 2010; "over 1,000" were predicted) despite the reality of a prolonged price slump. This indicates empirically that while erroneous assumptions in the model may have compensated for each other to some extent, the simple theoretical relationship that informs the model, namely between price and drilling rates, does not seem reassuringly robust at least over some phases of the highly volatile natural gas price cycle.

The Pennsylvania, New York, and West Virginia Marcellus Economic Impact Study

Although it was released after the Draft SGEIS was completed, we also consider an additional economic impact study. This study builds on the earlier studies focused on Pennsylvania. It is significant because it explicitly considers the potential impacts of future gas drilling in New York as well as in currently operating Marcellus Shale states. This "Three State" study (Considine 2010) estimates the economic impacts of Marcellus development activity for the two states with active Marcellus drilling during 2009 (Pennsylvania and West Virginia). Based on gas drilling and production forecasts, it further projects the associated economic impacts for all three states including New York through 2020.

As always, the assumptions and estimates about the size of the initial or direct impacts of gas drilling are central to the analysis. As in the "Emerging Giants" study, the estimates of industry spending for Pennsylvania are based on expenditures reported via a survey of natural gas production companies active in Pennsylvania in 2008 and 2009. The author uses the survey data to estimate industry spending in Pennsylvania of $3.2/4.5 billion in total for 2008/2009. It is important to underscore that even as estimated overall industry expenditures rose by 41% from one year to the next, the largest single component of this expenditure for both years was again for lease and bonus payments (57/38% for 2008/2009 respectively), with an additional 1% for royalties.[17] As emphasized earlier, this empirical data reinforces the importance of understanding how company expenditure patterns will rise and fall, and shift across different subcomponents such as landowners and gas industry service companies, during the evolving development of a gas play.

This estimate of industry spending provides the data for the initial economic change that is entered into the input-output model to project its impacts on the Pennsylvania economy. In a procedural improvement over the Broome county study, Considine's series of studies do not assume that the IMPLAN default databases accurately represent current shale drilling technology and purchasing patterns. Instead, he and his co-authors follow best practice procedures to introduce a new industry into the state model based on its unique purchasing patterns. To accomplish this, purchasing information was collected via the survey of gas industry companies for the "Emerging Giant" report. This data was used in that report and again in the 2010 three-state study. The survey requested summary information on purchases from all of the respondents' suppliers including the supplying firm's location, the dollar amounts involved, and a description of their purchases. The surveyed firms also provided information about their relevant payrolls, payments to land owners (lease, bonus payments and royalties) and taxes paid. Although this approach followed procedural best practice for input-output model refinements, it is unclear whether the data collected from seven firms accurately reflects the spending patterns of the entire and still evolving industry. As noted in relation to the earlier study, these companies reported that more than 95% of total spending occurs inside Pennsylvania, a result explained only by the finding that fully 69% of total in-state spending (65% of total spending) reported in the survey went directly to landowners and mineral rights owners who are assumed to be in-state residents.

Also as previously discussed, because of the significant proportions of industry payments that are received by landowners, the treatment of these expenditures is especially important. As in the "Emerging Giants" study, Considine adjusts the landowner payments for taxes to arrive at an estimate of disposable income that is assumed to be spent according to national patterns of consumer spending. He makes a further assumption that is arguably inconsistent with the short term input-output framework within which the study is presented. As a reminder, he treats all royalty and bonus receipts by landowners as current income rather than as an increment to wealth. As such, he assumes that it will be spent in the year received and in essentially the same proportions as income from the workplace. Special vacation trips, additional car purchases, new trust accounts for children, large investments in mutual funds, bathroom remodeling or second home purchases and the like are not considered.

In contrast, a similar economic study of the Haynesville Shale made a sharply different assumption (Scott 2009). To estimate economy-wide impacts, Haynesville landowner receipts were treated as additions to wealth such that, in the conservative base case analysis, only 5% of the value of this new wealth was assumed to be spent on consumption by landowner households. Considine's assumption unrealistically boosts the assumed direct economic impact for any year, especially compared to the base case propensity to spend out of wealth assumption used in the Haynesville study. Moreover, because consumers purchase goods and services from a comprehensive array of economic sectors, the distribution of multiplier impacts across the economy is more dispersed than would otherwise be the case. On the other hand, the Haynesville study for its part does not consider that the 95% of the new wealth that was assumed to be saved in the year it was received might boost spending in future years. As a general conclusion, it is clear that better estimates of the propensity of landowners to spend their bonus and royalty incomes are essential to improved economic impact analysis. It is not a comfortable stretch to simply assume that rural landowners and mineral rights owners would spend royalty payments in the same manner as the average consumer, or as would typical winners in the lottery or stock market. The previously mentioned Penn State University study of Pennsylvania landowners will take some significant preliminary steps in helping to remedy this knowledge gap when it is completed.

Considine's IMPLAN analysis in the "Three State" study concludes that the initial or direct effects of $3.8 billion in industry and landowner spending generate $7.2 billion in gross output, $3.9 billion in value added, and over 44,000 jobs statewide. In terms of multipliers, this indicates that for every $1 that the Marcellus industry spends in Pennsyvlania, $1.90 of total gross output or sales is generated and for every $1 million of gross output created by natural gas 6.2 jobs are created. Considine suggests that differences between these multipliers and similar ones found in studies from other states (his output multiplier is higher, while his job multiplier is mid-range) are due to his "detailed expenditure analysis in our benchmark year 2008 based upon company accounting data". We suspect that the differences have as much or more to do with his treatment of landowner income and the different sizes and structures of the other economies studied.

Because Marcellus production in New York was on hold, the "Three States" study only considers impacts on New York State as part of its projections for the future. Considine reasonably ties this future to various scenarios regarding the number of wells drilled for 2011, 2015 and 2020, noting in passing that, "Assessing the odds favoring any one of these three scenarios is difficult." Citing policy and geologic/economic considerations, he suggests that development in New York, if it occurs, would not be as widespread or aggressive as in Pennsylvania, though it would probably mimic that state's split between vertical and horizontal wells. In his Low Development Scenario, he assumes very conservatively that no wells will be drilled in New York over the next decade (versus 1220/1353/1465 for these years in PA, 227/252/273 in WV). He focuses most attention on the Medium Development Scenario which shows 42/314/340 wells drilled in New York (versus 2019/2239/2424 in PA, and 376/417/452 in WV), a relatively modest scale compared to Pennsylvania, though apparently assumed to concentrate in a small number of Southern Tier counties. The High Development scenario shows 52/406/502 wells in New York (2211/2903/3587 in PA, 464/609/752 in WV). The number of wells drilled is based on manipulations of the same statistical model critiqued previously that relates well drilling numbers to natural gas prices. The scenarios are varied further by assumptions about well yields, with averages of 1.5 billion cubic feet assumed in the Low, 2.0 in the Medium, and 2.8 in the High Development scenarios.

Based on the Medium Development Scenario, the study projects that in New York in 2015 $1.9 billion in company spending will generate $3 billion in total economic activity, and that 8,196 jobs created directly by company spending (primarily in mining and construction, but also substantially in wholesale and retail trade, and in health and social services) will generate a total of almost 16,000 jobs statewide (most of the additional jobs are in health and social services and retail trade). As we have emphasized in this report, it appears that the distribution of company spending to landowners and its treatment is very important for the results. In these scenarios, 39%/34%/40% of total company spending is presumed to go directly to landowners in 2011/2015/2020, with the lease share declining as the royalty share rises. The same critiques raised earlier apply about whether these funds will be spent locally/in-state or should be best treated as increments to income or to wealth.

Finally, it should be mentioned that Considine's "Three State" study also uses IMPLAN modeling capacities in a further analysis to link the three state economies via data on their interstate trade flows, ie. he employs a form of multiregional input-output analysis. This reduces the amount of spending estimated to leak entirely from the three state system of economies, which in turn increases the estimates of economic activity in each state.

Summary

In sum, Considine's relatively well documented "Three State" study involves a more sophisticated analysis than the Broome County study and goes to some length to develop a range of possible future impact scenarios, accounting for such factors as future natural gas prices, well depletion rates, and the splits between horizontal and vertical wells. It also improves on key default parameters in IMPLAN with primary survey data. While these estimates and assumptions about the future may prove incorrect, the use of a range of three development scenarios helps bracket the possibilities and draws attention to the significance of uncertainties. Apart from the generic concerns about the blind spots endemic to all input-output analysis discussed at the beginning of this report, the most important critique of this study has to do with the estimation and treatment of bonus, lease and royalty payments to landowners and other mineral rights owners.

Summary Evaluation of Impact Studies: Drilling Rates, Landowner Revenues Drive Study Results

The factors that most drive the economic impact study results in all of the studies reviewed are the dollar value and quantity of, and production timelines for, the gas that will be extracted and sold to consumers. These quantities are inextricably linked to drilling rates, whether they are already observed for the past, or projected or assumed for the future. However, even in more mature shale gas fields, only the early stages of a full development cycle have so far been observed. The Marcellus play is still in the very earliest phases of exploration and production. Thus, assumptions or observations supporting the estimates of the drilling rates and their determinants still involve significant uncertainty, are controversial, and deserve great scrutiny in any evaluation of the results and predictions made in these studies. For example, some contrarian industry analysts argue that the Barnett and Haynesville production evidence accumulated to date points strongly to the conclusion that economically recoverable shale gas reserves may be dramatically lower and more geographically concentrated than those that were quickly accepted by many, including both those advocating for and opposed to gas development, in the industry and general public (Berman 2010). At this point, no single perspective can be said to have a lock on the "right" estimate of the number of wells that will be drilled or the estimated ultimate recovery rates of shale gas; thus any economic impact analyst faces a formidable challenge right from the start.

Nearly as important as assumptions about the development of the play as a whole are the assumptions and estimates made about who has claims on the revenue streams generated by gas production. Particularly critical are: 1) the revenue split between people and businesses located inside versus outside the region, and 2) the split within the region between landowners and drilling related businesses. Only after these initial parameters are specified, whether again by observation, projection, or simple assumption, do other technical factors associated with the economic model of the regional economy become relevant.

What Critical Issues Are Not Adequately Addressed by Input-Output Models?

The economic impact analyses reviewed above provide at best a simplistic picture of the economic development consequences of investment connected with tight shale natural gas drilling operations. They do not adequately explore several serious economic issues that policy makers need to consider in crafting effective responses to gas drilling. In the following sections, we delve further into the two issues just highlighted: 1) how the pace, scale and distribution of drilling are likely to affect the distribution of costs and benefits to local communities where drilling is occurring; and 2) how the economic benefits, which accrue in the first instance to land owners and businesses that supply the gas industry, will affect regional expenditure patterns and the capture of gas industry investment. We also return to another topic mentioned at the outset of the report: the evidence that regions dependent on resource extraction industries have poor prospects for long term economic development, particularly without thoughtful and proactive policy interventions in place before extraction begins.

The Pace, Scale and Geography of Drilling: Regions and Communities

We have emphasized that the pace, scale and geographic distribution of drilling will determine the economic impacts, both positive and negative, on communities in the Marcellus Shale gas play region. Several key factors influencing the pace and scale of drilling are outside the control of state and local policy makers. They include market forces and knowledge about the detailed geology of much of the Marcellus region. The overall trajectories of these factors remain uncertain. Nevertheless, while acknowledging uncertainty, state and local policy makers can influence and regulate gas company as well as consumer behavior directly. They have the powers to tax, regulate, monitor, subsidize and/or negotiate for mitigation of various kinds of costs and a greater share of benefits. Some of the boundaries of these powers are currently being shaped and tested at federal, state and local levels. In any event, many financial, capital, and land use planning powers that can be used to manage the indirect consequences of drilling if not the drilling itself are fully accessible to capable governments. What is less clear is how many of the affected governments will have adequate access to the capabilities and actions needed to meet the governance challenges and opportunities that will arise.

Geography matters in assessing pace and scale impacts

Though the arc of some kind of economic boom and bust cycle is implicit in the very definition of an exhaustible resource, within the overall Marcellus region the recoverable resource is so large that extractive activity could fairly be anticipated over multiple decades. The regional economic effects, including in select communities that serve as regional service centers and economic hubs, might be similarly sustained over multiple decades. There are already indications that Pittsburgh, for example, will play a major role of this type for the Marcellus. Moreover, on a multi-state regional basis encompassing multiple metro and other urbanized areas, a large and diversified economy already exists and is unlikely to develop an outsized dependency on natural gas production. In contrast, any boom/bust drilling cycle for smaller individual communities, their residents, and many local land owners would likely be very much more telescoped in time and proportionately dramatic in scale. Though drilling and production strategies in the Marcellus are still evolving, it seems logical that actual drilling activity would be locally most intensive for several years (rather than decades), then move on. Because company payments to local businesses and landowners are dominated by activities immediately before, during, and after drilling, the injection of funds to local economies tends to closely follow the intensity of drilling itself.

Despite manifest uncertainties at both the local and regional levels, the cumulative market value of the hypothetical quantities of recoverable Marcellus gas is notable, even applying modest assumed future natural gas prices. Total value estimates span many billions of dollars to conceivably some trillions at the high end. Even spread out over many years of production, these numbers loom especially large during troubled economic times and in regional economies where economic stagnation or decline have persisted over many years.

Turning this hypothetical value into economic reality implies, however, extensive well drilling throughout vast expanses of the multi-state Marcellus region. Considine's "Emerging Giant" study speculates about drilling of up to approximately 30,000 wells by 2020. Substantial as this number appears at first glance, this projection may be far less than half the total number of wells that would be required in the longer term to support the highest ultimate recovery figures that have so far been proposed.[18] Nevertheless, it is precisely the number and uniform distribution of the wells evoked in these projections that raises the specter of widespread risks of water contamination, land and habitat disruption, housing shortages, and community stressors alongside the positive assumptions about landowner riches, jobs, and community wealth creation.

At least during the extended drilling phase of any Marcellus gas development, it seems inevitable that natural gas industry-related drilling activities would penetrate large swaths of a mostly rural landscape. While drilling has begun to appear in suburban and even urban contexts in the South, it is already clear that drilling in many more densely populated communities of the Northeast will face significant barriers. With well pad density anticipated for the time being at something between 1 and 16 per square mile,[19] many critics anticipate widespread "industrialization" of the rural farm and forest landscapes common to much of the region. Other industry critics argue, in partial contrast, that despite the vast physical expanse of the Marcellus shale resource, drilling will not be profitable outside of geographically concentrated regions of highest productivity. For example, one review of several developing shale plays categorizes three typical resource grades, each likely to experience different drilling patterns over time and space: a highly productive "compact core sweet-spot", a "reasonably sized average productivity area", and a more extensive low productivity "fringe area, often called the goat pasture." (Kuuskraa and Stevens 2009). Whichever analysis turns out to be correct for the Marcellus, there is little doubt the overall numbers and pattern over time and space of wells drilled will trigger the most significant economic, environmental, and social impacts that will accumulate with Marcellus shale gas development.

The Landowner Windfall – What Does It Mean for Economic Impact and Long Term Development?

In the studies we reviewed as well as in studies from other states, landowner lease and bonus payments (not just drilling industry salaries and input purchases from local businesses) constitute a very large and even dominant fraction of local spending by gas companies. This is true especially in phases of development where leasing (early on) or royalty payments (eg. when economic conditions lead to drilling slowdowns, or as the play is eventually exhausted) rather than current drilling activity dominate. It is even truer in a region new to gas development which lacks an existing cluster of gas industry support businesses. In either case, the split between gas company spending on landowners and on local businesses inevitably adjusts as gas field development matures through several phases over time. Clearly, the prominence of payments to landowners is derived from the need for energy companies to lease land from many private landowners. From an economic development perspective, this distinguishes Marcellus Shale development in important ways from that in most western states, where energy development is more heavily concentrated on public lands.

Local economic development strategies that ignore landowner behavior will likely overlook multiple factors of critical importance for economic development. This will be especially the case where and when gas industry companies pay out more to local land owners than they do to local business. Most local landowners can be expected to have a relatively high propensity to spend gas company payments locally or in near-by urban centers compared to gas industry service companies. As noted, little to no systematic empirical evidence yet exists on the economic behavior of different kinds of landowners who have received substantial leasing, or ultimately more importantly, royalty payments. Regardless, a proactive economic development strategy would seek opportunities to capture a greater share of landowner spending. In summary, these observations underscore the critical importance for the future regional economy of developing better information and policies that account for a) landowner spending patterns of both royalty and lease payments and b) shifts in the local patterns of gas company spending over time.

Other Distributional Effects

While shale gas development critics generally acknowledge the influx of dollars to local landowners and businesses, they challenge the extent to which local gas extraction actually channels economic benefits to more than a minority of property owners, businesses, and workers who live in the community, and especially to those who lived there prior to the onset of gas development. One signal concern is distributional, about whether benefits are limited to the few or are experienced community-wide. Again, more information is needed about where drilling is most likely to occur and who the owners of the leasing rights to these properties have been, are, and will be in the future. Another concern is about "leakage": how much of the money that flows into the community is either not respent locally or in fact accrues to nonlocal or temporary residents and firms in even the first instance? While programs like IMPLAN include default estimates of leakage from each sector of the economy, local validation of the plausibility of these generic estimates is important and often worth investment in research about the most intensively involved business sectors.

Even more fundamental than the critique of minimal or uneven benefit, critics have raised concerns about the extent to which gas development might lead to concrete economic losses for some or even most local businesses and residents across many economic sectors.[20] Certain kinds of losses could be related to increased competition with the gas industry for scarce economic inputs such as housing, labor or materials. According to this dynamic, numerous industry sectors or subsectors (e.g. tourism, light industry, agriculture, or construction), some with longer term development potential, are "crowded out" of the regional market as their costs of doing business increase. These crowding out effects are typically transmitted through increased market prices, for example for hotel rooms, trucking or accounting services. Some of these effects may be reversible as the gas industry fluctuates and inevitably declines, but others represent wasted investment and longer term lost opportunity, especially when existing skilled workers and an viable or latent nexus of synergistic businesses are displaced. Price effects are theoretically capable of being captured in some kinds of standard economic models that are more sophisticated than basic input-output models. Empirical research of a number of industries along these lines has found that input-output multipliers often overestimate actual economic growth due to these kinds of effects. Unfortunately, this kind of analysis is rarely practical at the community as opposed to regional scale. Finally, even if not directly associated through employment or ownership with industries subject to these kinds of crowding out or price effects, some community members, especially those on fixed incomes, renters, or others hurt by local price inflation, stand to suffer economic harm.

Another type of loss would not be transmitted through the same kinds of price signals and are much harder to predict with the standard analytic tools of economics and regional science. Examples include the potential effects on tourist, organic farming, and other businesses whose viability is anchored in the existing character and reputation of communities, water and environmental quality, and regional landscapes. While such effects will almost certainly be seen to some extent, the actual extent is very hard to evaluate. The essential difficulties here are first, in establishing and quantifying possible effects of drilling on the tangible and intangible entities such as reputation, regional "brand", and landscape quality, and second, once such links are established, predicting their economic consequences.

Questions About Long Term Economic Development in Regional Economies Dependent on Resource Extraction

While no study exists that has made a comprehensive effort to identify or quantify possible economic losses associated with shale gas development there are several streams of literature focused on the relation between longer term economic development and specialization in primary sectors like farming, forestry and mining. The first tradition focuses on studies of the observed economic performance of regional economies in the United States that are dependent on extractive resources. Although individual results show a mix of beneficial and harmful results, many studies determine that resource dependent economies tend to perform less well than others. In this tradition, one recent study considered 26 western counties that have concentrated on fossil fuel extraction from public lands for economic development, concluding that at least in recent years such counties have increasingly underperformed economically compared to less energy industry focused counties (Headwaters Economics 2008). Another older benchmark review of 19 separate studies of mining-dependent rural economies concluded that, "there is surprisingly little evidence that mining will bring about economic good times, while there is a good deal of evidence for expecting just the opposite." (Freudenburg and Wilson 2002)

Since the mid-1990's an extensive body of empirical research has also investigated the existence and dynamics of the so-called "resource curse" (Sachs and Warner 1995; Ross 1999). This literature was stimulated by the observation that many developing and some developed countries with rich natural resource endowments had, contrary to prevailing economic development theory, shown poor economic growth results over time. While there is ongoing debate over the existence, prevalence and specific mechanisms of a "resource curse", there is widespread consensus in the developing country literature that a resource curse exists but is not inevitable (Sinnot et al., 2010). Moreover, it is typically attributed to a combination of effects that involve both systematic failures of governance and policy as well as economic incentives to allocate "too many" resources to the extractive sectors of the economy (akin to "crowding out").

In 1999, Michael Ross summarized the curse literature to date by noting, "There is now strong evidence that states with abundant resource wealth perform less well than their resource poor counterparts, but there is little agreement on why this occurs." He drew attention to the most common rationales proffered to explain why a curse might exist. It is worth examining these to see which are more or less likely to be even relevant to the effect of gas development on regional economies in the United States.

Four of the groups of reasons summarized by Ross are economic. These are 1) a decline in terms of trade for primary commodities, 2) the instability of international commodity markets (making government revenues & foreign exchange unstable and investment risky), 3) the poor economic linkages between resource and nonresource sectors, especially as external investors remove profits from the local economy, and 4) the "Dutch Disease" that associates resource boom economies with a) increases in the exchange rate, making other domestic exports more expensive, and b) increased competition with other domestic sectors for scarce capital and labor.

In terms of their translatability to a subnational and domestic context, only some of these reasons are even theoretically relevant. The terms of trade logic is completely inapplicable. In contrast, the instability of commodity prices is partially salient, especially as both government revenues and investment risk are affected by unstable prices in regional markets. The linkage argument also seems potentially relevant insofar as nonlocal firms are likely to come into a region only temporarily, extract profits along with the gas, and be likely to purchase only a limited array of local goods and services lacking a well developed economy of strong, locally well linked sectors (again, the share of expenditures going to local landowners vs. local firms would have important implications). Part of the Dutch Disease argument also seems potentially relevant. Though the increased cost of domestic currency is obviously not relevant at a regional level, we have already discussed how tighter competition of the resource sector for factors of production is quite likely to crowd out competing sectors, at least during some time periods in the adaptation of the local economy.

Ross observes, in review, that proactive government policies could, in any event, ameliorate most or all of these economic resource curse problems. Consequently, "The failure of states to take measures that could change resource abundance from a liability to an asset has become the most puzzling part of the resource curse." Overall, the subsequent empirical literature has focused heavily on issues of governance. Ross himself emphasizes five explanations concerned with political and governance phenomena. Several seem unrelated to the context of regional economies in a developed country; others appear to have potential relevance. Among these, Ross identifies 1) cognitive explanations, which contend that resource booms produce a sort of short sightedness among policy makers (get rich quick mentality, laziness, excessive optimism followed by frantic retrenchment); 2) societal explanations, which argue that resource exports tend to empower sectors, classes or interest groups that favor growth impeding policies (e.g. firms and workers in the resource sectors accrue the power to maintain government policies investment, tax and trade policies that benefit them preferentially), and 3) related state centered explanations which contend that resource booms tend to weaken governing institutions by reducing financial accountability to the full range of domestic constituencies, i.e. place government more fully at the service of the extractive sector alone rather than society as whole.

Perhaps of most significance for the Marcellus shale economies are several recent subnational empirical studies of the resource curse phenomenon, three of which have investigated the issue within the United States using both state and county level data sets. Each of these studies (James and Aadland 2010; Papyrakis and Gerlagh 2007; Johnson 2003; Libman 2010) finds evidence that some version of a resource curse is detectable within a subnational economy, and that poor governance and crowding out effects are contributing factors of varying importance. Papyrakis and Gelragh optimistically conclude that, "prudent economic policies and cautious planning can reverse the pattern". However, none of these studies consider the unique attributes of natural gas production or the Marcellus shale resource as compared to the other "natural resources" included in them. Even granting the "curse" effect, the empirical specification of how much dependence on a single sector of the economy constitutes "overdependence" is not explicitly addressed. Thus, the question of the applicability of this work to development of the Marcellus remains an important open question that merits further sustained research.

Conclusions

Communities do not face a dogmatically predetermined outcome regarding the long-term economic development implications of drilling in their communities. Those starry eyed by the prospect of previously unimagined community wealth and those fearful of the certainty of economic decline are each looking into futures that are possible, but most likely exaggerated and more importantly not written in stone. The lesson of the economic impact studies, despite their limitations, is that large scale natural gas drilling would bring a wave of new money to the region. This money would increase the wealth and income of various individuals and communities at least during parts of the Marcellus development cycle.

Even abstracting from the possible worst environmental consequences of extensive drilling, it would also bring new risks and most unavoidably, significant change. Whether natural gas development would lead to economic diversification or overspecialized dependency is an important economic development concern. In relatively diverse local economies, both industry and consumer spending would be more likely to be locally retained, leading to larger multiplier effects. In such local economies, the gas industry would also be more likely to contribute to diversity and to lessen the potential for instability associated with concentration and overdependence on a commodity famous for price volatility in the short run and depletion in the long run. Even in smaller rural economies without much existing economic diversity, gas development might offer the possibilty of a diversification strategy. However, in such places the potential for a hard boom bust cycle, and for the gas industry's competition with pre-existing economic anchors, may be the greatest. For some individuals and communities, the wave of big money would likely rise and fall with an abruptness that many would find deleterious even as for others, the wave would be more sustained and positive.

The resource curse and boom/bust literature suggests that communities with anemic governance, and with little capacity to do more than let the volatility of the boom/bust cycle passively wash over them, can face a sobering and diminished future, especially in the longer term. The less well prepared or well positioned are likely to be left pondering the meaning of the words of Sheik Yamani, former oil minister for Saudi Arabia: "All in all, I wish we had discovered water." On the other hand, individuals and communities with the wherewithal to capitalize on the large influx of money passing through their communities have the potential to see significant, sustained economic benefits. These communities will understand the transitory and fluctuating nature of extractive wealth, and negotiate smartly and toughly with the gas companies. They will have plans and capacity to in the first place maximize their access to the flows passing through. In the second place they will develop the management strategies to invest boom revenues wisely. They will develop appropriate mitigation, land use and long term capital planning, taxation and investment strategies, and aggressively seek to diversify and stabilize their economies. First and foremost, they will recognize that they cannot vest their future in an industry guaranteed to eventually disappear.

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[2] Of course, the realms are not independent, as economic activity of various kinds can affect environmental quality, and changes in environmental quality can affect the health of the economy.

[3] Our limited scope focuses on regional economic development issues rather than larger policy issues such as what energy development strategies are "most appropriate" at either a regional or national scale. Even within this limitation, we do not directly address several significant policy-relevant topics to which we wish at least to draw attention because they are related in the first instance to economic development and are definitely deserving of further consideration. Foremost among these are the implications of the Marcellus Shale gas resource for 1) natural gas and other energy users in their roles as consumers, and 2) the potential influence on firm retention and/or attraction of development of a local energy resource.

[4] For a discussion focused on the importance of the pace and scale of change in gas drilling cycles, and recommendations that the pace be slowed down to mitigate negative aspects of the boom/bust phenomenon, see Haefele and Morton (2009).

[5] See Hargreaves (2010).

[6] These studies are included in the references. Several 2008/9 impact studies have received most attention. The Fort Worth area economy was reported to have seen gains of $11 billion in annual output (8.5% of total output) and 111,131 jobs (6.8% of total jobs) in 2008 associated with development of the Barnett Shale (Perryman 2009); in Louisiana the Haynesville Shale was linked to $2.4 billion in new business sales and 32,742 new jobs within the state of Louisiana (Scott 2009); in Arkansas's Fayetteville

Shale, natural gas extraction was associated with statewide impacts of $2.6 billion and employment of 9,533 people (Center for Business and Economic Research, 2008). A study of the West Virginia economy concluded that a $371 million 2008 impact on output, associated with more than 2,000 jobs, would increase to $2.9 billion in output and almost 17,000 jobs by 2020 (National Energy Technology Lab 2010). More recently, the Eagle Ford shale were estimated to create close to $1.3 billion of gross state product impact, support 12,601 full-time jobs, and add $2.9 billion in total economic output to the Texas economy (Center for Community and Business Research 2011). Pennsylvania and New York studies of the Marcellus are discussed below.

[7] Economic impact analysis should not be confused with cost benefit analysis. The latter focuses on measures of economic value (e.g. how much goods and services, including those like environmental quality for which markets may not exist, are actually worth), the former on indicators of economic activity (e.g. jobs and incomes). Fiscal impact analysis is often related directly to economic impact analysis. Starting with estimates of changing levels of economic activity, it looks at the implications for public sector costs and revenues. The economic impact studies reviewed here include fiscal analyses, but we do not attend to them other than to note that 1) the fiscal results are driven by the other economic impact results, 2) the studies do not take into account many of the cost and revenue implications that are distinctive to shale gas development, and 3) they are of limited use in differentiating impacts by each of the government jurisdictions affected.

[8]Recently, the work of Kilkenny and Partridge (2009) econometrically investigated the dependence of rural development on employment in traditional rural export sectors in the United States, concluding that, "The results reject the hypothesis that emphasizing traditional export employment results in rural growth." These results are grounded in export base theory that is broader than but applicable to the "resource curse" literature reviewed later in this paper.

[9] Pennsylvania provides some context. In 2009, 763 Marcellus wells were drilled statewide, with the largest concentration (138) in Washington County. Drilling accelerated in 2010. In 2010, 1,454 Marcellus wells had been drilled, with the largest concentrations in Bradford (386) and Tioga (266) counties. (See http://www.dep.state.pa.us/dep/deputate/minres/oilgas/BOGM%20Website%20Pictures/2009/Marcellus%20Wells%20permitted-drilled%20Jan-Dec%202009.jpg and http://www.dep.state.pa.us/dep/deputate/minres/oilgas/2010%20Wells%20Drilled%20by%20County.htm accessed 4/4/2010) Both counties are more rural than Broome County, with 62% and 59% greater land masses respectively and populations much less than half as large.

[10] See http://www.eia.doe.gov/oiaf/forecasting.html (accessed 12/10/2010)

[11] The 2008 Broome County MIG/IMPLAN model, for example, excludes the "Support activities for oil and gas operations" sector entirely due to a lack of transactions attributable to businesses classified in that sector.

[12] We tried to reproduce the analysis of impacts on the Broome County economy using the 2008 MIG/IMPLAN modeling system and data. A $7 billion dollar shock over ten years to the "Extraction of Oil and Gas" sector yields $8.3 billion in total output (967 jobs per year) including only business to business effects. The same shock to the "Oil and Gas Drilling" sector yields $7.8 billion in total output over the decade (1,325 jobs each year). These results suggest the report authors built a slightly different

version of the model than ours, but probably modeled the impact as a shock to one or both of these sectors.

[13] Most of the criticism of this study was related to its promotional tone, its simultaneous use of a Penn State University cover and financial sponsorship by the Marcellus Shale Committee (an industry sponsored organization), and the section of the study that sharply criticized the wisdom of the governor's proposed severance tax and environmental regulation of the gas industry. A revised version was later issued under a different cover without the tax analysis.

[14] The state currently shows 196 Marcellus wells were drilled throughout Pennsylvania in 2008. (See http://www.dep.state.pa.us/dep/deputate/minres/oilgas/2008%20Wells%20Drilled%20by%20County.htm accessed 12/20/2010) Applying the suggested 18.2% adjustment to this number of wells yields 232 wells, far less than the 364 wells used in the study. The reason for the difference in the DEP well count used in the study and that noted here is unclear. However, the impact based on 364 wells is obviously far greater than for 232.

[15] Tim Kelsey, personal email communication (February 17, 2011).

[16] An exploration of these essential issues is beyond the scope of this paper. However, there is much discussion of them in the industry blogosphere (eg. http://blogs.oilandgasinvestor.com/blog/2011/03/15/shale-gas-jvs-will-keep-gas-within-46-range-for-a-long-time/) and by industry analysts such as Tudor Pickering (see http://www.spegcs.org/attachments/studygroups/2/2010_01_Bus%20Dev%20-%20TPH%20Danny%20Rathan.pdf on joint ventures), Ben Smith (see eg. http://www.firstenercastfinancial.com/forums/natural-gas/1699-held-production.html on hold by production), and skeptic Arthur Berman (see eg. http://www.theoildrum.com/node/6785 on production over profit). (All accessed 4/1/2011)

[17] Estimates of total spending in 2008 are somewhat greater, and payments to landowners somewhat lower, in the more recent survey compared to the earlier survey. Presumably, this is due to differences in which companies responded and the completeness and accuracy of responses reported in the two surveys.

[18] Naïve estimates based on the extent of the entire Marcellus (95,000 sq. mi.) and reported well densities of 4-16 wells per square mile arrive at a range of 380,000 – 1,520,000 possible wells (NETL 2010b). A recent West Virginia study suggests 30,000 to 60,000 "proration units" (one well per unit) are possible over time in West Virginia alone (NETL 2010a). Engelder's (2009) well known 489 TCF estimate of recoverable gas appears to be based on the assumption that over 50,000 square mile sections of varying degrees of gas productivity would be drilled over 50 years, generally with 8 wells per section (presumably from a common drilling pad); hundreds of thousands of individual wells are again implied. A similar informal industry calculation using somewhat different simplifying assumptions (half of the 95,000 square mile formation is developed with 47,500 drill sites, with 8 to 16 wells per square mile unit) also points to hundreds of thousands of wells (Spigelmyer undated). As noted earlier, however, others (Berman 2010; also personal email communication April 4, 2011) have argued vigorously that only a fraction of these wells are likely to be profitable economically without large increases in the price of gas.

[19] Following current trends, the pattern of one pad with multiple wells is likely to prevail for economic and regulatory reasons, suggesting density near or even below the lowest end of this range are most likely. However, in some circumstances involving local circumstances, a cost-benefit shift favoring vertical drilling, evolution of extraction technology, and/or the potential use of infill wells in various locations, more dense drilling might become more economically advantageous.

[20] Barth (2010), for example, concludes that, "In reality, the economic impact may very well be negative. And the likelihood is that gas drilling would adversely affect other economic activities such as tourism and sport fishing and hunting. To some extent gas drilling and these other industries are likely to be mutually exclusive. The net effect is what must be considered." Measuring or predicting this "net effect" is far from a straightforward task, especially since much of the economic boost related to drilling will come via short term boom/bust cycles in a region that has struggled long term with outmigration and disinvestment trends.

Regulatory Impact Analysis

Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry

U.S. Environmental Protection Agency
Office of Air and Radiation
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1 EXECUTIVE SUMMARY

1.1 Background

The U.S. Environmental Protection Agency (EPA) reviewed the New Source Performance Standards (NSPS) for volatile organic compound and sulfur dioxide emissions from Natural Gas Processing Plants. As a result of these NSPS, this proposal amends the Crude Oil and Natural Gas Production source category currently listed under section 111 of the Clean Air Act to include Natural Gas Transmission and Distribution, amends the existing NSPS for volatile organic compounds (VOCs) from Natural Gas Processing Plants, and proposes NSPS for stationary sources in the source categories that are not covered by the existing NSPS. In addition, this proposal addresses the residual risk and technology review conducted for two source categories in the Oil and Natural Gas sector regulated by separate National Emission Standards for Hazardous Air Pollutants (NESHAP). It also proposes standards for emission sources not currently addressed, as well as amendments to improve aspects of these NESHAP related to applicability and implementation. Finally, it addresses provisions in these NESHAP related to emissions during periods of startup, shutdown, and malfunction.

As part of the regulatory process, EPA is required to develop a regulatory impact analysis (RIA) for rules that have costs or benefits that exceed $100 million. EPA estimates the proposed NSPS will have costs that exceed $100 million, so the Agency has prepared an RIA. Because the NESHAP amendments are being proposed in the same rulemaking package (i.e., same Preamble), we have chosen to present the economic impact analysis for the proposed NESHAP amendments within the same document as the NSPS RIA.

This RIA includes an economic impact analysis and an analysis of human health and climate impacts anticipated from the proposed NSPS and NESHAP amendments. We also estimate potential impacts of the proposed NSPS on the national energy economy using the U.S. Energy Information Administration's National Energy Modeling System (NEMS). The engineering compliance costs are annualized using a 7 percent discount rate. This analysis assumes an analysis year of 2015.

Several proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOCs, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One emissions control option, reduced emissions well completions, also recovers saleable hydrocarbon condensates which would otherwise be lost to the environment. The revenues derived from additional natural gas and condensate recovery are expected to offset the engineering costs of implementing the NSPS in the proposed option. In the economic impact and energy economy analyses for the NSPS, we present results for three regulatory options that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

1.2 NSPS Results

For the proposed NSPS, the key results of the RIA follow and are summarized in Table 1-1:

- **Benefits Analysis:** The proposed NSPS is anticipated to prevent significant new emissions, including 37,000 tons of hazardous air pollutants (HAPs), 540,000 tons of VOCs, and 3.4 million tons of methane. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAPs, ozone, and particulate matter (PM), we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, as well as additional natural gas recovery. The methane emissions reductions associated with the proposed NSPS are likely to result in significant climate co-benefits. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of carbon dioxide (CO_2), 510 tons of nitrogen oxides NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital cost of the proposed NSPS will be $740 million. The total annualized engineering costs of the proposed NSPS will be $740 million. When estimated revenues from additional natural gas and condensate recovery are included, the annualized engineering costs of the proposed NSPS are estimated at $-45 million, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf) and condensate price of $70/barrel. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA. The estimated engineering compliance costs that include the product recovery are sensitive to the assumption about the price of the recovered product. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. For example, $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million, given EPA estimates that 180 billion cubic feet of natural gas

will be recovered by implementing the proposed NSPS option. All estimates are in 2008 dollars.

- **Energy System Impacts:** Using the NEMS, when additional natural gas recovery is included, the analysis of energy system impacts for the proposed NSPS shows that domestic natural gas production is likely to increase slightly (about 20 billion cubic feet or 0.1 percent) and average natural gas prices to decrease slightly (about $0.04/Mcf or 0.9 percent at the wellhead for onshore production in the lower 48 states). Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.02/barrel or less than 0.1 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars.
- **Small Entity Analyses:** EPA performed a screening analysis for impacts on small entities by comparing compliance costs to revenues. For the proposed NSPS, we found that there will not be a significant impact on a substantial number of small entities (SISNOSE).
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NSPS is estimated at 230 full-time-equivalent employees. The annual labor requirement to comply with proposed NSPS is estimated at about 2,400 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

Table 1-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Oil and Natural Gas NSPS Regulatory Options in 2015 (millions of 2008$)[1]

	Option 1: Alternative	Option 2: Proposed[4]	Option 3: Alternative
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$19 million	-$45 million	$77 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	17,000 tons of HAPs[5]	37,000 tons of HAPs[5]	37,000 tons of HAPs[5]
	270,000 tons of VOCs	540,000 tons of VOCs	550,000 tons of VOCs
	1.6 million tons of methane[5]	3.4 million tons of methane[5]	3.4 million tons of methane[5]
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

1.3 NESHAP Amendments Results

For the proposed NESHAP amendments, the key results of the RIA follow and are summarized in Table 1-2:

- **Benefits Analysis:** The proposed NESHAP amendments are anticipated to reduce a significant amount of existing emissions, including 1,400 tons of HAPs, 9,200 tons of VOCs, and 4,900 tons of methane. Results from the residual risk assessment indicate that for existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with benzene as the primary cancer risk driver. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAPs, ozone, and PM, we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, and climate effects as well as additional natural gas recovery. The specific control technologies for the proposed NESHAP is anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital costs of the proposed NESHAP amendments to be $52 million. Total annualized engineering costs of the proposed NESHAP amendments are estimated to be $16 million. All estimates are in 2008 dollars.
- **Energy System Impacts:** We did not estimate the energy economy impacts of the proposed NESHAP amendments as the expected costs of the rule are not likely to have estimable impacts on the national energy economy.
- **Small Entity Analyses:** EPA performed a screening analysis for impacts on small entities by comparing compliance costs to revenues. For the proposed NESHAP amendments, we found that there will not be a significant impact on a substantial number of small entities (SISNOSE).
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NESHAP Amendments is estimated at 120 full-time-equivalent employees. The annual labor requirement to comply with proposed NESHAP Amendments is estimated at about 102 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

- **Break-Even Analysis:** A break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health benefits, ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the benefits to exceed the costs. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas, ozone benefits valued at $240 to $1,000 per ton of VOC emissions reduced, and climate co-benefits valued at $110 to $1,400 per short ton of methane reduced. All estimates are in 2008 dollars.

Table 1-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP in 2015 (millions of 2008$)[1]

	Option 1: Proposed (Floor)
Total Monetized Benefits[2]	N/A
Total Costs[3]	$16 million
Net Benefits	N/A
Non-monetized Benefits	1,400 tons of HAPs
	9,200 tons of VOCs[4]
	4,900 tons of methane[4]
	Health effects of HAP exposure
	Health effects of $PM_{2.5}$ and ozone exposure[4]
	Visibility impairment[4]
	Vegetation effects[4]
	Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NESHAP are anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, PM2.5 and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

1.4 Organization of this Report

The remainder of this report details the methodology and the results of the RIA. Section 2 presents the industry profile of the oil and natural gas industry. Section 3 describes the emissions and engineering cost analysis. Section 4 presents the benefits analysis. Section 5 presents statutory and executive order analyses. Section 6 presents a comparison of benefits and costs. Section 7 presents energy system impact, employment impact, and small business impact analyses.

2 INDUSTRY PROFILE

2.1 Introduction

The oil and natural gas industry includes the following five segments: drilling and extraction, processing, transportation, refining, and marketing. The Oil and Natural Gas NSPS and NESHAP amendments propose controls for the oil and natural gas products and processes of the drilling and extraction of crude oil and natural gas, natural gas processing, and natural gas transportation segments.

Most crude oil and natural gas production facilities are classified under NAICS 211: Crude Petroleum and Natural Gas Extraction (211111) and Natural Gas Liquid Extraction (211112). The drilling of oil and natural gas wells is included in NAICS 213111. Most natural gas transmission and storage facilities are classified under NAICS 486210—Pipeline Transportation of Natural Gas. While other NAICS (213112—Support Activities for Oil and Gas Operations, 221210—Natural Gas Distribution, 486110—Pipeline Transportation of Crude Oil, and 541360—Geophysical Surveying and Mapping Services) are often included in the oil and natural gas sector, these are not discussed in detail in the Industry Profile because they are not directly affected by the proposed NSPS and NESHAP amendments.

The outputs of the oil and natural gas industry are inputs for larger production processes of gas, energy, and petroleum products. As of 2009, the Energy Information Administration (EIA) estimates that about 526,000 producing oil wells and 493,000 producing natural gas wells operated in the United States. Domestic dry natural gas production was 20.5 trillion cubic feet (tcf) in 2009, the highest production level since 1970. The leading five natural gas producing states are Texas, Alaska, Wyoming, Oklahoma, and New Mexico. Domestic crude oil production in 2009 was 1,938 million barrels (bbl). The leading five crude oil producing states are Texas, Alaska, California, Oklahoma, and New Mexico.

The Industry Profile provides a brief introduction to the components of the oil and natural gas industry that are relevant to the proposed NSPS and NESHAP Amendments. The purpose is to give the reader a general understanding of the geophysical, engineering, and economic aspects of the industry that are addressed in subsequent economic analysis in this RIA. The Industry Profile relies heavily on background material from the U.S. EPA's "Economic Analysis of Air

Pollution Regulations: Oil and Natural Gas Production" (1996) and the U.S. EPA's "Sector Notebook Project: Profile of the Oil and Gas Extraction Industry" (2000).

2.2 Products of the Crude Oil and Natural Gas Industry

Each producing crude oil and natural gas field has its own unique properties. The composition of the crude oil and natural gas and reservoir characteristics are likely to be different from that of any other reservoir.

2.2.1 Crude Oil

Crude oil can be broadly classified as paraffinic, naphthenic (or asphalt-based), or intermediate. Generally, paraffinic crudes are used in the manufacture of lube oils and kerosene. Paraffinic crudes have a high concentration of straight chain hydrocarbons and are relatively low in sulfur compounds. Naphthenic crudes are generally used in the manufacture of gasolines and asphalt and have a high concentration of olefin and aromatic hydrocarbons. Naphthenic crudes may contain a high concentration of sulfur compounds. Intermediate crudes are those that are not classified in either of the above categories.

Another classification measure of crude oil and other hydrocarbons is by API gravity. API gravity is a weight per unit volume measure of a hydrocarbon liquid as determined by a method recommended by the American Petroleum Institute (API). A heavy or paraffinic crude oil is typically one with API gravity of 20^{o} or less, while a light or naphthenic crude oil, which typically flows freely at atmospheric conditions, usually has API gravity in the range of the high 30's to the low 40's.

Crude oils recovered in the production phase of the petroleum industry may be referred to as live crudes. Live crudes contain entrained or dissolved gases which may be released during processing or storage. Dead crudes are those that have gone through various separation and storage phases and contain little, if any, entrained or dissolved gases.

2.2.2 Natural Gas

Natural gas is a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exists in a gaseous phase or in solution with crude oil or other hydrocarbon liquids in natural underground reservoirs. Natural gas may contain contaminants, such as hydrogen sulfide (H_2S), CO_2, mercaptans, and entrained solids.

Natural gas may be classified as wet gas or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is either natural gas whose water content has been reduced through dehydration or natural gas that contains little or no recoverable liquid hydrocarbons.

Natural gas streams that contain threshold concentrations of H_2S are classified as sour gases. Those with threshold concentrations of CO_2 are classified as acid gases. The process by which these two contaminants are removed from the natural gas stream is called sweetening. The most common sweetening method is amine treating. Sour gas contains a H_2S concentration of greater than 0.25 grain per 100 standard cubic feet, along with the presence of CO_2. Concentrations of H_2S and CO_2, along with organic sulfur compounds, vary widely among sour gases. A majority total onshore natural gas production and nearly all of offshore natural gas production is classified as sweet.

2.2.3 Condensates

Condensates are hydrocarbons in a gaseous state under reservoir conditions, but become liquid in either the wellbore or the production process. Condensates, including volatile oils, typically have an API gravity of 40^{o} or more. In addition, condensates may include hydrocarbon liquids recovered from gaseous streams from various oil and natural gas production or natural gas transmission and storage processes and operations.

2.2.4 Other Recovered Hydrocarbons

Various hydrocarbons may be recovered through the processing of the extracted hydrocarbon streams. These hydrocarbons include mixed natural gas liquids (NGL), natural gasoline, propane, butane, and liquefied petroleum gas (LPG).

2.2.5 Produced Water

Produced water is the water recovered from a production well. Produced water is separated from the extracted hydrocarbon streams in various production processes and operations.

2.3 Oil and Natural Gas Production Processes

2.3.1 Exploration and Drilling

Exploration involves the search for rock formations associated with oil or natural gas deposits and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field and involves the construction of one or more wells from the beginning (called spudding) to either abandonment if no hydrocarbons are found or to well completion if hydrocarbons are found in sufficient quantities.

After the site of a well has been located, drilling commences. A well bore is created by using a rotary drill to drill into the ground. As the well bore gets deeper sections of drill pipe are added. A mix of fluids called drilling mud is released down into the drill pipe then up the walls of the well bore, which removes drill cuttings by taking them to the surface. The weight of the mud prevents high-pressure reservoir fluids from pushing their way out ("blowing out"). The well bore is cased in with telescoping steel piping during drilling to avoid its collapse and to prevent water infiltration into the well and to prevent crude oil and natural gas from contaminating the water table. The steel pipe is cemented by filling the gap between the steel casing and the wellbore with cement.

Horizontal drilling technology has been available since the 1950s. Horizontal drilling facilitates the construction of horizontal wells by allowing for the well bore to run horizontally underground, increasing the surface area of contact between the reservoir and the well bore so that more oil or natural gas can move into the well. Horizontal wells are particularly useful in unconventional gas extraction where the gas is not concentrated in a reservoir. Recent advances have made it possible to steer the drill in different directions (directional drilling) from the surface without stopping the drill to switch directions and allowing for a more controlled and precise drilling trajectory.

Hydraulic fracturing (also referred to as “fracking”) has been performed since the 1940s (U.S. DOE, 2009). Hydraulic fracturing involves pumping fluids into the well under very high pressures in order to fracture the formation containing the resource. Proppant is a mix of sand and other materials that is pumped down to hold the fractures open to secure gas flow from the formation (U.S. EPA, 2004).

2.3.2 Production

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. The major activities of crude oil and natural gas production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities.

Oil and natural gas are found in the pores of rocks and sand (Hyne, 2001). In a conventional source, the oil and natural gas have been pushed out of these pores by water and moved until an impermeable surface had been reached. Because the oil and natural gas can travel no further, the liquids and gases accumulate in a reservoir. Where oil and gas are associated, a gas cap forms above the oil. Natural gas is extracted from a well either because it is associated with oil in an oil well or from a pure natural gas reservoir. Once a well has been drilled to reach the reservoir, the oil and gas can be extracted in different ways depending on the well pressure (Hyne, 2001).

Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as does the ratio of water to hydrocarbons). This increase of gas over oil occurs because natural gas usually is in the top of the oil formation, while the well usually is drilled into the bottom portion to recover most of the liquid. Production sites often handle crude oil and natural gas from more than one well (Hyne, 2001).

Well pressure is required to move the resource up from the well to the surface. During **primary extraction,** pressure from the well itself drives the resource out of the well directly. Well pressure depletes during this process. Typically, about 30 to 35 percent of the resource in the reservoir is extracted this way (Hyne, 2001). The amount extracted depends on the specific well characteristics (such as permeability and oil viscosity). Lacking enough pressure for the resource to surface, gas or water is injected into the well to increase the well pressure and force the resource out (**secondary** or **improved oil recovery).** Finally, **in tertiary extraction** or **enhanced recovery,** gas, chemicals or steam are injected into the well. This can result in recovering up to 60 percent of the original amount of oil in the reservoir (Hyne, 2001).

In contrast to conventional sources, unconventional oil and gas are trapped in rock or sand or, in the case of oil, are found in rock as a chemical substance that requires a further chemical transformation to become oil (U.S. DOE, 2009). Therefore, the resource does not move into a reservoir as in the case with a conventional source. Mining, induced pressure, or heat is required to release the resource. The specific type of extraction method needed depends on the type of formation where the resource is located. Unconventional natural gas resource types relevant for this proposal include:

- **Shale Natural Gas:** Shale natural gas comes from sediments of clay mixed with organic matter. These sediments form low permeability shale rock formations that do not allow the gas to move. To release the gas, the rock must be fragmented, making the extraction process more complex than it is for conventional gas extraction. Shale gas can be extracted by drilling either vertically or horizontally, and breaking the rock using hydraulic fracturing (U.S. DOE, 2009).

- **Tight Sands Natural Gas:** Reservoirs are composed of low-porosity sandstones and carbonate into which natural gas has migrated from other sources. Extraction of the natural gas from tight gas reservoirs is often performed using horizontal wells. Hydraulic fracturing is often used in tight sands (U.S. DOE, 2009).

- **Coalbed Methane:** Natural gas is present in a coal bed due to the activity of microbes in the coal or from alterations of the coal through temperature changes. Horizontal drilling is used but given that coalbed methane reservoirs are frequently associated with underground water reservoirs, hydraulic fracturing is often restricted (Andrews, 2009).

2.3.3 Natural Gas Processing

Natural gas conditioning is the process of removing impurities from the gas stream so that it is of sufficient quality to pass through transportation systems and used by final consumers. Conditioning is not always required. Natural gas from some formations emerges from the well sufficiently pure that it can be sent directly to the pipeline. As the natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or other problems.

The most significant impurity is H_2S, which may or may not be contained in natural gas. H_2S is toxic (and potentially fatal at certain concentrations) to humans and is corrosive for pipes. It is therefore desirable to remove H_2S as soon as possible in the conditioning process.

Another concern is that posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges, especially at cold temperatures (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas in the subsurface. These other gases must be separated from the methane prior to sale. High vapor pressure hydrocarbons that are liquids at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately.

Dehydration removes water from the gas stream. Three main approaches toward dehydration are the use of a liquid or solid desiccant, and refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration. The glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract the water molecules. The solids can be regenerated simply by heating them above the boiling point of water. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing at or near the well.

Sweetening is the procedure in which H_2S and sometimes CO_2 are removed from the gas stream. The most common method is amine treatment. In this process, the gas stream is exposed to an amine solution, which will react with the H_2S and separate them from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product.

2.3.4 Natural Gas Transmission and Distribution

After processing, natural gas enters a network of compressor stations, high-pressure transmission pipelines, and often-underground storage sites. Compressor stations are any facility which supplies energy to move natural gas at increased pressure in transmission pipelines or into underground storage. Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure. Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

2.4 Reserves and Markets

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, has historically been consumed close to where it is produced. However, as pipeline infrastructure and LNG trade expand, natural gas is increasingly a national and international commodity. The following subsections provide historical and forecast data on the U.S. reserves, production, consumption, and foreign trade of crude oil and natural gas.

2.4.1 Domestic Proved Reserves

Table 2-1 shows crude oil and natural gas proved reserves, inferred reserves, and undiscovered and total technically recoverable resources as of 2007. According to EIA[1], these concepts are defined as:

- **Proved reserves:** estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.

- **Inferred reserves:** the estimate of total volume recovery from known crude oil or natural gas reservoirs or aggregation of such reservoirs is expected to increase during the time between discovery and permanent abandonment.

- **Technically recoverable:** resources that are producible using current technology without reference to the economic viability of production.

The sum of proved reserves, inferred reserves, and undiscovered technically recoverable resources equal the total technically recoverable resources. As seen in Table 2-1, as of 2007, proved domestic crude oil reserves accounted for about 12 percent of the totally technically recoverable crude oil resources.

[1] U.S. Department of Energy, Energy Information Administration, Glossary of Terms <http://www.eia.doe.gov/glossary/index.cfm?id=P> Accessed 12/21/2010.

Table 2-1 Technically Recoverable Crude Oil and Natural Gas Resource Estimates, 2007

Region	Proved Reserves	Inferred Reserves	Undiscovered Technically Recoverable Resources	Total Technically Recoverable Resources
Crude Oil and Lease Condensate (billion bbl)				
48 States Onshore	14.2	48.3	25.3	87.8
48 States Offshore	4.4	10.3	47.2	61.9
Alaska	4.2	2.1	42.0	48.3
Total U.S.	22.8	60.7	114.5	198.0
Dry Natural Gas (tcf)				
Conventionally Reservoired Fields	194.0	671.3	760.4	1625.7
48 States Onshore Non-Associated Gas	149.0	595.9	144.1	889.0
48 States Offshore Non-Associated Gas	12.4	50.7	233.0	296.0
Associated-Dissolved Gas	20.7		117.2	137.9
Alaska	11.9	24.8	266.1	302.8
Shale Gas and Coalbed Methane	43.7	385	64.2	493.0
Total U.S.	237.7	1056.3	824.6	2118.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Inferred reserves for associated-dissolved natural gas are included in "Undiscovered Technically Recoverable Resources." Totals may not sum due to independent rounding.

Proved natural gas reserves accounted for about 11 percent of the totally technically recoverable natural gas resources. Significant proportions of these reserves exist in Alaska and offshore areas.

Table 2-2 and Figure 2-1 show trends in crude oil and natural gas production and reserves from 1990 to 2008. In Table 2-2, proved ultimate recovery equals the sum of cumulative production and proved reserves. While crude oil and natural gas are nonrenewable resources, the table shows that proved ultimate recovery rises over time as new discoveries become economically accessible. Reserves growth and decline is also partly a function of exploration activities, which are correlated with oil and natural gas prices. For example, when oil prices are high there is more of an incentive to use secondary and tertiary recovery, as well as to develop unconventional sources.

Table 2-2 Crude Oil and Natural Gas Cumulative Domestic Production, Proved Reserves, and Proved Ultimate Recovery, 1977-2008

	Crude Oil and Lease Condensate (million bbl)			Dry Natural Gas (bcf)		
Year	Cumulative Production	Proved Reserves	Proved Ultimate Recovery	Cumulative Production	Proved Reserves	Proved Ultimate Recovery
1990	158,175	27,556	185,731	744,546	169,346	913,892
1991	160,882	25,926	186,808	762,244	167,062	929,306
1992	163,507	24,971	188,478	780,084	165,015	945,099
1993	166,006	24,149	190,155	798,179	162,415	960,594
1994	168,438	23,604	192,042	817,000	163,837	980,837
1995	170,832	23,548	194,380	835,599	165,146	1,000,745
1996	173,198	23,324	196,522	854,453	166,474	1,020,927
1997	175,553	23,887	199,440	873,355	167,223	1,040,578
1998	177,835	22,370	200,205	892,379	164,041	1,056,420
1999	179,981	23,168	203,149	911,211	167,406	1,078,617
2000	182,112	23,517	205,629	930,393	177,427	1,107,820
2001	184,230	23,844	208,074	950,009	183,460	1,133,469
2002	186,327	24,023	210,350	968,937	186,946	1,155,883
2003	188,400	23,106	211,506	988,036	189,044	1,177,080
2004	190,383	22,592	212,975	1,006,564	192,513	1,199,077
2005	192,273	23,019	215,292	1,024,638	204,385	1,229,023
2006	194,135	22,131	216,266	1,043,114	211,085	1,254,199
2007	196,079	22,812	218,891	1,062,203	237,726	1,299,929
2008	197,987	20,554	218,541	1,082,489	244,656	1,327,145

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

However, annual production as a percentage of proved reserves has declined over time for both crude oil and natural gas, from above 10 percent in the early 1990s to 8 to 9 percent from 2006 to 2008 for crude oil and from above 11 percent during the 1990s to about 8 percent from 2008 to 2008 for natural gas.

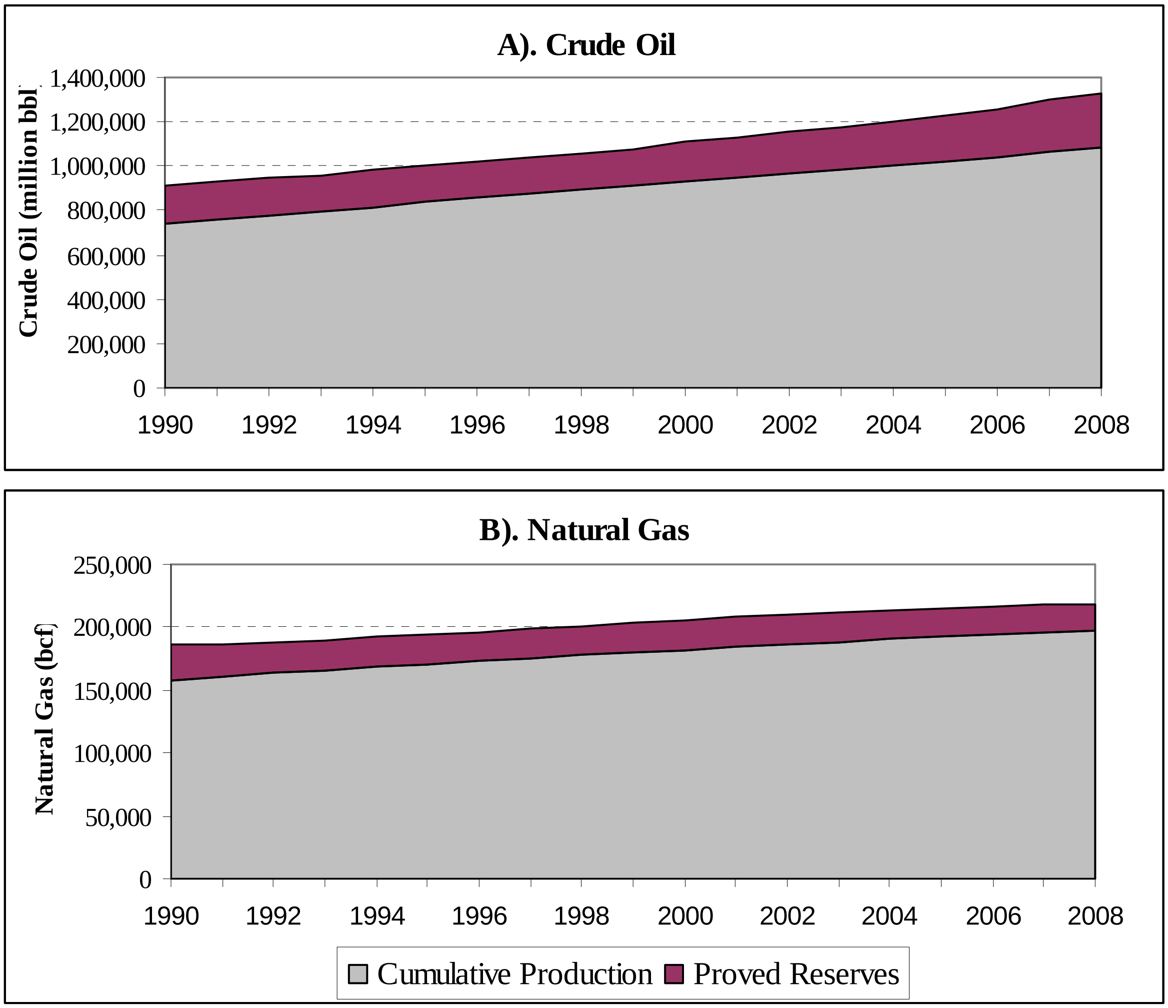

Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2008. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2008

Table 2-3 presents the U.S. proved reserves of crude oil and natural gas by state or producing area as of 2008. Four areas currently account for 77 percent of the U.S. total proved reserves of crude oil, led by Texas and followed by U.S. Federal Offshore, Alaska, and California. The top five states (Texas, Wyoming, Colorado, Oklahoma, and New Mexico) account for about 69 percent of the U.S. total proved reserves of natural gas.

Table 2-3 Crude Oil and Dry Natural Gas Proved Reserves by State, 2008

State/Region	Crude Oil (million bbls)	Dry Natural Gas (bcf)	Crude Oil (percent of total)	Dry Natural Gas (percent of total)
Alaska	3,507	7,699	18.3	3.1
Alabama	38	3,290	0.2	1.3
Arkansas	30	5,626	0.2	2.3
California	2,705	2,406	14.1	1.0
Colorado	288	23,302	1.5	9.5
Florida	3	1	0.0	0.0
Illinois	54	0	0.3	0.0
Indiana	15	0	0.1	0.0
Kansas	243	3,557	1.3	1.5
Kentucky	17	2,714	0.1	1.1
Louisiana	388	11,573	2.0	4.7
Michigan	48	3,174	0.3	1.3
Mississippi	249	1,030	1.3	0.4
Montana	321	1,000	1.7	0.4
Nebraska	8	0	0.0	0.0
New Mexico	654	16,285	3.4	6.7
New York	0	389	0.0	0.2
North Dakota	573	541	3.0	0.2
Ohio	38	985	0.2	0.4
Oklahoma	581	20,845	3.0	8.5
Pennsylvania	14	3,577	0.1	1.5
Texas	4,555	77,546	23.8	31.7
Utah	286	6,643	1.5	2.7
Virginia	0	2,378	0.0	1.0
West Virginia	23	5,136	0.1	2.1
Wyoming	556	31,143	2.9	12.7
Miscellaneous States	24	270	0.1	0.1
U.S. Federal Offshore	3,903	13,546	20.4	5.5
Total Proved Reserves	**19,121**	**244,656**	100.0	100.0

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Totals may not sum due to independent rounding.

2.4.2 Domestic Production

Domestic oil production is currently in a state of decline that began in 1970. Table 2-4 shows U.S. production in 2009 at 1938 million bbl per year, the highest level since 2004. However, annual domestic production of crude oil has dropped by almost 750 million bbl since 1990.

Table 2-4 Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average First Purchase Price

Year	Total Production (million bbl)	Producing Wells (1000s)	Avg. Well Productivity (bbl/well)	U.S. Average First Purchase Price/Barrel (2005 dollars)
1990	2,685	602	4,460	27.74
1991	2,707	614	4,409	22.12
1992	2,625	594	4,419	20.89
1993	2,499	584	4,279	18.22
1994	2,431	582	4,178	16.51
1995	2,394	574	4,171	17.93
1996	2,366	574	4,122	22.22
1997	2,355	573	4,110	20.38
1998	2,282	562	4,060	12.71
1999	2,147	546	3,932	17.93
2000	2,131	534	3,990	30.14
2001	2,118	530	3,995	24.09
2002	2,097	529	3,964	24.44
2003	2,073	513	4,042	29.29
2004	1,983	510	3,889	38.00
2005	1,890	498	3,795	50.28
2006	1,862	497	3,747	57.81
2007	1,848	500	3,697	62.63
2008	1,812	526	3,445	86.69
2009	1,938	526	3,685	51.37*

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

First purchase price represents the average price at the lease or wellhead at which domestic crude is purchased. * 2009 Oil price is preliminary

Average well productivity has also decreased since 1990 (Table 2-4 and Figure 2-2). These production and productivity decreases are in spite of the fact that average first purchase prices have shown a generally increasing trend. The exception to this general trend occurred in 2008 and 2009 when the real price increased up to 86 dollars per barrel and production in 2009 increased to almost 2 million bbl of oil.

Annual production of natural gas from natural gas wells has increased nearly 3000 bcf from the 1990 to 2009 (Table 2-5). Natural gas extracted from crude oil wells (associated natural gas) has remained more or less constant for the last twenty years. Coalbed methane has become a significant component of overall gas withdrawals in recent years.

Table 2-5 Natural Gas Production and Well Productivity, 1990-2009

	Natural Gas Gross Withdrawals (bcf)					Natural Gas Well Productivity	
Year	Natural Gas Wells	Crude Oil Wells	Coalbed Methane Wells	Total	Dry Gas Production*	Producing Wells (no.)	Avg. Productivity per Well (MMcf)
1990	16,054	5,469	NA	21,523	17,810	269,100	59.657
1991	16,018	5,732	NA	21,750	17,698	276,337	57.964
1992	16,165	5,967	NA	22,132	17,840	275,414	58.693
1993	16,691	6,035	NA	22,726	18,095	282,152	59.157
1994	17,351	6,230	NA	23,581	18,821	291,773	59.468
1995	17,282	6,462	NA	23,744	18,599	298,541	57.888
1996	17,737	6,376	NA	24,114	18,854	301,811	58.770
1997	17,844	6,369	NA	24,213	18,902	310,971	57.382
1998	17,729	6,380	NA	24,108	19,024	316,929	55.938
1999	17,590	6,233	NA	23,823	18,832	302,421	58.165
2000	17,726	6,448	NA	24,174	19,182	341,678	51.879
2001	18,129	6,371	NA	24,501	19,616	373,304	48.565
2002	17,795	6,146	NA	23,941	18,928	387,772	45.890
2003	17,882	6,237	NA	24,119	19,099	393,327	45.463
2004	17,885	6,084	NA	23,970	18,591	406,147	44.036
2005	17,472	5,985	NA	23,457	18,051	425,887	41.025
2006	17,996	5,539	NA	23,535	18,504	440,516	40.851
2007	17,065	5,818	1,780	24,664	19,266	452,945	37.676
2008	18,011	5,845	1,898	25,754	20,286	478,562	37.636
2009	18,881	5,186	2,110	26,177	20,955	495,697	38.089

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**
*Dry gas production is gas production after accounting for gas used repressurizing wells, the removal of nonhydrocarbon gases, vented and flared gas, and gas used as fuel during the production process.

The number of wells producing natural gas wells has nearly doubled between 1990 and 2009 (Figure 2-2). While the number of producing wells has increased overall, average well productivity has declined, despite improvements in exploration and gas well stimulation technologies.

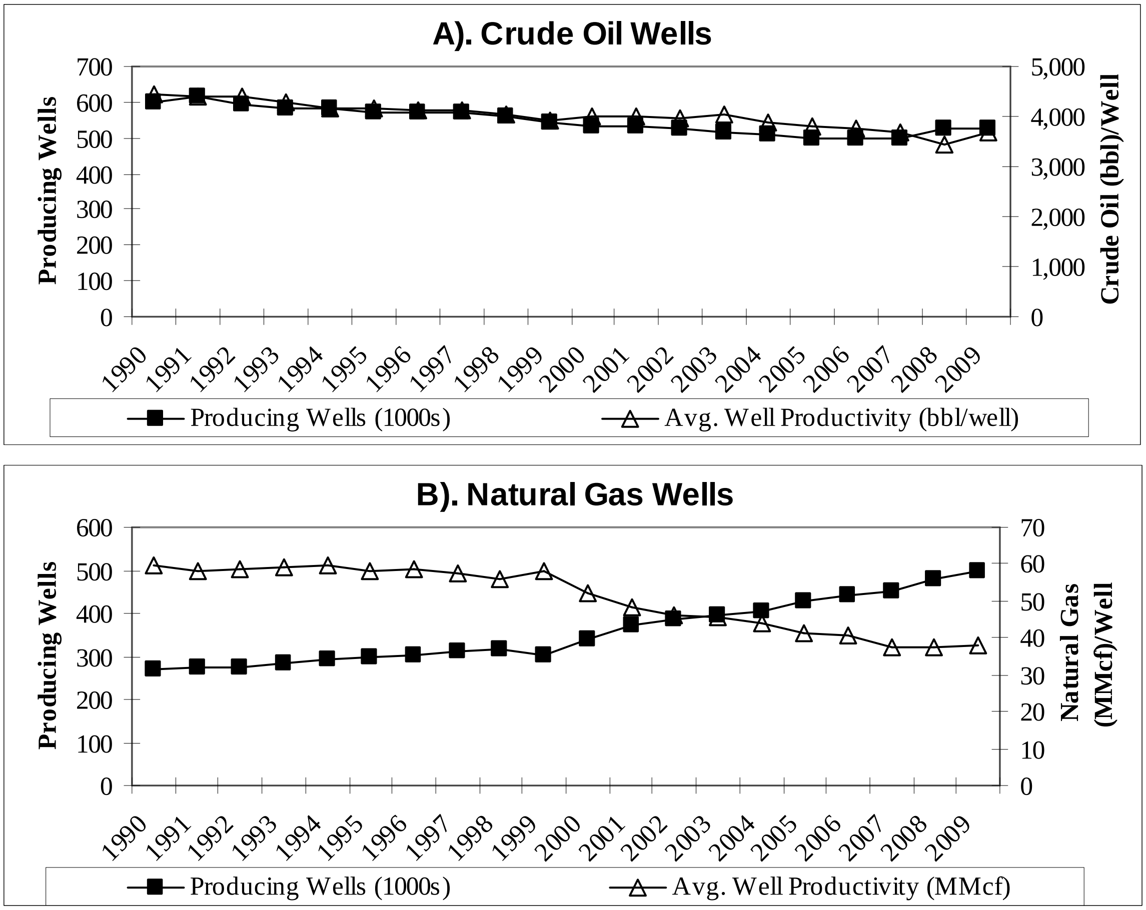

Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2009. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2009.

Domestic exploration and development for oil has continued during the last two decades. From 2002 to 2009, crude oil well drilling showed significant increases, although the 1992-2001 period showed relatively low levels of crude drilling activity compared to periods before and after (Table 2-6). The drop in 2009 showed a departure from this trend, likely due to the recession experienced in the U.S.

Meanwhile, natural gas drilling has increased significantly during the 1990-2009 period. Like crude oil drilling, 2009 saw a relatively low level of natural gas drillings. The success rate of wells (producing wells versus dry wells) has also increased gradually over time from 75 percent in 1990, to 86 percent in 2000, to 90 percent in 2009 (Table 2-6). The increasing success rate reflects improvements in exploration technology, as well as technological improvements in well drilling and completion. Similarly, well average depth has also increased by during this period (Table 2-6).

Table 2-6 Crude Oil and Natural Gas Exploratory and Development Wells and Average Depth, 1990-2009

	Wells Drilled					
Year	Crude Oil	Natural Gas	Dry Holes	Total	Successful Wells (percent)	Average Depth (ft)
1990	12,800	11,227	8,237	32,264	75	4,841
1991	12,542	9,768	7,476	29,786	75	4,872
1992	9,379	8,149	5,857	23,385	75	5,138
1993	8,828	9,829	6,093	24,750	75	5,407
1994	7,334	9,358	5,092	21,784	77	5,736
1995	8,230	8,081	4,813	21,124	77	5,560
1996	8,819	9,015	4,890	22,724	79	5,573
1997	11,189	11,494	5,874	28,557	79	5,664
1998	7,659	11,613	4,763	24,035	80	5,722
1999	4,759	11,979	3,554	20,292	83	5,070
2000	8,089	16,986	4,134	29,209	86	4,942
2001	8,880	22,033	4,564	35,477	87	5,077
2002	6,762	17,297	3,728	27,787	87	5,223
2003	8,104	20,685	3,970	32,759	88	5,418
2004	8,764	24,112	4,053	36,929	89	5,534
2005E	10,696	28,500	4,656	43,852	89	5,486
2006E	13,289	32,878	5,183	51,350	90	5,537
2007E	13,564	33,132	5,121	51,817	90	5,959
2008E	17,370	34,118	5,726	57,214	90	6,202
2009E	13,175	19,153	3,537	35,865	90	6,108

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Values for 2005-2009 are estimates.

Produced water is an important byproduct of the oil and natural gas industry, as management, including reuse and recycling, of produced water can be costly and challenging. Texas, California, Wyoming, Oklahoma, and Kansas were the top five states in terms of produced water volumes in 2007 (Table 2-7). These estimates do not include estimates of flowback water from hydraulic fracturing activities (ANL 2009).

Table 2-7 U.S. Onshore and Offshore Oil, Gas, and Produced Water Generation, 2007

State	Crude Oil (1000 bbl)	Total Gas (bcf)	Produced Water (1000 bbl)	Total Oil and Natural Gas (1000 bbls oil equivalent)	Barrels Produced Water per Barrel Oil Equivalent
Alabama	5,028	285	119,004	55,758	2.13
Alaska	263,595	3,498	801,336	886,239	0.90
Arizona	43	1	68	221	0.31
Arkansas	6,103	272	166,011	54,519	3.05
California	244,000	312	2,552,194	299,536	8.52
Colorado	2,375	1,288	383,846	231,639	1.66
Florida	2,078	2	50,296	2,434	20.66
Illinois	3,202	no data	136,872	3,202	42.75
Indiana	1,727	4	40,200	2,439	16.48
Kansas	36,612	371	1,244,329	102,650	12.12
Kentucky	3,572	95	24,607	20,482	1.20
Louisiana	52,495	1,382	1,149,643	298,491	3.85
Michigan	5,180	168	114,580	35,084	3.27
Mississippi	20,027	97	330,730	37,293	8.87
Missouri	80	no data	1,613	80	20.16
Montana	34,749	95	182,266	51,659	3.53
Nebraska	2,335	1	49,312	2,513	19.62
Nevada	408	0	6,785	408	16.63
New Mexico	59,138	1,526	665,685	330,766	2.01
New York	378	55	649	10,168	0.06
North Dakota	44,543	71	134,991	57,181	2.36
Ohio	5,422	86	6,940	20,730	0.33
Oklahoma	60,760	1,643	2,195,180	353,214	6.21
Pennsylvania	1,537	172	3,912	32,153	0.12
South Dakota	1,665	12	4,186	3,801	1.10
Tennessee	350	1	2,263	528	4.29
Texas	342,087	6,878	7,376,913	1,566,371	4.71
Utah	19,520	385	148,579	88,050	1.69
Virginia	19	112	1,562	19,955	0.08
West Virginia	679	225	8,337	40,729	0.20
Wyoming	54,052	2,253	2,355,671	455,086	5.18
State Total	***1,273,759***	***21,290***	***20,258,560***	***5,063,379***	***4.00***
Federal Offshore	467,180	2,787	587,353	963,266	0.61
Tribal Lands	9,513	297	149,261	62,379	2.39
Federal Total	***476,693***	***3,084***	***736,614***	***1,025,645***	***0.72***
U.S. Total	**1,750,452**	**24,374**	**20,995,174**	**6,089,024**	**3.45**

Source: Argonne National Laboratory and Department of Energy (2009). Natural gas production converted to barrels oil equivalent to facilitate comparison using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas. Totals may not sum due to independent rounding.

As can be seen in Table 2-7, the amount of water produced is not necessarily correlated with the ratio of water produced to the volume of oil or natural gas produced. Texas, Alaska and Wyoming were the three largest producers in barrels of oil equivalent (boe) terms, but had relatively low rates of water production compared to more Midwestern states, such Illinois, Missouri, Indiana, and Kansas.

Figure 2-3 shows the distribution of produced water management practices in 2007.

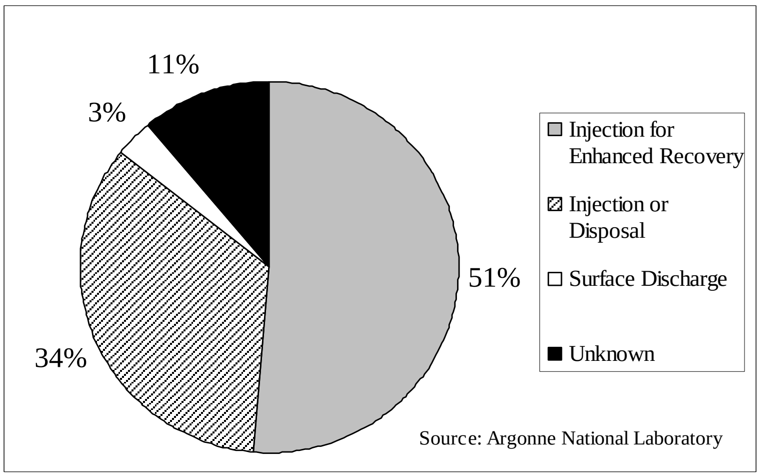

Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

More than half of the water produced (51 percent) was re-injected to enhance resource recovery through maintaining reservoir pressure or hydraulically pushing oil from the reservoir. Another third (34 percent) was injected, typically into wells whose primary purpose is to sequester produced water. A small percentage (three percent) is discharged into surface water when it meets water quality criteria. The destination of the remaining produced water (11 percent, the difference between the total managed and total generated) is uncertain (ANL, 2009).

The movement of crude oil and natural gas primarily takes place via pipelines. Total crude oil pipeline mileage has decreased during the 1990-2008 period (Table 2-8), appearing to follow the downward supply trend shown in Table 2-4. While exhibiting some variation, pipeline mileage transporting refined products remained relatively constant.

Table 2-8 U.S. Oil and Natural Gas Pipeline Mileage, 1990-2008

	Oil Pipelines			Natural Gas Pipelines			
Year	Crude Lines	Product Lines	Total	Distribution Mains	Transmission Pipelines	Gathering Lines	Total
1990	118,805	89,947	208,752	945,964	291,990	32,420	1,270,374
1991	115,860	87,968	203,828	890,876	293,862	32,713	1,217,451
1992	110,651	85,894	196,545	891,984	291,468	32,629	1,216,081
1993	107,246	86,734	193,980	951,750	293,263	32,056	1,277,069
1994	103,277	87,073	190,350	1,002,669	301,545	31,316	1,335,530
1995	97,029	84,883	181,912	1,003,798	296,947	30,931	1,331,676
1996	92,610	84,925	177,535	992,860	292,186	29,617	1,314,663
1997	91,523	88,350	179,873	1,002,942	294,370	34,463	1,331,775
1998	87,663	90,985	178,648	1,040,765	302,714	29,165	1,372,644
1999	86,369	91,094	177,463	1,035,946	296,114	32,276	1,364,336
2000	85,480	91,516	176,996	1,050,802	298,957	27,561	1,377,320
2001	52,386	85,214	154,877	1,101,485	290,456	21,614	1,413,555
2002	52,854	80,551	149,619	1,136,479	303,541	22,559	1,462,579
2003	50,149	75,565	139,901	1,107,559	301,827	22,758	1,432,144
2004	50,749	76,258	142,200	1,156,863	303,216	24,734	1,484,813
2005	46,234	71,310	131,348	1,160,311	300,663	23,399	1,484,373
2006	47,617	81,103	140,861	1,182,884	300,458	20,420	1,503,762
2007	46,658	85,666	147,235	1,202,135	301,171	19,702	1,523,008
2008	50,214	84,914	146,822	1,204,162	303,331	20,318	1,527,811

Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, *Natural Gas Transmission, Gas Distribution, and Hazardous Liquid Pipeline Annual Mileage*, available at http://ops.dot.gov/stats.htm as of Apr. 28, 2010. Totals may not sum due to independent rounding.

Table 2-8 splits natural gas pipelines into three types: distribution mains, transmission pipelines, and gathering lines. Gathering lines are low-volume pipelines that gather natural gas from production sites to deliver directly to gas processing plants or compression stations that connect numerous gathering lines to transport gas primarily to processing plants. Transmission pipelines move large volumes of gas to or from processing plants to distribution points. From these distribution points, the gas enters a distribution system that delivers the gas to final consumers. Table 2-8 shows gathering lines decreasing from 1990 from above 30,000 miles from 1990 to 1995 to around 20,000 miles in 2007 and 2008. Transmission pipelines added about 10,000 miles during this period, from about 292,000 in 1990 to about 303,000 miles in 2008. The most significant growth among all types of pipeline was in distribution, which increased about 260,000 miles during the 1990 to 2008 period, driving an increase in total natural gas pipeline mileage (Figure 2-1). The growth in distribution is likely driven by expanding production as well as expanding gas markets in growing U.S. towns and cities.

2.4.3 Domestic Consumption

Historical crude oil sector-level consumption trends for 1990 through 2009 are shown in Table 2-9 and Figure 2-4. Total consumption rose gradually until 2008 when consumption dropped as a result of the economic recession. The share of residential, commercial, industrial, and electric power on a percentage basis declined during this period, while the share of total consumption by the transportation sector rose from 64 percent in 1990 to 71 percent in 2009.

Table 2-9 Crude Oil Consumption by Sector, 1990-2009

		Percent of Total				
Year	Total (million bbl)	Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	6,201	4.4	2.9	25.3	64.1	3.3
1991	6,101	4.4	2.8	25.2	64.4	3.1
1992	6,234	4.4	2.6	26.5	63.9	2.5
1993	6,291	4.5	2.4	25.7	64.5	2.9
1994	6,467	4.3	2.3	26.3	64.4	2.6
1995	6,469	4.2	2.2	25.9	65.8	1.9
1996	6,701	4.4	2.2	26.3	65.1	2.0
1997	6,796	4.2	2.0	26.6	65.0	2.2
1998	6,905	3.8	1.9	25.6	65.7	3.0
1999	7,125	4.2	1.9	25.8	65.4	2.7
2000	7,211	4.4	2.1	24.9	66.0	2.6
2001	7,172	4.3	2.1	24.9	65.8	2.9
2002	7,213	4.1	1.9	25.0	66.8	2.2
2003	7,312	4.2	2.1	24.5	66.5	2.7
2004	7,588	4.0	2.0	25.2	66.2	2.6
2005	7,593	3.9	1.9	24.5	67.1	2.6
2006	7,551	3.3	1.7	25.1	68.5	1.4
2007	7,548	3.4	1.6	24.4	69.1	1.4
2008	7,136	3.7	1.8	23.2	70.3	1.1
2009*	6,820	3.8	1.8	22.5	71.1	0.9

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary.

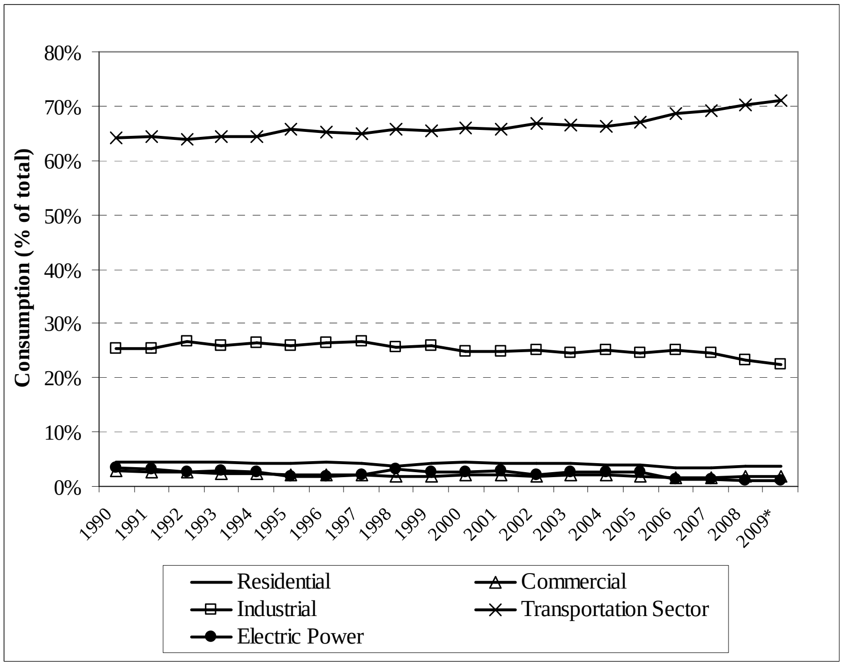

Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2009

Natural gas consumption has increased over the last twenty years. From 1990 to 2009, total U.S. consumption increased by an average of about 1 percent per year (Table 2-10 and Figure 2-5). Over the same period, industrial consumption of natural gas declined, whereas electric power generation increased its consumption quite dramatically, an important trend in the industry as many utilities increasingly use natural gas for peak generation or switch from coal-based to natural gas-based electricity generation. The residential, commercial, and transportation sectors maintained their consumption levels at more or less constant levels during this time period.

Table 2-10 Natural Gas Consumption by Sector, 1990-2009

Year	Total (bcf)	Percent of Total: Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	19,174	22.9	13.7	43.1	3.4	16.9
1991	19,562	23.3	13.9	42.7	3.1	17.0
1992	20,228	23.2	13.9	43.0	2.9	17.0
1993	20,790	23.8	13.8	42.7	3.0	16.7
1994	21,247	22.8	13.6	42.0	3.2	18.4
1995	22,207	21.8	13.6	42.3	3.2	19.1
1996	22,609	23.2	14.0	42.8	3.2	16.8
1997	22,737	21.9	14.1	42.7	3.3	17.9
1998	22,246	20.3	13.5	42.7	2.9	20.6
1999	22,405	21.1	13.6	40.9	2.9	21.5
2000	23,333	21.4	13.6	39.8	2.8	22.3
2001	22,239	21.5	13.6	38.1	2.9	24.0
2002	23,007	21.2	13.7	37.5	3.0	24.7
2003	22,277	22.8	14.3	37.1	2.7	23.1
2004	22,389	21.7	14.0	37.3	2.6	24.4
2005	22,011	21.9	13.6	35.0	2.8	26.7
2006	21,685	20.1	13.1	35.3	2.8	28.7
2007	23,097	20.4	13.0	34.1	2.8	29.6
2008	23,227	21.0	13.5	33.9	2.9	28.7
2009*	22,834	20.8	13.6	32.4	2.9	30.2

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary. Totals may not sum due to independent rounding.

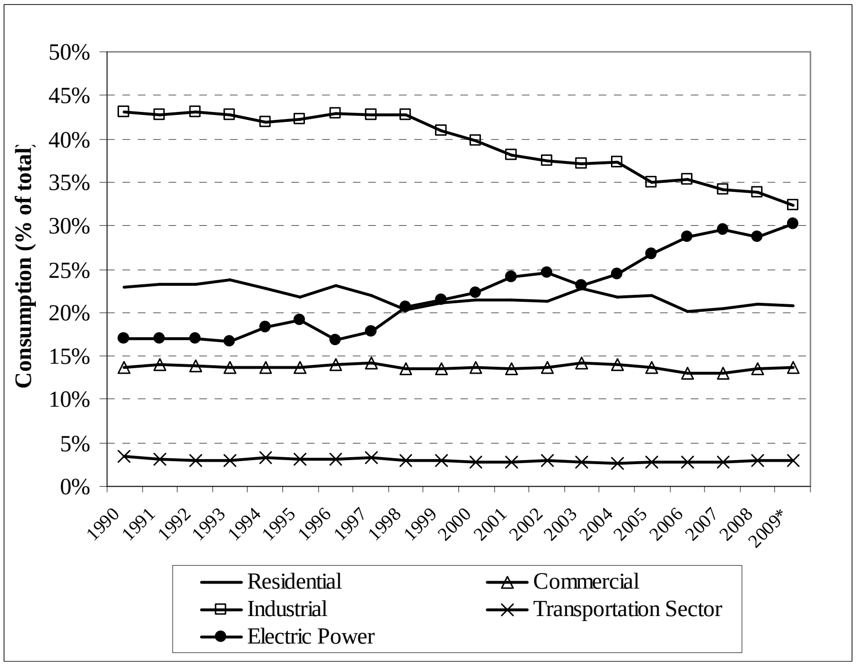

Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2009

2.4.4 International Trade

Imports of crude oil and refined petroleum products have increased over the last twenty years, showing increased substitution of imports for domestic production, as well as imports satisfying growing consumer demand in the U.S (Table 2-11). Crude oil imports have increased by about 2 percent per year on average, whereas petroleum products have increased by 1 percent on average per year.

Table 2-11 Total Crude Oil and Petroleum Products Imports (Million Bbl), 1990-2009

Year	Crude Oil	Petroleum Products	Total Petroleum
1990	2,151	775	2,926
1991	2,111	673	2,784
1992	2,226	661	2,887
1993	2,477	669	3,146
1994	2,578	706	3,284
1995	2,639	586	3,225
1996	2,748	721	3,469
1997	3,002	707	3,709
1998	3,178	731	3,908
1999	3,187	774	3,961
2000	3,320	874	4,194
2001	3,405	928	4,333
2002	3,336	872	4,209
2003	3,528	949	4,477
2004	3,692	1,119	4,811
2005	3,696	1,310	5,006
2006	3,693	1,310	5,003
2007	3,661	1,255	4,916
2008	3,581	1,146	4,727
2009	3,307	973	4,280

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** * 2009 Imports are preliminary.

Natural gas imports also increased steadily from 1990 to 2007 in volume and percentage terms (Table 2-12). The years 2007 and 2008 saw imported natural gas constituting a lower percentage of domestic natural gas consumption. In 2009, the U.S exported 700 bcf natural gas to Canada, 338 bcf to Mexico via pipeline, and 33 bcf to Japan in LNG-form. In 2009, the U.S. primarily imported natural gas from Canada (3268 bcf, 87 percent) via pipeline, although a growing percentage of natural gas imports are in LNG-form shipped from countries such as Trinidad and Tobago and Egypt. Until recent years, industry analysts forecast that LNG imports would continue to grow as a percentage of U.S consumption. However, it is possible that increasingly accessible domestic unconventional gas resources, such as shale gas and coalbed methane, might reduce the need for the U.S. to import natural gas, either via pipeline or shipped LNG.

Table 2-12 Natural Gas Imports and Exports, 1990-2009

Year	Total Imports (bcf)	Total Exports (bcf)	Net Imports (bcf)	Percent of U.S. Consumption
1990	1,532	86	1,447	7.5
1991	1,773	129	1,644	8.4
1992	2,138	216	1,921	9.5
1993	2,350	140	2,210	10.6
1994	2,624	162	2,462	11.6
1995	2,841	154	2,687	12.1
1996	2,937	153	2,784	12.3
1997	2,994	157	2,837	12.5
1998	3,152	159	2,993	13.5
1999	3,586	163	3,422	15.3
2000	3,782	244	3,538	15.2
2001	3,977	373	3,604	16.2
2002	4,015	516	3,499	15.2
2003	3,944	680	3,264	14.7
2004	4,259	854	3,404	15.2
2005	4,341	729	3,612	16.4
2006	4,186	724	3,462	16.0
2007	4,608	822	3,785	16.4
2008	3,984	1,006	2,979	12.8
2009*	3,748	1,071	2,677	11.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 Imports are preliminary.

2.4.5 Forecasts

In this section, we provide forecasts of well drilling activity and crude oil and natural gas domestic production, imports, and prices. The forecasts are from the 2011 Annual Energy Outlook produced by EIA, the most current forecast information available from EIA. As will be discussed in detail in Section 3, to analyze the impacts of the proposed NSPS on the national energy economy, we use the National Energy Modeling System (NEMS) that was used to produce the 2011 Annual Energy Outlook.

Table 2-13 and Figure 2-6 present forecasts of successful wells drilled in the U.S. from 2010 to 2035. Crude oil well forecasts for the lower 48 states show a rise from 2010 to a peak in 2019, which is followed by a gradual decline until the terminal year in the forecast, totaling a 28 percent decline for the forecast period. The forecast of successful offshore crude oil wells shows a variable but generally increasing trend.

Table 2-13 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

	Lower 48 U.S. States					Offshore		Totals	
Year	Crude Oil	Conventional Natural Gas	Tight Sands	Devonian Shale	Coalbed Methane	Crude Oil	Natural gas	Crude Oil	Natural Gas
2010	12,082	7,302	2,393	4,196	2,426	74	56	12,155	16,373
2011	10,271	7,267	2,441	5,007	1,593	81	73	10,352	16,380
2012	10,456	7,228	2,440	5,852	1,438	80	71	10,536	17,028
2013	10,724	7,407	2,650	6,758	1,564	79	68	10,802	18,447
2014	10,844	7,378	2,659	6,831	1,509	85	87	10,929	18,463
2015	10,941	7,607	2,772	7,022	1,609	84	87	11,025	19,096
2016	11,015	7,789	2,817	7,104	1,633	94	89	11,108	19,431
2017	11,160	7,767	2,829	7,089	1,631	104	100	11,264	19,416
2018	11,210	7,862	2,870	7,128	1,658	112	101	11,323	19,619
2019	11,268	8,022	2,943	7,210	1,722	104	103	11,373	20,000
2020	10,845	8,136	3,140	7,415	2,228	89	81	10,934	21,000
2021	10,849	8,545	3,286	7,621	2,324	91	84	10,940	21,860
2022	10,717	8,871	3,384	7,950	2,361	90	77	10,807	22,642
2023	10,680	9,282	3,558	8,117	2,499	92	96	10,772	23,551
2024	10,371	9,838	3,774	8,379	2,626	87	77	10,458	24,694
2025	10,364	10,200	3,952	8,703	2,623	93	84	10,457	25,562
2026	10,313	10,509	4,057	9,020	2,705	104	103	10,417	26,394
2027	10,103	10,821	4,440	9,430	2,862	99	80	10,202	27,633
2028	9,944	10,995	4,424	9,957	3,185	128	111	10,072	28,672
2029	9,766	10,992	4,429	10,138	3,185	121	127	9,887	28,870
2030	9,570	11,161	4,512	10,539	3,240	127	103	9,697	29,556
2031	9,590	11,427	4,672	10,743	3,314	124	109	9,714	30,265
2032	9,456	11,750	4,930	11,015	3,449	143	95	9,599	31,239
2033	9,445	12,075	5,196	11,339	3,656	116	107	9,562	32,372
2034	9,278	12,457	5,347	11,642	3,669	128	92	9,406	33,206
2035	8,743	13,003	5,705	12,062	3,905	109	108	8,852	34,782

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.**

Meanwhile, Table 2-13 and Figure 2-6 show increases for all types of natural gas drilling in the lower 48 states. Drilling in shale reservoirs is expected to rise most dramatically, about 190 percent during the forecast period, while drilling in coalbed methane and tight sands reservoirs increase significantly, 61 percent and 138 percent, respectively. Despite the growth in drilling in unconventional reservoirs, EIA forecasts successful conventional natural gas wells to increase about 78 percent during this period. Offshore natural gas wells are also expected to increase during the next 25 years, but not to the degree of onshore drilling.

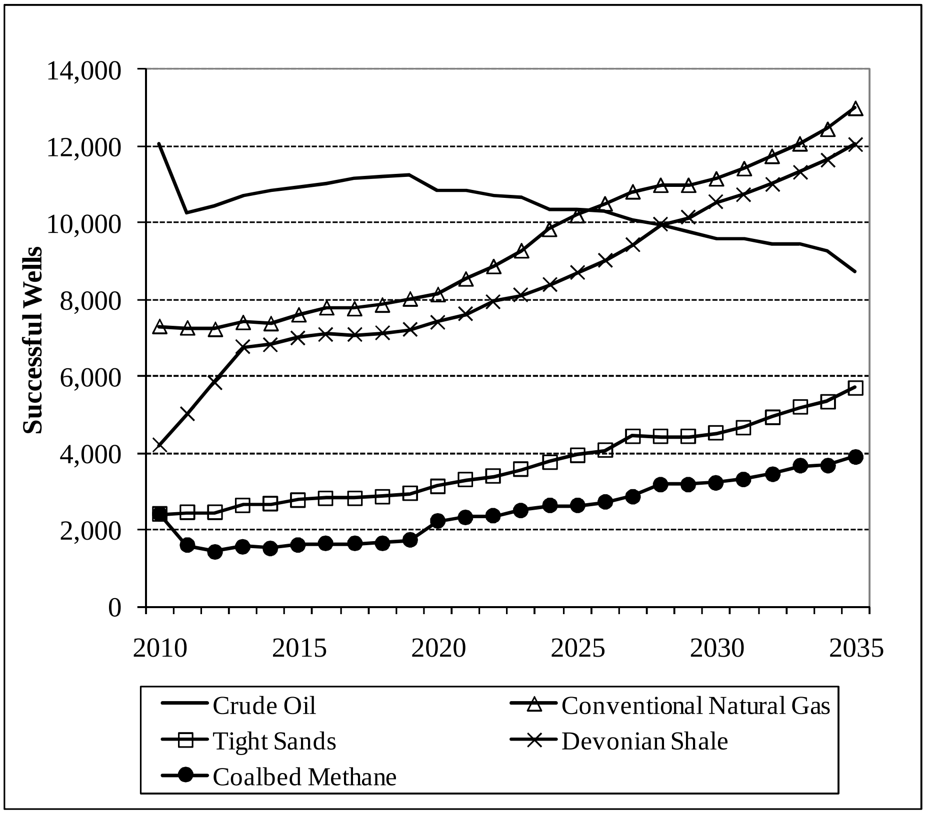

Figure 2-6 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

Table 2-14 presents forecasts of domestic crude oil production, reserves, imports and prices. Domestic crude oil production increases slightly during the forecast period, with much of the growth coming from onshore production in the lower 48 states. Alaskan oil production is forecast to decline from 2010 to a low of 99 million barrels in 2030, but rising above that level for the final five years of the forecast. Net imports of crude oil are forecast to decline slightly during the forecast period. Figure 2-7 depicts these trends graphically. All told, EIA forecasts total crude oil to decrease about 3 percent from 2010 to 2035.

Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2010-2035

	Domestic Production (million bbls)							
Year	Total Domestic	Lower 48 Onshore	Lower 48 Offshore	Alaska	Lower 48 End of Year Reserves	Net Imports	Total Crude Supply (million bbls)	Lower 48 Average Wellhead Price (2009 dollars per bbl)
2010	2,011	1,136	653	223	17,634	3,346	5,361	78.6
2011	1,993	1,212	566	215	17,955	3,331	5,352	84.0
2012	1,962	1,233	529	200	18,026	3,276	5,239	86.2
2013	2,037	1,251	592	194	18,694	3,259	5,296	88.6
2014	2,102	1,267	648	188	19,327	3,199	5,301	92.0
2015	2,122	1,283	660	179	19,690	3,177	5,299	95.0
2016	2,175	1,299	705	171	20,243	3,127	5,302	98.1
2017	2,218	1,320	735	163	20,720	3,075	5,293	101.0
2018	2,228	1,323	750	154	21,129	3,050	5,277	103.7
2019	2,235	1,343	746	147	21,449	3,029	5,264	105.9
2020	2,219	1,358	709	153	21,573	3,031	5,250	107.4
2021	2,216	1,373	680	163	21,730	3,049	5,265	108.8
2022	2,223	1,395	659	169	21,895	3,006	5,229	110.3
2023	2,201	1,418	622	161	21,921	2,994	5,196	112.0
2024	2,170	1,427	588	155	21,871	2,996	5,166	113.6
2025	2,146	1,431	566	149	21,883	3,010	5,155	115.2
2026	2,123	1,425	561	136	21,936	3,024	5,147	116.6
2027	2,114	1,415	573	125	22,032	3,018	5,131	117.8
2028	2,128	1,403	610	116	22,256	2,999	5,127	118.8
2029	2,120	1,399	614	107	22,301	2,988	5,108	119.3
2030	2,122	1,398	625	99	22,308	2,994	5,116	119.5
2031	2,145	1,391	641	114	22,392	2,977	5,122	119.6
2032	2,191	1,380	675	136	22,610	2,939	5,130	118.8
2033	2,208	1,365	691	152	22,637	2,935	5,143	119.1
2034	2,212	1,351	714	147	22,776	2,955	5,167	119.2
2035	2,170	1,330	698	142	22,651	3,007	5,177	119.5

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

Table 2-14 also shows forecasts of proved reserves in the lower 48 states. The reserves forecast shows steady growth from 2010 to 2035, an increase of 28 percent overall. This increment is larger than the forecast increase in production from the lower 48 states during this period, 8 percent, showing reserves are forecast to grow more rapidly than production. Table 2-14 also shows average wellhead prices increasing a total of 52 percent from 2010 to 2035, from $78.6 per barrel to $119.5 per barrel in 2008 dollar terms.

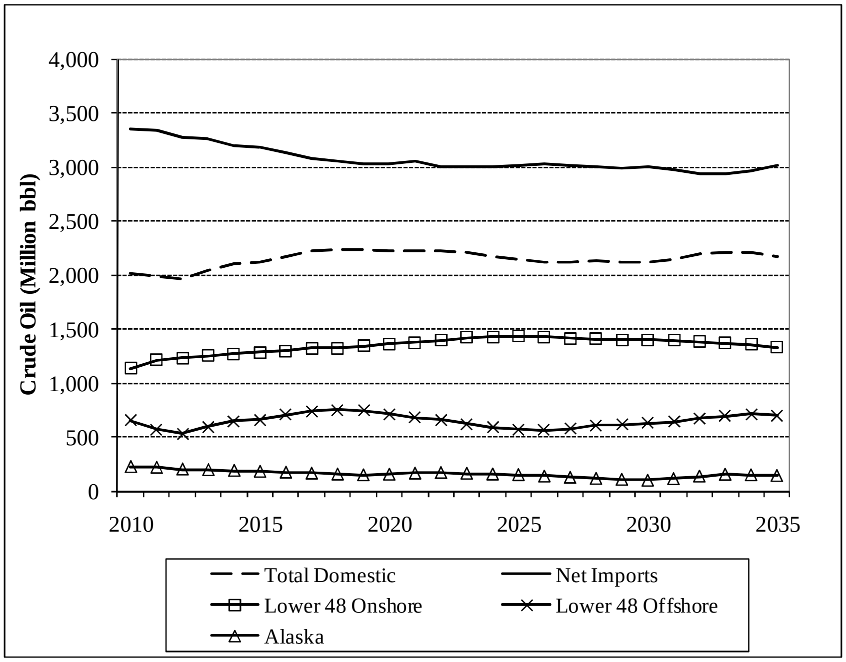

Figure 2-7 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2035

Table 2-15 shows domestic natural gas production is forecast to increase about 24 percent from 2010 to 2035. Contrasted against the much higher growth in natural gas wells drilled as shown in Table 2-13, per well productivity is expected to continue its declining trend. Meanwhile, imports of natural gas via pipeline are expected to decline during the forecast period almost completely, from 2.33 tcf in 2010 to 0.04 in 2035 tcf. Imported LNG also decreases from 0.41 tcf in 2010 to 0.14 tcf in 2035. Total supply, then, increases about 10 percent, from 24.08 tcf in 2010 to 26.57 tcf in 2035.

Table 2-15 Forecast of Natural Gas Supply, Lower 48 Reserves, and Wellhead Price

	Production		Net Imports				
Year	Dry Gas Production	Supplemental Natural Gas	Net Imports (Pipeline)	Net Imports (LNG)	Total Supply	Lower 48 End of Year Dry Reserves	Average Lower 48 Wellhead Price (2009 dollars per Mcf)
2010	21.28	0.07	2.33	0.41	24.08	263.9	4.08
2011	21.05	0.06	2.31	0.44	23.87	266.3	4.09
2012	21.27	0.06	2.17	0.47	23.98	269.1	4.09
2013	21.74	0.06	2.22	0.50	24.52	272.5	4.15
2014	22.03	0.06	2.26	0.45	24.80	276.6	4.16
2015	22.43	0.06	2.32	0.36	25.18	279.4	4.24
2016	22.47	0.06	2.26	0.36	25.16	282.4	4.30
2017	22.66	0.06	2.14	0.41	25.28	286.0	4.33
2018	22.92	0.06	2.00	0.43	25.40	289.2	4.37
2019	23.20	0.06	1.75	0.47	25.48	292.1	4.43
2020	23.43	0.06	1.40	0.50	25.40	293.6	4.59
2021	23.53	0.06	1.08	0.52	25.19	295.1	4.76
2022	23.70	0.06	0.89	0.49	25.14	296.7	4.90
2023	23.85	0.06	0.79	0.45	25.15	297.9	5.08
2024	23.86	0.06	0.77	0.39	25.08	298.4	5.27
2025	23.99	0.06	0.74	0.34	25.12	299.5	5.43
2026	24.06	0.06	0.71	0.27	25.10	300.8	5.54
2027	24.30	0.06	0.69	0.22	25.27	302.1	5.67
2028	24.59	0.06	0.67	0.14	25.47	304.4	5.74
2029	24.85	0.06	0.63	0.14	25.69	306.6	5.78
2030	25.11	0.06	0.63	0.14	25.94	308.5	5.82
2031	25.35	0.06	0.57	0.14	26.13	310.1	5.90
2032	25.57	0.06	0.50	0.14	26.27	311.4	6.01
2033	25.77	0.06	0.38	0.14	26.36	312.6	6.12
2034	26.01	0.06	0.23	0.14	26.44	313.4	6.24
2035	26.33	0.06	0.04	0.14	26.57	314.0	6.42

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

2.5 Industry Costs

2.5.1 Finding Costs

Real costs of drilling oil and natural gas wells have increased significantly over the past two decades, particularly in recent years. Cost per well has increased by an annual average of about 15 percent, and cost per foot has increased on average of about 13 percent per year (Figure 2-8).

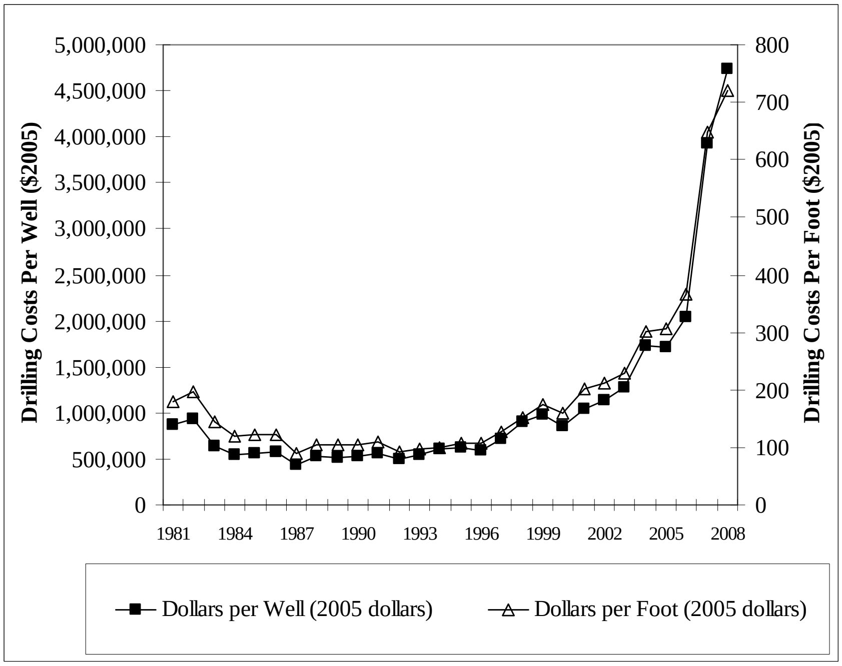

Figure 2-8 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

The average finding costs compiled and published by EIA add an additional level of detail to drilling costs, in that finding costs incorporate the costs more broadly associated with adding proved reserves of crude oil and natural gas. These costs include exploration and development costs, as well as costs associated with the purchase or leasing of real property. EIA publishes finding costs as running three-year averages, in order to better compare these costs, which occur over several years, with annual average lifting costs. Figure 2-9 shows average domestic onshore and offshore and foreign finding costs for the sample of U.S. firms in EIA's Financial Reporting System (FRS) database from 1981 to 2008. The costs are reported in 2008 dollars on a barrel of oil equivalent basis for crude oil and natural gas combined. The average domestic finding costs dropped from 1981 until the mid-1990s. Interestingly, in the mid-1990s, domestic onshore and offshore and foreign finding costs converged for a few years. After this period, offshore finding costs rose faster than domestic onshore and foreign costs.

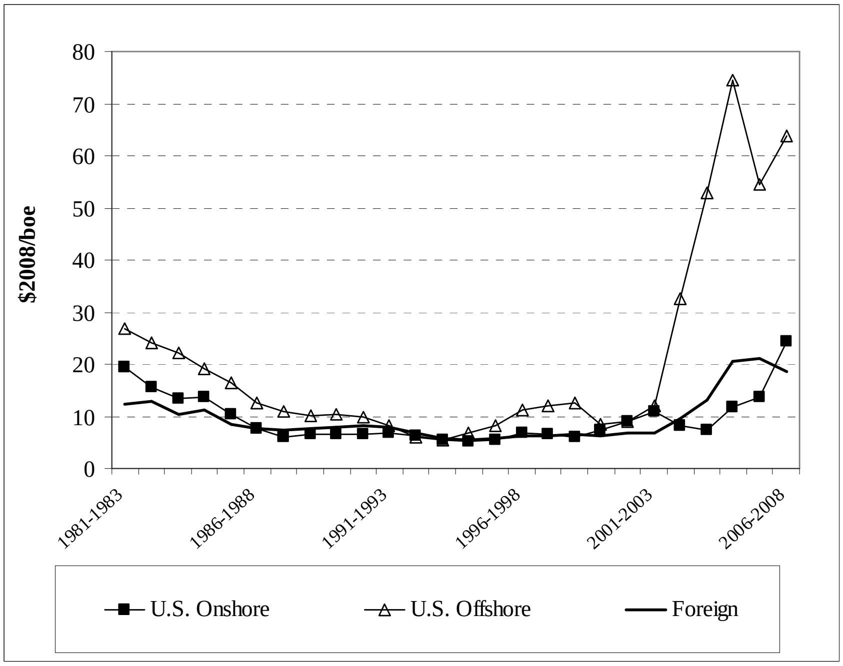

Figure 2-9 Finding Costs for FRS Companies, 1981-2008

After 2000, average finding costs rose sharply, with the finding costs for domestic onshore and offshore and foreign proved reserves diverging onto different trajectories. Note the drilling costs in Figure 2-8 and finding costs in Figure 2-9 present similar trends overall.

2.5.2 Lifting Costs

Lifting costs are the costs to produce crude oil or natural gas once the resource has been found and accessed. EIA's definition of lifting costs includes costs of operating and maintaining wells and associated production equipment. Direct lifting costs exclude production taxes or royalties, while total lifting costs includes taxes and royalties. Like finding costs, EIA reports average lifting costs for FRS firms in 2008 dollars on a barrel of oil equivalent basis. Total lifting costs are the sum of direct lifting costs and production taxes. Figure 2-10 depicts direct lifting cost trends from 1981 to 2008 for domestic and foreign production.

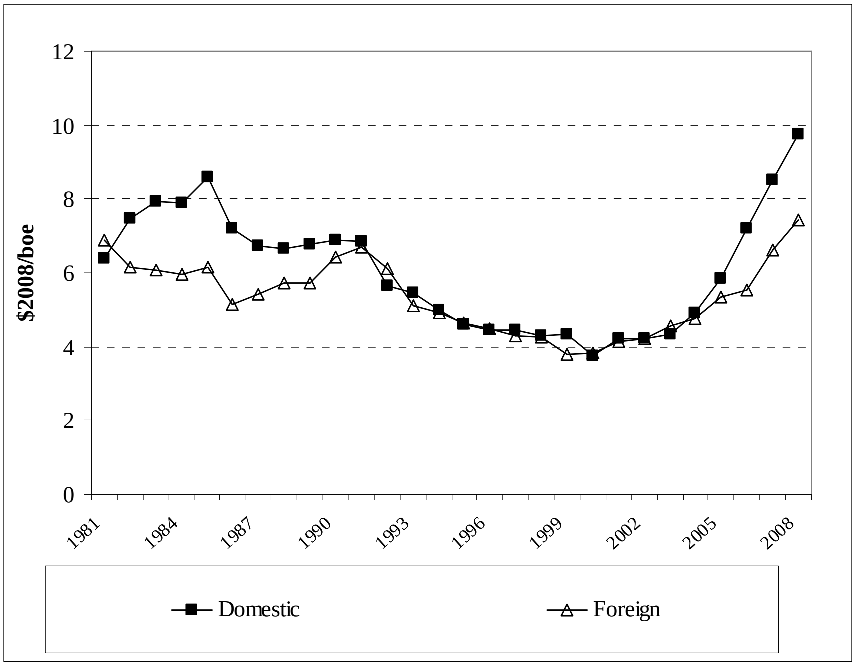

Figure 2-10 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2008 (3-year Running Average)

Direct lifting costs (excludes taxes and royalties) for domestic production rose a little more than $2 per barrels of oil equivalent from 1981 to 1985, then declined almost $5 per barrel of oil equivalent from 1985 until 2000. From 2000 to 2008, domestic lifting costs increased sharply, about $6 per barrel of oil equivalent. Foreign lifting costs diverged from domestic lifting costs from 1981 to 1991, as foreign lifting costs were lower than domestic costs during this period. Foreign and domestic lifting costs followed a similar track until they again diverged in 2004, with domestic lifting again becoming more expensive. Combined with finding costs, the total finding and lifting costs rose significantly in from 2000 to 2008.

2.5.3 Operating and Equipment Costs

The EIA report, "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009"[2], contains indices and estimated costs for domestic oil and natural gas equipment and production operations. The indices and cost trends track costs for representative operations in

[2] U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009." September 28, 2010. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

six regions (California, Mid-Continent, South Louisiana, South Texas, West Texas, and Rocky Mountains) with producing depths ranging from 2000 to 16,000 feet and low to high production rates (for example, 50,000 to 1 million cubic feet per day for natural gas).

Figure 2-11 depicts crude oil operating costs and equipment costs indices for 1976 to 2009, as well as the crude oil price in 1976 dollars. The indices show that crude oil operating and equipment costs track the price of oil over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and oil prices rose steeply in the late 1970s, but generally decreased from about 1980 until the late 1990s.

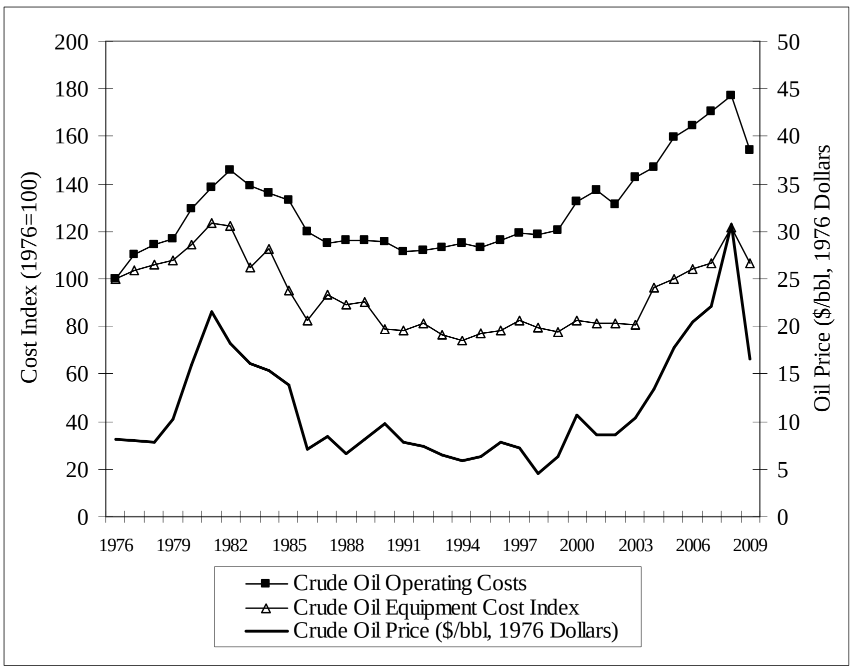

Figure 2-11 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009

Oil costs and prices again generally rose between 2000 to present, with a peak in 2008. The 2009 index values for crude oil operating and equipment costs are 154 and 107, respectively.

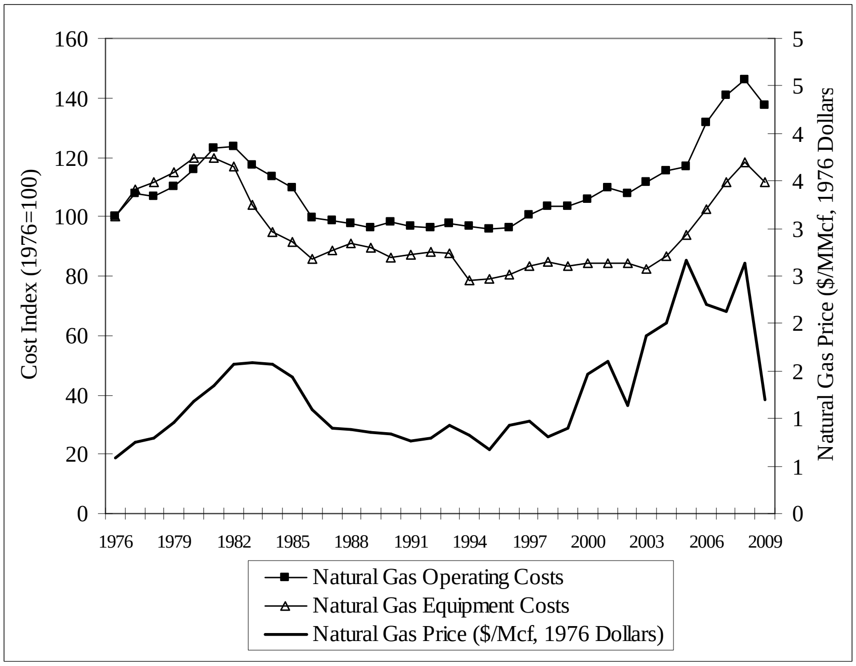

Figure 2-12 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

Figure 2-12 depicts natural gas operating and equipment costs indices, as well as natural gas prices. Similar to the cost trends for crude oil, natural gas operating and equipment costs track the price of natural gas over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and gas prices also rose steeply in the late 1970s, but generally decreased from about 1980 until the mid 1990s. The 2009 index values for natural gas operating and equipment costs are 137 and 112, respectively.

2.6 Firm Characteristics

A regulatory action to reduce pollutant discharges from facilities producing crude oil and natural gas will potentially affect the business entities that own the regulated facilities. In the oil and natural gas production industry, facilities comprise those sites where plant and equipment extract, process, and transport extracted streams recovered from the raw crude oil and natural gas resources. Companies that own these facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility.

2.6.1 Ownership

Enterprises in the oil and natural gas industry may be divided into different groups that include producers, transporters, and distributors. The producer segment may be further divided between major and independent producers. Major producers include large oil and gas companies that are involved in each of the five industry segments: drilling and exploration, production, transportation, refining, and marketing. Independent producers include smaller firms that are involved in some but not all of the five activities.

According to the Independent Petroleum Association of America (IPAA), independent companies produce approximately 68 percent of domestic crude oil production of our oil, 85 percent of domestic natural gas, and drill almost 90 percent of the wells in the U.S (IPAA, 2009). Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. IPAA reports that about 50 percent of its members' spending in 2007 was directed toward natural gas production, largely toward production of unconventional gas (IPAA, 2009). Meanwhile, transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

2.6.2 Size Distribution of Firms in Affected

As of 2007, there were 6,563 firms within the 211111 and 211112 NAICS codes, of which 6427 (98 percent) were considered small businesses (Table 2-16). Within NAICS 211111 and 211112, large firms compose about 2 percent of the firms, but account for 59 percent of employment and generate about 80 percent of estimated receipts listed under the NAICS.

Table 2-16 SBA Size Standards and Size Distribution of Oil and Natural Gas Firms

NAICS	NAICS Description	SBA Size Standard	Small Firms	Large Firms	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	98	41	139
213111	Drilling Oil and Gas Wells	500	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	61*	65*	126
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	24,683
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	500	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	20,796,681

Note: *The counts of small and large firms in NAICS 486210 is based upon firms with less than $7.5 million in receipts, rather than the $7 million required by the SBA Size Standard. We used this value because U.S. Census reports firm counts for firms with receipts less than $7.5 million. **Employment and receipts could not be split between small and large businesses because of non-disclosure requirements faced by the U.S. Census Bureau.
Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007."
<http://www.census.gov/econ/susb/>

The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 66 percent and 69 percent of employment and estimated receipts, respectively. Because there are relatively few firms within NAICS 486210, the Census Bureau cannot release breakdowns of firms by size in sufficient detail to perform similar calculation.

2.6.3 Trends in National Employment and Wages

As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in oil and natural gas-related NAICS codes from 1990 to 2009. The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of 313,703 in 1999, but rebounding to a 2008 peak of 511,805. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry.

Table 2-17 Oil and Natural Gas Industry Employment by NAICS, 1990-09

Year	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Ops. (213112)	Pipeline Trans. of Crude Oil (486110)	Pipeline Trans. of Natural Gas (486210)	Total
1990	182,848	8,260	52,365	109,497	11,112	47,533	411,615
1991	177,803	8,443	46,466	116,170	11,822	48,643	409,347
1992	169,615	8,819	39,900	99,924	11,656	46,226	376,140
1993	159,219	7,799	42,485	102,840	11,264	43,351	366,958
1994	150,598	7,373	44,014	105,304	10,342	41,931	359,562
1995	142,971	6,845	43,114	104,178	9,703	40,486	347,297
1996	139,016	6,654	46,150	107,889	9,231	37,519	346,459
1997	137,667	6,644	55,248	117,460	9,097	35,698	361,814
1998	133,137	6,379	53,943	122,942	8,494	33,861	358,756
1999	124,296	5,474	41,868	101,694	7,761	32,610	313,703
2000	117,175	5,091	52,207	108,087	7,657	32,374	322,591
2001	119,099	4,500	62,012	123,420	7,818	33,620	30,469
2002	116,559	4,565	48,596	120,536	7,447	31,556	329,259
2003	115,636	4,691	51,526	120,992	7,278	29,684	329,807
2004	117,060	4,285	57,332	128,185	7,073	27,340	341,275
2005	121,535	4,283	66,691	145,725	6,945	27,341	372,520
2006	130,188	4,670	79,818	171,127	7,202	27,685	420,690
2007	141,239	4,842	84,525	197,100	7,975	27,431	463,112
2008	154,898	5,183	92,640	223,635	8,369	27,080	511,805
2009	155,150	5,538	67,756	193,589	8,753	26,753	457,539

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

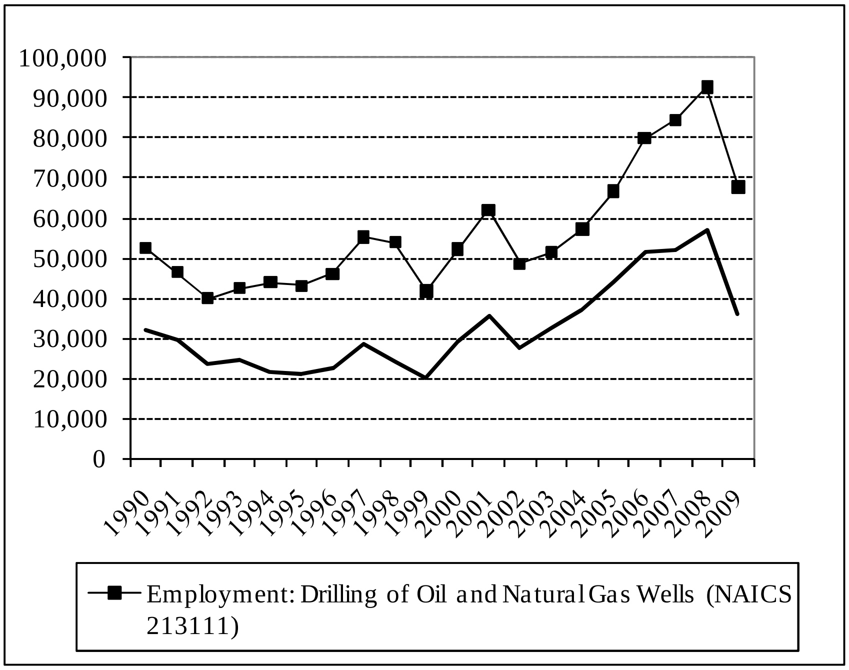

Figure 2-13 Employment in Drilling of Oil and Natural Gas Wells (NAICS 213111), and Total Oil and Natural Gas Wells Drilled, 1990-2009

Figure 2-13 compares employment in Drilling of Oil and Natural Gas Wells (NAICS 213111) with the total number of oil and natural gas wells drilled from 1990 to 2009. The figure depicts a strong positive correlation between employment in the sector with drilling activity. This correlation also holds throughout the period covered by the data.

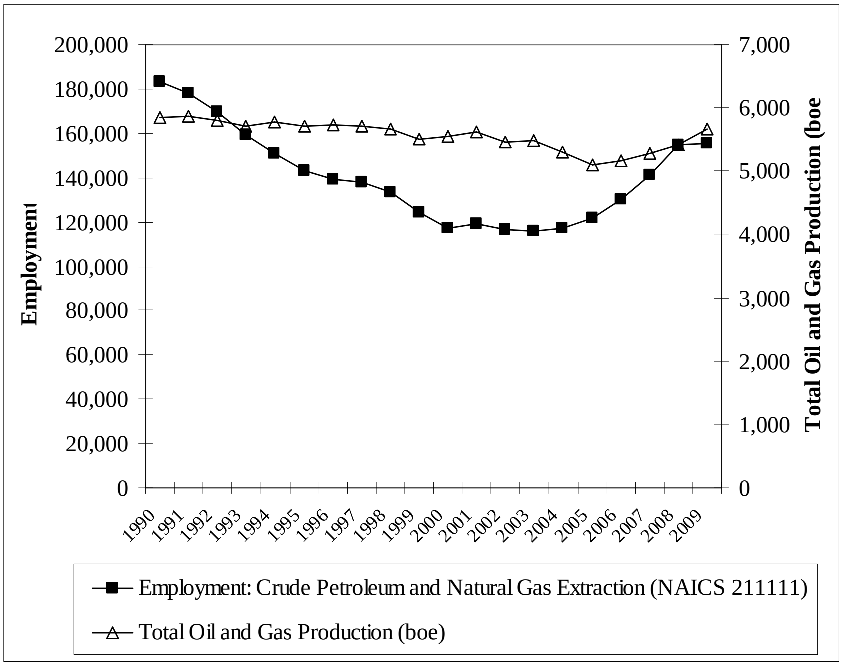

Figure 2-14 Employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Total Crude Oil and Natural Gas Production (boe), 1990-2009

Figure 2-14 compares employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) with total domestic oil and natural gas production from 1990 to 2009 in barrels of oil equivalent terms. While until 2003, employment in this sector and total production declined gradually, employment levels declined more rapidly. However, from 2004 to 2009 employment in Extraction recovered, rising to levels similar to the early 1990s.

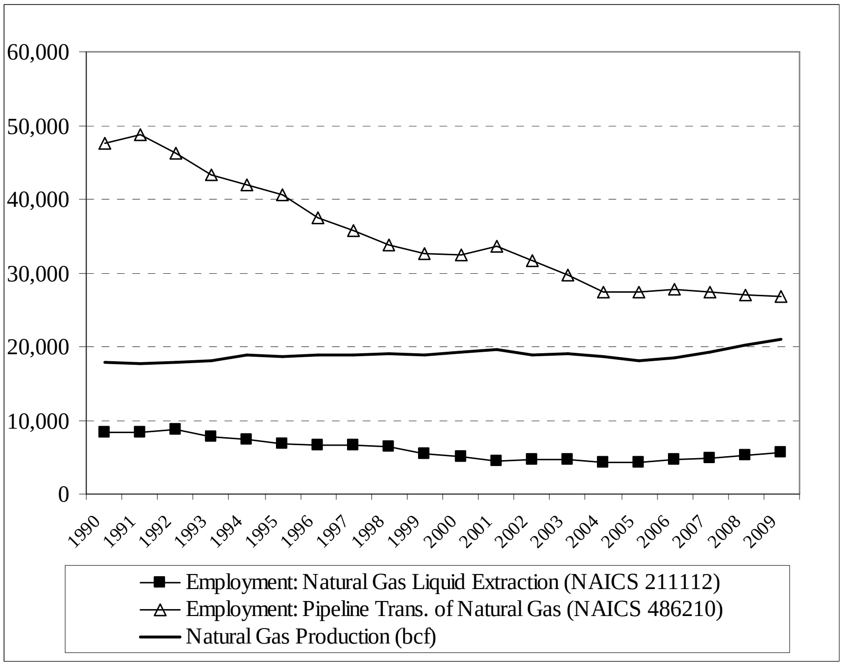

Figure 2-15 Employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009

Figure 2-15 depicts employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009. While total natural gas production has risen slightly over this time period, employment in natural gas pipeline transportation has steadily declined to almost half of its 1991 peak. Employment in natural gas liquid extraction declined from 1992 to a low in 2005, then rebounded slightly from 2006 to 2009. Overall, however, these trends depict these sectors becoming decreasingly labor intensive, unlike the trends depicted in Figure 2-13 and Figure 2-14.

From 1990 to 2009, average wages for the oil and natural gas industry have increased. Table 2-18 and Figure 2-16 show real wages (in 2008 dollars) from 1990 to 2009 for the NAICS codes associated with the oil and natural gas industry.

Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 (2008 dollars)

Year	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Operations (213112)	Pipeline Transportation of Crude Oil (486110)	Pipeline Transportation of Natural Gas (486210)	Total
1990	71,143	66,751	42,215	45,862	68,044	61,568	59,460
1991	72,430	66,722	43,462	47,261	68,900	65,040	60,901
1992	76,406	68,846	43,510	48,912	74,233	67,120	64,226
1993	77,479	68,915	45,302	50,228	72,929	67,522	64,618
1994	79,176	70,875	44,577	50,158	76,136	68,516	64,941
1995	81,433	67,628	46,243	50,854	78,930	71,965	66,446
1996	84,211	68,896	48,872	52,824	76,841	76,378	68,391
1997	89,876	79,450	52,180	55,600	78,435	82,775	71,813
1998	93,227	89,948	53,051	57,578	79,089	84,176	73,722
1999	98,395	89,451	54,533	59,814	82,564	94,471	79,078
2000	109,744	112,091	60,862	60,594	81,097	130,630	86,818
2001	111,101	111,192	61,833	61,362	83,374	122,386	85,333
2002	109,957	103,653	62,196	59,927	87,500	91,550	82,233
2003	110,593	112,650	61,022	61,282	87,388	91,502	82,557
2004	121,117	118,311	63,021	62,471	93,585	93,684	86,526
2005	127,243	127,716	70,772	67,225	92,074	90,279	90,292
2006	138,150	133,433	74,023	70,266	91,708	98,691	94,925
2007	135,510	132,731	82,010	71,979	96,020	105,441	96,216
2008	144,542	125,126	81,961	74,021	101,772	99,215	99,106
2009	133,575	123,922	80,902	70,277	100,063	100,449	96,298

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

Employees in the NAICS 211 codes enjoy the highest average wages in the industry, while employees in the NAICS 213111 code have relatively lower wages. Average wages in natural gas pipeline transportation show the highest variation, with a rapid climb from 1990 to 2000, more than doubling in real terms. However, since 2000 wages have declined in the pipeline transportation sector, while wages have risen in the other NAICS.

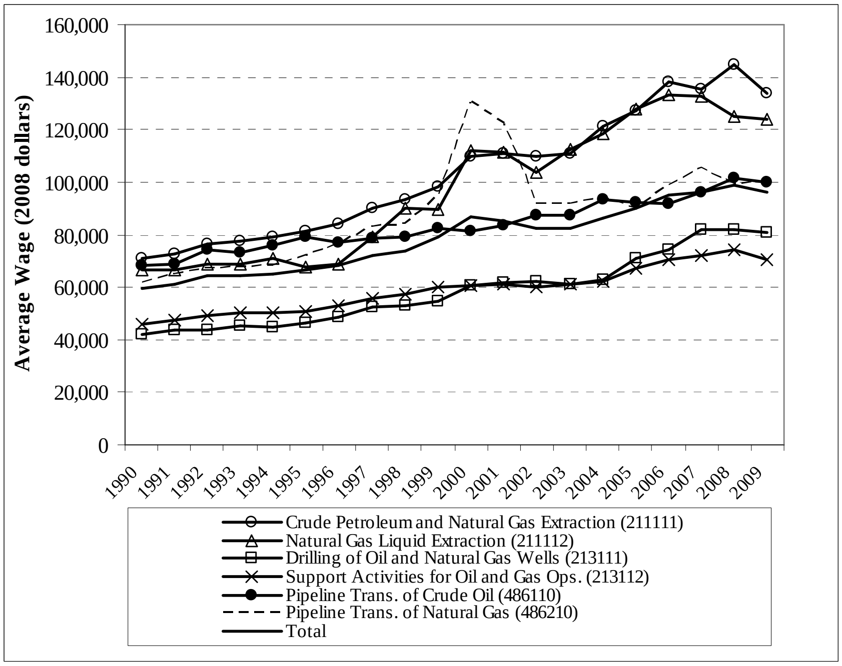

Figure 2-16 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 ($2008)

2.6.4 Horizontal and Vertical Integration

Because of the existence of major companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one. Vertical integration is a potentially important dimension in analyzing firm-level impacts because the regulation could affect a vertically integrated firm on more than one level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company that owns oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosene. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons. A horizontally integrated firm may own many facilities of which only some are directly affected by the regulation. Additionally, a horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation. A horizontally integrated firm could also be indirectly as well as directly affected by the regulation.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of regulation of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is less predominant than in the oil sector. Transmission and local distribution of natural gas usually occur at individual firms, although processing is increasing performed by the integrated major companies. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms only. Typically wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independents have to rely only on profits generated at the wellhead from the sale of oil and natural gas or the provision of oil and gas production-related engineering or financial services. Overall, independent producers typically sell their output to refineries or natural gas pipeline companies and are not vertically integrated. Independents may also own relatively few facilities, indicating limited horizontal integration.

2.6.5 Firm-level Information

The annual *Oil and Gas Journal* (OGJ) survey, the OGJ150, reports financial and operating results for top 150 public oil and natural gas companies with domestic reserves and headquarters in the U.S. In the past, the survey reported information on the top 300 companies, now the top 150. In 2010, only 137 companies are listed[3]. Table 2-19 lists selected statistics for

[3] Oil and Gas Journal. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.

the top 20 companies in 2010. The results presented in the table reflect relatively lower production and financial figures as a result of the economic recession of this period.

Total earnings for the top 137 companies fell from 2008 to 2009 from $71 billion to $27 billion, reflecting the weak economy. Revenues for these companies also fell 35 percent during this period. 69 percent of the firms posted net losses in 2009, compared to 46 percent one year earlier (*Oil and Gas Journal*, September 6, 2010).

The total worldwide liquids production for the 137 firms declined 0.5 percent to 2.8 billion bbl, while total worldwide gas production increased about 3 percent to a total of 16.5 tcf (*Oil and Gas Journal*, September 6, 2010). Meanwhile, the 137 firms on the OGJ list increased both oil and natural gas production and reserves from 2008 to 2009. Domestic production of liquids increased about 7 percent to 1.1 billion bbl, and natural gas production increased to 10.1 tcf. For context, the OGJ150 domestic crude production represents about 57 percent of total domestic production (1.9 billion bbl, according to EIA). The OGJ150 natural gas production represents about 54 percent of total domestic production (18.8 tcf, according to EIA).

The OGJ also releases a period report entitled “Worldwide Gas Processing Survey”, which provides a wide range of information on existing processing facilities. We used a recent list of U.S. gas processing facilities (*Oil and Gas Journal,* June 7, 2010) and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. As of 2009, there are 579 gas processing facilities in the U.S., with a processing capacity of 73,767 million cubic feet per day and throughout of 45,472 million cubic feet per day (Table 2-20). The overall trend in U.S. gas processing capacity is showing fewer, but larger facilities. For example, in 1995, there were 727 facilities with a capacity of 60,533 million cubic feet per day (U.S. DOE, 2006).

Trends in gas processing facility ownership are also showing a degree of concentration, as large firms own multiple facilities, which also tend to be relatively large facilities (Table 2-20). While we estimate 142 companies own the 579 facilities, the top 20 companies (in terms of total throughput) own 264 or 46 percent of the facilities. That larger companies tend to own larger facilities is indicated by these top 20 firms owning 86 percent of the total capacity and 88 percent of actual throughput.

Table 2-19 Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2010

						Worldwide Production		U.S. Production		
Rank by Total Assets	Company	Employees	Total Assets ($ millions)	Total Rev. ($ millions)	Net Inc. ($ millions)	Liquids (Million bbl)	Natural Gas (Bcf)	Liquids (Million bbl)	Natural Gas (Bcf)	Net Wells Drilled
1	ExxonMobil Corp.	102,700	233,323	310,586	19,280	725	2,383	112	566	466
2	Chevron Corp.	64,000	164,621	171,636	10,563	674	1,821	177	511	594
3	ConocoPhillips	30,000	152,588	152,840	4,858	341	1,906	153	850	692
4	Anadarko Petroleum Corp.	4,300	50,123	9,000	-103	88	817	63	817	630
5	Marathon Oil Corp.	28,855	47,052	54,139	1,463	90	351	23	146	115
6	Occidental Petroleum Corp.	10,100	44,229	15,531	2,915	179	338	99	232	260
7	XTO Energy Inc.	3,129	36,255	9,064	2,019	32	855	32	855	1,059
8	Chesapeake Energy Corp.	8,200	29,914	7,702	-5,805	12	835	12	835	1,003
9	Devon Energy Corp.	5,400	29,686	8,015	-2,479	72	966	43	743	521
10	Hess Corp.	13,300	29,465	29,569	740	107	270	26	39	48
11	Apache Corp.	3,452	28,186	8,615	-284	106	642	35	243	124
12	El Paso Corp.	4,991	22,505	4,631	-539	6	219	6	215	134
13	EOG Resources Inc.	2,100	18,119	14,787	547	29	617	26	422	652
14	Murphy Oil Corp.	8,369	12,756	18,918	838	48	68	6	20	3
15	Noble Energy Inc.	1,630	11,807	2,313	-131	29	285	17	145	540
16	Williams Cos. Inc.	4,801	9,682	2,219	400	0	3,435	0	3,435	488
17	Questar Corp.	2,468	8,898	3,054	393	4	169	4	169	194
18	Pioneer Nat. Resources Co.	1,888	8,867	1,712	-52	19	157	17	148	67
19	Plains Expl. & Prod. Co.	808	7,735	1,187	136	18	78	18	78	53
20	Petrohawk Energy Corp.	469	6,662	41,084	-1,025	2	174	2	174	162

Source: *Oil and Gas Journal*. “OGJ150 Financial Results Down in '09; Production, Reserves Up.” September 6, 2010.
Notes: The source for employment figures is the American Business Directory.

Table 2-20 Top 20 Natural Gas Processing Firms (Based on Throughput), 2009

Rank	Company	Processing Plants (No.)	Natural Gas Capacity (MMcf/day)	Natural Gas Throughput (MMcf/day)
1	BP PLC	19	13,378	11,420
2	DCP Midstream Inc.	64	9,292	5,586
3	Enterprise Products Operating LP—	23	10,883	5,347
4	Targa Resources	16	4,501	2,565
5	Enbridge Energy Partners LP—	19	3,646	2,444
6	Williams Cos.	10	4,826	2,347
7	Martin Midstream Partners	16	3,384	2,092
8	Chevron Corp.	23	1,492	1,041
9	Devon Gas Services LP	6	1,038	846
10	ExxonMobil Corp.	6	1,238	766
11	Occidental Petroleum Corp	7	776	750
12	Kinder Morgan Energy Partners	9	1,318	743
13	Enogex Products Corp.	8	863	666
14	Hess Corp.	3	1,060	613
15	Norcen Explorer	1	600	500
16	Copano Energy	1	700	495
17	Anadarko	18	816	489
18	Oneok Field Services	10	1,751	472
19	Shell	4	801	446
20	DTE Energy	1	800	400
	TOTAL FOR TOP 20	264	63,163	40,028
	TOTAL FOR ALL COMPANIES	579	73,767	45,472

Source: *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants.

The OGJ also issues a periodic report on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies, which amounts to 136 companies in 2010 (*Oil and Gas Journal*, November 1, 2010). Table 2-21 presents the pipeline mileage, volumes of natural gas transported, operating revenue, and net income for the top 20 U.S. natural gas pipeline companies in 2009. Ownership of gas pipelines is mostly independent from ownership of oil and gas production companies, as is seen from the lack of overlap between the OGJ list of pipeline companies and the OGJ150. This observation shows that the pipeline industry is still largely based upon firms serving regional market.

The top 20 companies maintain about 63 percent of the total pipeline mileage and transport about 54 percent of the volume of the industry (Table 2-21). Operating revenues of the top 20 companies equaled $11.5 billion, representing 60 percent of the total operating revenues for major and non-major companies. The top 20 companies also account for 64 percent of the net income of the industry.

Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2009

Rank	Company	Transmission (miles)	Vol. trans for others (MMcf)	Op. Rev. (thousand $)	Net Income
1	Natural Gas Pipeline Co of America	9,312	1,966,774	1,131,548	348,177
2	Dominion Transmission Inc.	3,452	609,193	831,773	212,365
3	Columbia Gas Transmission LLC	9,794	1,249,188	796,437	200,447
4	Panhandle Eastern Pipe Line Co. LP	5,894	675,616	377,563	196,825
5	Transcontinental Gas Pipe Line Co. LLC	9,362	2,453,295	1,158,665	192,830
6	Texas Eastern Transmission LP	9,314	1,667,593	870,812	179,781
7	Northern Natural Gas Co.	15,028	922,745	690,863	171,427
8	Florida Gas Transmission Co. LLC	4,852	821,297	520,641	164,792
9	Tennessee Gas Pipeline Co.	14,113	1,704,976	820,273	147,378
10	Southern Natural Gas Co.	7,563	867,901	510,500	137,460
11	El Paso Natural Gas Co.	10,235	1,493,213	592,503	126,000
12	Gas Transmission Northwest Corp.	1,356	809,206	216,526	122,850
13	Rockies Express Pipeline LLC	1,682	721,840	555,288	117,243
14	CenterPoint Energy Gas Transmission Co.	6,162	1,292,931	513,315	116,979
15	Colorado Interstate Gas Co.	4,200	839,184	384,517	108,483
16	Kern River Gas Transmission Co.	1,680	789,858	371,951	103,430
17	Trunkline LNG Co. LLC	—	—	134,150	101,920
18	Northwest Pipeline GP	3,895	817,832	434,379	99,340
19	Texas Gas Transmission LLC	5,881	1,006,906	361,406	91,575
20	Algonquin Gas Transmission LLC	1,128	388,366	237,291	82,472
	TOTAL FOR TOP 20	124,903	21,097,914	11,510,401	3,021,774
	TOTAL FOR ALL COMPANIES	198,381	38,793,532	18,934,674	4,724,456

Source: *Oil and Gas Journal*. “Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow.” November 1, 2010.

2.6.6 Financial Performance and Condition

From a broad industry perspective, the EIA Financial Reporting System (FRS) collects financial and operating information from a subset of the U.S. major energy producing companies. This information is used in annual report to Congress, as well as is released to the public in aggregate form. While the companies that report information to FRS each year changes, EIA makes an effort to retain sufficient consistency such that trends can be evaluated.

For 2008, there are 27 companies in the FRS[4] that accounted for 41 percent of total U.S. crude oil and NGL production, 43 percent of natural gas production, 77 percent of U.S. refining capacity, and 0.2 percent of U.S. electricity net generation (U.S. EIA, 2010). Table 2-22 shows a series of financial trends in 2008 dollars selected and aggregated from FRS firms' financial statements. The table shows operating revenues and expenses rising significantly from 1990 to 2008, with operating income (the difference between operating revenues and expenses) rising as well. Interest expenses remained relatively flat during this period. Meanwhile, recent years have shown that other income and income taxes have played a more significant role for the industry. Net income has risen as well, although 2008 saw a decline from previous periods, as oil and natural gas prices declined significantly during the latter half of 2008.

Table 2-22 Selected Financial Items from Income Statements (Billion 2008 Dollars)

Year	Operating Revenues	Operating Expenses	Operating Income	Interest Expense	Other Income*	Income Taxes	Net Income
1990	766.9	706.4	60.5	16.8	13.6	24.8	32.5
1991	673.4	635.7	37.7	14.4	13.4	15.4	21.3
1992	670.2	637.2	33.0	12.7	-5.6	12.2	2.5
1993	621.4	586.6	34.8	11.0	10.3	12.7	21.5
1994	606.5	565.6	40.9	10.8	6.8	14.4	22.5
1995	640.8	597.5	43.3	11.1	12.9	17.0	28.1
1996	706.8	643.3	63.6	9.1	13.4	26.1	41.8
1997	673.6	613.8	59.9	8.2	13.4	23.9	41.2
1998	614.2	594.1	20.1	9.2	11.0	6.0	15.9
1999	722.9	682.6	40.3	10.9	12.7	13.6	28.6
2000	1,114.3	1,011.8	102.5	12.9	18.4	42.9	65.1
2001	961.8	880.3	81.5	10.8	7.6	33.1	45.2
2002	823.0	776.9	46.2	12.7	7.9	17.2	24.3
2003	966.9	872.9	94.0	10.1	19.5	37.2	66.2
2004	1,188.5	1,051.1	137.4	12.4	20.1	54.2	90.9
2005	1,447.3	1,263.8	183.5	11.6	34.6	77.1	129.3
2006	1,459.0	1,255.0	204.0	12.4	41.2	94.8	138.0
2007	1,475.0	1,297.7	177.3	11.1	47.5	86.3	127.4
2008	1,818.1	1,654.0	164.1	11.4	32.6	98.5	86.9

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). * Other Income includes other revenue and expense (excluding interest expense), discontinued operations, extraordinary items, and accounting changes. Totals may not sum due to independent rounding.

[4] Alenco, Anadarko Petroleum Corporation, Apache Corporation, BP America, Inc., Chesapeake Energy Corporation, Chevron Corporation, CITGO Petroleum Corporation, ConocoPhillips, Devon Energy Corporation, El Paso Corporation, EOG Resources, Inc., Equitable Resources, Inc., Exxon Mobil Corporation, Hess Corporation, Hovensa, Lyondell Chemical Corporation, Marathon Oil Corporation, Motiva Enterprises, L.L.C., Occidental Petroleum Corporation, Shell Oil Company, Sunoco, Inc., Tesoro Petroleum Corporation, The Williams Companies, Inc., Total Holdings USA, Inc., Valero Energy Corp., WRB Refining LLC, and XTO Energy, Inc.

Table 2-23 shows in percentage terms the estimated return on investments for a variety of business lines, in 1998, 2003, and 2008, for FRS companies. For U.S. petroleum-related business activities, oil and natural gas production has remained the most profitable line of business relative to refining/marketing and pipelines, sustaining a return on investment greater than 10 percent for the three years evaluated. Returns to foreign oil and natural gas production rose above domestic production in 2008. Electric power generation and sales emerged in 2008 as a highly profitable line of business for the FRS companies.

Table 2-23 Return on Investment for Lines of Business (all FRS), for 1998, 2003, and 2008 (percent)

Line of Business	1998	2003	2008
Petroleum	10.8	13.4	12.0
U.S. Petroleum	10	13.7	8.2
Oil and Natural Gas Production	12.5	16.5	10.7
Refining/Marketing	6.6	9.3	2.6
Pipelines	6.7	11.5	2.4
Foreign Petroleum	11.9	13.0	17.8
Oil and Natural Gas Production	12.5	14.2	16.3
Refining/Marketing	10.6	8.0	26.3
Downstream Natural Gas*	-	8.8	5.1
Electric Power*	-	5.2	181.4
Other Energy	7.1	2.8	-2.1
Non-energy	10.9	2.4	-5.3

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). Note: Return on investment measured as contribution to net income/net investment in place. * The downstream natural gas and electric power lines of business were added to the EIA-28 survey form beginning with the 2003 reporting year.

The oil and natural gas industry also produces significant tax revenues for local, state, and federal authorities. Table 2-24 shows income and production tax trends from 1990 to 2008 for FRS companies. The column with U.S. federal, state, and local taxes paid or accrued includes deductions for the U.S. Federal Investment Tax Credit ($198 million in 2008) and the effect of the Alternative Minimum Tax ($34 million in 2008). Income taxes paid to state and local authorizes were $3,060 million in 2008, about 13 percent of the total paid to U.S. authorities.

Table 2-24 Income and Production Taxes, 1990-2008 (Million 2008 Dollars)

Year	U.S. Federal, State, and Local Taxes Paid or Accrued	Total Current	Total Deferred	Total Income Tax Expense	Other Non-Income Production Taxes Paid
1990	9,568	25,056	-230	24,826	4,341
1991	6,672	18,437	-3,027	15,410	3,467
1992	4,994	16,345	-4,116	12,229	3,097
1993	3,901	13,983	-1,302	12,681	2,910
1994	3,348	13,556	887	14,443	2,513
1995	6,817	17,474	-510	16,965	2,476
1996	8,376	22,493	3,626	26,119	2,922
1997	7,643	20,764	3,141	23,904	2,743
1998	1,199	7,375	-1,401	5,974	1,552
1999	2,626	13,410	140	13,550	2,147
2000	14,308	36,187	6,674	42,861	3,254
2001	10,773	28,745	4,351	33,097	3,042
2002	814	17,108	46	17,154	2,617
2003	9,274	30,349	6,879	37,228	3,636
2004	19,661	50,185	4,024	54,209	3,990
2005	29,993	72,595	4,529	77,125	5,331
2006	29,469	85,607	9,226	94,834	5,932
2007	28,332	84,119	2,188	86,306	7,501
2008	23,199	95,590	2,866	98,456	12,507

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The difference between total current taxes and U.S. federal, state, and local taxes in includes taxes and royalties paid to foreign countries. As can be seen in Table 2-24, foreign taxes paid far exceeds domestic taxes paid. Other non-income production taxes paid, which have risen almost three-fold between 1990 and 2008, include windfall profit and severance taxes, as well as other production-related taxes.

2.7 References

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3 EMISSIONS AND ENGINEERING COSTS

3.1 Introduction

This section includes three sets of discussions for both the proposed NSPS and NESHAP amendments:

- Emission Sources and Points
- Emissions Control Options
- Engineering Cost Analysis

3.2 Emissions Points, Controls, and Engineering Costs Analysis

This section discusses the emissions points and pollution control options for the proposed NSPS and NESHAP amendments. This discussion of emissions points and control options is meant to assist the reader of the RIA in better understanding the economic impact analysis. However, we provide reference to the detailed technical memoranda prepared by the Office of Air Quality Planning and Standards (OAQPS) for the reader interested in a greater level of detail. This section also presents the engineering cost analysis, which provides a cost basis for the energy system, welfare, employment, and small business analyses.

Before going into detail on emissions points and pollution controls, it is useful to provide estimates of overall emissions from the crude oil and natural industry to provide context for estimated reductions as a result of the regulatory options evaluated. To estimate VOC emissions from the oil and gas sector, we modified the emissions estimate for the crude oil and natural gas sector in the 2008 National Emissions Inventory (NEI). During this review, EPA identified VOC emissions from natural gas sources which are likely relatively under-represented in the NEI, natural gas well completions primarily. Crude oil and natural gas sector VOC emissions estimated in the 2008 NEI total approximately 1.76 million tons. Of these emissions, the NEI identifies about 21 thousand tons emitted from natural gas well completion processes. We substituted the estimates of VOC emissions from natural gas well completions estimated as part of the engineering analysis (510,000 tons, which is discussed in more detail in the next section), bringing the total estimated VOC emissions from the crude oil and natural gas sector to about 2.24 million tons VOC.

The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 ($MMtCO_2$-e). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 $MMtCO_2$-e to approximately 330 $MMtCO_2$-e.

3.2.1 Emission Points and Pollution Controls assessed in the RIA

3.2.1.1 NSPS Emission Points and Pollution Controls

A series of emissions controls were evaluated as part of the NSPS review. This section provides a basic description of possible emissions sources and the controls evaluated for each source to facilitate the reader's understanding of the economic impact and benefit analyses. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant chapters within the Technical Support Document (TSD) which is published in the Docket. The chapters are also referenced below. EPA is soliciting public comment and data relevant to several emissions-related issues related to the proposed NSPS. The comments we receive during the public comment period will help inform the rule development process as we work toward promulgating a final action.

Centrifugal and reciprocating compressors (TSD Chapter 6)**:** There are many locations throughout the oil and gas sector where compression of natural gas is required to move the gas along the pipeline. This is accomplished by compressors powered by combustion turbines, reciprocating internal combustion engines, or electric motors. Turbine-powered compressors use a small portion of the natural gas that they compress to fuel the turbine. The turbine operates a centrifugal compressor, which compresses and pumps the natural gas through the pipeline. Sometimes an electric motor is used to turn a centrifugal compressor. This type of compression does not require the use of any of the natural gas from the pipeline, but it does require a source of electricity. Reciprocating spark ignition engines are also used to power many compressors, referred to as reciprocating compressors, since they compress gas using pistons that are driven by the engine. Like combustion turbines, these engines are fueled by natural gas from the pipeline.

Both centrifugal and reciprocating compressors are sources of VOC emissions, and EPA evaluated compressors for coverage under the NSPS. Centrifugal compressors require seals around the rotating shaft to prevent gases from escaping where the shaft exits the compressor casing. The seals in some compressors use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated, and the gas is commonly vented to the atmosphere. These are commonly called "wet" seals. An alternative to a wet seal system is the mechanical dry seal system. This seal system does not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and static pressure. Fugitive VOC is emitted from dry seals around the compressor shaft. The use of dry gas seals substantially reduces emissions. In addition, they significantly reduce operating costs and enhance compressor efficiency.

Reciprocating compressors in the natural gas industry leak natural gas during normal operation. The highest volume of gas loss is associated with piston rod packing systems. Packing systems are used to maintain a tight seal around the piston rod, preventing the gas compressed to high pressure in the compressor cylinder from leaking, while allowing the rod to move freely. Monitoring and replacing compressor rod packing systems on a regular basis can greatly reduce VOC emissions.

Equipment leaks (TSD Chapter 8)**:** Equipment leaks are fugitive emissions emanating from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines, and other process and operation components. There are several potential reasons for equipment leak emissions. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. Because of the large number of valves, pumps, and other components within an oil and gas production, processing, and transmission facility, equipment leaks of volatile emissions from these components can be significant. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components. These types of equipment also exist at production sites and gas transmission/compressor stations. While the number of components at individual transmission/compressor stations is relatively smaller than at processing plants, collectively there are many components that can result in significant emissions. Therefore, EPA evaluated NSPS for equipment leaks for facilities in the production segment of the industry, which includes everything from the wellhead to the point that the gas enters the processing plant or refinery.

Pneumatic controllers (TSD Chapter 5): Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature. Pneumatic controllers are widely used in the oil and natural gas sector. In many situations, the pneumatic controllers used in the oil and gas sector make use of the available high-pressure natural gas to regulate temperature, pressure, liquid level, and flow rate across all areas of the industry. In these "gas-driven" pneumatic controllers, natural gas may be released with every valve movement or continuously from the valve control pilot. Not all pneumatic controllers are gas driven. These "non-gas driven" pneumatic controllers use sources of power other than pressurized natural gas. Examples include solar, electric, and instrument air. At oil and gas locations with electrical service, non gas-driven controllers are typically used. Gas-driven pneumatic controllers are typically characterized as "high-bleed" or "low-bleed", where a high-bleed device releases at least 6 cubic feet of gas per hour. EPA evaluated the impact of requiring low-bleed controllers.

Storage vessels (TSD Chapter 7): Crude oil, condensate, and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically located at tank batteries. A tank battery refers to the collection of process equipment used to separate, treat, and store crude oil, condensate, natural gas, and produced water. The extracted products from productions wells enter the tank battery through the production header, which may collect product from many wells. Emissions from storage vessels are a result of working, breathing, and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flashing emission will occur in the storage stage. The two ways of controlling tanks with significant emissions would be to install a vapor recovery unit (VRU) and recover all the vapors from the tanks or to route the emissions from the tanks to a control device.

Well completions (TSD Chapter 4): In the oil and natural gas sector, well completions contain multi-phase processes with various sources of emissions. One specific emission source during completion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during activities that involve re-drilling or re-fracturing an existing well. Well completions include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production.

Hydraulic fracturing is one completion step for improving gas production where the reservoir rock is fractured with very high pressure fluid, typically water emulsion with proppant (generally sand) that “props open” the fractures after fluid pressure is reduced. Emissions are a result of the backflow of the fracture fluids and reservoir gas at high velocity necessary to lift excess proppant to the surface. This multi-phase mixture is often directed to a surface impoundment where natural gas and VOC vapors escape to the atmosphere during the collection of water, sand, and hydrocarbon liquids. As the fracture fluids are depleted, the backflow eventually contains more volume of natural gas from the formation. Thus, we estimate completions involving hydraulic fracturing vent substantially more natural gas, approximately 230 times more, than completions not involving hydraulic fracturing. Specifically, we estimate that uncontrolled well completion emissions for a hydraulically fractured well are about 23 tons of VOC, where emissions for a conventional gas well completion are around 0.1 ton VOC. Our data indicate that hydraulically fractured wells have higher emissions but we believe some wells that are not hydraulically fractured may have higher emissions than our data show, or in some cases, hydraulically fractured wells could have lower emissions that our data show.

Reduced emission completions, which are sometimes referred to as "green completions" or "flareless completions," use equipment at the well site to capture and treat gas so it can be directed into the sales line and avoid emissions from venting. Equipment required to conduct a reduced emissions completion may include tankage, special gas-liquid-sand separator traps, and gas dehydration. Equipment costs associated with reduced emission completions will vary from well to well. Based on information provided to the EPA Natural Gas STAR program, 90 percent of gas potentially vented during a completion can be recovered during a reduced emission completion.

3.2.1.2 NESHAP Emission Points and Pollution Controls

A series of emissions controls will be required under the proposed NESHAP Amendments. This section provides a basic description of potential sources of emissions and the controls intended for each to facilitate the reader's understanding of the economic impacts and subsequent benefits analysis section. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant technical memos which are published in the Docket. The memos are also referenced below.

Glycol dehydrators[5]: Once natural gas has been separated from any liquid materials or products (e.g., crude oil, condensate, or produced water), residual entrained water is removed from the natural gas by dehydration. Dehydration is necessary because water vapor may form hydrates, which are ice-like structures, and can cause corrosion in or plug equipment lines. The most widely used natural gas dehydration processes are glycol dehydration and solid desiccant

[5] Memorandum. Brown, Heather, EC/R Incorporated, to Bruce Moore and Greg Nizich, EPA/OAQPS/SPPD/FIG. Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT - Glycol Dehydrators: Impacts of MACT Review Options. July 17,2011.

dehydration. Solid desiccant dehydration, which is typically only used for lower throughputs, uses adsorption to remove water and is not a source of HAP emissions. Glycol dehydration is an absorption process in which a liquid absorbent, glycol, directly contacts the natural gas stream and absorbs any entrained water vapor in a contact tower or absorption column. The rich glycol, which has absorbed water vapor from the natural gas stream, leaves the bottom of the absorption column and is directed either to (1) a gas condensate glycol separator (GCG separator or flash tank) and then a reboiler or (2) directly to a reboiler where the water is boiled off of the rich glycol. The regenerated glycol (lean glycol) is circulated, by pump, into the absorption tower. The vapor generated in the reboiler is directed to the reboiler vent. The reboiler vent is a source of HAP emissions. In the glycol contact tower, glycol not only absorbs water but also absorbs selected hydrocarbons, including BTEX and n-hexane. The hydrocarbons are boiled off along with the water in the reboiler and vented to the atmosphere or to a control device.

The most commonly used control device is a condenser. Condensers not only reduce emissions, but also recover condensable hydrocarbon vapors that can be recovered and sold. In addition, the dry non-condensable off-gas from the condenser may be used as fuel or recycled into the production process or directed to a flare, incinerator, or other combustion device.

If present, the GCG separator (flash tank) is also a potential source of HAP emissions. Some glycol dehydration units use flash tanks prior to the reboiler to separate entrained gases, primarily methane and ethane from the glycol. The flash tank off-gases are typically recovered as fuel or recycled to the natural gas production header. However, the flash tank may also be vented directly to the atmosphere. Flash tanks typically enhance the reboiler condenser’s emission reduction efficiency by reducing the concentration of non-condensable gases present in the stream prior to being introduced into the condenser.

Storage vessels: Please see the discussion of storage vessels in the NSPS section above.

3.2.2 Engineering Cost Analysis

In this section, we provide an overview of the engineering cost analysis used to estimate the additional private expenditures industry may make in order to comply with the proposed

NSPS and NESHAP amendments. A detailed discussion of the methodology used to estimate cost impacts is presented in series of memos published in the Docket as part of the TSD.

3.2.2.1 NSPS Sources

Table 3-1 shows the emissions sources, points, and controls analyzed in three NSPS regulatory options, which we term Option 1, Option 2, and Option 3. Option 2 was selected for proposal. The proposed Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly drilled natural gas wells that are hydraulically fractured. Option 2 also requires a subset of wells that are worked over, or recompleted, using hydraulic fracturing to implement RECs. The proposed Option 2 requires emissions reductions from reciprocating compressors at gathering and boosting stations, processing plants, transmission compressor stations, and underground storage facilities. The proposed Option 2 also requires emissions reductions from centrifugal compressors, processing plants, and transmission compressor stations. Finally, the proposed Option 2 requires emissions reductions from pneumatic controllers at oil and gas production facilities and natural gas transmission and storage and reductions from high throughput storage vessels.

Table 3-1 Emissions Sources, Points, and Controls Included in NSPS Options

Emissions Sources and Points	Emissions Control	Option 1	Option 2 (proposed)	Option 3
Well Completions of Post-NSPS Wells				
Hydraulically Fractured Gas Wells that Meet Criteria for Reduced Emissions Completion (REC)	REC	**X**	**X**	**X**
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC	Combustion	**X**	**X**	**X**
Conventional Gas Wells	Combustion			
Oil Wells	Combustion			
Well Recompletions				
Hydraulically Fractured Gas Wells (post-NSPS wells)	REC	**X**	**X**	**X**
Hydraulically Fractured Gas Wells (pre-NSPS wells)	REC		**X**	**X**
Conventional Gas Wells	Combustion			
Oil Wells	Combustion			
Equipment Leaks				
Well Pads	NSPS Subpart VV			**X**
Gathering and Boosting Stations	NSPS Subpart VV			**X**
Processing Plants	NSPS Subpart VVa		**X**	**X**
Transmission Compressor Stations	NSPS Subpart VV			**X**
Reciprocating Compressors				
Well Pads	Annual Monitoring/ Maintenance (AMM)			
Gathering/Boosting Stations	AMM	**X**	**X**	**X**
Processing Plants	AMM	**X**	**X**	**X**
Transmission Compressor Stations	AMM	**X**	**X**	**X**
Underground Storage Facilities	AMM	**X**	**X**	**X**
Centrifugal Compressors				
Processing Plants	Dry Seals/Route to Process or Control	**X**	**X**	**X**
Transmission Compressor Stations	Dry Seals/Route to Process or Control	**X**	**X**	**X**
Pneumatic Controllers -				
Oil and Gas Production	Low Bleed/Route to Process	**X**	**X**	**X**
Natural Gas Transmission and Storage	Low Bleed/Route to Process	**X**	**X**	**X**
Storage Vessels				
High Throughput	95% control	**X**	**X**	**X**
Low Throughput	95% control			

The distinction between Option 1 and the proposed Option 2 is the inclusion of completion combustion and REC requirements for recompletions at existing wells and an equipment leak standard for natural gas processing plants in Option 2. Option 2 requires the implementation of completion combustion and REC for existing wells as well as wells completed after the implementation date of the proposed NSPS. Option 1 applies the requirement only to new wells, not existing wells. The main distinction between proposed Option 2 and Option 3 is the inclusion of a suite of equipment leak standards. These equipment leak standards would apply at well pads, gathering and boosting stations, and transmission compressor stations. Option 1 differs from Option 3 in that it does not include the combustion and REC requirements at existing wells or the full suite of equipment leak standards.

Table 3-2 summarizes the unit level capital and annualized costs for the evaluated NSPS emissions sources and points. The detailed description of costs estimates is provided in the series of technical memos included in the TSD in the document, as referenced in Section 3.2.1 of this RIA. The table also includes the projected number of affected units. Four issues are important to note on Table 3-2: the approach to annualizing costs, the projection of affected units in the baseline; that capital and annualized costs are equated for RECs; and additional natural gas and hydrocarbon condensates that would otherwise be emitted to the environment are recovered from several control options evaluated in the NSPS review.

First, engineering capital costs were annualized using a 7 percent interest rate. However, different emissions control options were annualized using expected lifetimes that were determined to be most appropriate for individual options. For control options evaluated for the NSPS, the following lifetimes were used:

- Reduced emissions completions and combustion devices: 1 year (more discussion of the selection of a one-year lifetime follows in this section momentarily)
- Reciprocating compressors: 3 years
- Centrifugal compressors and pneumatic controllers: 10 years
- Storage vessels: 15 years
- Equipment leaks: 5 to 10 years, depending on specific control

To estimate total annualized engineering compliance costs, we added the annualized costs of each item without accounting for different expected lifetimes. An alternative approach would be to establish an overall, representative project time horizon and annualize costs after consideration of control options that would need to be replaced periodically within the given time horizon. For example, a 15 year project would require replacing reciprocating compressor-related controls five times, but only require a single installation of controls on storage vessels. This approach, however, is equivalent to the approach selected; that is to sum the annualized costs across options, without establishing a representative project time horizon.

Second, the projected number of affected units is the number of units that our analysis shows would be affected in 2015, the analysis year. The projected number of affected units accounts for estimates of the adoption of controls in absence of Federal regulation. While the procedures used to estimate adoption in absence of Federal regulation are presented in detail within the TSD, because REC requirements provide a significant component of the estimated emissions reductions and engineering compliance costs, it is worthwhile to go into some detail on the projected number of RECs within the RIA. We use EIA projections consistent with the Annual Energy Outlook 2011 to estimate the number of natural gas well completions with hydraulic fracturing in 2015, assuming that successful wells drilled in coal bed methane, shale, and tight sands used hydraulic fracturing. Based on this assumption, we estimate that 11,403 wells were successfully completed and used hydraulic fracturing. To approximate the number of wells that would not be required to perform RECs because of the absence of sufficient infrastructure, we draw upon the distinction in EIA analysis between exploratory and developmental wells. We assume exploratory wells do not have sufficient access to infrastructure to perform a REC and are exempt from the REC requirement. These 446 wells are removed from the REC estimate and are assumed to combust emissions using pit flares.

The number of hydraulically fractured recompletions of existing wells was approximated using assumptions found in Subpart W's TSD[6] and applied to well count data found in the proprietary HPDI® database. The underlying assumption is that wells found in coal bed

[6] U.S. Environmental Protection Agency (U.S. EPA). 2010. Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry: Background Technical Support Document. Climate Change Division. Washington, DC.

methane, shale, and tight sand formations require re-fracture, on average, every 10 years. In other words, 10 percent of the total wells classified as being performed with hydraulic fracturing would perform a recompletion in any given year. Natural gas well recompletions performed without hydraulic fracturing were based only on 2008 well data from HPDI®.

The number of completions and recompletions already controlling emissions in absence of a Federal regulation was estimated based on existing State regulations that require applicable control measures for completions and workovers in specific geographic locations. Based on this criterion, 15 percent of natural gas completions with hydraulic fracturing and 15 percent of existing natural gas workovers with hydraulic fracturing are estimated to be controlled by either flare or REC in absence of Federal regulations. Completions and recompletions without hydraulic fracturing were assumed as having no controls in absence of a Federal regulation. Following these procedures leads to an estimate of 9,313 completions of new wells and 12,050 recompletions of existing wells that will require either a REC under the proposed NSPS in 2015.

It should be noted that natural gas prices are stochastic and, historically, there have been periods where prices have increased or decreased rapidly. These price changes would be expected to affect adoption of emission reduction technologies in absence of regulation, particularly control measures such as RECs that capture emission significantly over short periods of time.

Third, for well completion requirements, annualized costs are set equal to capital costs. We chose to equate the capital and annualized cost because the completion requirements (combustion and RECs) are essentially one-shot events; the emissions controls are applied over the course of a well completion, which will typically range over a few days to a couple of weeks. After this relatively short period of time, there is no continuing control requirement, unless the well is again completed at a later date, sometimes years later. We reasoned that the absence of a continuing requirement makes it appropriate to equate capital and annualized costs.

Fourth, for annualized cost, we present two figures, the annualized costs with revenues from additional natural gas and condensate recovery and annualized costs without additional revenues this product recovery. Several emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOCs, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. When including the additional natural gas recovery in the cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. RECs also capture saleable condensates that would otherwise be lost to the environment. The engineering analysis assumes a REC will capture 34 barrels of condensate per REC and that the value of this condensate is $70/barrel.

The assumed price for natural gas is within the range of variation of wellhead prices for the 2010-11 period. The $4/Mcf is below the 2015 EIA-forecasted wellhead price, $4.22/Mcf in 2008 dollars. The $4/Mcf payment rate does not reflect any taxes or tax credits that might apply to producers implementing the control technologies. As natural gas prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional natural gas recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million in 2008 dollars.

As will be seen in subsequent analysis, the estimate of revenues from additional product recovery is critical to the economic impact analysis. However, before discussing this assumption in more depth, it is important to further develop the engineering estimates to contextualize the discussion and to provide insight into why, if it is profitable to capture natural gas emissions that are otherwise vented, producers may not already be doing so.

Table 3-3 presents the estimated nationwide compliance costs, emissions reductions, and VOC reduction cost-effectiveness broken down by emissions sources and points for those sources and points evaluated in the NSPS analysis. The reporting and recordkeeping costs for the proposed NSPS Option 2 are estimated at $18,805,398 and are included in Table 3-3. Because of time constraints, we were unable to estimate reporting and recordkeeping costs customized for Options 1 and 3; for these options, we use the same $18,805,398 for reporting and recordkeeping costs for these options.

As can be seen from Table 3-3 controls associated with well completions and recompletions of hydraulically fractured wells provide the largest potential for emissions reductions from evaluated emissions sources and points, as well as present the most significant compliance costs if revenue from additional natural gas recovery is not included. Emissions reductions from conventional natural gas wells and crude oil wells are clearly not as significant as the potential from hydraulically fractured wells, as was discussed in Section 3.2.1.1.

Several evaluated emissions sources and points are estimated to have net financial savings when including the revenue from additional natural gas recovery. These sources form the core of the three NSPS options evaluated in this RIA. Table 3-4 presents the estimated engineering costs, emissions reductions, and VOC reduction cost-effectiveness for the three NSPS options evaluated in the RIA. The resulting total national annualized cost impact of the proposed NSPS rule (Option 2) is estimated at $740 million per year without considering revenues from additional natural gas recovery. Annual costs for the proposed NSPS are estimated at -$45 million when revenue from additional natural gas recovery is included. All figures are in 2008 dollars.

Table 3-2 Summary of Capital and Annualized Costs per Unit for NSPS Emissions Points

Sources/Emissions Point	Projected No. of Affected Units	Capital Costs (2008$)	Per Unit Annualized Cost (2008$) Without Revenues from Additional Product Recovery	Per Unit Annualized Cost (2008$) With Revenues from Additional Product Recovery
Well Completions				
Hydraulically Fractured Gas Wells that Meet Criteria for REC	9,313	$33,237	$33,237	-$2,173
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	446	$3,523	$3,523	$3,523
Conventional Gas Wells	7,694	$3,523	$3,523	$3,523
Oil Wells	12,193	$3,523	$3,523	$3,523
Well Recompletions				
Hydraulically Fractured Gas Wells (existing wells)	12,050	$33,237	$33,237	-$2,173
Conventional Gas Wells	42,342	$3,523	$3,523	$3,523
Oil Wells	39,375	$3,523	$3,523	$3,523
Equipment Leaks				
Well Pads	4,774	$68,970	$23,413	$21,871
Gathering and Boosting Stations	275	$239,494	$57,063	$51,174
Processing Plants	29	$7,522	$45,160	$33,884
Transmission Compressor Stations	107	$96,542	$25,350	$25,350
Reciprocating Compressors				
Well Pads	6,000	$6,480	$3,701	$3,664
Gathering/Boosting Stations	210	$5,346	$2,456	$870
Processing Plants	209	$4,050	$2,090	-$2,227
Transmission Compressor Stations	20	$5,346	$2,456	$2,456
Underground Storage Facilities	4	$7,290	$3,349	$3,349
Centrifugal Compressors				
Processing Plants	16	$75,000	$10,678	-$123,730
Transmission Compressor Stations	14	$75,000	$10,678	-$77,622
Pneumatic Controllers -				
Oil and Gas Production	13,632	$165	$23	-$1,519
Natural Gas Trans. and Storage	67	$165	$23	$23
Storage Vessels				
High Throughput	304	$65,243	$14,528	$13,946
Low Throughput	17,086	$65,243	$14,528	$13,946

Table 3-3 Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015

Source/Emissions Point	Emissions Control	Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
		Without Addl. Revenues	With Addl. Revenues	VOC	Methane	HAP	Without Addl. Revenues	With Addl. Revenues
Well Completions (New Wells)								
Hydraulically Fractured Gas Wells	REC	$309,553,517	-$20,235,748	204,134	1,399,139	14,831	$1,516	-$99
Hydraulically Fractured Gas Wells	Combustion	$1,571,188	$1,571,188	9,801	67,178	712	$160	$160
Conventional Gas Wells	Combustion	$27,104,761	$27,104,761	857	5,875	62	$31,619	$31,619
Oil Wells	Combustion	$42,954,036	$42,954,036	83	88	0	$520,580	$520,580
Well Recompletions (Existing Wells)								
Hydraulically Fractured Gas Wells (existing wells)	REC	$400,508,928	-$26,181,572	264,115	1,810,245	19,189	$1,516	-$99
Conventional Gas Wells	Combustion	$149,164,257	$149,164,257	316	2,165	23	$472,227	$472,227
Oil Wells	Combustion	$138,711,979	$138,711,979	44	47	0	$3,134,431	$3,134,431
Equipment Leaks								
Well Pads	NSPS Subpart VV	$111,773,662	$104,412,154	10,646	38,287	401	$10,499	$9,808
Gathering and Boosting Stations	NSPS Subpart VV	$15,692,325	$14,072,850	2,340	8,415	88	$6,705	$6,013
Processing Plants	NSPS Subpart VVa	$1,309,650	$982,648	392	1,411	15	$3,343	$2,508
Transmission Compressor Stations	NSPS Subpart VV	$2,712,450	$2,712,450	261	9,427	8	$10,389	$10,389
Reciprocating Compressors								
Well Pads	Annual Monitoring/ Maintenance (AMM)	$22,204,209	$21,984,763	263	947	10	$84,379	$83,545
Gathering/Boosting Stations	AMM	$515,764	$182,597	400	1,437	15	$1,291	$457
Processing Plants	AMM	$436,806	-$465,354	1,082	3,892	41	$404	-$430
Transmission Compressor Stations	AMM	$47,892	$47,892	12	423	0	$4,093	$4,093
Underground Storage Facilities	AMM	$13,396	$13,396	2	87	0	$5,542	$5,542

Table 3-3 (continued) Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015

		Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
Source/Emissions Point	Emissions Control	Without Addl. Revenues	With Addl. Revenues	VOC	Methane	HAP	Without Addl. Revenues	With Addl. Revenues
Centrifugal Compressors								
Processing Plants	Dry Seals/Route to Process or Control	$170,853	-$1,979,687	288	3,183	10	$593	-$6,874
Transmission Compressor Stations	Dry Seals/Route to Process or Control	$149,496	-$1,086,704	43	1,546	1	$3,495	-$25,405
Pneumatic Controllers -								
Oil and Gas Production	Low Bleed/Route to Process	$320,071	-$20,699,918	25,210	90,685	952	$13	-$821
Natural Gas Trans. and Storage	Low Bleed/Route to Process	$1,539	$1,539	6	212	0	$262	$262
Storage Vessels								
High Throughput	95% control	$4,411,587	$4,234,856	29,654	6,490	876	$149	$143
Low Throughput	95% control	$248,225,012	$238,280,976	6,838	1,497	202	$36,298	$34,844

Table 3-4 Estimated Engineering Compliance Costs, NSPS (2008$)

	Option 1	Option 2 (Proposed)	Option 3
Capital Costs	$337,803,930	$738,530,998	$1,143,984,622
Annualized Costs			
Without Revenues from Additional Natural Gas Product Recovery	$336,163,858	$737,982,436	$868,160,873
With Revenues from Additional Natural Gas Product Recovery	-$19,496,449	-$44,695,374	$76,502,080
VOC Reductions (tons per year)	270,695	535,201	548,449
Methane Reduction (tons per year)	1,574,498	3,386,154	3,442,283
HAP Reductions (tons per year)	17,442	36,645	37,142
VOC Reduction Cost-Effectiveness ($/ton without additional product revenues)	$1,241.86	$1,378.89	$1,582.94
VOC Reduction Cost-Effectiveness ($/ton with additional product revenues)	-$72.02	-$83.51	$139.49

Note: the VOC reduction cost-effectiveness estimate assumes there is no benefit to reducing methane and HAP, which is not the case. We however present the per ton costs of reducing the single pollutant for illustrative purposes. As product prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional product recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million in 2008 dollars. The cost estimates for each regulatory option also include reporting and recordkeeping costs of $18,805,398.

As mentioned earlier, the single difference between Option 1 and the proposed Option 2 is the inclusion of RECs for recompletions of existing wells in Option 2. The implication of this inclusion in Option 2 is clear in Table 3-4, as the estimated engineering compliance costs without additional product revenue more than double and VOC emissions reductions also more than double. Meanwhile, the addition of equipment leaks standards in Option 3 increases engineering costs more than $400 million dollars in 2008 dollars, but only marginally increase estimates of emissions reductions of VOCs, methane, and HAPS.

As the price assumption is very influential on estimated impacts, we performed a simple sensitivity analysis of the influence of the assumed wellhead price paid to natural gas producers on the overall engineering costs estimate of the proposed NSPS. Figure 3-1 plots the annualized costs after revenues from natural gas product recovery have been incorporated (in millions of 2008 dollars) as a function of the assumed price of natural gas paid to producers at the wellhead for the recovered natural gas (represented by the sloped, dotted line). The vertical solid lines in the figure represent the natural gas price assumed in the RIA ($4.00/Mcf) for 2015 and the 2015 forecast by EIA in the 2011 Annual Energy Outlook ($4.22/Mcf) in 2008 dollars.

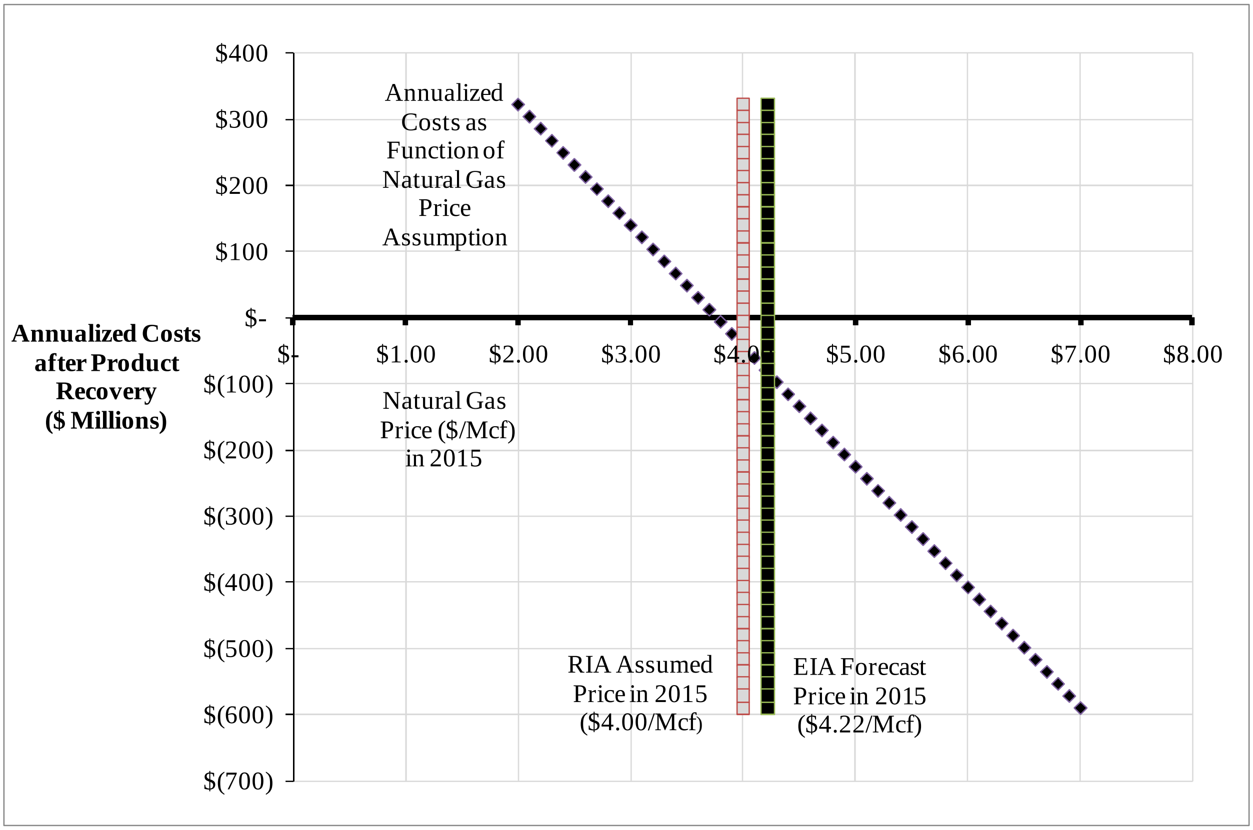

Figure 3-1 Sensitivity Analysis of Proposed NSPS Annualized Costs after Revenues from Additional Product Recovery are Included

As shown in Table 3-4, at the assumed $4/Mcf, the annualized costs are estimated at -$45 million. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook, the annualized costs are estimated at about -$90 million, which would approximately double the estimate of net cost savings of the proposed NSPS. As indicated by this difference, EPA has chosen a relatively conservative assumption (leading to an estimate of few savings and higher net costs) for the engineering costs analysis. The natural gas price at which the proposed NSPS breaks-even is around $3.77/Mcf. As mentioned earlier, a $1/Mcf change in the wellhead natural gas price leads to about a $180 million change in the annualized engineering costs of the proposed NSPS. Consequently, annualized engineering costs estimates would increase to about $140 million under a $3/Mcf price or decrease to about -$230 million under a $5/Mcf price.

It is additionally helpful to put the quantity of natural gas and condensate potentially recovered in the context of domestic production levels. To do so, it is necessary to make two adjustments. First, not all emissions reductions can be directed into production streams to be ultimately consumed by final consumers. Several controls require combustion of the natural gas rather than capture and direction into product streams. After adjusting estimates of national emissions reductions in Table 3-3 for these combustion-type controls, Options 1, 2, and 3 are estimated to capture about 83, 183, and 185 bcf of natural gas and 317,000, 726,000, and 726,000 barrels of condensate, respectively. For control options that are expected to recover natural gas products. Estimates of unit-level and nation-level product recovery are presented in Section 3 of the RIA. Note that completion-related requirements for new and existing wells generate all the condensate recovery for all NSPS regulatory options. For natural gas recovery, RECs contribute 77 bcf (92 percent) for Option 1, 176 bcf (97 percent) for Option 2, and 176 bcf (95 percent) for Option 3.

Table 3-5 Estimates of Control Unit-level and National Level Natural Gas and Condensate Recovery, NSPS Options, 2015

Source/ Emissions Points	Emissions Control	NSPS Option	Projected No. of Affected Units	Unit-level Product Recovery		Total Product Recovery	
				Natural Gas Savings (Mcf/unit)	Condensate (bbl/unit)	Natural Gas Savings (Mcf)	Condensate (bbl)
Well Completions							
Hydraulically Fractured Gas Wells	REC	1, 2, 3	9,313	8,258	34	76,905,813	316,657
Hydraulically Fractured Gas Wells	Combustion	1, 2, 3	446	0	0	0	0
Hydraulically Fractured Gas Wells (existing wells)	REC	2, 3	12,050	8,258	34	99,502,875	409,700
Equipment Leaks							
Well Pads	NSPS Subpart VV	3	4,774	386	0	1,840,377	0
Gathering and Boosting Stations	NSPS Subpart VV	3	275	1,472	0	404,869	0
Processing Plants	NSPS Subpart VVa	2, 3	29	2,819	0	81,750	0
Reciprocating Compressors							
Gathering/Boosting Stations	AMM	1, 2, 3	210	397	0	83,370	0
Processing Plants	AMM	1, 2, 3	375	1,079	0	404,677	0
Trans. Compressor Stations	AMM	1, 2, 3	199	1,122	0	223,374	0
Underground Storage Facilities	AMM	1, 2, 3	9	1,130	0	9,609	0
Centrifugal Compressors							
Processing Plants	Dry Seals/Route to Process or Ctrl	1, 2, 3	16	11,527	0	184,435	0
Trans. Compressor Stations	Dry Seals/Route to Process or Ctrl	1, 2, 3	14	5,716	0	80,018	0
Pneumatic Controllers -							
Oil and Gas Production	Low Bleed/Route to Process	1, 2, 3	13,632	386	0	5,254,997	0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	1, 2, 3	67	0	0	0	0
Processing Plants	Instrument Air	1, 2, 3	15	871.0	0	13,064	0
Storage Vessels							
High Throughput	95% control	1, 2, 3	304	146	0	44,189	0
Option 1 Total (Mcf)						**83,203,546**	**316,657**
Option 2 Total (Mcf)						**182,788,172**	**726,357**
Option 3 Total (Mcf)						**185,033,417**	**726,357**

A second adjustment to the natural gas quantities is necessary to account for nonhydrocarbon gases removed and gas that reinjected to repressurize wells, vented or flared, or consumed in production processes. Generally, wellhead production is metered at or near the wellhead and payments to producers are based on these metered values. In most cases, the natural gas is minimally processed at the meter and still contains impurities or co-products that must be processed out of the natural gas at processing plants. This means that the engineering cost estimates of revenues from additional natural gas recovery arising from controls implemented at the wellhead include payment for the impurities, such as the VOC and HAP content of the unprocessed natural gas. According to EIA, in 2009 the gross withdrawal of natural gas totaled 26,013 bcf, but 20,580 bcf was ultimately considered dry production (these figures exclude EIA estimates of flared and vented natural gas). Using these numbers, we apply a factor of 0.79 (20,580 bcf divided by 26,013 bcf) to the adjusted sums in the previous paragraph to estimate the volume of gas that is captured by controls that may ultimately by consumed by final consumers.

After making these adjustments, we estimate that Option 1 will potentially recover approximately 66 bcf, proposed Option 2 will potentially recover about 145 bcf, and Option 3 will potentially recover 146 bcf of natural gas that will ultimately be consumed by natural gas consumers.[7] EIA forecasts that the domestic dry natural gas production in 2015 will be 20,080 bcf. Consequently, Option 1, proposed Option 2, and Option 3 may recover production representing about 0.29 percent, 0.64 percent and 0.65 percent of domestic dry natural gas production predicted in 2015, respectively. These estimates, however, do not account for adjustments producers might make, once compliance costs and potential revenues from additional natural gas recovery factor into economic decisionmaking. Also, as discussed in the previous paragraph, these estimates do not include the nonhydrocarbon gases removed, natural gas reinjected to repressurize wells, and natural gas consumed in production processes, and therefore will be lower than the estimates of the gross natural gas captured by implementing controls.

[7] To convert U.S. short tons of methane to a cubic foot measure, we use the conversion factor of 48.04 Mcf per U.S. short ton.

Clearly, this discussion raises the question as to why, if emissions can be reduced profitably using environmental controls, more producers are not adopting the controls in their own economic self-interest. This question is made clear when examining simple estimates of the rate of return to installing emissions controls that, using the engineering compliance costs estimates, the estimates of natural gas product recovery, and assumed product prices (Table 3-6). The rates of return presented in are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula: product recovery, and assumed product prices (Table 3-6). The rates of return presented in are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula:

$$\text{rate of return} = \left(\frac{\text{estimated revenues}}{\text{estimated costs}} - 1 \right) \times 100 \, .$$

Table 3-6 Simple Rate of Return Estimate for NSPS Control Options

Emission Point	Control Option	Rate of Return
New Completions of Hydraulically Fractured Wells	Reduced Emissions Completions	6.5%
Re-completions of Existing Hydraulically Fractured Wells	Reduced Emissions Completions	6.5%
Reciprocating Compressors (Processing Plants)	Replace Packing Every 3 Years of Operation	208.3%
Centrifugal Compressors (Processing Plants)	Convert to Dry Seals	1158.7%
Centrifugal Compressors (Transmission Compressor Stations)	Convert to Dry Seals	726.9%
Pneumatic Controllers (Oil and Gas Production)	Low Bleed	6467.3%
Overall Proposed NSPS	**Low Bleed**	**6.1%**

Note: The table presents only control options where estimated revenues from natural gas product recovery exceeds estimated annualized engineering costs

Recall from Table 2-23 in the Industry Profile, that EIA estimates an industry-level rate of return on investments for various segments of the oil and natural gas industry. While the numbers varies greatly over time because of industry and economic factors, EIA estimates a 10.7 percent rate of return on investments for oil and natural gas production in 2008. While this amount is higher than the 6.5 percent rate estimated for RECs, it is significantly lower than the rate of returns estimated for other controls anticipated to have net savings.

Assuming financially rational producers, standard economic theory suggests that all oil and natural gas firms would incorporate all cost-effective improvements, which they are aware of, without government intervention. The cost analysis of this draft RIA nevertheless is based on the observation that emission reductions that appear to be profitable in our analysis have not been generally adopted. One possible explanation may be the difference between the average profit margin garnered by productive capital and the environmental capital where the primary motivation for installing environmental capital would be to mitigate the emission of pollutants and confer social benefits as discussed in Chapter 4.

Another explanation for why there appear to be negative cost control technologies that are not generally adopted is imperfect information. If emissions from the oil and natural gas sector are not well understood, firms may underestimate the potential financial returns to capturing emissions. Quantifying emissions is difficult and has been done in relatively few studies. Recently, however, advances in infrared imagery have made it possible to affordably visualize, if not quantify, methane emissions from any source using a handheld camera. This infrared camera has increased awareness within industry and among environmental groups and the public at large about the large number of emissions sources and possible scale of emissions from oil and natural gas production activities. Since, as discussed in the TSD chapter referenced above, 15 percent of new natural gas well completions with hydraulic fracturing and 15 percent of existing natural gas well recompletions with hydraulic fracturing are estimated to be controlled by either flare or REC in the baseline, it is unlikely that a lack of information will be a significant reason for these emission points to not be addressed in the absence of Federal regulation in 2015. However, for other emission points, a lack of information, or the cost associated with doing a feasibility study of potential emission capture technologies, may continue to prevent firms from adopting these improvements in the absence of regulation.

Another explanation is the cost associated with irreversibility associated with implementing these environmental controls are not reflected in the engineering cost estimates above. Due to the high volatility of natural gas prices, it is important to recognize the value of flexibility taken away from firms when requiring them to install and use a particular emissions capture technology. If a firm has not adopted the technology on its own, then a regulation mandating its use means the firm loses the option to postpone investment in the technology in order to pursue alternative investments today, and the option to suspend use of the technology if it becomes unprofitable in the future. Therefore, the full cost of the regulation to the firm is the engineering cost and the lost option value minus the revenues from the sale of the additional recovered product. In the absence of quantitative estimates of this option value for each emission point affected by the NSPS and NESHAP improvements, the costs presented in this RIA may underestimate the full costs faced by the affected firms. With these caveats in mind, EPA believes it is analytically appropriate to analyze costs and economic impacts costs presented in Table 3-2 and Table 3-3 using the additional product recovery and associated revenues.

3.2.2.2 NESHAP Sources

As discussed in Section 3.2.1.2, EPA examined three emissions points as part of its analysis for the proposed NESHAP amendments. Unlike the controls for the proposed NSPS, the controls evaluated under the proposed NESHAP amendments do not direct significant quantities of natural gas that would otherwise be flared or vented into the production stream. Table 3-7 shows the projected number of controls required, estimated unit-level capital and annualized costs, and estimated total annualized costs. The table also shows estimated emissions reductions for HAPs, VOCs, and methane, as well as a cost-effectiveness estimate for HAP reduction, based upon engineering (not social) costs.

Table 3-7 Summary of Estimated Capital and Annual Costs, Emissions Reductions, and HAP Reduction Cost-Effectiveness for Proposed NESHAP Amendments

Source/Emissions Point	Projected No. of Controls Required	Capital Costs/ Unit (2008$)	Annualized Cost/Unit (2008$)	Total Annualized Cost (2008$)	Emission Reductions (tons per year) HAP	VOC	Methane	HAP Reduction Cost-Effectiveness (2008$/ton)
Production - Small Glycol Dehydrators	115	65,793	30,409	3,497,001	548	893	324	6,377
Transmission - Small Glycol Dehydrators	19	19,537	19,000	361,000	243	475	172	1,483
Storage Vessels	674	65,243	14,528	9,791,872	589	7,812	4,364	16,618
Reporting and Recordkeeping	---	196	2,933	2,369,755	---	---	---	---
Total	**808**			**16,019,871**	**1,381**	**9,243**	**4,859**	**10,576**

Note: Totals may not sum due to independent rounding.

Under the Proposed NESHAP Amendments, about 800 controls will be required, costing a total of $16.0 million (Table 3-7). We include reporting and recordkeeping costs as a unique line item showing these costs for the entire set of proposed amendments. These controls will reduce HAP emissions by about 1,400 tons, VOC emissions by about 9,200 tons, and methane by about 4,859 tons. The cost-per-ton to reduce HAP emissions is estimated at about $11,000 per ton. All figures are in 2008 dollars.

3.3 References

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4 BENEFITS OF EMISSIONS REDUCTIONS

4.1 Introduction

The proposed Oil and Natural Gas NSPS and NESHAP amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of the industry. While we expect that these avoided emissions will result in improvements in air quality and reduce health effects associated with exposure to HAPs, ozone, and fine particulate matter ($PM_{2.5}$), we have determined that quantification of those health benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no health benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. For the proposed NSPS, the HAP and climate benefits can be considered "co-benefits", and for the proposed NESHAP amendments, the ozone and $PM_{2.5}$ health benefits and climate benefits can be considered "co-benefits". These co-benefits occur because the control technologies used to reduce VOC emissions also reduce emissions of HAPs and methane.

The proposed NSPS is anticipated to prevent 37,000 tons of HAPs, 540,000 tons of VOCs, and 3.4 million tons of methane from new sources, while the proposed NESHAP amendments is anticipated reduce 1,400 tons of HAPs, 9,200 tons of VOCs, and 4,900 tons of methane from existing sources. The specific control technologies for the proposed NSPS is also anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 2,800 tons of CO, 7.6 tons of PM, and 1,000 tons of THC, and proposed NESHAP is anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC. Both rules would have additional emission changes associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons for the proposed NSPS and 93 thousand metric tons for the proposed NESHAP. As described in the subsequent sections, these pollutants are associated with substantial health effects, welfare effects, and climate effects. With the data available, we are not able to provide a credible benefits estimates for any of these pollutants for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information, and the highly localized nature of air quality responses associated with HAP and VOC reductions. In addition, we do not yet have interagency agreed upon valuation estimates for greenhouse gases other than CO_2 that could be used to value the climate co-benefits associated with avoiding methane emissions. Instead, we provide a qualitative assessment of the benefits and co-benefits as well as a break-even analysis in Chapter 6 of this RIA. A break-even analysis answers the question, "What would the benefits need to be for the benefits to exceed the costs." While a break-even approach is not equivalent to a benefits analysis, we feel the results are illustrative, particularly in the context of previous benefit per ton estimates.

4.2 Direct Emission Reductions from the Oil and Natural Gas Rules

As described in Section 2 of this RIA, oil and natural gas operations in the U.S. include a variety of emission points for VOCs and HAPs including wells, processing plants, compressor stations, storage equipment, and transmission and distribution lines. These emission points are located throughout much of the country with significant concentrations in particular regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas gas compression stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density.

In implementing these rules, emission controls may lead to reductions in ambient $PM_{2.5}$ and ozone below the National Ambient Air Quality Standards (NAAQS) in some areas and assist other areas with attaining the NAAQS. Due to the high degree of variability in the responsiveness of ozone and $PM_{2.5}$ formation to VOC emission reductions, we are unable to determine how these rules might affect attainment status without air quality modeling data.[8] Because the NAAQS RIAs also calculate ozone and PM benefits, there are important differences worth noting in the design and analytical objectives of each RIA. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources. In short, NAAQS RIAs hypothesize, but do not predict, the control strategies that States may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. However,

[8] The responsiveness of ozone and $PM_{2.5}$ formation is discussed in greater detail in sections 4.4.1 and 4.5.1 of this RIA.

some costs and benefits estimated in this RIA account for the same air quality improvements as estimated in an illustrative NAAQS RIA.

By contrast, the emission reductions for this rule are from a specific class of well-characterized sources. In general, EPA is more confident in the magnitude and location of the emission reductions for these rules. It is important to note that emission reductions anticipated from these rules do not result in emission increases elsewhere (other than potential energy disbenefits). Emission reductions achieved under these and other promulgated rules will ultimately be reflected in the baseline of future NAAQS analyses, which would reduce the incremental costs and benefits associated with attaining the NAAQS. EPA remains forward looking towards the next iteration of the 5-year review cycle for the NAAQS, and as a result does not issue updated RIAs for existing NAAQS that retroactively update the baseline for NAAQS implementation. For more information on the relationship between the NAAQS and rules such as analyzed here, please see Section 1.2.4 of the SO_2 NAAQS RIA (U.S. EPA, 2010d). Table 4-1 shows the direct emission reductions anticipated for these rules by option. It is important to note that these benefits accrue at different spatial scales. HAP emission reductions reduce exposure to carcinogens and other toxic pollutants primarily near the emission source. Reducing VOC emissions would reduce precursors to secondary formation of $PM_{2.5}$ and ozone, which reduces exposure to these pollutants on a regional scale. Climate effects associated with long-lived greenhouse gases like methane are primarily at a global scale, but methane is also a precursor to ozone, a short-lived climate forcer that exhibits spatial and temporal variability.

Table 4-1 Direct Emission Reductions Associated with Options for the Oil and Natural Gas NSPS and NESHAP amendments in 2015 (short tons per year)

Pollutant	NESHAP Amendments	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3
HAPs	1,381	17,442	36,645	37,142
VOCs	9,243	270,695	535,201	548,449
Methane	4,859	1,574,498	3,386,154	3,442,283

4.3 Secondary Impacts Analysis for Oil and Gas Rules

The control techniques to avert leaks and vents of VOCs and HAPs are associated with several types of secondary impacts, which may partially offset the direct benefits of this rule. In this RIA, we refer to the secondary impacts associated with the specific control techniques as "producer-side" impacts.[9] For example, by combusting VOCs and HAPs, combustion increases emissions of carbon monoxide, NOx, particulate matter and other pollutants. In addition to "producer-side" impacts, these control techniques would also allow additional natural gas recovery, which would contribute to additional combustion of the recovered natural gas and ultimately a shift in the national fuel mix. We refer to the secondary impacts associated with the combustion of the recovered natural gas as "consumer-side" secondary impacts. We provide a conceptual diagram of both categories of secondary impacts in Figure 4-1.

[9] In previous RIAs, we have also referred to these impacts as energy disbenefits.

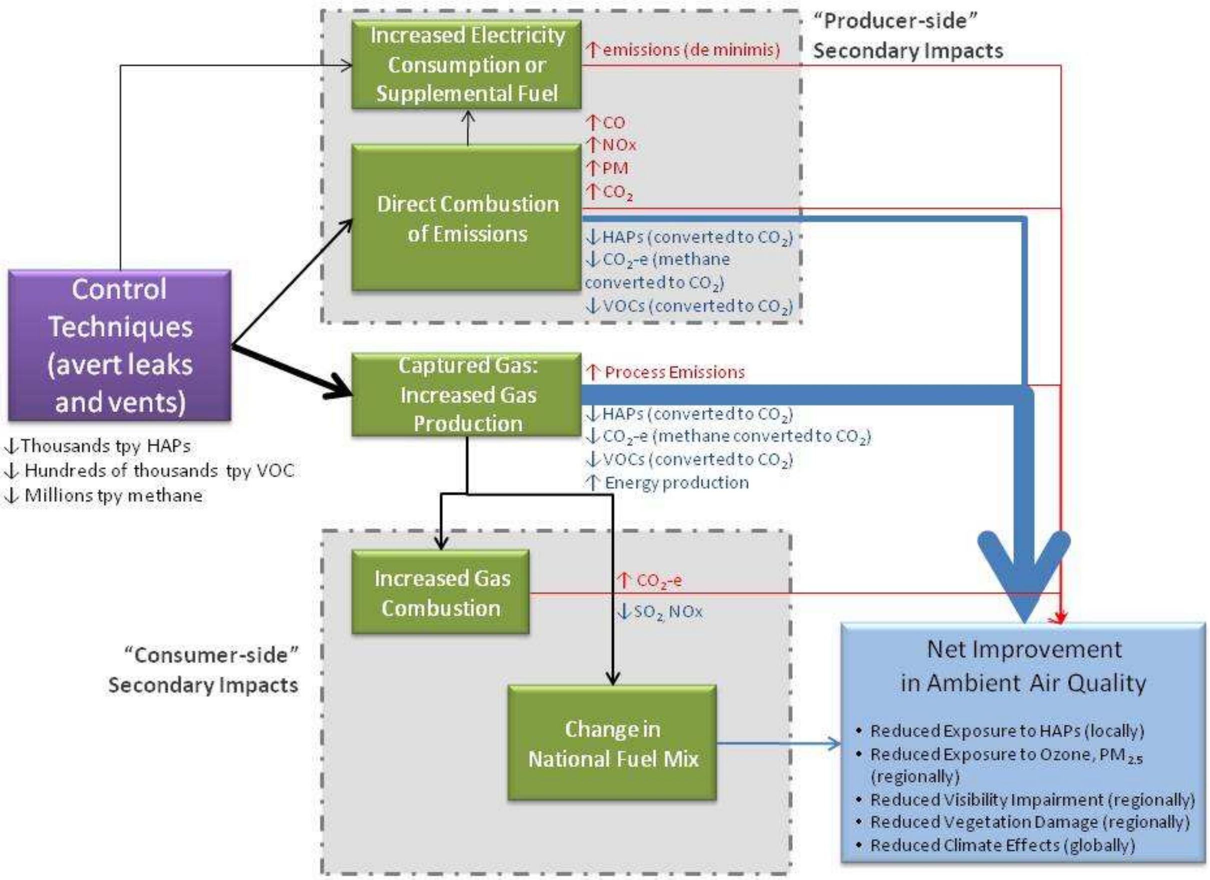

Figure 4-1 Conceptual Diagram of Secondary Impacts from Oil and Gas NSPS and NESHAP Amendments

Table 4-2 shows the estimated secondary impacts for the selected option for the "producer-side" impacts. Relative to the direct emission reductions anticipated from these rules, the magnitude of these secondary air pollutant impacts is small. Because the geographic distribution of these emissions from the oil and gas sector is not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009), we are unable to monetize the $PM_{2.5}$ disbenefits associated with the producer-side secondary impacts. In addition, it is not appropriate to monetize the disbenefits associated with the increased CO_2 emissions without monetizing the averted methane emissions because the overall global warming potential (GWP) is actually lower. Through the combustion process, methane emissions are converted to CO_2 emissions, which have 21 times less global warming potential compared to methane (IPCC, 2007).[10]

Table 4-2 Secondary Air Pollutant Impacts Associated with Control Techniques by Emissions Category ("Producer-Side") (tons per year)

Emissions Category	CO_2	NOx	PM	CO	THC
Completions of New Wells (NSPS)	587,991	302	5	1,644	622
Recompletions of Existing Wells (NSPS)	398,341	205	-	1,114	422
Pneumatic Controllers (NSPS)	22	1.0	2.6	-	-
Storage Vessels (NSPS)	856	0.5	0.0	2.4	0.9
Total NSPS	**987,210**	**508**	**7.6**	**2,760**	**1,045**
Total NESHAP (Storage Vessels)	**5,543**	**2.9**	**0.1**	**16**	**6**

For the "consumer-side" impacts associated with the NSPS, we modeled the impact of the regulatory options on the national fuel mix and associated CO_2-equivalent emissions (Table 4-3).[11] We provide the modeled results of the "consumer-side" CO_2-equivalent emissions in Table 7-12Error! Reference source not found.

The modeled results indicate that through a slight shift in the national fuel mix, the CO_2-equivalent emissions across the energy sector would increase by 1.6 million metric tons for the proposed NSPS option in 2015. This is in addition to the other secondary impacts and directly avoided emissions, for a total 62 million metric tons of CO_2-equivalent emissions averted as shown in Table 4-4. Due to time limitations under the court-ordered schedule, we did not estimate the other emissions (e.g., NOx, PM, SOx) associated with the additional national gas consumption or the change in the national fuel mix.

[10] This issue is discussed in more detail in Section 4.7 of this RIA.
[11] A full discussion of the energy modeling is available in Section 7 of this RIA.

Table 4-3 Modeled Changes in Energy-related CO_2-equivalent Emissions by Fuel Type for the Proposed Oil and Gas NSPS in 2015 (million metric tons) ("Consumer-Side")[1]

Fuel Type	NSPS Option 1 (million metric tons change in CO_2-e)	NSPS Option 2 (million metric tons change in CO_2-e) (Proposed)	NSPS Option 3 (million metric tons change in CO_2-e)
Petroleum	-0.51	-0.14	-0.18
Natural Gas	2.63	1.35	1.03
Coal	-3.04	0.36	0.42
Other	0.00	0.00	0.00
Total modeled Change in CO_2-e Emissions	**-0.92**	**1.57**	**1.27**

[1] These estimates reflect the modeled change in CO_2-e emissions using NEMS shown in Table 7-12. Totals may not sum due to independent rounding.

Table 4-4 Total Change in CO_2-equivalent Emissions including Secondary Impacts for the Proposed Oil and Gas NSPS in 2015 (million metric tons)

Emissions Source	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP Amendments
Averted CO_2-e Emissions from New Sources[1]	-30.00	-64.51	-65.58	-0.09
Additional CO_2-e Emissions from Combustion and Supplemental Energy (Producer-side)[2]	0.90	0.90	0.90	0.01
Total Modeled Change in Energy-related CO_2-e Emissions (Consumer-side)[3]	-0.92	1.57	1.27	--
Total Change in CO_2-e Emissions after Adjustment for Secondary Impacts	**-30.02**	**-62.04**	**-63.41**	**-0.09**

[1] This estimate reflects the GWP of the avoided methane emissions from new sources shown in Table 4-1 and has been converted from short tons to metric tons.

[2] This estimate represents the secondary producer-side impacts associated with additional CO_2 emissions from combustion and from additional electricity requirements shown in Table 4-2 and has been converted from short tons to metric tons. We use the producer-side secondary impacts associated with the proposed NSPS option as a surrogate for the impacts of the other options.

[3]This estimate reflects the modeled change in the energy–related consumer-side impacts shown in Table 4-3.

Totals may not sum due to independent rounding.

Based on these analyses, the net impact of both the direct and secondary impacts of these rules would be an improvement in ambient air quality, which would reduce exposure to various harmful pollutants, improve visibility impairment, reduce vegetation damage, and reduce potency of greenhouse gas emissions. Table 4-5 provides a summary of the direct and secondary emissions changes for each option.

Table 4-5 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP
Change in Direct Emissions	VOC	-270,000	-540,000	-550,000	-9,200
	Methane	-1,600,000	-3,400,000	-3,400,000	-4,900
	HAP	-17,000	-37,000	-37,000	-1,400
Change in Secondary Emissions (Producer-Side) [1]	CO_2	990,000	990,000	990,000	5,500
	NOx	510	510	510	2.9
	PM	7.6	7.6	7.6	0.1
	CO	2,800	2,800	2,800	16
	THC	1,000	1,000	1,000	6.0
Change in Secondary Emissions (Consumer-Side)	CO_2-e	-1,000,000	1,700,000	1,400,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e	-33,000,000	-68,000,000	-70,000,000	-96,000

[1] We use the producer-side secondary impacts associated with the proposed option as a surrogate for the impacts of the other options. Totals may not sum due to independent rounding.

4.4 Hazardous Air Pollutant (HAP) Benefits

Even though emissions of air toxics from all sources in the U.S. declined by approximately 42 percent since 1990, the 2005 National-Scale Air Toxics Assessment (NATA) predicts that most Americans are exposed to ambient concentrations of air toxics at levels that have the potential to cause adverse health effects (U.S. EPA, 2011d).[12] The levels of air toxics to which people are exposed vary depending on where people live and work and the kinds of activities in which they engage. In order to identify and prioritize air toxics, emission source types and locations that are of greatest potential concern, U.S. EPA conducts the NATA.[13] The most recent NATA was conducted for calendar year 2005 and was released in March 2011. NATA includes four steps:

[12] The 2005 NATA is available on the Internet at http://www.epa.gov/ttn/atw/nata2005/.

[13] The NATA modeling framework has a number of limitations that prevent its use as the sole basis for setting regulatory standards. These limitations and uncertainties are discussed on the 2005 NATA website. Even so, this modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting regulatory priorities, and informing the decision making process. U.S. EPA. (2011) 2005 National-Scale Air Toxics Assessment. http://www.epa.gov/ttn/atw/nata2005/

1) Compiling a national emissions inventory of air toxics emissions from outdoor sources

2) Estimating ambient and exposure concentrations of air toxics across the United States

3) Estimating population exposures across the United States

4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

Based on the 2005 NATA, EPA estimates that about 5 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer risk is about 50 in a million. Nationwide, the key pollutants that contribute most to the overall cancer risks are formaldehyde and benzene.[14,15] Secondary formation (e.g., formaldehyde forming from other emitted pollutants) was the largest contributor to cancer risks, while stationary, mobile and background sources contribute almost equal portions of the remaining cancer risk.

Noncancer health effects can result from chronic,[16] subchronic,[17] or acute[18] inhalation exposures to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems. According to the 2005 NATA, about three-fourths of the U.S. population was exposed to an average chronic concentration of air toxics that has the potential for adverse noncancer respiratory health effects. Results from the 2005 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

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[14] Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2005 NATA risk estimates can be found at http://www.epa.gov/ttn/atw/nata1999/riskbg.html#Z2.

[15] Details about the overall confidence of certainty ranking of the individual pieces of NATA assessments including both quantitative (e.g., model-to-monitor ratios) and qualitative (e.g., quality of data, review of emission inventories) judgments can be found at http://www.epa.gov/ttn/atw/nata/roy/page16.html.

[16] Chronic exposure is defined in the glossary of the Integrated Risk Information (IRIS) database (http://www.epa.gov/iris) as repeated exposure by the oral, dermal, or inhalation route for more than approximately 10% of the life span in humans (more than approximately 90 days to 2 years in typically used laboratory animal species).

[17] Defined in the IRIS database as repeated exposure by the oral, dermal, or inhalation route for more than 30 days, up to approximately 10% of the life span in humans (more than 30 days up to approximately 90 days in typically used laboratory animal species).

[18] Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

Figure 4-2 and Figure 4-3 depict the estimated census tract-level carcinogenic risk and noncancer respiratory hazard from the assessment. It is important to note that large reductions in HAP emissions may not necessarily translate into significant reductions in health risk because toxicity varies by pollutant, and exposures may or may not exceed levels of concern. For example, acetaldehyde mass emissions are more than double acrolein emissions on a national basis, according to EPA's 2005 National Emissions Inventory (NEI). However, the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is considerably lower than that for acetaldehyde, suggesting that acrolein could be potentially more toxic than acetaldehyde.[19] Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

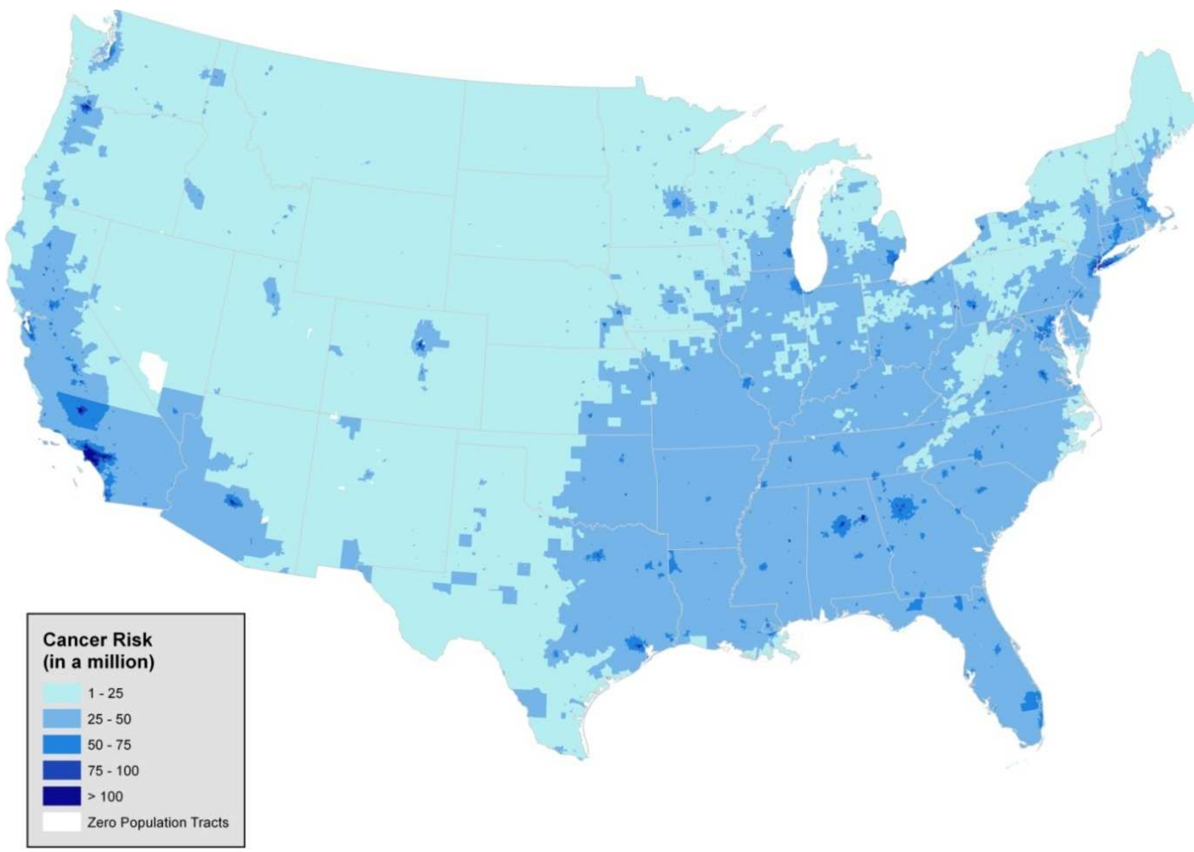

Figure 4-2 Estimated Chronic Census Tract Carcinogenic Risk from HAP exposure from outdoor sources (2005 NATA)

[19] Details on the derivation of IRIS values and available supporting documentation for individual chemicals (as well as chemical values comparisons) can be found at http://cfpub.epa.gov/ncea/iris/compare.cfm.

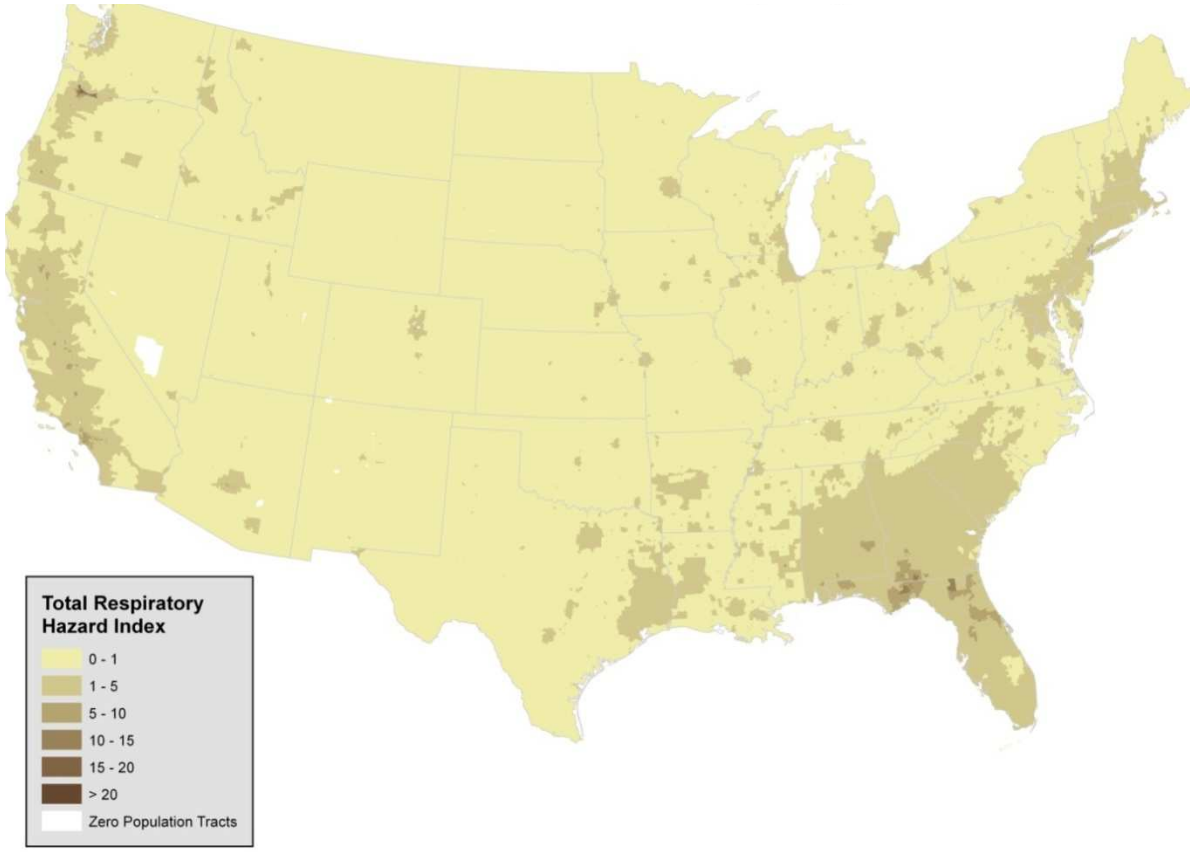

Figure 4-3 Estimated Chronic Census Tract Noncancer (Respiratory) Risk from HAP exposure from outdoor sources (2005 NATA)

Due to methodology and data limitations, we were unable to estimate the benefits associated with the hazardous air pollutants that would be reduced as a result of these rules.. In a few previous analyses of the benefits of reductions in HAPs, EPA has quantified the benefits of potential reductions in the incidences of cancer and non-cancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) developed through risk assessment procedures.[20] These URFs are designed to be conservative, and as such, are more likely to represent the high end of the distribution of risk rather than a best or most likely estimate of risk. As the purpose of a benefit analysis is to describe the benefits most likely to occur from a reduction in pollution, use of high-end, conservative risk estimates would overestimate the

[20] The unit risk factor is a quantitative estimate of the carcinogenic potency of a pollutant, often expressed as the probability of contracting cancer from a 70-year lifetime continuous exposure to a concentration of one µg/m^3 of a pollutant.

benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates in benefit analyses (U.S. EPA-SAB, 2002). Since this time, EPA has continued to develop better methods for analyzing the benefits of reductions in HAPs.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 2011a), EPA conducted a case study analysis of the health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act (IEc, 2009). While reviewing the draft report, EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAPs) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008).

In 2009, EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAPs. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn et al., 2011).

In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAPs, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAPs in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAPs anticipated to be reduced by these rules and we summarize the results of the residual risk assessment for the Risk and Technology Review (RTR). EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk.

Available emissions data show that several different HAPs are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAPs make up a large percentage the total

HAP emissions by mass from the oil and gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2011a). In the subsequent sections, we describe the health effects associated with the main HAPs of concern from the oil and natural gas sector: benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane. These rules combined are anticipated to avoid or reduce 58,000 tons of HAPs per year. With the data available, it was not possible to estimate the tons of each individual HAP that would be reduced.

EPA conducted a residual risk assessment for the NESHAP rule (U.S. EPA, 2011c). The results for oil and gas production indicate that maximum lifetime individual cancer risks could be 30 in-a-million for existing sources before and after controls with a cancer incidence of 0.02 before and after controls. For existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with a cancer incidence that decreases from 0.001 before controls to 0.0002 after controls. Benzene is the primary cancer risk driver. The results also indicate that significant noncancer impacts from existing sources are unlikely, especially after controls. EPA did not conduct a risk assessment for new sources affected by the NSPS. However, it is important to note that the magnitude of the HAP emissions avoided by new sources with the NSPS are more than an order of magnitude higher than the HAP emissions reduced from existing sources with the NESHAP.

4.4.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[21,22,23] EPA states in its IRIS database that data indicate a causal

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[21] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[22] International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345-389, 1982.

[23] Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691-3695.

relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human Services (DHHS) has characterized benzene as a known human carcinogen.[24,25] A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[26,27] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[28,29] In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.[30,31,32,33] EPA's IRIS program has not yet evaluated these new data.

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[24] International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[25] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: http://ntp.niehs.nih.gov/go/16183.

[26] Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193-197.

[27] Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541-554.

[28] Rothman, N., G.L. Li, M. Dosemeci, W.E. Bechtold, G.E. Marti, Y.Z. Wang, M. Linet, L.Q. Xi, W. Lu, M.T. Smith, N. Titenko-Holland, L.P. Zhang, W. Blot, S.N. Yin, and R.B. Hayes (1996) Hematotoxicity among Chinese workers heavily exposed to benzene. Am. J. Ind. Med. 29: 236-246.

[29] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene (Noncancer Effects). Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[30] Qu, O.; Shore, R.; Li, G.; Jin, X.; Chen, C.L.; Cohen, B.; Melikian, A.; Eastmond, D.; Rappaport, S.; Li, H.; Rupa, D.; Suramaya, R.; Songnian, W.; Huifant, Y.; Meng, M.; Winnik, M.; Kwok, E.; Li, Y.; Mu, R.; Xu, B.; Zhang, X.; Li, K. (2003). HEI Report 115, Validation & Evaluation of Biomarkers in Workers Exposed to Benzene in China.

[31] Qu, Q., R. Shore, G. Li, X. Jin, L.C. Chen, B. Cohen, et al. (2002). Hematological changes among Chinese workers with a broad range of benzene exposures. Am. J. Industr. Med. 42: 275-285.

[32] Lan, Qing, Zhang, L., Li, G., Vermeulen, R., et al. (2004). Hematotoxically in Workers Exposed to Low Levels of Benzene. Science 306: 1774-1776.

[33] Turtletaub, K.W. and Mani, C. (2003). Benzene metabolism in rodents at doses relevant to human exposure from Urban Air. Research Reports Health Effect Inst. Report No.113.

4.4.2 Toluene[34]

Under the 2005 Guidelines for Carcinogen Risk Assessment, there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

4.4.3 Carbonyl sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate

[34] All health effects language for this section came from: U.S. EPA. 2005. “Full IRIS Summary for Toluene (CASRN 108-88-3)” Environmental Protection Agency, Integrated Risk Information System (IRIS), Office of Health and Environmental Assessment, Environmental Criteria and Assessment Office, Cincinnati, OH. Available on the Internet at <http://www.epa.gov/iris/subst/0118.htm>.

the eyes and skin in humans.[35] No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under U.S. EPA's IRIS program for evidence of human carcinogenic potential.[36]

4.4.4 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral cavities in male and female rats exposed to ethylbenzene via the oral route.[37,38] The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP).[39,40] The NTP (1999) carried out a chronic inhalation

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[35] Hazardous Substances Data Bank (HSDB), online database). US National Library of Medicine, Toxicology Data Network, available online at http://toxnet.nlm.nih.gov/. Carbonyl health effects summary available at http://toxnet.nlm.nih.gov/cgi-bin/sis/search/r?dbs+hsdb:@term+@rn+@rel+463-58-1.

[36] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Carbonyl Sulfide. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0617.htm.

[37] Maltoni C, Conti B, Giuliano C and Belpoggi F, 1985. Experimental studies on benzene carcinogenicity at the Bologna Institute of Oncology: Current results and ongoing research. Am J Ind Med 7:415-446.

[38] Maltoni C, Ciliberti A, Pinto C, Soffritti M, Belpoggi F and Menarini L, 1997. Results of long-term experimental carcinogenicity studies of the effects of gasoline, correlated fuels, and major gasoline aromatics on rats. Annals NY Acad Sci 837:15-52.

[39]International Agency for Research on Cancer (IARC), 2000. Monographs on the Evaluation of Carcinogenic Risks to Humans. Some Industrial Chemicals. Vol. 77, p. 227-266. IARC, Lyon, France.

bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

4.4.5 Mixed xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely-related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects.[41] Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys.[42] Long-term inhalation exposure to xylenes in humans has been associated with a number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination.[43] EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

4.4.6 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central

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[40] National Toxicology Program (NTP), 1999. Toxicology and Carcinogenesis Studies of Ethylbenzene (CAS No. 100-41-4) in F344/N Rats and in B6C3F1 Mice (Inhalation Studies). Technical Report Series No. 466. NIH Publication No. 99-3956. U.S. Department of Health and Human Services, Public Health Service, National Institutes of Health. NTP, Research Triangle Park, NC.

[41] U.S. Environmental Protection Agency (U.S. EPA). 2003. Integrated Risk Information System File for Mixed Xylenes. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0270.htm.

[42] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53.

[43] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53.

nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.[44]

4.4.7 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by these rules, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in EPA's IRIS database.[45]

4.5 VOCs

4.5.1 VOCs as a PM2.5 precursor

This rulemaking would reduce emissions of VOCs, which are a precursor to $PM_{2.5.}$ Most VOCs emitted are oxidized to carbon dioxide (CO_2) rather than to PM, but a portion of VOC emission contributes to ambient $PM_{2.5}$ levels as organic carbon aerosols (U.S. EPA, 2009a). Therefore, reducing these emissions would reduce $PM_{2.5}$ formation, human exposure to $PM_{2.5}$, and the incidence of $PM_{2.5}$-related health effects. However, we have not quantified the $PM_{2.5}$-related benefits in this analysis. Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution. Given that a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions and the extremely small amount of VOC emissions from this sector relative to the entire VOC inventory it is unlikely this sector has a large contribution to

[44] U.S. EPA. 2005. Guidelines for Carcinogen Risk Assessment. EPA/630/P-03/001B. Risk Assessment Forum, Washington, DC. March. Available on the Internet at <http://www.epa.gov/ttn/atw/cancer_guidelines_final_3-25-05.pdf>.

[45] U.S. EPA Integrated Risk Information System (IRIS) database is available at: www.epa.gov/iris

ambient secondary organic carbon aerosols. Photochemical models typically estimate secondary organic carbon from anthropogenic VOC emissions to be less than 0.1 $\mu g/m^3$.

Due to time limitations under the court-ordered schedule, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of $PM_{2.5}$ formation to VOC emission reductions, we are unable to estimate the effect that reducing VOCs will have on ambient $PM_{2.5}$ levels without air quality modeling.

4.5.2 $PM_{2.5}$ health effects and valuation

Reducing VOC emissions would reduce $PM_{2.5}$ formation, human exposure, and the incidence of $PM_{2.5}$-related health effects. Reducing exposure to $PM_{2.5}$ is associated with significant human health benefits, including avoiding mortality and respiratory morbidity. Researchers have associated $PM_{2.5}$- exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009a). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to $PM_{2.5}$ (e.g., U.S. EPA (2010c)). These health effects include premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, hospital admissions, and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital and ER visits, work loss days, restricted activity days, and respiratory symptoms. Although EPA has not quantified these effects in previous benefits analyses, the scientific literature suggests that exposure to $PM_{2.5}$ is also associated with adverse effects on birth weight, pre-term births, pulmonary function, other cardiovascular effects, and other respiratory effects (U.S. EPA, 2009a).

EPA assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2009a). Based on our review of the current body of scientific literature, EPA estimates PM-related mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of $PM_{2.5}$ in the underlying epidemiology studies.

Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). Using the estimates in Fann, Fulcher, and Hubbell (2009), the monetized benefit-per-ton of reducing VOC emissions in nine urban areas of the U.S. ranges from $560 in Seattle, WA to $5,700 in San Joaquin, CA, with a national average of $2,400. These estimates assume a 50 percent reduction in VOCs, the Laden et al. (2006) mortality function (based on the Harvard Six City Study, a large cohort epidemiology study in the Eastern U.S.), an analysis year of 2015, and a 3 percent discount rate.

Based on the methodology from Fann, Fulcher, and Hubbell (2009), we converted their estimates to 2008$ and applied EPA's current VSL estimate.[46] After these adjustments, the range of values increases to $680 to $7,000 per ton of VOC reduced for Laden et al. (2006). Using alternate assumptions regarding the relationship between $PM_{2.5}$ exposure and premature mortality from empirical studies and supplied by experts (Pope et al., 2002; Laden et al., 2006; Roman et al., 2008), additional benefit-per-ton estimates are available from this dataset, as shown in Table 4-6. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) because they are both well-designed and peer reviewed studies, and EPA provides the benefit estimates derived from expert opinions in Roman et al. (2008) as a characterization of uncertainty. In addition to the range of benefits based on epidemiology studies, this study also provided a range of benefits associated with reducing emissions in eight specific urban areas. The range of VOC benefits that reflects the adjustments as well as the range of epidemiology studies and the range of the urban areas is $280 to $7,000 per ton of VOC reduced.

While these ranges of benefit-per-ton estimates provide useful context for the break-even analysis, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship

[46] For more information regarding EPA's current VSL estimate, please see Section 5.4.4.1 of the RIA for the proposed Federal Transport Rule (U.S. EPA, 2010a). EPA continues to work to update its guidance on valuing mortality risk reductions.

between VOC emissions and $PM_{2.5}$, these factors lead us to conclude that the available VOC benefit per ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

Table 4-6 Monetized Benefits-per-Ton Estimates for VOCs (2008$)

Area	Pope et al.	Laden et al.	Expert A	Expert B	Expert C	Expert D	Expert E	Expert F	Expert G	Expert H	Expert I	Expert J	Expert K	Expert L
Atlanta	$620	$1,500	$1,600	$1,200	$1,200	$860	$2,000	$1,100	$730	$920	$1,200	$980	$250	$940
Chicago	$1,500	$3,800	$4,000	$3,100	$3,000	$2,200	$4,900	$2,800	$1,800	$2,300	$3,000	$2,500	$600	$2,400
Dallas	$300	$740	$780	$610	$590	$420	$960	$540	$360	$450	$590	$480	$120	$460
Denver	$720	$1,800	$1,800	$1,400	$1,400	$1,000	$2,300	$1,300	$850	$1,100	$1,400	$1,100	$280	$850
NYC/ Philadelphia	$2,100	$5,200	$5,500	$4,300	$4,200	$3,000	$6,900	$3,900	$2,500	$3,200	$4,200	$3,400	$830	$3,100
Phoenix	$1,000	$2,500	$2,600	$2,000	$2,000	$1,400	$3,300	$1,800	$1,200	$1,500	$2,000	$1,600	$400	$1,500
Salt Lake	$1,300	$3,100	$3,300	$2,600	$2,500	$1,800	$4,100	$2,300	$1,500	$1,900	$2,500	$2,100	$530	$2,000
San Joaquin	$2,900	$7,000	$7,400	$5,800	$5,600	$4,000	$9,100	$5,200	$3,400	$4,300	$5,600	$4,600	$1,300	$4,400
Seattle	$280	$680	$720	$530	$550	$390	$890	$500	$330	$420	$550	$450	$110	$330
National average	**$1,200**	**$3,000**	**$3,200**	**$2,400**	**$2,400**	**$1,700**	**$3,900**	**$2,200**	**$1,400**	**$1,800**	**$2,400**	**$1,900**	**$490**	**$1,800**

* These estimates assume a 50 percent reduction in VOC emissions, an analysis year of 2015, and a 3 percent discount rate. All estimates are rounded to two significant digits. These estimates have been updated from Fann, Fulcher, and Hubbell (2009) to reflect a more recent currency year and EPA's current VSL estimate. Using a discount rate of 7 percent, the benefit-per-ton estimates would be approximately 9 percent lower. Assuming a 75 percent reduction in VOC emissions would increase the benefit-per-ton estimates by approximately 4 percent to 52 percent. Assuming a 25 percent reduction in VOC emissions would decrease the benefit-per-ton estimates by 5 percent to 52 percent. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) and provides the benefits estimates derived from the expert functions from Roman et al. (2008) as a characterization of uncertainty.

4.5.3 Organic PM welfare effects

According to the residual risk assessment for this sector (U.S. EPA, 2011a), persistent and bioaccumulative HAP reported as emissions from oil and gas operations include polycyclic organic matter (POM). POM defines a broad class of compounds that includes the polycyclic aromatic hydrocarbon compounds (PAHs). Several significant ecological effects are associated with deposition of organic particles, including persistent organic pollutants, and PAHs (U.S. EPA, 2009a).

PAHs can accumulate in sediments and bioaccumulate in freshwater, flora, and fauna. The uptake of organics depends on the plant species, site of deposition, physical and chemical properties of the organic compound and prevailing environmental conditions (U.S. EPA, 2009a). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. Deposition of PM to surfaces in urban settings increases the metal and organic component of storm water runoff. This atmospherically-associated pollutant burden can then be toxic to aquatic biota. The contribution of atmospherically deposited PAHs to aquatic food webs was demonstrated in high elevation mountain lakes with no other anthropogenic contaminant sources.

The recently completed Western Airborne Contaminants Assessment Project (WACAP) is the most comprehensive database on contaminant transport and PM depositional effects on sensitive ecosystems in the Western U.S. (Landers et al., 2008). In this project, the transport, fate, and ecological impacts of anthropogenic contaminants from atmospheric sources were assessed from 2002 to 2007 in seven ecosystem components (air, snow, water, sediment, lichen, conifer needles, and fish) in eight core national parks. The study concluded that bioaccumulation of semi-volatile organic compounds occurred throughout park ecosystems, an elevational gradient in PM deposition exists with greater accumulation in higher altitude areas, and contaminants accumulate in proximity to individual agriculture and industry sources, which is counter to the original working hypothesis that most of the contaminants would originate from Eastern Europe and Asia.

4.5.4 Visibility Effects

Reducing secondary formation of $PM_{2.5}$ would improve visibility throughout the U.S. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Suspended particles and gases degrade visibility by scattering and absorbing light. Higher visibility impairment levels in the East are due to generally higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Previous analyses (U.S. EPA, 2006b; U.S. EPA, 2010c; U.S. EPA, 2011a) show that visibility benefits are a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility related benefits, nor are we able to determine whether VOC emission reductions would be likely to have a significant impact on visibility in urban areas or Class I areas.

4.6 VOCs as an Ozone Precursor

This rulemaking would reduce emissions of VOCs, which are also precursors to secondary formation of ozone. Ozone is not emitted directly into the air, but is created when its two primary components, volatile organic compounds (VOC) and oxides of nitrogen (NOx), combine in the presence of sunlight. In urban areas, compounds representing all classes of VOCs and CO are important compounds for ozone formation, but biogenic VOCs emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2006a). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. However, we have not quantified the ozone-related benefits in this analysis for several reasons. First, previous rules have shown that the monetized benefits associated with reducing ozone exposure are generally smaller than PM-related benefits, even when ozone is the pollutant targeted for control (U.S. EPA, 2010a). Second, the complex non-linear chemistry of ozone formation introduces uncertainty to the development and application of a benefit-per-ton estimate. Third, the impact of reducing VOC emissions is spatially heterogeneous depending on local air chemistry. Urban areas with a high population concentration are often VOC-limited, which means that ozone is most effectively reduced by lowering VOCs. Rural areas and downwind suburban areas are often NOx-limited, which means that ozone concentrations are most effectively reduced by lowering NOx emissions, rather than lowering emissions of VOCs. Between these areas, ozone is relatively insensitive to marginal changes in both NOx and VOC.

Due to time limitations under the court-ordered schedule, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of ozone formation to VOC emission reductions, we are unable to estimate the effect that reducing VOCs will have on ambient ozone concentrations without air quality modeling.

4.6.1 Ozone health effects and valuation

Reducing ambient ozone concentrations is associated with significant human health benefits, including mortality and respiratory morbidity (U.S. EPA, 2010a). Epidemiological researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2006c). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to ozone (e.g., U.S. EPA, 2010a; U.S. EPA, 2011a). These health effects include respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days, as well as premature mortality. Although EPA has not quantified these effects in benefits analyses previously, the scientific literature is suggestive that exposure to ozone is also associated with chronic respiratory damage and premature aging of the lungs.

In a recent EPA analysis, EPA estimated that reducing 15,000 tons of VOCs from industrial boilers resulted in \$3.6 to \$15 million of monetized benefits from reduced ozone exposure (U.S. EPA, 2011b).[47] This implies a benefit-per-ton for ozone reductions of \$240 to \$1,000 per ton of VOCs reduced. While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in the boiler analysis. Therefore, we do not believe that those

[47] While EPA has estimated the ozone benefits for many scenarios, most of these scenarios also reduce NOx emissions, which make it difficult to isolate the benefits attributable to VOC reductions.

estimates to provide useful estimates of the monetized benefits of these rules, even as a bounding exercise.

4.6.2 Ozone vegetation effects

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2006a). Sensitivity to ozone is highly variable across species, with over 65 plan species identified as “ozone-sensitive”, many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced crop yields, visible foliar injury, reduced plant vigor (e.g., increased susceptibility to harsh weather, disease, insect pest infestation, and competition), species composition shift, and changes in ecosystems and associated ecosystem services.

4.6.3 Ozone climate effects

Ozone is a well-known short-lived climate forcing (SLCF) greenhouse gas (GHG) (U.S. EPA, 2006a). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun’s harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). A recent United Nations Environment Programme (UNEP) study reports that the threefold increase in ground level ozone during the past 100 years makes it the third most important contributor to human contributed climate change behind CO_2 and methane. This discernable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles. This study provides the most comprehensive analysis to date of the benefits of measures to reduce SLCF gases including methane, ozone, and black carbon assessing the health, climate, and agricultural benefits of a suite of mitigation technologies. The report concludes that the climate is changing now, and these changes have the potential to “trigger abrupt transitions such as the release of carbon from thawing permafrost and biodiversity loss” (UNEP 2011). While reducing long-lived GHGs such as CO_2 is necessary to protect against long-term climate change, reducing SLCF gases including ozone is beneficial and will slow the rate of climate change within the first half of this century (UNEP 2011).

4.7 Methane (CH_4)

4.7.1 Methane as an ozone precursor

This rulemaking would reduce emissions of methane, a long-lived GHG and also a precursor to ozone. In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2006a). Unlike NOx and VOCs, which affect ozone concentrations regionally and at hourly time scales, methane emission reductions require several decades for the ozone response to be fully realized, given methane's relatively long atmospheric lifetime (HTAP, 2010). Studies have shown that reducing methane can reduce global background ozone concentrations over several decades, which would benefit both urban and rural areas (West et al., 2006). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. The health, welfare, and climate effects associated with ozone are described in the preceding sections. Without air quality modeling, we are unable to estimate the effect that reducing methane will have on ozone concentrations at particular locations.

4.7.2 Methane climate effects and valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that once emitted into the atmosphere absorbs terrestrial infrared radiation which contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. According to the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (2007), in 2004 the cumulative changes in methane concentrations since preindustrial times contributed about 14 percent to global warming due to anthropogenic GHG sources, making methane the second leading long-lived climate forcer after CO_2 globally. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

Processes in the oil and gas category emit significant amounts of methane. The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 (MMtCO_2-e). In 2009, total methane emissions from the oil and gas industry represented nearly 40 percent of the total methane emissions from all sources and account for about 5 percent of all CO_2-equivalent (CO_2-e) emissions in the U.S., with natural gas systems being the single largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2011b, Table ES-2). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 MMtCO_2-e. The total methane emissions from Petroleum and Natural Gas Systems based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus Shale, is approximately 330 MMtCO_2-e.

This rulemaking proposes emission control technologies and regulatory alternatives that will significantly decrease methane emissions from the oil and natural gas sector in the United States. The regulatory alternative proposed for this rule is expected to reduce methane emissions annually by about 3.4 million short tons or approximately 65 million metric tons CO_2-e. These reductions represent about 26 percent of the GHG emissions for this sector reported in the 1990-2009 U.S. GHG Inventory (251.55 MMTCO_2-e). This annual CO_2-e reduction becomes about 62 million metric tons when the secondary impacts associated with increased combustion and supplemental energy use on the producer side and CO_2-e emissions from changes in consumption patterns previously discussed are considered. However, it is important to note the emissions reductions are based upon predicted activities in 2015; EPA did not forecast sector-level emissions to 2015 for this rulemaking. The climate co-benefit from these reductions are equivalent of taking approximately 11 million typical passenger cars off the road or eliminating electricity use from about 7 million typical homes each year.[48]

EPA estimates the social benefits of regulatory actions that have a small or "marginal" impact on cumulative global CO_2 emissions using the "social cost of carbon" (SCC). The SCC is an estimate of the net present value of the flow of monetized damages from a one metric ton increase in CO_2 emissions in a given year (or from the alternative perspective, the benefit to society of reducing CO_2 emissions by one ton). The SCC includes (but is not limited to) climate damages due to changes in net agricultural productivity, human health, property damages from flood risk, and ecosystem services due to climate change. The SCC estimates currently used by the Agency were developed through an interagency process that included EPA and other executive branch entities, and concluded in February 2010. The Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 for the final joint EPA/Department of Transportation Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards provides a complete discussion of the methods used to develop the SCC estimates (Interagency Working Group on Social Cost of Carbon, 2010).

To estimate global social benefits of reduced CO_2 emissions, the interagency group selected four SCC values for use in regulatory analyses: $6, $25, $40, and $76 per metric ton of CO_2 emissions in 2015, in 2008 dollars. The first three values are based on the average SCC estimated using three integrated assessment models (IAMs), at discount rates of 5.0, 3.0, and 2.5 percent, respectively. When valuing the impacts of climate change, IAMs couple economic and climate systems into a single model to capture important interactions between the components. SCCs estimated using different discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the distribution of SCC estimates from all three models at a 3.0 percent discount rate. It is included to represent higher-than-expected damages from temperature change further out in the tails of the SCC distribution.

[48] US Environmental Protection Agency. Greenhouse Gas Equivalency Calculator available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html accessed 07/19/11.

Although there are relatively few region- or country-specific estimates of SCC in the literature, the results from one model suggest the ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. For example, with a 2.5 or 3 percent discount rate, the U.S. benefit is about 7-10 percent of the global benefit, on average, across the scenarios analyzed. Alternatively, if the fraction of GDP lost due to climate change is assumed to be similar across countries, the domestic benefit would be proportional to the U.S. share of global GDP, which is currently about 23 percent. On the basis of this evidence, values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects. It is recognized that these values are approximate, provisional, and highly speculative. There is no a priori reason why domestic benefits should be a constant fraction of net global damages over time. (Interagency Working Group on Social Cost of Carbon, 2010).

The interagency group noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. The limited amount of research linking climate impacts to economic damages makes estimating damages from climate change even more difficult. The interagency group hopes that over time researchers and modelers will work to fill these gaps and that the SCC estimates used for regulatory analysis by the Federal government will continue to evolve with improvements in modeling. Additional details on these limitations are discussed in the SCC TSD.

A significant limitation of the aforementioned interagency process particularly relevant to this rulemaking is that the social costs of non-CO_2 GHG emissions were not estimated. Specifically, the interagency group did not directly estimate the social cost of non-CO_2 GHGs using the three models. Moreover, the group determined that it would not transform the CO_2 estimates into estimates for non-CO_2 GHGs using global warming potentials (GWPs), which measure the ability of different gases to trap heat in the atmosphere (i.e., radiative forcing per unit of mass) over a particular timeframe relative to CO_2. One potential method for approximating the value of marginal non-CO_2 GHG emission reductions is to convert the reductions to CO_2-equivalents which may then be valued using the SCC. Conversion to CO_2-e is typically done using the GWPs for the non-CO_2 gas. The GWP is an aggregate measure that approximates the additional energy trapped in the atmosphere over a given timeframe from a perturbation of a non-CO_2 gas relative to CO_2. The time horizon most commonly used is 100 years. One potential problem with utilizing temporally aggregated statistics, such as the GWPs, is that the additional radiative forcing from the GHG perturbation is not constant over time and any differences in temporal dynamics between gases will be lost. This is a potentially confounding issue given that the social cost of GHGs is based on a discounted stream of damages that are non-linear in temperature. For example, methane has an expected adjusted atmospheric lifetime of about 12 years and associated GWP of 21 (IPCC Second Assessment Report (SAR) 100-year GWP estimate). Gases with a shorter lifetime, such as methane, have impacts that occur primarily in the near term and thus are not discounted as heavily as those caused by the longer-lived gases, while the GWP treats additional forcing the same independent of when it occurs in time. Furthermore, the baseline temperature change is lower in the near term and therefore the additional warming from relatively short lived gases will have a lower marginal impact relative to longer lived gases that have an impact further out in the future when baseline warming is higher. The GWP also relies on an arbitrary time horizon and constant concentration scenario. Both of which are inconsistent with the assumptions used by the SCC interagency workgroup. Finally, impacts other than temperature change also vary across gases in ways that are not captured by GWP. For instance, CO_2 emissions, unlike methane will result in CO_2 passive fertilization to plants.

In light of these limitations, and the significant contributions of non-CO_2 emissions to climate change, further analysis is required to link non-CO_2 emissions to economic impacts and to develop social cost estimates for methane specifically. Such work would feed into efforts to develop a monetized value of reductions in methane greenhouse gas emissions in assessing the co-benefits of this rulemaking. As part of ongoing work to further improve the SCC estimates, the interagency group hopes to develop methods to value greenhouse gases other than CO_2, such as methane, by the time SCC estimates for CO_2 emissions are revised.

The EPA recognizes that the methane reductions proposed in this rule will provide significant economic climate co-benefits to society. However, EPA finds itself in the position of having no interagency accepted monetary values to place on these co-benefits. The ‘GWP approach’ of converting methane to CO_2-e using the GWP of methane, as previously described, is one approximation method for estimating the monetized value of the methane reductions anticipated from this rule. This calculation uses the GWP of the non-CO_2 gas to estimate CO_2 equivalents and then multiplies these CO_2 equivalent emission reductions by the SCC to generate monetized estimates of the co-benefits. If one makes these calculations for the proposed Option 2 (including expected methane emission reductions from the NESHAP amendments and NSPS and considers secondary impacts) of the oil and gas rule, the 2015 co-benefits vary by discount rate and range from about $373 million to over $4.7 billion; the SCC at the 3 percent discount rate ($25 per metric ton) results in an estimate of $1.6 billion in 2015. These co-benefits equate to a range of approximately $110 to $1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of $480 at the 3 percent discount rate

As previously stated, these co-benefit estimates are not the same as would be derived using a directly computed social cost of methane (using the integrated assessment models employed to develop the SCC estimates) for a variety of reasons including the shorter atmospheric lifetime of methane relative to CO_2 (about 12 years compared to CO_2 whose concentrations in the atmosphere decay on timescales of decades to millennia). The climate impacts also differ between the pollutants for reasons other than the radiative forcing profiles and atmospheric lifetimes of these gases. Methane is a precursor to ozone and ozone is a short-lived climate forcer as previously discussed. This use of the SAR GWP to approximate benefits may underestimate the direct radiative forcing benefits of reduced ozone levels, and does not capture any secondary climate co-benefits involved with ozone-ecosystem interactions. In addition, a recent NCEE working paper suggests that this quick ‘GWP approach’ to benefits estimation will likely understate the climate benefits of methane reductions in most cases (Marten and Newbold, 2011). This conclusion is reached using the 100 year GWP for methane of 25 as put forth in the IPCC Fourth Assessment Report as opposed to the lower value of 21 used in this analysis. Using the higher GWP estimate of 25 would increase these reported methane climate co-benefit estimates by about 19 percent. Although the IPCC Fourth Assessment Report suggested a GWP of 25, EPA has used GWP of 21 consistent with the IPCC SAR to estimate the methane climate co-benefits for this oil and gas proposal. The use of the SAR GWP values allows comparability of data collected in this proposed rule to the national GHG inventory that EPA compiles annually to meet U.S. commitments to the United Nations Framework Convention on Climate Change (UNFCCC). To comply with international reporting standards under the UNFCCC, official emission estimates are to be reported by the U.S. and other countries using SAR GWP values. The UNFCCC reporting guidelines for national inventories were updated in 2002 but continue to require the use of GWPs from the SAR. The parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon although other time horizon values are available. The SAR GWP value for methane is also currently used to establish GHG reporting requirements as mandated by the GHG Reporting Rule (2010e) and is used by the EPA to determine Title V and Prevention of Significant Deterioration GHG permitting requirements as modified by the GHG Tailoring Rule (2010f).

EPA also undertook a literature search for estimates of the marginal social cost of methane. A range of marginal social cost of methane benefit estimates are available in published literature (Fankhauser (1994), Kandlikar (1995), Hammitt et al. (1996), Tol et al. (2003), Tol, et al. (2006), Hope (2005) and Hope and Newberry (2006). Most of these estimates are based upon modeling assumptions that are dated and inconsistent with the current SCC estimates. Some of these studies focused on marginal methane reductions in the 1990s and early 2000s and report estimates for only the single year of interest specific to the study. The assumptions underlying the social cost of methane estimates available in the literature differ from those agreed upon by the SCC interagency group and in many cases use older versions of the IAMs. Without additional analysis, the methane climate benefit estimates available in the current literature are not acceptable to use to value the methane reductions proposed in this rulemaking.

Due to the uncertainties involved with ‘GWP approach’ estimates presented and estimates available in the literature, EPA chooses not to compare these co-benefit estimates to the costs of the rule for this proposal. Rather, the EPA presents the ‘GWP approach’ climate co-benefit estimates as an interim method to produce lower-bound estimates until the interagency group develops values for non-CO_2 GHGs. EPA requests comments from interested parties and the public about this interim approach specifically and more broadly about appropriate methods to monetize the climate co-benefits of methane reductions. In particular, EPA seeks public comments to this proposed rulemaking regarding social cost of methane estimates that may be used to value the co-benefits of methane emission reductions anticipated for the oil and gas industry from this rule. Comments specific to whether GWP is an acceptable method for generating a placeholder value for the social cost of methane until interagency modeled estimates become available are welcome. Public comments may be provided in the official docket for this proposed rulemaking in accordance with the process outlined in the preamble for the rule. These comments will be considered in developing the final rule for this rulemaking.

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5 STATUTORY AND EXECUTIVE ORDER REVIEWS

5.1 Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 5-1 shows the results of the cost and benefits analysis for these proposed rules.

Table 5-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS and NESHAP Amendments in 2015 (millions of 2008$)[1]

	Proposed NSPS	Proposed NESHAP Amendments	Proposed NSPS and NESHAP Amendments Combined
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$45 million	$16 million	-$29 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	37,000 tons of HAPs	1,400 tons of HAPs	38,000 tons of HAPs
	540,000 tons of VOCs	9,200 tons of VOCs	540,000 tons of VOCs
	3.4 million tons of methane	4,900 tons of methane	3.4 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

5.2 Paperwork Reduction Act

The information collection requirements in this proposed action have been submitted for approval to OMB under the PRA, 44 U.S.C. 3501, et seq. The ICR document prepared by the EPA has been assigned EPA ICR Numbers 1716.07 (40 CFR part 60, subpart OOOO), 1788.10 (40 CFR part 63, subpart HH), 1789.07 (40 CFR part 63, subpart HHH), and 1086.10 (40 CFR part 60, subparts KKK and subpart LLL).

The information to be collected for the proposed NSPS and the proposed NESHAP amendments are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

These proposed rules would require maintenance inspections of the control devices, but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

For sources subject to the proposed NSPS, the burden represents labor hours and costs associated from annual reporting and recordkeeping for each affected facility. The estimated burden is based on the annual expected number of affected operators for the first three years following the effective date of the standards. The burden is estimated to be 560,000 labor hours at a cost of around$18 million per year. This includes the labor and cost estimates previously estimated for sources subject to 40 CFR part 60, subpart KKK and subpart LLL (which is being incorporated into 40 CFR part 60, subpart OOOO). The average hours and cost per regulated entity, which is assumed to be on a per operator basis except for natural gas processing plants (which are estimated on a per facility basis) subject to the NSPS for oil and natural gas production and natural gas transmissions and distribution facilities would be 110 hours per response and $3,693 per response based on an average of 1,459 operators responding per year and 16 responses per year. The majority of responses are expected to be notifications of construction. One annual report is required that may include all affected facilities owned per each operator. Burden by for the proposed NSPS was based on EPA ICR Number 1716.07.

The estimated recordkeeping and reporting burden after the effective date of the proposed amendments is estimated for all affected major and area sources subject to the oil and natural gas production NESHAP (40 CFR 63, subpart HH) to be approximately 63,000 labor hours per year at a cost of $2.1 million per year. For the natural gas transmission and storage NESHAP, the recordkeeping and reporting burden is estimated to be 2,500 labor hours per year at a cost of $86,800 per year. This estimate includes the cost of reporting, including reading instructions, and information gathering. Recordkeeping cost estimates include reading instructions, planning activities, and conducting compliance monitoring. The average hours and cost per regulated entity subject to the oil and natural gas production NESHAP would be 72 hours per year and $2,500 per year based on an average of 846 facilities per year and three responses per facility. For the natural gas transmission and storage NESHAP, the average hours and cost per regulated entity would be 50 hours per year and $1,600 per year based on an average of 53 facilities per year and three responses per facility. Burden is defined at 5 CFR 1320.3(b). Burden for the oil and natural gas production NESHAP is estimated under EPA ICR Number 1788.10. Burden for the natural gas transmission and storage NESHAP is estimated under EPA ICR Number 1789.07.

5.3 Regulatory Flexibility Act

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) a small business whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

5.3.1 Proposed NSPS

After considering the economic impact of the Proposed NSPS on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities (SISNOSE). EPA performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. Based upon the analysis in Section 7.4 in this RIA, EPA recognizes that a subset of small firms is likely to be significantly impacted by the proposed NSPS. However, the number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that the firm-level compliance cost estimates used in the small business impacts analysis are likely over-estimates of the compliance costs faced by firms under the Proposed NSPS; these estimates do not include the revenues that producers are expected receive from the additional natural gas recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from well completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated, if not fully offset. Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities by the selection of highly cost-effective controls and specifying monitoring requirements that are the minimum to insure compliance.

5.3.2 Proposed NESHAP Amendments

After considering the economic impact of the Proposed NESHAP Amendments on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Based upon the analysis in Section 7.4 in this RIA, we estimate that 62 of the 118 firms (53 percent) that own potentially affected facilities are small entities. EPA performed a screening analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile 10 firms (16 percent) are likely to have impacts greater than 1 percent. Four of these 10 firms are likely to have impacts greater than 3 percent. While these 10 firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211. Although this final rule will not impact a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities by setting the final emissions limits at the MACT floor, the least stringent level allowed by law.

5.4 Unfunded Mandates Reform Act

This proposed rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any one year. Thus, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments nor does it impose obligations upon them.

5.5 Executive Order 13132: Federalism

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this proposed rule.

5.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. The EPA has concluded that this proposed rule will not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effect on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

5.7 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This proposed rule is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is economically significant as defined in Executive Order 12866. However, EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action would not relax the control measures on existing regulated sources. EPA's risk assessments (included in the docket for this proposed rule) demonstrate that the existing regulations are associated with an acceptable level of risk and provide an ample margin of safety to protect public health.

5.8 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211, (66 FR 28,355, May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: 1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or 2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action."

The proposed rules will result in the addition of control equipment and monitoring systems for existing and new sources within the oil and natural gas industry. The proposed NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed NESHAP amendments are not "significant energy actions" as defined in Executive Order 13211, (66 FR 28355, May 22, 2001).

The proposed NSPS is also unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed NSPS is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001). The basis for the determination is as follows.

We use the NEMS to estimate the impacts of the proposed NSPS on the United States energy system. The NEMS is a publically available model of the United States energy economy developed and maintained by the Energy Information Administration of the U.S. DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

Proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One pollution control requirement of the proposed NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the proposed NSPS.

The analysis of energy impacts for the proposed NSPS that includes the additional product recovery shows that domestic natural gas production is estimated to increase (20 billion cubic feet or 0.1 percent) and natural gas prices to decrease ($0.04/Mcf or 0.9 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. Domestic crude oil production is not estimated to change, while crude oil prices are estimated to decrease slightly ($0.02/barrel or less than 0.1 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. All prices are in 2008 dollars.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden.

5.9 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law No. 104-113 (15 U.S.C. 272 note) directs the EPA to use VCS in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the requirements of the NTTAA apply to this action. We are proposing to revise 40 CFR part 63, subparts HH and HHH to allow ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses (Part 10, Instruments and Apparatus) to be used in lieu of EPA Methods 3B, 6 and 16A. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990. Also, we are proposing to revise 40 CFR part 63, subpart HHH, to allow ASTM D6420-99(2004), "Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry" to be used in lieu of EPA Method 18. For a detailed discussion of this VCS, and its appropriateness as a substitute for Method 18, see the final oil and natural gas production NESHAP (Area Sources) (72 FR 36, January 3, 2007).

As a result, the EPA is proposing ASTM D6420-99 for use in 40 CFR part 63, subpart HHH. The EPA also proposes to allow Method 18 as an option in addition to ASTM D6420-99(2004). This would allow the continued use of GC configurations other than GC/MS.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

5.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on Environmental Justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

To examine the potential for any EJ issues that might be associated with each source category, we evaluated the distributions of HAP-related cancer and noncancer risks across different social, demographic, and economic groups within the populations living near the facilities where these source categories are located. The methods used to conduct demographic analyses for this rule are described in section VII.D of the preamble for this rule. The development of demographic analyses to inform the consideration of EJ issues in EPA rulemakings is an evolving science. The EPA offers the demographic analyses in this proposed rulemaking as examples of how such analyses might be developed to inform such consideration, and invites public comment on the approaches used and the interpretations made from the results, with the hope that this will support the refinement and improve utility of such analyses for future rulemakings.

For the demographic analyses, we focused on the populations within 50 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater, or noncancer HI of 1 or greater (based on the emissions of the source category or the facility, respectively). We examined the distributions of those risks across various demographic groups, comparing the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. The results, including other risk metrics, such as average risks for the exposed populations, are documented in source category-specific technical reports in the docket for both source categories covered in this proposal.

As described in the preamble, our risk assessments demonstrate that the regulations for the oil and natural gas production and natural gas transmission and storage source categories, are associated with an acceptable level of risk and that the proposed additional requirements will provide an ample margin of safety to protect public health.

Our analyses also show that, for these source categories, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic noncancer health impacts are unlikely. The EPA has determined that although there may be an existing disparity in HAP risks from these sources between some demographic groups, no demographic group is exposed to an unacceptable level of risk.

6 COMPARISON OF BENEFITS AND COSTS

Because we are unable to estimate the monetary value of the emissions reductions from the proposed rule, we have chosen to rely upon a break-even analysis to estimate what the monetary value benefits would need to attain in order to equal the costs estimated to be imposed by the rule. A break-even analysis answers the question, "What would the benefits need to be for the benefits to exceed the costs." While a break-even approach is not equivalent to a benefits analysis or even a net benefits analysis, we feel the results are illustrative, particularly in the context of previously modeled benefits.

The total cost of the proposed NSPS in the analysis year of 2015 when the additional natural gas and condensate recovery is included in the analysis is estimated at -$45 million for domestic producers and consumers. EPA anticipates that this rule would prevent 540,000 tons of VOC, 3.4 million tons of methane, and 37,000 tons of HAPs in 2015 from new sources. In 2015, EPA estimates the costs for the NESHAP amendments floor option to be $16 million.[49] EPA anticipates that this rule would reduce 9,200 tons of VOC, 4,900 tons of methane, and 1,400 tons of HAPs in 2015 from existing sources. For the NESHAP amendments, a break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health benefits, and ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

For the proposed NSPS, the revenue from additional natural gas recovery already exceeds the costs, which renders a break-even analysis unnecessary. However, as discussed in Section 3.2.2., estimates of the annualized engineering costs that include revenues from natural gas product recovery depend heavily upon assumptions about the price of natural gas and hydrocarbon condensates in analysis year 2015. Therefore, we have also conducted a break-even analysis for the price of natural gas. For the NSPS, a break-even analysis suggests that the price

[49] See Section 3 of this RIA for more information regarding the cost estimates for the NESHAP.

of natural gas would need to be at least $3.77 per Mcf in 2015 for the revenue from product recovery to exceed the annualized costs. EIA forecasts that the price of natural gas would be $4.26 per Mcf in 2015. In addition to the revenue from product recovery, the NSPS would avert emissions of VOCs, HAPs, and methane, which all have value that could be incorporated into the break-even analysis. Figure 6-1 illustrates one method of analyzing the break-even point with alternate natural gas prices and VOC benefits. If, as an illustrative example, the price of natural gas was only $3.00 per Mcf, VOCs would need to be valued at $260 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

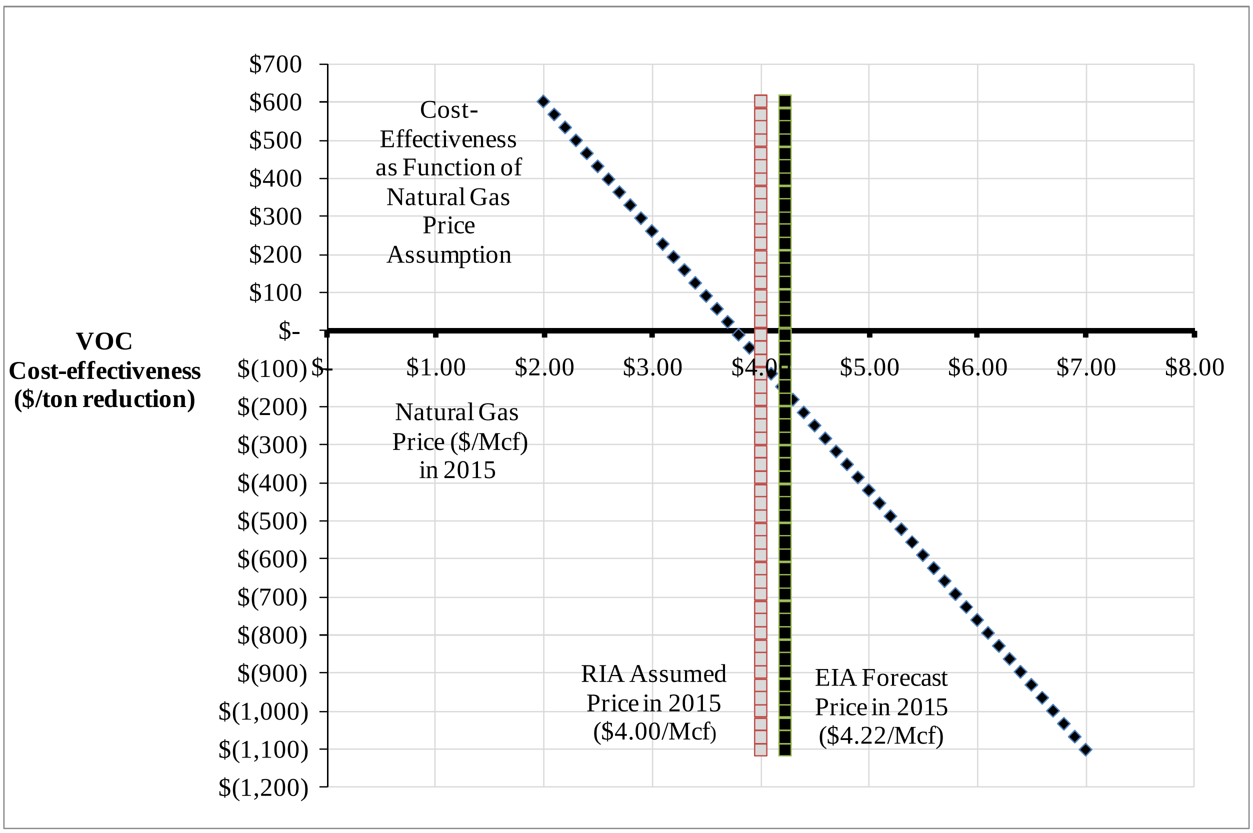

Figure 6-1 Illustrative Break-Even Diagram for Alternate Natural Gas Prices for the NSPS

With the data available, we are not able to provide a credible benefit-per-ton estimate for any of the pollutant reductions for these rules to compare to the break-even estimates. Based on the methodology from Fann, Fulcher, and Hubbell (2009), average $PM_{2.5}$ health-related benefits of VOC emissions are valued at \$280 to \$7,000 per ton across a range of eight urban areas.[50] In addition, ozone benefits have been previously valued at \$240 to \$1,000 per ton of VOC reduced. Using the GWP approach, the climate co-benefits range from approximately \$110 to \$1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of \$760 at the 3 percent discount rate.

These break-even benefit-per-ton estimates assume that all other pollutants have zero value. Of course, it is inappropriate to assume that the value of reducing any of these pollutants is zero. Thus, the real break-even estimate is actually lower than the estimates provided above because the other pollutants each have non-zero benefits that should be considered. Furthermore, a single pollutant can have multiple effects (e.g., VOCs contribute to both ozone and $PM_{2.5}$ formation that each have health and welfare effects) that would need to be summed in order to develop a comprehensive estimate of the monetized benefits associated with reducing that pollutant.

As previously described, the revenue from additional natural gas recovery already exceeds the costs of the NSPS, but even if the price of natural gas was only \$3.00 per Mcf, it is likely that the VOC benefits would exceed the costs, As a result, even if VOC emissions from oil and natural gas operations result in monetized benefits that are substantially below the average modeled benefits, there is a reasonable chance that the benefits of these rules would exceed the costs, especially if we were able to monetize all of the benefits associated with ozone formation, visibility, HAPs, and methane.

Table 6-1 and Table 6-2 present the summary of the benefits, costs, and net benefits for the NSPS and NESHAP amendment options, respectively. Table 6-3 provides a summary of the direct and secondary emissions changes for each option.

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[50] See Section 4.5 of this RIA for more information regarding $PM_{2.5}$ benefits and Section 4.6 for more information regarding ozone benefits.

Table 6-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS in 2015 (millions of 2008$)[1]

	Option 1: Alternative	Option 2: Proposed[4]	Option 3: Alternative
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$19 million	-$45 million	$77 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	17,000 tons of HAPs[5]	37,000 tons of HAPs[5]	37,000 tons of HAPs[5]
	270,000 tons of VOCs	540,000 tons of VOCs	550,000 tons of VOCs
	1.6 million tons of methane	3.4 million tons of methane	3.4 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

Table 6-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP amendments in 2015 (millions of 2008$)[1]

	Option 1: Proposed (Floor)
Total Monetized Benefits[2]	N/A
Total Costs[3]	$16 million
Net Benefits	N/A
Non-monetized Benefits	1,400 tons of HAPs 9,200 tons of VOCs[4] 4,900 tons of methane[4] Health effects of HAP exposure Health effects of $PM_{2.5}$ and ozone exposure[4] Visibility impairment[4] Vegetation effects[4] Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NESHAP are anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.

[3] The cost estimates are assumed to be equivalent to the engineering cost estimates. The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

Table 6-3 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP
Change in Direct Emissions	VOC	-270,000	-540,000	-550,000	-9,200
	Methane	-1,600,000	-3,400,000	-3,400,000	-4,900
	HAP	-17,000	-37,000	-37,000	-1,400
Change in Secondary Emissions (Producer-Side) [1]	CO_2	990,000	990,000	990,000	5,500
	NOx	510	510	510	2.9
	PM	7.6	7.6	7.6	0.1
	CO	2,800	2,800	2,800	16
	THC	1,000	1,000	1,000	6.0
Change in Secondary Emissions (Consumer-Side)	CO_2-e	-1,000,000	1,700,000	1,400,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e	-33,000,000	-68,000,000	-70,000,000	-96,000

[1] We use the producer-side secondary impacts associated with the proposed NSPS option as a surrogate for the impacts of the other options.

7 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

7.1 Introduction

This section includes three sets of analyses for both the NSPS and NESHAP amendments:

- Energy System Impacts
- Employment Impacts
- Small Business Impacts Analysis

7.2 Energy System Impacts Analysis of Proposed NSPS

We use the National Energy Modeling System (NEMS) to estimate the impacts of the proposed NSPS on the U.S. energy system. The impacts we estimate include changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas. We evaluate whether and to what extent the increased production costs imposed by the NSPS might alter the mix of fuels consumed at a national level. With this information we estimate how the changed fuel mix affects national level CO_2-equivalent greenhouse gas emissions from energy sources. We additionally combine these estimates of changes in CO_2-equivalent greenhouse gas emissions from energy sources and emissions co-reductions of methane from the engineering analysis with NEMS analysis to estimate the net change in CO_2-equivalent greenhouse gas emissions from energy-related sources, but this analysis is reserved for the secondary environmental impacts analysis within Section 4.

A brief conceptual discussion about our energy system impacts modeling approach is necessary before going into detail on NEMS, how we implemented the regulatory impacts, and results. Economically, it is possible to view the recovered natural gas as an explicit output or as contributing to an efficiency gain at the producer level. For example, the analysis for the proposed NSPS shows that about 97 percent of the natural gas captured by emissions controls suggested by the rule is captured by performing RECs on new and existing wells that are completed after being hydraulically fractured. The assumed $4/Mcf price for natural gas is the price paid to producers at the wellhead. In the natural gas industry, production is metered at or very near to the wellhead, and producers are paid based upon this metered production. Depending on the situation, the gas captured by RECs is sent through a temporary or permanent meter. Payments for the gas are typically made within 30 days.

To preview the energy systems modeling using NEMS, results show that after economic adjustments to the new regulations are made by producers, the captured natural gas represents both increased output (a slight increment in aggregate production) and increased efficiency (producing slightly more for less). However, because of differing objectives for the regulatory analysis we treat the associated savings differently in the engineering cost analysis (as an explicit output) and in NEMS (as an efficiency gain).

In the engineering cost analysis, it is necessary to estimate the expected costs and revenues from implementing emissions controls at the unit level. Because of this, we estimate the net costs as expected costs minus expected revenues for representative units. On the other hand, NEMS models the profit maximizing behavior of representative project developers at a drilling project level. The net costs of the regulation alter the expected discounted cash flow of drilling and implementing oil and gas projects, and the behavior of the representative drillers adjusts accordingly. While in the regulatory case natural gas drilling has become more efficient because of the gas recovery, project developers still interact with markets for which supply and demand are simultaneously adjusting. Consequently, project development adjusts to a new equilibrium. While we believe the cost savings as measured by revenues from selling recovered gas (engineering costs) and measured by cost savings from averted production through efficiency gains (energy economic modeling) are approximately the same, it is important to note that the engineering cost analysis and the national-level cost estimates do not incorporate economic feedbacks such as supply and demand adjustments.

7.2.1 Description of the Department of Energy National Energy Modeling System

NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration of the U.S. Department of Energy. NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy economy from the current year to 2035. DOE first developed NEMS in the 1980s, and the model has been undergone frequent updates and expansion since. DOE uses the modeling system extensively to produce issue reports, legislative analyses, and respond to Congressional inquiries.

EIA is legally required to make the NEMS system source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of the NEMS model, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues.

NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions. The dynamics of the energy system are governed by assumptions about energy and environmental policies, technological developments, resource supplies, demography, and macroeconomic conditions. An overview of the model and complete documentation of NEMS can be found at <http://www.eia.doe.gov/oiaf/aeo/overview/index.html>.

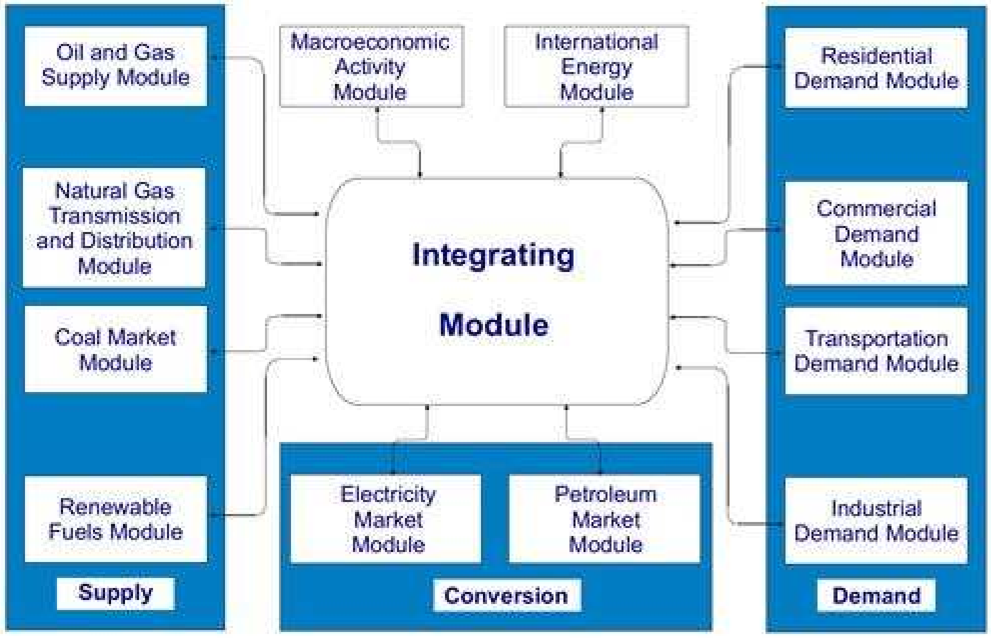

Figure 7-1 Organization of NEMS Modules (source: U.S. Energy Information Administration)

NEMS is a large-scale, deterministic mathematical programming model. NEMS iteratively solves multiple models, linear and non-linear, using nonlinear Gauss-Seidel methods (Gabriel et al. 2001). What this means is that NEMS solves a single module, holding all else constant at provisional solutions, then moves to the next model after establishing an updated provisional solution.

NEMS provides what EIA refers to as “mid-term” projections to the year 2035. However, as this RIA is concerned with estimating regulatory impacts in the first year of full implementation, our analysis focuses upon estimated impacts in the year 2015, with regulatory costs first imposed in 2011. For this RIA, we draw upon the same assumptions and model used in the Annual Energy Outlook 2011.[51] The RIA baseline is consistent with that of the Annual Energy Outlook 2011 which is used extensively in Section 2 in the Industry Profile.

[51] Assumptions for the 2011 Annual Energy Outlook can be found at <http://www.eia.gov/forecasts/aeo/assumptions/index.cfm>.

7.2.2 Inputs to National Energy Modeling System

To model potential impacts associated with the NSPS, we modified oil and gas production costs within the Oil and Gas Supply Module (OGSM) of NEMS and domestic and Canadian natural gas production within the Natural Gas Transmission and Distribution Module (NGTDM). The OGSM projects domestic oil and gas production from onshore, offshore, Alaskan wells, as well as having a smaller-scale treatment of Canadian oil and gas production (U.S. EIA, 2010). The treatment of oil and gas resources is detailed in that oil, shale oil, conventional gas, shale gas, tight sands gas, and coalbed methane (CBM) are explicitly modeled. New exploration and development is pursued in the OGSM if the expected net present value of extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern finding and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the Oil and Natural Gas NSPS. We are able to target additional expenditures for environmental controls expected to be required by the NSPS on new exploratory and developmental oil and gas production activities, as well as add additional costs to existing projects. We model the impacts of additional environmental costs, as well as the impacts of additional product recovery. We explicitly model the additional natural gas recovered when implementing the NSPS regulatory options. However, we are unable to explicitly model the additional production of condensates expected to be recovered by reduced emissions completions, although we incorporate expected revenues from the condensate recovery in the economic evaluation of new drilling projects.

While the oil production simulated by the OGSM is sent to the refining module (the Petroleum Market Module), simulated natural gas production is sent to a transmission and distribution network captured in the NGTDM. The NGTDM balances gas supplies and prices and "negotiates" supply and consumption to determine a regional equilibrium between supply, demand and prices, including imports and exports via pipeline or LNG. Natural gas transmitted through a simplified arc-node representation of pipeline infrastructure based upon pipeline economics.

7.2.2.1 Compliance Costs for Oil and Gas Exploration and Production

As the NSPS affects new emissions sources, we chose to estimate impacts on new exploration and development projects by adding costs of environmental regulation to the algorithm that evaluates the profitability of new projects. Additional NSPS costs associated with reduced emission completions and future recompletions for new wells are added to drilling, completion, and stimulation costs, as these are, in effect, associated with activities that occur within a single time period, although they may be repeated periodically, as in the case of recompletions. Costs required for reduced emissions recompletions on existing wells are added to stimulation expenses for existing wells exclusively. Other costs are operations and maintenance-type costs and are added to fixed operation and maintenance (O&M) expenses associated with new projects. The one-shot and continuing O&M expenses are estimated and entered on a per well basis, depending on whether the costs would apply to oil wells, natural gas wells, both oil and natural gas wells, or a subset of either. We base the per well cost estimates on the engineering costs including revenues from additional product recovery. This approach is appropriate given the structure of the NEMS algorithm that estimates the net present value of drilling projects.

One concern in basing the regulatory costs inputs into NEMS on the net cost of the compliance activity (estimated annualized cost of compliance minus estimated revenue from product recovery) is that potential barriers to obtaining capital may not be adequately incorporated in the model. However, in general, potential barriers to obtaining additional capital should be reflected in the annualized cost via these barriers increasing the cost of capital. With this in mind, assuming the estimates of capital costs and product recovery are valid, the NEMS results will reflect barriers to obtaining the retired capital. A caveat to this is that the estimated unit-level capital costs of controls which are newly required at a national-level as a result of the proposed regulation—RECs, for example—may not incorporate potential additional transitional costs as the supply of control equipment adjusts to new demand.

Table 7-1 shows the incremental O&M expenses that accrue to new drilling projects as a result of producers having to comply with the relevant NSPS option. We estimate those costs as a function of new wells expected to be drilled in a representative year. To arrive at estimates of the per well costs, we first identify which emissions reductions will apply primarily to crude oil wells, to natural gas wells, or to both crude oil and natural gas wells. Based on the baseline projections of successful completions in 2015, we used 19,097 new natural gas wells and 12,193 new oil wells as the basis of these calculations. We then divide the estimated compliance costs for the given emissions point (from Table 3-3) by the appropriate number of expected new wells in the year of analysis. The result yields an approximation of a per well compliance costs. We assume this approximation is representative of the incremental cost faced by a producer when evaluating a prospective drilling project.

Like the engineering analysis, we assume that hydraulically fractured well completions and recompletions will be required of wells drilled into tight sand, shale gas, and coalbed methane formations. While costs for well recompletions reflect the cost of a single recompletion, the engineering cost analysis assumed that one in ten new wells drilled after the implementation of the promulgation and implementation of the NSPS are completed using hydraulic fracturing will receive a recompletion in any given year using hydraulic fracturing. Meanwhile, within NEMS, wells are assumed to be stimulated every five years. We assume these more frequent stimulations are less intensive than stimulation using hydraulic fracturing but add costs such that the recompletions costs reflect the same assumptions as the engineering analysis. In entering compliance costs into NEMS, we also account for reduced emissions completions, completion combustion, and recompletions performed in absence of the regulation, using the same assumptions as the engineering costs analysis (Table 7-2).

Table 7-1 Summary of Additional Annualized O&M Costs (on a Per New Well Basis) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Well Costs (2008$) Option 1	Option 2 (Proposed)	Option 3	Wells Applied To in NEMS
Equipment Leaks					
Well Pads	Subpart VV	Not in Option	Not in Option	$3,552	Oil and Gas
Gathering and Boosting Stations	Subpart VV	Not in Option	Not in Option	$806	Gas
Processing Plants	Subpart VVa	Not in Option	$56	$56	None
Transmission Compressor Stations	Subpart VV	Not in Option	Not in Option	$320	Gas
Reciprocating Compressors					
Well Pads	Annual Monitoring/ Maintenance	Not in Option	Not in Option	Not in Option	None
Gathering/Boosting Stations	AMM	$17	$17	$17	Gas
Processing Plants	AMM	$12	$12	$12	Gas
Transmission Compressor Stations	AMM	$19	$19	$19	Gas
Underground Storage Facilities	AMM	$1	$1	$1	Gas
Centrifugal Compressors					
Processing Plants	Dry Seals/Route to Process or Control	-$113	-$113	-$113	Gas
Transmission Compressor Stations	Dry Seals/Route to Process or Control	-$62	-$62	-$62	Gas
Pneumatic Controllers -					
Oil and Gas Production	Low Bleed/Route to Process	-$698	-$698	-$698	Oil and Gas
Natural Gas Transmission and Storage	Low Bleed/Route to Process	$0.10	$0.10	$0.10	Gas
Storage Vessels					
High Throughput	95% control	$143	$143	$143	Oil and Gas
Low Throughput	95% control	Not in Option	Not in Option	Not in Option	None

Table 7-2 Summary of Additional Per Completion/Recompletion Costs (2008$) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Completion/Recompletion Costs (2008$) Option 1	Option 2 (proposed)	Option 3	Wells Applied To in NEMS
Well Completions					
Hydraulically Fractured Gas Wells	REC	-$1,275	-$1,275	-$1,275	New Tight Sand/ Shale Gas/CBM
Conventional Gas Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Oil Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Well Recompletions					
Hydraulically Fractured Gas Wells (post-NSPS wells)	REC	-$1,535	-$1,535	-$1,535	Existing Tight Sand/ Shale Gas /Coalbed Methane
Hydraulically Fractured Gas Wells (existing wells)	REC	Not in Option	-$1,535	-$1,535	Existing Tight Sand/ Shale Gas /Coalbed Methane
Conventional Gas Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Oil Wells	Combustion	Not in Option	Not in Option	Not in Option	None

7.2.2.2 Adding Averted Methane Emissions into Natural Gas Production

A significant benefit of controlling VOC emissions from oil and natural gas production is that methane that would otherwise be lost to the atmosphere can be directed into the natural gas production stream. We chose to model methane capture in NEMS as an increase in natural gas industry productivity, ensuring that, within the model, natural gas reservoirs are not decremented by production gains from methane capture. We add estimates of the quantities of methane captured (or otherwise not vented or combusted) to the base quantities that the OGSM model supplies to the NGTDM model. We subdivide the estimates of commercially valuable averted emissions by region and well type in order to more accurately portray the economics of implementing the environmental technology. Adding the averted methane emissions in this manner has the effect of moving the natural gas supply curve to the right an increment consistent with the technically achievable emissions transferred into the production stream as a result of the proposed NSPS.

For all control options, with the exception of recompletions on existing wells, we enter the increased natural gas recovery into NEMS on a per-well basis for new wells, following an estimation procedure similar to that of entering compliance costs into NEMS on a per well basis for new wells. Because each NSPS Option is composed of a different suite of emissions controls, the per-well natural gas recovery value for new wells is different across wells. For Option 1, we estimate that natural gas recovery is 5,739 Mcf per well. For Option 2 and Option 3, we estimate that natural gas recovery is 5,743 Mcf per well. We make a simplifying assumption that natural gas recovery accruing to new wells accrues to new wells in shale gas, tight sands, and CBM fields. We make these assumptions because new wells in these fields are more likely to satisfy criteria such that RECs are required, which contributed that large majority of potential natural gas recovery. Note that these per well natural gas recovery is lower than the per well estimate when RECs are implemented. The estimate is lower because we account for emissions that are combusted, RECs that are implemented absent Federal regulation, as well as the likelihood that natural gas is used during processing and transmission or reinjected.

We treat the potential natural gas recovery associated with recompletions of existing wells (in proposed Option 2 and Option 3) differently in that we estimated the natural gas recovery by natural gas resource type and NSPS Option based on a combination of the engineering analysis and production patterns from the 2011 Annual Energy Outlook. We estimate that additional natural gas product recovered by recompleting existing wells in proposed Option 2 and Option 3 to be 78.7 bcf, with 38.4 bcf accruing to shale gas, 31.4 bcf accruing to tight sands, and 8.9 bcf accruing to CBM, respectively. This quantity is distributed within the NGTDM to reflect regional production by resource type.

7.2.2.3 Fixing Canadian Drilling Costs to Baseline Path

Domestic drilling costs serve as a proxy for Canadian drilling costs in the Canadian oil and natural gas sub-model within the NGTDM. This implies that, without additional modification, additional costs imposed by a U.S. regulation will also impact drilling decisions in Canada.   Changes in international oil and gas trade are important in the analysis, as a large majority of natural gas imported into the U.S. originates in Canada. To avoid this problem, we fixed Canadian drilling costs using U.S. drilling costs from the baseline scenario. This solution enables a more accurate analysis of U.S.-Canada energy trade, as increased drilling costs in the U.S. as a result of environmental regulation serve to increase Canada's comparative advantage.

7.2.3 Energy System Impacts

As mentioned earlier, we estimate impacts to drilling activity, reserves, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas, as well as whether and to what extent the NSPS might alter the mix of fuels consumed at a national level. In each of these estimates, we present estimates for the baseline year of 2015 and results for the three NSPS options. For context, we provide estimates of production activities in 2011.

7.2.3.1 Impacts on Drilling Activities

Because the potential costs of the NSPS options are concentrated in production activities, we first report estimates of impacts on crude oil and natural gas drilling activities and production and price changes at the wellhead. Table 7-3 presents estimates of successful wells drilled in the U.S. in 2015, the analysis year, for the three NSPS options and in the baseline.

Table 7-3 Successful Oil and Gas Wells Drilled, NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Successful Wells Drilled					
Natural Gas	16,373	19,097	19,191	18,935	18,872
Crude Oil	10,352	11,025	11,025	11,025	11,028
Total	**26,725**	**30,122**	**30,216**	**29,960**	**29,900**
% Change in Successful Wells Drilled from Baseline					
Natural Gas			0.49%	-0.85%	-1.18%
Crude Oil			0.00%	0.00%	0.03%
Total			**0.31%**	**-0.54%**	**-0.74%**

We estimate that the number of successful natural gas wells drilled increases slightly for Option 1, while the number of successful crude oil wells drilled does not change. In Options 2, where costs of the natural gas processing plants equipment leaks standard and REC requirements for existing wells apply, natural gas wells drilling is forecast to decrease less than 1 percent, while crude oil drilling does not change. For Option 3, where the addition of an additional equipment leak standards add to the incremental costs, natural gas well drilling is estimated to decrease about 1.2%. The number of successful crude oil wells drilled under Option 3 increases very slightly. While it may seem counter-intuitive that the number of successful crude wells increased as costs increase, it is important to note that crude oil and natural gas drilling compete with each other for factors of production, such as labor and material. The environmental compliance costs of the NSPS options predominantly affect natural gas drilling. As natural gas drilling declines, for example, as a result of increased compliance costs, crude oil drilling may increase because of the increased availability of labor and material, as well as the likelihood that crude oil can substitute for natural gas to some extent.

Table 7-4 presents the forecast of successful wells by well type, for onshore drilling in the lower 48 states. The results show that conventional well drilling is unaffected by the regulatory options, as reduced emission completion and completion combustion requirements are directed not toward wells in conventional reserves but toward wells that are hydraulically fractured, the wells in so-called unconventional reserves. The impacts on drilling tight sands, shale gas, and coalbed methane vary by option.

Table 7-4 Successful Wells Drilled by Well Type (Onshore, Lower 48 States), NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Successful Wells Drilled					
Conventional Gas Wells	7,267	7,607	7,607	7,607	7,607
Tight Sands	2,441	2,772	2,791	2,816	2,780
Shale Gas	5,007	7,022	7,074	6,763	6,771
Coalbed Methane	1,593	1,609	1,632	1,662	1,627
Total	**16,308**	**19,010**	**19,104**	**18,849**	**18,785**
% Change in Successful Wells Drilled from Baseline					
Conventional Gas Wells			0.00%	0.00%	0.00%
Tight Sands			0.70%	1.60%	0.29%
Shale Gas			0.74%	-3.68%	-3.57%
Coalbed Methane			1.44%	3.28%	1.09%
Total			**0.50%**	**-0.85%**	**-1.18%**

Well drilling in tight sands is estimated to increase slightly from the baseline under all three options, 0.70 percent, 1.60 percent, and 0.29% for Options 1, 2, and 3, respectively. Wells in CBM reserves are also estimated to increase from the baseline under all three options, or 1.44 percent, 3.28 percent, and 1.09 percent for Options 1, 2, and 3, respectively. However, drilling in shale gas is forecast to decline from the baseline under Options 2 and 3, by 3.68 percent and 3.57 percent, respectively.

7.2.3.2 Impacts on Production, Prices, and Consumption

Table 7-5 shows estimates of the changes in the domestic production of natural gas and crude oil under the NSPS options, as of 2015. Domestic crude oil production is not forecast to change under any of the three regulatory options, again because impacts on crude oil drilling of the NSPS are expected to be negligible.

Table 7-5 Annual Domestic Natural Gas and Crude Oil Production, NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Domestic Production					
Natural Gas (trillion cubic feet)	21.05	22.43	22.47	22.45	22.44
Crude Oil (million barrels/day)	5.46	5.81	5.81	5.81	5.81
% Change in Domestic Production from Baseline					
Natural Gas			0.18%	0.09%	0.04%
Crude Oil			0.00%	0.00%	0.00%

Natural gas production, on the other hand, increases under all three regulatory options for the NSPS from the baseline. A main driver for these increases is the additional natural gas recovery engendered by the control requirements. Another driver for the increases under Option 1 is the increase in natural gas well drilling. While we showed earlier that natural gas drilling is estimated to decline under Options 2 and 3, the increased natural gas recovery is sufficient to offset the production loss from relatively fewer producing wells.

For the proposed option, the NEMS analysis shown in Table 7-5 estimates a 20 bcf increase in domestic natural gas production. This amount is less than the amount estimated in the engineering analysis to be captured by emissions controls implemented as a result of the proposed NSPS (approximately 180 bcf). This difference is because NEMS models the adjustment of energy markets to the now relatively more efficient natural gas production sector. At the new natural gas supply and demand equilibrium in 2015, the modeling estimates 20 bcf more gas is produced at a relatively lower wellhead price (which will be presented momentarily). However, at the new equilibrium, producers implementing emissions controls still capture and sell approximately 180 bcf of natural gas. For example, as shown in Table 7-4, about 11,200 new unconventional natural gas wells are completed under the proposed NSPS; using assumptions from the engineering cost analysis about RECs required under State regulations and exploratory wells exempted from REC requirements, about 9,000 NSPS-required RECs would be performed on new natural gas well completions, according to the NEMS analysis. This recovered natural gas substitutes for natural gas that would be produced from the ground absent the rule. In effect, then, about 160 bcf of natural gas that would have been extracted and emitted into the atmosphere is left in the formation for future extraction.

As we showed for natural gas drilling, Table 7-6 shows natural gas production from onshore wells in the lower 48 states by type of well, predicted for 2015, the analysis year. Production from conventional natural gas wells and CBM wells are estimated to increase under all NSPS regulatory options. Production from shale gas reserves is estimated to decrease under Options 2 and 3, however, from the baseline projection. Production from tight sands is forecast to decline slightly under Option 1.

Table 7-6 Natural Gas Production by Well Type (Onshore, Lower 48 States), NSPS Options

	2011	Future NSPS Scenario, 2015 Baseline	Option 1	Option 2 (Proposed)	Option 3
Natural Gas Production by Well Type (trillion cubic feet)					
Conventional Gas Wells	4.06	3.74	3.75	3.76	3.76
Tight Sands	5.96	5.89	5.87	6.00	6.00
Shale Gas	5.21	7.20	7.26	7.06	7.06
Coalbed Methane	1.72	1.67	1.69	1.72	1.71
Total	**16.95**	**18.51**	**18.57**	**18.54**	**18.53**
% Change in Natural Gas Production by Well Type from Baseline					
Conventional Gas Wells			0.32%	0.42%	0.48%
Tight Sands			-0.43%	1.82%	1.72%
Shale Gas			0.73%	-1.97%	-1.93%
Coalbed Methane			1.07%	2.86%	2.60%
Total			0.31%	0.16%	0.13%

Note: Totals may not sum due to independent rounding.

Overall, of the regulatory options, the proposed Option 2 is estimated to have the highest natural gas production from onshore wells in the lower 48 states, showing a 1.2% increase over the baseline projection.

Table 7-7 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states, estimated for 2015, the year of analysis. All NSPS options show a decrease in wellhead natural gas and crude oil prices. The decrease in wellhead natural gas price form the baseline is attributable largely to the increased productivity of natural gas wells as a result of capturing a portion of completion emissions (in Options 1, 2, and 3) and in capturing recompletion emissions (in Options 2 and 3).

Table 7-7 Lower 48 Average Natural Gas and Crude Oil Wellhead Price, NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Lower 48 Average Wellhead Price					
Natural Gas (2008$ per Mcf)	4.07	4.22	4.18	4.18	4.19
Crude Oil (2008$ per barrel)	83.65	94.60	94.59	94.58	94.58
% Change in Lower 48 Average Wellhead Price from Baseline					
Natural Gas			-0.94%	-0.94%	-0.71%
Crude Oil			-0.01%	-0.02%	-0.02%

Table 7-8 presents estimates of the price of natural gas to final consumers in 2008 dollars per million BTU. The production price decreases estimated across NSPS are largely passed on to consumers but distributed unequally across consuming sectors. Electric power sector consumers of natural gas are estimated to receive the largest price decrease while the transportation and residential sectors are forecast to receive the smallest price decreases.

Table 7-8 Delivered Natural Gas Prices by Sector (2008$ per million BTU), 2015, NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Delivered Prices (2008$ per million BTU)					
Residential	10.52	10.35	10.32	10.32	10.33
Commercial	9.26	8.56	8.52	8.53	8.54
Industrial	4.97	5.08	5.05	5.05	5.06
Electric Power	4.81	4.77	4.73	4.74	4.75
Transportation	12.30	12.24	12.20	12.22	12.22
Average	**6.76**	**6.59**	**6.55**	**6.57**	**6.57**
% Change in Delivered Prices from Baseline					
Residential			**-0.29%**	**-0.29%**	**-0.19%**
Commercial			**-0.47%**	**-0.35%**	**-0.23%**
Industrial			**-0.59%**	**-0.59%**	**-0.39%**
Electric Power			**-0.84%**	**-0.63%**	**-0.42%**
Transportation			**-0.33%**	**-0.16%**	**-0.16%**
Average			**-0.60%**	**-0.41%**	**-0.30%**

Final consumption of natural gas is also estimated to increase in 2015 from the baseline under all NSPS options, as is shown on Table 7-9. Like delivered price, the consumption shifts are distributed differently across sectors.

Table 7-9 Natural Gas Consumption by Sector, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Consumption (trillion cubic feet)					
Residential	4.76	4.81	4.81	4.81	4.81
Commercial	3.22	3.38	3.38	3.38	3.38
Industrial	6.95	8.05	8.06	8.06	8.06
Electric Power	7.00	6.98	7.00	6.98	6.97
Transportation	0.03	0.04	0.04	0.04	0.04
Pipeline Fuel	0.64	0.65	0.65	0.66	0.66
Lease and Plant Fuel	1.27	1.20	1.21	1.21	1.21
Total	**23.86**	**25.11**	**25.15**	**25.14**	**25.13**
% Change in Consumption from Baseline					
Residential			0.00%	0.00%	0.00%
Commercial			0.00%	0.00%	0.00%
Industrial			0.12%	0.12%	0.12%
Electric Power			0.29%	0.00%	-0.14%
Transportation			0.00%	0.00%	0.00%
Pipeline Fuel			0.00%	1.54%	1.54%
Lease and Plant Fuel			0.83%	0.83%	0.83%
Total			**0.16%**	**0.12%**	**0.08%**

Note: Totals may not sum due to independent rounding.

7.2.3.3 Impacts on Imports and National Fuel Mix

The NEMS modeling shows that impacts from all NSPS options are not sufficiently large to affect the trade balance of natural gas. As shown in Table 7-10, estimates of crude oil and natural gas imports do not vary from the baseline in 2015 for each regulatory option.

Table 7-10 Net Imports of Natural Gas and Crude Oil, NSPS Options

	2011	Future NSPS Scenario, 2015 Baseline	Option 1	Option 2 (Proposed)	Option 3
Net Imports					
Natural Gas (trillion cubic feet)	2.75	2.69	2.69	2.69	2.69
Crude Oil (million barrels/day)	9.13	8.70	8.70	8.70	8.70
% Change in Net Imports					
Natural Gas			0.00%	0.00%	0.00%
Crude Oil			0.00%	0.00%	0.00%

Table 7-11 evaluates estimates of energy consumption by energy type at the national level for 2015, the year of analysis. All three NSPS options are estimated to have small effects at the national level. For Option 1, we estimate an increase in 0.02 quadrillion BTU in 2015, a 0.02 percent increase. The percent contribution of natural gas and biomass is projected to increase, while the percent contribution of liquid fuels and coal is expected to decrease under Option 1. Meanwhile, under the proposed Options 2, total energy consumption is also forecast to rise 0.02 quadrillion BTU, with increase coming from natural gas primarily, with an additional small increase in coal consumption. Under Option 3, total energy consumption is forecast to rise 0.01 quadrillion BTU, or 0.01%, with a slight decrease in liquid fuel consumption from the baseline, but increases in natural gas and coal consumption.

Table 7-11 Total Energy Consumption by Energy Type (Quadrillion BTU), NSPS Options

		Future NSPS Scenario, 2015			
	2011	**Baseline**	**Option 1**	**Option 2 (Proposed)**	**Option 3**
Consumption (quadrillion BTU)					
Liquid Fuels	37.41	39.10	39.09	39.10	39.09
Natural gas	24.49	25.77	25.82	25.79	25.79
Coal	20.42	19.73	19.71	19.74	19.74
Nuclear Power	8.40	8.77	8.77	8.77	8.77
Hydropower	2.58	2.92	2.92	2.92	2.92
Biomass	2.98	3.27	3.28	3.27	3.27
Other Renewable Energy	1.72	2.14	2.14	2.14	2.14
Other	0.30	0.31	0.31	0.31	0.31
Total	**98.29**	**102.02**	**102.04**	**102.04**	**102.03**
% Change in Consumption from Baseline					
Liquid Fuels			-0.03%	0.00%	-0.03%
Natural Gas			0.19%	0.08%	0.08%
Coal			-0.10%	0.05%	0.05%
Nuclear Power			0.00%	0.00%	0.00%
Hydropower			0.00%	0.00%	0.00%
Biomass			0.31%	0.00%	0.00%
Other Renewable Energy			0.00%	0.00%	0.00%
Other			0.00%	0.00%	0.00%
Total			**0.02%**	**0.02%**	**0.01%**

Note: Totals may not sum due to independent rounding.

With the national profile of energy consumption estimated to change slightly under the regulatory options in 2015, the year of analysis, it is important to examine whether aggregate energy-related CO_2-equivalent greenhouse gas (GHG) emissions also shift. A more detailed discussion of changes in CO_2-equivalent GHG emissions from a baseline is presented within the benefits analysis in Section 4. Here, we present a single NEMS-based table showing estimated changes in energy-related “consumer-side” GHG emissions. We use the terms “consumer-side” emissions to distinguish emissions from the consumption of fuel from emissions specifically associated with the extraction, processing, and transportation of fuels in the oil and natural gas sector under examination in this RIA. We term the emissions associated with extraction, processing, and transportation of fuels “producer-side” emissions.

Table 7-12 Modeled Change in Energy-related "Consumer-Side" CO_2-equivalent GHG Emissions

	2011	Future NSPS Scenario, 2015 Baseline	Option 1	Option 2 (Proposed)	Option 3
Energy-related CO_2-equivalent GHG Emissions (million metric tons CO_2-equivalent)					
Petroleum	2,359.59	2,433.60	2,433.12	2,433.49	2,433.45
Natural Gas	1,283.78	1,352.20	1,354.47	1,353.19	1,352.87
Coal	1,946.02	1,882.08	1,879.84	1,883.24	1,883.30
Other	11.99	11.99	11.99	11.99	11.99
Total	**5,601.39**	**5,679.87**	**5,679.42**	**5,681.91**	**5,681.61**
% Change in Energy-related CO_2-equivalent GHG Emissions from Baseline					
Petroleum			-0.02%	0.00%	-0.01%
Natural Gas			0.17%	0.07%	0.05%
Coal			-0.12%	0.06%	0.06%
Other			0.00%	0.00%	0.00%
Total			**-0.01%**	**0.04%**	**0.03%**

Note: Excludes "producer-side" emissions and emissions reductions estimated to result from NSPS alternatives. Totals may not sum due to independent rounding.

As is shown in Table 7-12, NSPS Option 1 is predicted to slightly decrease aggregate consumer-side energy-related CO_2-equivalent GHG emissions, by about 0.01 percent, while the mix of emissions shifts slightly away from coal and petroleum toward natural gas. Proposed Options 2 and 3 are estimated to increase consumer-side aggregate energy-related CO_2-equivalent GHG emissions by about 0.04 and 0.03 percent, respectively, mainly because consumer-side emissions from natural gas and coal combustion increase slightly.

7.3 Employment Impact Analysis

While a standalone analysis of employment impacts is not included in a standard cost-benefit analysis, such an analysis is of particular concern in the current economic climate of sustained high unemployment. Executive Order 13563, states, "Our regulatory system must protect public health, welfare, safety, and our <u>environment</u> while promoting economic growth, innovation, competitiveness, and <u>job creation</u>" (emphasis added). Therefore, we seek to inform the discussion of labor demand and job impacts by providing an estimate of the employment impacts of the proposed regulations using labor requirements for the installation, operation, and maintenance of control requirements, as well as reporting and recordkeeping requirements. Unlike several recent RIAs, however, we do not provide employment impacts estimates based on the study by Morgenstern et al. (2002); we discuss this decision after presenting estimates of the labor requirements associated with reporting and recordkeeping and the installation, operation, and maintenance of control requirements.

7.3.1 Employment Impacts from Pollution Control Requirements

Regulations set in motion new orders for pollution control equipment and services. New categories of employment have been created in the process of implementing regulations to make our air safer to breathe. When a new regulation is promulgated, a response of industry is to order pollution control equipment and services in order to comply with the regulation when it becomes effective. Revenue and employment in the environmental technology industry have grown steadily between 2000 and 2008, reaching an industry total of approximately $300 billion in revenues and 1.7 million employees in 2008.[52] While these revenues and employment figures represent gains for the environmental technologies industry, they are costs to the regulated industries required to install the equipment. Moreover, it is not clear the 1.7 million employees in 2008 represent new employment as opposed to workers being shifted from the production of goods and services to environmental compliance activities.

Once the equipment is installed, regulated firms hire workers to operate and maintain the pollution control equipment – much like they hire workers to produce more output. Morgenstern et al. (2002) examined how regulated industries respond to regulation. The authors found that, on average for the industries they studied, employment increases in regulated firms. Of course, these firms may also reassign existing employees to perform these activities.

[52] In 2008, the industry totaled approximately $315 billion in revenues and 1.9 million employees including indirect employment effects, pollution abatement equipment production employed approximately 4.2 million workers in 2008. These indirect employment effects are based on a multiplier for indirect employment = 2.24 (1982 value from Nestor and Pasurka - approximate middle of range of multipliers 1977-1991). Environmental Business International (EBI), Inc., San Diego, CA. Environmental Business Journal, monthly (copyright). http://www.ebiusa.com/ EBI data taken from the Department of Commerce International Trade Administration Environmental Industries Fact Sheet from April 2010: http://web.ita.doc.gov/ete/eteinfo.nsf/068f3801d047f26e85256883006ffa54/4878b7e2fc08ac6d85256883006c452c?OpenDocument

Environmental regulations support employment in many basic industries. In addition to the increase in employment in the environmental protection industry (via increased orders for pollution control equipment), environmental regulations also support employment in industries that provide intermediate goods to the environmental protection industry. The equipment manufacturers, in turn, order steel, tanks, vessels, blowers, pumps, and chemicals to manufacture and install the equipment. Bezdek et al. (2008) found that investments in environmental protection industries create jobs and displace jobs, but the net effect on employment is positive.

The focus of this part of the analysis is on labor requirements related to the compliance actions of the affected entities within the affected sector. We do not estimate any potential changes in labor outside of the oil and natural gas sector. This analysis estimates the employment impacts due to the installation, operation, and maintenance of control equipment, as well as employment associated with new reporting and recordkeeping requirements.

It is important to highlight that unlike the typical case where to reduce a bad output (i.e., emissions) a firm often has to reduce production of the good output, many of the emission controls required by the proposed NSPS will simultaneously increase production of the good output and reduce production of bad outputs. That is, these controls jointly produce environmental improvements and increase output in the regulated sector. New labor associated with implementing these controls to comply with the new regulations can also be viewed as additional labor increasing output while reducing undesirable emissions.

No estimates of the labor used to manufacture or assemble pollution control equipment or to supply the materials for manufacture or assembly are included because U.S. EPA does not currently have this information. The employment analysis uses a bottom-up engineering-based methodology to estimate employment impacts. The engineering cost analysis summarized in this RIA includes estimates of the labor requirements associated with implementing the proposed regulations. Each of these labor changes may either be required as part of an initial effort to comply with the new regulation or required as a continuous or annual effort to maintain compliance. We estimate up-front and continual, annual labor requirements by estimating hours of labor required and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

In other employment analyses U.S. EPA distinguished between employment changes within the regulated industry and those changes outside the regulated industry (e.g. a contractor from outside the regulated facility is employed to install a control device). For this regulation however, the structure of the industry makes this difficult. The mix of in-house versus contracting services used by firms is very case-specific in the oil and natural gas industry. For example, sometimes the owner of the well, processing plant, or transmission pipelines uses in–house employees extensively in daily operations, while in other cases the owner relies on outside contractors for many of these services. For this reason, we make no distinction in the quantitative estimates between labor changes within and outside of the regulated sector.

The results of this employment estimate are presented in Table 7-13 for the proposed NSPS and in Table 7-14 for the proposed NESHAP amendments. The tables breaks down the installation, operation, and maintenance estimates by type of pollution control evaluated in the RIA and present both the estimated hours required and the conversion of this estimate to FTE. For both the proposed NSPS and NESHAP amendments, reporting and recordkeeping requirements were estimated for the entire rules rather than by anticipated control requirements; the reporting and recordkeeping estimates are consistent with estimates EPA submitted as part of its Information Collection Request (ICR).

The up-front labor requirement is estimated at 230 FTEs for the proposed NSPS and about 120 FTEs for the proposed NESHAP amendments. These up-front FTE labor requirements can be viewed as short-term labor requirements required for affected entities to comply with the new regulation. Ongoing requirements are estimated at about 2,400 FTEs for the proposed NSPS and about 102 FTEs for the proposed NESHAP amendments. These ongoing FTE labor requirements can be viewed as sustained labor requirements required for affected entities to continuously comply with the new regulation

Two main categories contain the majority of the labor requirements for the proposed rules: implementing reduced emissions completions (RECs) and reporting and recordkeeping requirements for the proposed NSPS. Also, note that pneumatic controllers have no up-front or continuing labor requirements. While the controls do require labor for installation, operation, and maintenance, the required labor is less than that of the controllers that would be used absent the regulation. In this instance, we assume the incremental labor requirements are zero.

Implementing RECs are estimated to require about 2,230 FTE, over 90 percent of the total continuing labor requirements for the proposed NSPS.[53] We denote REC-related requirements as continuing, or annual, as the REC requirements will in fact recur annually, albeit at different wells each year. The REC requirements are associated with certain new well completions or existing well recompletions, which while individual completions occur over a short period of time (days to a few weeks), new wells and other existing wells are completed or recompleted annually. Because of these reasons, we assume the REC-related labor requirements are annual.

7.3.2 Employment Impacts Primarily on the Regulated Industry

In previous RIAs, we transferred parameters from a study by Morgenstern et al. (2002) to estimate employment effects of new regulations. (See, for example, the Regulatory Impact Analysis for the recently finalized Industrial Boilers and CISWI rulemakings, promulgated on February 21, 2011). The fundamental insight of Morgenstern, et al. is that environmental regulations can be understood as requiring regulated firms to add a new output (environmental quality) to their product mixes. Although legally compelled to satisfy this new demand, regulated firms have to finance this additional production with the proceeds of sales of their other (market) products. Satisfying this new demand requires additional inputs, including labor, and may alter the relative proportions of labor and capital used by regulated firms in their production processes.

Morgenstern et al. concluded that increased abatement expenditures in these industries generally do not cause a significant change in employment. Using plant-level Census

[53] As shown on earlier in this section, we project that the number of successful natural gas wells drilled in 2015 will decline slightly from the baseline projection. Therefore, there may be small employment losses in drilling-related employment that partly offset gains in employment from compliance-related activities.

information between the years 1979 and 1991, Morgenstern et al. estimate the size of each effect for four polluting and regulated industries (petroleum refining, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million (1987$) spending on pollution abatement results in a (statistically insignificant) net increase of 1.55 (+/- 2.24) jobs. As a result, the authors conclude that increases in pollution abatement expenditures do not necessarily cause economically significant employment changes.

For this version of RIA for the proposed NSPS and NESHAP amendments, however, we chose not to quantitatively estimate employment impacts using Morgenstern et al. because of reasons specific to the oil and natural gas industry and proposed rules. We believe the transfer of parameter estimates from the Morgenstern et al. study to the proposed NSPS and NESHAP amendments is beyond the range of the study for two reasons.

Table 7-13 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NSPS Option in 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit Up- Front Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total Up- Front Labor Estimate (hours)	Total Annual Labor Estimate (hours)	Up-Front Full-Time Equivalent	Annual Full-Time Equivalent
Well Completions								
Hydraulically Fractured Gas Wells	Reduced Emissions Completion (REC)	9,313	0	218	0	2,025,869	0.0	974.0
Hydraulically Fractured Gas Wells	Combustion	446	0	22	0	9,626	0.0	4.6
Well Recompletions								
Hydraulically Fractured Gas Wells (pre-NSPS wells)	REC	12,050	0	218	0	2,621,126	0.0	1,260.2
Equipment Leaks								
Processing Plants	NSPS Subpart VVA	29	587	887	17,023	25,723	8.2	12.4
Reciprocating Compressors								
Gathering/Boosting Stations	AMM	210	1	1	210	210	0.1	0.1
Processing Plants	AMM	375	1	1	375	375	0.2	0.2
Transmission Compressor Stations	AMM	199	1	1	199	199	0.1	0.1
Underground Storage Facilities	AMM	9	1	1	9	9	0.0	0.0
Centrifugal Compressors								
Processing Plants	Dry Seals/Route to Process or Control	16	355	0	5,680	0	2.7	0.0
Transmission Compressor Stations	Dry Seals/Route to Process or Control	14	355	0	4,970	0	2.4	0.0
Pneumatic Controllers								
Oil and Gas Production	Low Bleed/Route to Process	13,632	0	0	0	0	0.0	0.0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	67	0	0	0	0	0.0	0.0
Storage Vessels								
High Throughput	95% control	304	271	190	82,279	57,582	39.6	27.7
Reporting and Recordkeeping for Complete NSPS		---	---	---	360,443	201,342	173.3	96.8
TOTAL		**---**	**---**	**---**	**471,187**	**4,942,060**	**226.5**	**2,376.0**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 7-14 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NESHAP Amendments in 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit One-time Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total One-Time Labor Estimate (hours)	Total Annual Labor Estimate (hours)	One-time Full-Time Equivalent	Annual Full-Time Equivalent
Small Glycol Dehydrators								
Production	Combustion devices, recovery devices, process modifications	115	27	285	3,108	32,821	1.5	15.8
Transmission	Combustion devices, recovery devices, process modifications	19	27	285	513	5,423	0.2	2.6
Storage Vessels								
Production	Combustion devices, recovery devices	674	311	198	209,753	133,231	100.8	64.1
Reporting and Recordkeeping for Complete NESHAP Amendments		---	---	---	36,462	39,923	17.5	19.2
TOTAL		**---**	**--**	**---**	**249,836**	**211,398**	**120.1**	**101.6**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

First, the possibility that the revenues producers are estimated to receive from additional natural gas recovery as a result of the proposed NSPS might offset the costs of complying with the rule presents challenges to estimating employment effects (see Section 3.2.2.1 of the RIA for a detailed discussion of the natural gas recovery). The Morgenstern et al. paper, for example, is intended to analyze the impact of environmental compliance expenditures on industry employment levels, and it may not be appropriate to draw on their demand and net effects when compliance costs are expected to be negative.

Second, the proposed regulations primarily affect the natural gas production, processing, and transmission segments of the industry. While the natural gas processing segment of the oil and natural gas industry is similar to petroleum refining, which is examined in Morgenstern et al., the production side of the oil and natural gas (drilling and extraction, primarily) and natural gas pipeline transmission are not similar to petroleum refining. Because of the likelihood of negative compliance costs for the proposed NSPS and the segments of the oil and natural gas industry affected by the proposals are not examined by Morgenstern et al., we decided not to use the parameters estimated by Morgenstern et al. to estimate within-industry employment effects for the proposed oil and natural gas NESHAP amendments and NSPS.

That said, the likelihood of additional natural gas recovery is an important component of the market response to the rule, as it is expected that this additional natural gas recovery will reduce the price of natural gas. Because of the estimated fall in prices in the natural gas sector due to the proposed NSPS, prices in other sectors that consume natural gas are likely drop slightly due to the decrease in energy prices. This small production increase and price decrease may have a slight stimulative effect on employment in industries that consume natural gas.

7.4 Small Business Impacts Analysis

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

After considering the economic impact of the proposed rules on small entities for both the NESHAP and NSPS, the screening analysis indicates that these proposed rules will not have a significant economic impact on a substantial number of small entities (or "SISNOSE"). The supporting analyses for these determinations are presented in this section of the RIA.

As discussed in previous sections of the economic impact analysis, under the proposed NSPS, some affected producers are likely to be able to recover natural gas that would otherwise be vented to the atmosphere, as well as recover saleable condensates that would otherwise be emitted. EPA estimates that the revenues from this additional natural gas product recovery will offset the costs of implementing control options implemented as a result of the Proposed NSPS. Because the total costs of the rule are likely to be more than offset by the revenues producers gain from increased natural gas recovery, we expect there will be no SISNOSE arising from the proposed NSPS. However, not all components of the proposed NSPS are estimated to have cost savings. Therefore, we analyze potential impacts to better understand the potential distribution of impacts across industry segments and firms. We feel taking this approach strengthens the determination that there will be no SISNOSE. Unlike the controls for the proposed NSPS, the controls evaluated under the proposed NESHAP amendments do not recover significant quantities of natural gas products.

7.4.1 Small Business National Overview

The industry sectors covered by the final rule were identified during the development of the engineering cost analysis. The U.S. Census Bureau's Statistics of U.S. Businesses (SUSB) provides national information on the distribution of economic variables by industry and enterprise size. The Census Bureau and the Office of Advocacy of the Small Business Administration (SBA) supported and developed these files for use in a broad range of economic analyses.[54] Statistics include the total number of establishments, and receipts for all entities in an industry; however, many of these entities may not necessarily be covered by the final rule. SUSB also provides statistics by enterprise employment and receipt size (Table 7-15 and Table 7-16).

[54] See http://www.census.gov/csd/susb/ and http://www.sba.gov/advocacy/ for additional details.

The Census Bureau's definitions used in the SUSB are as follows:

- *Establishmen*t: A single physical location where business is conducted or where services or industrial operations are performed.
- *Firm:* A firm is a business organization consisting of one or more domestic establishments in the same state and industry that were specified under common ownership or control. The firm and the establishment are the same for single-establishment firms. For each multi-establishment firm, establishments in the same industry within a state will be counted as one firm- the firm employment and annual payroll are summed from the associated establishments.
- *Receipts*: Receipts (net of taxes) are defined as the revenue for goods produced, distributed, or services provided, including revenue earned from premiums, commissions and fees, rents, interest, dividends, and royalties. Receipts exclude all revenue collected for local, state, and federal taxes.
- *Enterprise*: An enterprise is a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the sum of employment of all associated establishments.

Because the SBA's business size definitions (SBA, 2008) apply to an establishment's "ultimate parent company," we assumed in this analysis that the "firm" definition above is consistent with the concept of ultimate parent company that is typically used for SBREFA screening analyses, and the terms are used interchangeably.

Table 7-15 Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

NAICS	NAICS Description	SBA Size Standard (effective Nov. 5, 2010)	Owned by Firms with: < 20 Employees	20-99 Employees	100-499 Employees	Total < 500 Employees	> 500 Employees	Total Firms
Number of Firms by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	5,759	455	115	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	77	9	12	98	41	139
213111	Drilling Oil and Gas Wells	500	1,580	333	97	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	63	12	9	84	42	126
Total Employment by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	21,170	16,583	17,869	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	372	305	1,198	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	5,972	13,787	16,893	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	241	382	1,479	2,102	22,581	24,683
Estimated Receipts by Firm Size ($1000)								
211111	Crude Petroleum and Natural Gas Extraction	500	12,488,688	15,025,443	17,451,805	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	209,640	217,982	1,736,706	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	1,101,481	2,460,301	3,735,652	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	332,177	518,341	1,448,020	2,298,538	18,498,143	20,796,681

Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007." <http://www.census.gov/econ/susb/>

Table 7-16 Distribution of Small and Large Firms by Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

			Percent of Firms		
NAICS	NAICS Description	Total Firms	Small Businesses	Large Businesses	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	6,424	98.5%	1.5%	100.0%
211112	Natural Gas Liquid Extraction	139	70.5%	29.5%	100.0%
213111	Drilling Oil and Gas Wells	2,059	97.6%	2.4%	100.0%
486210	Pipeline Transportation of Natural Gas	126	48.4%	51.6%	100.0%
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	133,286	41.7%	58.3%	100.0%
211112	Natural Gas Liquid Extraction	8,523	22.0%	78.0%	100.0%
213111	Drilling Oil and Gas Wells	106,426	34.4%	65.6%	100.0%
486210	Pipeline Transportation of Natural Gas	24,683	N/A*	N/A*	N/A*
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	194,107,252	23.2%	76.8%	100.0%
211112	Natural Gas Liquid Extraction	39,977,741	5.4%	94.6%	100.0%
213111	Drilling Oil and Gas Wells	23,848,238	30.6%	69.4%	100.0%
486210	Pipeline Transportation of Natural Gas	20,796,681	N/A*	N/A*	N/A*

Note: Employment and receipts could not be broken down between small and large businesses because of non-disclosure requirements.

Source: SBA

While the SBA and Census Bureau statistics provide informative broad contextual information on the distribution of enterprises by receipts and number of employees, it is also useful to additionally contrast small and large enterprises (where large enterprises are defined as those that are not small, according to SBA criteria) in the oil and natural gas industry. The summary statistics presented in previous tables indicate that there are a large number of relatively small firms and a small number of large firms. Given the majority of expected impacts of the proposed rules arises from well completion-related requirements, which impacts production activities, exclusively, some explanation of this particular market structure is warranted as it pertains to production and small entities. An important question to answer is whether there are particular roles that small entities serve in the production segment of the oil and natural gas industry that may be disproportionately affected by the proposed rules.

The first important broad distinction among firms is whether they are independent or integrated. Independent firms concentrate on exploration and production (E&P) activities, while integrated firms are vertically integrated and often have operations in E&P, processing, refining, transportation, and retail. To our awareness, there are no small integrated firms. Independent firms may own and operate wells or provide E&P-related services to the oil and gas industry. Since we are focused on evaluating potential impacts to small firms owning and operating new and existing hydraulically fractured wells, we should narrow down on this sector.

In our understanding, there is no single industry niche for small entities in the production segment of the industry since small operators have different business strategies and that small entities can own different types of wells. The organization of firms in oil and natural gas industry also varies greatly from firm to firm. Additionally, oil and natural gas resources vary widely geographically and can vary significantly within a single field.

Among many important roles, independent small operators historically pioneered exploration in new areas, as well as developed new technologies. By taking on these relatively large risks, these small entrepreneurs (wildcatters) have been critical sources of industrial innovation and opened up critical new energy supplies for the U.S. (HIS Global Insight). In recent decades, as the oil and gas industry has concentrated via mergers, many of these smaller firms have been absorbed into large firms.

Another critical role, which provides an interesting contrast to small firms pioneering new territory, is that smaller independents maintain and operate a large proportion of the Nation's low producing wells, which are also known as marginal or stripper wells (Duda et al. 2005). While marginal wells represent about 80 percent of the population of producing wells, they produce about 15 percent of domestic production, according to EIA (Table 7-17).

Table 7-17 Distribution of Crude Oil and Natural Gas Wells by Productivity Level, 2009

Type of Wells	Wells (no.)	Wells (%)	Production (MMbbl for oil and Bcf gas)	Production (%)
Crude Oil				
Stripper Wells (<15 boe per year)	310,552	85%	311	19%
Other Wells (>=15 boe per year)	52,907	15%	1,331	81%
Total Crude Oil Wells	**363,459**	**100%**	**1,642**	**100%**
Natural Gas				
Natural Gas Stripper Wells (<15 boe per year)	338,056	73%	2,912	12%
Other Natural Gas Wells (>=15 boe per year)	123,332	27%	21,048	88%
Total Natural Gas Wells	**461,388**	**100%**	**23,959**	**100%**

Source: U.S. Energy Information Administration, **Distribution of Wells by Production Rate Bracket.** <http://www.eia.gov/pub/oil_gas/petrosystem/us_table.html> Accessed 7/10/11.

Note: Natural gas production converted to barrels oil equivalent (boe) uses the conversion of 0.178 barrels of crude oil to 1000 cubic feet natural gas.

Many of these wells were likely drilled and initially operated by major firms (although the data are not available to quantify the percentage of wells initially drilled by small versus large producers). Well productivity levels typically follow a steep decline curve; high production in earlier years but sustained low production for decades. Because of relatively low overhead of maintaining and operating few relatively co-located wells, some small operators with a particular business strategy purchase low producing wells from the majors, who concentrate on new opportunities. As small operators have provided important technical innovation in exploration, small operators have also been sources of innovation in extending the productivity and lifespan of existing wells (Duda et al. 2005).

7.4.2 Small Entity Economic Impact Measures

The proposed Oil and Natural Gas NSPS and NESHAP amendments will affect the owners of the facilities that will incur compliance costs to control their regulated emissions. The owners, either firms or individuals, are the entities that will bear the financial impacts associated with these additional operating costs. The proposed rule has the potential to impact all firms owning affected facilities, both large and small.

The analysis provides EPA with an estimate of the magnitude of impacts the proposed NSPS and NESHAP amendments may have on the ultimate domestic parent companies that own facilities EPA expects might be impacted by the rules. The analysis focuses on small firms because they may have more difficulty complying with a new regulation or affording the costs associated with meeting the new standard. This section presents the data sources used in the screening analysis, the methodology we applied to develop estimates of impacts, the results of the analysis, and conclusions drawn from the results.

The small business impacts analysis for the NSPS and NESHAP amendments relies upon a series of firm-level sales tests (represented as cost-to-revenue ratios) for firms that are likely to be associated with NAICS codes listed in Table 7-15. For both the NSPS and NESHAP amendments, we obtained firm-level employment, revenues, and production levels using various sources, including the American Business Directory, the *Oil and Gas Journal*, corporate websites, and publically-available financial reports. Using these data, we estimated firm-level compliance cost impacts and calculated cost-to-revenue ratios to identify small firms that might be significantly impacts by the rules. The approaches taken for the NSPS and NESHAP amendments differed; more detail on approaches for each set of proposed rules is presented in the following sections.

For the sales test, we divided the estimates of annualized establishment compliance costs by estimates of firm revenue. This is known as the cost-to-revenue ratio, or the "sales test." The "sales test" is the impact methodology EPA employs in analyzing small entity impacts as opposed to a "profits test," in which annualized compliance costs are calculated as a share of profits. The sales test is often used because revenues or sales data are commonly available for entities impacted by EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Revenues as typically published are correct figures and are more reliably reported when compared to profit data. The use of a "sales test" for estimating small business impacts for a rulemaking such as this one is consistent with guidance offered by EPA on compliance with SBREFA[55] and is consistent with guidance published by the U.S. SBA's Office of Advocacy that suggests that cost as a percentage

[55] The SBREFA compliance guidance to EPA rulewriters regarding the types of small business analysis that should be considered can be found at <http://www.epa.gov/sbrefa/documents/rfaguidance11-00-06.pdf>

of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities (U.S. SBA, 2010).[568]

7.4.3 Small Entity Economic Impact Analysis, Proposed NSPS

7.4.3.1 Overview of Sample Data and Methods

The proposed NSPS covers emissions points within various stages of the oil and natural gas production process. We expect that firms within multiple NAICS codes will be affected, namely the NAICS categories presented in Table 7-15. Because of the diversity of the firms potentially affected, we decided to analyze three distinct groups of firms within the oil and natural gas industry, while accounting for overlap across the groups. We analyze firms that are involved in oil and natural gas extraction that are likely to drill and operate wells, while a subset are integrated firms involved in multiple segments of production, as well as retailing products. We also analyze firms that primarily operate natural gas processing plants. A third set of firms we analyzed contains firms that primarily operate natural gas compression and pipeline transmission.

To identify firms involved in the drilling and primary production of oil and natural gas, we relied upon the annual *Oil and Gas Journal* 150 Survey (OGJ 150) as described in the Industry Profile in Section 2. While the OGJ 150 lists public firms, we believe the list is reasonably representative of the larger population of public and private firms operating in this segment of the industry. While the proportion of small firm in the OGJ 150 is smaller than the proportion evaluated by the Census SUSB, the OGJ 150 provides detailed information on the production activities and financial returns of the firms within the list, which are critical ingredients to the small business impacts analysis. We drew upon the OGJ 150 lists published for the years 2008 and 2009 (*Oil and Gas Journal*, September 21, 2009 and *Oil and Gas Journal*, September 6, 2010). The year 2009 saw relatively low levels of drilling activities because of the economic recession, while 2008 saw a relatively high level of drilling activity because of high fuel prices. Combined, we believe these two years of data are representative.

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[56]U.S. SBA, Office of Advocacy. A Guide for Government Agencies, How to Comply with the Regulatory Flexibility Act, Implementing the President's Small Business Agenda and Executive Order 13272, June 2010.

To identify firms that process natural gas, the OGJ also releases a period report entitled "Worldwide Gas Processing Survey", which provides a wide range of information on existing processing facilities. We used the most recent list of U.S. gas processing facilities[57] and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. To identify firms that compress and transport natural gas via pipelines, we examined the periodic OGJ survey on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies.[58] For these firms, we also used the American Business Directory and corporate websites to best identify the ultimate owner of the facilities or companies.

After combining the information for exploration and production firms, natural gas processing firms, and natural gas pipeline transmission firms in order to identify overlaps across the list, the approach yielded a sample of 274 firms that would potentially be affected by the proposed NSPS in 2015 assuming their 2015 production activities were similar to those in 2008 and 2009. We estimate that 129 (47 percent) of these firms are small according to SBA criteria. We estimate 121 firms (44 percent) are not small firms according to SBA criteria. We are unable to classify the remaining 24 firms (9 percent) because of a lack of required information on employee counts or revenue estimates.

Table 7-18 shows the estimated revenues for 250 firms for which we have sufficient data that would be potentially affected by the proposed NSPS based upon their activities in 2008 and 2009. We segmented the sample into four groups, production and integrated firms, processing firms, pipeline firms, and pipelines/processing firms. For the firms in the pipelines/processing group, we were unable to determine the firms' primary line of business, so we opted to group together as a fourth group.

[57] Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010.
[58] Oil and Gas Journal. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

Table 7-18 Estimated Revenues for Firms in Sample, by Firm Type and Size

		Estimated Revenues (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Production and Integrated						
Small	79	18,554.5	234.9	76.3	0.1	1,116.9
Large	49	1,347,463.0	27,499.2	1,788.3	12.9	310,586.0
Subtotal	128	1,366,017.4	10,672.0	344.6	0.1	310,586.0
Pipeline						
Small	11	694.5	63.1	4.6	0.5	367.0
Large	36	166,290.2	4,619.2	212.9	7.1	112,493.0
Subtotal	47	166,984.6	3,552.9	108.0	0.5	112,493.0
Processing						
Small	39	4,972.1	127.5	26.9	1.9	1,459.1
Large	23	177,632.1	8,881.6	2,349.4	10.4	90,000.0
Subtotal	62	182,604.2	3,095.0	41.3	1.9	90,000.0
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Subtotal	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Total						
Small	**129**	**24,221.1**	**187.8**	**34.9**	**0.1**	**1,459.1**
Large	**121**	**1,866,513.7**	**15,817.9**	**1,672.1**	**7.1**	**310,586.0**
Total	**250**	**1,890,734.8**	**7,654.8**	**163.9**	**0.1**	**310,586.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants. *Oil and Gas Journal*. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010. American Business Directory was used to determine number of employees.

As shown in Table 7-18, there is a wide variety of revenue levels across firm size, as well as across industry segments. The estimated revenues within the sample are concentrated on integrated firms and firms engaged in production activities (the E&P firms mentioned earlier).

The oil and natural gas industry is capital-intensive. To provide more context on the potential impacts of new regulatory requirements, Table 7-19 presents descriptive statistics for small and large integrated and production firms from the sample of firms (121 of the 128 integrated and production firms listed in the *Oil and Gas Journal*; capital and exploration expenditures for 7 firms were not reported in the *Oil and Gas Journal*).

Table 7-19 Descriptive Statistics of Capital and Exploration Expenditures, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

		Capital and Exploration Expenditures (millions, 2008 dollars)				
Firm Size	Number	Total	Average	Median	Minimum	Maximum
Small	76	13,478.8	177.4	67.1	0.1	2,401.9
Large	45	126,749.3	2,816.7	918.1	10.3	22,518.7
Total	**121**	**140,228.2**	**1,158.9**	**192.8**	**0.1**	**22,518.7**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

The average 2008 and 2009 total capital and exploration expenditures for the sample of 121 firms were $140 billion in 2008 dollars). About 10 percent of this total was spent by small firms. Average capital and explorations expenditures for small firms are about 6 percent of large firms; median expenditures of small firms are about 7 percent of large firms' expenditures. For small firms, capital and exploration expenditures are high relative to revenue, which appears to hold true more generally for independent E&P firms compared to integrated major firms. This would seem to indicate the capital-intensive nature of E&P activities. As expected, this would drive up ratios comparing estimated engineering costs to revenues and capital and exploration expenditures.

Table 7-20 breaks down the estimated number of natural gas and crude oil wells drilled by the 121 firms in the sample for which the *Oil and Gas Journal* information reported well-drilling estimates. Note the fractions on the minimum and maximum statistics; the fractions reported are due to our assumptions to estimate oil and natural gas wells drilled from the total wells drilled reported by the *Oil and Gas Journal*. The OGJ150 lists new wells drilled by firm in 2008 and 2009, but the drilling counts are not specific to crude oil or natural gas wells. We apportion the wells drilled to natural gas and crude oil wells using the distribution of well drilling in 2009 (63 percent natural gas and 37 percent oil).

Table 7-20 Descriptive Statistics of Estimated Wells Drilled, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

			Estimated Average Wells Natural Gas and Crude Oil Wells Drilled (2008 and 2009)				
Well Type	Firm Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Natural Gas							
	Small	76	2,288.3	30.1	6.0	0.2	259.3
	Large	45	9,445.1	209.9	149.1	0.6	868.3
	Subtotal	121	11,733.4	97.0	28.3	0.2	868.3
Crude Oil							
	Small	76	1,317.1	17.3	3.5	0.1	149.2
	Large	45	5,436.3	120.8	85.8	0.4	499.7
	Subtotal	121	6,753.4	55.8	16.3	0.1	499.7
Total							
	Small	**76**	**3,605.4**	**47.4**	**9.5**	**0.0**	**408.5**
	Large	**45**	**14,881.4**	**330.7**	**234.9**	**0.0**	**1,368.0**
	Total	**121**	**18,486.8**	**152.8**	**44.6**	**0.0**	**1,368.0**

Sources: *Oil and Gas Journal*. “OGJ150.” September 21, 2009; *Oil and Gas Journal*. “OGJ150 Financial Results Down in '09; Production, Reserves Up.” September 6, 2010. American Business Directory was used to determine number of employees.

This table highlights the fact that many firms drill relatively few wells; the median for small firms is 6 natural gas wells compared to 149 for large firms. Later in this section, we examine whether this distribution has implications for the engineering costs estimates, as well as the estimates of expected natural product recovery from controls such as RECs.

Unlike the analysis that follows for the analysis of impacts on small business from the NESHAP amendments, we have no specific data on potentially affected facilities under the NSPS. The NSPS will apply to new and modified sources, for which data are not fully available in advance, particularly in the case of new and modified sources such as well completions and recompletions which are spatially diffuse and potentially large in number.

The engineering cost analysis estimated compliance costs in a top-down fashion, projecting the number of new sources at an annual level and multiplying these estimates by model unit-level costs to estimate national impacts. To estimate per-firm compliance costs in this analysis, we followed a procedure similar to that of entering estimate compliance costs in NEMS on a per well basis. We first use the OGJ150-based list to estimate engineering compliance costs for integrated and production companies that may operate facilities in more than one segment of the oil and natural gas industry. We then estimate the compliance costs per crude oil and natural gas well by totaling all compliance costs estimates in the engineering cost estimates for the proposed NSPS and dividing that cost by the total number of crude oil and natural gas wells forecast as of 2015, the year of analysis. These compliance costs include the expected revenue from natural gas and condensate recovery that result from implementation of some proposed controls.

This estimation procedure yielded an estimate of crude well compliance costs of $162 per drilled well and natural gas well compliance costs of $38,719 without considering estimated revenues from product recovery and -$2,455 per drilled well with estimated revenues from product recovery included. Note that the divergence of estimated per well costs between crude oil and natural gas wells is because the proposed NSPS requirements are primary directed toward natural gas wells. Also note that the per well cost savings estimate for natural gas wells is different than the estimated cost of implementing a REC; this difference is because this estimate is picking up savings from other control options. We then estimate a single-year, firm-level compliance cost for this subset of firms by multiplying the per well cost estimates with the well count estimates.

The OGJ reports plant processing capacity in terms of MMcf/day. In the energy system impacts analysis, the NEMS model estimates a 6.5 percent increase (from 21.05 tcf in 2011 to 22.43 tcf in 2015) in domestic natural gas production from 2011 to 2015, the analysis year. On this, basis, we estimate that natural gas processing capacity for all plants in the OGJ list will increase 1.3 percent per year. This annual increment is equivalent to an increase in national gas processing capacity of 350 bcf per year. We assume that the engineering compliance costs estimates associated with processing are distributed according to the proportion of the increased national processing capacity contributed by each processing plant. These costs are estimated at $6.9 million without estimated revenues from product recovery and $2.3 million with estimated revenues from product recovery, respectively, in 2008 dollars, or about $20/MMcf without revenues and $7/MMcf with revenues.

The OGJ report on pipeline companies has the advantage that it reports expenditures on plant additions. We assume that the firm-level proposed compression and transmission-related NSPS compliance costs are proportional to the expenditures on plant additions and that these additions reflect a representative year or this analysis. We estimate the annual compression and transmission-related NSPS compliance costs at $5.5 million without estimated revenues from product recovery and $3.7 million with estimated revenues from product recovery, respectively, in 2008 dollars.

7.4.3.2 Small Entity Impact Analysis, Proposed NSPS, Results

Summing estimated annualized engineering compliance costs across industry segment and individual firms in our sample, we estimate firms in the OGJ-based sample will face about $480 million in 2008 dollars, about 65 percent of the estimated annualized costs of the Proposed NSPS without including revenues from additional product recovery ($740 million). When including revenues from additional product recovery, the estimated compliance costs for the firms in the sample is about -$23 million, compared to engineering cost estimate of -$45 million.

Table 7-21 presents the distribution of estimated proposed NSPS compliance costs across firm size for the firms within our sample. Evident from this table, about 98 percent of the estimated engineering compliance costs accrue to the integrated and production segment of the industry, again explain by the fact that completion-related requirements contribute the bulk of the estimated engineering compliance costs (as well as estimated emissions reductions). About 17 percent of the total estimated engineering compliance costs (and about 18 percent of the costs accruing the integrated and production segment) are focused on small firms.

Table 7-21 Distribution of Estimated Proposed NSPS Compliance Costs Without Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

		Estimated Engineering Compliance Costs Without Estimated Revenues from Natural Gas Product Recovery (2008 dollars)				
Firm Type/Size	Number of Firms	Total	Mean	Median	Minimum	Maximum
Production and Integrated						
Small	79	82,293,903	1,041,695	221,467	3,210	10,054,401
Large	49	387,489,928	7,907,958	5,730,634	15,238	33,677,388
Subtotal	128	469,783,831	3,670,186	969,519	3,210	33,677,388
Pipeline						
Small	11	3,386	308	111	18	1,144
Large	36	1,486,929	41,304	3,821	37	900,696
Subtotal	47	1,490,314	31,709	2,263	18	900,696
Processing						
Small	39	476,165	12,209	1,882	188	276,343
Large	23	859,507	37,370	8,132	38	423,645
Subtotal	62	1,335,672	21,543	2,730	38	423,645
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	5,431,510	417,808	147,925	2,003	2,630,236
Subtotal	13	5,431,510	417,808	147,925	2,003	2,630,236
Total						
Small	**129**	**82,773,454**	**641,655**	**49,386**	**18**	**10,054,401**
Large	**121**	**395,267,874**	**3,266,677**	**57,220**	**37**	**33,677,388**
Total	**250**	**478,041,328**	**1,912,165**	**55,888**	**18**	**33,677,388**

These distributions are similar when the revenues from expected natural gas recovery are included (Table 7-22). About 21 percent of the total savings from the proposed NSPS is expected to accrue to small firms (about 19 percent of the savings to the integrated and production segment accrue to small firms). Note also in Table 7-22 that the pipeline and processing segments (and the pipeline/processing firms) are not expected to experience net cost savings (negative costs) from the proposed NSPS.

Table 7-22 Distribution of Estimated Proposed NSPS Compliance Costs With Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

		Estimated Engineering Compliance Costs With Estimated Revenues from Natural Gas Product Recovery (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Mean	Median	Minimum	Maximum
Production and Integrated						
Small	79	-5,065,551	-64,121	-13,729	-620,880	8,699
Large	49	-22,197,126	-453,003	-318,551	-2,072,384	423,760
Subtotal	128	-27,262,676	-212,990	-43,479	-2,072,384	423,760
Pipeline						
Small	11	2,303	209	76	12	779
Large	36	1,011,572	28,099	2,599	25	612,753
Subtotal	47	1,013,876	21,572	1,539	12	612,753
Processing						
Small	39	160,248	4,109	634	63	93,000
Large	23	289,258	12,576	2,737	13	142,573
Subtotal	62	449,506	7,250	919	13	142,573
Pipelines/Processing						
Small	0	---	---	---	---	---
Large	13	3,060,373	235,413	86,301	716	1,746,730
Subtotal	13	3,060,373	235,413	86,301	716	1,746,730
Total						
Small	**129**	**-4,902,999**	**-38,008**	**-2,520**	**-620,880**	**93,000**
Large	**121**	**-17,835,922**	**-147,404**	**634**	**-2,072,384**	**1,746,730**
Total	**250**	**-22,738,922**	**-90,956**	**22**	**-2,072,384**	**1,746,730**

Table 7-23 Summary of Sales Test Ratios, Without Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS

		Descriptive Statistics for Sales Test Ratio Without Estimated Revenues from Natural Gas Product Recovery (%)			
Firm Type/Size	Number of Firms	Mean	Median	Minimum	Maximum
Production and Integrated					
Small	79	2.18%	0.49%	0.01%	50.83%
Large	49	0.41%	0.28%	<0.01%	2.83%
Subtotal	128	1.50%	0.39%	<0.01%	50.83%
Pipeline					
Small	11	<0.01%	<0.01%	<0.01%	0.01%
Large	36	0.01%	<0.01%	<0.01%	0.06%
Subtotal	47	0.01%	<0.01%	<0.01%	0.06%
Processing					
Small	39	0.05%	0.01%	<0.01%	0.33%
Large	23	0.02%	0.01%	<0.01%	0.15%
Subtotal	62	0.04%	0.01%	<0.01%	0.33%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	<0.01%	<0.01%	<0.01%	0.01%
Subtotal	13	<0.01%	<0.01%	<0.01%	0.01%
Total					
Small	**129**	**1.34%**	**0.15%**	**<0.01%**	**50.83%**
Large	**121**	**0.17%**	**0.01%**	**<0.01%**	**2.83%**
Total	**250**	**0.78%**	**0.03%**	**<0.01%**	**50.83%**

The mean cost-sales ratio for all businesses when estimated product recovery is excluded from the analysis of the sample data is 0.78 percent, with a median ratio of 0.03 percent, a minimum of less than 0.01 percent, and a maximum of over 50 percent (Table 7-23). For small firms in the sample, the mean and median cost-sales ratios are 1.34 percent and 0.15 percent, respectively, with a minimum of less than 0.01 percent and a maximum of over 50 percent (Table 7-23). Each of these statistics indicates that, when considered in the aggregate, impacts are relatively higher on small firms than large firms when the estimated revenue from additional natural gas product recovery is excluded. However, as the next table shows, the reverse is true when these revenues are included.

Table 7-24 Summary of Sales Test Ratios, With Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS

		Descriptive Statistics for Sales Test Ratio With Estimated Revenues from Natural Gas Product Recovery (%)			
Firm Type/Size	Number of Firms	Mean	Median	Minimum	Maximum
Production and Integrated					
Small	79	-0.13%	-0.03%	-2.96%	<0.00%
Large	49	-0.02%	-0.02%	-0.17%	0.06%
Subtotal	128	-0.09%	-0.02%	-2.96%	0.06%
Pipeline					
Small	11	<0.00%	<0.01%	<0.01%	0.01%
Large	36	0.01%	<0.01%	<0.01%	0.04%
Subtotal	47	0.01%	<0.01%	<0.01%	0.04%
Processing					
Small	39	0.01%	<0.01%	<0.01%	0.05%
Large	23	<0.00%	<0.01%	<0.01%	0.05%
Subtotal	62	0.01%	<0.01%	<0.01%	0.05%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	<0.01%	<0.01%	<0.01%	0.01%
Subtotal	13	<0.01%	<0.01%	<0.01%	0.01%
Total					
Small	**129**	**-0.08%**	**-0.01%**	**-2.96%**	**0.05%**
Large	**121**	**-0.01%**	**<0.01%**	**-0.17%**	**0.06%**
Total	**250**	**-0.04%**	**<0.01%**	**-2.96%**	**0.06%**

The mean cost-sales ratio for all businesses when estimated product recovery is included is in the sample is -0.04 percent, with a median ratio of less than 0.01 percent, a minimum of -2.96 percent, and a maximum of 0.06 percent (Table 7-24). For small firms in the sample, the mean and median cost-sales ratios are -0.08 percent and -0.01 percent, respectively, with a minimum of -2.96 percent and a maximum of 0.05 percent (Table 7-24). Each of these statistics indicates that, when considered in the aggregate, impacts are small on small business when the estimated revenue from additional natural gas product recovery are included, the reverse of the conclusion found when these revenues are excluded.

Meanwhile, Table 7-25 presents the distribution of estimated cost-sales ratios for the small firms in our sample with and without including estimates of the expected natural gas product recover from implementing controls. When revenues estimates are included, all 129 firms (100 percent) have estimated cost-sales ratios less than 1 percent. While less than 1 percent, the highest cost-sales ratios for small firms in the sample experiencing impacts are largely driven by costs accruing to processing and pipeline firms. That said, the incremental costs imposed on firms that process natural gas or transport natural gas via pipelines are not estimated to create significant impacts on a cost-sales ratio basis at the firm-level.

Table 7-25 Impact Levels of Proposed NSPS on Small Firms as a Percent of Small Firms in Sample, With and Without Revenues from Additional Natural Gas Product Recovery

	Without Estimated Revenues from Natural Gas Product Recovery		With Estimated Revenues from Natural Gas Product Recovery	
Impact Level	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected
C/S Ratio less than 1%	109	84.5%	129	100.00%
C/S Ratio 1-3%	11	8.5%	0	0.00%
CS Ratio greater than 3%	9	7.0%	0	0.00%

When the estimated revenues from product recovery are not included in the analysis, 11 firms (about 9 percent) are estimated to have sales test ratios between 1 and 3 percent. Nine firms (about 7 percent) are estimated to have sales test ratios greater than 3 percent. These results noted, the exclusion of product recovery is somewhat artificial. While the mean engineering compliance costs and revenues estimates are valid, drawing on the means ignores the distribution around the mean estimates, which risks masking effects. Because of this risk, the following section offers a qualitative discussion of small entities with regard to obtaining REC services, the validity of the cost and performance of RECs for small firms, as well as offers a discussion about whether older equipment, which may be disproportionately owned and operated be smaller producers, would be affected by the proposed NSPS.

7.4.3.3 Small Entity Impact Analysis, Proposed NSPS, Additional Qualitative Discussion

3.5.3.3.1 Small Entities and Reduced Emissions Completions

Because REC requirements of the proposed NSPS are expected to contribute the large majority of engineering compliance costs, it is important to examine these requirements more closely in the context small entities. Important issues to resolve are the scale of REC costs within a drilling project, how the payment system for recovered natural gas functions, whether small entities pursue particular “niche” strategies that may influence the costs or performance in a way that makes the estimates costs and revenues invalid.

According to the most recent natural gas well cost data from EIA, the average cost of drilling and completing a producing natural gas well in 2007 was about $4.8 million (adjusted to 2008 dollars). This average includes lower cost wells that may be relatively shallow or are not hydraulically fractured. Hydraulically fractured wells in deep formations may cost up to $10 million. RECs contracted from a service provider are estimated to cost $33,200 (in 2008 dollars) or roughly 0.3%-0.7% of the typical cost of a drilling and completing a natural gas well. As this range does not include revenues expected from natural gas and hydrocarbon condensate recovery expected to offset REC implementation costs, REC costs likely represent a small increment of the overall burden of a drilling project.

To implement an REC, a service provider, which may itself be a small entity, is typically contracted to bring a set of equipment to the well pad temporarily to capture the stream that would otherwise be vented to the atmosphere. Typically, service providers are engaged in a long term drilling program in a particular basin covering multiple wells on multiple well pads. For gas captured and sold to the gathering system, Lease Automatic Custody Transfer (LACT) meters are normally read daily automatically, and sales transactions are typically settled at the end of the month. Invoices from service providers are generally delivered in 30-day increments during the well development time period, as well as at the end of the working contract for that well pad. The conclusion from the information, based on the available information, in most cases, the owner/operator incurs the REC cost within the same 30 day period that the owner/operator receives revenue as a result of the REC.

We assume small firms are performing RECs in CO and WY, as in many instances RECs are required under state regulation. In addition to State regulations, some companies are implementing RECs voluntarily such as through participation in the EPA Natural Gas STAR Program and the focus of recent press reports.

As described in more detail below, many small independent E&P companies often do not conduct any of the actual field work. These firms will typically contract the drilling, completion, testing, well design, environmental assessment, and maintenance. Therefore, we believe it is likely that small independent E&P firms will contract for RECs from service providers if required to perform RECs. An important reminder is that performing a REC is a straightforward and inexpensive extension of drilling, completion, and testing activities.

To the extent that very small firms may specialize in operating relatively few low-producing stripper wells, it is important to ask whether low-producing wells are likely candidates for re-fracturing/re-completion and, if so, whether the expected costs and revenues would be valid. These marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion. To the extent the marginal wells may be good candidates for re-fracturing/completion, the REC costs are valid estimates. The average REC cost is valid for RECs performed on any well, regardless of the operator size. The reason for this is that the REC service is contracted out to specialty service providers who charge daily rates for the REC equipment and workers. The cost is not related to any well characteristic.

Large operators may receive a discount for offering larger contracts which help a service provider guarantee that REC equipment will be utilized. However, we should note that the existence of a potential discount for larger contracts is based on a strong assumption; we do not have evidence to support this assumption. Since contracting REC equipment is analogous to contracting for drilling equipment, completion equipment, etc., the premium would likely be in the same range as other equipment contracted by small operators. Since the REC cost is a small portion of the overall well drilling and completion cost, the effect of any bulk discount disparity between large and small operators will be small, if in fact it does exist.

Although small operators may own the majority of marginal and stripper wells, they will make decisions based on economics just as any sized company would. For developing a new well, any sized company will expect a return on their investment meaning the potential for sufficient gas, condensate, and/or oil production to pay back their investment and generate a return that exceeds alternative investment opportunities. Therefore, small or large operators that are performing hydraulic fracture completions will experience the same distribution of REC performance. For refracturing an existing well, the well must be a good candidate to respond to the re-fracture/completion with a production increase that merits the investment in the re-fracture/completion.

Plugging and abandoning wells is complex and costly, so sustaining the productivity of wells is important for maximizing the exploitation of proven domestic resources. However, many marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion, which means they are likely unaffected by the proposed NSPS.

3.5.3.3.2 Age of Equipment and Proposed Regulations

Given a large fraction of domestic oil and natural gas production is produced from older and generally low productivity wells, it is important to examine whether the proposed requirements might present impediments to owners and operators of older equipment. The NSPS is a standard that applies to new or modified sources. Because of this, NSPS requirements target new or modified affected facilities or equipment, such as processing plants and compressors. While the requirements may apply to modifications of existing facilities, it is important to discuss well completion-related requirements aside from other requirements in the NSPS distinctly.

Excluding well completion requirements from the cost estimates, the non-completion NSPS requirements (related to equipment leaks at processing plants, reciprocating and centrifugal compressors, pneumatic controllers, and storage vessels) are estimated to require $27 million in annualized engineering costs. EPA also estimates that the annualized costs of these requirements will be mostly if not fully offset by revenues expected from natural gas recovery. EPA does not expect these requirements to disproportionately affect producers with older equipment. Meanwhile, the REC and emissions combustion requirements in the proposed NSPS relate to well completion activities at new hydraulically fractured natural gas wells and existing wells which are recompleted after being fractured or re-fractured. These requirements constitute the bulk of the expected engineering compliance expenditures (about $710 million in annualized costs) and expected revenues from natural gas product recovery (about $760 million in revenues, annually).

While age of the well and equipment may be an important factor for small and large producers in determining whether it is economical to fracture or re-fracture an existing well, this equipment is unlikely to be subject to the NSPS. To comply with completion-related requirements, producers are likely to rely heavily on portable and temporary completion equipment brought to the wellpad over a short period of time (a few days to a few weeks) to capture and combust emissions that are otherwise vented. The equipment at the wellhead—newly installed in the case of new well completions or already in place and operating in the case of existing wells—is not likely to be subject to the NSPS requirement.

7.4.3.4 Small Entity Impact Analysis, Proposed NSPS, Screening Analysis Conclusion

The number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to reduced emissions completion activities occur without a significant time lag between implementing the control and obtaining the recovered product unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions and recompletions occur over a short span of time, during which the additional product recovery is also accomplished.

7.4.4 Small Entity Economic Impact Analysis, Proposed NESHAP Amendments

The proposed NESHAP amendments will affect facilities operating three types of equipment: glycol dehydrators at production facilities, glycol dehydrators at transmission and compression facilities, and storage vessels. We identified likely affected facilities in the National Emissions Inventory (NEI) and estimated the number of newly required controls of each type that would be required by the NESHAP amendments for each facility. We then used available data sources to best identify the ultimate owner of the equipment that would likely require new controls and linked facility-level compliance cost estimates to firm-level employment and revenue data. These data were then used to calculate an estimated compliance costs to revenues ratio to identify small businesses that might be significantly impacted by the NESHAP.

While we were able to identify the owners all but 14 facilities likely to be affected, we could not obtain employment and revenue levels for all of these firms. Overall, we expect about 447 facilities to be affected, and these facilities are owned by an estimated 160 firms. We were unable to obtain financial information on 42 (26 percent) of these firms due to inadequate data. In some instances, firms are private, and financial data is not available. In other instance, firms may no longer exist, since NEI data are not updated continuously. From the ownership information and compliance cost estimates from the engineering analysis, we estimated total compliance cost per firm.

Of the 118 firms for which we have financial information, we identified 62 small firms and 56 large firms that would be affected by the NESHAP amendments. Annual compliance costs for small firms are estimated at $3.0 million (18 percent of the total compliance costs), and annual compliance costs for large firms are estimated at $10.7 million (67 percent of the total compliance costs). The facilities for which we were unable to identify the ultimate owners, employment, and revenue levels would have an estimated annual compliance cost of $2.3 million (15 percent of the total). All figures are in 2008 dollars.

The average estimated annualized compliance cost for the 62 small firms identified in the dataset is $48,000, while the mean annual revenue figure for the same firms is over $120 million, or less than 1 percent for a average sales-test ratio for all 62 firms (Table 7-26). The median sale-test ratio for these firms is smaller at 0.14 percent. Large firms are likely to see an average of $190,000 in annual compliance costs, whereas average revenue for these firms exceeds $30 billion since this set of firms includes many of the very large, integrated energy firms. For large firms, the average sales-test ratio is about 0.01 percent, and the median sales-test ratio is less than 0.01 percent (Table 7-26).

Table 7-26 Summary of Sales Test Ratios for Firms Affected by Proposed NESHAP Amendments

Firm Size	No. of Known Affected Firms	% of Total Known Affected Firms	Mean C/S Ratio	Median C/S Ratio	Min. C/S Ratio	Max. C/S Ratio
Small	62	53%	0.62%	0.14%	< 0.01%	6.2%
Large	56	47%	0.01%	< 0.01%	< 0.01%	0.4%
All	118	100%	0.34%	0.02%	< 0.01%	6.2%

Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile 10 firms (16 percent) are likely to have impacts greater than 1 percent (Table 7-27). Four of these 10 firms are likely to have impacts greater than 3 percent (Table 7-27) While these 10 firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211 (Table 7-27).

Table 7-27 Affected Small Firms as a Percent of Small Firms Nationwide, Proposed NESHAP amendments

Firm Size	Number of Small Firms Affected Nationwide	% of Small Firms Affected Nationwide	Affected Firms as a % of National Firms (6,427)
C/S Ratio less than 1%	52	83.9%	0.81%
C/S Ratio 1-3%	6	9.7%	0.09%
CS Ratio greater than 3%	4	6.5%	0.06%

Screening Analysis Conclusion: While there are significant impacts on small business, the analysis shows that a substantial number of small firms are not impacted. Based upon the analysis in this section, we presume there is no SISNOSE arising from the proposed NESHAP amendments.

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ORIGINAL ARTICLE

Long-Term Ozone Exposure and Mortality

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ABSTRACT

BACKGROUND

Although many studies have linked elevations in tropospheric ozone to adverse health outcomes, the effect of long-term exposure to ozone on air pollution–related mortality remains uncertain. We examined the potential contribution of exposure to ozone to the risk of death from cardiopulmonary causes and specifically to death from respiratory causes.

METHODS

Data from the study cohort of the American Cancer Society Cancer Prevention Study II were correlated with air-pollution data from 96 metropolitan statistical areas in the United States. Data were analyzed from 448,850 subjects, with 118,777 deaths in an 18-year follow-up period. Data on daily maximum ozone concentrations were obtained from April 1 to September 30 for the years 1977 through 2000. Data on concentrations of fine particulate matter (particles that are ≤2.5 μm in aerodynamic diameter [$PM_{2.5}$]) were obtained for the years 1999 and 2000. Associations between ozone concentrations and the risk of death were evaluated with the use of standard and multilevel Cox regression models.

RESULTS

In single-pollutant models, increased concentrations of either $PM_{2.5}$ or ozone were significantly associated with an increased risk of death from cardiopulmonary causes. In two-pollutant models, $PM_{2.5}$ was associated with the risk of death from cardiovascular causes, whereas ozone was associated with the risk of death from respiratory causes. The estimated relative risk of death from respiratory causes that was associated with an increment in ozone concentration of 10 ppb was 1.040 (95% confidence interval, 1.010 to 1.067). The association of ozone with the risk of death from respiratory causes was insensitive to adjustment for confounders and to the type of statistical model used.

CONCLUSIONS

In this large study, we were not able to detect an effect of ozone on the risk of death from cardiovascular causes when the concentration of $PM_{2.5}$ was taken into account. We did, however, demonstrate a significant increase in the risk of death from respiratory causes in association with an increase in ozone concentration.

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Studies conducted over the past 15 years have provided substantial evidence that long-term exposure to air pollution is a risk factor for cardiopulmonary disease and death.[1-5] Recent reviews of this literature suggest that fine particulate matter (particles that are ≤2.5 μm in aerodynamic diameter [$PM_{2.5}$]) has a primary role in these adverse health effects.[6,7] The particulate-matter component of air pollution includes complex mixtures of metals, black carbon, sulfates, nitrates, and other direct and indirect byproducts of incomplete combustion and high-temperature industrial processes.

Ozone is a single, well-defined pollutant, yet the effect of exposure to ozone on air pollution–related mortality remains inconclusive. Several studies have evaluated this issue, but they have been short-term studies,[8-10] have failed to show a statistically significant effect,[1,3] or have been based on limited mortality data.[11] Recent reviews by the Environmental Protection Agency (EPA)[12] and the National Research Council[13] have questioned the overall consistency of the available data correlating exposure to ozone and mortality. Similar conclusions about the evidence base for the long-term effects of ozone on mortality were drawn by a panel of experts in the United Kingdom.[14]

Nonetheless, previous studies have suggested that a measurable effect of ozone may exist, particularly with respect to the risk of death from cardiopulmonary causes. In one of the larger studies, ozone was significantly associated with death from cardiopulmonary causes[15] but not with death from ischemic heart disease. However, the estimated effect of ozone on the risk of death from cardiopulmonary causes in this study was attenuated when $PM_{2.5}$ was added to the analysis in copollutant models. On the basis of suggested effects of ozone on the risk of death from cardiopulmonary causes (which includes death from respiratory causes) but an absence of evidence for effects of ozone on the risk of death from ischemic heart disease, we hypothesized that ozone might have a primary effect on the risk of death from respiratory causes.

METHODS

HEALTH, MORTALITY, AND CONFOUNDING DATA

Our study used data from the American Cancer Society Cancer Prevention Study II (CPS II) cohort.[16] The CPS II cohort consists of more than 1.2 million participants who were enrolled by American Cancer Society volunteers between September 1982 and February 1983 in all 50 states, the District of Columbia, and Puerto Rico. Enrollment was restricted to persons who were at least 30 years of age living in households with at least one person 45 years of age or older. After providing written informed consent, the participants completed a confidential questionnaire that included questions on demographic characteristics, smoking history, alcohol use, diet, and education.[17] Deaths were ascertained until August 1988 by personal inquiries of family members by the volunteers and thereafter by linkage with the National Death Index. Through 1995, death certificates were obtained and coded for cause of death. Beginning in 1996, codes for cause of death were provided by the National Death Index.[18]

The study population for our analysis included only those participants in CPS II who resided in U.S. metropolitan statistical areas within the 48 contiguous states or the District of Columbia (according to their address at the time of enrollment) and for whom data were available from at least one pollution monitor within their metropolitan area. The study was approved by the Ottawa Hospital Research Ethics Board, Canada.

Data on "ecologic" risk factors at the level of the metropolitan area representing social variables (educational level, percentage of homes with air conditioning, percentage of the population who were nonwhite), economic variables (household income, unemployment, income disparity), access to medical care (number of physicians and hospital beds per capita), and meteorologic variables were obtained from the 1980 U.S. Census and other secondary sources (see the Supplementary Appendix, available with the full text of this article at NEJM.org). These ecologic risk factors, as well as the individual risk factors collected in the CPS II questionnaire, were assessed as potential confounders of the effects of ozone.[3,5,19,20]

ESTIMATES OF EXPOSURE TO AIR POLLUTION

Ozone data were obtained from 1977 (5 years before the identification of the CPS II cohort) through 2000 for all air-pollution monitors in the study metropolitan areas from the EPA's Aerometric Information Retrieval System. Ozone data at each monitoring site were collected on an hourly basis, and the daily maximum value for the site was determined. All available daily maximum values for the monitoring site were averaged over each quarter year. The quarterly average values were reported for each monitor only when at least 75% of daily observations for that quarter were available.

The averages of the second (April through June) and third (July through September) quarters were calculated for each monitor if both quarterly averages were available. The period from April through September was selected because ozone concentrations tend to be elevated during the warmer seasons and because fewer data were available for the cooler seasons.

The average of the second and third quarterly averages for each year was then computed for all the monitors within each metropolitan area to form a single annual time series of air-pollution measurements for each metropolitan area for the period from 1977 to 2000. In addition, a summary measure of long-term exposure to ambient warm-season ozone was defined as the average of annual time-series measurements during the entire period from 1977 to 2000. Individual measures of exposure to ozone were then defined by assigning the average for the metropolitan area to each cohort member residing in that area.

Data on exposure to $PM_{2.5}$ were also obtained from the Aerometric Information Retrieval System database for the 2-year period from 1999 to 2000 (data on $PM_{2.5}$ were not available before 1999 for most metropolitan areas).[5] The average concentrations of $PM_{2.5}$ were included in our analyses to distinguish the effect of particulates from that of ozone on outcomes.

STATISTICAL ANALYSIS

Standard and multilevel random-effects Cox proportional-hazard models were used to assess the risk of death in relation to exposures to pollution. The subjects were matched according to age (in years), sex, and race. A total of 20 variables with 44 terms were used to control for individual characteristics that might confound or modify the association between air pollution and death. These variables, which were considered to be of potential importance on the basis of previous studies, included individual risk factors for which data had been collected in the CPS II questionnaire. Seven ecologic covariates obtained from the 1980 U.S. Census (median household income, the proportion of persons living in households with an income below 125% of the poverty line, the percentage of persons over the age of 16 years who were unemployed, the percentage of adults with less than a high-school [12th-grade] education, the percentage of homes with air conditioning, the Gini coefficient of income inequality [ranging from 0 to 1, with 0 indicating an equal distribution of income and 1 indicating that one person has all the income and everyone else has no income[20]], and the percentage of persons who were white) were also included. These variables were included at two levels: as the average for the metropolitan statistical area and as the difference between the average for the ZIP Code of residence and the average for the metropolitan statistical area. Additional sensitivity analyses were undertaken for ecologic variables that were available for only a subgroup of the 96 metropolitan statistical areas (see the Supplementary Appendix). Models were estimated for either ozone or $PM_{2.5}$. In addition, models with both $PM_{2.5}$ and ozone were estimated.

In additional analyses, our basic Cox models were modified by incorporating an adjustment for community-level random effects, which allowed us to take into account residual variation in mortality among communities.[21] The baseline hazard function was modulated by a community-specific random variable representing the residual risk of death for subjects in that community after individual and ecologic risk factors had been controlled for (see the Supplementary Appendix).

A formal analysis was conducted to assess whether a threshold existed for the association between exposure to ozone and the risk of death (see the Supplementary Appendix). A standard threshold model was postulated in which there was no association between exposure to ozone and the risk of death below a specified threshold concentration and a linear association (on the logarithmic scale of the proportional-hazards model) above the threshold.

The question of whether specific time windows were associated with the health effects was investigated by subdividing the follow-up interval into four periods (1982 to 1988, 1989 to 1992, 1993 to 1996, and 1997 to 2000). Exposures were matched for each of these periods and also tested for a 10-year average on the basis of the 5-year follow-up period and the 5 years before the follow-up period (see the Supplementary Appendix).

RESULTS

The analytic cohort included 448,850 subjects residing in 96 metropolitan statistical areas (Fig. 1).

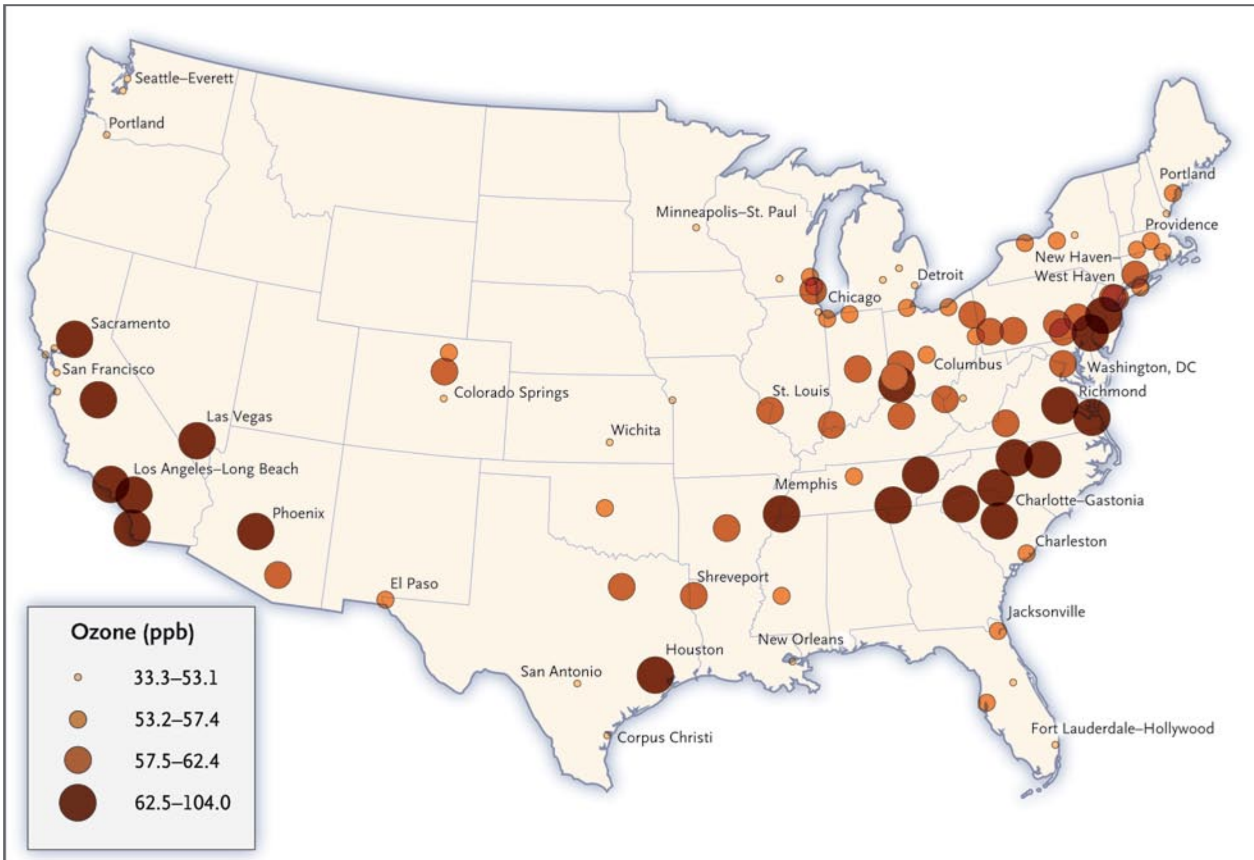

Figure 1. Ozone Concentrations in the 96 Metropolitan Statistical Areas in Which Members of the American Cancer Society Cohort Resided in 1982.

The average exposures were estimated from 1 to 57 monitoring sites within each metropolitan area from April 1 to September 30 for the years 1977 through 2000.

In 1980, the populations of these 96 areas ranged from 94,436 to 8,295,900. Data were available on the concentration of ambient ozone from all 96 areas and on the concentration of $PM_{2.5}$ from 86 areas. The average number of air-pollution monitors per metropolitan area was 11 (range, 1 to 57), and more than 80% of the areas had 6 or more monitors.

The average ozone concentration for each metropolitan area during the interval from 1977 to 2000 ranged from 33.3 ppb to 104.0 ppb (Fig. 1). The highest regional concentrations were in Southern California and the lowest in the Pacific Northwest and parts of the Great Plains. Moderately elevated concentrations were present in many areas of the East, Midwest, South, and Southwest.

The baseline characteristics of the study population, overall and as a function of exposure to ozone, are presented in Table 1. The mean age of the cohort was 56.6 years, 43.4% were men, 93.7% were white, 22.4% were current smokers, and 30.5% were former smokers. On the basis of estimates from 1980 Census data, 62.3% of homes had air conditioning at the time of initial data collection.

During the 18-year follow-up period (from initial CPS II data collection in 1982 through the end of follow-up in 2000), there were 118,777 deaths in the study cohort (Table 2). Of these, 58,775 were from cardiopulmonary causes, including 48,884 from cardiovascular causes (of which 27,642 were due to ischemic heart disease) and 9891 from respiratory causes.

In the single-pollutant models, exposure to ozone was not associated with the overall risk of death (relative risk, 1.001; 95% confidence interval [CI], 0.996 to 1.007) (Table 3). However, it was significantly correlated with an increase in the risk of death from cardiopulmonary causes. A

10-ppb increment in exposure to ozone elevated the relative risk of death from the following causes: cardiopulmonary causes (relative risk, 1.014; 95% CI, 1.007 to 1.022), cardiovascular causes (relative risk, 1.011; 95% CI, 1.003 to 1.023), ischemic heart disease (relative risk, 1.015; 95% CI, 1.003 to 1.026), and respiratory causes (relative risk, 1.029; 95% CI, 1.010 to 1.048).

Inclusion of the concentration of $PM_{2.5}$ measured in 1999 and 2000 as a copollutant (Table 3) attenuated the association with exposure to ozone for all the end points except death from respiratory causes, for which a significant correlation persisted (relative risk, 1.040; 95% CI, 1.013 to 1.067). The concentrations of ozone and $PM_{2.5}$ were positively correlated (r=0.64 at the subject level and r=0.56 at the metropolitan-area level), resulting in unstable risk estimates for both pollutants. The concentration of $PM_{2.5}$ remained significantly associated with death from cardio-

Table 1. Baseline Characteristics of the Study Population in the Entire Cohort and According to Exposure to Ozone.*

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
No. of MSAs	96	24	24	24	24
No. of MSAs with data on $PM_{2.5}$	86	21	20	23	22
Concentration of $PM_{2.5}$ ($\mu g/m^3$)		11.9±2.5	13.1±2.9	14.7±2.1	15.4±3.2
Individual risk factors					
Age (yr)	56.6±10.5	56.7±10.4	56.4±10.7	56.3±10.4	56.9±10.5
Male sex (%)	43.4	43.5	43.1	43.5	43.2
White race (%)	93.7	94.3	95.1	93.9	91.8
Education (%)					
Less than high school	12.1	11.5	13.6	12.1	11.6
High school	30.6	30.2	33.6	32.1	27.4
Beyond high school	57.3	58.3	52.8	55.8	61.0
Smoking status					
Current smokers					
Percentage of subjects	22.4	22.0	23.5	22.2	21.9
No. of cigarettes/day	22.0±12.4	22.0±12.3	22.0±12.5	22.2±12.5	21.9±12.4
Duration of smoking (yr)	33.5±11.0	33.4±10.8	33.4±11.1	33.4±11.0	33.9±11.2
Started smoking <18 yr of age (%)	9.6	9.3	10.5	9.4	9.3
Started smoking ≥18 yr of age (%)	13.2	13.3	13.4	13.3	13.0
Former smokers					
Percentage of subjects	30.5	31.2	30.8	29.5	30.4
No. of cigarettes/day	21.6±14.7	21.6±14.6	22.2±15.1	21.6±14.6	21.3±14.6
Duration of smoking (yr)	22.2±12.6	22.1±12.5	22.6±12.6	22.0±12.5	22.4±12.7
Started smoking <18 yr of age (%)	11.9	11.8	12.7	11.5	11.8
Started smoking ≥18 yr of age (%)	18.5	19.3	17.9	17.9	18.5
Exposure to smoking (hr/day)	3.3±4.4	3.2±4.4	3.4±4.5	3.4±4.5	3.1±4.4
Pipe or cigar smoker only (%)	4.1	4.0	4.2	4.3	3.8
Marital status (%)					
Married	83.5	84.2	83.0	83.7	83.1
Single	3.6	3.4	4.0	3.8	3.2
Separated, divorced, or widowed	12.9	12.4	13.0	12.5	13.7

Table 1. (Continued.)

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
Body-mass index†	25.1±4.1	25.1±4.1	25.3±4.2	25.1±4.1	24.8±4.0
Level of occupational exposure to particulate matter (%)‡					
0	50.7	50.9	50.0	50.8	51.0
1	13.3	13.4	13.1	13.3	13.3
2	11.4	11.5	10.8	11.4	11.9
3	4.6	4.7	4.8	4.6	4.5
4	6.1	6.2	6.2	6.1	6.0
5	4.2	4.2	4.3	4.1	4.1
6	1.1	1.0	9.5	1.4	8.4
Not able to ascertain	8.6	8.2	1.2	8.4	0.9
Self-reported exposure to dust or fumes (%)	19.5	19.5	19.8	19.7	19.1
Level of dietary-fat consumption (%)§					
0	14.5	13.7	14.9	14.1	15.3
1	15.9	15.8	16.5	15.6	15.9
2	17.4	17.6	17.7	17.2	17.1
3	21.2	21.8	21.1	21.3	20.8
4	30.9	31.1	29.8	31.9	30.9
Level of dietary-fiber consumption (%)¶					
0	16.6	16.0	17.5	16.7	16.6
1	19.9	19.4	20.5	20.1	19.7
2	18.8	18.6	19.2	19.1	18.5
3	22.8	23.0	22.4	22.8	22.7
4	21.9	23.0	20.4	21.3	22.5
Alcohol consumption (%)					
Beer					
Drinks beer	22.9	24.3	23.2	22.9	21.4
Does not drink beer	9.7	9.5	9.3	9.5	10.2
No data	67.4	66.2	67.5	67.6	68.4
Liquor					
Drinks liquor	28.0	30.4	27.9	25.4	27.9
Does not drink liquor	8.8	8.4	8.5	10.1	9.2
No data	63.2	61.2	63.6	65.5	62.9
Wine					
Drinks wine	23.5	25.4	22.5	21.1	24.3
Does not drink wine	8.9	8.7	8.8	9.3	9.1
No data	67.6	65.9	68.7	69.6	66.6

Table 1. (Continued.)

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
Ecologic risk factors‖					
Nonwhite race (%)	11.6±16.8	10.5±16.4	9.3±15.5	10.2±16.0	15.9±18.3
Home with air conditioning (%)	62.3±27.0	55.4±31.2	59.4±24.0	65.3±24.8	69.1±24.3
High-school education or greater (%)	51.7±8.2	53.5±7.9	52.4±7.5	50.8±7.2	50.0±9.5
Unemployment rate (%)	11.7±3.1	12.1±3.4	11.3±2.6	11.3±2.9	11.8±3.4
Gini coefficient of income inequality**	0.37±0.04	0.37±0.05	0.37±0.04	0.37±0.04	0.38±0.04
Proportion of population with income <125% of poverty line	0.12±0.08	0.11±0.08	0.12±0.08	0.11±0.07	0.13±0.09
Annual household income (thousands of dollars)††	20.7±6.6	21.9±7.1	19.8±6.0	21.2±6.7	19.7±6.3

* MSA denotes metropolitan statistical area, and $PM_{2.5}$ fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Plus–minus values are means ±SD. Because of rounding, percentages may not total 100. All baseline characteristics included in the survival model are listed (age, sex, and race were included as stratification factors). The model also includes squared terms for the number of cigarettes smoked per day and the number of years of smoking for both current and former smokers and a squared term for body-mass index.

† The body-mass index is the weight in kilograms divided by the square of the height in meters.

‡ Occupational exposure to particulate matter increases with increasing index number. The index was calculated by assigning a relative level of exposure to $PM_{2.5}$ associated with a cohort member's job and industry. These assignments were performed by industrial hygienists on the basis of their knowledge of typical exposure patterns for each occupation and specific job.[22]

§ Dietary-fat consumption increases with increasing index number. Dietary information from cohort members was used to define the level of fat consumption according to five ordered categories.[20]

¶ Dietary-fiber consumption increases with increasing index number. Dietary information from cohort members was used to define the level of fiber consumption according to five ordered categories.[23]

‖ For the ecologic variables, the model included terms for influences at the level of the average for the metropolitan statistical area and at the level of the difference between the value for the ZIP Code of residence and the average for the metropolitan statistical area to represent between- and within-metropolitan area confounding influence. Some values for ecologic variables and individual variables differ, although they appear to measure the same risk factor. For example, for the entire cohort, the percentage of whites as listed under individual variables is 93.7, whereas the percentage of nonwhites as listed under ecologic variables is 11.6±16.8. This apparent contradiction is explained by the fact that the former is an exact figure based on the individual reports of the study participants in the CPS II questionnaire, whereas the latter is a mean (±SD) for the population based on Census estimates for each metropolitan statistical area.

** The Gini coefficient is a statistical dispersion measure used to calculate income inequality. The coefficient ranges from 0 to 1, with 0 indicating an equal distribution of income and 1 indicating that one person has all the income and everyone else has no income.[20] A coefficient of 0.37 indicates that on average there is a measurable inequality in the distribution of income among the different income groups within the MSAs.

†† Average household incomes for the cohort and for each quartile of ozone concentration were calculated from the median household income for the metropolitan statistical area.

pulmonary causes, cardiovascular causes, and ischemic heart disease when ozone was included in the model. The association of ozone concentrations with death from respiratory causes remained significant after adjustment for $PM_{2.5}$.

Risk estimates for ozone-related death from respiratory causes were insensitive to the use of a random-effects survival model allowing for spatial clustering within the metropolitan area and state of residence (Table 1S in the Supplementary Appendix). The association between increased ozone concentrations and increased risk of death from respiratory causes was also insensitive to adjustment for several ecologic variables considered individually (Table 2S in the Supplementary Appendix).

Subgroup analyses showed that environmental temperature and region of the country, but not sex, age at enrollment, body-mass index, education, or concentration of $PM_{2.5}$, significantly modified the effects of ozone on the risk of death from respiratory causes (Table 4).

Figure 2 illustrates the shape of the relation between exposure to ozone and death from re-

Table 2. Number of Deaths in the Entire Cohort and According to Exposure to Ozone.

Cause of Death	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
	number of deaths				
Any cause	118,777	32,957	25,642	27,782	32,396
Cardiopulmonary	58,775	16,328	12,621	13,544	16,282
Cardiovascular	48,884	13,605	10,657	11,280	13,342
Ischemic heart disease	27,642	7,714	6,384	6,276	7,268
Respiratory	9,891	2,723	1,964	2,264	2,940

Table 3. Relative Risk of Death Attributable to a 10-ppb Change in the Ambient Ozone Concentration.*

Cause of Death	Single-Pollutant Model†			Two-Pollutant Model‡	
	Ozone (96 MSAs)	Ozone (86 MSAs)	$PM_{2.5}$ (86 MSAs)	Ozone (86 MSAs)	$PM_{2.5}$ (86 MSAs)
	relative risk (95% CI)				
Any cause	1.001 (0.996–1.007)	1.001 (0.996–1.007)	1.048 (1.024–1.071)	0.989 (0.981–0.996)	1.080 (1.048–1.113)
Cardiopulmonary	1.014 (1.007–1.022)	1.016 (1.008–1.024)	1.129 (1.094–1.071)	0.992 (0.982–1.003)	1.153 (1.104–1.204)
Respiratory	1.029 (1.010–1.048)	1.027 (1.007–1.046)	1.031 (0.955–1.113)	1.040 (1.013–1.067)	0.927 (0.836–1.029)
Cardiovascular	1.011 (1.003–1.023)	1.014 (1.005–1.023)	1.150 (1.111–1.191)	0.983 (0.971–0.994)	1.206 (1.150–1.264)
Ischemic heart disease	1.015 (1.003–1.026)	1.017 (1.006–1.029)	1.211 (1.156–1.268)	0.973 (0.958–0.988)	1.306 (1.226–1.390)

* MSA denotes metropolitan statistical area, and $PM_{2.5}$ fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Ozone concentrations were measured from April to September during the years from 1977 to 2000, with follow-up from 1982 to 2000; changes in the concentration of $PM_{2.5}$ of 10 μg per cubic meter were recorded for members of the cohort in 1999 and 2000. These models are adjusted for all the individual and ecologic risk factors listed in Table 1. For the ecologic variables, the model included terms for influences at the level of the average for the metropolitan statistical area and at the level of the difference between the value for the ZIP Code of residence and the average for the metropolitan statistical area to represent between- and within-metropolitan area confounding influence. The risk of death was stratified according to age (in years), sex, and race.

† The single-pollutant models were based on 96 metropolitan statistical areas for which information on ozone was available and 86 metropolitan statistical areas for which information on both ozone and fine particulate matter was available.

‡ The two-pollutant models were based on 86 metropolitan statistical areas for which information on both ozone and fine particulate matter was available.

spiratory causes. There was limited evidence that a threshold model specification improved model fit as compared with a nonthreshold linear model (P=0.06) (Table 3S in the Supplementary Appendix).

Because air-pollution data from 1977 to 2000 were averaged, exposure values for persons who died during this period are based partly on data that were obtained after death had occurred. Further investigation by dividing this interval into specific time windows of exposure revealed no significant difference between the effects of earlier and later time windows within the period of follow-up. Allowing for a 10-year period of exposure to ozone (5 years of follow-up and 5 years before the follow-up period) did not appreciably alter the risk estimates (Table 4S in the Supplementary Appendix). Thus, when exposure values were matched more closely to the follow-up period and when exposure values were based on data obtained before the deaths, there was little change in the results.

DISCUSSION

Our principal finding is that ozone and $PM_{2.5}$ contributed independently to increased annual mortality rates in this large, U.S. cohort study in analyses that controlled for many individual and ecologic risk factors. In two-pollutant models that included ozone and $PM_{2.5}$, ozone was significantly associated only with death from respiratory causes.

For every 10-ppb increase in exposure to ozone, we observed an increase in the risk of death from respiratory causes of about 2.9% in single-pollutant models and 4% in two-pollutant models. Although this increase may appear moderate, the risk of dying from a respiratory cause is more than three times as great in the metropolitan areas with the highest ozone concentrations as in those with the lowest ozone concentrations. The effects of ozone on the risk of death from respiratory causes were insensitive to adjustment for individual, neighborhood, and metropolitan-area confounders or to differences in multilevel-model specifications.

There is biologic plausibility for a respiratory effect of ozone. In laboratory studies, ozone can increase airway inflammation[24] and can worsen pulmonary function and gas exchange.[25] In addition, exposure to elevated concentrations of tropospheric ozone has been associated with numerous adverse health effects, including the induction[26] and exacerbation[27,28] of asthma, pulmonary dysfunction,[29,30] and hospitalization for respiratory causes.[31]

Despite these observations, previous studies linking long-term exposure to ozone with death have been inconclusive. One cohort study conducted in the Midwest and eastern United States reported an inverse but nonsignificant association between ozone concentrations and mortality.[1] Subsequent reanalyses of this study replicated these findings but also suggested a positive association with exposure to ozone during warm seasons.[3] A study of approximately 6000 nonsmoking Seventh-Day Adventists living in Southern California showed elevated risks among men after long-term exposure to ozone,[11] but this finding was based on limited mortality data.

Previous studies using the CPS II cohort have also produced mixed results for ozone. An earlier examination based on a large sample of more than 500,000 people from 117 metropolitan areas and 8 years of follow-up indicated nonsignificant results for the relation between ozone and death from any cause and a significant inverse association between ozone and death from lung cancer. A positive association between death from cardiopulmonary causes and summertime exposure to ozone was observed in single-pollutant

Table 4. Relative Risk of Death from Respiratory Causes Attributable to a 10-ppb Change in the Ambient Ozone Concentration, Stratified According to Selected Risk Factors.*

Stratification Variable	% of Subjects in Stratum	Relative Risk (95% CI)	P Value of Effect Modification
Sex			0.11
Male	43	1.01 (0.99–1.04)	
Female	57	1.04 (1.03–1.07)	
Age at enrollment (yr)			0.74
<50	26	1.00 (0.90–1.11)	
50–65	54	1.03 (1.01–1.06)	
>65	20	1.02 (1.00–1.05)	
Education			0.48
High school or less	43	1.02 (1.00–1.05)	
Beyond high school	57	1.03 (1.01–1.06)	
Body-mass index†			0.96
<25.0	53	1.03 (1.01–1.06)	
25.0–29.9	36	1.03 (0.99–1.06)	
≥30.0	11	1.03 (0.96–1.10)	
$PM_{2.5}$ ($\mu g/m^3$)‡			0.38
<14.3	44	1.05 (1.01–1.09)	
>14.3	56	1.03 (1.00–1.05)	
Region§			0.05
Northeast	24.8	0.99 (0.92–1.07)	
Industrial Midwest	29.7	1.00 (0.91–1.09)	
Southeast	21.0	1.12 (1.05–1.19)	
Upper Midwest	5.2	1.14 (0.68–1.90)	
Northwest	7.7	1.06 (1.00–1.13)	
Southwest	3.9	1.21 (1.04–1.40)	
Southern California	7.8	1.01 (0.96–1.07)	
External temperature (°C)‡¶			0.01
<23.3	24	0.96 (0.90–1.01)	
>23.3 to <25.4	29	0.97 (0.87–1.08)	
>25.4 to <28.7	22	1.04 (0.92–1.16)	
>28.7	25	1.05 (1.03–1.08)	

* $PM_{2.5}$ denotes fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Ozone exposures for the cohort were measured from April to September during the years from 1977 to 2000, with follow-up from 1982 to 2000, with adjustment for individual risk factors, and with baseline hazard function stratified according to age (single-year groupings), sex, and race. These analyses are based on the single-pollutant model for ozone shown in Table 3. Because of rounding, percentages may not total 100.

† The body-mass index is the weight in kilograms divided by the square of the height in meters.

‡ Stratum cutoff is based on the median of the distribution at the metropolitan-area level, not at the subject level.

§ Definitions of regions are those used by the Environmental Protection Agency.[3]

¶ External temperature is calculated as the average daily maximum temperature recorded between April and September from 1977 to 2000.

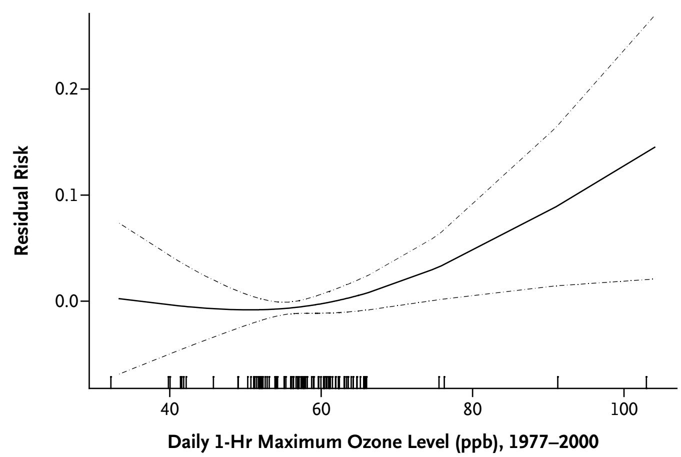

Figure 2. Exposure–Response Curve for the Relation between Exposure to Ozone and the Risk of Death from Respiratory Causes.

The curve is based on a natural spline with 2 df estimated from the residual relative risk of death within a metropolitan statistical area (MSA) according to a random-effects survival model. The dashed lines indicate the 95% confidence interval of fit, and the hash marks indicate the ozone levels of each of the 96 MSAs.

models, but the association with ozone was nonsignificant in two-pollutant models.[3] Further analyses based on 16 years of follow-up in 134 cities produced similarly elevated but nonsignificant associations that were suggestive of effects of summertime (July to September) exposure to ozone on death from cardiopulmonary causes.[5]

The increase in deaths from respiratory causes with increasing exposure to ozone may represent a combination of short-term effects of ozone on susceptible subjects who have influenza or pneumonia and long-term effects on the respiratory system caused by airway inflammation,[24] with subsequent loss of lung function in childhood,[32] young adulthood,[33,34] and possibly later life.[35] If exposure to ozone accelerates the natural loss of adult lung function with age, those exposed to higher concentrations of ozone would be at greater risk of dying from a respiratory-related syndrome.

In our two-pollutant models, the adjusted estimates of relative risk for the effect of ozone on the risk of death from cardiovascular causes were significantly less than 1.0, seemingly suggesting a protective effect. Such a beneficial influence of ozone, however, is unlikely from a biologic standpoint. The association of ozone with cardiovascular end points was sensitive to adjustment for exposure to $PM_{2.5}$, making it difficult to determine precisely the independent contributions of these copollutants to the risk of death. There was notable collinearity between the concentrations of ozone and $PM_{2.5}$.

Furthermore, measurement at central monitors probably represents population exposure to $PM_{2.5}$ more accurately than it represents exposure to ozone. Ozone concentration tends to vary spatially within cities more than does $PM_{2.5}$ concentration, because of scavenging of ozone by nitrogen oxide near roadways.[36] In the presence of a high density of local traffic, the measurement error is probably higher for exposure to ozone than for exposure to $PM_{2.5}$. The effects of ozone could therefore be confounded by the presence of $PM_{2.5}$ because of collinearity between the measurements of the two pollutants and the higher precision of measurements of $PM_{2.5}$.[37]

Measurements of $PM_{2.5}$ were available only for the end of the study follow-up period (1999 and 2000). Widespread collection of these data began only after the EPA adopted regulatory limits on such particulates in 1997. Since particulate air pollution has probably decreased in most metropolitan areas during the follow-up interval of our study, it is likely that we have underestimated the effect of $PM_{2.5}$ in our analysis.

A limitation of our study is that we were not able to account for the geographic mobility of the population during the follow-up period. We had information on home addresses for the CPS II cohort only at the time of initial enrollment in 1982 and 1983. Census data indicate that during the interval between 1982 and 2000, approximately 2 to 3% of the population moved from one state to another annually (with the highest rates in an age group younger than that of our study population).[38] However, any bias due to a failure to account for geographic mobility is likely to have attenuated, rather than exaggerated, the effects of ozone on mortality.

In summary, we investigated the effect of tropospheric ozone on the risk of death from any cause and cause-specific death in a large cohort, using data from 96 metropolitan statistical areas across the United States and controlling for the effect of particulate air pollutants. We were unable to detect a significant effect of exposure to ozone on the risk of death from cardiovascular causes when particulates were taken into account, but we did demonstrate a significant effect of exposure to ozone on the risk of death from respiratory causes.

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This article is dedicated to the memory of our coauthor and friend, Dr. Jeanne Calle, who died unexpectedly on February 17, 2009.

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EPA United States Environmental Protection Agency

Ground-level Ozone
Health Effects

Ozone in the air we breathe can harm our health—typically on hot, sunny days when ozone can reach unhealthy levels. Even relatively low levels of ozone can cause health effects. People with lung disease, children, older adults, and people who are active outdoors may be particularly sensitive to ozone.

Children are at greatest risk from exposure to ozone because their lungs are still developing and they are more likely to be active outdoors when ozone levels are high, which increases their exposure. Children are also more likely than adults to have asthma.

Breathing ozone can trigger a variety of health problems including chest pain, coughing, throat irritation, and congestion. It can worsen bronchitis, emphysema, and asthma. Ground level ozone also can reduce lung function and inflame the linings of the lungs. Repeated exposure may permanently scar lung tissue.

Ozone can:

- Make it more difficult to breathe deeply and vigorously.
- Cause shortness of breath and pain when taking a deep breath.
- Cause coughing and sore or scratchy throat.
- Inflame and damage the airways.
- Aggravate lung diseases such as asthma, emphysema, and chronic bronchitis.
- Increase the frequency of asthma attacks.
- Make the lungs more susceptible to infection.
- Continue to damage the lungs even when the symptoms have disappeared.

These effects may lead to increased school absences, medication use, visits to doctors and emergency rooms, and hospital admissions. Research also indicates that ozone exposure may increase the risk of premature death from heart or lung disease.

Ozone is particularly likely to reach unhealthy levels on hot sunny days in urban environments. It is a major part of urban smog. Ozone can also be transported long distances by wind. For this reason, even rural areas can experience high ozone levels. And, in some cases, ozone can occur throughout the year in some southern and mountain regions. Learn more about the formation and transport of ground level ozone.

The AIRNow Web site provides daily air quality reports for many areas. These reports use the Air Quality Index (or AQI) to tell you how clean or polluted the air is. EnviroFlash, a free service, can alert you via email when your local air quality is a concern. Sign up at www.enviroflash.info.

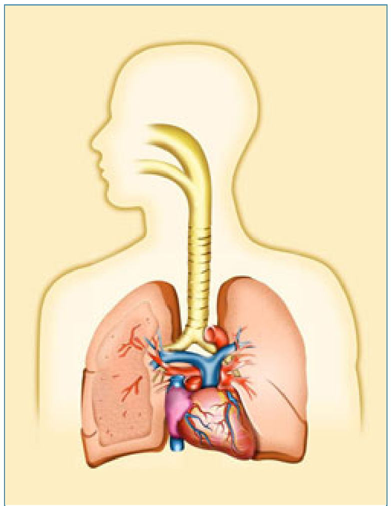
If you're a health care provider, visit AIRNow's Health Care Provider page for educational materials and trainings.

For more information on how EPA works to reduce ground level ozone, visit the Ozone Standards page.

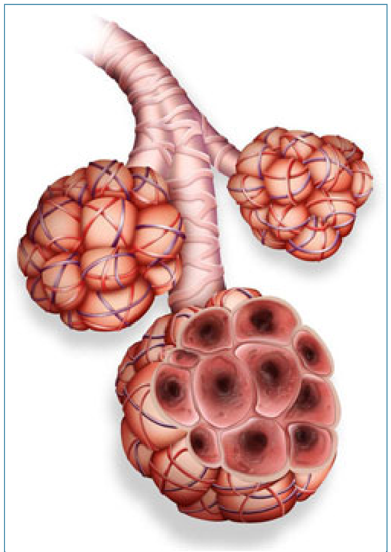
For more information on ground level ozone, health and the environment, visit:

- Ozone and Your Health (PDF) (2 pp, 2.5 MB) This short, colorful pamphlet tells who is at risk from exposure to ozone, what health effects are caused by ozone, and simple measures that can be taken to reduce health risk.
- Ozone: Good Up High, Bad Nearby (PDF) (2 pp, 1.3 MB) Ozone acts as a protective layer high above the earth, but it can be harmful to breathe. This publication provides basic information about ground level and high-altitude ozone.
- EPA's Air Quality Guide for Ozone Provides detailed information about what the Air Quality Index means. Helps determine ways to protect your family's health when ozone levels reach the unhealthy range, and ways you can help reduce ozone air pollution.
- Ozone and Your Patients' Health Training for Health Care Providers Designed for family practice doctors, pediatricians, nurse practitioners,

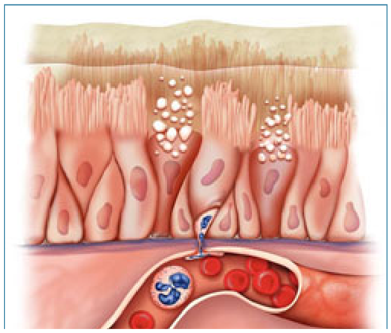
What are the effects of ozone?



Effects on the Airways. Ozone is a powerful oxidant that can irritate the air ways causing coughing, a burning sensation, wheezing and shortness of breath and it can aggravate asthma and other lung diseases.

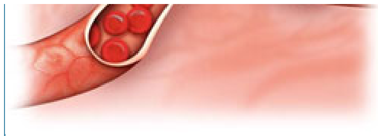


Alveoli filled with trapped air. Ozone can cause the muscles in the airways to constrict, trapping air in the alveoli. This leads to wheezing and shortness of breath. In people with asthma it can result in asthma attacks.



asthma educators, and other medical professionals who counsel patients about asthma and respiratory symptoms.

- AIRNow Health Providers Information Provides information on how to help patients protect their health by reducing their exposure to air pollution.
- EPA's Asthma Web Site EPA's Communities in Action Asthma Initiative is a coordinated effort to reduce the burden of asthma and includes programs to address indoor and outdoor environments that cause, trigger or exacerbate asthma symptoms.
- Smog - Who Does it Hurt? (PDF) (10 pp, 819 KB) This 8-page booklet provides more detailed information than "Ozone and Your Health" about ozone health effects and how to avoid them.
- Summertime Safety: Keeping Kids Safe from Sun and Smog (PDF) (2 pp, 314 KB) This document discusses summer health hazards that pertain particularly to children and includes information about EPA's Air Quality Index and UV Index tools.



Airway Inflammation. With airway inflammation, there is an influx of white blood cells, increased mucous production, and fluid accumulation and retention. This causes the death and shedding of cells that line the airways and has been compared to the skin inflammation caused by sunburn.

Ozone and Your Patients' Health Training for Health Care Providers

Last updated on 11/1/2012

United States Environmental Protection Agency

Nitrogen Dioxide
Health

Current scientific evidence links short-term NO_2 exposures, ranging from 30 minutes to 24 hours, with adverse respiratory effects including airway inflammation in healthy people and increased respiratory symptoms in people with asthma.

Also, studies show a connection between breathing elevated short-term NO_2 concentrations, and increased visits to emergency departments and hospital admissions for respiratory issues, especially asthma.

NO_2 concentrations in vehicles and near roadways are appreciably higher than those measured at monitors in the current network. In fact, in-vehicle concentrations can be 2-3 times higher than measured at nearby area-wide monitors. Near-roadway (within about 50 meters) concentrations of NO_2 have been measured to be approximately 30 to 100% higher than concentrations away from roadways.

Individuals who spend time on or near major roadways can experience short-term NO_2 exposures considerably higher than measured by the current network. Approximately 16% of U.S housing units are located within 300 ft of a major highway, railroad, or airport (approximately 48 million people). This population likely includes a higher proportion of non-white and economically-disadvantaged people.

NO_2 exposure concentrations near roadways are of particular concern for susceptible individuals, including people with asthma asthmatics, children, and the elderly

The sum of nitric oxide (NO) and NO_2 is commonly called nitrogen oxides or NOx. Other oxides of nitrogen including nitrous acid and nitric acid are part of the nitrogen oxide family. While EPA's National Ambient Air Quality Standard (NAAQS) covers this entire family, NO_2 is the component of greatest interest and the indicator for the larger group of nitrogen oxides.

NOx react with ammonia, moisture, and other compounds to form small particles. These small particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death.

Ozone is formed when NOx and volatile organic compounds react in the presence of heat and sunlight. Children, the elderly, people with lung diseases such as asthma, and people who work or exercise outside are at risk for adverse effects from ozone. These include reduction in lung function and increased respiratory symptoms as well as respiratory-related emergency department visits, hospital admissions, and possibly premature deaths.

Emissions that lead to the formation of NO_2 generally also lead to the formation of other NOx. Emissions control measures leading to reductions in NO_2 can generally be expected to reduce population exposures to all gaseous NOx. This may have the important co-benefit of reducing the formation of ozone and fine particles both of which pose significant public health threats.

Last updated on 12/10/2012

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888 First Street, N. E., Room 1A
Washington, D.C. 20426

SUBJECT: Draft Environmental Impact Statement for the Clean Energy LNG Project, May 2006 CEQ No. 20060206 and ERP No. FRC - E0315-MS

Dear Ms. Salas:

Pursuant to Section 309 of the Clean Air Act [CAA] and Section 102[2][C] of the National Environmental Policy Act [NEPA], EPA-Region 4 has reviewed the Federal Energy Regulatory Commission [FERC] Draft Environmental Impact Statement [DEIS] for the Clean Energy [Applicant] LNG Pipeline LLC project. Under Section 309 of the CAA, EPA is responsible for reviewing and commenting on major federal actions significantly affecting the quality of the human environment. EPA also serves as a cooperating agency during the NEPA process. Our review of the DEIS includes comments in accordance with both EPA roles.

The subject document is an evaluation of the environmental consequences of construction/operation of a liquefied natural gas [LNG] import terminal and natural gas pipeline complex in Pascagoula, Mississippi. Functionally, this on-shore facility would consist of the means to receive, store, and re-gasify LNG, which would be transported to the site via specialized ships and then transhipped to various end-users by a pipeline system. The import terminal would consist of two full containment storage tanks [160,000 cubic meter]; the LNG re-gasification system [10 submerged combustion vaporizers - *"closed-loop"*]; and operational equipment, including support/pipeline interconnects, electric transmission, vapor handling, and infrastructure. Condensate from the re-vaporization system would be discharged into the marine environment adjacent the facility. The exact constituent[s]/temperature differential of this discharge are not provided; however, based on our analysis of similar LNG re-gasification systems, this effluent should pose only nominal adverse impacts to the receiving waters. Dredging a berthing area for the LNG ships would generate approximately 3 million cubic yards of material with disposal proposed in the existing designated site south of Horn Island.

The facility would re-vaporize and deliver natural gas at a continuous rate of approximately 1.5 billion cubic feet per day. An existing distribution network - with some new construction - would be used to transport the finished gas product to various market users. Because of its exposed location, a circumferential dike wall [45' x 25'] would be constructed to mitigate the potential hazards of hurricane surge. Construction of the proposed project is forecast to be completed in 2009.

FERC examines multiple alternatives in the DEIS, including: alternative sites [on-and offshore] for the port; alternative pipeline routes; terminal slip configurations; re-vaporization technologies; dredge material placement options; and various infrastructure siting locations. Application of screening criteria and purpose/need analyses narrowed the range of options to a manageable number and these were carried forward for further review. After evaluation, the array of alternatives was further winnowed. Among this final set of practicable options is the applicant's proposal, *i.e.*, location south of the Chevron Refinery; "Louisville/Nashville" pipeline alignment to the Gulfstream/BP/Destin interconnections; use of closed-loop vaporization; and disposal of excess excavated material in the Horn Island site. The DEIS compared/contrasted impacts resulting from the action alternatives with the no-action option.

We recognize the importance of bringing additional natural gas supplies into the eastern Gulf of Mexico region. On the basis of our current understanding, it appears that the overall impacts, as well as the specific kinds of effects, associated with the proposed Clean Energy project can be effectively mitigated via collaboration among the involved parties. However, as described in our detailed comments, we recommend the Final EIS contain specific baseline data about certain environmental effects of the proposed project. In addition, the detailed comments identify additional functional areas that we believe warrant more substantiation, including a wetland mitigation package; the effects of terminal construction/operation on near-shore aquatic resources; the acceptability of the excavated material for offshore disposal; a more comprehensive cumulative impacts assessment; and more thorough evaluation of socioeconomic factors to support conclusions regarding environmental justice [EJ] issues.

As a result of our long-term experience with similar coastal facilities, discussions with the applicant's consultant during the NEPA process, and numerous interactions with state/federal agencies, we believe concerns and issues raised in our comments can be resolved. Hence, we have assigned a rating of **EC-2** to the overall action, including the applicant's proposal. That is, we have environmental concerns [**EC**] about the degree/extent to which the long-term operation of this proposed re-gasification facility could affect local environmental quality and [**2**] we recommend additional information be provided in the Final EIS to strengthen the evaluation of the proposed project's overall impacts. To expedite review and facilitate evaluation of project-related materials, we recommend FERC provide us with the information requested in our detailed comments before circulation of the Final EIS. We believe that expeditious evaluation of these materials could also be enhanced through a series of informal technical meetings among our staff, FERC staff, and representatives of the applicant.

Because the evaluation process is time constrained, we will make resolution of the noted outstanding issues a high priority. Our technical staff will continue to work with your staff through the remainder of the NEPA process to reach agreement on an environmentally acceptable outcome.

Thank you for the opportunity to review and comment on this DEIS. If you have further questions, please have your staff contact Dr. Gerald Miller by telephone at [404] 562-9626 or by e-mail at miller.gerald@epa.gov.

Sincerely,

Heinz J. Mueller, Chief
NEPA Program Office

Enclosure

DETAILED COMMENTS

On the basis of our initial review, we determined that additional data, as well as clarification of existing information, would improve the NEPA analysis. This supplemental information is important for federal and state agencies to complete their determination of the proposed project's environmental consequences and assist in evaluating applications for permits/approvals.

AIR QUALITY

We recommend resolving the following issues to aid informed decision-making regarding the proposed project's air quality impacts and to expeditiously facilitate securing the necessary state/federal permits:

1. Identification of the standards and/or target values used in a particular analysis [Air Quality Section-4.11.1] is important in understanding the acceptability of the proposed project's ambient impacts. The DEIS identifies only the national ambient air quality standards [NAAQS] and prevention of significant deterioration [PSD] increments. We recommend FERC provide a more complete evaluation of standards and targets, including other air quality related values [e.g., visibility, deposition, etc.] in the PSD Class I area and sensitive receptors within PSD Class II areas.

2. Although the DEIS provides project emissions for both the construction and operation of the facility [Tables 4.12.1-3 and 4.12.1-4, respectively], we recommend the Final EIS provide further information on the bases for the estimated emissions. For example, the assumptions [*e.g.*, hours spent unloading] and bases [*e.g.*, types of fuel] used for calculating the magnitude of the LNG ship unloading emissions would aid our evaluation. We recommend FERC include detailed emission estimates for each pollutant in the Final EIS.

3. The DEIS indicates [page 4-111] that the applicant should provide additional emissions information requested by the Mississippi Department of Environmental Quality [MDEQ] to determine if the proposed project would be subject to PSD permitting requirements. We recommend FERC work with the applicant to ensure submission of such information as soon as possible.

4. Table 4.12.1-1 provides the NAAQS and monitored ambient background concentrations for the pollutants of concern. Because the periods of record [*i.e.*, years 2000 to 2004] are not associated with the NAAQS, they are not necessary in *footnotes b* through *g*. Instead, a reference in *footnote a* would be sufficient. Additionally, the basis [*e.g.*, highest, high second-highest, etc.] for the monitored concentrations that are provided in the table can also be placed in *footnote a*.

5. Table 4.12.1-1 provides an 8-hour ozone background measurement greater than the NAAQS. The Final EIS should address this apparent NAAQS violation and include a discussion of the potential impact of the proposed project on ambient ozone levels.

6. Chevron's Casotte Landing project is an LNG import facility being proposed in the immediate area. Both proposed projects have similar schedules and could impact the same area. Section 4.14 provides a cumulative impact assessment of the proposed Clean Energy project, along with the construction and operation of two other projects [*i.e.*, the proposed Casotte Landing LNG project and the proposed Chevron Pascagoula Refinery Expansion]. However, the DEIS compares the estimated emissions for these three proposed projects to the total emissions in Jackson County, in lieu of providing a cumulative assessment. Additionally, the DEIS indicates that the separate air quality permitting process will ensure acceptable air quality impacts for each proposed project, but the document gives no quantitative ambient impact assessments. To improve the Final EIS, we recommend FERC incorporate ambient air quality assessments that include compliance with the NAAQS, PSD increments, and air quality related values in the PSD Class I area and at sensitive receptors within the PSD Class II area.

Further, a complete cumulative impact assessment should not be limited to the noted three actions. As indicated in Section 1.2 of the DEIS, the assessment of cumulative impacts includes other past, present, and reasonably foreseeable future projects and activities. We also recommend FERC include a more complete cumulative air quality assessment to ensure compliance with applicable ambient air quality standards.

7. The DEIS provides a preliminary quantitative *project-only* impact assessment pertaining only to the Breton National Wildlife Area PSD Class I area. Table 4.12.1-2. provides the modeling results. The following comments apply to this assessment:

a. Because only project emissions are modeled, the resultant concentrations cannot be compared to the cumulative PSD increments standard. Project-only impacts are more appropriately compared to the Class I significant impact levels.

b. The DEIS should address Class I area air quality-related values [AQRV] of visibility and deposition.

c. The operational project emissions [Table 4.12.1-4] have changed since the release of the administrative DEIS, but the modeled project concentrations in Table 4.12.1-2 have not. We recommend explaining the reason[s] why the latter concentrations have not changed.

d. FERC should provide specific information on the modeling [*e.g.*, input emissions and meteorology used, assumptions and procedures used, etc.].

e. We recommend FERC provide an electronic version of the input and output modeling files with the next submission to EPA.

[Note - We recommend FERC re-examine the 100 km distance limit used for modeling analyses in the PSD Class I area. Upon consideration of the anticipated impacts of the proposed project and its proximity to a Class I area, the Federal Land Manager may require impact assessments using distance limits up to 300 km.]

8. Table 4.12.1-3 of the DEIS provides emission estimates from the proposed project's construction activities. The magnitude of some construction emissions are larger than those associated with operation of the facility. As a result, we recommend the DEIS include impact analyses to explain or support the statement that construction emissions would have no significant effect on air quality.

9. Assessments of the maximum air quality impacts in the Class II area surrounding the proposed facility should be provided for both operational and construction impacts. We recommend FERC provide a more complete evaluation of applicable ambient air standards [*e.g.*, NAAQS, visibility, ozone, etc.].

10. Section 5.1.11 of the DEIS provides conclusions regarding air quality impacts. We recommend the Final EIS provide more complete data on project emissions and a more thorough assessment of ambient impacts to strengthen this section.

RECOMMENDATIONS: We recommend FERC provide us with the information requested in this section as soon as practicable to facilitate full assessment of the potential impacts of the proposed project.

Subject matter contacts: Mr. Stan Krivo, 404-562-9123 and Ms. Katy Forney, 404-562-9130

DREDGED MATERIAL DISPOSAL

According to information contained in the DEIS, the applicant proposes to use the existing Ocean Dredged Material Disposal Site south of Horn Island to dispose of material which would be excavated to accommodate the LNG ships. Under Section 103 of the Marine Protection, Research, and Sanctuaries Act [MPRSA], permits for ocean disposal of dredged materials are issued by the U.S. Army Corps of Engineers [COE], subject to concurrence by EPA, in accordance with the process described in Section 103(c) of MPRSA.

We recommend the Final EIS contain sufficient information to allow us to fully assess proposed ocean disposal operations and to determine compliance with the Ocean Dumping Criteria (40 CFR Parts 227 and 228). We understand that the applicant has not made an initial submission to the COE District Office in Mobile.

RECOMMENDATIONS: Before a conclusive review of the applicant's proposal [i.e., using the existing ODMDS south of Horn Island] to dispose of material which would be excavated to accommodate the LNG ships can be accomplished, we request the applicant provide us a copy of its submission to the Mobile District Corps of Engineers. We further request this information be provided before circulation of the Final EIS for review/comment. We recommend FERC work with the applicant to ensure that appropriate information is submitted to the Mobile District Corps of Engineers as soon as practicable to allow us to fully assess the applicant's dredged material disposal proposal.

Subject matter contact: Mr. Doug Johnson, 404-562-9386 or Dr. Susan Rees, 251-694-4141 at the Mobile District

ENVIRONMENTAL JUSTICE

The provisions of Executive Order 12898, requiring federal agencies to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of activities on minority and low-income populations, apply to this proposal and should be used to address the impacts of the LNG terminal on such populations within the project area. Section 4.9 of the DEIS contains information on socioeconomic factors that characterize the surrounding areas and the potential impacts of the construction and operation of the terminal on the overall population, housing, property values, and other pertinent community aspects. However, we recommend the Final EIS provide further information to better permit a correlation as to whether or not the environmental effects of the proposed project could result in a disproportionate burden on minority and low-income populations.

The DEIS states that FERC has not identified any adverse human health or environmental effects that would be borne disproportionately by any low income or minority group. While this might, in fact, be the case, this conclusory statement should be explained with some analysis.

RECOMMENDATIONS: We recommend the Final EIS provide a more thorough evaluation of socioeconomic factors to support the conclusion that the proposed project would not cause disproportionate adverse effects on minority and low-income populations from an environmental and human health perspective. This can be most effectively accomplished by requesting the applicant to consult with EPA Region 4 and/or the Mississippi Department of Environmental Quality for assistance.

Subject matter contact: Ms. Gracy Danois, 404-562-9119

EVALUATION OF RISK ANALYSIS

From our review, it appears the DEIS contains apparent gaps/inconsistencies in the calculations relating to thermal radiation and flammable vapor hazard distances. Page 5-12, states:

> "thermal radiation and flammable vapor hazard distances were calculated for an accident or an attack on a LNG carrier. For 1-, 1.5-, 2.5-, 3.0-, and 3.9-meter-diameter holes in an LNG cargo tank, we estimated distances to range from 2,164 to 5,250 feet for a thermal radiation level of 1,600 BTU/hr/ft^2, the level which is hazardous to unprotected persons located outdoors". [1,600 BTU/hr/ft^2 is the level of exposure at which firefighters are required to wear protective clothing, and is a common threshold of safety for the LNG industry].

Based on a 1-meter-diameter hole, an un-ignited release would result in an estimated pool radius of 421 feet. The un-ignited vapor cloud would extend to 9,776 feet to the lower flammable limit [LFL] and 14,377 feet to one-half the LFL. [The LFL is the point at which combustion can occur. Within this range a simple light switch or car motor could serve as an ignition source.] Flammable vapor dispersion for larger holes is not performed since, realistically, the cloud would not even extend to the maximum distance for a hole one meter in diameter, before encountering an ignition source.

Further, page ES-7, states, "the closest residences are approximately 1.7 [8,976 feet] miles northwest of the proposed LNG terminal site." Page 5-12 states that the maximum range for thermal radiation [from a pool fire] is 5,250 feet and that the flammable vapor cloud distance for a 1-meter hole release is 9,776 feet. Consequently, residents living within the potential danger zone could be impacted by an accident /attack that results from a release from a 1-meter diameter hole or greater.

However, on page 5-12, the DEIS states, ". . .realistically, the cloud would not even extend to the maximum distance for a 1-meter diameter hole before encountering an ignition source." This paragraph ends with the conclusory statement, ". . .the risk to the public from accidental causes should be considered negligible." For the reasons stated above, we recommend the Final EIS provide further analysis supporting this statement.

In Section 5.2 beginning on page 5-9, FERC presents a list of recommended items to mitigate the environmental impacts associated with the construction and operation of the proposed project. EPA supports these measures and further recommends inclusion of the following measures, which are used throughout the chemical processing industry:

1. Page 5-22, "46. The final design shall include a HAZOP review of the completed design. A copy of the review and a list of the recommendations shall be filed." We recommend FERC add the following: "The facility shall develop both a plan to

implement the recommendations of the HAZOP review and a quality assurance plan or check list to verify completion of the implementation of the recommendations in both plans."

2. Page 5-23, "60. The facility shall be subject to regular FERC staff and technical reviews...." We recommend FERC add the following: "Further, the facility shall implement a management of change [MOC] program to track changes in the facility, such as additions to or modifications of process equipment, and changes in alarms, instrumentation, and control schemes. The MOC program ensures that changes made by operations and maintenance personnel do not result in deviations from established safe operating limits. The MOC program should require a continuous updating of engineering drawings, e.g., process, instrumentation, mechanical, and electrical. As part of the MOC program, the HAZOP review should be updated at reasonable intervals in accordance with industry best management practices to include an evaluation of any changes and their consequences."

For details, see American Institute of Chemical Engineers Center [AIChE] for Chemical Process Safety "Plant Guidelines for Technical Management of Chemical Process Safety," 1995, or D. Crowl, "Chemical Process Safety Fundamentals with Applications, 1990.

RECOMMENDATIONS: We recommend the Final EIS include these additional provisions. Subject matter contact, Ms. Phyllis Warrilow, 404-562-9198

CUMULATIVE IMPACTS

As indicated in the DEIS, the assessment of cumulative impacts includes other past, present, and reasonably foreseeable future projects and activities. Thus, a complete cumulative impact assessment unlikely would be limited to effects associated with this specific proposed project, the proposed Clean Energy project, and the proposed Chevron Pascagoula Refinery Expansion.

RECOMMENDATIONS: We recommend FERC identify the geographic area and planning horizon for which cumulative impacts are being assessed, and explain the rationale for the area and horizon chosen. Cumulative impacts resulting from existing or reasonably foreseeable projects within the selected area and horizon should be identified and assessed. (See 18 CFR 380.12(b)(3)). We suggest FERC utilize the Council on Environmental Quality's 1997 Guidance, *Considering Cumulative Effects Under the National Environmental Policy Act*, in conducting the evaluation.

Subject matter contact : Ms. Katy Forney, 404-562-9130

ONSHORE EFFECTS

As the DEIS acknowledges, the proposed project will affect wetlands. Direct and associated impacts include: conversion of 2.6 acres of forested wetlands to emergent wetlands [maintained right-of-way]; the permanent loss of 4.9 acres of intertidal mudflats [construction of the terminal facility]; and temporary impacts to 14.1 wetland acres [construction of the pipeline facilities]. The berthing area would convert 61.3 acres of shallow water to deep water habitat in an area designated as Essential Fish Habitat. The applicant's proposal to mitigate for the conversion of 2.6 acres of wetlands through payment into a wetlands' mitigation bank at a 2:1 ratio. The applicant also proposes creation/restoration of 7.6 acres of marsh wetlands to compensate for the loss of the 4.9 acres of intertidal mud flats and 61.3 acres of shallow water habitat. Further, the DEIS does not provide a restoration plan for the temporary impacts to 14.1 wetland acres and/or a compensatory mitigation plan for the temporal loss associated with these impacts.

RECOMMENDATIONS: We recommend the wetlands and dredging impacts sections of the Final EIS provide a description of a restoration and contingency plan, which would be consistent with COE regulations requiring appropriate and practicable compensatory mitigation to replace functional losses to aquatic resources. Specifically, we would recommend the Final EIS address offsets to impacts to the intertidal mud flats and shallow water habitats, as provided by the COE regulations. EPA technical staff will continue to work with their state/federal counterparts, as well as the applicant, to ensure all the functional losses associated with the proposed project are addressed.

Subject matter contact: Ms. Andrea Wade, 404-562-9419

UNEP

World Meteorological Organization

Integrated Assessment of Black Carbon and Tropospheric Ozone

Summary for Decision Makers









A complete elaboration of the topics covered in this summary can be found in the Integrated Assessment of Black Carbon and Tropospheric Ozone report and in the fully referenced underlying research, analyses and reports.

For details of UNEP's regional and sub-regional areas referred to throughout this document see http://geodata.grid.unep.ch/extras/geosubregions.php.

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Disclaimers

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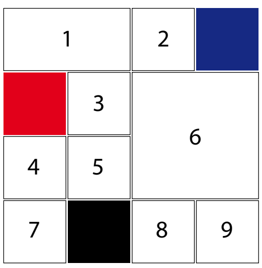

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Integrated Assessment of Black Carbon and Tropospheric Ozone

Summary for Decision Makers

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Main Messages

Scientific evidence and new analyses demonstrate that control of black carbon particles and tropospheric ozone through rapid implementation of proven emission reduction measures would have immediate and multiple benefits for human well-being.

Black carbon exists as particles in the atmosphere and is a major component of soot, it has significant human health and climate impacts. At ground level, ozone is an air pollutant harmful to human health and ecosystems, and throughout the troposphere, or lower atmosphere, is also a significant greenhouse gas. Ozone is not directly emitted, but is produced from emissions of precursors of which methane and carbon monoxide are of particular interest here.

THE CHALLENGE

1. **The climate is changing now, warming at the highest rate in polar and high-altitude regions.** Climate change, even in the near term, has the potential to trigger abrupt transitions such as the release of carbon from thawing permafrost and biodiversity loss. The world has warmed by about 0.8°C from pre-industrial levels, as reported by the

Credit: Kevin Hicks

Traditional brick kilns in South Asia are a major source of black carbon. Improved kiln design in this region is significantly reducing emissions.

Intergovernmental Panel on Climate Change (IPCC). The Parties to the United Nations Framework Convention on Climate Change (UNFCCC) have agreed that warming should not exceed 2˚C above pre-industrial levels.

2. **Black carbon and ozone in the lower atmosphere are harmful air pollutants that have substantial regional and global climate impacts.** They disturb tropical rainfall and regional circulation patterns such as the Asian monsoon, affecting the livelihoods of millions of people.

3. **Black carbon's darkening of snow and ice surfaces increases their absorption of sunlight, which, along with atmospheric heating, exacerbates melting of snow and ice around the world, including in the Arctic, the Himalayas and other glaciated and snow-covered regions.** This affects the water cycle and increases risks of flooding.

4. **Black carbon, a component of particulate matter, and ozone both lead to adverse impacts on human health leading to premature deaths worldwide. Ozone is also the most important air pollutant responsible for reducing crop yields, and thus affects food security.**

REDUCING EMISSIONS

5. **Reducing black carbon and tropospheric ozone now will slow the rate of climate change within the first half of this century. Climate benefits from reduced ozone are achieved by reducing emissions of some of its precursors, especially methane which is also a powerful greenhouse gas.** These short-lived climate forcers – methane, black carbon and ozone – are fundamentally different from longer-lived greenhouse gases, remaining in the atmosphere for only a relatively short time. Deep and immediate carbon dioxide reductions are required to protect long-term climate, as this cannot be achieved by addressing short-lived climate forcers.

6. **A small number of emission reduction measures targeting black carbon and ozone precursors could immediately begin to protect climate, public health, water and food security, and ecosystems.** Measures include the recovery of methane from coal, oil and gas extraction and transport, methane capture in waste management, use of clean-burning stoves for residential cooking, diesel particulate filters for vehicles and the banning of field burning of agricultural waste. Widespread implementation is achievable with existing technology but would require significant strategic investment and institutional arrangements.

7. **The identified measures complement but do not replace anticipated carbon dioxide reduction measures.** Major carbon dioxide reduction strategies mainly target the energy and large industrial sectors and therefore would not necessarily result in significant reductions in emissions of black carbon or the ozone precursors methane and carbon monoxide. Significant reduction of the short-lived climate forcers requires a specific strategy, as many are emitted from a large number of small sources.

BENEFITS OF EMISSION REDUCTIONS

8. **Full implementation of the identified measures would reduce future global warming by 0.5°C (within a range of 0.2–0.7°C, Figure 1).** If the measures were to be implemented by 2030, they could halve the potential increase in global temperature projected for 2050 compared to the Assessment's reference scenario based on current policies and energy and fuel projections. The rate of regional temperature increase would also be reduced.

9. **Both near-term and long-term strategies are essential to protect climate.** Reductions in near-term warming can be achieved by control of the short-lived climate forcers whereas carbon dioxide emission reductions, beginning now, are required to limit long-term climate change. Implementing both reduction strategies is needed to improve the chances of keeping the Earth's global mean temperature increase to within the UNFCCC 2°C target.

10. **Full implementation of the identified measures would have substantial benefits in the Arctic, the Himalayas and other glaciated and snow-covered regions.** This could reduce warming in the Arctic in the next 30 years by about two-thirds compared to the projections of the Assessment's reference scenario. This substantially decreases the risk of changes in weather patterns and amplification of global warming resulting from changes in the Arctic. Regional benefits of the black carbon measures, such as their effects on snow- and ice-covered regions or regional rainfall patterns, are largely independent of their impact on global mean warming.

11. **Full implementation of the identified measures could avoid 2.4 million premature deaths (within a range of 0.7–4.6 million) and the loss of 52 million tonnes (within a range of 30–140 million tonnes), 1–4 per cent, of the global production of maize, rice, soybean and wheat each year (Figure 1).** The most substantial benefits will be felt immediately in or close to the regions where action is taken to reduce emissions, with the greatest health and crop benefits expected in Asia.

RESPONSES

12. The identified measures are all currently in use in different regions around the world to achieve a variety of environment and development objectives. **Much wider and more rapid implementation is required to achieve the full benefits identified in this Assessment.**

13. **Achieving widespread implementation of the identified measures would be most effective if it were country- and region-specific, and could be supported by the considerable existing body of knowledge and experience.** Accounting for near-term climate co-benefits could leverage additional action and funding on a wider international scale which would facilitate more rapid implementation of the measures. Many measures achieve cost savings over time. However, initial capital investment could be problematic in some countries, necessitating additional support and investment.

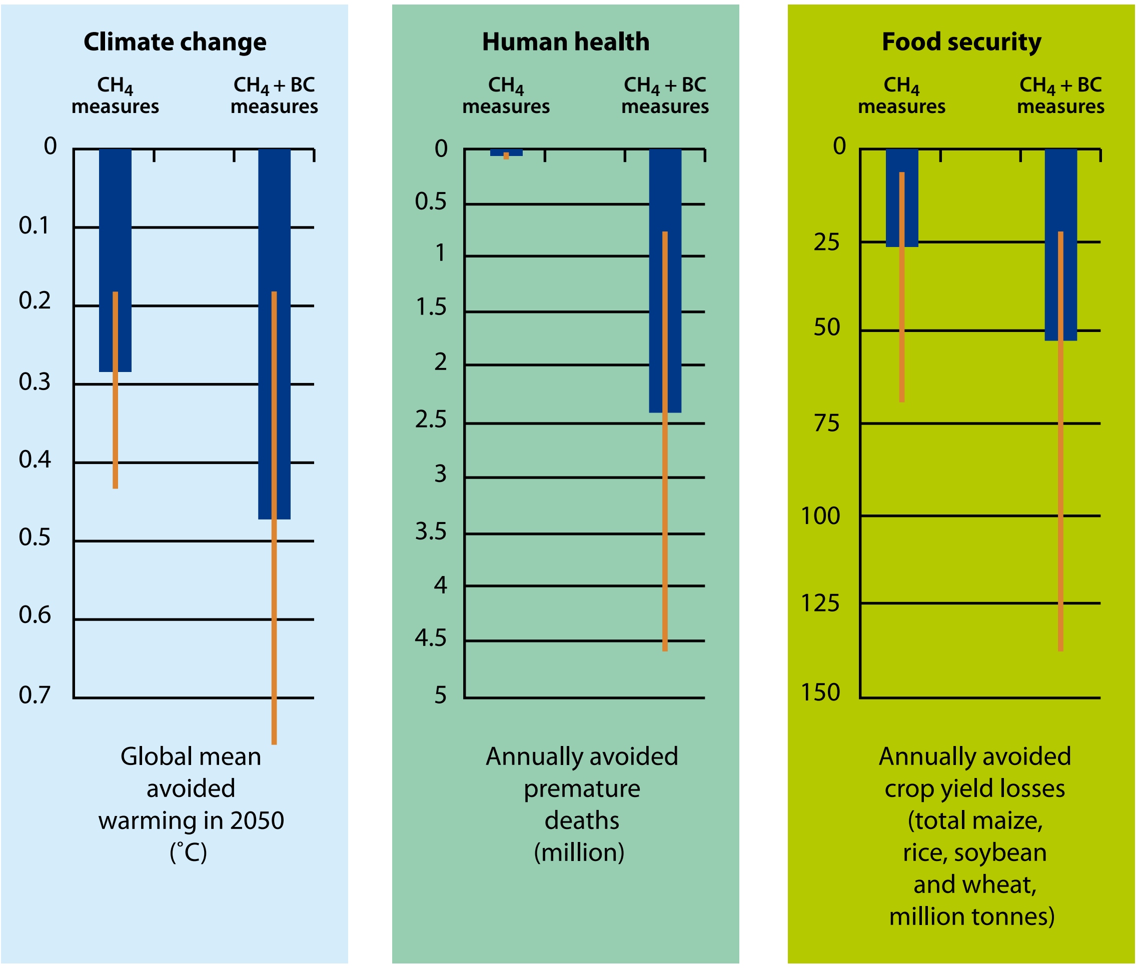

Figure 1. Global benefits from full implementation of the identified measures in 2030 compared to the reference scenario. The climate change benefit is estimated for a given year (2050) and human health and crop benefits are for 2030 and beyond.

14. **At national and sub-national scales many of the identified measures could be implemented under existing policies designed to address air quality and development concerns. Improved cooperation within and between regions would enhance widespread implementation and address transboundary climate and air quality issues.** International policy and financing instruments to address the co-benefits of reducing emissions of short-lived climate forcers need development and strengthening. Supporting and extending existing relevant regional arrangements may provide an opportunity for more effective cooperation, implementation and assessment as well as additional monitoring and research.

15. **The Assessment concludes that there is confidence that immediate and multiple benefits will be realized upon implementation of the identified measures.** The degree of confidence varies according to pollutant, impact and region. For example, there is higher confidence in the effect of methane measures on global temperatures than in the effect of black carbon measures, especially where these relate to the burning of biomass. There is also high confidence that benefits will be realized for human health from reducing particles, including black carbon, and to crop yields from reducing tropospheric ozone concentrations. Given the scientific complexity of the issues, further research is required to optimize near-term strategies in different regions and to evaluate the cost-benefit ratio for individual measures.

Introduction

Black carbon (BC, Box 1) and tropospheric ozone (O_3, Box 2) are harmful air pollutants that also contribute to climate change. In recent years, scientific understanding of how BC and O_3 affect climate and public health has significantly improved. This has catalysed a demand for information and action from governments, civil society and other stakeholders. The United Nations (UN) has been requested to urgently provide science-based advice on action to reduce the impacts of these pollutants[1].

The United Nations Environment Programme (UNEP), in consultation with partners, initiated an assessment designed to provide an interface between knowledge and action, science and policy, and to provide a scientifically credible basis for informed decision-making. The result is a comprehensive analysis of drivers of emissions, trends in concentrations, and impacts on climate, human health and ecosystems of BC, tropospheric O_3 and its precursors. BC, tropospheric O_3 and methane (CH_4) are often referred to as short-lived climate forcers (SLCFs) as they have a short lifetime in the atmosphere (days to about a decade) relative to carbon dioxide (CO_2).

The Assessment is an integrated analysis of multiple co-emitted pollutants reflecting the fact that these pollutants are not emitted in isolation (Boxes 1 and 2). The Assessment determined that under current policies, emissions of BC and O_3 precursors are expected globally either to increase or to remain roughly constant unless further mitigation action is taken.

The Integrated Assessment of Black Carbon and Tropospheric Ozone convened more than 50 authors to assess the state of science and existing policy options for addressing these pollutants. The Assessment team examined policy responses, developed an outlook to 2070 illustrating the benefits of political decisions made today and the risks to climate, human health and crop yields over the next decades if action is delayed. Placing a premium on robust science and analysis, the Assessment was driven by four main policy-relevant questions:

- Which measures are likely to provide significant combined climate and air-quality benefits?
- How much can implementation of the identified measures reduce the rate of global mean temperature increase by mid-century?
- What are the multiple climate, health and crop-yield benefits that would be achieved by implementing the measures?
- By what mechanisms could the measures be rapidly implemented?

In order to answer these questions, the Assessment team determined that new analyses were needed. The Assessment therefore relies on published literature as much as possible and on new simulations by two independent climate-chemistry-aerosol models: one developed and run by the NASA-Goddard Institute for Space Studies (GISS) and the other developed by the Max Planck Institute in Hamburg, Germany (ECHAM), and run at the Joint Research Centre of the European Commission in Ispra, Italy. The specific measures and emission estimates for use in developing this Assessment were selected using the International Institute for Applied Systems Analysis Greenhouse Gas and Air Pollution Interactions and Synergies (IIASA GAINS) model. For a more detailed description of the modelling see Chapter 1.

[1] The Anchorage Declaration of 24 April 2009, adopted by the Indigenous People's Global Summit on Climate Change; the Tromsø Declaration of 29 April 2009, adopted by the Sixth Ministerial Meeting of the Arctic Council and the 8th Session of the Permanent Forum on Indigenous Issues under the United Nations Economic and Social Council (May 2009) called on UNEP to conduct a fast track assessment of short-term drivers of climate change, specifically BC, with a view to initiating the negotiation of an international agreement to reduce emissions of BC. A need to take rapid action to address significant climate forcing agents other than CO_2, such as BC, was reflected in the 2009 declaration of the G8 leaders (Responsible Leadership for a Sustainable Future, L'Aquila, Italy, 2009).

Box 1: What is black carbon?

Black carbon (BC) exists as particles in the atmosphere and is a major component of soot. BC is not a greenhouse gas. Instead it warms the atmosphere by intercepting sunlight and absorbing it. BC and other particles are emitted from many common sources, such as cars and trucks, residential stoves, forest fires and some industrial facilities. BC particles have a strong warming effect in the atmosphere, darken snow when it is deposited, and influence cloud formation. Other particles may have a cooling effect in the atmosphere and all particles influence clouds. In addition to having an impact on climate, anthropogenic particles are also known to have a negative impact on human health.

Black carbon results from the incomplete combustion of fossil fuels, wood and other biomass. Complete combustion would turn all carbon in the fuel into carbon dioxide (CO_2). In practice, combustion is never complete and CO_2, carbon monoxide (CO), volatile organic compounds (VOCs), organic carbon (OC) particles and BC particles are all formed. There is a close relationship between emissions of BC (a warming agent) and OC (a cooling agent). They are always co-emitted, but in different proportions for different sources. Similarly, mitigation measures will have varying effects on the BC/OC mix.

The black in BC refers to the fact that these particles absorb visible light. This absorption leads to a disturbance of the planetary radiation balance and eventually to warming. The contribution to warming of 1 gramme of BC seen over a period of 100 years has been estimated to be anything from 100 to 2 000 times higher than that of 1 gramme of CO_2. An important aspect of BC particles is that their lifetime in the atmosphere is short, days to weeks, and so emission reductions have an immediate benefit for climate and health.

Credit: NASA-MODIS

Haze with high particulate matter concentrations containing BC and OC, such as this over the Bay of Bengal, is widespread in many regions.

Credit: Caramel/flickr

High emitting vehicles are a significant source of black carbon and other pollutants in many countries.

Credit: Luisa Molina

No retrofit system	Retrofitted with	Retrofitted with	Retrofitted with
Uncontrolled Diesel Exhaust	**Diesel Oxidation Catalyst (DOC)**	**Partial Filter**	**Diesel Particulate Filter (DPF)**
(Level 1)	(Level 1)	(Level 2)	(Level 3)
Old technlogy Little black carbon removal Little ultrafine PM removal Does not remove lube oil ash	Old technlogy Little black carbon removal Little ultrafine PM removal Does not remove lube oil ash	Little black carbon removal Little ultrafine PM removal Does not remove lube oil ash	New Technology Used on all new trucks since 2007 >85% black carbon removal >85% ultrafine removal >85% lube oil ash removal

Some of the largest emission reductions are obtained using diesel particle filters on high emitting vehicles. The exhibits above are actual particulate matter (PM) collection samples from an engine testing laboratory (International Council of Clean Transportation (ICCT)).

Box 2: What is tropospheric ozone?

Ozone (O_3) is a reactive gas that exists in two layers of the atmosphere: the stratosphere (the upper layer) and the troposphere (ground level to ~10–15 km). In the stratosphere, O_3 is considered to be beneficial as it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, at ground level, it is an air pollutant harmful to human health and ecosystems, and it is a major component of urban smog. In the troposphere, O_3 is also a significant greenhouse gas. The threefold increase of the O_3 concentration in the northern hemisphere during the past 100 years has made it the third most important contributor to the human enhancement of the global greenhouse effect, after CO_2 and CH_4.

In the troposphere, O_3 is formed by the action of sunlight on O_3 precursors that have natural and anthropogenic sources. These precursors are CH_4, nitrogen oxides (NO_X), VOCs and CO. It is important to understand that reductions in both CH_4 and CO emissions have the potential to substantially reduce O_3 concentrations and reduce global warming. In contrast, reducing VOCs would clearly be beneficial but has a small impact on the global scale, while reducing NO_X has multiple additional effects that result in its net impact on climate being minimal.

Credit: Luisa Molina

Credit: Warren Gretz/DOE/NREL

Tropospheric ozone is a major constituent of urban smog, left Tokyo, Japan; right Denver, Colorado, USA

Limiting Near-Term Climate Changes and Improving Air Quality

Identifying effective response measures

The Assessment identified those measures most likely to provide combined benefits, taking into account the fact that BC and O_3 precursors are co-emitted with different gases and particles, some of which cause warming and some of which, such as organic carbon (OC) and sulphur dioxide (SO_2) lead to cooling. The selection criterion was that the measure had to be likely to reduce global climate change and also provide air quality benefits, so-called win-win measures. Those measures that provided a benefit for air quality but increased warming were not included in the selected measures. For example, measures that primarily reduce emissions of SO_2 were not included.

The identified measures (Table 1) were chosen from a subset of about 2 000 separate measures that can be applied to sources in IIASA's GAINS model. The selection was based on the net influence on warming, estimated using the metric Global Warming Potential (GWP), of all of the gases and particles that are affected by the measure. The selection gives a useful indication of the potential for realizing a win for climate. All emission reduction measures were assumed to benefit air quality by reducing particulate matter and/or O_3 concentrations.

This selection process identified a relatively small set of measures which nevertheless provide about 90 per cent of the climate benefit compared to the implementation of all 2 000 measures in GAINS. The final analysis of the benefits for temperature, human health and crop yields considered the emissions of all substances resulting from the full implementation of the identified measures through the two global composition-climate models GISS and ECHAM (see Chapter 4). One hundred per cent implementation of the measures globally was used to illustrate the existing potential to reduce climate and air quality impacts, but this does not make any assumptions regarding the feasibility of full implementation everywhere. A discussion of the challenges involved in widespread implementation of the measures follows after the potential benefit has been demonstrated.

Achieving large emission reductions

The packages of policy measures in Table 1 were compared to a reference scenario (Table 2). Figure 2 shows the effect of the packages of policy measures and the reference scenario relative to 2005 emissions.

There is tremendous regional variability in how emissions are projected to change by the year 2030 under the reference scenario. Emissions of CH_4 – a major O_3 precursor and a potent greenhouse gas – are expected to increase in the future (Figure 2). This increase will occur despite current and planned regulations, in large part due to anticipated economic growth and the increase in fossil fuel production projected to accompany it. In contrast, global emissions of BC and accompanying co-emitted pollutants are expected to remain relatively constant through to 2030. Regionally, reductions in BC emissions are expected due to tighter standards on road transport and more efficient combustion replacing use of biofuels in the residential and commercial sectors,

Table 1. Measures that improve climate change mitigation and air quality and have a large emission reduction potential

Measure[1]	Sector
CH_4 measures	
Extended pre-mine degasification and recovery and oxidation of CH_4 from ventilation air from coal mines	Extraction and transport of fossil fuel
Extended recovery and utilization, rather than venting, of associated gas and improved control of unintended fugitive emissions from the production of oil and natural gas	
Reduced gas leakage from long-distance transmission pipelines	
Separation and treatment of biodegradable municipal waste through recycling, composting and anaerobic digestion as well as landfill gas collection with combustion/utilization	Waste management
Upgrading primary wastewater treatment to secondary/tertiary treatment with gas recovery and overflow control	
Control of CH_4 emissions from livestock, mainly through farm-scale anaerobic digestion of manure from cattle and pigs	Agriculture
Intermittent aeration of continuously flooded rice paddies	
BC measures (affecting BC and other co-emitted compounds)	
Diesel particle filters for road and off-road vehicles	Transport
Elimination of high-emitting vehicles in road and off-road transport	
Replacing coal by coal briquettes in cooking and heating stoves	Residential
Pellet stoves and boilers, using fuel made from recycled wood waste or sawdust, to replace current wood-burning technologies in the residential sector in industrialized countries	
Introduction of clean-burning biomass stoves for cooking and heating in developing countries[2, 3]	
Substitution of clean-burning cookstoves using modern fuels for traditional biomass cookstoves in developing countries[2, 3]	
Replacing traditional brick kilns with vertical shaft kilns and Hoffman kilns	Industry
Replacing traditional coke ovens with modern recovery ovens, including the improvement of end-of-pipe abatement measures in developing countries	
Ban of open field burning of agricultural waste[2]	Agriculture

1 There are measures other than those identified in the table that could be implemented. For example, electric cars would have a similar impact to diesel particulate filters but these have not yet been widely introduced; forest fire controls could also be important but are not included due to the difficulty in establishing the proportion of fires that are anthropogenic.
2 Motivated in part by its effect on health and regional climate, including areas of ice and snow.
3 For cookstoves, given their importance for BC emissions, two alternative measures are included.

although these are offset to some extent by increased activity and economic growth. The regional BC emission trends, therefore, vary significantly, with emissions expected to decrease in North America and Europe, Latin America and the Caribbean, and in Northeast Asia, Southeast Asia and the Pacific, and to increase in Africa and South, West and Central Asia.

The full implementation of the selected measures by 2030 leads to significant reductions of SLCF emissions relative to current emissions or to the 2030 emissions in the reference scenario (Figure 2). It also reduces a high proportion of the emissions relative to the maximum reduction from the implementation of all 2 000 or so measures in the GAINS model. The measures designed to reduce BC also have a considerable impact on OC, total fine particulate matter ($PM_{2.5}$) and CO emissions, removing more than half the total anthropogenic emissions. The largest BC emission reductions are obtained through measures controlling incomplete combustion of biomass and diesel particle filters.

The major sources of CO_2 are different from those emitting most BC, OC, CH_4 and CO. Even in the few cases where there is overlap, such as diesel vehicles, the particle filters that reduce BC, OC and CO have minimal effect on CO_2. The measures to reduce CO_2 over the next 20 years (Table 2) therefore hardly affect the emissions of BC, OC or CO. The influence of the CH_4 and BC measures is thus the same regardless of whether the CO_2 measures are imposed or not.

Reducing near-term global warming

The Earth is projected to continue the rapid warming of the past several decades and, without additional mitigation efforts, under the reference scenario global mean temperatures are projected to rise about a further 1.3˚C (with a range of 0.8–2.0˚C) by the middle of this century, bringing the total warming from pre-industrial levels to about 2.2˚C (Figure 3). The Assessment shows that the measures targeted to reduce emissions of BC and CH_4 could greatly reduce global mean warming rates over the next few decades (Figure 3). Figure 1 shows that over half of the reduced global mean warming is achieved by the CH_4 measures and the remainder by BC measures. The greater confidence in the effect of CH_4 measures on warming is reflected in the narrower range of estimates.

When all measures are fully implemented, warming during the 2030s relative to the present day is only half as much as if no measures had been implemented. In contrast, even a fairly aggressive strategy to reduce CO_2 emissions under the CO_2 measures scenario does little to mitigate warming over the next 20–30 years. In fact, sulphate particles, reflecting particles that offset some of the committed warming for the short time they are in the atmosphere, are derived from SO_2 that is co-emitted with CO_2 in some of the highest-emitting activities, including coal burning in large-scale combustion such as in power plants. Hence, CO_2 measures alone may temporarily enhance near-term warming as sulphates are reduced (Figure 3;

Table 2. Policy packages used in the Assessment

Scenario	Description[1]
Reference	Based on energy and fuel projections of the International Energy Agency (IEA) *World Energy Outlook 2009* and incorporating all presently agreed policies affecting emissions
CH_4 measures	Reference scenario plus the CH_4 measures
BC measures	Reference scenario plus the BC measures (the BC measures affect many pollutants, especially BC, OC, and CO)
CH_4 + BC measures	Reference scenario plus the CH_4 and BC measures
CO_2 measures	Emissions modelled using the assumptions of the IEA *World Energy Outlook 2009* 450 Scenario[2] and the IIASA GAINS database. Includes CO_2 measures only. The CO_2 measures affect other emissions, especially SO_2[3]
CO_2 + CH_4 + BC measures	CO_2 measures plus CH_4 and BC measures

1 In all scenarios, trends in all pollutant emissions are included through 2030, after which only trends in CO_2 are included.
2 The 450 Scenario is designed to keep total forcing due to long-lived greenhouse gases (including CH_4 in this case) at a level equivalent to 450 ppm CO_2 by the end of the century.
3 Emissions of SO_2 are reduced by 35–40 per cent by implementing CO_2 measures. A further reduction in sulphur emissions would be beneficial to health but would increase global warming. This is because sulphate particles cool the Earth by reflecting sunlight back to space.

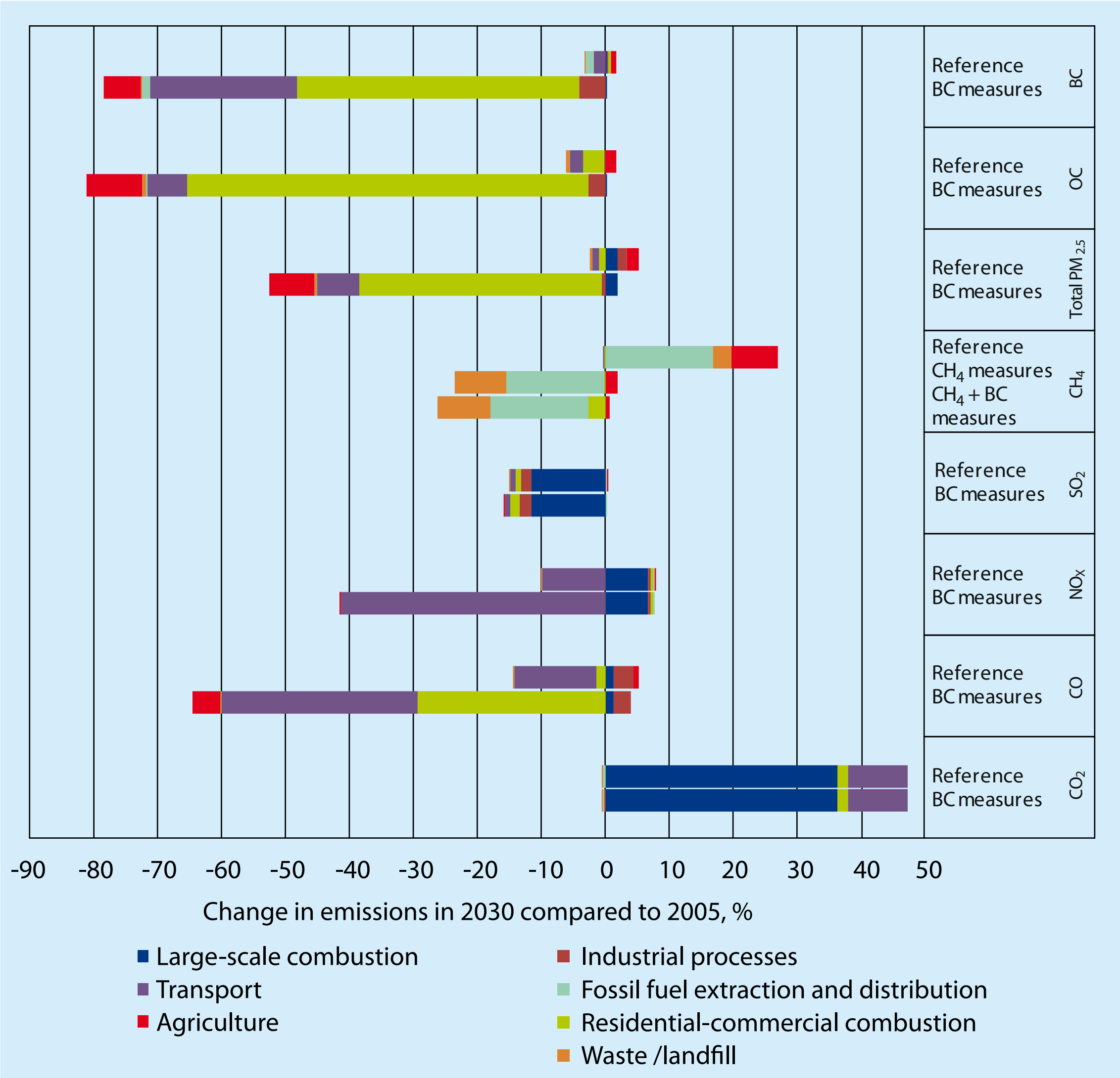

Figure 2. Percentage change in anthropogenic emissions of the indicated pollutants in 2030 relative to 2005 for the reference, CH_4, BC and CH_4 + BC measures scenarios. The CH_4 measures have minimal effect on emissions of anything other than CH_4. The identified BC measures reduce a large proportion of total BC, OC and CO emissions. SO_2 and CO_2 emissions are hardly affected by the identified CH_4 and BC measures, while NO_X and other $PM_{2.5}$ emissions are affected by the BC measures.

temperatures in the CO_2 measures scenario are slightly higher than those in the reference scenario during the period 2020–2040).

The CO_2 measures clearly lead to long-term benefits, with a dramatically lower warming rate in 2070 than under the scenario with only near-term CH_4 + BC measures. Owing to the long residence time of CO_2 in the atmosphere, these long-term benefits will only be achieved if CO_2 emission reductions are brought in quickly. In essence, the near-term CH_4 and BC measures examined in this Assessment are effectively decoupled from the CO_2 measures both in that they target different source sectors and in that their impacts on climate change take place over different timescales.

Near-term warming may occur in sensitive regions and could cause essentially irreversible changes, such as loss of Arctic land-ice, release of CH_4 or CO_2 from Arctic permafrost and species loss. Indeed, the projected warming in the reference scenario is greater in the Arctic than globally. Reducing the near-term rate of warming hence decreases the risk of irreversible transitions that could influence the global climate system for centuries.

Staying within critical temperature thresholds

Adoption of the near-term emission control measures described in this Assessment, together with measures to reduce CO_2 emissions, would greatly improve the chances of keeping Earth's temperature increase to less than 2°C relative to pre-industrial levels (Figure 3). With the CO_2 measures alone, warming exceeds 2°C before 2050. Even with both the CO_2 measures and CH_4 measures envisioned under the same IEA 450 Scenario, warming exceeds 2°C in the 2060s (see Chapter 5). However, the combination of CO_2, CH_4, and BC measures holds the temperature increase below 2°C until around 2070. While CO_2 emission reductions even larger than those in the CO_2 measures scenario would of course mitigate more warming, actual CO_2 emissions over the past decade have consistently exceeded the most pessimistic emission scenarios of the IPCC. Thus, it seems unlikely that reductions more stringent than those in the CO_2 measures scenario will take place during the next 20 years.

Examining the more stringent UNFCCC 1.5°C threshold, the CO_2 measures scenario exceeds this by 2030, whereas the near-term measures proposed in the Assessment delay that exceedance until after 2040. Again, while substantially deeper early reductions in CO_2 emissions than those in the CO_2 measures scenario could also delay the crossing of the 1.5°C temperature threshold, such reductions would undoubtedly be even more difficult to achieve. However, adoption of the Assessment's near-term measures (CH_4 + BC) along with the CO_2 reductions would provide

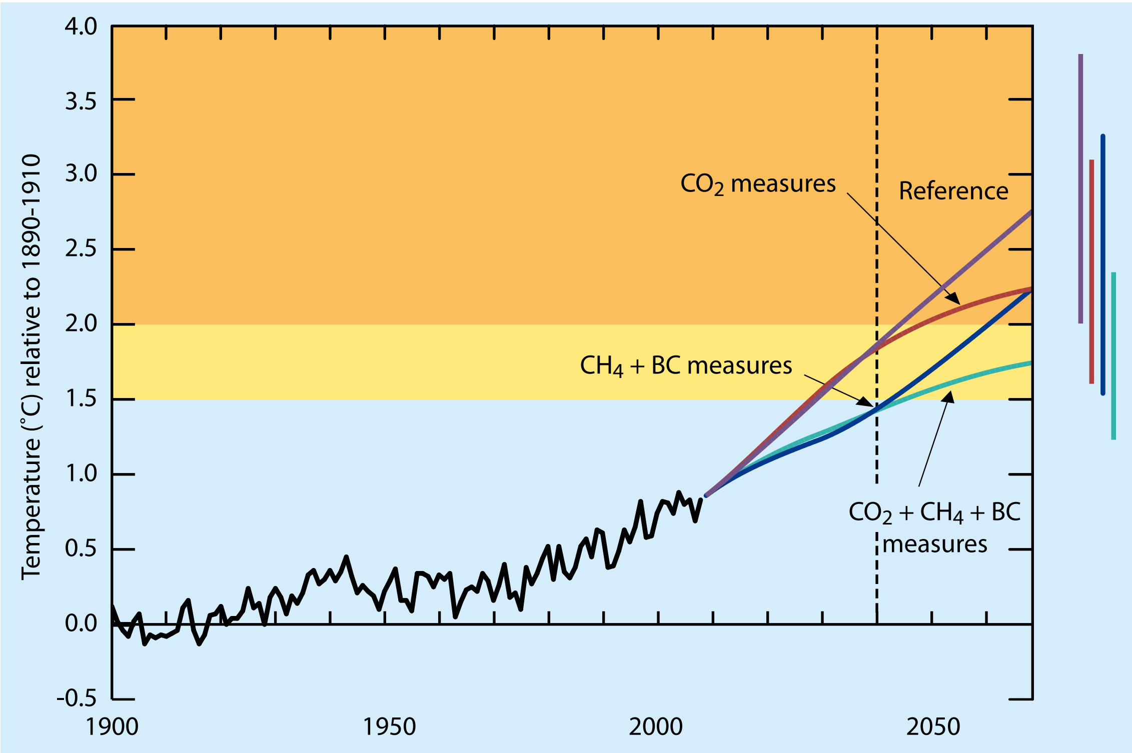

Figure 3. Observed deviation of temperature to 2009 and projections under various scenarios. Immediate implementation of the identified BC and CH_4 measures, together with measures to reduce CO_2 emissions, would greatly improve the chances of keeping Earth's temperature increase to less than 2°C relative to pre-industrial levels. The bulk of the benefits of CH_4 and BC measure are realized by 2040 (dashed line).
Explanatory notes: Actual mean temperature observations through 2009, and projected under various scenarios thereafter, are shown relative to the 1890–1910 mean temperature. Estimated ranges for 2070 are shown in the bars on the right. A portion of the uncertainty is common to all scenarios, so that overlapping ranges do not mean there is no difference, for example, if climate sensitivity is large, it is large regardless of the scenario, so temperatures in all scenarios would be towards the high-end of their ranges.

a substantial chance of keeping the Earth's temperature increase below 1.5˚C for the next 30 years.

Benefits of early implementation

There would clearly be much less warming during 2020–2060 were the measures implemented earlier rather than later (Figure 4). Hence there is a substantial near-term climate benefit in accelerating implementation of the identified measures even if some of these might eventually be adopted owing to general air-quality and development concerns. Clearly the earlier implementation will also have significant additional human health and crop-yield benefits.

Accelerated adoption of the identified measures has only a modest effect on long-term climate change in comparison with waiting 20 years, however (Figure 4). This reinforces the conclusion that reducing emissions of O_3 precursors and BC can have substantial benefits in the near term, but that mitigating long-term climate change depends on reducing emissions of long-lived greenhouse gases such as CO_2.

Regional climate benefits

While global mean temperatures provide some indication of climate impacts, temperature changes can vary dramatically from place to place even in response to relatively uniform forcing from long-lived greenhouse gases. Figure 5 shows that warming is projected to increase for all regions with some variation under the reference scenario, while the Assessment's measures provide the benefit of reduced warming in all regions.

Climate change also encompasses more than just temperature changes. Precipitation, melting rates of snow and ice, wind patterns, and clouds are all affected, and these in turn have an impact on human well-being by influencing factors such as water availability, agriculture and land use.

Both O_3 and BC, as well as other particles, can influence many of the processes that lead to the formation of clouds and precipitation. They alter surface temperatures, affecting evaporation. By absorbing sunlight in the atmosphere, O_3 and especially BC can affect cloud formation, rainfall and weather patterns. They can change wind patterns by affecting the regional temperature contrasts that drive the winds, influencing where rain and snow fall. While some aspects of these effects are local, they can also affect temperature, cloudiness, and precipitation far away from the emission sources. The regional changes in all these aspects of climate will be significant, but are currently not well quantified.

Tropical rainfall patterns and the Asian monsoon

Several detailed studies of the Asian monsoon suggest that regional forcing by absorbing particles substantially alters precipitation patterns (as explained in the previous section). The fact that both O_3 and particle changes are predominantly in the northern hemisphere means that they cause temperature gradients between the two hemispheres that influence rainfall patterns throughout the tropics. Implementation of the measures analysed in this Assessment would substantially decrease the regional atmospheric heating by particles (Figure 6), and are hence very likely to reduce regional shifts in precipitation. As the reductions of atmospheric forcing are greatest over the Indian sub-continent and other parts of Asia, the emission reductions may have a substantial effect on the Asian monsoon, mitigating disruption of traditional rainfall patterns. However, results from global climate models are not yet robust for the magnitude or timing of monsoon shifts resulting from either greenhouse gas increases or changes in absorbing particles. Nonetheless, results from climate models provide examples of the type of change that might be expected. Shifts in the timing and strength of precipitation can have significant impacts on human well-being because of changes in water

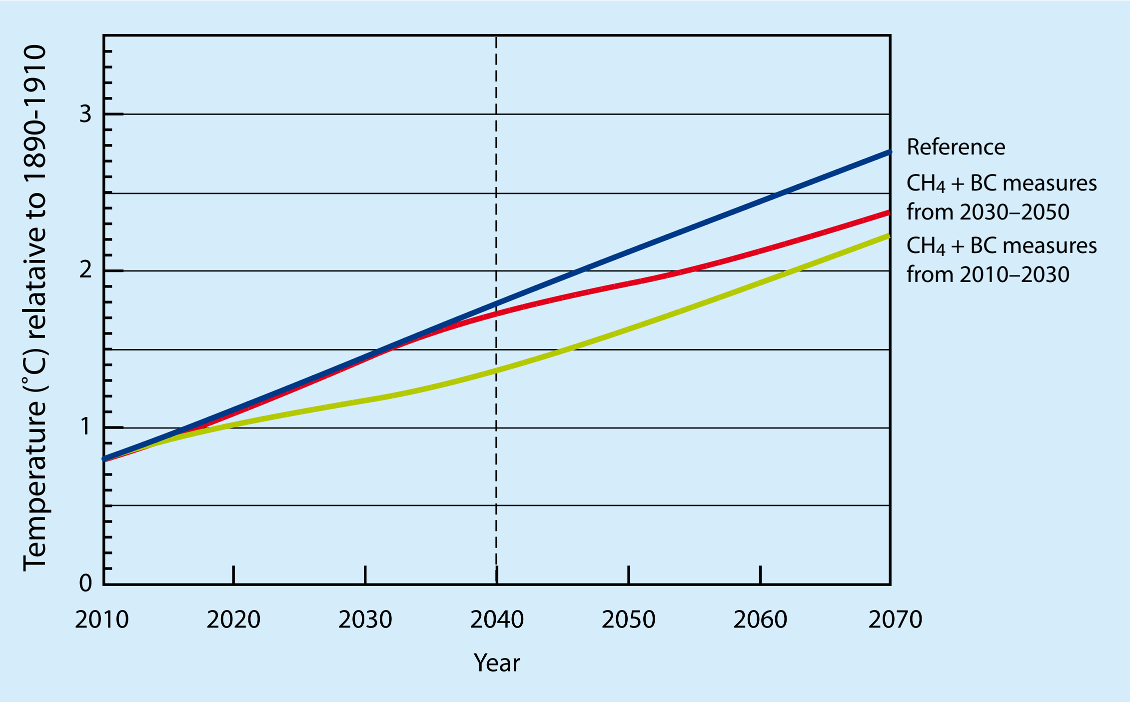

Figure 4. Projected global mean temperature changes for the reference scenario and for the CH_4 and BC measures scenario with emission reductions starting immediately or delayed by 20 years.

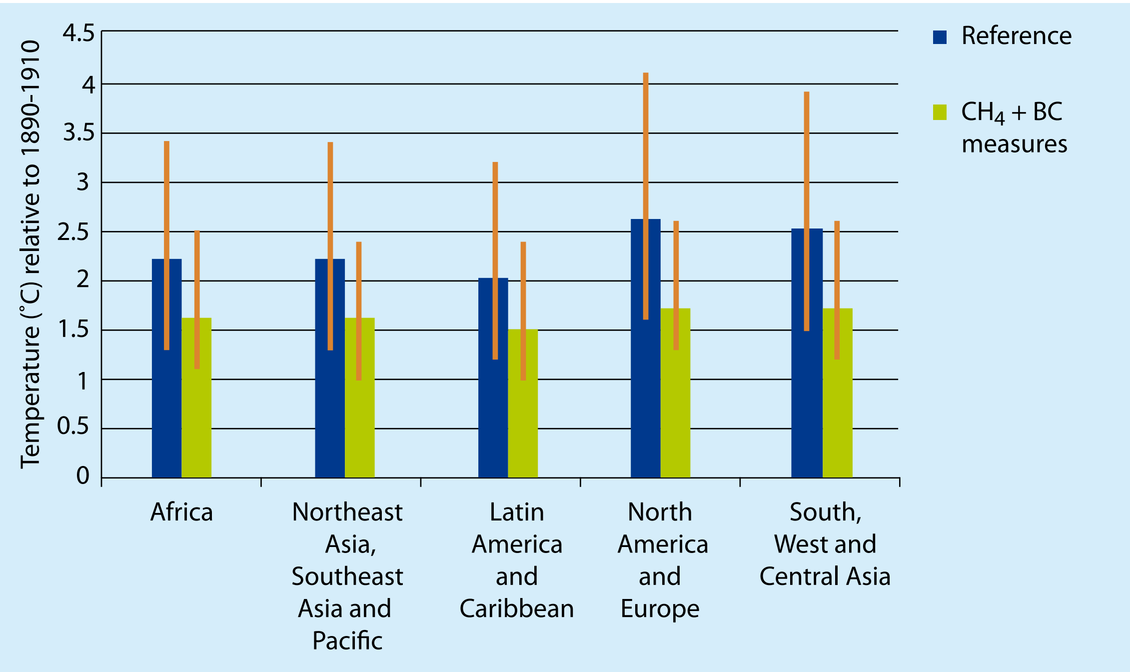

Figure 5. Comparison of regional mean warming over land (°C) showing the change in 2070 compared with 2005 for the reference scenario (Table 2) and the CH_4 + BC measures scenario. The lines on each bar show the range of estimates.

supply and agricultural productivity, drought and flooding. The results shown in Figure 6 suggest that implementation of the BC measures could also lead to a considerable reduction in the disruption of traditional rainfall patterns in Africa.

Decreased warming in polar and other glaciated regions

Implementation of the measures would substantially slow, but not halt, the current rapid pace of temperature rise and other changes already occurring at the poles and high-altitude glaciated regions, and the reduced warming in these regions would likely be greater than that seen globally. The large benefits occur in part because the snow/ice darkening effect of BC is substantially greater than the cooling effect of reflective particles co-emitted with BC, leading to greater warming impacts in these areas than in areas without snow and ice cover.

Studies in the Arctic indicate that it is highly sensitive both to local pollutant emissions and those transported from sources close to the Arctic, as well as to the climate impact of pollutants in the mid-latitudes of the northern hemisphere. Much of the need for implementation lies within Europe and North America. The identified measures could reduce warming in the Arctic by about 0.7°C (with a range of 0.2–1.3°C) in 2040. This is nearly two-thirds of the estimated 1.1°C (with a range of 0.7–1.7°C) warming projected for the Arctic under the reference scenario, and should substantially decrease the risk of global impacts from changes in this sensitive region, such as sea ice loss, which affects global albedo, and permafrost melt. Although not identified as a measure for use in this Assessment, the control of boreal forest fires may also be important in reducing impacts in the Arctic.

The Antarctic is a far less studied region in terms of SLCF impacts. However, there are studies demonstrating BC deposition even in central portions of the continent, and reductions in O_3 and CH_4 should slow warming in places like the Antarctic Peninsula, currently the spot on the globe showing the most rapid temperature rise of all.

The Himalayas and the Tibetan Plateau are regions where BC is likely to have serious impacts. In the high valleys of the Himalayas, for example, BC levels can be as high as in

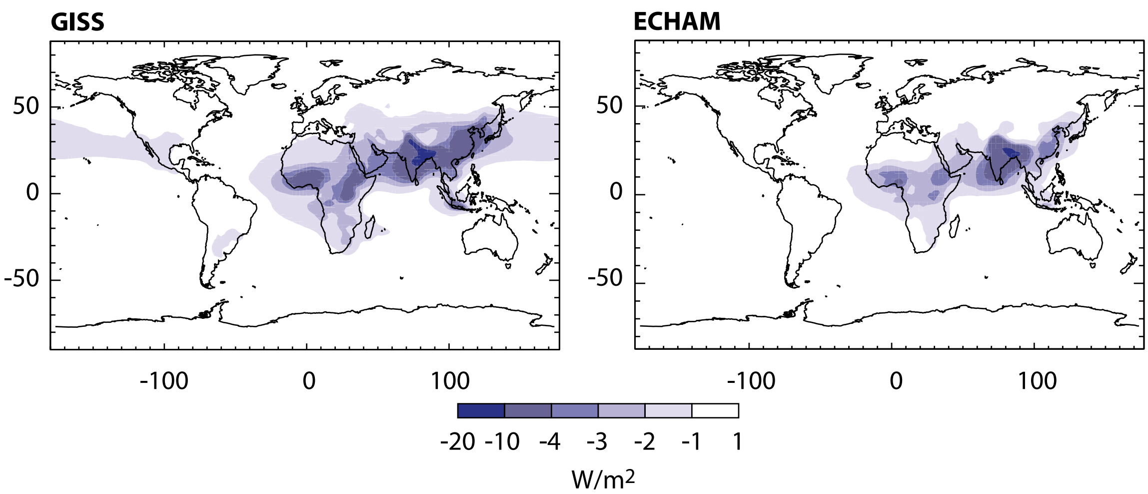

Figure 6. Change in atmospheric energy absorption (Watts per square metre, W/m^2 as annual mean), an important factor driving tropical rainfall and the monsoons resulting from implementation of BC measures. The changes in absorption of energy by the atmosphere are linked with changes in regional circulation and precipitation patterns, leading to increased precipitation in some regions and decreases in others. BC solar absorption increases the energy input to the atmosphere by as much as 5–15 per cent, with the BC measures removing the bulk of that heating. Results are shown for two independent models to highlight the similarity in the projections of where large regional decreases would occur.

a mid-sized city. Reducing emissions from local sources and those carried by long-range transport should lower glacial melt in these regions, decreasing the risk of impacts such as catastrophic glacial lake outbursts.

Benefits of the measures for human health

Fine particulate matter (measured as $PM_{2.5}$, which includes BC) and ground-level O_3 damage human health. $PM_{2.5}$ causes premature deaths primarily from heart disease and lung cancer, and O_3 exposure causes deaths primarily from respiratory illness. The health benefit estimates in the Assessment are limited to changes in these specific causes of death and include uncertainty in the estimation methods. However, these pollutants also contribute significantly to other health impacts including acute and chronic bronchitis and other respiratory illness, non-fatal heart attacks, low birth weight and results in increased emergency room visits and hospital admissions, as well as loss of work and school days.

Under the reference scenario, that is, without implementation of the identified measures, changes in concentrations of $PM_{2.5}$ and O_3 in 2030, relative to 2005, would have substantial effects globally on premature deaths related to air pollution. By region, premature deaths from outdoor pollution are projected to change in line with emissions. The latter are expected to decrease significantly over North America and Europe due to implementation of the existing and expected legislation. Over Africa and Latin America and the Caribbean, the number of premature deaths from these pollutants is expected to show modest changes under the reference scenario (Figure 7). Over Northeast Asia, Southeast Asia and Pacific, premature deaths are projected to decrease substantially due to reductions in $PM_{2.5}$ in some areas. However, in South, West and Central Asia, premature deaths are projected to rise significantly due to growth in emissions.

In contrast to the reference scenario, full implementation of the measures identified in the Assessment would substantially improve air quality and reduce premature deaths globally due to significant reductions in indoor and outdoor air pollution. The reductions in $PM_{2.5}$ concentrations resulting from the BC measures would, by 2030, avoid an estimated 0.7–4.6 million annual premature deaths due to outdoor air pollution (Figure 1).

Regionally, implementation of the identified measures would lead to greatly improved air quality and fewer premature deaths, especially in Asia (Figure 7). In fact, more than 80 per cent of the health benefits of implementing all measures occur in Asia. The benefits are large enough for all the worsening trends in human health due to outdoor air pollution to be reversed and turned into improvements, relative to 2005. In Africa, the benefit is substantial, although not as great as in Asia.

Benefits of the measures for crop yields

Ozone is toxic to plants. A vast body of literature describes experiments and observations showing the substantial effects of O_3 on visible leaf health, growth and productivity for a large number of crops, trees and other plants. Ozone also affects vegetation composition and diversity. Globally, the full implementation of CH_4 measures results in significant reductions in O_3 concentrations leading to avoided yield losses of about 25 million tonnes of four staple crops each year. The implementation of the BC measures would account for about a further 25 million tonnes of avoided yield losses in comparison with the reference scenario (Figure 1). This is due to significant reductions in emissions of the precursors CO, VOCs and NO_X that reduce O_3 concentrations.

The regional picture shows considerable differences. Under the reference scenario, O_3 concentrations over Northeast, Southeast

Asia and Pacific are projected to increase, resulting in additional crop yield losses (Figures 7 and 8). In South, West and Central Asia, both health and agricultural damage are projected to rise (Figure 8). Damage to agriculture is projected to decrease strongly over North America and Europe while changing minimally over Africa and Latin America and the Caribbean. For the whole Asian region maize yields show a decrease of 1–15 per cent, while yields decrease by less than 5 per cent for wheat and rice. These yield losses translate into nearly 40 million tonnes for all crops for the whole Asian region, reflecting the substantial cultivated area exposed to elevated O_3 concentrations in India – in particular the Indo-Gangetic Plain region. Rice production is also affected, particularly in Asia where elevated O_3 concentrations are likely to continue to increase to 2030. Yield loss values for rice are uncertain, however, due to a lack of experimental evidence on concentration-response functions. In contrast, the European and North American regional analyses suggest that all crops will see an improvement in yields under the reference scenario between 2005 and 2030. Even greater improvements would be seen upon implementation of the measures.

The identified measures lead to greatly reduced O_3 concentrations, with substantial benefits to crop yields, especially in Asia (Figure 8). The benefits of the measures are large enough to reverse all the worsening trends seen in agricultural yields and turn them into improvements, relative to 2005, with the exception of crop yields in Northeast and Southeast Asia and Pacific. Even in that case, the benefits of full implementation are quite large, with the measures reducing by 60 per cent the crop losses envisaged in the reference scenario.

It should be stressed that the Assessment's analyses include only the direct effect of changes in atmospheric composition on health and agriculture through changes in exposure to pollutants. As such, they do not include the benefits that avoided climate change would have on human health and agriculture due to factors such as reduced disruption of precipitation patterns, dimming, and reduced frequency of heat waves. Furthermore, even the direct influence on yields are based on estimates for only four staple crops, and impacts on leafy crops, productive grasslands and food quality were not included, so that the calculated values are likely to be an

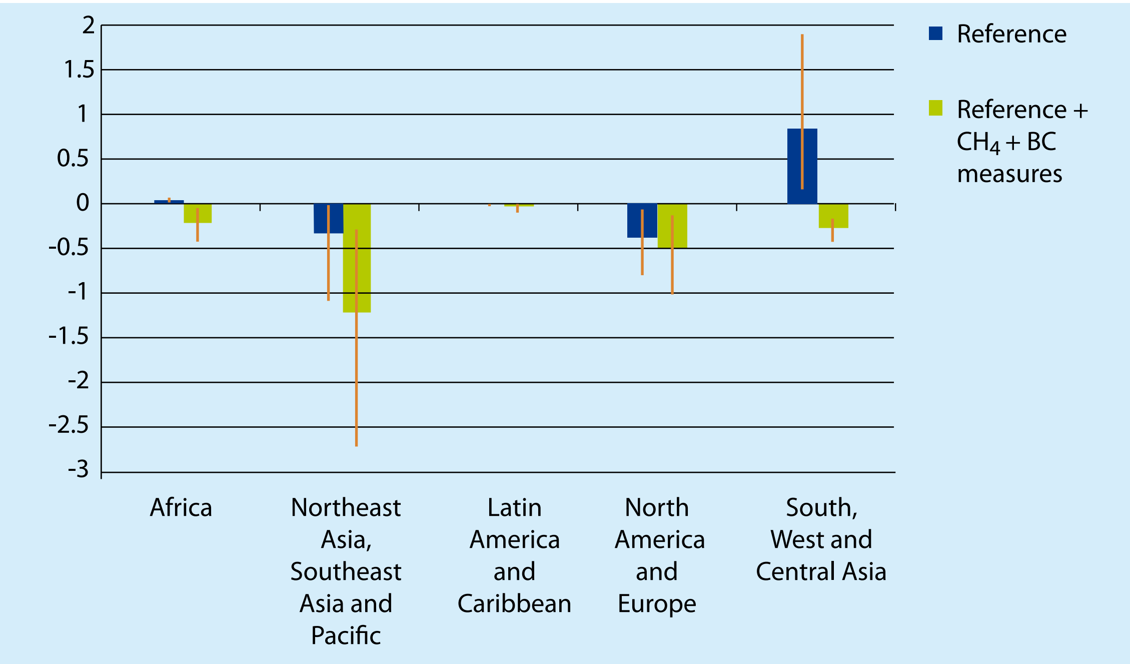

Figure 7. Comparison of premature mortality (millions of premature deaths annually) by region, showing the change in 2030 in comparison with 2005 for the reference scenario emission trends and the reference plus CH_4 + BC measures. The lines on each bar show the range of estimates.

The measures identified in the Assessment include replacement of traditional cookstoves, such as that shown here, with clean burning stoves which would substantially improve air quality and reduce premature deaths due to indoor and outdoor air pollution.

underestimate of the total impact. In addition, extrapolation of results from a number of experimental studies to assess O_3 impacts on ecosystems strongly suggests that reductions in O_3 could lead to substantial increases in the net primary productivity. This could have a substantial impact on carbon sequestration, providing additional climate benefits.

Relative importance and scientific confidence in the measures

Methane measures have a large impact on global and regional warming, which is achieved by reducing the greenhouse gases CH_4 and O_3. The climate mitigation impacts of the CH_4 measures are also the most certain because there is a high degree of confidence in the warming effects of this greenhouse gas. The reduced methane and hence O_3 concentrations also lead to significant benefits for crop yields.

The BC measures identified here reduce concentrations of BC, OC and O_3 (largely through reductions in emissions of CO). The warming effect of BC and O_3 and the compensating cooling effect of OC, introduces large uncertainty in the net effect of some BC measures on global warming (Figure 1). Uncertainty in the impact of BC measures is also larger than that for CH_4 because BC and OC can influence clouds that have multiple effects on climate that are not fully understood. This uncertainly in global impacts is particularly large for the

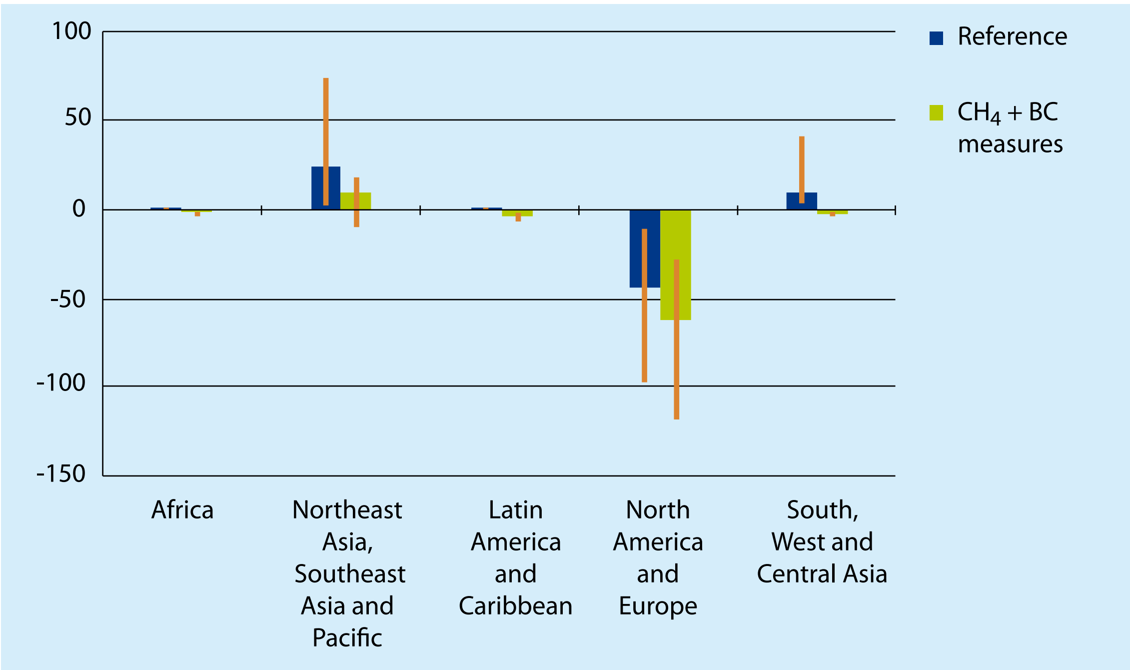

Figure 8. Comparison of crop yield losses (million tonnes annually of four key crops – wheat, rice, maize and soy combined) by region, showing the change in 2030 compared with 2005 for the reference emission trends and the reference with CH_4 + BC measures. The lines on each bar show the range of estimates.

Widespread haze over the Himalayas where BC concentrations can be as high as in mid-sized cities.

Reducing emissions should lower glacial melt and decrease the risk of outbursts from glacial lakes.

measures concerning biomass cookstoves and open burning of biomass. Hence with respect to global warming, there is much higher confidence for measures that mitigate diesel emissions than biomass burning because the proportion of co-emitted cooling OC particles is much lower for diesel.

On the other hand, there is higher confidence that BC measures have large impacts on human health through reducing concentrations of inhalable particles, on crop yields through reduced O_3, and on climate phenomena such as tropical rainfall, monsoons and snow-ice melt. These regional impacts are largely independent of the measures' impact on global warming. In fact, regionally, biomass cookstoves and open biomass burning can have much larger effects than fossil fuels. This is because BC directly increases atmospheric heating by absorbing sunlight, which, according to numerous published studies, affects the monsoon and tropical rainfall, and this is largely separate from the effect of co-emitted OC. The same conclusion applies with respect to the impact of BC measures on snow and ice. BC, because it is dark, significantly increases absorption of sunlight by snow and ice when it is deposited on these bright surfaces. OC that is deposited along with BC has very little effect on sunlight reflected by snow and ice since these surfaces are already very white. Hence knowledge of these regional impacts is, in some cases, more robust than the global impacts, and with respect to reducing regional impacts, all of the BC measures are likely to be significant. Confidence is also high that a large proportion of the health and crop benefits would be realized in Asia.

Mechanisms for rapid implementation

In December 2010 the Parties to the UNFCCC agreed that warming should not exceed 2˚C above pre-industrial levels during this century. This Assessment shows that measures to reduce SLCFs, implemented in combination with CO_2 control measures, would increase the chances of staying below the 2˚C target. The measures would also slow the rate of near-term temperature rise and also lead to significant improvements in health, decreased disruption of regional precipitation patterns and water supply, and in improved food security. The impacts of the measures on temperature change are felt over large geographical areas, while the air quality impacts are more localized near the regions where changes in emissions take place. Therefore, areas that control their emissions will receive the greatest human health and food supply benefits; additionally many of the climate benefits will be felt close to the region taking action.

The benefits would be realized in the near term, thereby providing additional incentives to overcome financial and institutional hurdles to the adoption of these measures. Countries in all regions have successfully implemented the identified measures to some degree for multiple environment and development objectives. These experiences

Credit: Brian Yap

Field burning of agricultural waste is a common way to dispose of crop residue in many regions.

provide a considerable body of knowledge and potential models for others that wish to take action.

In most countries, mechanisms are already in place, albeit at different levels of maturity, to address public concern regarding air pollution problems. Mechanisms to tackle anthropogenic greenhouse gases are less well deployed, and systems to maximize the co-benefits from reducing air pollution and measures to address climate change are virtually non-existent. Coordination across institutions to address climate, air pollution, energy and development policy is particularly important to enhance achievement of all these goals simultaneously.

Many BC control measures require implementation by multiple actors on diffuse emission sources including diesel vehicles, field burning, cookstoves and residential heating. Although air quality and emission standards exist for particulate matter in some regions, they may or may not reduce BC, and implementation remains a challenge. Relevance, benefits and costs of different measures vary from region to region. Many of the measures entail cost savings but require substantial upfront investments. Accounting for air quality, climate and development co-benefits will be key to scaling up implementation.

Methane is one of the six greenhouse gases governed by the Kyoto Protocol, but there are no explicit targets for it. Many CH_4 measures are cost-effective and its recovery is, in many cases, economically profitable. There have been many Clean Development Mechanism (CDM) projects in key CH_4 emitting sectors in the past, though few such projects have been launched in recent years because of lack of financing.

Case studies from both developed and developing countries (Box 3) show that there are technical solutions available to deliver all of the measures (see Chapter 5). Given appropriate policy mechanisms the measures can be implemented, but to achieve the benefits at the scale described much wider implementation is required.

Credit: US EPA

To the naked eye, no emissions from an oil storage tank are visible (left), but with the aid of an infrared camera, escaping CH_4 is evident (right).

Box 3: Case studies of implementation of measures

CH_4 measures

Landfill biogas energy

Landfill CH_4 emissions contribute 10 per cent of the total greenhouse gas emissions in Mexico. Bioenergia de Nuevo Léon S.A. de C.V. (BENLESA) is using landfill biogas as fuel. Currently, the plant has an installed capacity of 12.7 megawatts. Since its opening in September 2003, it has avoided the release of more than 81 000 tonnes of CH_4, equivalent to the reduction in emissions of 1.7 million tonnes of CO_2, generating 409 megawatt hours of electricity. A partnership between government and a private company turned a liability into an asset by converting landfill gas (LFG) into electricity to help drive the public transit system by day and light city streets by night. LFG projects can also be found in Armenia, Brazil, China, India, South Africa, and other countries.

Recovery and flaring from oil and natural gas production

Oil drilling often brings natural gas, mostly CH_4, to the surface along with the oil, which is often vented to the atmosphere to maintain safe pressure in the well. To reduce these emissions, associated gas may be flared and converted to CO_2, or recovered, thus eliminating most of its warming potential and removing its ability to form ozone (O_3). In India, Oil India Limited (OIL), a national oil company, is undertaking a project to recover the gas, which is presently flared, from the Kumchai oil field, and send it to a gas processing plant for eventual transport and use in the natural gas grid. Initiatives in Angola, Indonesia and other countries are flaring and recovering associated gas yielding large reductions in CH_4 emissions and new sources of fuel for local markets.

Livestock manure management

In Brazil, a large CDM project in the state of Mina Gerais seeks to improve waste management systems to reduce the amount of CH_4 and other greenhouse gas emissions associated with animal effluent. The core of the project is to replace open-air lagoons with ambient temperature anaerobic digesters to capture and combust the resulting biogas. Over the course of a 10-year period (2004–2014) the project plans to reduce CH_4 and other greenhouse gas emissions by a total of 50 580 tonnes of CO_2 equivalent. A CDM project in Hyderabad, India, will use the poultry litter CH_4 to generate electricity which will power the plant and supply surplus electricity to the Andhra Pradesh state grid.

Credit: Raphaël V/flickr

Farm scale anaerobic digestion of manure from cattle is one of the key CH_4 measures

Box 3: Case studies of implementation of measures *(continued)*

BC measures

Diesel particle filters

In Santiago, municipal authorities, responding to public concern on air pollution, adopted a new emissions standard for urban buses, requiring installation of diesel particle filters (DPFs). Currently about one-third of the fleet is equipped with filters; it is expected that the entire fleet will be retrofitted by 2018. New York City adopted regulations in 2000 and 2003 requiring use of DPFs in city buses and off-road construction equipment working on city projects. London fitted DPFs to the city's bus fleet over several years beginning in 2003. Low emission zones in London and other cities create incentives for diesel vehicle owners to retrofit with particle filters, allowing them to drive within the city limits. Implementation in developing regions will require greater availability of low sulphur diesel, which is an essential prerequisite for using DPFs.

Improved brick kilns

Small-scale traditional brick kilns are a significant source of air pollution in many developing countries; there are an estimated 20 000 in Mexico alone, emitting large quantities of particulates. An improved kiln design piloted in Ciudad Juárez, near the border with the United States of America, improved efficiency by 50 per cent and decreased particulate pollution by 80 per cent. In the Bac Ninh province of Viet Nam, a project initiated with the aim of reducing ambient air pollution levels and deposition on surrounding rice fields piloted the use of a simple limestone scrubbing emissions control device and demonstrated how a combination of regulation, economic tools, monitoring and technology transfer can significantly improve air quality.

A traditional brick kiln (left) and an improved (right) operating in Mexico.

Potential international regulatory responses

International responses would facilitate rapid and widespread implementation of the measures. Since a large portion of the impacts of SLCFs on climate, health, food security and ecosystems is regional or local in nature, regional approaches incorporating national actions could prove promising for their cost-effective reduction. This approach is still in its very early stage in most regions of the world. For example, the Convention on Long-Range Transboundary Air Pollution (CLRTAP) recently agreed to address BC in the revision of the Gothenburg Protocol in 2011 and to consider the impacts of CH_4 as an O_3 precursor in the longer term.

Other regional agreements (Box 4) are fairly new, and predominantly concentrate on scientific cooperation and capacity building. These arrangements might serve as a platform from which to address the emerging challenges related to air pollution from BC and tropospheric O_3 and provide potential vehicles for finance, technology transfer and capacity development. Sharing good practices

Box 4: Examples of regional atmospheric pollution agreements

The Convention on Long-Range Transboundary Air Pollution (CLRTAP) is a mature policy framework covering Europe, Central Asia and North America. Similar regional agreements have emerged in the last decades in other parts of the world. The Malé Declaration on Control and Prevention of Air Pollution and its Likely Transboundary Effects for South Asia was agreed in 1998 and addresses air quality including tropospheric O_3 and particulate matter. The Association of Southeast Asian Nations (ASEAN) Haze Protocol is a legally binding agreement addresses particulate pollution from forest fires in Southeast Asia. In Africa there are a number of framework agreements between countries in southern Africa (Lusaka Agreement), in East Africa (Nairobi Agreement); and West and Central Africa (Abidjan Agreement). In Latin America and the Caribbean a ministerial level intergovernmental network on air pollution has been formed and there is a draft framework agreement and ongoing collaboration on atmospheric issues under UNEP's leadership.

on an international scale, as is occurring within the Arctic Council, in a coordinated way could provide a helpful way forward.

This Assessment did not assess the cost-effectiveness of different identified measures or policy options under different national circumstances. Doing so would help to inform national air quality and climate policy makers, and support implementation on a wider scale. Further study and analyses of the local application of BC and tropospheric O_3 reduction technologies, costs and regulatory approaches could contribute to advancing adoption of effective action at multiple levels. This work would be best done based on local knowledge. Likewise further evaluation of the regional and global benefits of implementing specific measures by region would help to better target policy efforts. In support of these efforts, additional modelling and monitoring and measurement activities are needed to fill remaining knowledge gaps.

Opportunities for international financing and cooperation

The largest benefits would be delivered in regions where it is unlikely that significant national funds would be allocated to these issues due to other pressing development needs. International financing and technology support would catalyse and accelerate the adoption of the identified measures at sub-national, national and regional levels, especially in developing countries. Financing would be most effective if specifically targeted towards pollution abatement actions that maximize air quality and climate benefits.

Funds and activities to address CH_4 (such as the Global Methane Initiative; and the Global Methane Fund or Prototype Methane Financing Facility) and cookstoves (the Global Alliance for Clean Cookstoves) exist or are under consideration and may serve as models for other sectors. Expanded action will depend on donor recognition of the opportunity represented by SLCF reductions as a highly effective means to address near-term climate change both globally and especially in sensitive regions of the world.

Black carbon and tropospheric O_3 may also be considered as part of other environment, development and energy initiatives such as bilateral assistance, the UN Development Assistance Framework, the World Bank Energy Strategy, the Poverty and Environment Initiative of UNEP and the United Nations Development Programme (UNDP), interagency cooperation initiatives in the UN system such as the Environment Management Group and UN Energy, the UN Foundation, and the consideration by the UN Conference on Sustainable Development (Rio+20) of the institutional framework for sustainable development. These, and others, could take advantage of the opportunities identified in the Assessment to achieve their objectives.

Credit: John Ogren, NOAA

Aerosol measurement instruments

Credit: Christian Lagerek

Concluding Remarks

The Assessment establishes the climate co-benefits of air-quality measures that address black carbon and tropospheric ozone and its precursors, especially CH_4 and CO. The measures identified to address these short-lived climate forcers have been successfully tried around the world and have been shown to deliver significant and immediate development and environmental benefits in the local areas and regions where they are implemented.

Costs and benefits of the identified measures are region specific, and implementation often faces financial, regulatory and institutional barriers. However, widespread implementation of the identified measures can be effectively leveraged by recognizing that near-term strategies can slow the rate of global and regional warming, improving our chances of keeping global temperature increase below bounds that significantly lower the probability of major disruptive climate events. Such leverage should spur multilateral initiatives that focus on local priorities and contribute to the global common good.

It is nevertheless stressed that this Assessment does not in any way suggest postponing immediate and aggressive global action on anthropogenic greenhouse gases; in fact it requires such action on CO_2. This Assessment concludes that the chance of success with such longer-term measures can be greatly enhanced by simultaneously addressing short-lived climate forcers.

The benefits identified in this Assessment can be realised with a concerted effort globally to reduce the concentrations of black carbon and tropospheric ozone. A strategy to achieve this, when developed and implemented, will lead to considerable benefits for human well-being.

Glossary

Aerosol	A collection of airborne solid or liquid particles (excluding pure water), with a typical size between 0.01 and 10 micrometers (μm) and residing in the atmosphere for at least several hours. Aerosols may be of either natural or anthropogenic origin. Aerosols may influence climate in two ways: directly through scattering or absorbing radiation, and indirectly through acting as condensation nuclei for cloud formation or modifying the optical properties and lifetime of clouds.
Biofuels	Biofuels are non-fossil fuels. They are energy carriers that store the energy derived from organic materials (biomass), including plant materials and animal waste.
Biomass	In the context of energy, the term biomass is often used to refer to organic materials, such as wood and agricultural wastes, which can be burned to produce energy or converted into a gas and used for fuel.
Black carbon	Operationally defined aerosol species based on measurement of light absorption and chemical reactivity and/or thermal stability. Black carbon is formed through the incomplete combustion of fossil fuels, biofuel, and biomass, and is emitted in both anthropogenic and naturally occurring soot. It consists of pure carbon in several linked forms. Black carbon warms the Earth by absorbing heat in the atmosphere and by reducing albedo, the ability to reflect sunlight, when deposited on snow and ice.
Carbon sequestration	The uptake and storage of carbon. Trees and plants, for example, absorb carbon dioxide, release the oxygen and store the carbon.
Fugitive emissions	Substances (gas, liquid, solid) that escape to the air from a process or a product without going through a smokestack; for example, emissions of methane escaping from coal, oil, and gas extraction not caught by a capture system.
Global warming potential (GWP)	The global warming potential of a gas or particle refers to an estimate of the total contribution to global warming over a particular time that results from the emission of one unit of that gas or particle relative to one unit of the reference gas, carbon dioxide, which is assigned a value of one.
High-emitting vehicles	Poorly tuned or defective vehicles (including malfunctioning emission control system), with emissions of air pollutants (including particulate matter) many times greater than the average.
Hoffman kiln	Hoffmann kilns are the most common kiln used in production of bricks. A Hoffmann kiln consists of a main fire passage surrounded on each side by several small rooms which contain pallets of bricks. Each room is connected to the next room by a passageway carrying hot gases from the fire. This design makes for a very efficient use of heat and fuel.
Incomplete combustion	A reaction or process which entails only partial burning of a fuel. Combustion is almost always incomplete and this may be due to a lack of oxygen or low temperature, preventing the complete chemical reaction.
Oxidation	The chemical reaction of a substance with oxygen or a reaction in which the atoms in an element lose electrons and its valence is correspondingly increased.

Ozone	Ozone, the triatomic form of oxygen (O_3), is a gaseous atmospheric constituent. In the troposphere, it is created both naturally and by photochemical reactions involving gases resulting from human activities (it is a primary component of photochemical smog). In high concentrations, tropospheric ozone can be harmful to a wide range of living organisms. Tropospheric ozone acts as a greenhouse gas. In the stratosphere, ozone is created by the interaction between solar ultraviolet radiation and molecular oxygen. Stratospheric ozone provides a shield from ultraviolet B (UVB) radiation.
Ozone precursor	Chemical compounds, such as carbon monoxide (CO), methane (CH_4), non-methane volatile organic compounds (NMVOC), and nitrogen oxides (NO_x), which in the presence of solar radiation react with other chemical compounds to form ozone in the troposphere.
Particulate matter	Very small pieces of solid or liquid matter such as particles of soot, dust, or other aerosols.
Pre-industrial	Prior to widespread industrialisation and the resultant changes in the environment. Typically taken as the period before 1750.
Radiation	Energy transfer in the form of electromagnetic waves or particles that release energy when absorbed by an object.
Radiative forcing	Radiative forcing is a measure of the change in the energy balance of the Earth-atmosphere system with space. It is defined as the change in the net, downward minus upward, irradiance (expressed in Watts per square metre) at the tropopause due to a change in an external driver of climate change, such as, for example, a change in the concentration of carbon dioxide or the output of the Sun.
Smog	Classically a combination of smoke and fog in which products of combustion, such as hydrocarbons, particulate matter and oxides of sulphur and nitrogen, occur in concentrations that are harmful to human beings and other organisms. More commonly, it occurs as photochemical smog, produced when sunlight acts on nitrogen oxides and hydrocarbons to produce tropospheric ozone.
Stratosphere	Region of the atmosphere between the troposphere and mesosphere, having a lower boundary of approximately 8 km at the poles to 15 km at the equator and an upper boundary of approximately 50 km. Depending upon latitude and season, the temperature in the lower stratosphere can increase, be isothermal, or even decrease with altitude, but the temperature in the upper stratosphere generally increases with height due to absorption of solar radiation by ozone.
Transboundary movement	Movement from an area under the national jurisdiction of one State to or through an area under the national jurisdiction of another State or to or through an area not under the national jurisdiction of any State.
Transport (atmospheric)	The movement of chemical species through the atmosphere as a result of large-scale atmospheric motions.
Troposphere	The lowest part of the atmosphere from the surface to about 10 km in altitude in mid-latitudes (ranging from 9 km in high latitudes to 16 km in the tropics on average) where clouds and "weather" phenomena occur. In the troposphere temperatures generally decrease with height.

Acronyms and Abbreviations

ASEAN	Association of Southeast Asian Nations
BC	black carbon
BENLESA	Latin America Bioenergia de Nuevo Léon S.A. de C.V.
CDM	Clean Development Mechanism
CH_4	methane
CLRTAP	Convention on Long-Range Transboundary Air Pollution
CO	carbon monoxide
CO_2	carbon dioxide
DPF	diesel particle filter
ECHAM	Climate-chemistry-aerosol model developed by the Max Planck Institute in Hamburg, Germany
G8	Group of Eight: Canada, France, Germany, Italy, Japan, Russian Federation, United Kingdom, United States
GAINS	Greenhouse Gas and Air Pollution Interactions and Synergies
GISS	Goddard Institute for Space Studies
GWP	global warming potential
IEA	International Energy Agency
IIASA	International Institute for Applied System Analysis
IPCC	Intergovernmental Panel on Climate Change
LFG	landfill gas
NASA	National Aeronautics and Space Administration
NO_x	nitrogen oxides
O_3	ozone
OC	organic carbon
OIL	Oil India Limited
PM	particulate matter ($PM_{2.5}$ has a diameter of 2.5µm or less)
ppm	parts per million
SLCF	short-lived climate forcer
SO_2	sulphur dioxide
UN	United Nations
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
UV	ultraviolet
VOC	volatile organic compound
WMO	World Meteorological Organization

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About the Assessment:

Growing scientific evidence of significant impacts of black carbon and tropospheric ozone on human well-being and the climatic system has catalysed a demand for information and action from governments, civil society and other main stakeholders. The United Nations, in consultation with partner expert institutions and stakeholder representatives, organized an integrated assessment of black carbon and tropospheric ozone, and its precursors, to provide decision makers with a comprehensive assessment of the problem and policy options needed to address it.

An assessment team of more than 50 experts was established, supported by the United Nations Environment Programme, World Meteorological Organization and Stockholm Environment Institute. The Assessment was governed by the Chair and four Vice-Chairs, representing Asia and the Pacific, Europe, Latin America and the Caribbean and North America regions. A High-level Consultative Group, comprising high-profile government advisors, respected scientists, representatives of international organizations and civil society, provided strategic advice on the assessment process and preparation of the *Summary for Decision Makers*.

The draft of the underlying Assessment and its *Summary for Decision Makers* were extensively reviewed and revised based on comments from internal and external review experts. Reputable experts served as review editors to ensure that all substantive expert review comments were afforded appropriate consideration by the authors. The text of the *Summary for Decision Makers* was accepted by the Assessment Chair, Vice-Chairs and the High-level Consultative Group members.

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This document summarizes findings and conclusions of the assessment report: Integrated Assessment of Black Carbon and Tropospheric Ozone. The assessment looks into all aspects of anthropogenic emissions of black carbon and tropospheric ozone precursors, such as methane. It analyses the trends in emissions of these substances and the drivers of these emissions; summarizes the science of atmospheric processes where these substances are involved; discusses related impacts on the climatic system, human health, crops in vulnerable regions and ecosystems; and societal responses to the environmental changes caused by those impacts. The Assessment examines a large number of potential measures to reduce harmful emissions, identifying a small set of specific measures that would likely produce the greatest benefits, and which could be implemented with currently available technology. An outlook up to 2070 is developed illustrating the benefits of those emission mitigation policies and measures for human well-being and climate. The Assessment concludes that rapid mitigation of anthropogenic black carbon and tropospheric ozone emissions would complement carbon dioxide reduction measures and would have immediate benefits for human well-being.

The Summary for Decision Makers was prepared by a writing team with inputs from the members of the High-level Consultative Group and with support from UNEP and WMO. It is intended to serve decision makers at all levels as a guide for assessment, planning and management for the future.

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United States Environmental Protection Agency

Carbon Monoxide
Health

CO can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain) and tissues. At extremely high levels, CO can cause death.

Exposure to CO can reduce the oxygen-carrying capacity of the blood. People with several types of heart disease already have a reduced capacity for pumping oxygenated blood to the heart, which can cause them to experience myocardial ischemia (reduced oxygen to the heart), often accompanied by chest pain (angina), when exercising or under increased stress. For these people, short-term CO exposure further affects their body's already compromised ability to respond to the increased oxygen demands of exercise or exertion.

Last updated on 12/10/2012

United States Environmental Protection Agency

Climate Change
Human Health Impacts & Adaptation

climatechange/impacts-adaptation/health.html#adapt

[Climate Impacts on Human Health] [Adaptation Examples in Human Health]

Weather and climate play a significant role in people's health. Changes in climate affect the average weather conditions that we are accustomed to. Warmer average temperatures will likely lead to hotter days and more frequent and longer heat waves. This could increase the number of heat-related illnesses and deaths. Increases in the frequency or severity of extreme weather events such as storms could increase the risk of dangerous flooding, high winds, and other direct threats to people and property. Warmer temperatures could increase the concentrations of unhealthy air and water pollutants. Changes in temperature, precipitation patterns, and extreme events could enhance the spread of some diseases.

ON THIS PAGE

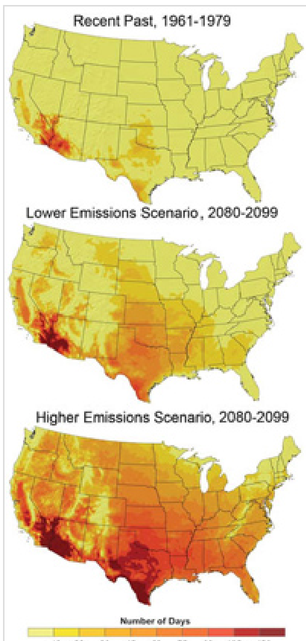
Key Points

- A warmer climate is expected to both increase the risk of heat-related illnesses and death and worsen conditions for air quality.
- Climate change will likely increase the frequency and strength of extreme events (such as floods, droughts, and storms) that threaten human safety and health.
- Climate changes may allow some diseases to spread more easily.

Sun setting over a city on a hot day. Source: EPA (2010)

The impacts of climate change on health will depend on many factors. These factors include the effectiveness of a community's public health and safety systems to address or prepare for the risk and the behavior, age, gender, and economic status of individuals affected. Impacts will likely vary by region, the sensitivity of populations, the extent and length of exposure to climate change impacts, and society's ability to adapt to change.

Although the United States has well-developed public health systems (compared with those of many developing countries), climate change will still likely affect many Americans. In addition, the impacts of climate change on public health around the globe could have important consequences for the United States. For example, more frequent and intense storms may require more disaster relief and declines in agriculture may increase food shortages.



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The number of 100-degree days per year is projected to increase. Source: USGCRP (2009)

Impacts from Heat Waves

Heat waves can lead to heat stroke and dehydration, and are the most common cause of weather-related deaths.[1] [2] Excessive heat is more likely to impact populations in northern latitudes where people are less prepared to cope with excessive temperatures. Young children, older adults, people with medical conditions, and the poor are more vulnerable than others to heat-related illness. The share of the U.S. population composed of adults over age 65 is currently 12%, but is projected to grow to 21% by 2050, leading to a larger vulnerable population.[1]

Climate change will likely lead to more frequent, more severe, and longer heat waves in the summer (see 100-degree-days figure), as well as less severe cold spells in the winter. A recent assessment of the science suggests that increases in heat-related deaths due to climate change would outweigh decreases in deaths from cold-snaps.[1]

Urban areas are typically warmer than their rural surroundings. Climate change could lead to even warmer temperatures in cities. This would increase the demand for electricity in the summer to run air conditioning, which in turn would increase air pollution and greenhouse gas emissions from power plants. The impacts of future heat waves could be especially severe in

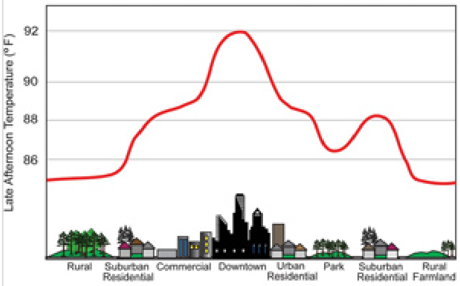
Related Links

EPA:

- Climate Change Indicators in the United States
- Heat Island Effect
- Excessive Heat Events Guidebook
- Global Change Research Program
- Climate Change and Children's Health
- Climate Change and Health Effects on Older Adults
- *Assessment of the Impacts of Global Change on Regional U.S. Air Quality: A Synthesis of Climate Change Impacts on Ground-Level Ozone*
- *Our Nation's Air: Status and Trends Through 2008*

Other:

- CDC Climate Change and Public Health
- USGCRP *Synthesis Assessment Product 4.6: Analyses of the Effects of Global Change on Human Health and Welfare and Human Systems*
- IPCC Fourth Assessment Report, Working Group II EXIT Disclaimer
- USGCRP, Global Climate Change Impacts in the United States: Human Health
- NRC America's Climate Choices: Adapting to the Impacts of Climate Change EXIT Disclaimer
- National Institute of Environmental Health Sciences: *A Human Health Perspective on Climate Change* (PDF)
- World Health Organization, *Climate Change and Human Health: Risks and Responses* EXIT Disclaimer



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The "urban heat island" refers to the fact that the local temperature in urban areas is a few degrees higher than the surrounding area. Source: USGCRP (2009)

large metropolitan areas. For example, in Los Angeles, annual heat-related deaths are projected to increase two- to seven-fold by the end of the 21st century, depending on the future growth of greenhouse gas emissions. [1] Heat waves are also often accompanied by periods of stagnant air, leading to increases in air pollution and the associated health effects

Impacts from Extreme Weather Events

The frequency and intensity of extreme precipitation events is projected to increase in some locations, as is the severity (wind speeds and rain) of tropical storms. [1] These extreme weather events could cause injuries and, in some cases, death. As with heat waves, the people most at risk include young children, older adults, people with medical conditions, and the poor. Extreme events can also indirectly threaten human health in a number of ways. For example, extreme events can:

- Reduce the availability of fresh food and water. [2]
- Interrupt communication, utility, and health care services. [2]
- Contribute to carbon monoxide poisoning from portable electric generators used during and after storms. [2]
- Increase stomach and intestinal illness among evacuees. [1]
- Contribute to mental health impacts such as depression and post-traumatic stress disorder (PTSD). [1]

Flooded streets in New Orleans after Hurricane Katrina in 2005. Source: FEMA (2005)

Climate Change Affects Human Health and Welfare

In 2008, the U.S. Global Change Research Program produced a report that analyzed the impacts of global climate change on human health and welfare. The report finds that:

- Many of the expected health effects are likely to fall mostly on the poor, the very old, the very young, the disabled, and the uninsured.
- Climate change will likely result in regional differences in U.S. impacts, due not only to a regional pattern of changes in climate but also to regional variations in the distribution of sensitive populations and the ability of communities to adapt to climate changes.
- Adaptation should begin now, starting with public health infrastructure. Individuals, communities, and government agencies can take steps to moderate the impacts of climate change on human health. (To learn more, see the Health Adaptation section)

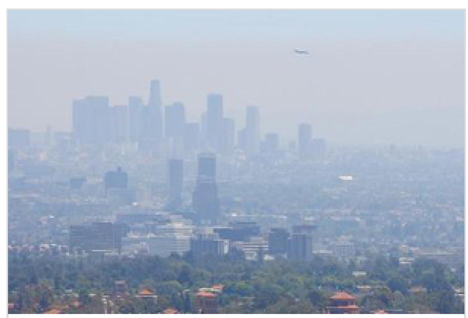
Impacts from Reduced Air Quality

Despite significant improvements in U.S. air quality since the 1970s, as of 2008 more than 126 million Americans lived in counties that did not meet national air quality standards. [3]

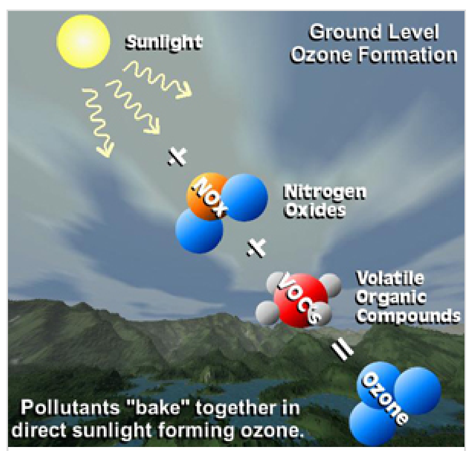
Increases in Ozone

Scientists project that warmer temperatures from climate change will increase the frequency of days with unhealthy levels of ground-level ozone, a harmful air pollutant, and a component in smog. [2] [3]

- Ground-level ozone can damage lung tissue and can reduce lung function and inflame airways. This can increase respiratory symptoms and aggravate asthma or other lung diseases. It is especially harmful to children, older adults, outdoor workers, and those with asthma and other chronic lung diseases. [4]
- Ozone exposure also has been associated with increased susceptibility to respiratory infections, medication use, doctor visits, and emergency department visits and hospital admissions for individuals with lung disease. Some studies suggest that ozone may increase the risk of premature mortality, and possibly even the development of asthma. [1] [2] [3] [5]
- Ground-level ozone is formed when certain air pollutants, such as carbon monoxide, oxides of nitrogen (also called NO_X), and volatile organic compounds, are exposed to each other in sunlight. Ground-level ozone is one of the pollutants in smog. [2] [3]
- Because warm, stagnant air tends to increase the formation of ozone, climate change is likely to increase levels of ground-level ozone in already-polluted areas of the United States and increase the number of days with poor air quality. [1] If emissions of air pollutants remain fixed at today's levels until 2050, warming from climate change alone could increase the number of Red Ozone Alert Days (when the air is unhealthy for everyone) by 68% in the 50 largest eastern U.S. cities. [1] (See Box below "EPA Report on Air Quality and Climate Change.")



Smog in Los Angeles decreases visibility and can be harmful to human health. Source: California Air Resources Board (2011)



Ozone chemistry. Source: NASA (2012)

Changes in Fine Particulate Matter

Particulate matter is the term for a category of extremely small particles and liquid droplets suspended in the atmosphere. Fine particles include particles smaller than 2.5 micrometers (about one ten-thousandth of an inch). These particles may be emitted directly or may be formed in the atmosphere from chemical reactions of gases such as sulfur dioxide, nitrogen dioxide, and volatile organic compounds.

- Inhaling fine particles can lead to a broad range of adverse health effects, including premature mortality, aggravation of cardiovascular and respiratory disease, development of chronic lung disease, exacerbation of asthma, and decreased lung function growth in children. [6]
- Sources of fine particle pollution include power plants, gasoline and diesel engines, wood combustion, high-temperature industrial processes such as smelters and steel mills, and forest fires. [6]

Due to the variety of sources and components of fine particulate matter, scientists do not yet know whether climate change will increase or decrease particulate matter concentrations across the United States. [7] [8] A lot of particulate matter is cleaned from the air by rainfall, so increases in precipitation could have a beneficial effect. At the same time, other climate-related changes in stagnant air episodes, wind patterns, emissions from vegetation and the chemistry of atmospheric pollutants will likely affect particulate matter levels. [2] Climate change will also affect particulates through changes in wildfires, which are expected to become more frequent and intense in a warmer climate. [7]

Changes in Allergens

Climate change may affect allergies and respiratory health. [4] The spring pollen season is already occurring earlier in the United States due to climate change. The length of the season may also have increased. In addition, climate change may facilitate the spread of ragweed, an invasive plant with very allergenic pollen. Tests on ragweed show that increasing carbon dioxide concentrations and temperatures would increase the amount and timing of ragweed pollen production. [1] [2] [9]

Impacts from Climate-Sensitive Diseases

Changes in climate may enhance the spread of some diseases. [1] Disease-causing agents, called pathogens, can be transmitted through food, water, and animals such as deer, birds, mice, and insects. Climate change could affect all of these transmitters.

Food-borne Diseases

- Higher air temperatures can increase cases of salmonella and other bacteria-related food poisoning because bacteria grow more rapidly in warm environments. These diseases can cause gastrointestinal distress and, in severe cases, death. [1]
- Flooding and heavy rainfall can cause overflows from sewage treatment plants into fresh water sources. Overflows could contaminate certain food crops with pathogen-containing feces. [1]

Water-borne Diseases

- Heavy rainfall or flooding can increase water-borne parasites such as *Cryptosporidium* and *Giardia* that are sometimes found in drinking water. [1] These parasites can cause gastrointestinal distress and in severe cases, death.
- Heavy rainfall events cause stormwater runoff that may contaminate water bodies used for recreation (such as lakes and beaches) with other bacteria. [9] The most common illness contracted from contamination at beaches is gastroenteritis, an inflammation of the stomach and the intestines that can cause symptoms such as vomiting, headaches, and fever. Other minor illnesses include ear, eye, nose, and throat infections. [2]

EPA Report on Air Quality and Climate Change

Improving America's air quality is one of EPA's top priorities. EPA's Global Change Research Program is investigating the potential consequences of climate change on U.S. air quality. A recent interim assessment finds that:

- Climate change could increase surface-level ozone concentrations in areas w here pollution levels are already high.
- Climate change could make U.S. air quality management more difficult.
- Policy makers should consider the potential impacts of climate change on air quality w hen making air quality management decisions.

Animal-borne Diseases

- The geographic range of ticks that carry Lyme disease is limited by temperature. As air temperatures rise, the range of these ticks is likely to continue to expand northward. [9] Typical symptoms of Lyme disease include fever, headache, fatigue, and a characteristic skin rash.
- In 2002, a new strain of West Nile virus, which can cause serious, life-altering disease, emerged in the United States. Higher temperatures are favorable to the survival of this new strain. [1]

Mosquitoes favor w arm, w et climates and can spread diseases such as West Nile virus.

The spread of climate-sensitive diseases will depend on both climate and non-climate factors. The United States has public health infrastructure and programs to monitor, manage, and prevent the spread of many diseases. The risks for climate-sensitive diseases can be much higher in poorer countries that have less capacity to prevent and treat illness. [9] For more information, please visit the International Impacts & Adaptation page.

Other Heath Linkages

Other linkages exist between climate change and human health. For example, changes in temperature and precipitation, as well as droughts and floods, will likely affect agricultural yields and production. In some regions of the world, these impacts may compromise food security and threaten human health through malnutrition, the spread of infectious diseases, and food poisoning. The worst of these effects are projected to occur in developing countries, among vulnerable populations. [9] Declines in human health in other countries might affect the United States through trade, migration and immigration and have implications for national security. [1] [2]

Although the impacts of climate change have the potential to affect human health in the United States and around the world, there is a lot we can do to prepare for and adapt to these changes. Learn about how we can adapt to climate impacts on health.

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WCMS
Last updated on 6/14/2012

EPA United States Environmental Protection Agency

Sulfur Dioxide

Health

Current scientific evidence links short-term exposures to SO_2, ranging from 5 minutes to 24 hours, with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms. These effects are particularly important for asthmatics at elevated ventilation rates (e.g., while exercising or playing.)

Studies also show a connection between short-term exposure and increased visits to emergency departments and hospital admissions for respiratory illnesses, particularly in at-risk populations including children, the elderly, and asthmatics.

EPA's National Ambient Air Quality Standard for SO_2 is designed to protect against exposure to the entire group of sulfur oxides (SOx). SO_2 is the component of greatest concern and is used as the indicator for the larger group of gaseous sulfur oxides (SOx). Other gaseous sulfur oxides (e.g. SO3) are found in the atmosphere at concentrations much lower than SO_2.

Emissions that lead to high concentrations of SO_2 generally also lead to the formation of other SOx. Control measures that reduce SO_2 can generally be expected to reduce people's exposures to all gaseous SOx. This may have the important co-benefit of reducing the formation of fine sulfate particles, which pose significant public health threats.

SOx can react with other compounds in the atmosphere to form small particles. These particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death. EPA's NAAQS for particulate matter (PM) are designed to provide protection against these health effects.

Last updated on 7/12/2012

United States Environmental Protection Agency

Particulate Matter (PM)
Health

The size of particles is directly linked to their potential for causing health problems. Small particles less than10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream.

Exposure to such particles can affect both your lungs and your heart. Small particles of concern include "inhalable coarse particles" (such as those found near roadways and dusty industries), which are larger than 2.5 micrometers and smaller than 10 micrometers in diameter; and "fine particles" (such as those found in smoke and haze), which are 2.5 micrometers in diameter and smaller.

The Clean Air Act requires EPA to set air quality standards to protect both public health and the public welfare (e.g. visibility, crops and vegetation). Particle pollution affects both.

Health Effects

Particle pollution - especially fine particles - contains microscopic solids or liquid droplets that are so small that they can get deep into the lungs and cause serious health problems. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including:

- premature death in people with heart or lung disease,
- nonfatal heart attacks,
- irregular heartbeat,
- aggravated asthma,
- decreased lung function, and
- increased respiratory symptoms, such as irritation of the airways, coughing or difficulty breathing.

People with heart or lung diseases, children and older adults are the most likely to be affected by particle pollution exposure. However, even if you are healthy, you may experience temporary symptoms from exposure to elevated levels of particle pollution. For more information about asthma, visit www.epa.gov/asthma.

Environmental Effects

Visibility impairment
Fine particles ($PM_{2.5}$) are the main cause of reduced visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas. For more information about visibility, visit www.epa.gov/visibility.

Environmental damage
Particles can be carried over long distances by wind and then settle on ground or water. The effects of this settling include: making lakes and streams acidic; changing the nutrient balance in coastal waters and large river basins; depleting the nutrients in soil; damaging sensitive forests and farm crops; and affecting the diversity of ecosystems. More information about the effects of particle pollution and acid rain.

Aesthetic damage
Particle pollution can stain and damage stone and other materials, including culturally important objects such as statues and monuments. More information about the effects of particle pollution and acid rain.

For more information on particle pollution, health and the environment, visit:

Particle Pollution and Your Health (PDF) (2pp, 320k): Learn who is at risk from exposure to particle pollution, what health effects you may experience as a result of particle exposure, and simple measures you can take to reduce your risk.

How Smoke From Fires Can Affect Your Health: It's important to limit your exposure to smoke -- especially if you may be susceptible. This publication provides steps you can take to protect your health.

Integrated Science Assessment for Particulate Matter (December 2009): This comprehensive assessment of scientific data about the health and environmental effects of particulate matter is an important part of EPA's review of its particle pollution standards.

Last updated on 1/23/2013

Visibility

Basic Information

How far can you see?

Every year there are over 280 million visitors to our nation's most treasured parks and wilderness areas. Unfortunately, many visitors aren't able to see the spectacular vistas they expect. During much of the year a veil of white or brown haze hangs in the air blurring the view. Most of this haze is not natural. It is air pollution, carried by the wind often many hundreds of miles from where it originated.

In our nation's scenic areas, the visual range has been substantially reduced by air pollution. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles. In the West, visual range has decreased from 140 miles to 35-90 miles.

What is haze?

Haze is caused when sunlight encounters tiny pollution particles in the air. Some light is absorbed by particles. Other light is scattered away before it reaches an observer. More pollutants mean more absorption and scattering of light, which reduce the clarity and color of what we see. Some types of particles such as sulfates, scatter more light, particularly during humid conditions.

Where does haze-forming pollution come from?

Air pollutants come from a variety of natural and manmade sources. Natural sources can include windblown dust, and soot from wildfires. Manmade sources can include motor vehicles, electric utility and industrial fuel burning, and manufacturing operations. Particulate matter pollution is the major cause of reduced visibility (haze) in parts of the United States, including many of our national parks. Find out more about particulate pollution.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are carried many miles from the source of the pollutants.

What else can these pollutants do to you and the environment?

Some of the pollutants which form haze have also been linked to serious health problems and environmental damage. Exposure to very small particles in the air have been linked with increased respiratory illness, decreased lung function, and even premature death. In addition, particles such as nitrates and sulfates contribute to acid rain formation which makes lakes, rivers, and streams unsuitable for many fish, and erodes buildings, historical monuments, and paint on cars.

You w ill need Adobe Acrobat Reader to view the Adobe PDF files on this page. See EPA's PDF page for more information about getting and using the free Acrobat Reader.

How can I learn more about visibility?

How Air Pollution Affects the View (PDF) (2 pp, 793 KB) - EPA brochure describing the health and environmental effects of haze.

Introduction to Visibility (PDF) (79 pp., 3.3 MB) - Report by William Malm, National Park Service and Colorodo State Institute for Research on the Atmosphere

What other Federal agencies address visibility?

- National Park Service EXIT Disclaimer
- U.S. Forest Service EXIT Disclaimer
- U.S. Fish and Wildlife Service EXIT Disclaimer

Last updated on 5/31/2012

DOE/EIA-0581(2009)

The National Energy Modeling System: An Overview 2009

October 2009

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

This publication is on the WEB at:
www.eia.doe.gov/oiaf/aeo/overview/

Preface

The National Energy Modeling System: An Overview 2009 provides a summary description of the National Energy Modeling System, which was used to generate the projections of energy production, demand, imports, and prices through the year 2030 for the *Annual Energy Outlook 2009, (DOE/EIA-0383(2009))*, released in March 2009. *AEO2009* presents national projections of energy markets for five primary cases—a reference case and four additional cases that assume higher and lower economic growth and higher and lower world oil prices than in the reference case. The Overview presents a brief description of the methodology and scope of each of the component modules of NEMS. The model documentation reports listed in the appendix of this document provide further details.

The Overview was prepared by the Energy Information Administration, Office of Integrated Analysis and Forecasting under the direction of John J. Conti (john.conti@eia.doe.gov, 202/586-2222), Director, Office of Integrated Analysis and Forecasting; Paul D. Holtberg (paul.holtberg@eia.doe.gov, 202/586-1284), Director of the Demand and Integration Division; Joseph A. Beamon (jbeamon@eia.doe.gov, 202/586-2025), Director of the Coal and Electric Power Division; A. Michael Schaal (michael,schaal@eia.doe.gov, 202/586-5590), Director of the Oil and Gas Division; Glen E. Sweetnam (glen.sweetnam@eia.doe.gov, 202-586-2188), Director, International, Economic, and Greenhouse Gases Division; and Andy S. Kydes (akydes@eia.doe.gov, 202/586-2222), Senior Technical Advisor.

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AEO2009 is available on the EIA Home Page on the Internet (http://www.eia.doe.gov/oiaf/aeo/index.html). Assumptions underlying the projections are available in Assumptions to the Annual Energy Outlook 2009 at http://www.eia.doe.gov/oiaf/aeo/assumption/index.html. Tables of regional projections and other underlying details of the reference case are available at http://www.eia.doe.gov/oiaf/aeo/supplement/index.html. Model documentation reports and The National Energy Modeling System: An Overview 2009 are also available on the Home Page at http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model documentation.

For ordering information and for questions on energy statistics, please contact EIA's National Energy Information Center.

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Introduction

Introduction

The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system of U.S. through 2030. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS was designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE).

The National Energy Modeling System: An Overview 2009 provides an overview of the structure and methodology of NEMS and each of its components. This chapter provides a description of the design and objectives of the system, followed by a chapter on the overall modeling structure and solution algorithm. The remainder of the report summarizes the methodology and scope of the component modules of NEMS. The model descriptions are intended for readers familiar with terminology from economic, operations research, and energy modeling. More detailed model documentation reports for all the NEMS modules are also available from EIA (Appendix, “Bibliography”).

Purpose of NEMS

NEMS is used by EIA to project the energy, economic, environmental, and security impacts on the United States of alternative energy policies and different assumptions about energy markets. The projection horizon is approximately 25 years into the future. The projections in *Annual Energy Outlook 2009 (AEO2009)* are from the present through 2030. This time period is one in which technology, demographics, and economic conditions are sufficiently understood in order to represent energy markets with a reasonable degree of confidence. NEMS provides a consistent framework for representing the complex interactions of the U.S. energy system and its response to a wide variety of alternative assumptions and policies or policy initiatives. As an annual model, NEMS can also be used to examine the impact of new energy programs and policies.

Energy resources and prices, the demand for specific energy services, and other characteristics of energy markets vary widely across the United States. To address these differences, NEMS is a regional model. The regional disaggregation for each module reflects the availability of data, the regional format typically used to analyze trends in the specific area, geology, and other factors, as well as the regions determined to be the most useful for policy analysis. For example, the demand modules (e.g., residential, commercial, industrial and transportation) use the nine Census divisions, the Electricity Market Module uses 15 supply regions based on the North American Electric Reliability Council (NERC) regions, the Oil and Gas Supply Modules use 12 supply regions, including 3 offshore and 3 Alaskan regions, and the Petroleum Market Module uses 5 regions based on the Petroleum Administration for Defense Districts.

Baseline projections are developed with NEMS and published annually in the *Annual Energy Outlook (AEO)*. In accordance with the requirement that EIA remain policy-neutral, the *AEO* projections are generally based on Federal, State, and local laws and regulations in affect at the time of the projection. The potential impacts of pending or proposed legislation, regulations, and standards or of sections of legislation that have been enacted but that require implementing regulations or appropriations of funds that have not been provided or specified in the legislation itself are not reflected in NEMS. The first version of NEMS, completed in December 1993, was used to develop the projections presented in the *Annual Energy Outlook 1994*. This report describes the version of NEMS used for the *AEO2009*.[1]

The projections produced by NEMS are not considered to be statements of what will happen but of what might happen, given the assumptions and methodologies used. Assumptions include, for example, the estimated size of the economically recoverable resource base of fossil fuels, and changes in world energy supply and demand. The projections are business-as-usual trend estimates, given known technological and demographic trends.

Analytical Capability

NEMS can be used to analyze the effects of existing and proposed government laws and regulations related to energy production and use; the potential impact of new and advanced energy production, conversion, and consumption technologies; the impact and cost of greenhouse gas control; the impact of increased use of renewable energy sources; and the potential savings

1 Energy Information Administration, *Annual Energy Outlook 2009,* DOE/EIA-0383(2009) (Washington, DC, March 2009)

from increased efficiency of energy use; and the impact of regulations on the use of alternative or reformulated fuels.

In addition to producing the analyses in the *AEO*, NEMS is used for one-time analytical reports and papers, such as *An Updated Annual Energy Outlook 2009 Reference Case Reflecting Provisions of the American Recovery and Reinvestment Act and Recent Changes in the Economic Outlook*,[2] which updates the *AEO2009* reference case to reflect the enactment of the American Recovery and Reinvestment Act in February 2009 and to adopt a revised macroeconomic outlook for the U.S. and global economies. The revised *AEO2009* reference case will be used as the starting point for pending and future analyses of proposed energy and environmental legislation. Other analytical papers, which either describe the assumptions and methodology of the NEMS or look at current energy markets issues, are prepared using the NEMS. Many of these papers are published in the Issues In Focus section of the *AEO*. Past and current analyses are available at http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_analyes.html.

NEMS has also been used for a number of special analyses at the request of the Administration, U.S. Congress, other offices of DOE and other government agencies, who specify the scenarios and assumptions for the analysis. Some recent examples include:

- *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009*,[3] requested by Chairman Henry Waxman and Chairman Edward Markey to analyze the impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (ACESA), which was passed by the House of Representatives on June 26, 2009. ACESA is a complex bill that regulates emissions of greenhouse gases through market-based mechanisms, efficiency programs, and economic incentives.
- *Impacts of a 25-Percent Renewable Electricity Standard as Proposed in the American Clean Energy and Security Act*,[4] requested by Senator Markey to analyze the effects of a 25-percent Federal renewable electricity standard (RES) as included in the discussion draft of broader legislation, the American Clean Energy and Security Act.
- *Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues*,[5] requested by Senator Sessions *to* analyze the environmental and energy efficiency attributes of diesel-fueled light-duty vehicles (LDV's), including comparison of the characteristics of the vehicles with those of similar gasoline-fueled, E85-fueled, and hybrid vehicles, as well as a discussion of any technical, economic, regulatory, or other obstacles to increasing the use of diesel-fueled vehicles in the United States.
- *The Impact of Increased Use of Hydrogen on Petroleum Consumption and Carbon Dioxide Emissions*,[6] requested by Senator Dorgan to analyze the impacts on U.S. energy import dependence and emissions reductions resulting from the commercialization of advanced hydrogen and fuel cell technologies in the transportation and distributed generation markets.
- *Analysis of Crude Oil Production in the Arctic National Wildlife Refuge*,[7] requested by Senator Stevens to access the impact of Federal oil and natural gas leasing in the coastal plain of the Arctic National Wildlife Refuge in Alaska.
- *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of*

2 Energy Information Administration, *An Updated Annual Energy Outlook 2009 Reference Case Reflecting Provisions of the American Recovery and Reinvestment Act and Recent Changes in the Economic Outlook*, SR/OIAF/2009-4 (Washington, DC, April 2009).

3 Energy Information Administration, Energy Market and Economic Impacts of H.R. 2454, the American Clean energy and Security Act of 2009, SR/OIAF/2009-05 (Washington, DC, August 2009).

4 Energy Information Administration, *Impacts of a 25-Percent Renewable Electricity Standard as proposed in the American Clean Energy and Security Act Discussion*, SR/OIAF/2009-03 (Washington, DC, April 2009)

5 Energy Information Administration, *Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues*, SR/OIAF/2009-02 (Washington, DC, February 2009).

6 Energy Information Administration, *The Impact of Increased Use of Hydrogen on Petroleum Consumption and Carbon Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues*, SR/OIAF/2008-04 (Washington, DC, September 2008).

7 Energy Information Administration, *Analysis of Crude Oil Production in the Arctic National Wildlife Refuge*, SR/OIAF/2008-03 (Washington, DC, May 2008).

2007,[8] requested by Senators Lieberman, Warner, Inhofe, Voinovich, and Barrasso to analyze the impacts of the greenhouse gas cap-and-trade program that would be established under Title I of S.2191.

- *Energy Market and Economic Impact*s of S.1766, the Low Carbon Economy Act of 2007,[9] requested by Senators Bingaman and Specter to analyze the impact of the mandatory greenhouse gas allowance program under S.1766 designed to maintain covered emissions at approximately 2006 levels in 2020, 1990 levels in 2030, and at least 60 percent below 1990 levels by 2050.

Representations of Energy Market Interactions

NEMS is designed to represent the important interactions of supply and demand in U.S. energy markets. In the United States, energy markets are driven primarily by the fundamental economic interactions of supply and demand. Government regulations and policies can exert considerable influence, but the majority of decisions affecting fuel prices and consumption patterns, resource allocation, and energy technologies are made by private individuals who value attributes other than life cycle costs or companies attempting to optimize their own economic interests. NEMS represents the market behavior of the producers and consumers of energy at a level of detail that is useful for analyzing the implications of technological improvements and policy initiatives.

Energy Supply/Conversion/Demand Interactions

NEMS is a modular system. Four end-use demand modules represent fuel consumption in the residential, commercial, transportation, and industrial sectors, subject to delivered fuel prices, macroeconomic influences, and technology characteristics. The primary fuel supply and conversion modules compute the levels of domestic production, imports, transportation costs, and fuel prices that are needed to meet domestic and export demands for energy, subject to resource base characteristics, industry infrastructure and technology, and world market conditions. The modules interact to solve for the economic supply and demand balance for each fuel. Because of the modular design, each sector can be represented with the methodology andthe level of detail, including regional detail, appropriate for that sector. The modularity also facilitates the analysis, maintenance, and testing of the NEMS component modules in the multi-user environment.

Domestic Energy System/Economy Interactions

The general level of economic activity, represented by gross domestic product, has traditionally been used as a key explanatory variable or driver for projections of energy consumption at the sectoral and regional levels. In turn, energy prices and other energy system activities influence economic growth and activity. NEMS captures this feedback between the domestic economy and the energy system. Thus, changes in energy prices affect the key macroeconomic variables—such as gross domestic product, disposable personal income, industrial output, housing starts, employment, and interest rates—that drive energy consumption and capacity expansion decisions.

Domestic/World Energy Market Interactions

World oil prices play a key role in domestic energy supply and demand decision making and oil price assumptions are a typical starting point for energy system projections. The level of oil production and consumption in the U.S. energy system also has a significant influence on world oil markets and prices. In NEMS, an international module represents the response of world oil markets (supply and demand) to assumed world oil prices. The results/outputs of the module are international liquids consumption and production by region, and a crude oil supply curve representing international crude oil similar in quality to West Texas Intermediate that is available to U.S. markets through the Petroleum Market Module (PMM) of NEMS. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international liquids supply and demand, current investment trends in exploration and development, and long-term resource economics for 221 countries/territories. The oil production estimates include both conventional and unconventional supply recovery technologies.

8 Energy Information Administration, *Energy Market and Economic Impacts of S.2191, the Lieberan-Warner Climate Security Act of 2007*, SR/OIAF/2008-01 (Washington, DC, April 2008).

9 Energy Information Administration, *Energy Market and Economic Impacts of S.1766, the Low Carbon Economy Act of 2007*, SR/OIAF/2007-06 (Washington, DC, January 2008).

Economic Decision Making Over Time

The production and consumption of energy products today are influenced by past investment decisions to develop energy resources and acquire energy-using capital stock. Similarly, the production and consumption of energy in a future time period will be influenced by decisions made today and in the past.

Current investment decisions depend on expectations about future markets. For example, expectations of rising energy prices in the future increase the likelihood of current decisions to invest in more energy-efficient technologies or alternative energy sources. A variety of assumptions about planning horizons, the formation of expectations about the future, and the role of those expectations in economic decision making are applied within the individual NEMS modules.

Technology Representation

A key feature of NEMS is the representation of technology and technology improvement over time. Five of the sectors—residential, commercial, transportation, electricity generation, and refining—include extensive treatment of individual technologies and their characteristics, such as the initial capital cost, operating cost, date of availability, efficiency, and other characteristics specific to the particular technology. For example, technological progress in lighting technologies results in a gradual reduction in cost and is modeled as a function of time in these end-use sectors. In addition, the electricity sector accounts for technological optimism in the capital costs of first-of-a-kind generating technologies and for a decline in cost as experience with the technologies is gained both domestically and internationally. In each of these sectors, equipment choices are made for individual technologies as new equipment is needed to meet growing demand for energy services or to replace retired equipment.

In the other sectors—industrial, oil and gas supply, and coal supply—the treatment of technologies is more limited due to a lack of data on individual technologies. In the industrial sector, only the combined heat and power and motor technologies are explicitly considered and characterized. Cost reductions resulting from technological progress in combined heat and power technologies are represented as a function of time as experience with the technologies grows. Technological progress is not explicitly modeled for the industrial motor technologies. Other technologies in the energy-intensive industries are represented by technology bundles, with technology possibility curves representing efficiency improvement over time. In the oil and gas supply sector, technological progress is represented by econometrically estimated improvements in finding rates, success rates, and costs. Productivity improvements over time represent technological progress in coal production.

External Availability

In accordance with EIA requirements, NEMS is fully documented and archived. EIA has been running NEMS on four EIA terminal servers and several dual-processor personal computers (PCs) using the Windows XP operating system. The archive file provides the source language, input files, and output files to replicate the *Annual Energy Outlook* reference case runs on an identically equipped computer; however, it does not include the proprietary portions of the model, such as the IHS Global Insight, Inc. (formerly DRI-WEFA) macroeconomic model and the optimization modeling libraries. NEMS can be run on a high-powered individual PC as long as the required proprietary software resides on the PC. Because of the complexity of NEMS, and the relatively high cost of the proprietary software, NEMS is not widely used outside of the Department of Energy. However, NEMS, or portions of it, is installed at the Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, the Electric Power Research Institute, the National Energy Technology Laboratory, the National Renewable Energy Laboratory, several private consulting firms, and a few universities.

Overview of NEMS

Overview of NEMS

NEMS explicitly represents domestic energy markets by the economic decision making involved in the production, conversion, and consumption of energy products. Where possible, NEMS includes explicit representation of energy technologies and their characteristics. Since energy costs, availability, and energy-consuming characteristics vary widely across regions, considerable regional detail is included. Other details of production and consumption are represented to facilitate policy analysis and ensure the validity of the results. A summary of the detail provided in NEMS is shown in Table 1.

Table 1. Characteristics of Selected Modules

Energy Activity	Categories	Regions
Residential Demand	Twenty four end-use services Three housing types Fifty end-use technologies	Nine Census divisions
Commercial demand	Ten end-use services Eleven building types Eleven distributed generation technologies Sixty-three end-use technologies	Nine Census divisions
Industrial demand	Seven energy-intensive industries Eight non-energy-intensive industries Six non-manufacturing industries Cogeneration	Four Census regions, shared to nine Census divisions
Transportation demand	Six car sizes Six light truck sizes Sixty-three conventional fuel-saving technologies for light-duty vehicles Gasoline, diesel, and fourteen alternative-fuel vehicle technologies for light-duty vehicles Twenty vintages for light-duty vehicles Regional, narrow, and wide-body aircraft Six advanced aircraft technologies Light, medium, and heavy freight trucks Thirty-seven advanced freight truck technologies	Nine Census divisions
Electricity	Eleven fossil generation technologies Two distributed generation technologies Eight renewable generation technologies Conventional and advanced nuclear Storage technology to model load shifting Marginal and average cost pricing Generation capacity expansion Seven environmental control technologies	Fifteen electricity supply regions (including Alaska and Hawaii) based on the North American Electric Reliability Council regions and subregions Nine Census divisions for demand Fifteen electricity supply regions
Renewables	Two wind technologies—onshore and offshore—, geothermal, solar thermal, solar photovoltaic, landfill gas, biomass, conventional hydropower	
Oil supply	Lower-48 onshore Lower-48 deep and shallow offshore Alaska onshore and offshore	Six lower 48 onshore regions Three lower 48 offshore regions Three Alaska regions
Natural gas supply	Conventional lower-48 onshore Lower-48 deep and shallow offshore Coalbed methane Gas shales Tight sands	Six lower 48 onshore regions Three lower 48 offshore regions Three Alaska regions
Natural gas transmission and distribution	Core vs. noncore delivered prices Peak vs. off-peak flows and prices Pipeline capacity expansion Pipeline and distributor tariffs Canada, Mexico, and LNG imports and exports Alaska gas consumption and supply	Twelve lower 48 regions Ten pipeline border points Eight LNG import regions
Refining	Five crude oil categories Fourteen product categories More than 40 distinct technologies Refinery capacity expansion	Five refinery regions based on the Petroleum Administration for Defense Districts
Coal supply	Three sulfur categories Four thermal categories Underground and surface mining types Imports and Exports	Fourteen supply regions Fourteen demand regions Seventeen export regions Twenty import regions

Major Assumptions

Each module of NEMS embodies many assumptions and data to characterize the future production, conversion, or consumption of energy in the United States. Two of the more important factors influencing energy markets are economic growth and oil prices.

The *AEO2009* includes five primary fully-integrated cases: a reference case, high and low economic growth cases, and high and low oil price cases. The primary determinant for different economic growth rates are assumptions about growth in the labor force and productivity, while the long-term oil price paths are based on access to and cost of oil from the non-Organization of Petroleum Exporting Countries (OPEC), OPEC supply decisions, and the supply potential of unconventional liquids, as well as the demand for liquids.

In addition to the five primary fully-integrated cases, *AEO2009* includes 34 other cases that explore the impact of varying key assumptions in the individual components of NEMS. Many of these cases involve changes in the assumptions that impact the penetration of new or improved technologies, which is a major uncertainty in formulating projections of future energy markets. Some of these cases are run as fully integrated cases (e.g., integrated 2009 technology case, integrated high technology case, low and high renewables technology cost cases, slow and rapid oil and gas technology cases, and low and high coal cost cases). Others exploit the modular structure of NEMS by running only a portion of the entire modeling system in order to focus on the first-order impacts of changes in the assumptions (e.g., 2009, high, and best available technology cases in the residential and commercial sectors, 2009 and high technology cases in the industrial sector and, low and high technology cases in the transportation sector).

NEMS Modular Structure

Overall, NEMS represents the behavior of energy markets and their interactions with the U.S. economy. The model achieves a supply/demand balance in the end-use demand regions, defined as the nine Census divisions (Figure 1), by solving for the prices of each energy type that will balance the quantities producers are willing to supply with the quantities consumers wish to consume. The system reflects market economics, industry structure, and existing energy policies and regulations that influence market behavior.

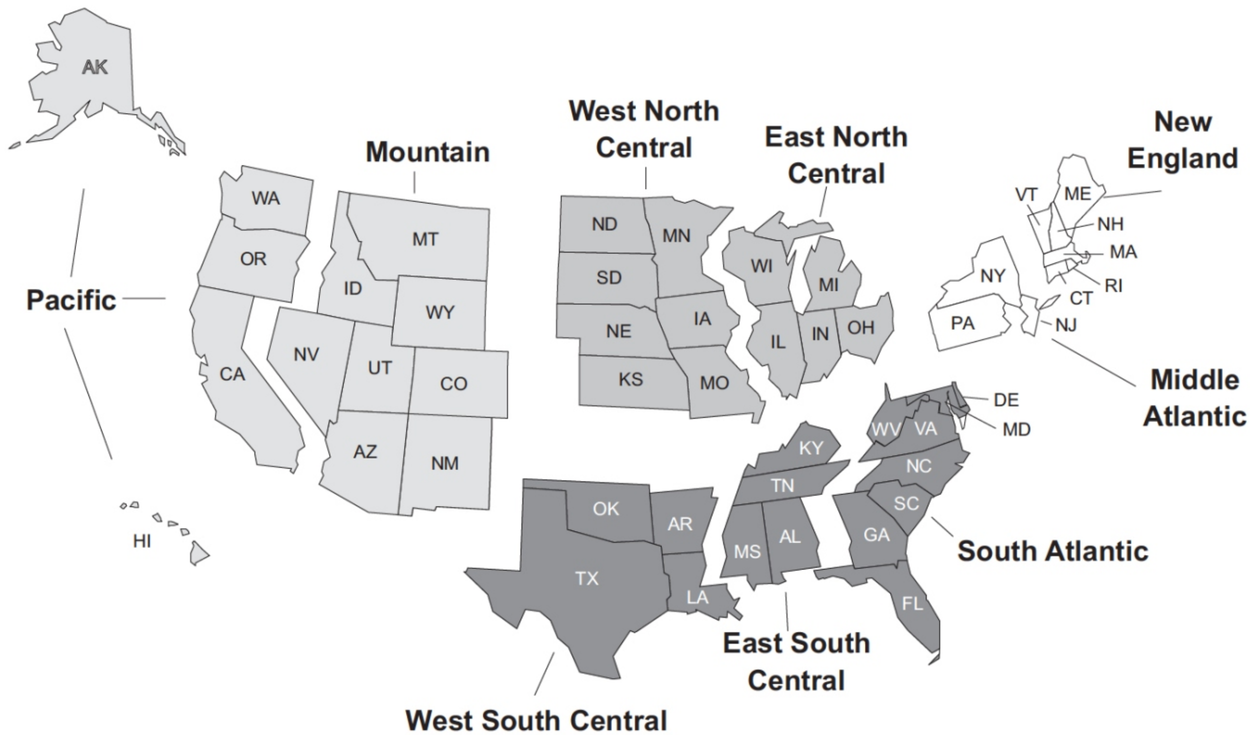
NEMS consists of four supply modules (oil and gas, natural gas transmission and distribution, coal market, and renewable fuels); two conversion modules (electricity market and petroleum market); four end-use demand modules (residential demand, commercial demand, industrial demand, and transportation demand); one module to simulate energy/economy interactions (macroeconomic activity); one module to simulate international energy markets (international energy); and one module that provides the mechanism to achieve a general market equilibrium among all the other modules (integrating module). Figure 2 depicts the high-level structure of NEMS.

Because energy markets are heterogeneous, a single methodology does not adequately represent all supply, conversion, and end-use demand sectors. The modularity of the NEMS design provides the flexibility for each component of the U.S. energy system to use the methodology and coverage that is most appropriate. Furthermore, modularity provides the capability to execute the modules individually or in collections of modules, which facilitates the development and analysis of the separate component modules. The interactions among these modules are controlled by the integrating module.

The NEMS global data structure is used to coordinate and communicate the flow of information among the modules. These data are passed through common interfaces via the integrating module. The global data structure includes energy market prices and consumption; macroeconomic variables; energy production, transportation, and conversion information; and centralized model control variables, parameters, and assumptions. The global data structure excludes variables that are defined locally within the modules and are not communicated to other modules.

A key subset of the variables in the global data structure is the end-use prices and quantities of fuels that are used to equilibrate the NEMS energy balance in the convergence algorithm. These delivered prices of energy and the quantities demanded are defined by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The regions used for the price and quantity variables in the global data structure are the nine Census divisions. The four Census regions (shown in Figure 1 by breaks between State groups) and nine Census divisions are a common, mainstream level of regionality widely used by EIA and other organizations for data collection and analysis.

Figure 1. Census Division



Division 1

New England

Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2

Middle Atlantic

New Jersey
New York
Pennsylvania

Division 3

East North Central

Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4

West North Central

Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5

South Atlantic

Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6

East South Central

Alabama
Kentucky
Mississippi
Tennessee

Division 7

West South Central

Arkansas
Louisiana
Oklahoma
Texas

Division 8

Mountain

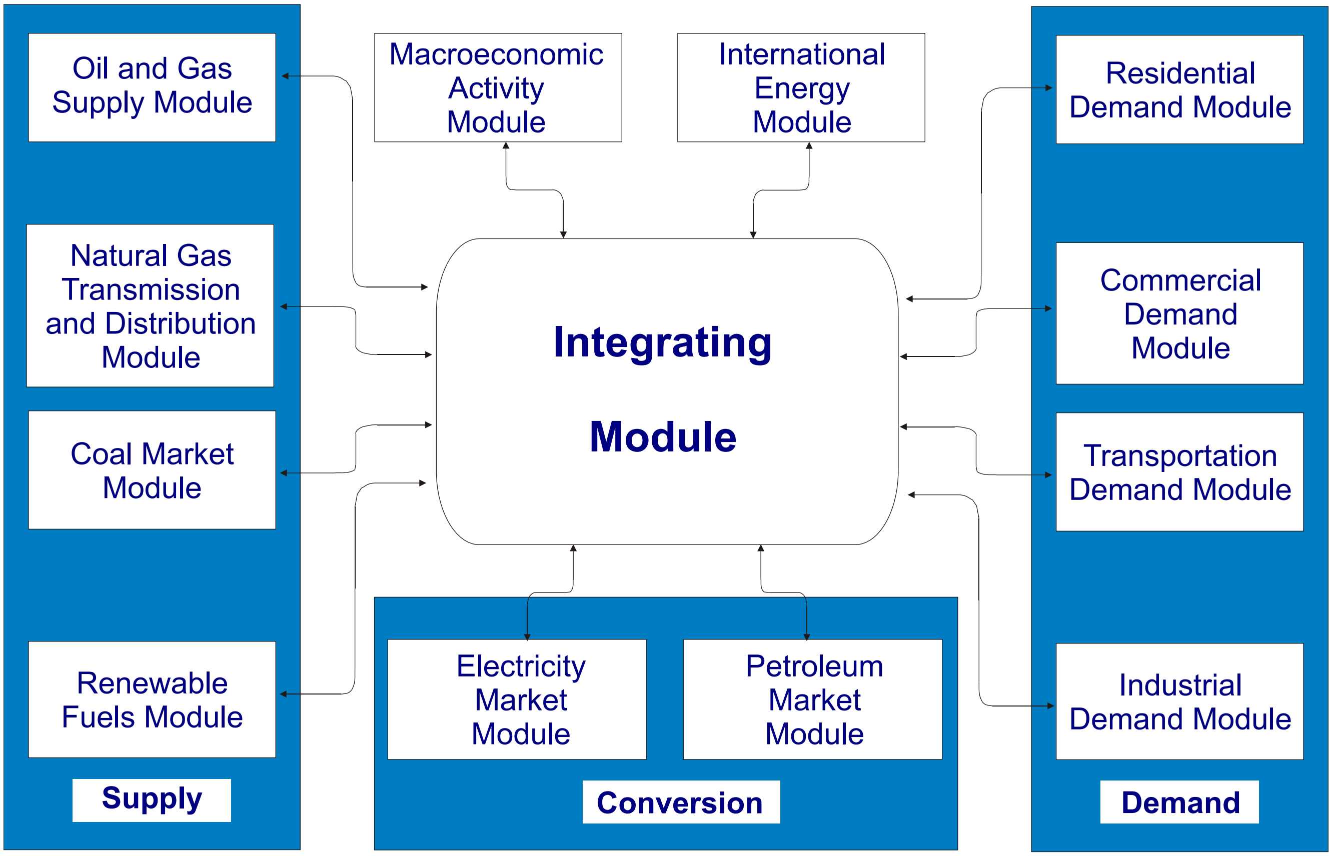
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9

Pacific

Alaska
California
Hawaii
Oregon
Washington

Figure 2. National Energy Modeling System



Integrating Module

The NEMS integrating module controls the entire NEMS solution process as it iterates to determine a general market equilibrium across all the NEMS modules. It has the following functions:

- Manages the NEMS global data structure
- Executes all or any of the user-selected modules in an iterative convergence algorithm
- Checks for convergence and reports variables that remain out of convergence
- Implements convergence relaxation on selected variables between iterations to accelerate convergence
- Updates expected values of the key NEMS variables.

The integrating module executes the demand, conversion, and supply modules iteratively until it achieves an economic equilibrium of supply and demand in all the consuming and producing sectors. Each module is called in sequence and solved, assuming that all other variables in the energy markets are fixed. The modules are called iteratively until the end-use prices and quantities remain constant within a specified tolerance, a condition defined as convergence. Equilibration is achieved annually throughout the projection period, currently through 2030, for each of the nine Census divisions.

In addition, the macroeconomic activity and international energy modules are executed iteratively to incorporate the feedback on the economy and international energy markets from changes in the domestic energy markets. Convergence tests check the stability of a set of key macroeconomic and international trade variables in response to interactions with the domestic energy system.

The NEMS algorithm executes the system of modules until convergence is reached. The solution procedure for one iteration involves the execution of all the component modules, as well as the updating of expectation variables (related to foresight assumptions) for use in the next iteration. The system is executed sequentially for each year in the projection period. During each iteration, the modules are executed in turn, with intervening convergence checks that isolate specific modules that are not converging. A convergence check is made for each price and quantity variable to see whether the percentage change in the variable is within the assumed tolerance. To avoid unnecessary iterations for changes in insignificant values, the quantity convergence check is omitted for quantities less than a user-specified minimum level. The order of execution of the modules may affect the rate of convergence but will generally not prevent convergence to an equilibrium solution or significantly alter the results. An optional relaxation routine can be executed to dampen swings in solution values between iterations. With this option, the current iteration values are reset partway between solution values from the current and previous iterations. Because of the modular structure of NEMS and the iterative solution algorithm, any single module or subset of modules can be executed independently. Modules not executed are bypassed in the calling sequence, and the values they would calculate and provide to the other modules are held fixed at the values in the global data structure, which are the solution values from a previous run of NEMS. This flexibility is an aid to independent development, debugging, and analysis.

Carbon Dioxide Emissions

Carbon Dioxide Emissions

The emissions policy submodule, part of the integrating module, estimates energy-related carbon dioxide emissions and is capable of representing two related greenhouse gas (GHG) emissions policies: a cap-and-trade program and a carbon dioxide emission tax.

Carbon dioxide emissions are calculated from fossil-fuel energy consumption and fuel-specific emissions factors. The estimates are adjusted for carbon capture technologies where applicable. Carbon dioxide emissions from energy use are dependent on the carbon content of the fossil fuel, the fraction of the fuel consumed in combustion, and the consumption of that fuel. The product of the carbon content at full combustion and the combustion fraction yields an adjusted carbon emission factor. The adjusted carbon emissions factors, one for each fuel and sector, are provided as input to the emissions policy module.

Data on past carbon dioxide emissions and emissions factors are updated each year from the EIA's annual inventory, *Emissions of Greenhouse Gases the United States*.[10] To provide a more complete accounting of greenhouse gas emissions consistent with that inventory, a baseline emissions projection for the non-energy carbon dioxide and other greenhouse gases may be specified as an exogenous input.

To represent carbon tax or cap-and-trade policies, an incremental cost of using each fossil fuel, on a dollar-per-Btu basis, is calculated based the carbon dioxide emissions factors and the per-ton carbon dioxide tax or cap-and-trade allowance cost. This incremental cost, or carbon price adjustment, is added to the corresponding energy prices as seen by the energy demand modules. These price adjustments influence energy demand and energy-related CO_2 emissions, as well as macroeconomic trends.

Under a cap-and-trade policy, the allowance or permit price is determined in an iterative solution process such that the annual covered emissions match the cap each year. If allowance banking is permitted, a constant-growth allowance price path is found such that cumulative emissions over the banking interval match the cumulative covered emissions. To the extent the policies cover greenhouse gases other than CO_2, the coverage assumptions and abatement potential for the gases must be provided as input. In past studies, EIA has drawn on work by the Environmental Protection Agency (EPA) to represent exogenous estimates of emissions abatement and the use of offsets as a function of allowance prices.

Representing specific cap-and-trade policies in NEMS almost always requires customization of the model. Among the issues that must be addressed are what gases and sectors are covered, what offsets are eligible as compliance measures, how the revenues raised by the taxes or allowance sales are used, how allowances or the value of allowances are distributed, and how the distribution affects energy pricing or the cost of using energy.

10 Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2007*, DOE/EIA-0573 (2007) (Washington, DC, December 2008), web site www.eia.doe.gov/oiaf/1605/ggrpt/index.html.

Macroeconomic Activity Module

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) links NEMS to the rest of the economy by providing projections of economic driver variables for use by the supply, demand, and conversion modules of NEMS. The derivation of the baseline macroeconomic projection lays a foundation for the determination of the energy demand and supply forecast. MAM is used to present alternative macroeconomic growth cases to provide a range of uncertainty about the growth potential for the economy and its likely consequences for the energy system. MAM is also able to address the macroeconomic impacts associated with changing energy market conditions, such as alternative world oil price assumptions. Outside of the *AEO* setting, MAM represents a system of linked modules which can assess the potential impacts on the economy of changes in energy events or policy proposals. These economic impacts then feed back into NEMS for an integrated solution. MAM consists of five submodules:

- Global Insight Model of the U.S. Economy
- Global Insight Industry Model
- Global Insight Employment Model
- EIA Regional Model
- EIA Commercial Floorspace Model

The IHS Global Insight Model of the U.S. Economy (Macroeconomic Model) is the same model used by IHS Global Insight, Inc. to generate the economic projections behind the company's monthly assessment of the U.S. economy. The Industry and Employment submodules, are derivatives of IHS Global Insight's Industry and Employment Models, and have been tailored to provide the industry and regional detail required by NEMS. The Regional and Commercial Floorspace Submodules were developed by EIA to complement the set of Global Insight models, providing a fully integrated approach to projecting economic activity at the national, industry and regional levels. The set of models is designed to run in a recursive manner (see Figure 3). Global Insight's Macroeconomic Model determines the national economy's growth path and final demand mix. The Global Insight Macroeconomic Model provides projections of over 1300 concepts spanning final demands, aggregate supply, prices, incomes, international trade, industrial detail, interest rates and financial flows.

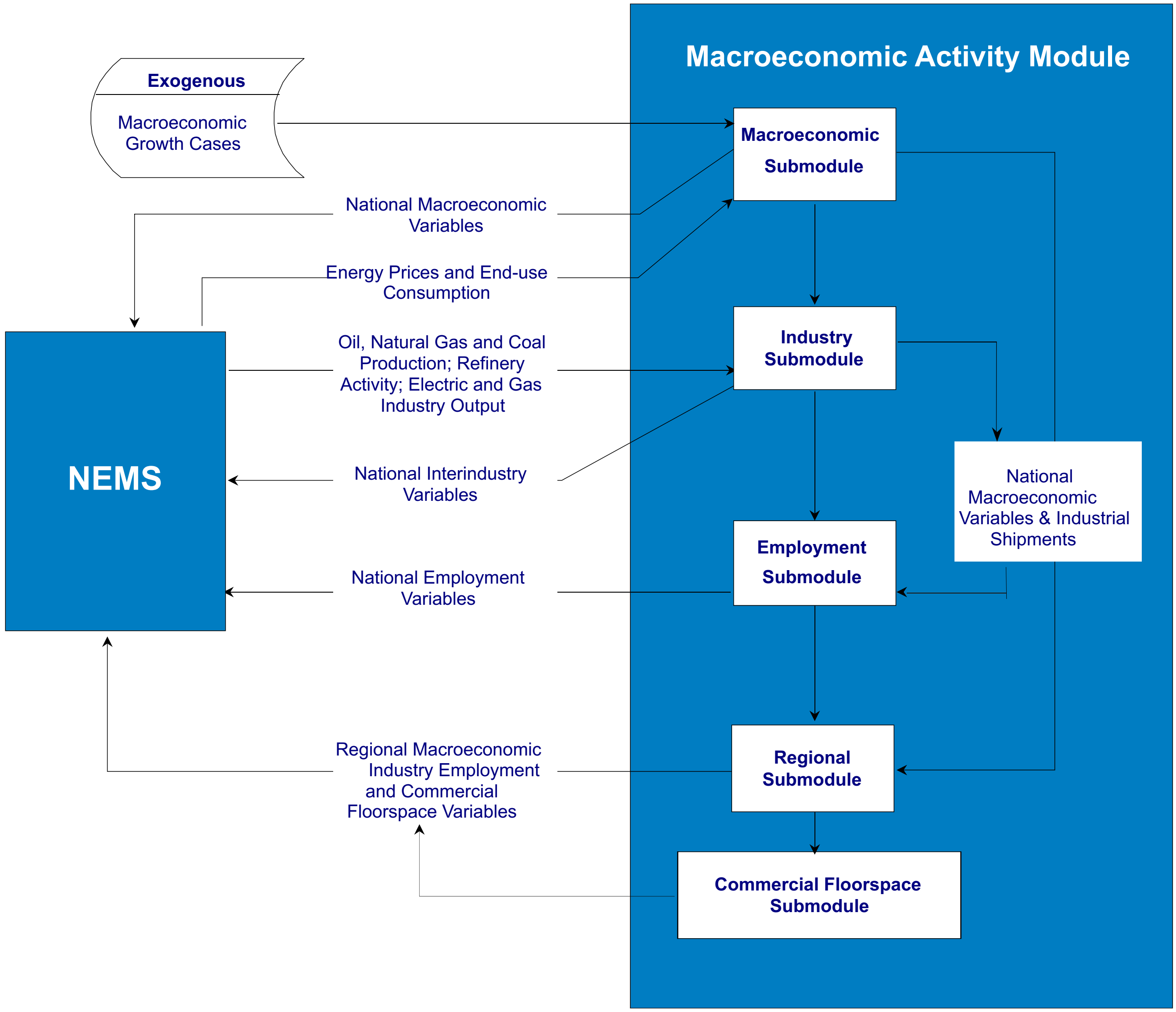
The Industry Submodule takes the final demand projections from the Macroeconomic Submodule as inputs to provide projections of output and other key indicators for 61 sectors, covering the entire economy. This is later aggregated to 41 sectors to provide information to NEMS. The Industry Submodule insures that supply by industry is consistent with the final demands (consumption, investment, government spending, exports and imports) generated in the Macroeconomic Submodule.

The Employment Submodule takes the industry output projections from the Industry Submodule and national wage rates, productivity trends and average work-week trends from the Macroeconomic Submodule to project employment for the 41 NEMS industries. The sum of non-agricultural employment is constrained to sum to the national total projected by the Macroeconomic Submodule.

The Regional Submodule determines the level of industry output and employment, population, incomes, and housing activity in each of nine Census regions. The Commercial Floorspace Submodule calculates regional floorspace for 13 types of building use by Census Division.

MAM Outputs	Inputs from NEMS	Exogenous Inputs
Gross domestic product Other economic activity measures, including housing starts, commercial floorspace growth, vehicle sales, population Price indices and deflators Production and employment for manufacturing Production and employment for nonmanufacturing Interest rates	Petroleum, natural gas, coal, and electricity prices Oil, natural gas, and coal production Electric and gas industry output Refinery output End-use energy consumption by fuel	Macroeconomic variables defining alternative economic growth cases

Figure 3. Macroeconomic Activity Module Structure



Integrated forecasts of NEMS center around estimating the state of the energy-economy system under a set of alternative energy conditions. Typically, the projections fall into the following four types of integrated NEMS simulations:

- Baseline Projection
- Alternative World Oil Prices
- Proposed Energy Fees or Emissions Permits
- Proposed Changes in Combined Average Fuel Economy (CAFE) Standards

In these integrated NEMS simulations, projection period baseline values for over 240 macroeconomic and demographic variables from MAM are passed to NEMS which solves for demand, supply and prices of energy for the projection period. These energy prices and quantities are passed back to MAM and solved in the Macroeconomic, Industry, Employment, Regional, and Commercial Floorspace Submodules in the EViews environment.[11]

11 Eviews is a model building nad operating software package maintained by QMS (Quantitative Micro Software.)

International Energy Module

International Energy Module

The International Energy Module (IEM) (Figure 4) performs the following functions:

- Calculates the world oil price (WOP) that equilibrates world crude-like liquids supply with demand for each year. The WOP is defined as the price of light, low sulfur crude oil delivered to Cushing, Oklahoma.
- Provides the projected world crude-like liquids supply curve (for each year) used by the Petroleum Market Module (PMM). These curves are adjusted to reflect expected conditions in international oil markets and projected changes in U.S. crude-like liquids production and consumption.
- Provide annual regional (country) level production detail for conventional and unconventional liquids based on exogenous assumptions about expected country-level liquid fuels production and producer behavior.
- Projects crude oil and light and heavy refined product import quantities into the U.S. by year and by source based on exogenous assumptions about future exploration, production, refining, and distribution investments worldwide.

Scope of IEM

Non-U.S. liquid fuels markets are represented in NEMS by the interaction between the PMM and the IEM. Using the specific algorithm described in the documentation of this module, IEM calculates the WOP that equilibrates world crude-like liquids supply with demand for each year. The IEM then estimates new world crude-like liquids supply curves based on exogenous, expected U.S. and world crude-like liquids supply and demand curves and that incorporate any changes in U.S. crude-like liquids production or consumption projected by other NEMS modules. Operationally, IEM passes to PMM an array of nine points of this supply curve, with the equilibrium point being the fifth point of this array.

Input data into IEM contain the historical percentages of imports of oils, heavy and light products imported into U.S. from different regions in the world. Using these values and total imports into the U.S. of crudes, heavy and light products provided by PMM, IEM generates a report, with imports by source for every year in the projection.

While the IEM is intended to be executed as a module of the NEMS system, and utilizing its complete capabilities and features requires a NEMS interface, it is also possible to execute the IEM module on a stand-alone basis. In stand-alone mode, the IEM calculates the WOP based on an exogenously specified projection of U.S. crude-like liquids production and consumption. Sensitivity analyses can be conducted to examine the response of the world oil market to changes in oil price, production capacity, and demand. To summarize, the model searches for the WOP that equilibrates crude-like liquids supply and demand at the world level.

Based on the final results for U.S. total liquids production and consumption, IEM also provides an International Petroleum Supply and Disposition Summary table for world conventional and unconventional liquids production as well as for world liquids demand by region. Exogenous data used to build this report is contained in omsinput.wk1 file. Each scenario has its own version of this file.

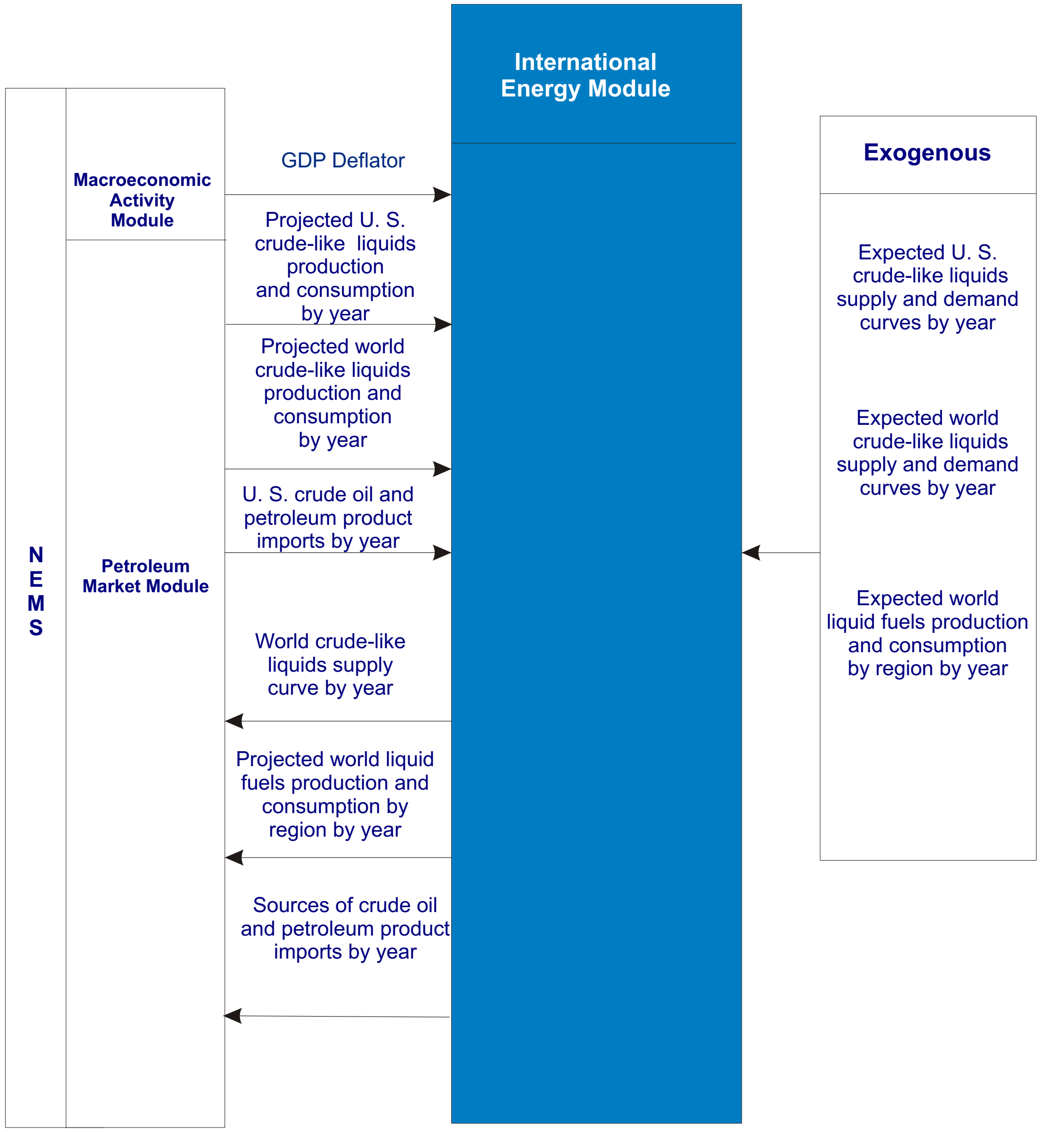
Because U.S. production and consumption of conventional liquids are dynamic values (output from NEMS), all other world regions have been proportionally updated such that the world liquids production and consumption reflect the corresponding value as in the *International Energy Outlook* (*IEO*).

Relation to Other NEMS Components

The IEM both uses information from and provides information to other NEMS components. It primarily uses information about projected U.S and world crude-like liquids production and consumption and petroleum imports and provides information about the world liquid fuels markets, including global crude-like liquids supply curves and the sources of petroleum imports into the U.S. It should be noted, however, that the present focus of the IEM is on the international oil market where the

IEM *Outputs*	Inputs from NEMS	Exogenous Inputs
World crude-like liquids supply curves Projected world liquid fuels production and consumption by region Sources of crude oil and petroleum product imports by year	Controlling information: iteration count, time horizon, etc GDP deflator Projected U.S. and world crude-like liquids production and consumption U.S. crude oil and petroleum product imports	Expected US and world crude-like liquids supply and demand curves Expected world liquid fuel production and consumption by region

Figure 4. International Energy Module Structure



WOP is computed. Any interactions between the U.S. and foreign regions in fuels other than oil (for example, coal trade) are modeled in the particular NEMS module that deals with that fuel.

For U.S. crude-like liquids production and consumption in any year of the projection period, the IEM uses projections generated by the NEMS PMM (based on supply curves provided by the Oil and Gas Supply Module (OGSM) and demand curves from the end-use demand modules).

U.S. and world expected crude-like liquids supply and demand curves, for any year in the projection period, are exogenously provided through data included in input file omsecon.txt, as detailed in the documentation of the IEM.

Residential Demand Module

Residential Demand Module

The residential demand module (RDM) projects energy consumption by Census division for seven marketed energy sources plus solar, wind, and geothermal energy. RDM is a structural model and its demand projections are built up from projections of the residential housing stock and energy-consuming equipment. The components of RDM and its interactions with the NEMS system are shown in Figure 5. NEMS provides projections of residential energy prices, population, disposable income, and housing starts, which are used by RDM to develop projections of energy consumption by end–use service, fuel type, and Census division.

RDM incorporates the effects of four broadly-defined determinants of energy consumption: economic and demographic effects, structural effects, technology turnover and advancement effects, and energy market effects. Economic and demographic effects include the number, dwelling type (single-family, multifamily or mobile homes), occupants per household, disposable income, and location of housing units.Structural effects include increasing average dwelling size and changes in the mix of desired end-use services provided by energy (new end uses and/or increasing penetration of current end uses, such as the increasing popularity of electronic equipment and computers). Technology effects include changes in the stock of installed equipment caused by normal turnover of old, worn out equipment with newer versions that tend to be more energy efficient, the integrated effects of equipment and building shell (insulation level) in new construction, and the projected availability of even more energy-efficient equipment in the future. Energy market effects include the short-run effects of energy prices on energy demands, the longer-run effects of energy prices on the efficiency of purchased equipment and the efficiency of building shells, and limitations on minimum levels of efficiency imposed by legislated efficiency standards.

Housing Stock Submodule

The base housing stock by Census division and dwelling type is derived from EIA's 2005 Residential Energy Consumption Survey (RECS). Each element of the of the base stock is retired on the basis of a constant rate of decay for each dwellling type. RDM receives as an input from the macroeconomic activity module projections of housing additions by type and Census division. RDM supplements the surviving stocks from the previous year with the projected additions by dwelling type and Census division. The average square footage of new construction is based on recent upward trends developed from the RECS and the Census Bureau's Characteristics of New Housing.

Appliance Stock Submodule

The installed stock of appliances is also taken from the 2005 RECS. The efficiency of the appliance stock is derived from historical shipments by efficiency level over a multi-year interval for the following equipment: heat pumps, gas furnaces, central air conditioners, room air conditioners, water heaters, refrigerators, freezers, stoves, dishwashers, clothes washers, and clothes dryers. A linear retirement function with both minimum and maximum equipment lives is used to retire equipment in surviving housing units. For equipment where shipment data are available, the efficiency of the retiring equipment varies over the projection. In early years, the retiring efficiency tends to be lower as the older, less efficient equipment in the stock turns over first. Also, as housing units retire, the associated appliances are removed from the base appliance stock as well. Additions to the base stock are tracked separately for housing units existing in 2005 and for cumulative new construction.

As appliances are removed from the stock, they are replaced by new appliances with generally higher efficiencies due to technology improvements, equipment standards, and market forces. Appliances added due to new construction are accumulated and retired parallel to appliances in the existing stock. Appliance stocks are maintained by fuel, end use, and technology as shown in Table 2.

Technology Choice Submodule

Fuel-specific equipment choices are made for both new construction and replacement purchases. For new construction, initial heating system shares (taken from the most recently available Census Bureau survey data covering new construction, currently 2005) are adjusted

RDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy demand by service and fuel type Changes in housing and appliance stocks Appliance stock efficiency	Energy product prices Housing starts Population	Current housing stocks and retirement rates Current appliance stocks and life expectancy New appliance types, efficiences, and costs Housing shell retrofit indices Unit energy consumption Square footage

Figure 5. Residential Demand Module Structure

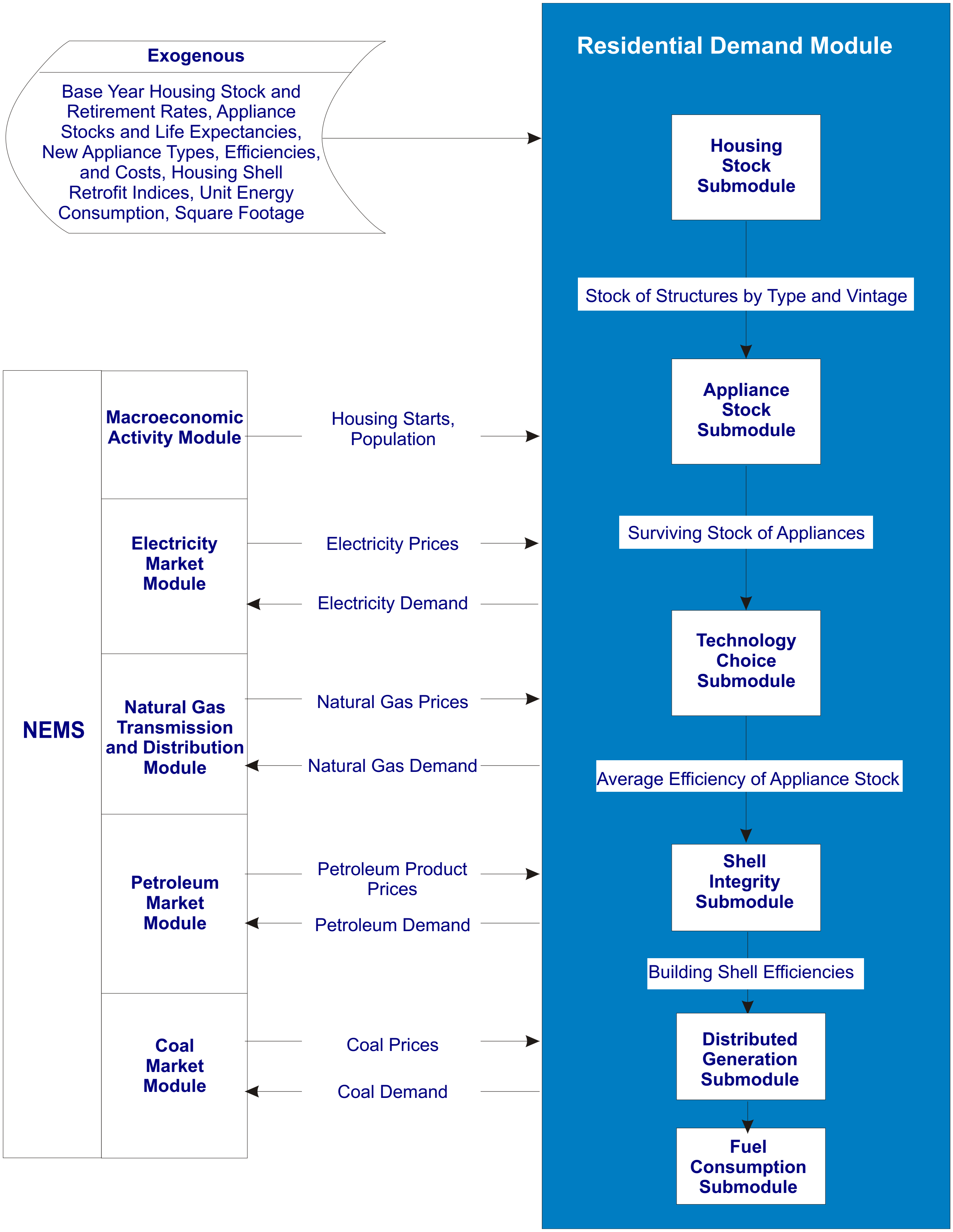


Table 2. NEMS Residential Module Equipment Summary

Space Heating Equipment: electric furnace, electric air-source heat pump, natural gas furnace, natural gas hydronic, kerosene furnace, liquefied petroleum gas, distillate furnace, distillate hydronic, wood stove, ground-source heat pump, natural gas heat pump.

Space Cooling Equipment: room air conditioner, central air conditioner, electric air-source heat pump, ground-source heat pump, natural gas heat pump.

Water Heaters: solar, natural gas, electric distiallate, liquefied petroleum gas.

Refrigerators: 18 cubic foot top-mounted freezer, 25 cubic foot side-by-side with through-the-door features.

Freezers: chest - manual defrost, upright - manual defrost.

Lighting: incandescent, compact fluorescent, LED, halogen, linear fluoresent.

Clothes Dryers: natural gas, electric.

Cooking: natural gas, electric, liquefied petroleum gas.

Dishwashers

Clothes Washers

Fuel Cells

Solar Photovoltaic

Wind

based on relative life cycle costs for all competing technology and fuel combinations. Once new home heating system shares are established, the fuel choices for other services, such as water heating and cooking, are determined based on the fuel chosen for space heating. For replacement purchases, fuel switching is allowed for an assumed percentage of all replacements but is dependent on the estimated costs of fuel-switching (for example, switching from electric to gas heating is assumed to involve the costs of running a new gas line).

For both replacement equipment and new construction, a “second-stage” of the equipment choice decision requires selecting from several available efficiency levels. The efficiency range of available equipment represents a “menu” of efficiency levels and installed cost combinations projected to be available at the time the choice is being made. Costs and efficiencies for selected appliances are shown in Table 3, derived from the report Assumptions to the *Annual Energy Outlook 2009*.[12] At the low end of the efficiency range are the minimum levels required by legislated standards. In any given year, higher efficiency levels are associated with higher installed costs. Thus, purchasing higher than the minimum efficiency involves a trade-off between higher installation costs and future savings in energy expenditures. In RDM, these trade-offs are calibrated to recent shipment, cost, and efficiency data. Changes in purchases by efficiency level are based on changes in either the installed capital costs or changes in the first-year operating costs across the available efficiency levels. As energy prices increase, the incentive of greater energy expenditures savings will promote increased purchases of higher-efficiency equipment. In some cases, due to government programs or general projections of technology improvement, increases in efficiency or decreases in the installed costs of higher-efficiency equipment will also promote purchases of higher-efficiency equipment.

Shell Integrity Submodule

Shell integrity is also tracked separately for the existing housing stock and new construction. Shell integrity for existing construction is assumed to respond to increases in real energy prices by becoming more efficient. There is no change in existing shell integrity when real energy prices decline. New shell efficiencies are based on the cost and performance of the heating and cooling equipment as well as the shell characteristics. Several efficiency levels of shell characteristics are available throughout the projection period and can change over time based on changes in building codes. All shell efficiencies are subject to a maximum shell efficiency based on studies of currently available residential construction methods.

Distributed Generation Submodule

Distributed generation equipment with explicit technology characterizations is also modeled for residential customers. Currently, three technologies are characterized, photovoltaics, wind, and fuel cells. The submodule incorporates historical estimates of photovoltaics (residential-sized fuel cells are not expected to be commercialized until after 2005, the base year of the model) from its technology characterization and exogenous penetration input file. Program-based photovoltaic

12 Energy Information Administration, Assumptions to the Annual Energy Outlook 2009, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2009).pdf (Washington, DC, March 2009).

estimates for the Department of Energy's Million Solar Roofs program are also input to the submodule from the exogenous penetration portion of the input file. Endogenous, economic purchases are based on a penetration function driven by a cash flow model that simulates the costs and benefits of distributed generation purchases. The cash flow calculations are developed from NEMS projected energy prices coupled with the technology characterizations provided from the input file.

Potential economic purchases are modeled by Census division and technology for all years subsequent to the base year. The cash flow model develops a 30-year cost-benefit horizon for each potential investment. It includes considerations of annual costs (down payments, loan payments, maintenance costs and, for fuel cells, gas costs) and annual benefits (interest tax deductions, any applicable tax credits, electricity cost savings, and water heating savings for fuel cells) over the entire 30-year period. Penetration for a potential investment in either photovoltaics, wind, or fuel cells is a function of whether it achieves a cumulative positive discounted cash flow, and if so, how many years it takes to achieve it.

Once the cumulative stock of distributed equipment is projected, reduced residential purchases of electricity are provided to NEMS. For fuel cells, increased residential natural gas consumption is also provided to NEMS based on the calculated energy input requirements of the fuel cells, partially offset by natural gas water heating savings from the use of waste heat from the fuel cell.

Energy Consumption Submodule

The fuel consumption submodule modifies base year energy consumption intensities in each projection year. Base year energy consumption for each end use is derived from energy intensity estimates from the 2005 RECS. The base year energy intensities are modified for the following effects: (1) increases in efficiency, based on a comparison of the appliance stock serving this end use relative to the base year stock, (2) changes in shell integrity for space heating and cooling end uses, (3) changes in real fuel prices—(short-run price elasticity effects), (4) changes in square footage, (5) changes in the number of occupants per household, (6) changes in disposable income, (7) changes in weather relative to the base year, (8) adjustments in utilization rates caused by efficiency increases (efficiency "rebound" effects), and (9) reductions in purchased electricity and increases in natural gas consumption from distributed generation. Once these modifications are made, total energy use is computed across end uses and housing types and then summed by fuel for each Census division.

Table 3. Characteristics of Selected Equipment

Equipment Type	Relative Performance[1]	2007 Installed Cost ($2007)[2]	Efficiency[3]	2020 Installed Cost ($2007)[2]	Efficiency[3]	Approximate Hurdle Rate
Electric Heat Pump	Minimum	$3,800	13.0	$3,800	13.0	15%
	Best	$6,700	17.0	$6,700	20.0	
Natural Gas Furnace	Minimum	$1,900	0.80	$1,900	0.80	15%
	Best	$3,050	0.96	$2,700	0.96	
Room Air Conditioner	Minimum	$310	9.8	$310	9.8	140%
	Best	$925	11.7	$875	12.0	
Central Air Conditioner	Minimum	$3,000	13.0	$3,000	13.0	15%
	Best	$5,700	21.0	$5,750	23.0	
Refrigerator (23.9 cubic ft in adjusted volume)	Minimum	$550	510	$550	510	19%
	Best	$950	417	$1000	417	
Electric Water Heater	Minimum	$400	0.90	$400	0.90	30%
	Best	$1,400	2.4	$1,700	2.4	

[1]Minimum performance refers to the lowest efficiency equipment available. Best refers to the highest efficiency equipment available.

[2]Installed costs are given in 2007 dollars in the original source document.

[3]Efficiency measurements vary by equipment type. Electric heat pumps and central air conditioners are rated for cooling performance using the Seasonal Energy Efficiency Ratio (SEER); natural gas furnaces are based on Annual Fuel Utilization Efficiency; room air conditioners are based on Energy Efficiency Ratio (EER); refrigerators are based on kilowatt-hours per year; and water heaters are based on Energy Factor (delivered Btu divided by input Btu).

Source: Navigant Consulting, *EIA Technology Forecast Updates-Residential and Commercial Buildings Technologies*, September 2007.

Commercial Demand Module

Commercial Demand Module

The commercial demand module (CDM) projects energy consumption by Census division for eight marketed energy sources plus solar, wind, and geothermal energy. For the three major commercial sector fuels, electricity, natural gas and distillate oil, CDM is a structural model and the projections are built up from the stock of commercial floorspace and energy-consuming equipment. For the remaining five marketed minor fuels, simple econometric projections are made.

The commercial sector encompasses business establishments that are not engaged in industrial or transportation activities. Commercial sector energy is consumed mainly in buildings, except for a relatively small amount for services such as street lights and water supply. CDM incorporates the effects of four broadly-defined determinants of energy consumption: economic and demographics, structural, technology turnover and change, and energy markets. Demographic effects include total floorspace, building type and location. Structural effects include changes in the mix of desired end-use services provided by energy (such as the penetration of telecommunications equipment, personal computers and other office equipment). Technology effects include changes in the stock of installed equipment caused by the normal turnover of old, worn out equipment to newer versions that tend to be more energy efficient, the integrated effects of equipment and building shell (insulation level) in new construction, and the projected availability of equipment with even greater energy-efficiency. Energy market effects include the short-run effects of energy prices on energy demands, the longer-run effects of energy prices on the efficiency of purchased equipment, and limitations on minimum levels of efficiency imposed by legislated efficiency standards. The model structure carries out a sequence of five basic steps, as shown in Figure 6. The first step is to project commercial sector floorspace. The second step is to project the energy services (space heating, lighting, etc.) required by the projected floorspace. The third step is to project the electricity generation and water and space heating supplied by distributed generation and combined heat and power (CHP) technologies. The fourth step is to select specific technologies (natural gas furnaces, fluorescent lights, etc.) to meet the demand for energy services. The last step is to determine how much energy will be consumed by the equipment chosen to meet the demand for energy services.

Floorspace Submodule

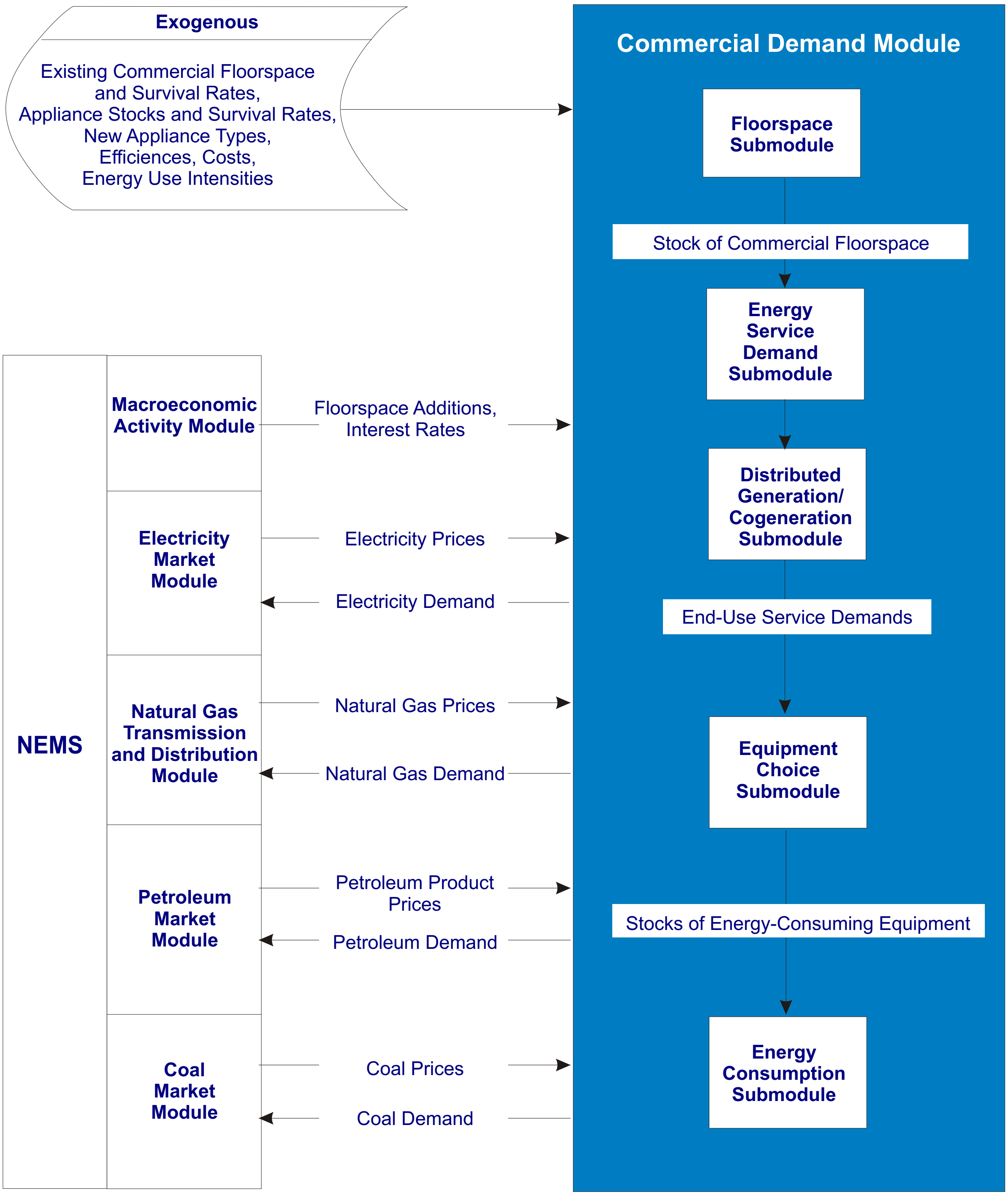
The base stock of commercial floorspace by Census division and building type is derived from EIA's 2003 Commercial Buildings Energy Consumption Survey (CBECS). CDM receives projections of total floorspace by building type and Census division from the macroeconomic activity module (MAM) based on IHS Global Insight, Inc. definitions of the commercial sector. These projections embody both economic and demographic effects on commercial floorspace. Since the definition of commercial floorspace from IHS Global Insight, Inc. is not calibrated to CBECS, CDM estimates the surviving floorspace from the previous year and then calibrates its new construction so that growth in total floorspace matches that from MAM by building type and Census division.

CDM models commercial floorspace for the following 11 building types:

- Assembly
- Education
- Food sales
- Food service
- Health care
- Lodging
- Office-large
- Office-small
- Mercantile and service
- Warehouse
- Other

CDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy demand by service and fuel type Changes in floorspace and appliance stocks	Energy product prices Interest rates Floorspace growth	Existing commercial floorspace Floorspace survival rates Appliance stocks and survival New appliance types, efficiencies, costs Energy use intensities

Figure 6. Commercial Demand Module Structure



Commercial Demand Module

Energy Service Demand Submodule

Energy consumption is derived from the demand for energy services. So the next step is to project energy service demands for the projected floorspace. CDM models service demands for the following ten end-use services:

- Heating
- Cooling
- Ventilation
- Water heating
- Lighting
- Cooking
- Refrigeration
- Office equipment personal computer
- Office equipment other
- Other end uses.

Different building types require unique combinations of energy services. A hospital must have more light than a warehouse. An office building in the Northeast requires more heating than one in the South. Total service demand for any service depends on the floorspace, type, and location of buildings. Base service demand by end use by building type and Census division is derived from estimates developed from CBECS energy consumption data. Projected service demands are adjusted for trends in new construction based on CBECS data concerning recent construction.

Distributed Generation and CHP Submodule

Commercial consumers may decide to purchase equipment to generate electricity (and perhaps provide heat as well) rather than depend on purchased electricity to fulfill all of their electric power requirements. The third step of the commercial module structure is to project electricity generation, fuel consumption, water heating, and space heating supplied by eleven distributed generation and CHP technologies. The technologies characterized include: photovoltaic solar systems, wind turbines, natural gas fuel cells, reciprocating engines, turbines and microturbines, diesel engine, coal-fired CHP, and municipal solid waste, wood, and hydroelectric generators.

Existing electricity generation by CHP technologies is derived from historical data contained in the most recent year's version of Form EIA-860, Annual Electric Generator Report. The estimated units form the installed base of CHP equipment that is carried forward into future years and supplemented with any additions. Proven installations of solar photovoltaic systems, wind turbines and fuel cells are also included based on information from the Departments of Energy and Defense. For years following the base year, an endogenous projection of distributed generation and CHP is developed based on the economic returns projected for distributed generation technologies. A detailed discounted cash-flow approach is used to estimate the internal rate of return for an investment. The calculations include the annual costs (down payments, loan payments, maintenance costs, and fuel costs) and returns (tax deductions, tax credits, and energy cost savings) from the investment covering a 30-year period from the time of the investment decision. Penetration of these technologies is a function of how quickly an investment in a technology is estimated to recoup its flow of costs. In terms of NEMS projections, investments in distributed generation reduce purchases of electricity. Fuel consuming technologies also generate waste heat that is assumed to be partially captured and used to offset commercial water heating and space heating energy use.

Equipment Choice Submodule

Once service demands are projected, the next step is to define the type and efficiency of equipment that will be used to satisfy the demands. The bulk of equipment required to meet service demand will carry over from the equipment stock of the previous model year. However, equipment must always be purchased to satisfy service demand for new construction. It must also be purchased to replace equipment that has either worn out (replacement equipment) or reached the end of its economically useful life (retrofit equipment). For required equipment replacements, CDM uses a constant decay rate based on equipment life. A technology will be retrofitted only if the combined annual operating and maintenance costs plus annualized capital costs of a potential technology are lower than the annual operating and maintenance costs of an existing technology.

Equipment choices are made based on a comparison of annualized capital and operating and maintenance costs across all allowable equipment for a particular end-use service. In order to add inertia to the equipment choices, only subsets of the total menu of potentially available equipment may be allowed for defined market segments. For example, only 7 percent of floorspace in large office buildings may consider all available equipment using any fuel or technology when making space heating equipment replacement decisions. A second segment equal to 31 percent of floorspace, must select from technologies using the same fuel as already installed. A third segment, the remaining 62 percent of floorspace, is constrained to consider only different efficiency levels of the same fuel and technology already installed. For lighting and refrigeration, all replacement choices are limited to the same technology class, where technologies are broadly defined to encompass the principal competing technologies for a particular application. For example, a commercial ice maker may replace another ice maker, but may not replace a refrigerated vending machine.

When computing annualized costs to determine equipment choices, commercial floorspace is segmented by what are referred to as hurdle rates or implicit discount rates (to distinguish them from the generally lower and more common notion of financial discount rates). Seven segments are used to simulate consumer behavior when purchasing commercial equipment. The segments range from rates as low as the 10-year Treasury bond rate to rates high enough to guarantee that only equipment with the lowest capital cost (and least efficiency) is chosen. As real energy prices increase (decrease) there is an incentive for all but the highest implicit discount rate segments to purchase increased (decreased) levels of efficiency.

The equipment choice submodule is designed to choose among a discrete set of technologies that are characterized by a menu which defines availability, capital costs, maintenance costs, efficiencies, and equipment life. Technology characteristics for selected space heating equipment are shown Table 4, derived from the report *Assumptions to the Annual Energy Outlook 2009*.[13] This menu of equipment includes technological innovation, market developments, and policy interventions. For the *AEO2009*, the technology types that are included for seven of the ten service demand categories are listed in Table 5.

The remaining three end-use services (PC-related office equipment, other office equipment, and other end uses) are considered minor services and are projected using exogenous equipment efficiency and market penetration trends.

Energy Consumption Submodule

Once the required equipment choices have been made, the total stock and efficiency of equipment for a particular end use are determined. Energy consumption by fuel can be calculated from the amount of service demand satisfied by each technology and the corresponding efficiency of the technology. At this stage, adjustments to energy consumption are also made. These include adjustments for changes in real energy prices (short-run price elasticity effects), adjustments in utilization rates caused by efficiency increases (efficiency rebound effects), and changes for weather relative to the CBECS survey year. Once these modifications are made, total energy use is computed across end uses and building types for the three major fuels, for each Census division. Combining these projections with the econometric/trend projections for the five minor fuels yields total projected commercial energy consumption.

13 Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2009).pdf (Washington, DC, March 2009)

Table 4. Capital Cost and Efficiency Ratings of Selected Commercial Space Heating Equipment[1]

Equipment Type	Vintage	Efficiency[2]	Capital Cost ($2007 per Mbtu/hour) [3]	Maintenance Cost ($2007 per Mbtu/hour) [3]	Service Life (Years)
Electric Rooftop Heat Pump	2007- typical	3.2	$72.78	$1.39	15
	2007- high efficiency	3.4	$96.67	$1.39	15
	2010 - typical (standard)	3.3	$76.67	$1.39	15
	2010 - high efficiency	3.4	$96.67	$1.39	15
	2020 - typical	3.3	$76.67	$1.39	15
	2020 - high efficiency	3.4	$96.67	$1.39	15
Ground-Source Heat Pump	2007 - typical	3.5	$140.00	$16.80	20
	2007 - high efficiency	4.9	$170.00	$16.80	20
	2010 - typical	3.5	$140.00	$16.80	20
	2010 - high efficiency	4.9	$170.00	$16.80	20
	2020 - typical	4.0	$140.00	$16.80	20
	2020 - high efficiency	4.9	$170.00	$16.80	20
Electric Boiler	Current typical	0.98	$17.53	$0.58	21
Packaged Electric	Typical	0.96	$16.87	$3.95	18
Natural Gas Furnace	Current Standard	0.80	$9.35	$0.97	20
	2007 - high efficiency	0.82	$9.90	$0.94	20
	2020 - typical	0.81	$9.23	$0.96	20
	2020 - high efficiency	0.90	$11.57	$0.86	20
	2030 - typical	0.82	$9.12	$0.94	20
	2030 - high efficiency	0.91	$11.44	$0.85	20
Natural Gas Boiler	Current Standard	0.80	$22.42	$0.50	25
	2007 - mid efficiency	0.85	$25.57	$0.47	25
	2007 - high efficiency	0.96	$39.96	$0.52	25
	2020 - typical	0.82	$21.84	$0.49	25
Natural Gas Heat Pump	2007 - absorption	1.4	$158.33	$2.50	15
	2010 - absorption	1.4	$158.33	$2.50	15
	2020 - absorption	1.4	$158.33	$2.50	15
Distillate Oil Furnace	Current Standard	0.81	$11.14	$0.96	20
	2020 - typical	0.81	$11.14	$0.96	20
Distillate Oil Boiler	Current Standard	0.83	$17.63	$0.15	20
	2007 - high efficiency	0.89	$19.84	$0.14	20
	2020 - typical	0.83	$17.63	$015	20

[1]Equipment listed is for the New England Census division, but is also representative of the technology data for the rest of the U.S. See the source referenced below for the complete set of technology data.·

[2]Efficiency measurements vary by equipment type. Electric rooftop air-source heat pumps, ground source and natural gas heat pumps are rated for heating performance using coefficient of performance; natural gas and distillate furnaces are based on Thermal Efficiency; and boilers are based on combustion efficiency.

[3]Capital and maintenance costs are given in 2007 dollars.

Source: Energy Information Administration, "EIA - Technology Forecast Updates - Residential and Commercial Building Technologies - Reference Case Second Edition (Revised)", Navigant Consulting, Inc., Reference Number 20070831.1, September 2007.

Table 5. Commercial End-Use Technology Types

End-Use Service by Fuel	Technology Types
Electric Space Heating	air-source heat pump, ground-source heat pump, boiler, packaged space heating
Natural Gas Space Heating	boiler, furnace, absorption heat pump
Fuel Oil Space Heating	boiler, furnace
Electric Space Cooling	air-source heat pump, ground-source heat pump, reciprocating chiller, centrifugal chiller, screw chiller, scroll chiller, rooftop air conditioner, residential style central air conditioner, window unit
Natural Gas Space Cooling	absorption chiller, engine-driven chiller, rooftop air conditioner, engine-driven heat pump, absorption heat pump
Electric Water Heating	electric resistance, heat pump water heater, solar water heater with electric back-up
Natural Gas Water Heating	natural gas water heater
Fuel Oil Water Heating	fuel oil water heater
Ventilation	constant air volume (CAV) system, variable air volume (VAV) system
Electric Cooking	range/oven/griddle, induction range/oven/griddle
Natural Gas Cooking	range/oven/griddle, power burner range/oven/griddle
Incandescent Style Lighting	incandescent, compact fluorescent, halogen, halogen-infrared, light emitting diode (LED)
Four-foot Fluorescent Lighting	magnetic ballast, electronic ballast-T8 electronic w/controls, electronic w/reflectors, electronic ballast-T5, electronic ballast-super T8, LED,
Eight-foot Fluorescent Lighting	magnetic ballast, electronic ballast, electronic-high output, LED
High Intensity-Discharge Lighting	metal halide, mercury vapor, high pressure sodium, electronic-T8 high output, electronic-T5 high output, LED
Refrigeration	supermarket compressor rack, suupermarket condenser, supermarket display case, walk-in cooler, walk-in freezer, reach-in refrigerator, reach-in freezer, ice machine, beverage merchandiser, refrigerated vending machine

Industrial Demand Module

Industrial Demand Module

The Industrial Demand Module (IDM) projects energy consumption for fuels and feedstocks for fifteen manufacturing industries and six nonmanufacturing industries, subject to delivered prices of energy and macroeconomic variables representing the value of shipments for each industry. The module includes electricity generated through Combined Heat and Power (CHP) systems that is either used in the industrial sector or sold to the electricity grid. The IDM structure is shown in Figure 7.

Industrial energy demand is projected as a combination of "bottom up" characterizations of the energy-using technology and "top down" econometric estimates of behavior. The influence of energy prices on industrial energy consumption is modeled in terms of the efficiency of use of existing capital, the efficiency of new capital acquisitions, and the mix of fuels utilized, given existing capital stocks. Energy conservation from technological change is represented over time by trend-based "technology possibility curves." These curves represent the aggregate efficiency of all new technologies that are likely to penetrate the future markets as well as the aggregate improvement in efficiency of 2002 technology.

IDM incorporates three major industry categories: energy-intensive manufacturing industries, non-energy-intensive manufacturing industries, and nonmanufacturing industries (see Table 6). The level and type of modeling and detail is different for each. Manufacturing disaggregation is at the 3-digit North American Industrial Classification System (NAICS) level, with some further disaggregation of large and energy-intensive industries. Detailed industries include food, paper, chemicals, glass, cement, steel, and aluminum. Energy product demands are calculated independently for each industry.

Each industry is modeled (where appropriate) as three interrelated components: buildings (BLD), boilers/steam/cogeneration (BSC), and process/assembly (PA) activities. Buildings are estimated to account for 4 percent of energy consumption in manufacturing industries (in nonmanufacturing industries, building energy consumption is not currently calculated).

Table 6. Economic Subsectors Within the IDM

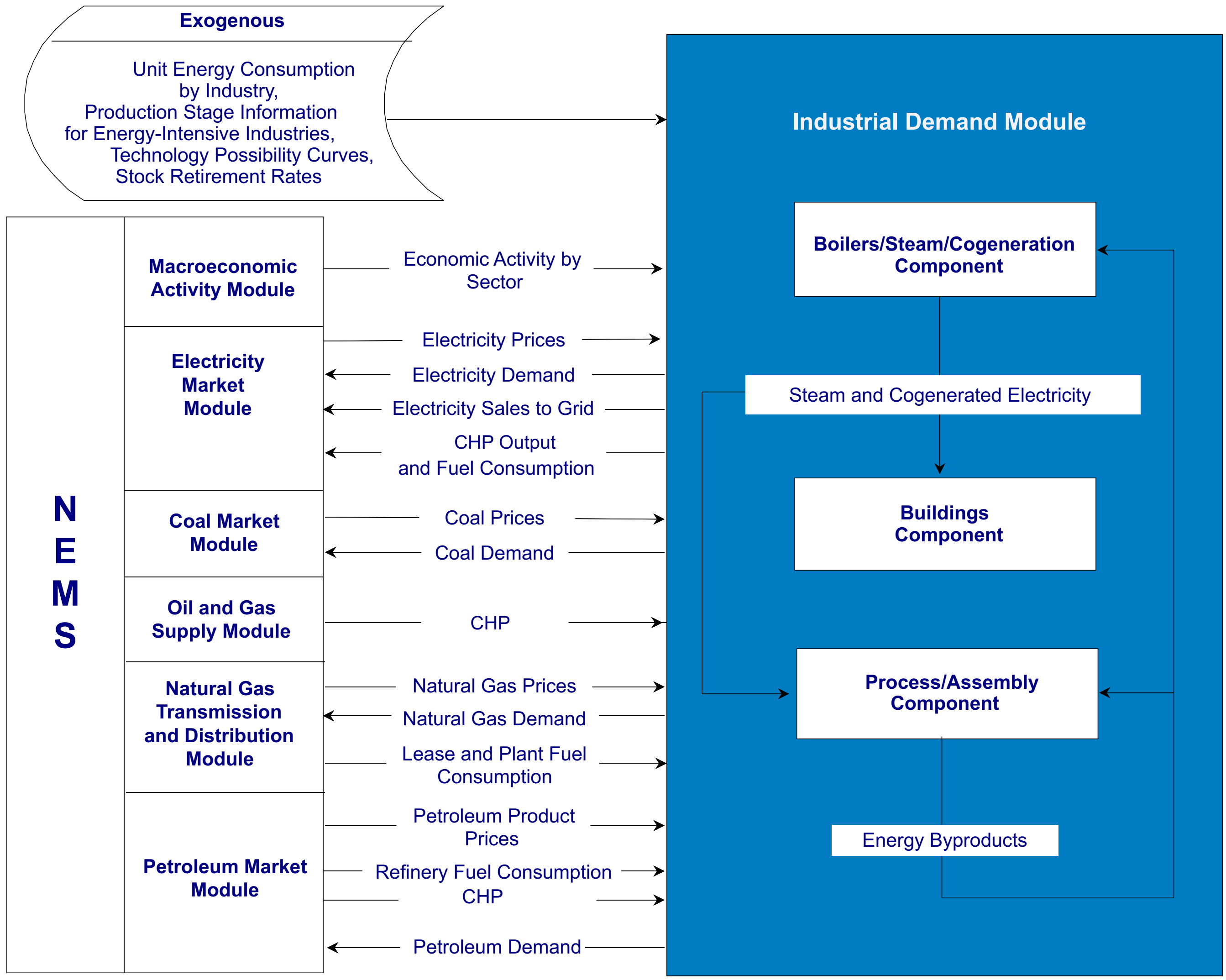
Energy-Intensive Manufacturing	**Nonmanufacturing Industries**
Food and Kindred Products (NAICS 311)	Agricultural Production - Crops (NAICS 111)
Paper and Allied Products (NAICS 322)	Other Agriculture including Livestock (NAICS 112-115)
Bulk Chemicals (NAICS 325)	Coal Mining (NAICS 2121)
Glass and Glass Products (NAICS 3272)	Oil and Gas Extraction (NAICS 211)
Hydraulic Cement (NAICS 32731)	Metal and Other Nonmetallic Mining (NAICS 2122-2123)
Blast Furnaces and Basic Steel (NAICS 331111)	Construction (NAICS 233-235)
Aluminum (NAICS 3313)	
Nonenergy-Intensive Manufacturing	
Metals-Based Durables (NAICS 332-336)	
Other Manufacturing (all remaining manufacturing NAICS)	

NAICS = North American Industry Classification System

Consequently, IDM uses a simple modeling approach for the BLD component. Energy consumption in industrial buildings is assumed to grow at the same rate as the average growth rate of employment and output in that industry. The BSC component consumes energy to meet the steam demands from and provide internally generated electricity to the other two components. The boiler component consumes by-product fuels and fossil fuels to produce steam, which is passed to the PA and BLD components.

IDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy demand by service and fuel type Electricity sales to grid Cogeneration output and fuel consumption	Energy product prices Economic output by industry Refinery fuel consumption Lease and plant fuel consumption Cogeneration from refineries and oil and gas production	Production stages in energy-intensive industries Technology possibility curves Unit energy consumption of outputs Capital stock retirement rates

Figure 7. Industrial Demand Module Structure



IDM models "traditional" CHP based on steam demand from the BLD and the PA components. The "non-traditional" CHP units are represented in the electricity market module since these units are mainly grid-serving, electricity-price-driven entities.

CHP capacity, generation, and fuel use are calculated from exogenous data on existing and planned capacity additions and new additions determined from an engineering and economic evaluation. Existing CHP capacity and planned additions are derived from Form EIA-860, "Annual Electric Generator Report," formerly Form EIA-867, "Annual Nonutility Power Producer Report." Existing CHP capacity is assumed to remain in service throughout the projection or, equivalently, to be refurbished or replaced with similar units of equal capacity.

Calculation of unplanned CHP capacity additions begins in 2009. Modeling of unplanned capacity additions is done in two parts: biomass-fueled and fossil-fueled. Biomass CHP capacity is assumed to be added to the extent possible as additional biomass waste products are produced, primarily in the pulp and paper industry. The amount of biomass CHP capacity added is equal to the quantity of new biomass available (in Btu), divided by the total heat rate from biomass steam turbine CHP.

Table 7. Fuel-Consuming Activities for the Energy-Intensive Manufacturing Subsectors

End Use Characterization
Food: direct fuel, hot water/steam, refrigeration, and other energy uses.
Bulk Chemicals: direct fuel, hot water/steam, electrotytic, and other energy uses.
Process Step characterization
Pulp and Paper: wood preparation, waste pulping, mechanical pulping, semi-chemical pulping, kraft pulping, bleaching, and paper making.
Glass: batch preparation, melting/refining, and forming.
Cement: dry process clinker, wet process clinker, and finish grinding.
Steel: coke oven, open hearth steel making, basic oxygen furnace steel making, electric arc furnace steel making, ingot casting, continuous casting, hot rolling, and cold rolling.
Aluminum: primary and secondary (scrap) aluminum smelting, semi-fabrication (e.g. sheet, wire, etc.).

It is assumed that the technical potential for fossil-fuel source CHP is based primarily on supplying thermal requirements. First, the model assesses the amount of capacity that could be added to generate the industrial steam requirements not met by existing CHP. The second step is an economic evaluation of gas turbine prototypes for each steam load segment. Finally, CHP additions are projected based on a range of acceptable payback periods.

The PA component accounts for the largest share of direct energy consumption for heat and power, 55 percent. For the seven most energy-intensive industries, process steps or end uses are modeled using engineering concepts. The production process is decomposed into the major steps, and the energy relationships among the steps are specified.

The energy intensities of the process steps or end uses vary over time, both for existing technology and for technologies expected to be adopted in the future. In IDM, this variation is based on engineering judgement and is reflected in the parameters of technology possibility curves, which show the declining energy intensity of existing and new capital relative to the 2002 stock.

IDM uses "technology bundles" to characterize technological change in the energy-intensive industries. These bundles are defined for each production process step for five of the industries and for end uses in the remaining two energy-intensive industries. The process step industries are pulp and paper, glass, cement, steel, and aluminum. The end-use industries are food and bulk chemicals (see Table 7).

Machine drive electricity consumption in the food, bulk chemicals, metal-based durables, and balance of manufacturing sectors is calculated by a motor stock model. The beginning stock of motors is modified over the projection horizon as motors are added to accommodate growth in shipments for each sector, as motors are retired and replaced, and as failed motors are rewound. When a new motor is added, either to accommodate growth or as a replacement, an economic choice is made between purchasing a motor that meets the EPACT minimum for efficiency or a premium efficiency motor. There are seven motor size groups in each of the four industries. The EPACT efficiency standards only apply to the five smallest groups (up to 200 horsepower). As the motor stock changes over the projection horizon, the overall efficiency of the motor population changes as well.

The Unit Energy Consumption (UEC) is defined as the energy use per ton of throughput at a process step or as energy use per dollar of shipments for the end-use industries. The "Existing UEC" is the current average installed intensity as of 2002. The "New 2002 UEC" is the intensity assumed to prevail for a new installation in 2002. Similarly, the "New 2030 UEC" is the intensity expected to prevail for a new installation in 2030. For intervening years, the intensity is interpolated.

The rate at which the average intensity declines is determined by the rate and timing of new additions to capacity. In IDM, the rate and timing of new additions are functions of retirement rates and industry growth rates.

IDM uses a vintaged capital stock accounting framework that models energy use in new additions to the stock and in the existing stock. This capital stock is represented as the aggregate vintage of all plants built within an industry and does not imply the inclusion of specific technologies or capital equipment.

The capital stock is grouped into three vintages: old, middle, and new. The old vintage consists of capital in production prior to 2002, which is assumed to retire at a fixed rate each year. Middle-vintage capital is that added after 2002. New production capacity is built in the projection years when the capacity of the existing stock of capital in

IDM cannot produce the output projected by the NEMS regional submodule of the macroeconomic activity module. Capital additions during the projection horizon are retired in subsequent years at the same rate as the pre-2002 capital stock.

The energy-intensive and/or large energy-consuming industries are modeled with a structure that explicitly describes the major process flows or "stages of production" in the industry (some industries have major consuming uses).

Technology penetration at the level of major processes in each industry is based on a technology penetration curve relationship. A second relationship can provide additional energy conservation resulting from increases in relative energy prices. Major process choices (where applicable) are determined by industry production, specific process flows, and exogenous assumptions.

Recycling, waste products, and byproduct consumption are modeled using parameters based on off-line analysis and assumptions about the manufacturing processes or technologies applied within industry. These analyses and assumptions are mainly based upon environmental regulations such as government requirements about the share of recycled paper used in offices. IDM also accounts for trends within industry toward the production of more specialized products such as specialized steel which can be produced using scrap material versus raw iron ore.

Transportation Demand Module

Transportation Demand Module

The transportation demand module (TRAN) projects the consumption of transportation sector fuels by transportation mode, including the use of renewables and alternative fuels, subject to delivered prices of energy and macroeconomic variables, including disposable personal income, gross domestic product, level of imports and exports, industrial output, new car and light truck sales, and population. The structure of the module is shown in Figure 8.

Projections of future fuel prices influence fuel efficiency, vehicle-miles traveled, and alternative-fuel vehicle (AFV) market penetration for the current fleet of vehicles. Alternative-fuel vehicle shares are projected on the basis of a multinomial logit model, subject to State and Federal government mandates for minimum AFV sales volumes.

Fuel Economy Submodule

This submodule projects new light-duty vehicle fuel economy by 12 U.S. Environmental Protection Agency (EPA) vehicle size classes and 16 propulsion technologies (gasoline, diesel, and 14 AFV technologies) as a function of energy prices and income-related variables. There are 61 fuel-saving technologies which vary in cost and marginal fuel savings by size class. Characteristics of a sample of these technologies are shown in Table 8, a complete list is published in Assumptions to the Annual Energy Outlook 2009.[14] Technologies penetrate the market based on a cost-effectiveness algorithm that compares the technology cost to the discounted stream of fuel savings and the value of performance to the consumer. In general, higher fuel prices lead to higher fuel efficiency estimates within each size class, a shift to a more fuel-efficient size class mix, and an increase in the rate at which alternative-fuel vehicles enter the marketplace.

Regional Sales Submodule

Vehicle sales from the MAM are divided into car and light truck sales. The remainder of the submodule is a simple accounting mechanism that uses endogenous estimates of new car and light truck sales and the historical regional vehicle sales adjusted for regional population trends to produce estimates of regional sales, which are subsequently passed to the alternative-fuel vehicle and the light-duty vehicle stock submodules.

Alternative-Fuel Vehicle Submodule

This submodule projects the sales shares of alternative-fuel technologies as a function of technology attributes, costs, and fuel prices. The alternative-fuel vehicles attributes are shown in Table 9, derived from *Assumptions to the Annual Energy Outlook 2009*. Both conventional and new technology vehicles are considered. The alternative-fuel vehicle submodule receives regional new car and light truck sales by size class from the regional sales submodule.

The projection of vehicle sales by technology utilizes a nested multinomial logit (NMNL) model that predicts sales shares based on relevant vehicle and fuel attributes. The nesting structure first predicts the probability of fuel choice for multi-fuel vechicles within a technology set. The second level nesting predicts penetration among similar technologies within a technology set (i.e. gasoline versus diesel hybrids). The third level choice determines market share among the the different technology sets.[15]

TRAN Outputs	Inputs from NEMS	Exogenous Inputs
Fuel demand by mode Sales, stocks, and characteristics of vehicle types by size class Vehicle-miles traveled Fuel economy by technology type Alternative-fuel vehicle sales by technology type Light-duty commercial fleet vehicle characteristics	Energy product prices Gross domestic product Disposable personal income Industrial output Vehicle sales International trade Natural gas pipeline Population	Existing vehicle stocks by vintage and fuel economy Vehicle survival rates New vehicle technology characteristics Fuel availability Commercial availability Vehicle safety and emissions reglations Vehicle miles-per-gallon degradation rates

14 Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009* http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2009) (Washington, DC, January 2009).

15 Greene, David L. and S.M. Chin, "Alternative Fuels and Vehicles (AFV) Model Changes," Center for Transportation Analysis, Oak Ridge National Laboratory, page 1, (Oak Ridge, TN, November 14, 2000).

Table 8. Selected Technology Characteristics for Automobiles

	Fractional Fuel Efficiency Change	First Year Introduced	Fractional Horsepower Change
Material Substitution IV	0.099	2006	0
Drag Reduction IV	0.042	2000	0
5-Speed Automatic	0.025	1995	0
CVT	0.052	1998	0
Automated Manual Trans	0.073	2004	0
VVL-6 Clinder	0.033	2000	0.10
Camless Valve Actuation 6 Cylinder	0.058	2020	0.13
Electric Power Steering	0.015	2004	0
42V-Launch Assist and Regen	0.075	2005	-0.05

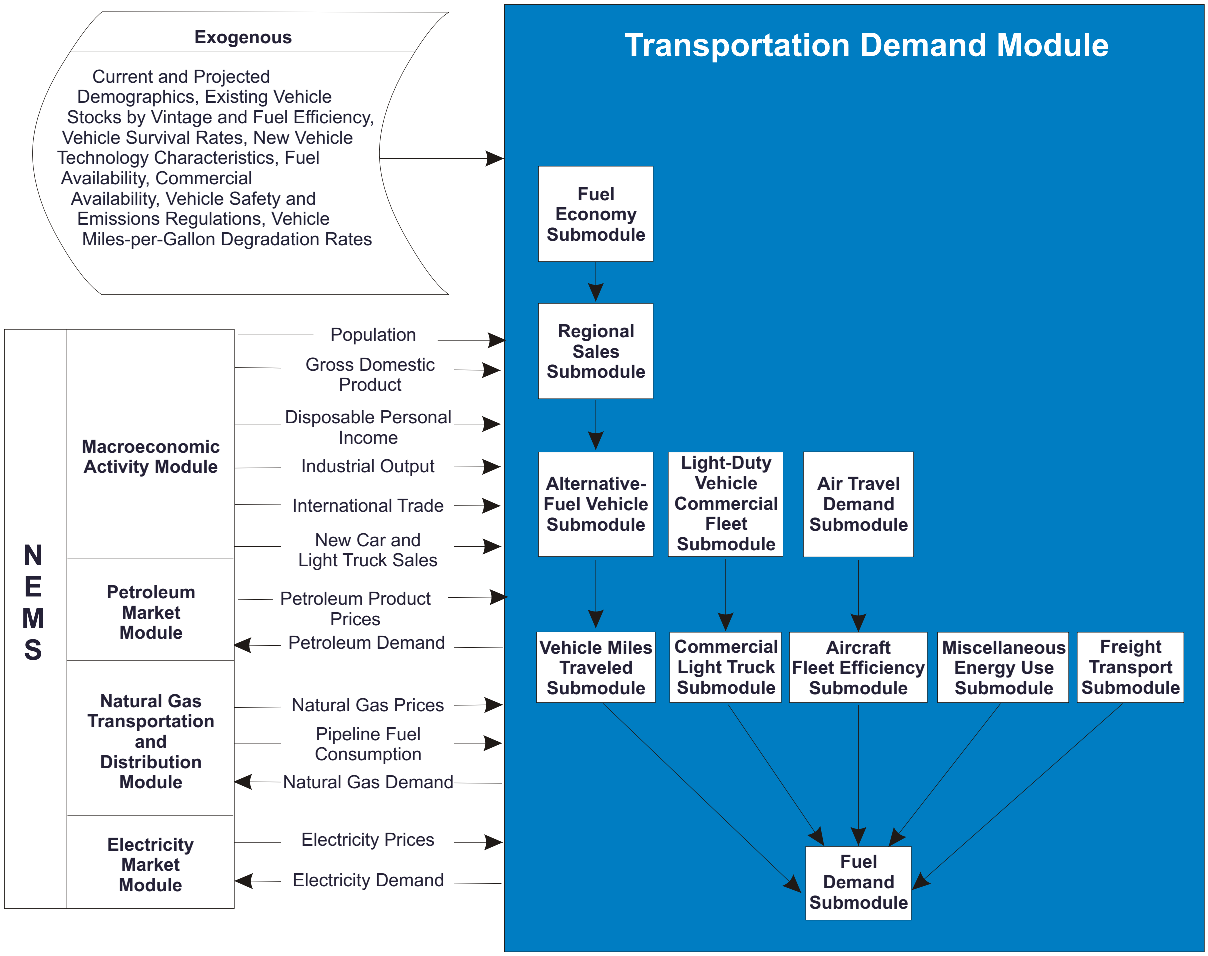
Table 9. Examples of Midsize Automobile Attributes

	Year	Gasoline	TDI Diesel	Ethanol Flex	LPG Bi-Fuel	Electric Gasoline Hybrid	Fuel Cell Hydrogen
Vehicle Price (thousand 2007 dollars)	2006	28.0	29.8	28.7	33.3	31.1	78.6*
	2030	29.8	30.7	30.2	35.0	31.0	54.2
Vehicle Miles per Gallon	2006	29.5	39.8	29.9	29.6	42.7	53.3*
	2030	37.8	48.2	38.1	37.7	51.0	54.9
Vehicle Range (miles)	2006	521	704	381	417	652	594*
	2030	674	910	492	539	843	674

*First year of availability

Transportation Demand Module

Figure 8. Transportation Demand Module Structure



Alternative Fuel Vehicles

Ethanol flex-fueled
Ethanol neat (85 percent ethanol)
Compressed natural gas (CNG)
CNG bi-fuel
Liquefied petroleum gas (LPG)
LPG bi-fuel
Battery electric vehicle
Plug-in hybrid with 10 mile all electric range
Plug-in hybrid with 40 mile all electric range
Gasoline hybrid
Diesel Hybrid
Fuel cell gasoline
Fuel cell hydrogen
Fuel cell methanol

The technology sets include:

- Conventional fuel capable (gasoline, diesel, bi-fuel and flex-fuel),
- Hybrid (gasoline and diesel) and plug-in hybrid
- Dedicated alternative fuel (compressed natural gas (CNG), liquified petroleum gas (LPG), and ethanol),
- Fuel cell (gasoline, methanol, and hydrogen),
- Electric battery powered (nickel-metal hydride, lithium)

The vehicles attributes considered in the choice algorithm include: price, maintenance cost, battery replacement cost, range, multi-fuel capability, home refueling capability, fuel economy, acceleration and luggage space.

With the exception of maintenance cost, battery replacement cost, and luggage space, vehicle attributes are determined endogenously.[16] The fuel attributes used in market share estimation include availability and price. Vehicle attributes vary by six EPA size classes for cars and light trucks and fuel availability varies by Census division. The NMNL model coefficients were developed to reflect purchase preferences for cars and light trucks separately.

Light-Duty Vehicle (LDV) Stock Submodule

This submodule specifies the inventory of LDVs from year to year. Survival rates are applied to each vintage, and new vehicle sales are introduced into the vehicle stock through an accounting framework. The fleet of vehicles and their fuel efficiency characteristics are important to the translation of transportation services demand into fuel demand.

TRAN maintains a level of detail that includes twenty vintage classifications and six passenger car and six light truck size classes corresponding to EPA interior volume classifications for all vehicles less than 8,500 pounds, as follows:

Light Duty Vehicle Size Classes

Cars:
- Mini-compact - less than 85 cubic feet
- Subcompact - between 85 and 99 cubic feet
- Compact - between 100 and 109 cubic feet
- Mid-size - between 110 and 119 cubic feet
- Large - 120 or more cubic feet
- Two-seater - designed to seat two adults

Trucks:
- Small vans - gross vehicle weight rating (GVWR) less than 4,750 pounds
- Large vans - GVWR 4,750 to 8,500 pounds
- Small pickups - GVWR less than 4,750 pounds
- Large pickups - GVWR 4,750 to 8,500 pounds
- Small utility - GVWR less than 4,750 pounds
- Large utility - GVWR 4,750 to 8,500 pounds

Vehicle-Miles Traveled (VMT) Submodule

This submodule projects travel demand for automobiles and light trucks. VMT per capita estimates are based on the fuel cost of driving per mile and per capita disposable personal income. Total VMT is calculated by multiplying VMT by the number of licensed drivers.

LDV Commercial Fleet Submodule

This submodule generates estimates of the stock of cars and trucks used in business, government, and utility fleets. It also estimates travel demand, fuel efficiency, and energy consumption for the fleet vehicles prior to their transition to the private sector at predetermined vintages.

Commercial Light Truck Submodule

The commercial light truck submodule estimates sales, stocks, fuel efficiencies, travel, and fuel demand for all trucks greater than 8,500 pounds and less than 10,000 pounds gross vehicle weight rating.

Air Travel Demand Submodule

This submodule estimates the demand for both passenger and freight air travel. Passenger travel is projected by domestic travel (within the U.S.), international travel (between U.S. and Non U.S.), and Non U.S. travel. Dedicated air freight travel is estimated for U.S. and Non U.S. demand. In each of the market segments, the demand for air travel is estimated as a function of the cost of air travel (including fuel costs) and economic growth (GDP, disposable income, and merchandise exports).

Aircraft Fleet Efficiency Submodule

This submodule projects the total world-wide stock and the average fleet efficiency of narrow body, wide body, and regional jets required to meet the projected travel demand. The stock estimation is based on the growth of travel demand and the flow of aircraft into and out of the United States The overall fleet efficiency is determined by the weighted average of the surviving aircraft efficiency (including retrofits) and the efficiencies of the newly acquired aircraft. Efficiency improvements of new aircraft are determined by projecting the market penetration of advanced aircraft technologies.

16 Energy and Environmental Analysis, Inc., Updates to the Fuel Economy Model (FEM) and Advanced Technology Vehicle (ATV:) Module of the National Energy Modeling System (NEMS) Transportation Model, prepared for the Energy Information Administration (EIA),

Freight Transport Submodule

This submodule translates NEMS estimates of industrial production into ton-miles traveled for rail and ships and into vehicle vehicle-miles traveled for trucks, then into fuel demand by mode of freight travel. The freight truck stock is subdivided into medium and heavy-duty trucks. VMT freight estimates by truck size class and technology are based on matching freight needs, as measured by the growth in industrial output by NAICS code, to VMT levels associated with truck stocks and new vehicles. Rail and shipping ton-miles traveled are also estimated as a function of growth in industrial output.

Freight truck fuel efficiency growth rates are tied to historical growth rates by size class and are also dependent on the maximum penetration, introduction year, fuel trigger price (based on cost-effectiveness), and fuel economy improvement of advanced technologies, which include alternative-fuel technologies. A subset of the technology characteristics are shown in Table 10. In the rail and shipping modes, energy efficiency estimates are structured to evaluate the potential of both technology trends and efficiency improvements related to energy prices.

Miscellaneous Energy Use Submodule

This submodule projects the use of energy in military operations, mass transit vehicles, recreational boats, and lubricants, based on endogenous variables within NEMS (e.g., vehicle fuel efficiencies) and exogenous variables (e.g., the military budget).

Table 10. Example of Truck Technology Characteristics (Diesel)

	Fuel Economy Improvement (percent)		Maximum Penetration (percent)		Introduction Year		Capital Cost (2001 dollars)	
	Medium	Heavy	Medium	Heavy	Medium	Heavy	Medium	Heavy
Aero Dynamics: bumper, underside air battles, wheel well covers	3.6	2.3	50	40	2002	N/A	N/A	$1,500
Low rolling resistence tires	2.3	2.7	50	66	2004	2005	$180	$550
Transmission: lock-up, electronic controls, reduced friction	1.8	1.8	100	100	2005	2005	$750	$1,000
Diesel Engine: hybrid electric powertrain	36.0	N/A	15	N/A	2010	N/A	$6,000	N/A
Reduce waste heat, thermal mgmt	N/A	9.0	N/A	35	N/A	2010	N/A	$2,000
Weight reduction	4.5	9.0	20	30	2010	2005	$1,300	$2,000
Diesel Emission No_x non-thermal plasma catalyst	-1.5	-1.5	25	25	2007	2007	$1,000	$1,250
PM catalytic filter	-2.5	-1.5	95	95	2008	2006	$1,000	$1,500
HC/CO: oxidation catalyst	-0.5	-0.5	95	95	2002	2002	$150	$250
NO_x adsorbers	-3.0	-3.0	90	90	2007	2007	$1,500	$2,500

Electricity Market Module

Electricity Market Module

The electricity market module (EMM) represents the generation, transmission, and pricing of electricity, subject to: delivered prices for coal, petroleum products, and natural gas; the cost of centralized generation from renewable fuels; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. The submodules consist of capacity planning, fuel dispatching, finance and pricing, and load and demand (Figure 9). In addition, nonutility supply and electricity trade are represented in the fuel dispatching and capacity planning submodules. Nonutility generation from CHP and other facilities whose primary business is not electricity generation is represented in the demand and fuel supply modules. All other nonutility generation is represented in the EMM. The generation of electricity is accounted for in 15 supply regions (Figure 10), and fuel consumption is allocated to the 9 Census divisions.

The EMM determines airborne emissions produced by the generation of electricity. It represents limits for sulfur dioxide and nitrogen oxides specified in the Clean Air Act Amendments of 1990 (CAAA90) and the Clean Air Interstate Rule. The *AEO2009* also models State-level regulations implementing mercury standards. The EMM also has the ability to track and limit emissions of carbon dioxide, and the *AEO2009* includes the regional carbon restrictions of the Regional Greenhouse Gas Initiative (RGGI).

Operating (dispatch) decisions are provided by the cost-minimizing mix of fuel and variable operating and maintenance (O&M) costs, subject to environmental costs. Capacity expansion is determined by the least-cost mix of all costs, including capital, O&M, and fuel. Electricity demand is represented by load curves, which vary by region and season. The solution to the submodules of EMM is simultaneous in that, directly or indirectly, the solution for each submodule depends on the solution to every other submodule. A solution sequence through the submodules can be viewed as follows:

- The electricity load and demand submodule processes electricity demand to construct load curves
- The electricity capacity planning submodule projects the construction of new utility and nonutility plants, the level of firm power trades, and the addition of equipment for environmental compliance
- The electricity fuel dispatch submodule dispatches the available generating units, both utility and nonutility, allowing surplus capacity in select regions to be dispatched to meet another regions needs (economy trade)
- The electricity finance and pricing submodule calculates total revenue requirements for each operation and computes average and marginal-cost based electricity prices.

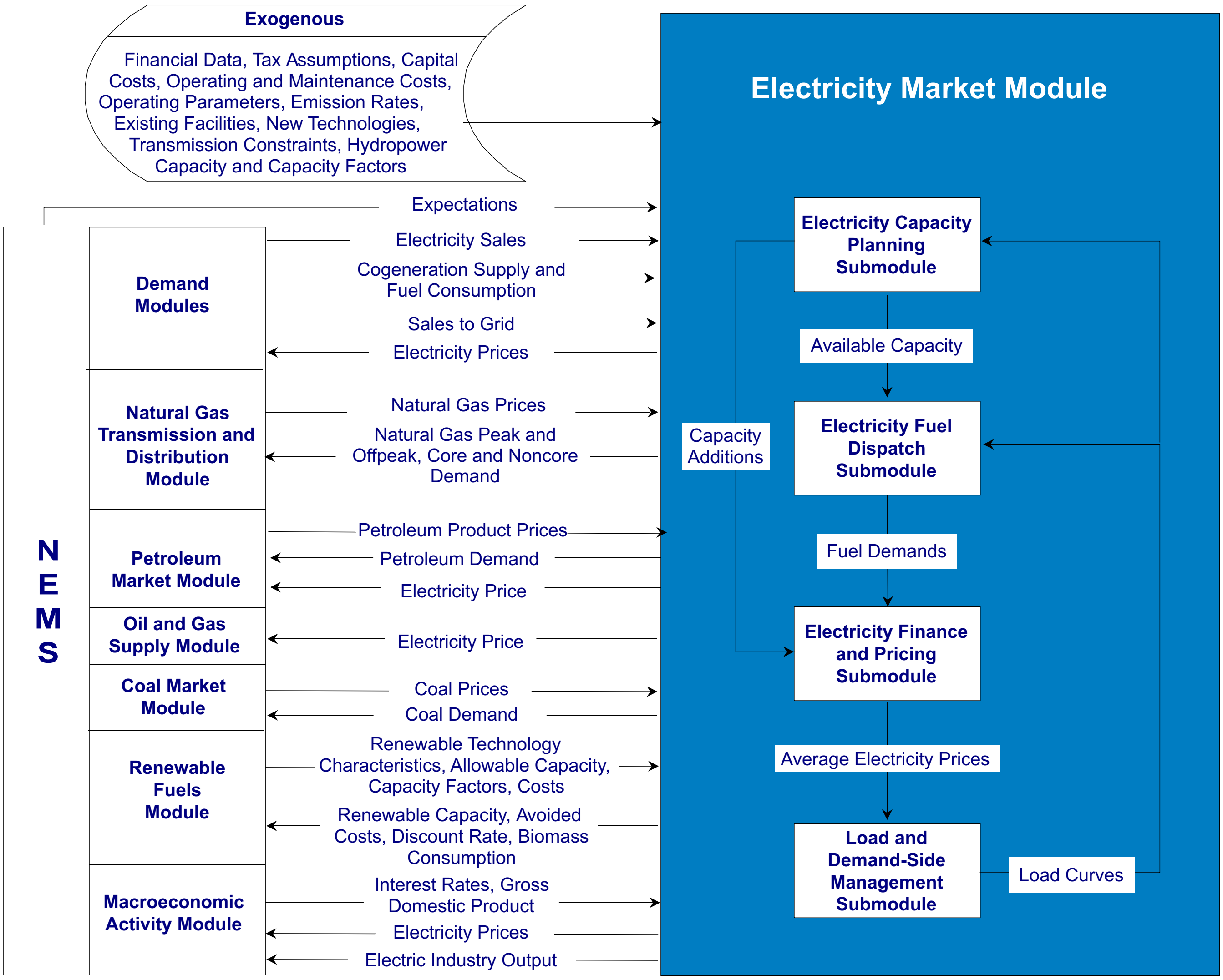
Electricity Capacity Planning Submodule

The electricity capacity planning (ECP) submodule determines how best to meet expected growth in electricity demand, given available resources, expected load shapes, expected demands and fuel prices, environmental constraints, and costs for utility and nonutility technologies. When new capacity is required to meet growth in electricity demand, the technology chosen is determined by the timing of the demand increase, the expected utilization of the new capacity, the operating efficiencies, and the construction and operating costs of available technologies.

The expected utilization of the capacity is important in the decision-making process. A technology with relatively high capital costs but comparatively low operating costs (primarily fuel costs) may be the appropriate choice if the capacity is expected to operate continuously (base load). However, a plant type with high operating costs but low capital costs may be the most economical selection to serve the peak load (i.e., the highest demands on the system), which occurs infrequently. Intermediate or cycling load occupies a middle ground between base and peak load and is best served

EMM Outputs	Inputs from NEMS	Exogenous Inputs
Electricity prices and price components Fuel demands Capacity additions Capital requirements Emissions Renewable capacity Avoided costs	Electricity sales Fuel prices Cogeneration supply and fuel consumption Electricity sales to the grid Renewable technology characteristics, allowable capacity, and costs Renewable capacity factors Gross domestic product Interest rates	Financial data Tax assumptions Capital costs Operation and maintenance costs Operating parameters Emmissions rates New technologies Existing facilities Transmission constraints

Figure 9. Electricity Market Module Strucuture



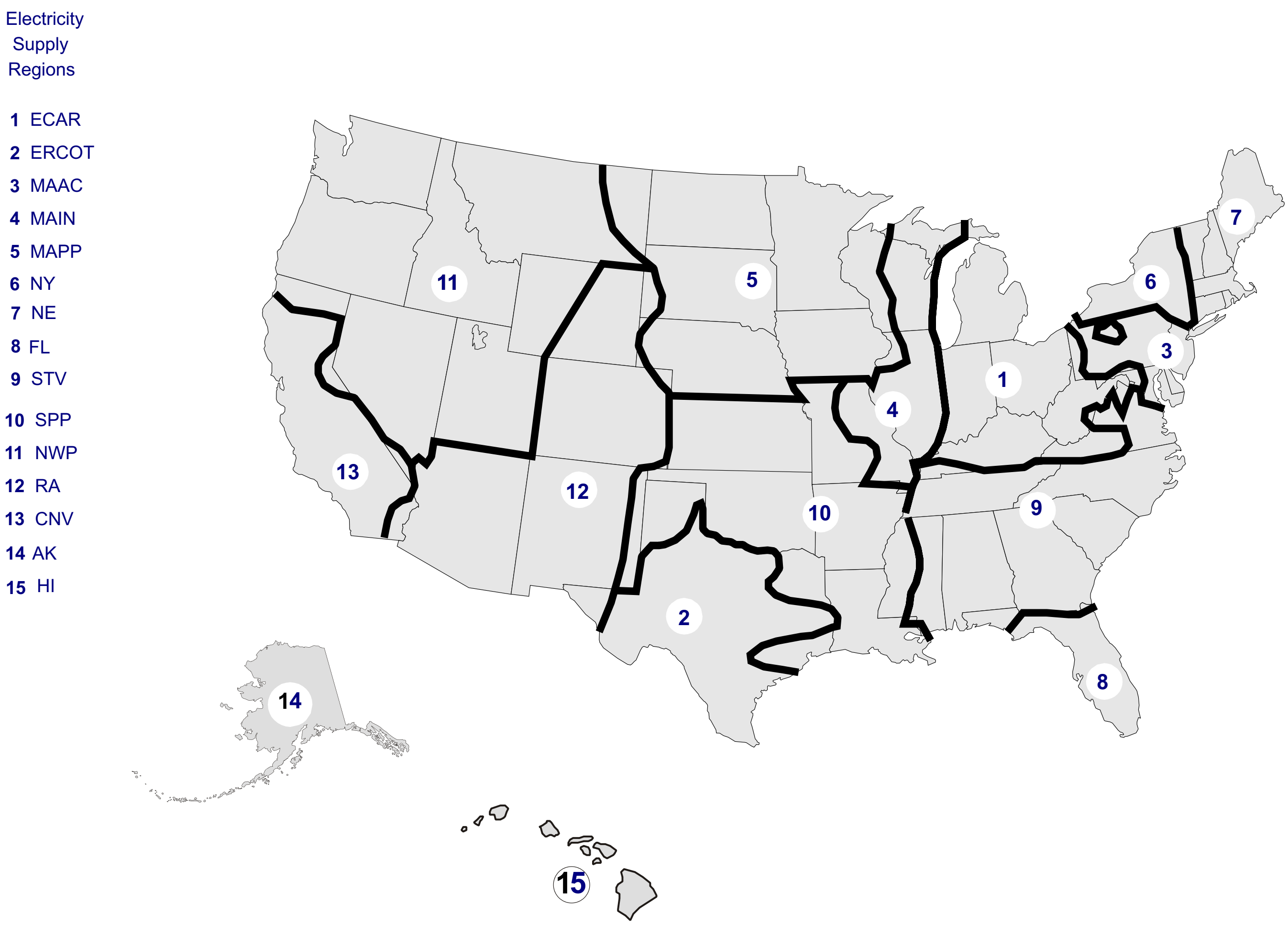
by plants that are cheaper to build than baseload plants and cheaper to operate than peak load plants.

Technologies are compared on the basis of total capital and operating costs incurred over a 20-year period. As new technologies become available, they are competed against conventional plant types. Fossil-fuel, nuclear, and renewable central-station generating technologies are represented, as listed in Table 11. The EMM also considers two distributed generation technologies -baseload and peak. The EMM also has the ability to model a demand storage technology to represent load shifting.

Uncertainty about investment costs for new technologies is captured in ECP using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.

Learning factors represent reductions in capital costs due to learning-by-doing. For new technologies, cost reductions due to learning also account for international experience in building generating capacity. These factors

Figure 10. Electricity Market Module Supply Regions



are calculated for each of the major design components of a plant type design. For modeling purposes, components are identified only if the component is shared between multiple plant types, so that the ECP can reflect the learning that occurs across technologies. The cost adjustment factors are based on the cumulative capacity of a given component. A 3-step learning curve is utilized for all design components.

Typically, the greatest amount of learning occurs during the initial stages of development and the rate of cost reductions declines as commercialization progresses. Each step of the curve is characterized by the learning rate and the number of doublings of capacity in which this rate is applied. Depending on the stage of development for a particular component, some of the learning may already be incorporated in the initial cost estimate.

Capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new technologies are assumed to contribute to reductions in capital costs for units that are installed in the United States to the extent that (1) the technology characteristics are similar to those used in U.S. markets, (2) the design and construction firms and key personnel compete in the U.S. market, (3) the owning and operating firm competes actively in the United States, and (4) there exists relatively complete information about the status of the associated facility. If the new foreign units do not satisfy one or more of these requirements, they are given a reduced weight or not included in the learning effects calculation. Capital costs, heat rates, and first year of availablilty from the *AEO2009* reference case are shown in Table 12; capital costs represent the costs of building new plants ordered in 2008. Additional information about costs and performance characteristics can be found on page 89 of the "Assumptions to the Annual Energy Outlook 2009."[17]

Initially, investment decisions are determined in ECP using cost and performance characteristics that are represented as single point estimates corresponding to the average (expected) cost. However, these parameters are also subject to uncertainty and are better represented by distributions. If the distributions of two or more options overlap, the option with the lowest average cost is not likely to capture the entire market. Therefore, ECP uses a market-sharing algorithm to adjust the initial solution and reallocate some of the capacity expansion decisions to technologies that are competitive but do not have the lowest average cost.

Fossil-fired steam and nuclear plant retirements are calculated endogenously within the model. Plants are retired if the market price of electricity is not sufficient to support continued operation. The expected revenues from these plants are compared to the annual going-forward costs, which are mainly fuel and O&M costs. A plant is retired if these costs exceed the revenues and the overall cost of electricity can be reduced by building replacement capacity.

The ECP submodule also determines whether to contract for unplanned firm power imports from Canada and from neighboring electricity supply regions. Imports from Canada are competed using supply curves developed from cost estimates for potential hydroelectric projects in Canada. Imports from neighboring electricity supply regions are competed in the ECP based on the cost of the unit in the exporting region plus the additional cost of transmitting the power. Transmission costs are computed as a fraction of revenue.

After building new capacity, the submodule passes total available capacity to the electricity fuel dispatch submodule and new capacity expenses to the electricity finance and pricing submodule.

Table 11. Generating Technologies

Fossil
Existing coal steam plants (with or without environmental controls) New pulverized coal with environmental controls Advanced clean coal technology Advanced clean coal technology with sequestration Oil/Gas steam Conventional combined cycle Advanced combined cycle Advanced combined cycle with sequestration Conventional combustion turbine Fuel cells
Nuclear
Conventional nuclear Advanced nuclear
Renewables
Conventional hydropower Pumped storage Geothermal Solar-thermal Solar-photovoltaic Wind - onshore and offshore Wood Municipal solid waste
Environmental controls include flue gas desulfurization (FGD), selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), fabric filters, spray cooling, activated carbon injection (ACI), and particulate removal equipiment.

Electricity Fuel Dispatch Submodule

Given available capacity, firm purchased-power agreements, fuel prices, and load curves, the electricity fuel dispatch (EFD) submodule minimizes variable costs as it solves for generation facility utilization and economy power exchanges to satisfy demand in each time period and region. Limits on emissions of sulfur dioxide from generating units and the engineering characteristics of units serve as constraints. Coal-fired capacity can co-fire with biomass in order to lower operating costs and/or emissions.

The EFD uses a linear programming (LP) approach to provide a minimum cost solution to allocating (dispatching) capacity to meet demand. It simulates the electric transmission network on the NERC region level and simultaneously dispatches capacity regionally by time slice until demand for the year is met. Traditional cogeneration and firm trade capacity is removed from the load duration curve prior to the dispatch decision. Capacity costs for each time slice are based on fuel and variable O&M costs, making adjustments for RPS

17 Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2009).pdf (March 2009)

credits, if applicable, and production tax credits. Generators are required to meet planned maintenance requirements, as defined by plant type.

Interregional economy trade is also represented in the EFD submodule by allowing surplus generation in one region to satisfy electricity demand in an importing region, resulting in a cost savings. Economy trade with Canada is determined in a similar manner as interregional economy trade. Surplus Canadian energy is allowed to displace energy in an importing region if it results in a cost savings. After dispatching, fuel use is reported back to the fuel supply modules and operating expenses and revenues from trade are reported to the electricity finance and pricing submodule.

Electricity Finance and Pricing Submodule

The costs of building capacity, buying power, and generating electricity are tallied in the electricity finance and pricing (EFP) submodule, which simulates both competitive electricity pricing and the cost-of-service method often used by State regulators to determine the price of electricity. The AEO2009 reference case assumes a transition to full competitive pricing in New York, Mid-Atlantic Area Council, and Texas, and a 95 percent transition to competitive pricing in New England (Vermont being the only fully-regulated State in that region). California returned to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998. In addition electricity prices in the

Table 12. 2008 Overnight Capital Costs (including Contingencies), 2008 Heat Rates, and Online Year by Technology for the AEO2009 Reference Case

Technology	Capital Costs[1] (2007$/KW)	Heatrate in 2008 (Btu/kWhr)	Online Year[2]
Scrubbed Coal New	2058	9200	2012
Integrated Coal-gasification Comb Cycle (IGCC)	2378	8765	2012
IGCC with carbon sequestration	3496	10781	2016
Coventional Gas/Oil Comb Cycle	962	7196	2011
Advanced Gas/Oil Comb Cycle (CC)	948	6752	2011
Advanced CC with carbon sequestration	1890	8613	2016
Conventional Combusion Turbine	670	10810	2010
Advanced Combusition Turbine	634	9289	2010
Fuel Cells	5360	7930	2011
Adv nuclear	3318	10434	2016
Distributed Generation - Base	1370	9050	2011
Distributed Generation - Peak	1645	10069	2010
Biomass	3766	9646	2012
MSW - Landfill Gas	2543	13648	2010
Geothermal[3]	1711	34633	2010
Conventional Hydropower [3,4]	2242	9919	2012
Wind[4]	1923	9919	2009
Wind Offshore[4]	3851	9919	2012
Solar Thermal	5021	9919	2012
Photovoltaic	6038	9919	2011

[1]Overnight capital cost including contingency factors, excluding reigonal multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2008. Capital costs are shown before investment tax credits are applied, where applicable.

[2]Online year represents the first year that a new unit could be completed, given an order date of 2008. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge the significant market activity already occuring in anticipation of the expiration of the Production Tax Credit in 2009 for wind and 2010 for the others.

[3]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[4]For hydro, wind, and solar technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2007. This isused for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

East Central Area Reliability Council, the Mid-American Interconnected Network, the Southeastern Electric Reliability Council, the Southwest Power Pool, the Northwest Power Pool, and the Rocky Mountain Power Area/Arizona are a mix of both competitive and regulated prices. Since some States in each of these regions have not taken action to deregulate their pricing of electricity, prices in those States are assumed to continue to be based on traditional cost-of-service pricing. The price for mixed regions is a load-weighted average of the competitive price and the regulated price, with the weight based on the percent of electricity load in the region that has taken action to deregulate. In regions where none of the states in the region have introduced competition—Florida Reliability Coordinating Council and Mid-Continent Area Power Pool—electricity prices are assumed to remain regulated and the cost-of-service calculation is used to determine electricity prices.

Using historical costs for existing plants (derived from various sources such as Federal Energy Regulatory Commission Form 1, Annual Report of Major Electric Utilities, Licensees and Others, and Form EIA-412, Annual Report of Public Electric Utilities), cost estimates for new plants, fuel prices from the NEMS fuel supply modules, unit operating levels, plant decommissioning costs, plant phase-in costs, and purchased power costs, the EFP submodule calculates total revenue requirements for each area of operation—generation, transmission, and distribution—for pricing of electricity in the fully regulated States. Revenue requirements shared over sales by customer class yield the price of electricity for each class. Electricity prices are returned to the demand modules. In addition, the submodule generates detailed financial statements.

For those States for which it is applicable, the EFP also determines competitive prices for electricity generation. Unlike cost-of-service prices, which are based on average costs, competitive prices are based on marginal costs. Marginal costs are primarily the operating costs of the most expensive plant required to meet demand. The competitive price also includes a reliability price adjustment, which represents the value consumers place on reliability of service when demands are high and available capacity is limited. Prices for transmission and distribution are assumed to remain regulated, so the delivered electricity price under competition is the sum of the marginal price of generation and the average price of transmission and distribution.

Electricity Load and Demand Submodule

The electricity load and demand (ELD) submodule generates load curves representing the demand for electricity. The demand for electricity varies over the course of a day. Many different technologies and end uses, each requiring a different level of capacity for different lengths of time, are powered by electricity. For operational and planning analysis, an annual load duration curve, which represents the aggregated hourly demands, is constructed. Because demand varies by geographic area and time of year, the ELD submodule generates load curves for each region and season.

Emissions

EMM tracks emission levels for sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Facility development, retrofitting, and dispatch are constrained to comply with the pollution constraints of the CAAA90 and other pollution constraints including the Clean Air Interstate Rule. An innovative feature of this legislation is a system of trading emissions allowances. The trading system allows a utility with a relatively low cost of compliance to sell its excess compliance (i.e., the degree to which its emissions per unit of power generated are below maximum allowable levels) to utilities with a relatively high cost of compliance. The trading of emissions allowances does not change the national aggregate emissions level set by CAAA90, but it does tend to minimize the overall cost of compliance.

In addition to SO_2, and NO_x, the EMM also determines mercury and carbon dioxide emissions. It represents control options to reduce emissions of these four gases, either individually or in any combination. Fuel switching from coal to natural gas, renewables, or nuclear can reduce all of these emissions. Flue gas desulfurization equipment can decrease SO_2 and mercury emissions. Selective catalytic reduction can reduce NO_x and mercury emissions. Selective non-catalytic reduction and low-NO_x burners can lower NO_x emissions. Fabric filters and activated carbon injection can reduce mercury emissions. Lower emissions resulting from demand reductions are determined in the end-use demand modules.

The *AEO2009* includes a generalized structure to model current state-level regulations calling for the best available control technology to control mercury. The *AEO2009* also includes the carbon caps for States that are part of the RGGI.

Renewable Fuels Module

Renewable Fuels Module

The renewable fuels module (RFM) represents renewable energy resoures and large–scale technologies used for grid-connected U.S. electricity supply (Figure 11). Since most renewables (biomass, conventional hydroelectricity, geothermal, landfill gas, solar photovoltaics, solar thermal, and wind) are used to generate electricity, the RFM primarily interacts with the electricity market module (EMM).

New renewable energy generating capacity is either model–determined or based on surveys or other published information. A new unit is only included in surveys or acccepted from published information if it is reported to or identified by the EIA and the unit meets EIA criteria for inclusion (the unit exists, is under construction, under contract, is publicly declared by the vendor, or is mandated by state law, such as under a state renewable portfolio standard). EIA may also assume minimal builds for reasons based on historical experience (floors). The penetration of grid-connected renewable energy generating technologies, with the exception of landfill gas, is determined by the EMM.

Each renewable energy submodule of the RFM is treated independently of the others, except for their least-cost competition in the EMM. Because variable operation and maintenance costs for renewable technologies are lower than for any other major generating technology, and because they generally produce little or no air pollution, all available renewable capacity, except biomass, is assumed to be dispatched first by the EMM. Because of its potentially significant fuel cost, biomass is dispatched according to its variable cost by the EMM.

With significant growth over time, installation costs are assumed to be higher because of growing constraints on the availability of sites, natural resource degradation, the need to upgrade existing transmission or distribution networks, and other resource-specific factors.

Geothermal-Electric Submodule

The geothermal-electric submodule provides the EMM the amounts of new geothermal capacity that can be built at known and well characterized geothermal resource sites, along with related cost and performance data. The information is expressed in the form of a three–step supply function that represents the aggregate amount of new capacity and associated costs that can be offered in each year in each region.

Only hydrothermal (hot water and steam) resources are considered. Hot dry rock resources are not included, because they are not expected to be economically accessible during the NEMS projection horizon.

Capital and operating costs are estimated separately, and life-cycle costs are calculated by the RFM. The costing methodology incorporates any applicable effects of Federal and State energy tax construction and production incentives

Wind-Electric Submodule

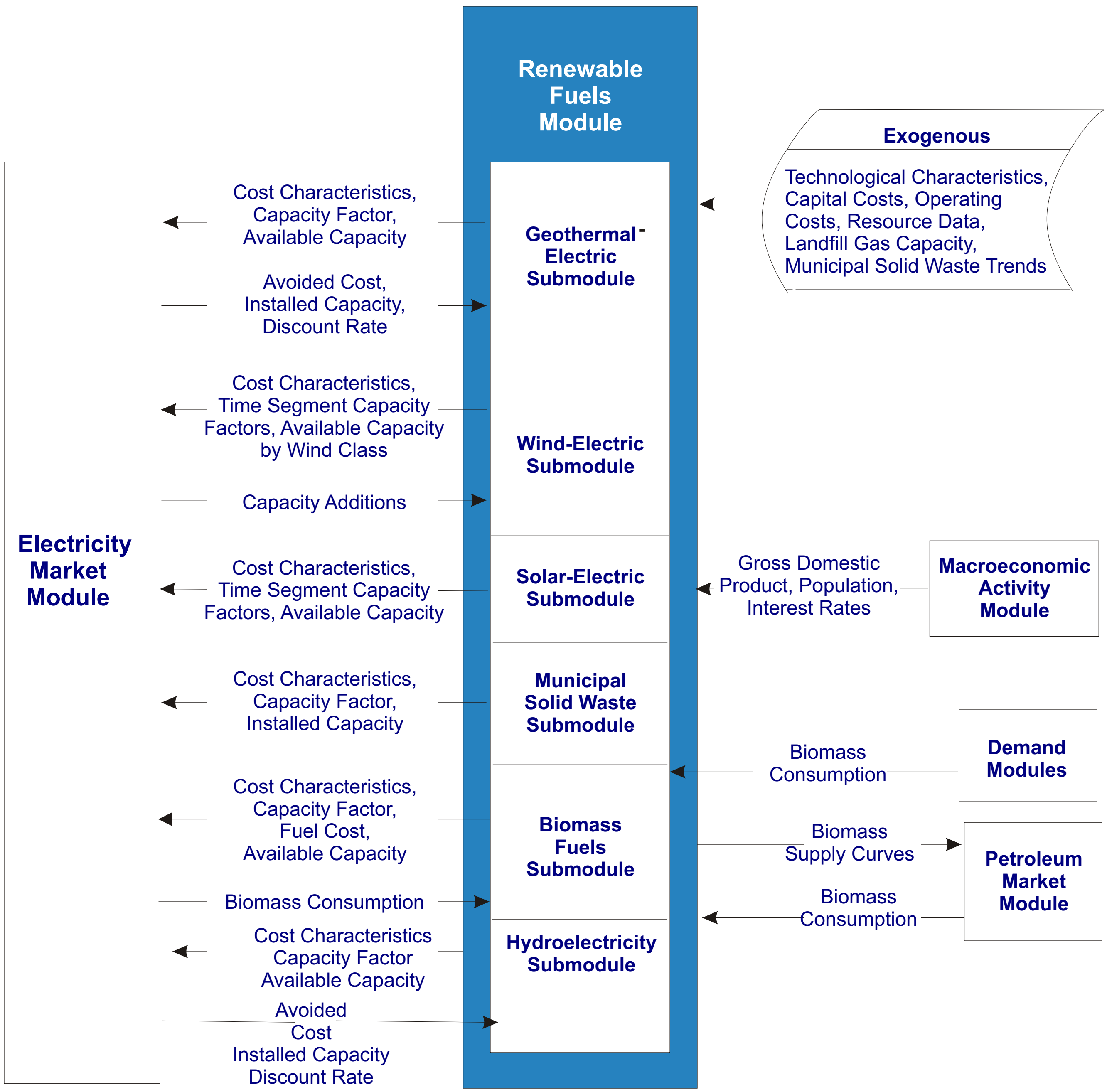
The wind-electric submodule projects the availability of wind resources as well as the cost and performance of wind turbine generators. This information is passed to EMM so that wind turbines can be built and dispatched in competition with other electricity generating technologies. The wind turbine data are expressed in the form of energy supply curves that provide the maximum amount, capital cost, and capacity factor of turbine generating capacity that could be installed in a region in a year, given the available land area and wind speed. The model also evaluates the contribution of the wind capacity to meeting system reliability requirements so that the EMM can appropriately incorporate wind capacity into calculations for regional reliability reserve margins.

Solar-Electric Submodule

The solar-electric submodule represents both photovoltaic and high-temperature thermal electric (concen-

RFM Outputs	Inputs from NEMS	Exogenous Inputs
Energy production capacities Capital costs Operating costs (including wood supply prices for the wood submodule) Capacity factors Available capacity Biomass fuel costs Biomass supply curves	Installed energy production capacity Gross domestic product Population Interest Rates Avoided cost of electricity Discount rate Capacity additions Biomass consumption	Site-specific geothermal resource quantity data Site-specific wind resource quality data Plant utilization (capacity factor) Technology cost and performance parameters Landfill gas capacity

Figure 11. Renewable Fuels Module Structure



trating solar power) installations. Only central-station, grid-connected applications constructed by a utility or independent power producer are considered in this portion of the model.

The solar-electric submodule provides the EMM with time-of-day and seasonal solar availability data for each region, as well as current costs. The EMM uses this data to evaluate the cost and performance of solar-electric technologies in regional grid applications. The commercial and residential demand modules of NEMS also model photovoltaic systems installed by consumers, as discussed in the demand module descriptions under "Distributed Generation."

Landfill Gas Submodule

The landfill gas submodule provides annual projections of electricity generation from methane from landfills (landfill gas). The submodule uses the quantity of municipal solid waste (MSW) that is produced, the proportion of MSW that will be recycled, and the methane emission characteristics of three types of landfills to produce projections of the future electric power generating capacity from landfill gas. The amount of methane available is calculated by first determining the amount of total waste generated in the United States. The amount of total waste generated is derived from an econometric equation that uses gross domestic product and population as the projection drivers. It is assumed that no new mass burn waste–to–energy (MSW) facilities will be built and operated during the projection period in the United States. It is also assumed that operational mass-burn facilities will continue to operate and retire as planned throughout the projection period. The landfill gas submodule passes cost and performance characteristics of the landfill gas–to–electricity technology to the EMM for capacity planning decisions. The amount of new land-fill-gas-to-electricity capacity competes with other technologies using supply curves that are based on the amount of high, medium, and low methane producing landfills located in each EMM region.

Biomass Fuels Submodule

The biomass fuels submodule provides biomass-fired plant technology characterizations (capital costs, operating costs, capacity factors, etc.) and fuel information for EMM, thereby allowing biomass-fueled power plants to compete with other electricity generating technologies.

Biomass fuel prices are represented by a supply curve constructed according to the accessibility of resources to the electricity generation sector. The supply curve employs resource inventory and cost data for four categories of biomass fuel - urban wood waste and mill residues, forest residues, energy crops, and agricultural residues. Fuel distribution and preparation cost data are built into these curves. The supply schedule of biomass fuel prices is combined with other variable operating costs associated with burning biomass. The aggregate variable cost is then passed to EMM.

Hydroelectricity Submodule

The hydroelectricity submodule provides the EMM the amounts of new hydroelectric capacity that can be built at known and well characterized sites, along with related cost and performance data. The information is expressed in the form of a three–step supply function that represents the aggregate amount of new capacity and associated costs that can be offered in each year in each region. Sites include undeveloped stretches of rivers, existing dams or diversions that do not currently produce power, and existing hydroelectric plants that have known capability to expand operations through the addition of new generating units. Capacity or efficiency improvements through the replacement of existing equipment or changes to operating procedures at a facility are not included in the hydroelectricity supply.

Oil And Gas Supply Module

Oil and Gas Supply Module

The OGSM consists of a series of process submodules that project the availability of domestic crude oil production and dry natural gas production from onshore, offshore, and Alaskan reservoirs, as well as conventional gas production from Canada. The OGSM regions are shown in Figure 12.

The driving assumption of OGSM is that domestic oil and gas exploration and development are undertaken if the discounted present value of the recovered resources at least covers the present value of taxes and the cost of capital, exploration, development, and production. Crude oil is transported to refineries, which are simulated in the PMM, for conversion and blending into refined petroleum products. The individual submodules of the OGSM are solved independently, with feedbacks achieved through NEMS solution iterations (Figure 13).

Technological progress is represented in OGSM through annual increases in the finding rates and success rates, as well as annual decreases in costs. For conventional onshore, a time trend was used in econometrically estimated equations as a proxy for technology. Reserve additions per well (or finding rates) are projected through a set of equations that distinquish between new field discoveries and discoveries (extensions) and revisions in known fields. The finding rate equations capture the impacts of technology, prices, and declining resources. Another representation of technology is in the success rate equations. Success rates capture the impact of technology and saturation of the area through cumulative drilling. Technology is further represented in the determination of drilling, lease equipment, and operating costs. Technological progress puts downward pressure on the drilling, lease equipment, and operating cost projections. For unconventional gas, a series of eleven different technology groups are represented by time–dependent adjustments to factors which influence finding rates, success rates, and costs.

Conventional natural gas production in Western Canada is modeled in OGSM with three econometrically estimated equations: total wells drilled, reserves added per well, and expected production-to-reserves ratio. The model performs a simple reserves accounting and applies the expected production-to-reserve ratio to estimate an expected production level, which in turn is used to establish a supply curve for conventional Western Canada natural gas. The rest of the gas production sources in Canada are represented in the Natural Gas Transmission and Distribution Module (NGTDM).

Lower 48 Onshore and Shallow Offshore Supply Submodule

The lower 48 onshore supply submodule projects crude oil and natural gas production from conventional recovery techniques. This submodule accounts for drilling, reserve additions, total reserves, and production -to-reserves ratios for each lower 48 onshore supply region.

The basic procedure is as follows:

- First, the prospective costs of a representative drilling project for a given fuel category and well class within a given region are computed. Costs are a function of the level of drilling activity, average well depth, rig availability, and the effects of technological progress.
- Second, the present value of the discounted cash flows (DCF) associated with the representative project is computed. These cash flows include both the capital and operating costs of the project, including royalties and taxes, and the revenues derived from a declining well production profile, computed after taking into account the progressive effects of resource depletion and valued at constant real prices as of the year of initial valuation.
- Third, drilling levels are calculated as a function of projected profitability as measured by the projected DCF levels for each project and national level cashflow.

OGSM Outputs	Inputs from NEMS	Exogenous Inputs
Crude oil production Domestic nonassociated and Canadian conventional natural gas suply curves Cogeneration from oil and gas producton Reserves and reserve additions Drilling levels Domestic associated-dissolved gas production	Domestic and Canadian natural gas production and wellhead prices Crude oil demand World oil price Electricity price Gross domestic product Inflation rate	Resource levels Initial finding rate parameters and costs Production profiles Tax parameters

Figure 12. Oil and Gas Supply Module Regions

- Fourth, regional finding rate equations are used to project new field discoveries from new field wildcats, new pools, and extensions from other exploratory drilling, and reserve revisions from development drilling.
- Fifth, production is determined on the basis of reserves, including new reserve additions, previous productive capacity, flow from new wells, and, in the case of natural gas, fuel demands. This occurs within the market equilibration of the NGTDM for natural gas and within OGSM for oil.

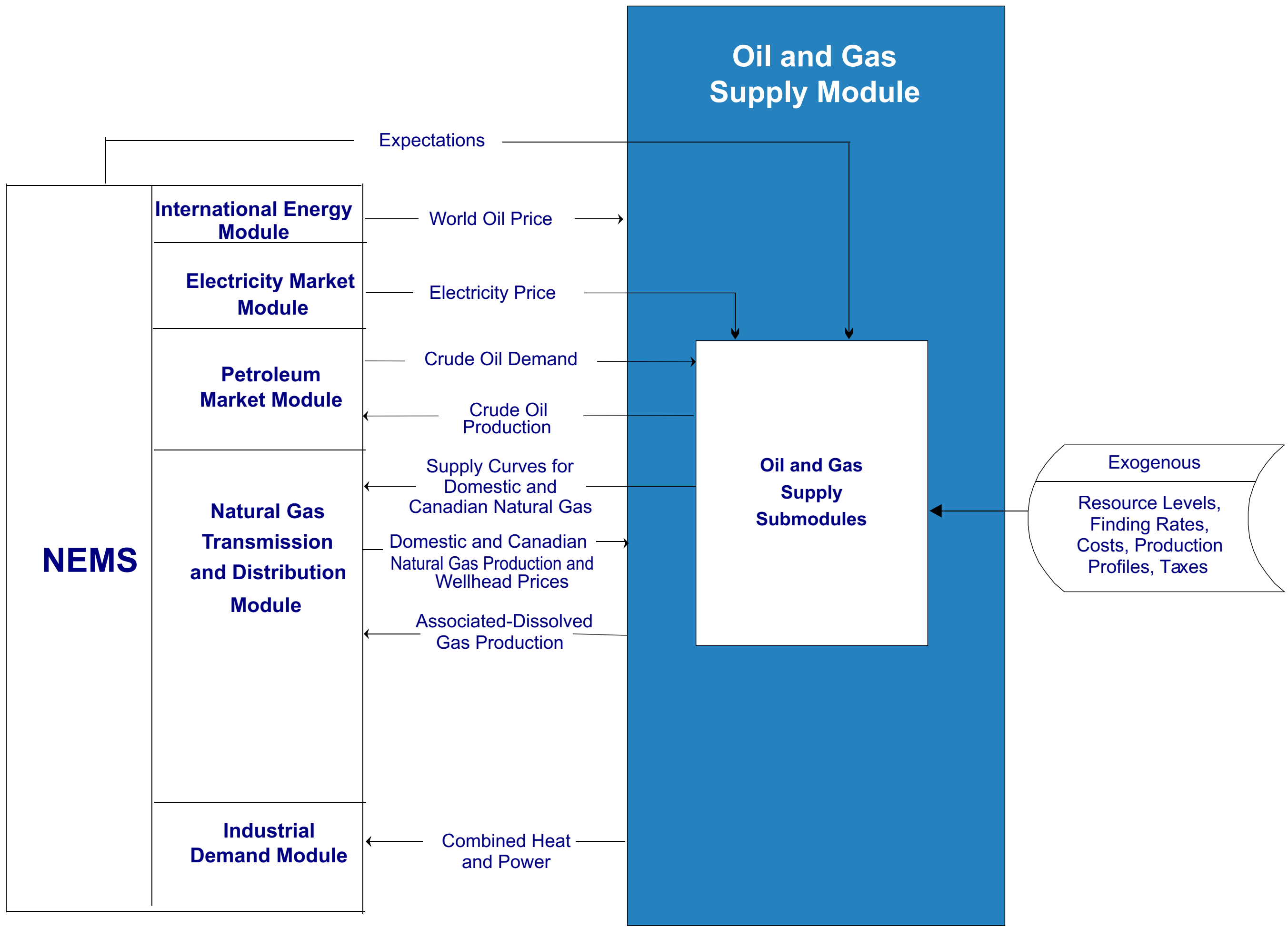
Unconventional Gas Recovery Supply Submodule

Unconventional gas is defined as gas produced from nonconventional geologic formations, as opposed to conventional (sandstones) and carbonate rock formations. The three unconventional geologic formations considered are low–permeability or tight sandstones, gas shales and coalbed methane.

For unconventional gas, a play–level model calculates the economic feasibility of individual plays based on locally specific wellhead prices and costs, resource quantity and quality, and the various effects of technology on both resources and costs. In each year, an initial resource characterization determines the expected ultimate recovery (EUR) for the wells drilled in a particular play. Resource profiles are adjusted to reflect assumed technological impacts on the size, availability, and industry knowledge of the resources in the play.

Oil and Gas Supply Module

Figure 13. Oil and Gas Supply Module Structure



Subsequently, prices received from NGTDM and endogenously determined costs adjusted to reflect technological progress are utilized to calculate the economic profitability (or lack thereof) for the play. If the play is profitable, drilling occurs according to an assumed schedule, which is adjusted annually to account for technological improvements, as well as varying economic conditions. This drilling results in reserve additions, the quantities of which are directly related to the EURs for the wells in that play. Given these reserve additions, reserve levels and expected production–to–reserves (P/R) ratios are calculated at both the OGSM and the NGTDM region level. The resultant values are aggregated with similar values from the conventional onshore and offshore submodules. The aggregate P/R ratios and reserve levels are then passed to NGTDM, which determines the prices and production for the following year through market equilibration.

Offshore Supply Submodule

This submodule uses a field-based engineering approach to represent the exploration and development of U.S. offshore oil and natural gas resources. The submodule simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore resources are divided into 3 categories:

- **Undiscovered Fields.** The number, location, and size of the undiscovered fields are based on the MMS's 2006 hydrocarbon resource assessment.
- **Discovered, Undeveloped Fields.** Any discovery that has been announced but is not currently producing is evaluated in this component of the model. The first production year is an input and is based on announced plans and expectations.

- **Producing Fields.** The fields in this category have wells that have produced oil and/or gas through the year prior to the AEO projection. The production volumes are from the Minerals Management Service (MMS) database.

Resource and economic calculations are performed at an evaluation unit basis. An evaluation unit is defined as the area within a planning area that falls into a specific water depth category. Planning areas are the Western Gulf of Mexico (GOM), Central GOM, Eastern GOM, Pacific, and Atlantic. There are six water depth categories: 0-200 meters, 200-400 meters, 400-800 meters, 800-1600 meters, 1600-2400 meters, and greater than 2400 meters.

Supply curves for crude oil and natural gas are generated for three offshore regions: Pacific, Atlantic, and GOM. Crude oil production includes lease condensate. Natural gas production accounts for both nonassociated gas and associated-dissolved gas. The model is responsive to changes in oil and natural gas prices, royalty relief assumptions, oil and natural gas resource base, and technological improvements affecting exploration and development.

Alaska Oil and Gas Submodule

This submodule projects the crude oil and natural gas produced in Alaska. The Alaskan oil submodule is divided into three sections: new field discoveries, development projects, and producing fields. Oil transportation costs to lower 48 facilities are used in conjunction with the relevant market price of oil to calculate the estimated net price received at the wellhead, sometimes called the netback price. A discounted cash flow method is used to determine the economic viability of each project at the netback price.

Alaskan oil supplies are modeled on the basis of discrete projects, in contrast to the onshore lower 48 conventional oil and gas supplies, which are modeled on an aggregate level. The continuation of the exploration and development of multiyear projects, as well as the discovery of new fields, is dependent on profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, historical production patterns, and announced plans for currently producing fields.

- Alaskan gas production is set separately for any gas targeted to flow through a pipeline to the lower 48 States and gas produced for consumption in the State and for export to Japan. The latter is set based on a projection of Alaskan consumption in the NGTDM and an exogenous specification of exports. North Slope production for the pipeline is dependent on construction of the pipeline, set to commence if the lower 48 average wellhead price is maintained at a level exceeding the established comparable cost of delivery to the lower 48 States.

Natural Gas Transmission and Distribution Module

Natural Gas Transmission And Distribution Module

The NGTDM of NEMS represents the natural gas market and determines regional market–clearing prices for natural gas supplies and for end–use consumption, given the information passed from other NEMS modules (Figure 14). A transmission and distribution network (Figure 15), composed of nodes and arcs, is used to simulate the interregional flow and pricing of gas in the contiguous United States and Canada in both the peak (December through March) and offpeak (April through November) period. This network is a simplified representation of the physical natural gas pipeline system and establishes the possible interregional flows and associated prices as gas moves from supply sources to end users.

Flows are further represented by establishing arcs from transshipment nodes to each demand sector represented in an NGTDM region (residential, commercial, industrial, electric generators, and transportation). Mexican exports and net storage injections in the offpeak period are also represented as flow exiting a transshipment node. Similarly, arcs are also established from supply points into a transshipment node. Each transshipment node can have one or more entering arcs from each supply source represented: U.S. or Canadian onshore or U.S. offshore production, liquefied natural gas imports, supplemental gas production, gas produced in Alaska and transported via pipeline, Mexican imports, or net storage withdrawals in the region in the peak period. Most of the types of supply listed above are set independently of current year prices and before NGTDM determines a market equilibrium solution.

Only the onshore and offshore lower 48 U.S. and Western Canadian Sedimentary Basin production, along with net storage withdrawals, are represented by short–term supply curves and set dynamically during the NGTDM solution process. The construction of natural gas pipelines from Alaska and Canada's MacKenzie Delta are triggered when market prices exceed estimated project costs. The flow of gas during the peak period is used to establish interregional pipeline and storage capacity requirements and the associated expansion. These capacity levels provide an upper limit for the flow during the offpeak period.

Arcs between transshipment nodes, from the transshipment nodes to end–use sectors, and from supply sources to transshipment nodes are assigned tariffs. The tariffs along interregional arcs reflect reservation (represented with volume dependent curves) and usage fees and are established in the pipeline tariff submodule. The tariffs on arcs to end–use sectors represent the interstate pipeline tariffs in the region, intrastate pipeline tariffs, and distributor markups set in the distributor tariff submodule. Tariffs on arcs from supply sources represent gathering charges or other differentials between the price at the supply source and the regional market hub. The tariff associated with injecting, storing, and withdrawing from storage is assigned to the arc representing net storage withdrawals in the peak period. During the primary solution process in the interstate transmission submodule, the tariffs along an interregional arc are added to the price at the source node to arrive at a price for the gas along the arc right before it reaches its destination node.

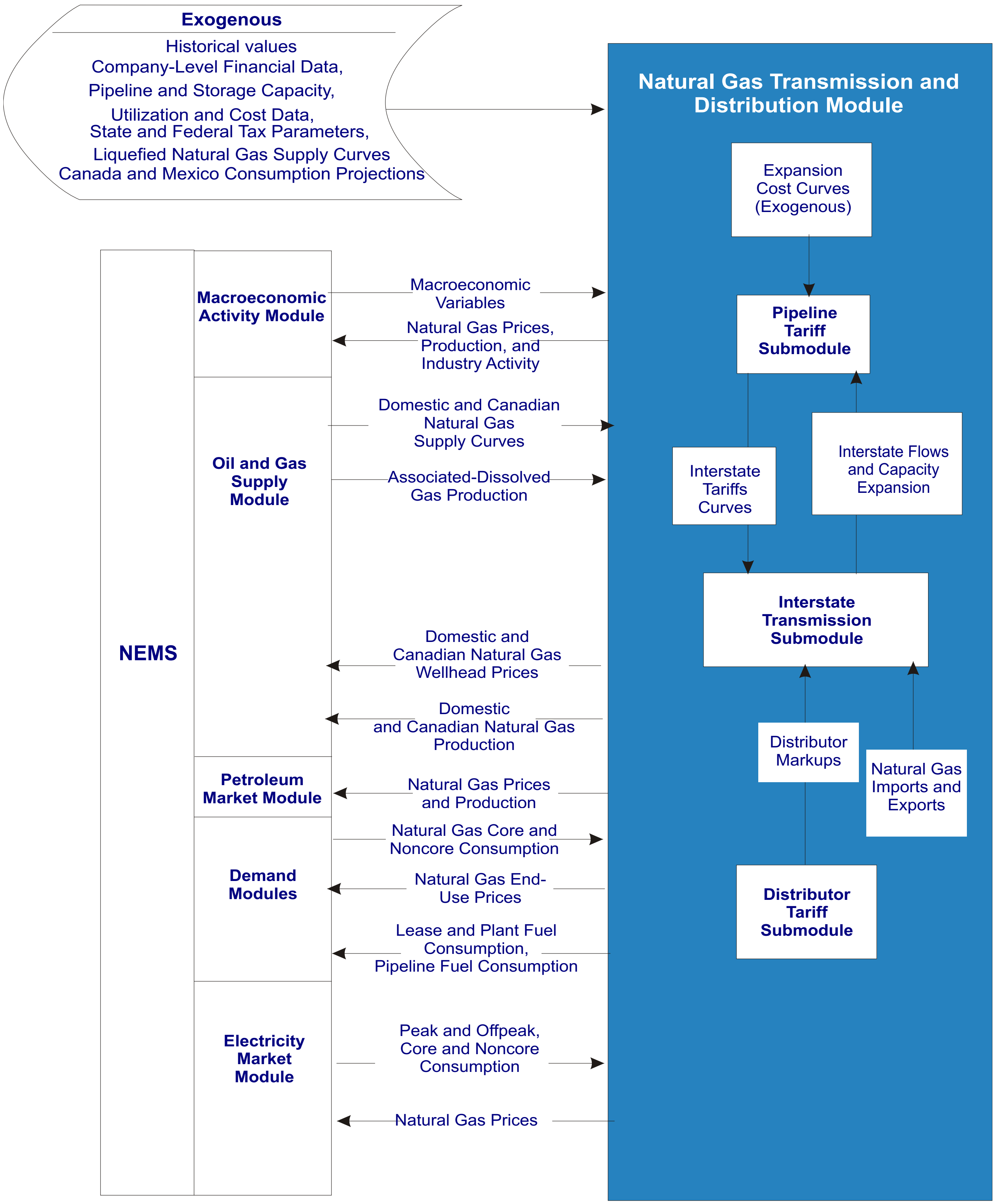
Interstate Transmission Submodule

The interstate transmission submodule (ITS) is the main integrating module of NGTDM. One of its major functions is to simulate the natural gas price determination process. ITS brings together the major economic factors that influence regional natural gas trade on a seasonal basis in the United States, the balancing of the demand for and the domestic supply of natural gas, including competition from imported natural gas. These are examined in combination with the relative prices associated with moving the gas from the producer to the end user where and when (peak versus offpeak) it is

NGTDM Outputs	Inputs from NEMS	Exogenous Inputs
Natural gas delivered prices Domestic and Canadian natural gas wellhead prices Domestic natural gas production Mexican and liquefied natural gas imports and exports Canadian natural gas imports and production Lease and plant fuel consumption Pipeline and distribution tariffs Interregional natural gas flows Storage and pipeline capacity expansion Supplemental gas production	Natural gas demands Domestic and Canadian natural gas supply curves Macroeconomic variables Associated-dissolved natural gas production	Historical consumption and flow patterns Historical supplies Pipeline company-level financial data Pipeline and storage capacity and utilization data Historical end-use citygate, and wellhead prices State and Federal tax parameters Pipeline and storage expansion cost data Liquefied natural gas supply curves Canada and Mexico consumption projections

Natural Gas Transmission And Distribution Module

Figure 14. Natural Gas Transmission and Distribution Module Structure



needed. In the process, ITS simulates the decision–making process for expanding pipeline and/or seasonal storage capacity in the U.S. gas market, determining the amount of pipeline and storage capacity to be added between or within regions in NGTDM. Storage serves as the primary link between the two seasonal periods represented.

ITS employs an iterative heuristic algorithm, along with an acyclic hierarchical representation of the primary arcs in the network, to establish a market equilibrium solution. Given the consumption levels from other NEMS modules, the basic process followed by ITS involves first establishing the backward flow of natural gas in each period from the consumers, through the network, to the producers, based primarily on the relative prices offered for the gas from the previous ITS iteration. This process is performed for the peak period first since the net withdrawals from storage during the peak period will establish the net injections during the offpeak period. Second, using the model's supply curves, wellhead and import prices are set corresponding to the desired production volumes. Also, using the pipeline and storage tariffs from the pipeline tariff submodule, pipeline and storage tariffs are set corresponding to the associated flow of gas, as determined in the first step. These prices are then translated from the producers, back through the network, to the city gate and the end users, by adding the appropriate tariffs along the way. A regional storage tariff is added to the price of gas injected into storage in the offpeak to arrive at the price of the gas when withdrawn in the peak period. This process is then repeated until the solution has converged. Finally, delivered prices are derived for residential, commercial, and transportation customers, as well as for both core and noncore industrial and electric generation sectors using the distributor tariffs provided by the distributor tariff submodule.

Pipeline Tariff Submodule

The pipeline tariff submodule (PTS) provides usage fees and volume dependent curves for computing unitized reservation fees (or tariffs) for interstate transportation and storage services within the ITS. These curves extend beyond current capacity levels and relate incremental pipeline or storage capacity expansion to corresponding estimated rates. The underlying basis for each tariff curve in the model is a projection of the associated regulated revenue requirement. Econometrically estimated equations within a general accounting framework are used to track costs and compute revenue requirements associated with both reservation and usage fees under current rate design and regulatory scenarios. Other than an assortment of macroeconomic indicators, the primary input to PTS from other modules in NEMS is pipeline and storage capacity utilization and expansion in the previous projection year.

Once an expansion is projected to occur, PTS calculates the resulting impact on the revenue requirement. PTS assumes rolled–in (or average), not incremental, rates for new capacity. The pipeline tariff curves generated by PTS are used within the ITS when determining the relative cost of purchasing and moving gas from one source versus another in the peak and offpeak seasons.

Distributor Tariff Submodule

The distributor tariff submodule (DTS) sets distributor markups charged by local distribution companies for the distribution of natural gas from the city gate to the end user. For those that do not typically purchase gas through a local distribution company, this markup represents the differential between the citygate and delivered price. End–use distribution service is distinguished within the DTS by sector (residential, commercial, industrial, electric generators, and transportation), season (peak and offpeak), and service type (core and noncore).

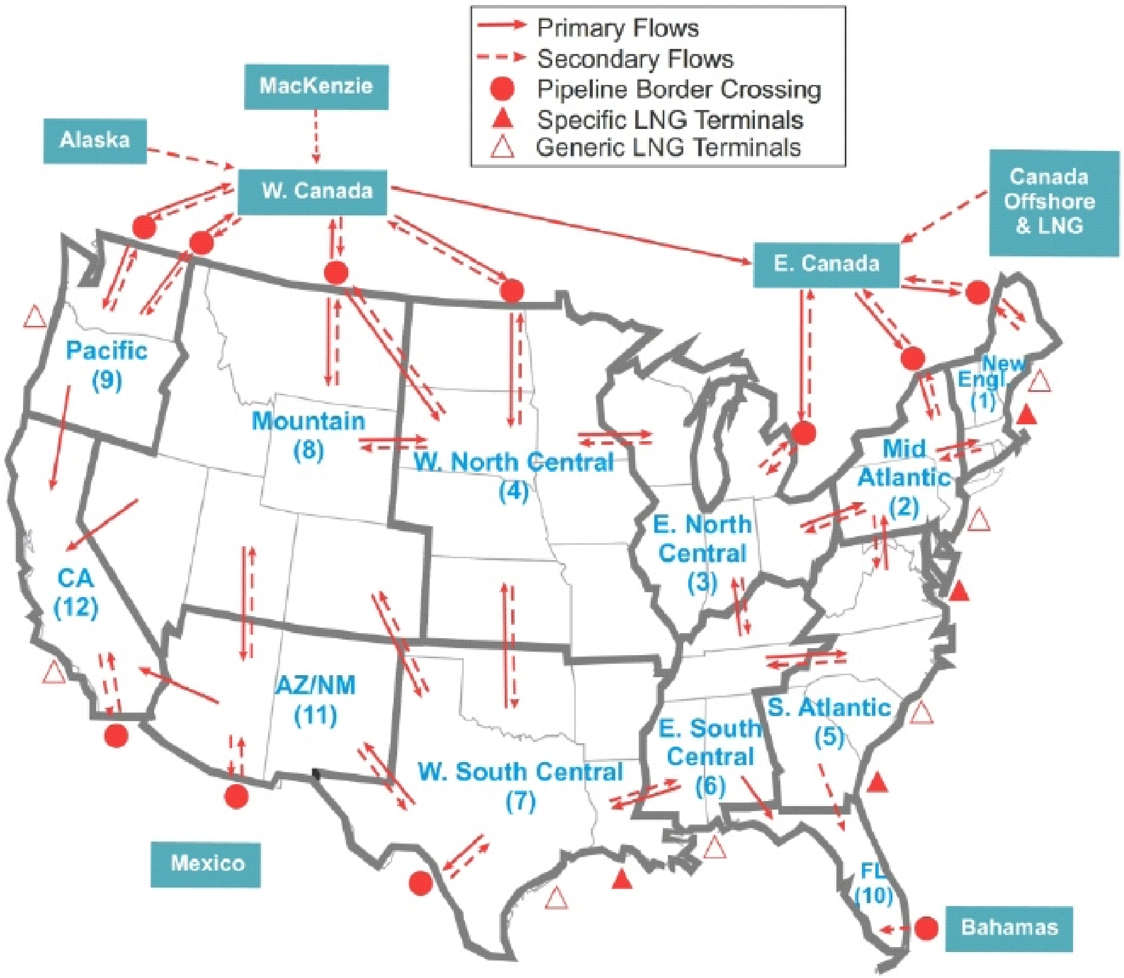
Distributor tariffs for all but the transportation sector are set using econometrically estimated equations. The natural gas vehicle sector markups are calculated separately for fleet and personal vehicles and account for distribution to delivery stations, retail markups, and federal and state motor fuels taxes.

Natural Gas Imports and Exports

Liquefied natural gas imports for the U.S., Canada, and Baja, Mexico are set at the beginning of each NEMS iteration within the NGTDM by evaluating seasonal east and west supply curves, based on outputs from EIA's International Natural Gas Model, at associated regasification tailgate prices set in the previous NEMS iteration. A sharing algorithm is used to allocate the resulting import volumes to particular regions. LNG exports to Japan from Alaska are set exogenously by the OGSM.

The Mexico model is largely based on exogenously specified assumptions about consumption and production growth rates and LNG import levels. For the most part, natural gas imports from Mexico are set exogenously for each of the three border crossing points with

Figure 15. Natural Gas Transmission and Distribution Module Network



the United States, with the exception of any gas that is imported into Baja, Mexico in liquid form only to be exported to the United States. Exports to Mexico from the United States are established before the NGTDM equilibrates and represent the required level to balance the assumed consumption in (and exports from) Mexico against domestic production and LNG imports. The production levels are also largely assumption based, but are set to vary with changes in the expected wellhead price in the United States.

A node for east and west Canada is included in the NGTDM equilibration network, as well as seven border crossings into the United States. The model includes a representation/accounting of the U.S. border crossing pipeline capacity, east and west seasonal storage transfers, east and west consumption, east and west LNG imports, eastern production, conventional/tight sands production in the west, and coalbed/shale production. Imports from the United States, conventional production in eastern Canada, and base level natural gas consumption (which varies with the world oil price) are set exogenously. Conventional/tight sands production in the west is set using a supply curve from the OGSM. Coalbed and shale gas production are effectively based on an assumed production growth rate which is adjusted with realized prices.

Petroleum Market Module

Petroleum Market Module

The PMM represents domestic refinery operations and the marketing of liquid fuels to consumption regions. PMM solves for liquid fuel prices, crude oil and product import activity (in conjunction with the IEM and the OGSM), and domestic refinery capacity expansion and fuel consumption. The solution satisfies the demand for liquid fuels, incorporating the prices for raw material inputs, imported liquid fuels, capital investment, as well as the domestic production of crude oil, natural gas liquids, and other unconventional refinery inputs. The relationship of PMM to other NEMS modules is illustrated in Figure 16.

The PMM is a regional, linear programming formulation of the five Petroleum Administration for Defense Districts (PADDs) (Figure 17). For each region two distinct refinery are modeled. One is highly complex using over 40 different refinrry processes, while the second is defined as a simple refinery that provides marginal cost economics. Refining capacity is allowed to expand in each region, but the model does not distinguish between additions to existing refineries or the building of new facilities. Investment criteria are developed exogenously, although the decision to invest is endogenous.

PMM assumes that the petroleum refining and marketing industry is competitive. The market will move toward lower-cost refiners who have access to crude oil and markets. The selection of crude oils, refinery process utilization, and logistics (transportation) will adjust to minimize the overall cost of supplying the market with liquid fuels.

PMM's model formulation reflects the operation of domestic liquuid fuels. If demand is unusually high in one region, the price will increase, driving down demand and providing economic incentives for bringing supplies in from other regions, thus restoring the supply and demand balance.

Existing regulations concerning product types and specifications, the cost of environmental compliance, and Federal and State taxes are also modeled. PMM incorporates provisions from the Energy Independence and Security Act of 2007 (EISA2007) and the Energy Policy Act of 2005 (EPACT05). The costs of producing new formulations of gasoline and diesel fuel as a result of the CAAA90 are determined within the linear-programming representation by incorporating specifications and demands for these fuels.

PMM also includes the interaction between the domestic and international markets. Prior to AEO2009, PMM postulated entirely exogenous prices for oil on the international market (the world oil price). Subsequent AEOs include an International Energy Module (IEM) that estimates supply curves for imported crude oils and products based on, among other factors, U.S. participation in global trade of crude oil and liquid fuels.

Regions

PMM models U.S. crude oil refining capabilities based on the five PADDs which were established during World War II and are still used by EIA for data collection and analysis. The use of PADD data permits PMM to take full advantage of EIA's historical database and allows analysis within the same framework used by the petroleum industry.

PMM Outputs	Inputs from NEMS	Exogenous Inputs
Petroleum product prices	Petroleum product demand by sector	Processing unit operating parameters
Crude oil imports and exports	Domestic crude oil production	Processing unit capacities
Crude oil demand	World oil price	Product specifications
Petroleum product imports and exports	International crude oil supply curves	Operating costs
Refinery activity and fuel use	International product supply curves	Capital costs
Ethanol demand and price	International oxygenates supply curves	Transmission and distribution costs
Combined heat and power (CHP)	Natural gas prices	Federal and State taxes
Natural gas plant liquids production	Electricity prices	Agricultural feedstock quantities and costs
Processing gain	Natural glas production	CHP unit operating parameters
Capacity additions	Macroeconomic variables	CHP unit capacities
Capital expenditures	Biomass supply curves	
Revenues	Coal prices	

Figure 16. Petroleum Market Module Structure

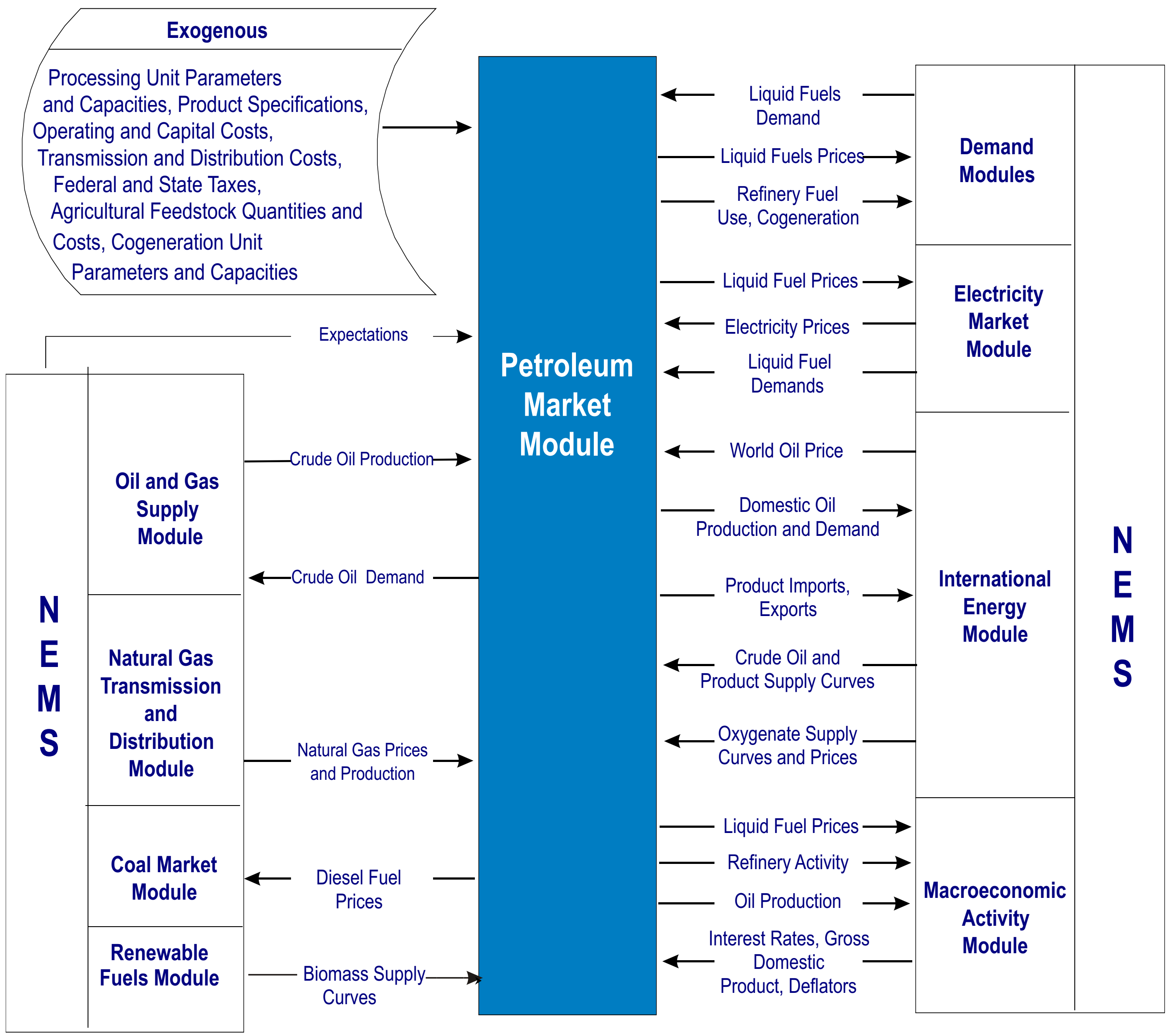
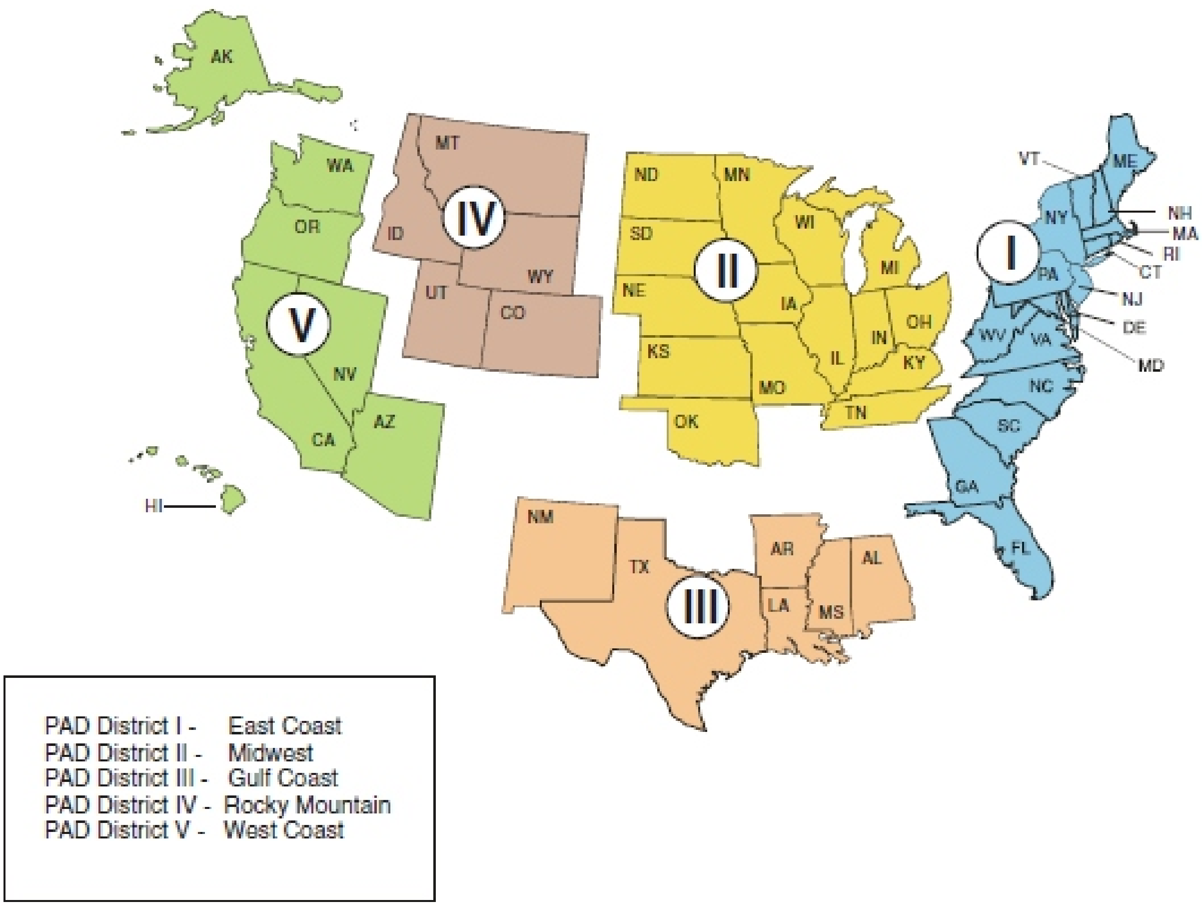


Figure 17. Petroleum Administration for Defense Districts



Product Categories

Product categories, specifications and recipe blends modeled in PMM include the following:

Liquid Fuels Modeled in PMM

Motor gasoline: conventional (oxygenated and non-oxygentated), reformulated, and California reformulated
Jet fuels: kerosene-based
Distillates: kerosene, heating oil, low sulfur (LSD) and ultra-low-sulfur (ULSD) highway diesel, distillate fuel oil, and distillate fuel from various non-crude feedstocks (coal, biomass, natural gas) via the Fischer-Tropsch process (BTL, CTL, GTL)
Alternative Fuel: Biofuels [including ethanol, biodiesel (methyl-ester), renewable diesel, biomass-to-liquids (BTL)], coal-to-liquids (CTL), gas-to-liquids (GTL).
Residual fuels: low sulfur and high sulfur residual fuel oil
Liquefied petroleum gas (LPG): a light-end mixture used for fuel in a wide range of sectors comprised primarily of propane
Natural gas plant:ethane, propane, iso and normal butane, and pentanes plus (natural gasoline)
Petrochemical feedstocks
Other: asphalt and road oil, still gas, (refinery fuel) petroleum coke, lubes and waxes, special naphthas

Fuel Use

PMM determines refinery fuel use by refining region for purchased electricity, natural gas, distillate fuel, residual fuel, liquefied petroleum gas, and other petroleum. The fuels (natural gas, petroleum, other gaseous fuels, and other) consumed within the refinery to generate electricity from CHP facilities are also determined.

Crude Oil Categories

Both domestic and imported crude oils are aggregated into five categories as defined by API gravity and sulfur content ranges. This aggregation of crude oil types allows PMM to account for changes in crude oil composition over time. A composite crude oil with the appropriate yields and qualities is developed for each category by averaging characteristics of foreign and domestic crude oil streams.

Refinery Processes

The following distinct processes are represented in the PMM:

1) Crude Oil Distillation
   a. Atmospheric Crude Unit
   b. Vacuum Crude Unit

2) Residual Oil Upgrading
   a. Coker - Delayed, fluid
   b. Thermal Cracker/Visbreaker
   c. Residuum Hydrocradker
   d. Solvent Deasphalting
3) Cracking
   a. Fluidized Catalytic Cracker
   b. Hydrocracker
4) Final Product Treating/Upgrading
   a. Traditional Hydrotreating
   b. Modern Hydrotreating
   c. Alkylation
   d. Jet Fuel Production
   e. Benzene Saturation
   f. Catalytic Reforming
5) Light End Treating
   a. Saturated Gas Plant
   b. Isomerization
   c. Dimerization/Polymerization
   d. C2-C5 Dehydrogenation
6) Non-Fuel Production
   a. Sulfur Plant
   b. Methanol Production
   c. Oxgenate Production
   d. Lube and Wax Production
   e. Steam/Power Generation
   f. Hydrogen Production
   g. Aromatics Production
7) Specialty Unit Operations
   a. Olefins to Gasoline/Diesel
   b. Methanol to Olefins
8) Merchant Facilities
   a. Coal/Gas/Biomass to Liquids
   b. Natural Gas Plant
   c. Ethanol Production
   d. Biodiesel Plant

Natural Gas Plants

Natural gas plant liquids (ethane, propane, normal butane, isobutane, and natural gasoline) produced from natural gas processing plants are modeled in PMM. Their production levels are based on the projected natural gas supply and historical liquids yields from various natural gas sources. These products move directly into the market to meet demand (e.g., for fuel or petrochemical feedstocks) or are inputs to the refinery.

Petroleum Market Module

Biofuels

PMM contains submodules which provide regional supplies and prices for biofuels: ethanol (conventional/corn, advanced, cellulosic) and various forms of biomass-based diesel: FAME (methyl ester), biomass-to-liquid (Fisher-Tropsch), and renewable ("green") diesel (hydrogenation of vegetable oils or fats). Ethanol is assumed to be blended either at 10 percent into gasoline (conventional or reformulated) or as E85. Food feedstock supply curves (corn, soybean oil, etc.) are updated to USDA baseline projections; biomass feedstocks are drawn from the same supply curves that also supply biomass fuel to renewable power generation within the Renewable Fuels Module of NEMS. The merchant processing units which generate the biofuels supplies sum these feedstock costs with other cost inputs (e.g., capital, operating). A major driving force behind the production of these biofuels is the Renewable Fuels Standard under EISA2007. Details on the market penetration of the advanced biofuels production capacity (such as cellulosic ethanol and BTL) which are not yet commercialized can be found in the PMM documentation.

End-Use Markups

The linear programming portion of the model provides unit prices of products sold in the refinery regions (refinery gate) and in the demand regions (wholesale). End use markups are added to produce a retail price for each of the Census Divisions. The mark ups are based on an average of historical markups, defined as the difference between the end-use prices by sector and the corresponding wholesale price for that product. The average is calculated using data from 2000 to the present. Because of the lack of any consistent trend in the historical end-use markups, the markups remain at the historical average level over the projection period.

State and Federal taxes are also added to transportation fuel prices to determine final end-use prices. Previous tax trend analysis indicates that state taxes increase at the rate of inflation, while Federal taxes do not. In PMM, therefore state taxes are held constant in real terms throughout the projection while Federal taxes are felated at the rate of inflation.[18]

Gasoline Types

Motor vehicle fuel in PMM is categorized into four gasoline blends (conventional, oxygenated conventional, reformulated, and California reformulated) and also E85. While federal law does not mandate gasoline to be oxygenated, all gasoline complying with the Federal reformulated gasoline program is assumed to contain 10 percent ethanol, while conventional gasoline may be "clear" (no ethanol) or used as E10. As the mandate for biofuels grows under the Renewable Fuels Standard, the proportion of conventional gasoline that is E10 also generally grows. California reformulated motor gasoline is assumed to contain 5.7% ethanol in 2009 and 10 percent thereafter in line with its approval of the use of California's Phase 3 reformulated gasoline.

EIA defines E85 as a gasoline type but is treated as a separate fuel in PMM. The transportation module in NEMS provides PMM with a flex fuel vehicle (FFV) demand, and PMM computes a supply curve for E85. This curve incorporates E85 infrastructure and station costs, as well as a logit relationship between the E85 station availability and demand of E85. Infrastructure costs dictate that the E85 supplies emerge in the Midwest first, followed by an expansion to the coasts.

Ultra–Low–Sulfur Diesel

By definition, Ultra Low Sulfur Diesel (ULSD) is highway diesel fuel that contains no more than 15 ppm sulfur at the pump. As of June 2006, 80 percent of all highway diesel produced or imported into the United States was required to be ULSD, while the remaining 20 percent contained a maximum of 500 parts per million. By December 1, 2010 all highway fuel sold at the pump will be required to be ULSD. Major assumptions related to the ULSD rule are as follows:

- Highway diesel at the refinery gate will contain a maximum of 7-ppm sulfur. Although sulfur content is limited to 15 ppm at the pump, there is a general consensus that refineries will need to produce diesel below 10 ppm sulfur in order to allow for contamination during the distribution process.
- Demand for highway grade diesel, both 500 and 15 ppm combined, is assumed to be equivalent to the total transportation distillate demand. Historically, highway grade diesel supplied has nearly matched total transportation distillate sales, although some highway grade

18 http://www.eia.doe.gov/oiaf/archive/aeo07/leg_reg.html.

diesel has gone to non-transportation uses such as construction and agriculture.

Gas, Coal and Biomass to Liquids

Natural gas, coal, and biomass conversion to liquid fuels is modeled in the PMM based on a three step process known as indirect liquefaction. This process is sometimes called Fischer-Tropsch (FT) liquefaction after the inventors of the second step.

The liquid fuels produced include four separate products: FT light naphtha, FT heavy naphtha, FT kerosene, and FT diesel. The FT designation is used to distinguish these liquid fuels from their petroleum counterparts. This is necessary due to the different physical and chemical properties of the FT fuels. For example, FT diesel has a typical cetane rating of approximately 70-75 while that of petroleum diesel is typically much lower (about 40). In addition, the above production methods have differing impacts with regard to current and potential legislation, particularly RFS and CO2.

Coal Market Module

Coal Market Module

The coal market module (CMM) represents the mining, transportation, and pricing of coal, subject to end-use demand. Coal supplies are differentiated by thermal grade, sulfur content, and mining method (underground and surface). CMM also determines the minimum cost pattern of coal supply to meet exogenously defined U.S. coal export demands as a part of the world coal market. Coal distribution, from supply region to demand region, is projected on a cost-minimizing basis. The domestic production and distribution of coal is projected for 14 demand regions and 14 supply regions (Figures 18 and 19).

The CMM components are solved simultaneously. The sequence of solution among components can be summarized as follows. Coal supply curves are produced by the coal production submodule and input to the coal distribution submodule. Given the coal supply curves, distribution costs, and coal demands, the coal distribution submodule projects delivered coal prices. The module is iterated to convergence with respect to equilibrium prices to all demand sectors. The structure of the CMM is shown in Figure 20.

Coal Production Submodule

This submodule produces annual coal supply curves, relating annual production to minemouth prices. The supply curves are constructed from an econometric analysis of prices as a function of productive capacity, capacity utilization, productivity, and various factor input costs. A separate supply curve is provided for surface and underground mining for all significant production by coal thermal grade (metallurgical, bituminous, subbituminous and lignite), and sulfur level in each supply region. Each supply curve is assigned a unique heat, sulfur, and mercury content, and carbon dioxide emissions factor. Constructing curves for the coal types available in each region yields a total of 40 curves that are used as inputs to the coal distribution submodule. Supply curves are updated for each year in the projection period. Coal supply curves are shared with both the EMM and the PMM. For detailed assumptions, please see the Assumptions to the Annual Energy Outlook updated each year with the release of the AEO.

Coal Distribution Submodule: Domestic Component

The coal distribution submodule is a linear program that determines the least-cost supplies of coal for a given set of coal demands by demand region and sector, accounting for transportation costs from the different supply curves, heat and sulfur content, and existing coal supply contracts. Existing supply contracts between coal producers and electricity generators are incorporated in the model as minimum flows for supply curves to coal demand regions. Depending on the specific scenario, coal distribution may also be affected by any restrictions on sulfur dioxide, mercury, or carbon dioxide emissions.

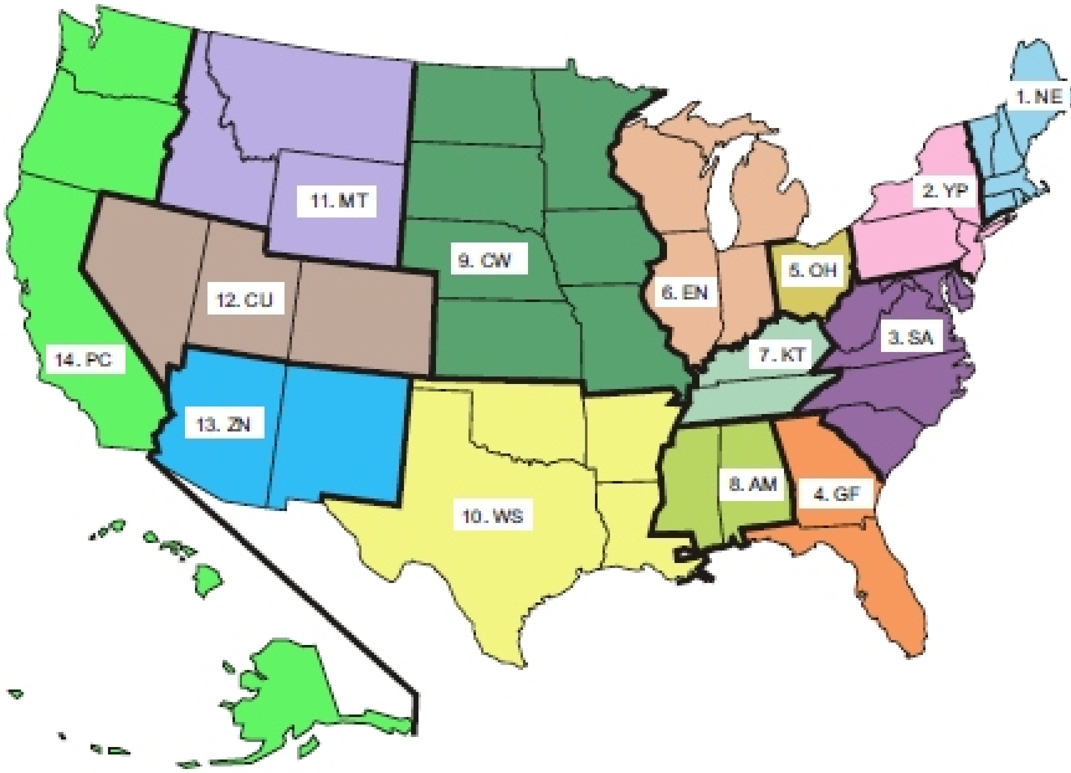
Coal transportation costs are simulated using interregional coal transportation costs derived by subtracting reported minemouth costs for each supply curve from reported delivered costs for each demand type in each demand region. For the electricity sector, higher transportation costs are assumed for market expansion in certain supply and demand region combinations. Transportation rates are modified over time using econometrically based multipliers which considers the impact of changing productivity and equipment costs. When diesel fuel prices are sufficiently high, a fuel surcharge is also added to the transportation costs.

Coal Distribution Submodule: International Component

The international component of the coal distribution submodule projects quantities of coal imported and exported from the United States. The quantities are determined within a world trade context, based on assumed characteristics of foreign coal supply and demand. The component disaggregates coal into 17 export regions and 20 import regions, as shown inTable 13. The supply and demand components of world coal trade are

CMM Outputs	Inputs from NEMS	Exogenous Inputs
Coal production and distribution Minemouth coal prices End-use coal prices U.S. coal exports and imports Transportation rates Coal quality by source, destination, and end-use sector World coal flows	Coal demand Interest rates Price indices and deflators Diesel fuel prices Electricity prices	Base year production, productive capacity, capacity utilization, prices, and coal quality parameters Contract quantities Labor productivity Labor costs Domestic transportation costs International transportation costs International supply curves International coal import demands

Figure 18. Coal Market Module Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

segmented into two separate markets: 1) coking coal, which is used for the production of coke for the steelmaking process; and 2) steam coal, which is primarily consumed in the electricity and industrial sectors.

The international component is solved as part of the linear program that optimizes U.S. coal supply. It determines world coal trade distribution by minimizing overall costs for coal, subject to coal supply prices in the United States and other coal exporting regions plus transportation costs. The component also incorporates supply diversity constraints that reflect the observed tendency of coal-importing countries to avoid excessive dependence upon one source of supply, even at a somewhat higher cost.

Figure 19. Coal Market Module Supply Regions

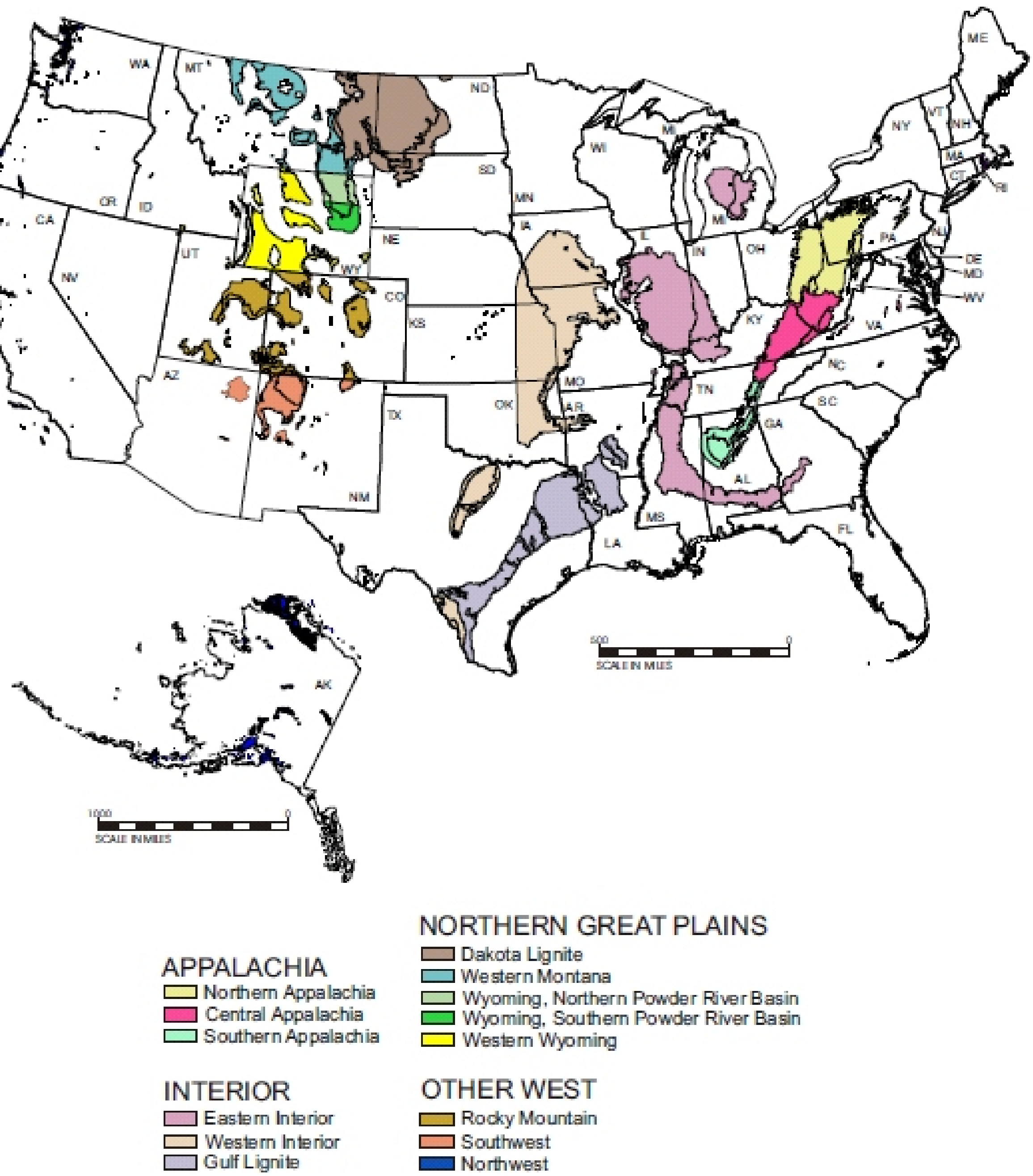
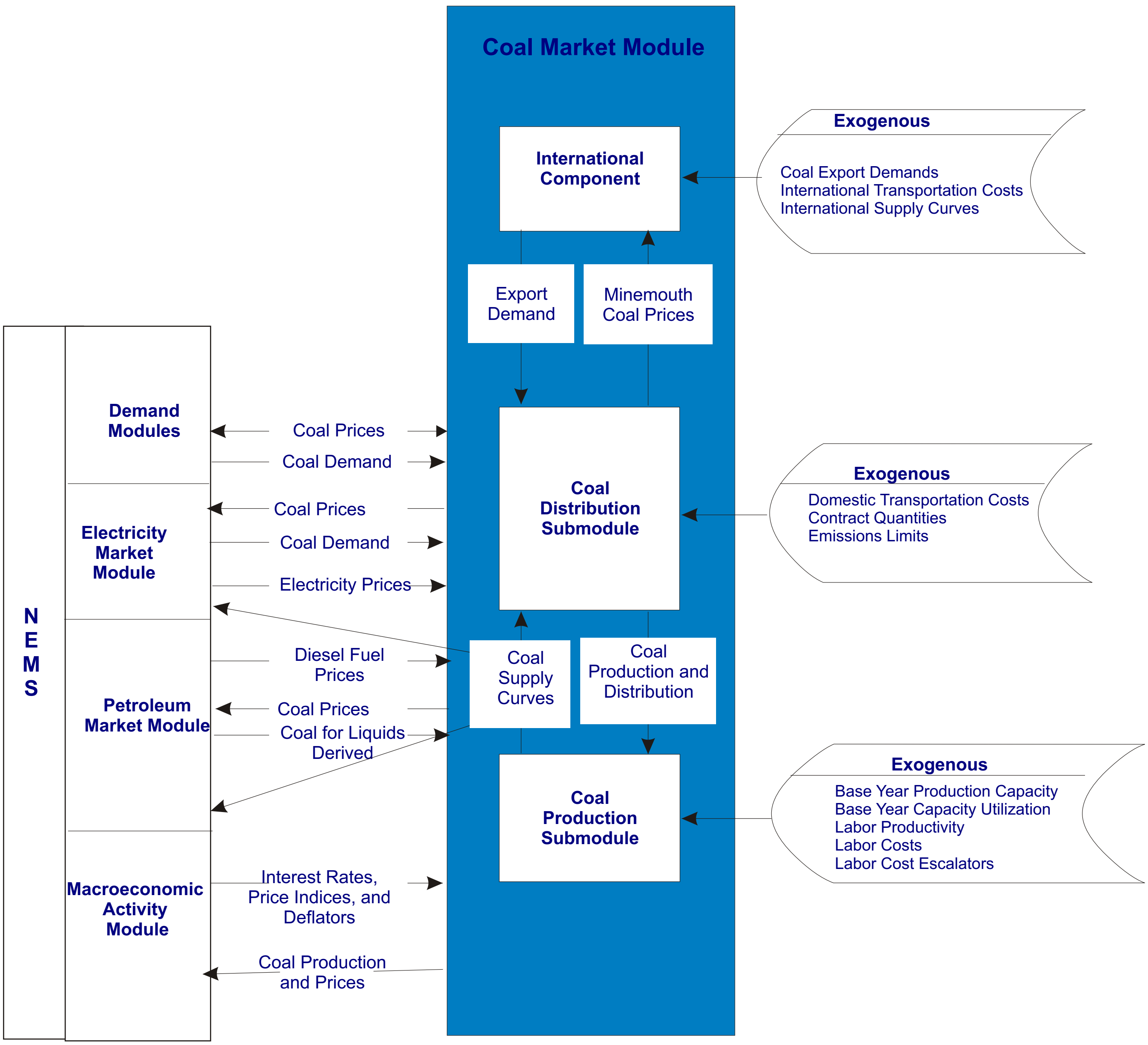


Table 13. Coal Export Component

Coal Export Regions	Coal Import Regions
U.S. East Coast	U.S. East Coast
U.S. Gulf Coast	U.S. Gulf Coast
U.S. Southwest and West	U.S. Northern Interior
U.S. Northern Interior	U.S. Noncontiguous
U.S. Noncontiguous	Eastern Canada
Australia	Interior Canada
Western Canada	Scandinavia
Interior Canada	United Kingdom and Ireland
Southern Africa	Germany and Austria
Poland	Other Northwestern Europe
Eurasia-exports to Europe	Iberia
Eurasia-exports to Asia	Italy
China	Mediterranean and Eastern Europe
Colombia	Mexico
Indonesia	South America
Venezuela	Japan
Vietnam	East Asia
	China and Hong Kong
	ASEAN (Association of Southeast Asian Nations)
	India and South Asia

Coal Market Module

Figure 20. Coal Market Module Structure



Appendix

Appendix Bibliography

The National Energy Modeling System is documented in a series of model documentation reports, available on the EIA Web site at http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model documentation or by contacting the National Energy Information Center (202/586-8800).

Energy Information Administration, *Integrating Module of the National Energy Modeling System: Model Documentation* DOE/EIA-M057(2009) (Washington, DC, May 2009).

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DOE/EIA-M062(2011)

Model Documentation

Natural Gas Transmission and Distribution Module of the National Energy Modeling System

February 2012

Office of Petroleum, Gas, and Biofuels Analysis
U.S. Energy Information Administration
U.S. Department of Energy
Washington, DC 20585

Contact Information

The Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System is developed and maintained by the U.S. Energy Information Administration (EIA), Office of Petroleum, Gas, and Biofuels Analysis. General questions about the use of the model can be addressed to Michael Schaal (202) 586-5590, Director of the Office of Petroleum, Gas, and Biofuels Analysis. Specific questions concerning the NGTDM may be addressed to:

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This report documents the archived version of the NGTDM that was used to produce the natural gas forecasts presented in the *Annual Energy Outlook 2011*, (DOE/EIA-0383(2011). The purpose of this report is to provide a reference document for model analysts, users, and the public that defines the objectives of the model, describes its basic approach, and provides detail on the methodology employed.

The model documentation is updated annually to reflect significant model methodology and software changes that take place as the model develops. The next version of the documentation is planned to be released in the first quarter of 2012.

Update Information

This edition of the model documentation of the Natural Gas Transmission and Distribution Module (NGTDM) reflects changes made to the module over the past year for the *Annual Energy Outlook 2011*. Aside from general data and parameter updates, the notable changes include the following:

- Reestimated equations for distributor and pipeline tariffs.

- Updated coalbed and shale undiscovered resource assumptions in Canada.

- Moved representation of conventional and tight natural gas production in Western Canada from the Oil and Gas Supply Module to the NGTDM.

Contents

Tables

Figures

Abbreviations and Acronyms

AEO	Annual Energy Outlook
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
BTU	British Thermal Unit
DTS	Distributor Tariff Submodule
EMM	Electricity Market Module
GAMS	Gas Analysis Modeling System
IFFS	Integrated Future Forecasting System
ITS	Interstate Transmission Submodule
MEFS	Mid-term Energy Forecasting System
MMBTU	Million British thermal units
Mcf	Thousand cubic feet
MMcf	Million cubic feet
MMcfd	Million cubic feet per day
MMBBL	Million barrels
NEMS	National Energy Modeling System
NGA	Natural Gas Annual
NGM	Natural Gas Monthly
NGTDM	Natural Gas Transmission and Distribution Module
OGSM	Oil and Gas Supply Module
PIES	Project Independence Evaluation System
PMM	Petroleum Market Module
PTS	Pipeline Tariff Submodule
STEO	Short-Term Energy Outlook
Tcf	Trillion cubic feet
WCSB	Western Canadian Sedimentary Basin

1. Background/Overview

The Natural Gas Transmission and Distribution Module (NGTDM) is the component of the National Energy Modeling System (NEMS) that is used to represent the U.S. domestic natural gas transmission and distribution system. NEMS was developed by the former Office of Integrated Analysis and Forecasting of the U.S. Energy Information Administration (EIA) and is the third in a series of computer-based, midterm energy modeling systems used since 1974 by the EIA and its predecessor, the Federal Energy Administration, to analyze and project U.S. domestic energy-economy markets. From 1982 through 1993, the Intermediate Future Forecasting System (IFFS) was used by the EIA for its integrated analyses. Prior to 1982, the Midterm Energy Forecasting System (MEFS), an extension of the simpler Project Independence Evaluation System (PIES), was employed. NEMS was developed to enhance and update EIA's modeling capability. Greater structural detail in NEMS permits the analysis of a broader range of energy issues. While NEMS was initially developed in 1992 the model is updated each year, from simple historical data updates to complete replacements of submodules.

The time horizon of NEMS is the midterm period that extends approximately 25 years to year 2035. In order to represent the regional differences in energy markets, the component modules of NEMS function at regional levels appropriate for the markets represented, with subsequent aggregation/disaggregation to the Census Division level for reporting purposes. The projections in NEMS are developed assuming that energy markets are in equilibrium[1] using a recursive price adjustment mechanism.[2]. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for the economic competition between the various fuels and sources. NEMS is organized and implemented as a modular system.[3] The NEMS modules represent each of the fuel supply markets, conversion sectors (e.g., refineries and power generation), and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. A routine was also added to the system that simulates a carbon emissions cap and trade system with annual fees to limit carbon emissions from energy-related fuel combustion. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, Census Division, and end-use sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production activity, and international petroleum supply availability.

The integrating routine of NEMS controls the execution of each of the component modules. The modular design provides the capability to execute modules individually, thus allowing independent analysis with, as well as development of, individual modules. This modularity allows the use of the methodology and level of detail most appropriate for each energy sector. Each forecasting year, NEMS solves by iteratively calling each module in sequence (once in each NEMS iteration) until the delivered prices and quantities of each fuel in each region have

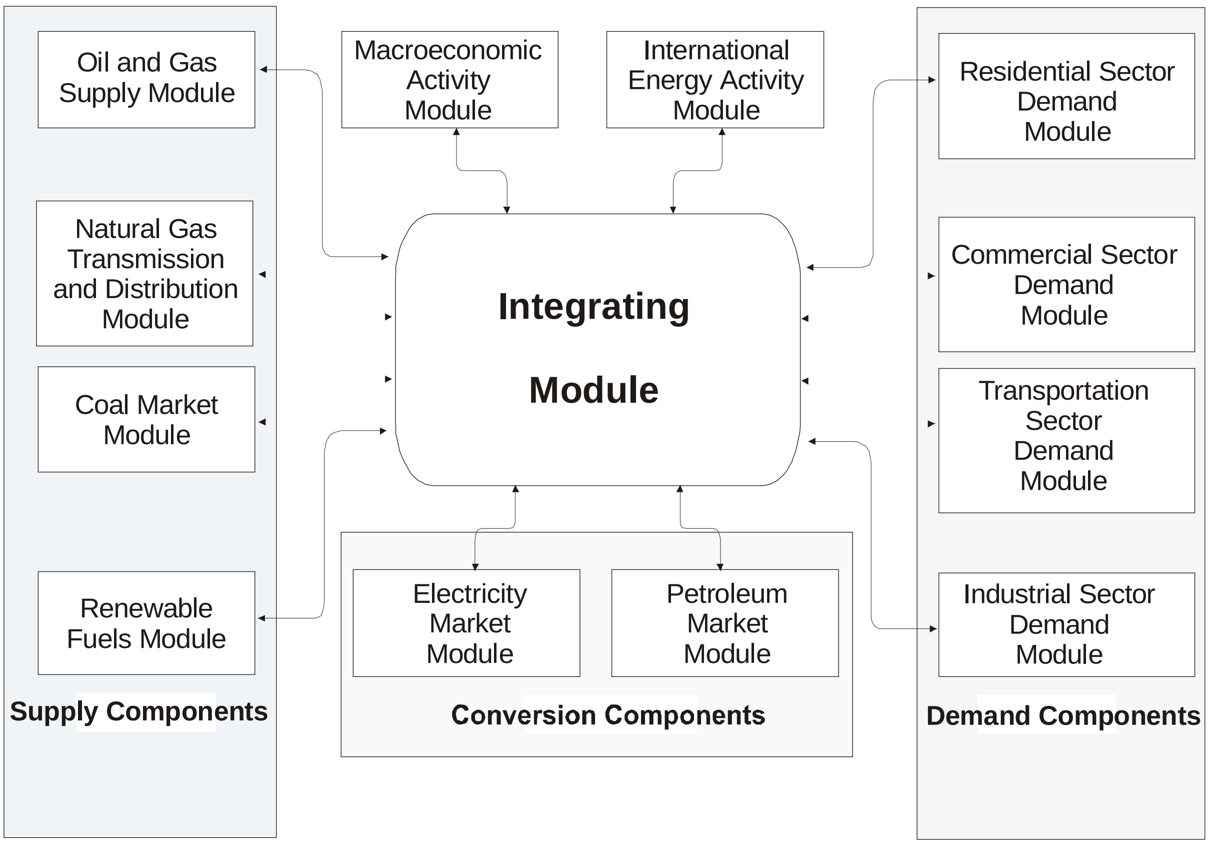
[1]Markets are said to be in equilibrium when the quantities demanded equal the quantities supplied at the same price; that is, at a price that sellers are willing to provide the commodity and consumers are willing to purchase the commodity.

[2]The central theme of the approach used is that supply and demand imbalances will eventually be rectified through an adjustment in prices that eliminates excess supply or demand.

[3]The NEMS is composed of 13 modules including a system integration routine.

converged within tolerance between the various modules, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Module solutions are reported annually through the midterm horizon. A schematic of the NEMS is provided in **Figure 1-1**, while a list of the associated model documentation reports is in Appendix C, including a report providing an overview of the whole system.

Figure 1-1. Schematic of the National Energy Modeling System



NGTDM Overview

The NGTDM module within the NEMS represents the transmission, distribution, and pricing of natural gas. Based on information received from other NEMS modules, the NGTDM also includes representations of the end-use demand for natural gas, the production of domestic natural gas, and the availability of natural gas traded on the international market. The NGTDM links natural gas suppliers (including importers) and consumers in the lower 48 States and across the Mexican and Canadian borders via a natural gas transmission and distribution network, while determining the flow of natural gas and the regional market clearing prices between suppliers and end-users. For two seasons of each forecast year, the NGTDM determines the production, flows, and prices of natural gas within an aggregate representation of the U.S./Canadian pipeline network, connecting domestic and foreign supply regions with 12 U.S. and 2 Canadian demand regions. Since the NEMS operates on an annual (not a seasonal) basis, NGTDM results are generally passed to other NEMS modules as annual totals or quantity-weighted annual averages. Since the Electricity Market Module has a seasonal component, peak and off-peak[4] prices are also provided for natural gas to electric generators.

Natural gas pricing and flow patterns are derived by obtaining a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The methodology employed allows for the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of primary pipeline and storage capacity expansion requirements. Key components of interstate pipeline tariffs are projected, along with distributor tariffs.

The lower-48 demand regions represented are the 12 NGTDM regions (**Figure 1-2**). These regions are an extension of the 9 Census Divisions, with Census Division 5 split into South Atlantic and Florida, Census Division 8 split into Mountain and Arizona/New Mexico, Census Division 9 split into California and Pacific, and Alaska and Hawaii handled independently. Within the U.S. regions, consumption is represented for five end-use sectors: residential, commercial, industrial, electric generation, and transportation (or natural gas vehicles), with the industrial and electric generator sectors further distinguished by core and noncore segments. One or more domestic supply region is represented in each of the 12 NGTDM regions. Canadian supply and demand are represented by two interconnected regions -- East Canada and West Canada -- which connect to the lower 48 regions via seven border crossing nodes. The demarcation of East and West Canada is at the Manitoba/Ontario border. In addition, the model accounts for the potential construction of a pipeline from Alaska to Alberta and one from the MacKenzie Delta to Alberta, if market prices are high enough to make the projects economic. The representation of the natural gas market in Canada is much less detailed than for the United States since the primary focus of the model is on the domestic U.S. market. Potential liquefied natural gas (LNG) imports into North America are modeled for each of the coastal regions represented in the model, including seven regions in the United States, a potential import point in the Bahamas, potential import points in eastern and western Canada, and in western Mexico (if destined for the United States).[5] Any LNG facilities in existence or under construction are represented in the model. However, the model does not project the construction of any additional facilities. Finally, LNG exports from Alaska's Nikiski plant are included, as well as three import/export border crossings at the Mexican border.

The module consists of three major components: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS). The ITS is the integrating submodule of the NGTDM. It simulates the natural gas price determination process by bringing together all major economic factors that influence regional natural gas trade in the United States, including pipeline and storage capacity expansion decisions. The Pipeline Tariff Submodule (PTS) generates a representation of tariffs for interstate transportation and storage services, both existing and expansions. The Distributor Tariff Submodule (DTS) generates markups for distribution services provided by local distribution companies and for

[4]The peak period covers the period from December through March; the off-peak period covers the remaining months.
[5]The LNG imports into Mexico to serve the Mexico market are set exogenously.

transmission services provided by intrastate pipeline companies. The modeling techniques employed are a heuristic/iterative process for the ITS, an accounting algorithm for the PTS, and a series of historically based and econometrically based equations for the DTS.

Figure 1-2. Natural Gas Transmission and Distribution (NGTDM) Regions

NGTDM Objectives

The purpose of the NGTDM is to derive natural gas delivered and wellhead prices, as well as flow patterns for movements of natural gas through the regional interstate network. Although the NEMS operates on an annual basis, the NGTDM was designed to be a two-season model, to better represent important features of the natural gas market. The prices and flow patterns are derived by obtaining a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The representations of the key features of the transmission and distribution network are the focus of the various components of the NGTDM. These key modeling objectives/capabilities include:

- Represent interregional flows of gas and pipeline capacity constraints
- Represent regional and import supplies
- Determine the amount and the location of required additional pipeline and storage capacity on a regional basis, capturing the economic tradeoffs between pipeline and storage capacity additions
- Provide a peak/off-peak, or seasonal analysis capability
- Represent transmission and distribution service pricing

Overview of the Documentation Report

The archived version of the NGTDM that was used to produce the natural gas forecasts used in support of the *Annual Energy Outlook 2011*, DOE/EIA-0383(2011) is documented in this report. The purpose of this report is to provide a reference document for model analysts, users, and the public that defines the objectives of the model, describes its basic design, provides detail on the methodology employed, and describes the model inputs, outputs, and key assumptions. It is intended to fulfill the legal obligation of the EIA to provide adequate documentation in support of its models (Public Law 94-385, Section 57.b.2). Subsequent chapters of this report provide:

- A description of the interface between the NEMS and the NGTDM and the representation of demand and supply used in the module (Chapter 2)
- An overview of the solution methodology of the NGTDM (Chapter 3)
- The solution methodology for the Interstate Transmission Submodule (Chapter 4)
- The solution methodology for the Distributor Tariff Submodule (Chapter 5)
- The solution methodology for the Pipeline Tariff Submodule (Chapter 6)
- A description of module assumptions, inputs, and outputs (Chapter 7).

The archived version of the model is available through the National Energy Information Center (202-586-8800, infoctr@eia.doe.gov) and is identified as NEMS2011 (part of the National Energy Modeling System archive package as archived for the Annual Energy Outlook 2011, DOE/EIA-0383(2011)).

The document includes a number of appendices to support the material presented in the main body of the report. Appendix A presents the module abstract. Appendix B lists the major references used in developing the NGTDM. Appendix C lists the various NEMS Model Documentation Reports for the various modules that are mentioned throughout the NGTDM documentation. A mapping of equations presented in the documentation to the relevant subroutine in the code is provided in Appendix D. Appendix E provides a mapping between the variables that are assigned values through READ statements in the module and the data input files that are read. The input files contain detailed descriptions of the input data, including variable names, definitions, sources, units and derivations.[6] Appendix F documents the

[6]The NGTDM data files are available upon request by contacting Joe Benneche at Joseph.Benneche@eia.doe.gov or (202) 586-6132. Alternatively an archived version of the NEMS model (source code and data files) can be downloaded from ftp://ftp.eia.doe.gov/pub/forecasts/aeo.

derivation of all empirical estimations used in the NGTDM. Variable cross-reference tables are provided in Appendix G. Finally, Appendix H contains a description of the algorithm used to project new coal-to-gas plants and the pipeline quality gas produced.

2. Demand and Supply Representation

This chapter describes how supply and demand are represented within the NGTDM and the basic role that the Natural Gas Transmission and Distribution Module (NGTDM) fulfills in the NEMS. First, a general description of the NEMS is provided, along with an overview of the NGTDM. Second, the data passed to and from the NGTDM and other NEMS modules is described along with the methodology used within the NGTDM to transform the input values prior to their use in the model. The natural gas demand representation used in the module is described, followed by a section on the natural gas supply interface and representation, and concluding with a section on the representation of demand and supply in Alaska.

A Brief Overview of NEMS and the NGTDM

The NEMS represents all of the major fuel markets (crude oil and petroleum products, natural gas, coal, electricity, and imported energy) and iteratively solves for an annual supply/demand balance for each of the nine Census Divisions, accounting for the price responsiveness in both energy production and end-use demand, and for the interfuel substitution possibilities. NEMS solves for an equilibrium in each forecast year by iteratively operating a series of fuel supply and demand modules to compute the end-use prices and consumption of the fuels represented, effectively finding the intersection of the theoretical supply and demand curves reflected in these modules.[7] The end-use demand modules (for the residential, commercial, industrial, and transportation sectors) are detailed representations of the important factors driving energy consumption in each of these sectors. Using the delivered prices of each fuel, computed by the supply modules, the demand modules evaluate the consumption of each fuel, taking into consideration the interfuel substitution possibilities, the existing stock of fuel and fuel conversion burning equipment, and the level of economic activity. Conversely, the fuel conversion and supply modules determine the end-use prices needed in order to supply the amount of fuel demanded by the customers, as determined by the demand modules. Each supply module considers the factors relevant to that particular fuel, for example: the resource base for oil and gas, the transportation costs for coal, or the refinery configurations for petroleum products. Electric generators and refineries are both suppliers and consumers of energy.

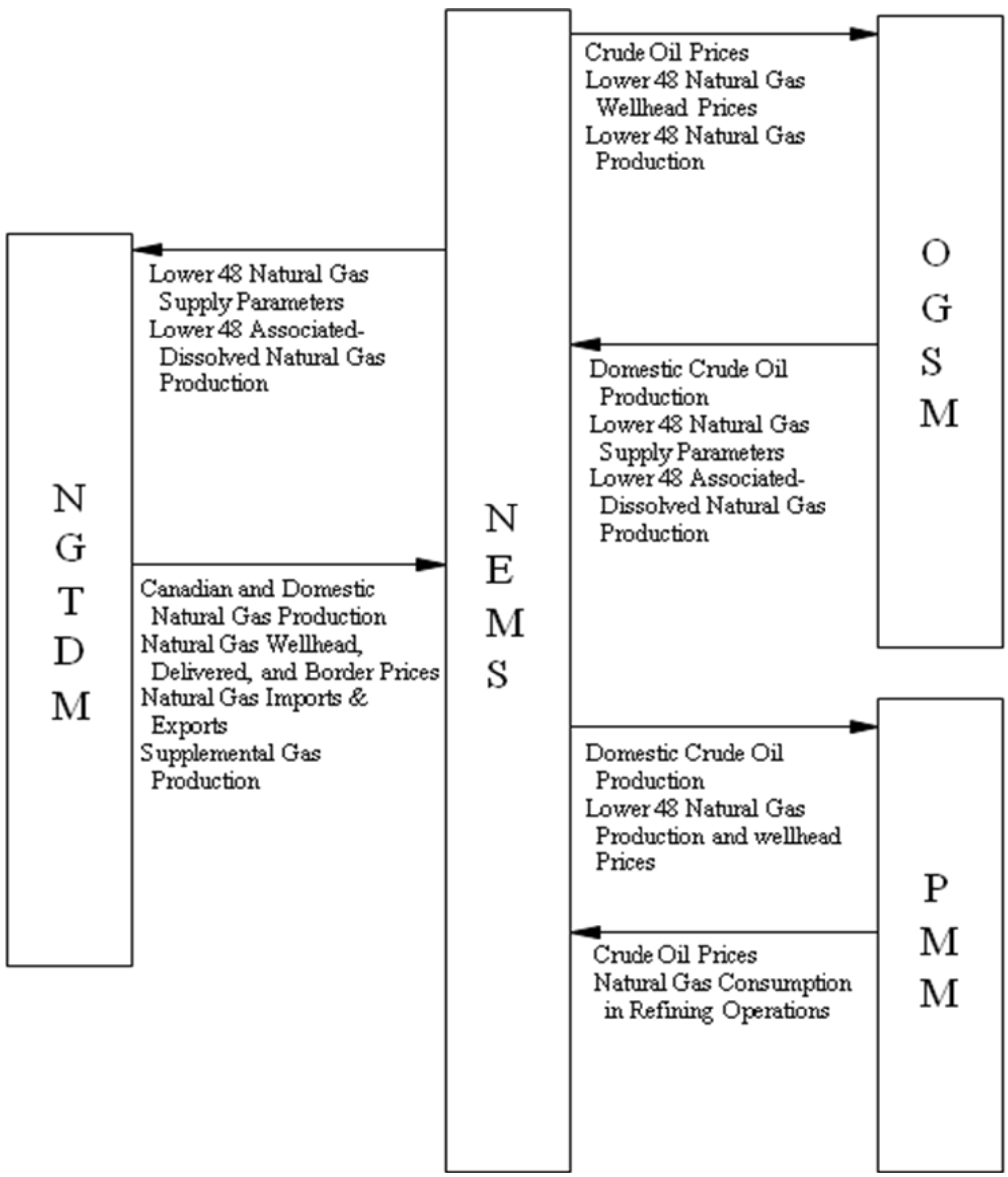
Within the NEMS system, the NGTDM provides the interface for natural gas between the Oil and Gas Supply Module (OGSM) and the demand modules in NEMS, including the Electricity Market Module (EMM). Since the other modules provide little, if any, information on markets outside of the United States, the NGTDM uses supply curves for liquefied natural gas (LNG) imports based on output results from EIA's separate International Natural Gas Model (INGM) and includes a simple representation of natural gas markets in Canada and Mexico in order to project LNG and pipeline import levels into the United States. The NGTDM estimates the price and flow of dry natural gas supplied internationally from the contiguous U.S. border[8] or

[7]A more detailed description of the NEMS system, including the convergence algorithm used, can be found in "Integrating Module of the National Energy Modeling System: Model Documentation 2010." DOE/EIA-M057(2010), May 2010 or "The National Energy Modeling System: An Overview 2009," DOE/EIA-0581(2009), October 2009.

[8]Natural gas exports are also accounted for within the model.

domestically from the wellhead (and indirectly from natural gas processing plants) to the domestic end-user. In so doing, the NGTDM models the markets for the transmission (pipeline companies) and distribution (local distribution companies) of natural gas in the contiguous United States.[9] The primary data flows between the NGTDM and the other oil and gas modules in NEMS, the Petroleum Market Module (PMM) and the OGSM are depicted in **Figure 2-1**.

Figure 2-1. Primary Data Flows between Oil and Gas Modules of NEMS



[9]Because of the distinct separation in the natural gas market between Alaska, Hawaii, and the contiguous United States, natural gas consumption in, and the associated supplies from, Alaska and Hawaii are modeled separately from the contiguous United States within the NGTDM.

In each NEMS iteration, the demand modules in NEMS provide the level of natural gas that would be consumed at the burner-tip in each region by the represented sector at the delivered price set by the NGTDM in the previous NEMS iteration. At the beginning of each forecast year during a model run, the OGSM provides an expected annual level of natural gas produced at the wellhead in each region represented, given the oil and gas wellhead prices from the previous forecast year. (Some supply sources (e.g., Canada) are modeled directly in the NGTDM.) The NGTDM uses this information to build "short-term" (annual or seasonal) supply and demand curves to approximate the supply or demand response to price. Given these short-term demand and supply curves, the NGTDM solves for the delivered, wellhead, and border prices that represent a natural gas market equilibrium, while accounting for the costs and market for transmission and distribution services (including its physical and regulatory constraints).[10] These solution prices, and associated production levels, are in turn passed to the OGSM and the demand modules, including the EMM, as primary input variables for the next NEMS iteration and/or forecast year. Most of the calculations within OGSM are performed only once each NEMS iteration, after the NEMS has converged to an equilibrium solution. Information from OGSM is passed as needed to the NGTDM to solve for the following forecast year.

The NGTDM is composed of three primary components or submodules: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS). The ITS is the central module of the NGTDM, since it is used to derive network flows and prices of natural gas in conjunction with a peak[11] and off-peak natural gas market equilibrium. Conceptually the ITS is a simplified representation of the natural gas transmission and distribution system, structured as a network composed of nodes and arcs. The other two primary components serve as satellite submodules to the ITS, providing parameters which define the tariffs to be charged along each of the interregional, intraregional, intrastate, and distribution segments. Data are also passed back to these satellite submodules from the ITS. Other parameters for defining the natural gas market (such as supply and demand curves) are derived based on information passed primarily from other NEMS modules. However in some cases, supply (e.g., synthetic gas production) and demand components (e.g., pipeline fuel) are modeled exclusively in the NGTDM.

The NGTDM is called once each NEMS iteration, but all submodules are not run for every call. The PTS is executed only once for each forecast year, on the first iteration for each year. The ITS and the DTS are executed once every NEMS iteration. The calling sequence of and the interaction among the NGTDM modules is as follows for each forecast year executed in NEMS:

First Iteration:

a. The PTS determines the revenue requirements associated with interregional / interstate pipeline company transportation and storage services, using a cost based approach, and uses this information and cost of expansion estimates as a basis in establishing fixed rates and volume dependent tariff curves (variable rates) for pipeline and storage usage.

[10]Parameters are provided by OGSM for the construction of supply curves for domestic non-associated natural gas production. The NGTDM establishes a supply curve for conventional Western Canada. The use of demand curves in the NGTDM is an option; the model can also respond to fixed consumption levels.

[11]The peak period covers the period from December through March; the off-peak period covers the remaining months.

b. The ITS establishes supply levels (e.g., for supplemental supplies) and supply curves for production and LNG imports based on information from other modules.

Each Iteration:

a. The DTS sets markups for intrastate transmission and for distribution services using econometric relationships based on historical data, largely driven by changes in consumption levels.
b. The ITS processes consumption levels from NEMS demand modules as required, (e.g., annual consumption levels are disaggregated into peak and off-peak levels) before determining a market equilibrium solution across the two-period NGTDM network.
c. The ITS employs an iterative process to determine a market equilibrium solution which balances the supply and demand for natural gas across a U.S./Canada network, thereby setting prices throughout the system and production and import levels. This operation is performed simultaneously for both the peak and off-peak periods.

Last Iteration:

a. In the process of establishing a network/market equilibrium, the ITS also determines the associated pipeline and storage capacity expansion requirements. These expansion levels are passed to the PTS and are used in the revenue requirements calculation for the next forecast year. One of the inputs to the NGTDM is "planned" pipeline and storage expansions. These are based on reported pending and commenced construction projects and analysts' judgment as to the likelihood of the project's completion. For the first two forecast years, the model does not allow builds beyond these planned expansion levels.
b. Other outputs from NGTDM are passed to report writing routines.

For the historical years (1990 through 2009), a modified version of the above process is followed to calibrate the model to history. Most, but not all, of the model components are known for the historical years. In a few cases, historical levels are available annually, but not for the peak and off-peak periods (e.g., the interstate flow of natural gas and regional wellhead prices). The primary unknowns are pipeline and storage tariffs and market hub prices. When prices are translated from the supply nodes, through the network to the end-user (or city gate) in the historical years, the resulting prices are compared against published values for city gate prices. These differentials (benchmark factors) are carried through and applied during the forecast years as a calibration mechanism. In the most recent historical year (2009) even fewer historical values are known; and the process is adjusted accordingly.

The primary outputs from the NGTDM, which are used as input in other NEMS modules, result from establishing a natural gas market equilibrium solution: delivered prices, wellhead and border crossing prices, non-associated natural gas production, and Canadian and LNG import levels. In addition, the NGTDM provides a forecast of lease and plant fuel consumption, pipeline fuel use, as well as pipeline and distributor tariffs, pipeline and storage capacity expansion, and interregional natural gas flows.

Natural Gas Demand Representation

Natural gas produced within the United States is consumed in lease and plant operations, delivered to consumers, exported internationally, or consumed as pipeline fuel. The consumption of gas as lease, plant, and pipeline fuel is determined within the NGTDM. Gas used in well, field, and lease operations and in natural gas processing plants is set equal to a historically observed percentage of dry gas production.[12] Pipeline fuel use depends on the amount of gas flowing through each region, as described in Chapter 4. The representation in the NGTDM of gas delivered to consumers is described below.

Classification of Natural Gas Consumers

Natural gas that is delivered to consumers is represented within the NEMS at the Census Division level and by five primary end-use sectors: residential, commercial, industrial, transportation, and electric generation.[13] These demands are further distinguished by customer class (core or non-core), reflecting the type of natural gas transmission and distribution service that is assumed to be predominately purchased. A "core" customer is expected to generally require guaranteed or firm service, particularly during peak days/periods during the year. A "non-core" customer is expected to require a lower quality of transmission services (non-firm service) and therefore, consume gas under a less certain and/or less continuous basis. While customers are distinguished by customer class for the purpose of assigning different delivered prices, the NGTDM does not explicitly distinguish firm versus non-firm transmission service. Currently in NEMS, all customers in the transportation, residential, and commercial sectors are classified as core.[14] Within the industrial sector the non-core segment includes the industrial boiler market and refineries; the core makes up the rest. The electric generating units defining each of the two customer classes modeled are as follows: (1) core − gas steam units or gas combined cycle units, (2) non-core − dual-fired turbine units, gas turbine units, or dual-fired steam plants (consuming both natural gas and residual fuel oil).[15]

For any given NEMS iteration and forecast year, the demand modules in NEMS determine the level of natural gas consumption for each region and customer class given the delivered price for the same region, class, and sector, as calculated by the NGTDM in the previous NEMS iteration. Within the NGTDM, each of these consumption levels (and its associated price) is used in

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[12]The regional factors used in calculating lease and plant fuel consumption (PCTLP) are initially based on historical averages (1996 through 2009) and held constant throughout the forecast period. However, a model option allows for these factors to be scaled in the first one or two forecast years so that the resulting national lease and plant fuel consumption will match the annual published values presented in the latest available *Short-Term Energy Outlook* (STEO), DOE/EIA-0202), (Appendix E, STQLPIN). The adjustment attributable to benchmarking to STEO (if selected as an option) is phased out by the year STPHAS_YR (Appendix E). For *AEO2011* these factors were phased out by 2014. A similar adjustment is performed on the factors used in calculating pipeline fuel consumption using STEO values from STQGPTR (Appendix E).

[13]Natural gas burned in the transportation sector is defined as compressed natural gas or liquefied natural gas that is burned in natural gas vehicles; and the electric generation sector includes all electric power generators whose primary business is to sell electricity, or electricity and heat, to the public, including combined heat and power plants, small power producers, and exempt wholesale generators.

[14]The NEMS is structurally able to classify a segment of these sectors as non-core, but currently sets the non-core consumption at zero for the residential, commercial, and transportation sectors.

[15]Currently natural gas prices for the core and non-core segments of the electric generation sector are set to the same average value.

conjunction with an assumed price elasticity as a basis for building an annual demand curve. [The price elasticities are set to zero if fixed consumption levels are to be used.] These curves are used within the NGTDM to minimize the required number of NEMS iterations by approximating the demand response to a different price. In so doing, the price where the implied market equilibrium would be realized can be approximated. Each of these market equilibrium prices is passed to the appropriate demand module during the next NEMS iteration to determine the consumption level that the module would actually forecast at this price. Once the NEMS converges, the difference between the actual consumption, as determined by the NEMS demand modules, and the approximated consumption levels in the NGTDM are insignificant.

For all but the electric sector, the NGTDM disaggregates the annual Census division regional consumption levels into the regional and seasonal representation that the NGTDM requires. The regional representation for the electric generation sector differs from the other NEMS sectors as described below.

Regional/Seasonal Representations of Demand

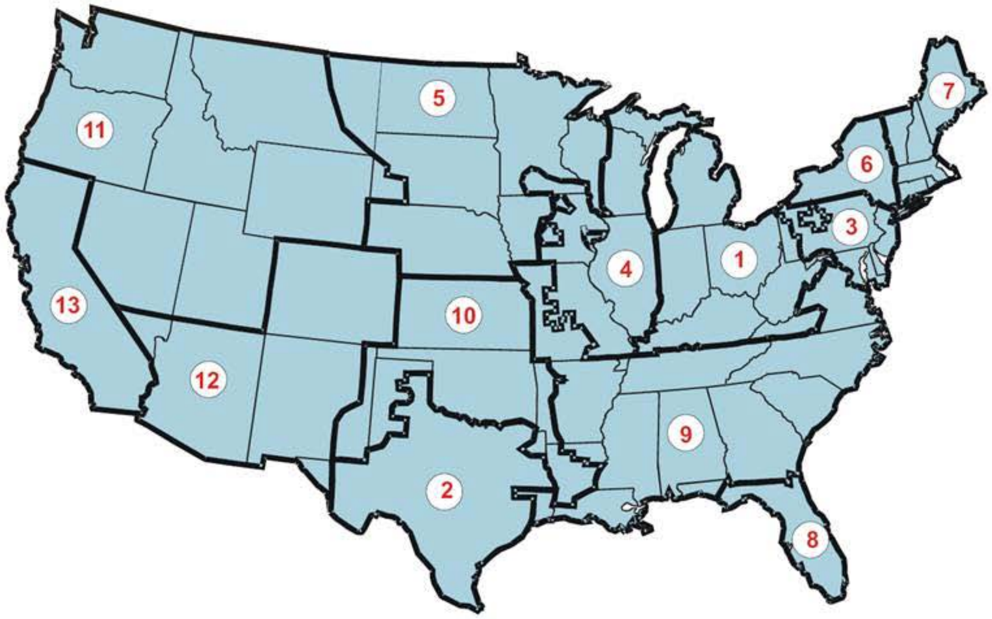
Natural gas consumption levels by all non-electric[16] sectors are provided by the NEMS demand modules for the nine Census divisions, the primary integrating regions represented in the NEMS. Alaska and Hawaii are included within the Pacific Census Division. The EMM represents the electricity generation process for 13 electricity supply regions, the nine North American Electric Reliability Council (NERC) Regions and four selected NERC Subregions (**Figure 2-2**). Within the EMM, the electric generators' consumption of natural gas is disaggregated into subregions that can be aggregated into Census Divisions or into the regions used in the NGTDM.

With the few following exceptions, the regional detail provided at a Census division level is adequate to build a simple network representative of the contiguous U.S. natural gas pipeline system. First, Alaska is not connected to the rest of the Nation by pipeline and is therefore treated separately from the contiguous Pacific Division in the NGTDM. Second, Florida receives its gas from a distinctly different route than the rest of the South Atlantic Division and is therefore isolated. A similar statement applies to Arizona and New Mexico relative to the Mountain Division. Finally, California is split off from the contiguous Pacific Division because of its relative size coupled with its unique energy related regulations. The resulting 12 primary regions represented in the NGTDM are referred to as the "NGTDM Regions" (as shown in **Figure 1-2**).

The regions represented in the EMM do not always align with State borders and generally do not share common borders with the Census divisions or NGTDM regions. Therefore, demand in the electric generation sector is represented in the NGTDM at a seventeen subregional (NGTDM/EMM) level which allows for a reasonable regional mapping between the EMM and the NGTDM regions (**Figure 2-3**). The seventeenth region is Alaska. Within the EMM, the disaggregation into subregions is based on the relative geographic location (and natural gas-fired generation capacity) of the current and proposed electricity generation plants within each region.

[16]The term "non-electric" sectors refer to sectors (other than commercial and industrial combined heat and power generators) that do not produce electricity using natural gas (i.e., the residential, commercial, industrial, and transportation demand sectors).

Figure 2-2. Electricity Market Module (EMM) Regions

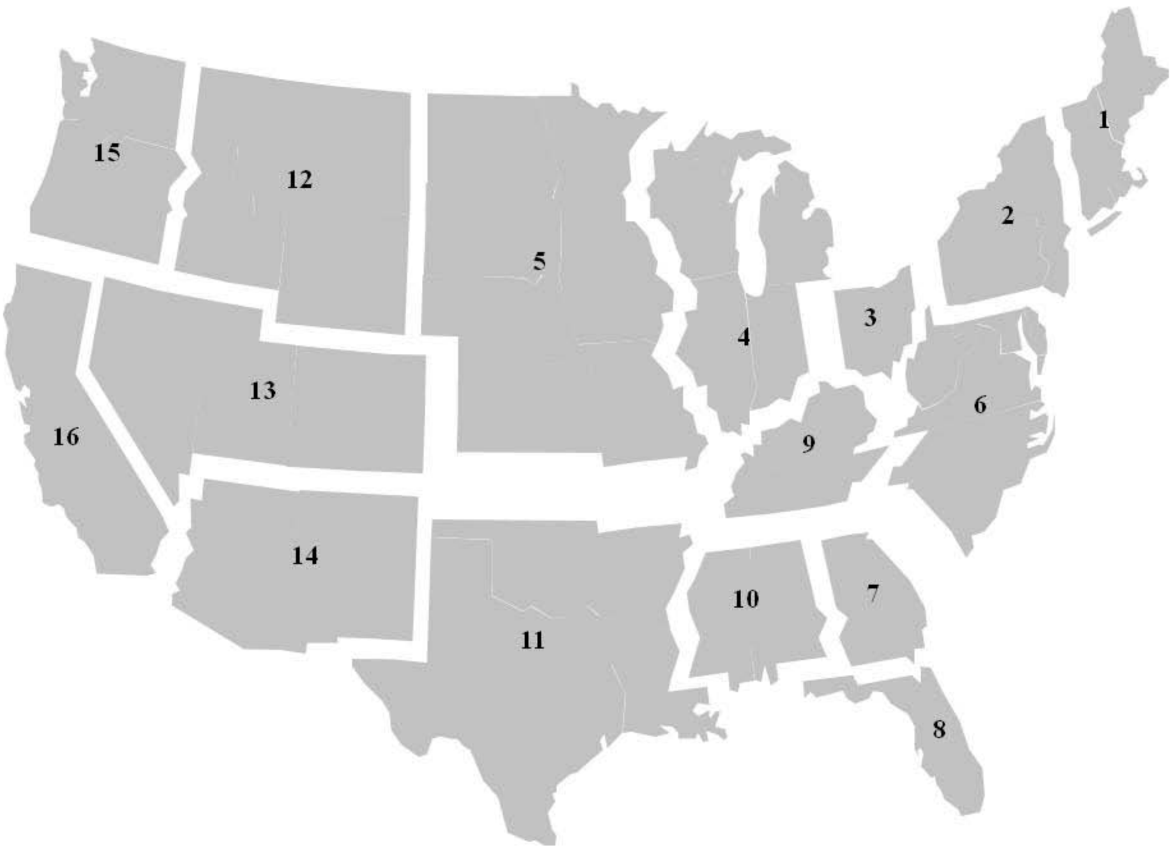


1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New York (NY)
7. New England (NE)
8 Florida Reliability Coordinating Council (FL)
9 Southeastern Electric Reliability Council (SERC)
10 Southwest Power Pool (SPP)
11 Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13 California (CA)

Annual consumption levels for each of the non-electric sectors are disaggregated from the nine Census divisions to the two seasonal periods and the twelve NGTDM regions by applying average historical shares (2001 to 2009) that are held constant throughout the forecast (census − NG_CENSHR, seasons − PKSHR_DMD). For the Pacific Division, natural gas consumption estimates for Alaska are first subtracted to establish a consumption level for just the contiguous Pacific Division before the historical share is applied. The consumption of gas in Hawaii was considered to be negligible and is not handled separately. Within the NGTDM, a relatively simple series of equations (described later in the chapter) was included for approximating the consumption of natural gas by each non-electric sector in Alaska. These estimates, combined with the levels provided by the EMM for consumption by electric generators in Alaska, are used in the calculation of the production of natural gas in Alaska.

Unlike the non-electric sectors, the factors (core − PKSHR_UDMD_F, non-core − PKSHR_UDMD_I) for disaggregating the annual electric generator sector consumption levels (for each NGTDM/EMM region and customer type − core and non-core) into seasons are adjusted over the forecast period. Initially average historical shares (1994 to 2009, except New England − 1997 to 2009) are established as base level shares (core − BASN_PKSHR_UF,

Figure 2-3. NGTDM/EMM Regions



non-core − BASN_PKSHR_UI). The peak period shares are increased each year of the forecast by 0.5 percent (with a corresponding decrease in the off-peak shares) not to exceed 32 percent of the year.[17]

Natural Gas Demand Curves

While the primary analysis of energy demand takes place in the NEMS demand modules, the NGTDM itself directly incorporates price responsive demand curves to speed the overall convergence of NEMS and to improve the quality of the results obtained when the NGTDM is run as a stand-alone model. The NGTDM may also be executed to determine delivered prices for fixed consumption levels (represented by setting the price elasticity of demand in the demand curve equation to zero). The intent is to capture relatively minor movements in consumption levels from the provided base levels in response to price changes, not to accurately mimic the expected response of the NEMS demand modules. The form of the demand curves for the firm transmission service type for each non-electric sector and region is:

[17] The peak period covers 33 percent of the year.

$$NGDMD\_CRVF_{s,r} = BASQTY\_F_{s,r} * (PR / BASPR\_F_{s,r})^{NONU\_ELAS\_F_s} \quad (1)$$

where,

$BASPR\_F_{s,r}$	=	delivered price to core sector s in NGTDM region r in the previous NEMS iteration (1987 dollars per Mcf)
$BASQTY\_F_{s,r}$	=	natural gas quantity which the NEMS demand modules indicate would be consumed at price BASPR_F by core sector s in NGTDM region r (Bcf)
$NONU\_ELAS\_F_s$	=	short-term price elasticity of demand for core sector s (set to zero for *AEO2011* or to represent fixed consumption levels)
PR	=	delivered price at which demand is to be evaluated (1987 dollars per Mcf)
$NGDMD\_CRVF_{s,r}$	=	estimate of the natural gas which would be consumed by core sector s in region r at the price PR (Bcf)
s	=	core sector (1-residential, 2-commercial, 3-industrial, 4-transportation)

The form of the demand curve for the non-electric interruptible transmission service type is identical, with the following variables substituted: NGDMD_CRVI, BASPR_I, BASQTY_I, and NONU_ELAS_I (all set to zero for *AEO2011*). For the electric generation sector the form is identical as well, except there is no sector index and the regions represent the 16 NGTDM/EMM lower 48 regions, not the 12 NGTDM regions. The corresponding set of variables for the core and non-core electric generator demand curves are [NGUDMD_CRVF, BASUPR_F, BASUQTY_F, UTIL_ELAS_F] and [NGUDMD_CRVI, BASUPR_I, BASUQTY_I, UTIL_ELAS_I], respectively. For the *AEO2011* all of the electric generator demand curve elasticities were set to zero.

Domestic Natural Gas Supply Interface and Representation

The primary categories of natural gas supply represented in the NGTDM are non-associated and associated-dissolved gas from onshore and offshore U.S. regions; pipeline imports from Mexico; Eastern, Western (conventional and unconventional), and Arctic Canada production; LNG imports; natural gas production in Alaska (including that which is transported through Canada via pipeline[18]); synthetic natural gas produced from coal and from liquid hydrocarbons; and other supplemental supplies. Outside of Alaska (which is discussed in a later section) the only supply categories from this list that are allowed to vary within the NGTDM in response to a change in the current year's natural gas price are the non-associated gas from onshore and offshore U.S. regions, conventional gas from the Western Canada region, and LNG imports.[19]

[18] Several different options have been proposed for bringing stranded natural gas in Alaska to market (i.e., by pipeline, as LNG, and as liquids). Previously, the LNG option was deemed the least likely and is not considered in this version of the model, but will be reassessed in the future. The Petroleum Market Module forecasts the potential conversion of Alaska natural gas into liquids. The NGTDM allows for the building of a generic pipeline from Alaska into Alberta, although not at the same time as a MacKenzie Valley pipeline. The pipeline is assumed to have first access to the currently proved reserves in Alaska which are assumed to be producible at a relatively low cost given their association with oil production.

[19] Liquefied natural gas imports are set based on the price in the previous NEMS iteration and are effectively "fixed" when the NGTDM determines a natural gas market equilibrium solution; whereas the other two categories are determined as a part of the

The supply levels for the remaining categories are fixed at the beginning of each forecast year (i.e., before market clearing prices are determined), with the exception of associated-dissolved gas (determined in OGSM).[20] With the exception of LNG, the NGTDM applies average historical relationships to convert annual "fixed" supply levels to peak and off-peak values. These factors are held constant throughout the forecast period.

Within the OGSM, natural gas supply activities are modeled for 12 U.S. supply regions (6 onshore, 3 offshore, and 3 Alaskan geographic areas). The six onshore OGSM regions within the contiguous United States, shown in **Figure 2-4**, do not generally share common borders with the NGTDM regions. The NGTDM represents onshore supply for the 17 regions resulting from overlapping the OGSM and NGTDM regions (**Figure 2-5**). A separate component of the NGTDM models the foreign sources of gas that are transported via pipeline from Canada and Mexico. Seven Canadian and three Mexican border crossings demarcate the foreign pipeline interface in the NGTDM. Potential LNG imports are represented at each of the coastal NGTDM regions; however, import volumes will only be projected based on where existing or exogenously set additional regasification capacity exists (e.g., if a facility is under construction or deemed highly likely to be constructed).[21]

"Variable" Dry Natural Gas Production Supply Curve

The two "variable" (or price responsive) natural gas supply categories represented in the model are domestic non-associated production and total production from the Western Canadian Sedimentary Basin (WCSB). Non-associated natural gas is largely defined as gas that is produced from gas wells, and is assumed to vary in response to a change in the natural gas price. Associated-dissolved gas is defined as gas that is produced from oil wells and can be classified as a byproduct in the oil production process. Each domestic supply curve is defined through its associated parameters as being net of lease and plant fuel consumption (i.e., the amount of dry gas available for market after any necessary processing and before being transported via pipeline). For both of these categories, the supply curve represents annual production levels. The methodology for translating this annual form into a seasonal representation is presented in Chapter 4.

The supply curve for regional non-associated lower 48 natural gas production and for WCSB production is built from a price/quantity (P/Q) pair, where quantity is the "expected" production (XQBASE) or the base production level as defined by the product of reserves times the "expected" production-to-reserves ratio (as set in the OGSM) and price is the projected wellhead price (XPBASE, presented below) for the expected production. The basic assumption behind the curve is that the realized market price will increase from the base price if the current year's production levels exceed the expected production; and the opposite will occur if current production is less In addition, it is assumed that the relative price response will likely be greater for a marginal increase in production above the expected production, compared to below. To

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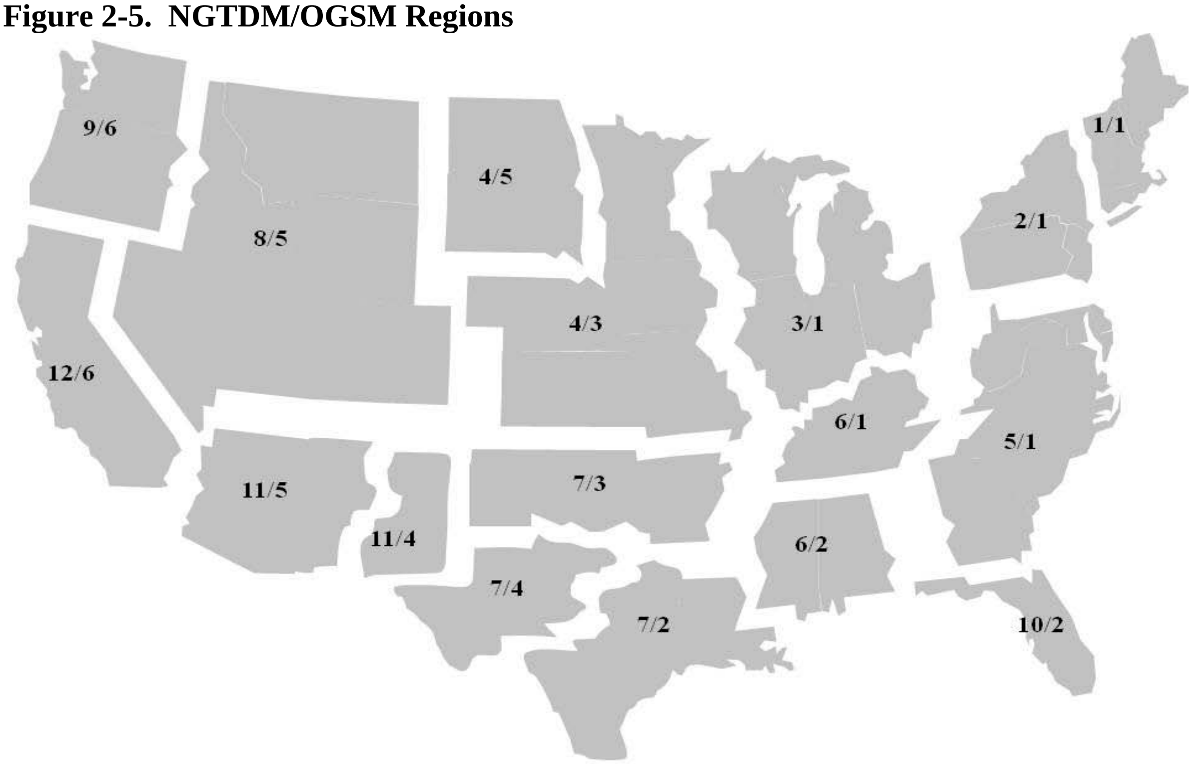
market equilibrium process in the NGTDM.

[20]For programming convenience natural gas produced with oil shales (OGSHALENG) is also added to this category.

[21]Structurally an LNG regasification terminal in the Bahamas would be represented as entering into Florida and be reported as pipeline imports, although modeled as LNG imports. No regasification terminals are considered for Alaska or Hawaii.

Figure 2-4. Oil and Gas Supply Module (OGSM) Regions

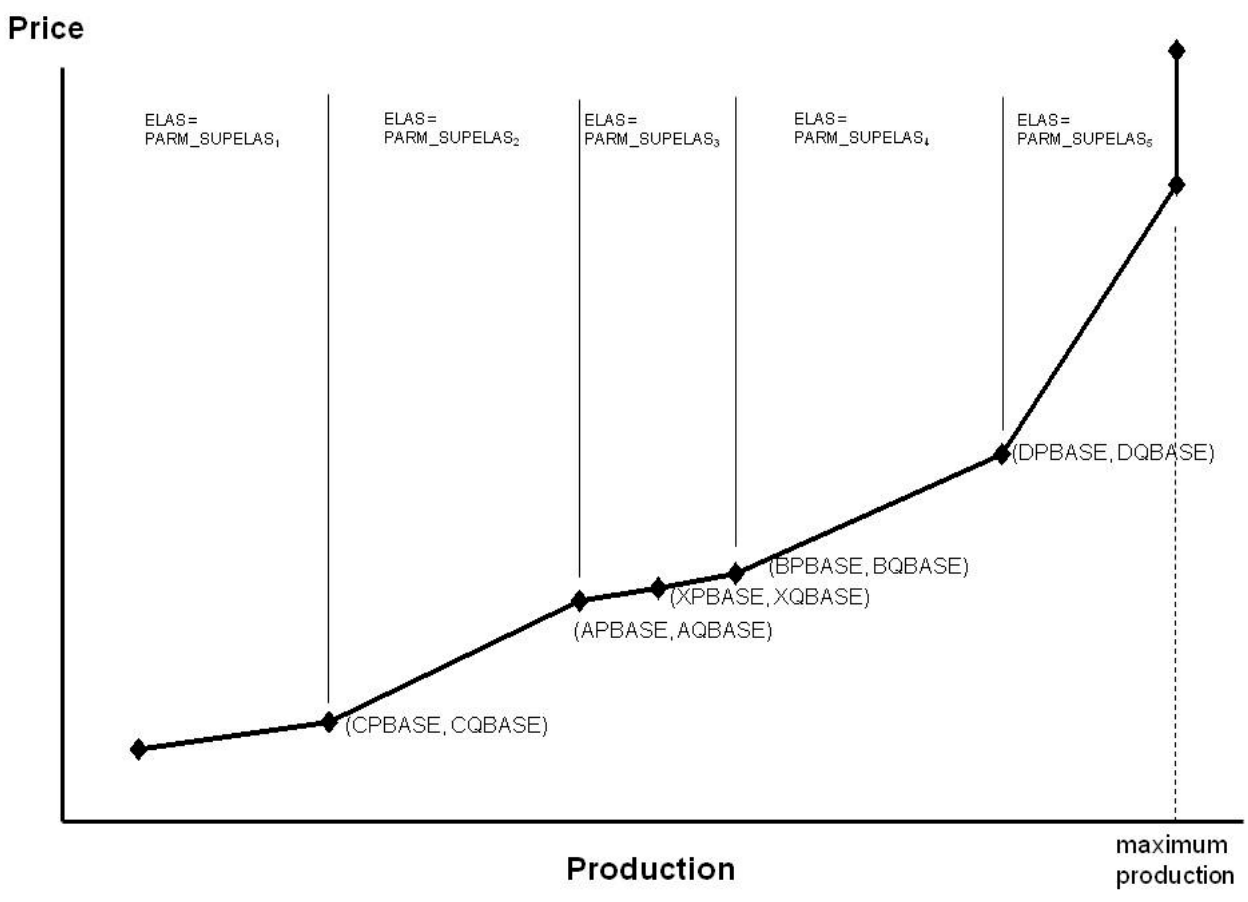
Figure 2-5. NGTDM/OGSM Regions



NGTDM Region Number / OGSM Region Number represent these assumptions, five segments of the curve are defined from the base point. The middle segment is centered around the base point, extends plus or minus a percent (PARM_SUPCRV3, Appendix E) from the base quantity, and if activated, is generally set nearly horizontal (i.e., there is little price response to a quantity change). The next two segments, on either side of the middle, extend more vertically (with a positive slope), and reach plus or minus a percent (PARM_SUPCRV5, Appendix E) beyond the end of the middle segment. The remaining two segments extend the curve above and below even further for the case with relatively large annual production changes, and can be assigned the same or different slopes from their adjacent segments. The slope of the upper segment(s) is generally set greater than or equal to that of the lower segment(s). An illustrative presentation of the supply curve is provided in **Figure 2-6**. The general structure for all five segments of the supply curve, in terms of defining price (NGSUP_PR) as a function of the quantity or production level (QVAR), is:

$$\text{NGSUP\_PR} = \text{PBASE} * (((\frac{1}{\text{ELAS}}) * (\frac{\text{QVAR - QBASE}}{\text{QBASE}})) + 1) \tag{2}$$

Figure 2-6. Generic Supply Curve



A more familiar form of this equation is the definition of elasticity (ξ) as: $\xi = (\Delta Q/Q_o) / (\Delta P/P_o)$, where Δ symbolizes "the change in" and Q_o and P_o represent a base level price/quantity pair.

Each of the five segments is assigned different values for the variables ELAS, PBASE, and QBASE:

Lowest segment:

$$\begin{aligned}\text{PBASE} = \text{CPBASE} = \text{APBASE} * (1 - \\ (\text{PARM\_SUPCRV5}/\text{PARM\_SUPELAS2})\end{aligned} \tag{3}$$

$$\text{QBASE} = \text{CQBASE} = \text{AQBASE} * (1 - \text{PARM\_SUPCRV5}) \tag{4}$$

$$\text{ELAS} = \text{PARM\_SUPELAS1} = 0.40 \tag{5}$$

Lower segment:

$$\begin{aligned}\text{PBASE} = \text{APBASE} = \text{XPBASE} * \\ (1 - (\text{PARM\_SUPCRV3}/\text{PARM\_SUPELAS3}))\end{aligned} \tag{6}$$

$$\text{QBASE} = \text{AQBASE} = \text{XQBASE} * (1 - \text{PARM\_SUPCRV3}) \tag{7}$$

$$\text{ELAS} = \text{PARM\_SUPELAS2} = 0.35 \tag{8}$$

Middle segment:
(in historical years)

$$\text{PBASE} = \text{XPBASE} = \text{historical wellhead price} \tag{9}$$

$$\text{QBASE} = \text{XQBASE} = \text{QSUP}_s/(1 - \text{PERCNT}_n) \tag{10}$$

(in forecast years)

$$\text{PBASE} = \text{XPBASE} = \text{ZWPRLAG}_s \tag{11}$$

$$\text{QBASE} = \text{XQBASE} = \text{ZOGRESNG}_s * \text{ZOGPRRNG}_s \tag{12}$$

$$\text{ELAS} = \text{PARM\_SUPELAS3} = 1.00 \tag{13}$$

Upper segment:

$$\begin{aligned}\text{PBASE} = \text{BPBASE} = \text{XPBASE} * \\ (1 + (\text{PARM\_SUPCRV3}/\text{PARM\_SUPELAS3}))\end{aligned} \tag{14}$$

$$\text{QBASE} = \text{BQBASE} = \text{XQBASE} * (1 + \text{PARM\_SUPCRV3}) \tag{15}$$

$$\text{ELAS} = \text{PARM\_SUPELAS4} = 0.25 \tag{16}$$

Uppermost segment:

$$\begin{aligned} &\text{PBASE} = \text{DPBASE} = \text{BPBASE} * \\ &\qquad (1 + (\text{PARM\_SUPCRV5/PARM\_SUPELAS4})) \end{aligned} \quad (17)$$

$$\text{QBASE} = \text{DQBASE} = \text{BQBASE} * (1 + \text{PARM\_SUPCRV5}) \quad (18)$$

$$\text{ELAS} = \text{PARM\_SUPELAS5} = 0.20 \quad (19)$$

where,

NGSUP_PR	=	Wellhead price (1987$/Mcf)
QVAR	=	Production, including lease & plant (Bcf)
XPBASE	=	Base wellhead price on the supply curve (1987$/Mcf)
XQBASE	=	Base wellhead production on the supply curve (Bcf)
PBASE	=	Base wellhead price on a supply curve segment (1987$/Mcf)
QBASE	=	Base wellhead production on a supply curve segment (Bcf)
AQBASE, BQBASE, CQBASE, DQBASE	=	Production levels defining the supply curve in Figure 2-6 (Bcf)
APBASE, BPBASE, CPBASE, DPBASE	=	Price levels defining the supply curve in Figure 2-6 (Bcf)
ELAS	=	Elasticity (percent change in quantity over percent change in price) (analyst judgment)
PARM_SUPCRV3	=	(defined in preceding paragraph)
PARM_SUPCRV5	=	(defined in preceding paragraph)
PARM_SUPELAS#	=	Elasticity (percentage change in quantity over percentage change in price) on different segments (#) of supply curve
$ZWPRLAG_s$	=	Lagged (last year's) wellhead price for supply source s (1987/Mcf)
$ZOGRESNG_s$	=	Natural gas proved reserves for supply source s at the beginning of the year (Bcf)
$ZOGPRRNG_s$	=	Natural gas production to reserves ratio for supply sources (fraction)
$PERCNT_n$	=	Percent lease and plant
s	=	supply source
n	=	region/node
t	=	year

The parameters above will be set depending on the location of QVAR relative to the base quantity (XQBASE) (i.e., on which segment of the curve that QVAR falls). In the above equation, the QVAR variable includes lease and plant fuel consumption. Since the ITM domestic production quantity (VALUE) represents supply levels net of lease and plant, this value must be adjusted once it is sent to the supply curve function, and before it can be evaluated, to generate a corresponding supply price. The adjustment equation is:

$$QVAR = (VALUE - FIXSUP) / (1.0 - PERCNT_n)$$

$$[\text{where,} \quad FIXSUP = ZOGCCAPPRD_s * (1.0 - PERCNT_n)]$$

where,

QVAR	=	Production, including lease and plant consumption
VALUE	=	Production, net of lease and plant consumption

$PERCNT_n$ = Percent lease and plant consumption in region/node n (set to PCTLP, set to zero for Canada)

$ZOGCCAPPRD_s$ = Coalbed gas production related to the Climate Change Action Plan (from OGSM)[22]

FIXSUP = ZOGCCAPPRD net of lease and plant consumption

s = NGTDM/OGSM supply region

n = region/node

Associated-Dissolved Natural Gas Production

Associated-dissolved natural gas refers to the natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved). The production of associated-dissolved natural gas is tied directly with the production (and price) of crude oil. The OGSM projects the level of associated-dissolved natural gas production and the results are passed to the NGTDM for each iteration and forecast year of the NEMS. Within the NGTDM, associated-dissolved natural gas production is considered "fixed" for a given forecast year and is split into peak and off-peak values based on average (1994-2009) historical shares of total (including non-associated) peak production in the year (PKSHR_PROD).

Supplemental Gas Sources

Existing sources for synthetically produced pipeline-quality, natural gas and other supplemental supplies are assumed to continue to produce at historical levels. While the NGTDM has an algorithm (see Appendix H) to project potential new coal-to-gas plants and their gas production, the annual production of synthetic natural gas from coal at the existing plant is exogenously specified (Appendix E, SNGCOAL), independent of the price of natural gas in the current forecast year. The *AEO2011* forecast assumes that the sole existing plant (the Great Plains Coal Gasification Plant in North Dakota) will continue to operate at recent historical levels indefinitely. Regional forecast values for other supplemental supplies (SNGOTH) are set at historical averages (2003 to 2008) and held constant over the forecast period. Synthetic natural gas is no longer produced from liquid hydrocarbons in the continental United States; although small amounts were produced in Illinois in some historical years. This production level (SNGLIQ) is set to zero for the forecast. The small amount produced in Hawaii is accounted for in the output reports (set to the historical average from 1997 to 2008). If the option is set for the first two forecast years of the model to be calibrated to the *Short Term Energy Outlook (STEO)* forecast, then these three categories of supplemental gas are similarly scaled so that their sum will equal the national annual forecast for total supplemental supplies published in the *STEO* (Appendix E, STOGPRSUP). To guarantee a smooth transition, the scaling factor in the last STEO year can be progressively phased out over the first STPHAS_YR (Appendix E) forecast years of the NGTDM. Regional peak and off-peak supply levels for the three supplemental gas supplies are generated by applying the same average (1990-2009) historical share (PKSHR_SUPLM) of national supplemental supplies in the peak period.

[22]This special production category is not included in the reserves and production-to-reserve ratios calculated in the OGSM, so it was necessary to account for it separately when relevant. It is no longer relevant and is set to zero.

Natural Gas Imports and Exports Interface and Representation

The NGTDM sets the parameters for projecting gas imported through LNG facilities, the parameters and forecast values associated with the Canada gas market, and the projected values for imports from and exports to Mexico.

Canada

A node for east and west Canada is included in the NGTDM equilibration network, as well as seven border crossings. The model includes a representation/accounting of the U.S. border crossing pipeline capacity, east and west seasonal storage transfers, east and west consumption, east and west LNG imports (described in a later section), eastern production, conventional/tight sands production in the west, and coalbed/shale production. The ultimate determination of the import volumes into the United States occurs in the equilibration process of the NGTDM.

Base level consumption of natural gas in Eastern and Western Canada (Appendix E, CN_DMD), including gas used in lease, plant, and pipeline operations, is set exogenously,[23] and ultimately split into seasonal periods using PKSHR_CDMD (Appendix E). The projected level of oil produced from oil sands is also set exogenously to the NGTDM (based on the same source) and varies depending on the world oil price case. Starting in a recent historical year (Appendix E, YDCL_GASREQ), the natural gas required to support the oil sands production is set at an assumed ratio (Appendix E, INIT_GASREQ) of the oil sands production. Over the projection period this ratio is assumed to decline with technological improvements and as other fuel options become viable. The applied ratio in year t is set by multiplying the initially assumed rate by $(t\text{-}YDCL\_GASREQ+1)^{DECL\_GASREQ}$, where DECL_GASREQ is assumed based on anecdotal information (Appendix E). The oil sands related gas consumption under reference case world oil prices is subtracted from the base level total consumption and the remaining volumes are adjusted slightly based on differences in the world oil price in the model run versus the world oil price used in setting the base level consumption, using an assumed elasticity (Appendix E, CONNOL_ELAS). Finally, total consumption is set to this adjusted value plus the calculated gas consumed for oil sands production under the world oil price case selected. Oil sands production is assumed to just occur in Western Canada.

Currently, the NGTDM exogenously sets a forecast of the physical capacity of natural gas pipelines crossing at seven border points from Canada into the United States (excluding any expansion related to the building of an Alaska pipeline). This option can also be used within the model, if border crossing capacity is set endogenously, to establish a minimum pipeline build level (Appendix E, ACTPCAP and PLANPCAP). The model allows for an endogenous setting of annual Canadian pipeline expansion at each Canada/U.S. border crossing point based on the annual growth rate of consumption in the U.S. market it predominately serves. The resulting physical capacity limit is then multiplied by a set of exogenously specified maximum utilization rates for each seasonal period to establish maximum effective capacity limits for these pipelines (Appendix E, PKUTZ and OPUTZ). "Effective capacity" is defined as the maximum seasonal,

[23]se values were based on projections taken from the *International Energy Outlook 2010*.

physically sustainable, capacity of a pipeline times the assumed maximum utilization rate. It should be noted that some of the natural gas on these lines passes through the United States only temporarily before reentering Canada, and therefore is not classified as imports.[24] If a decision is made to construct a pipeline from Alaska (or the MacKenzie Delta) to Alberta, the import pipeline capacity added from the time the decision is made until the pipeline is in service is tracked. This amount is subtracted from the size of the pipeline to Alberta to arrive at an approximation for the amount of additional import capacity that will be needed to bring the Alaska or MacKenzie[25] gas to the United States. This total volume is apportioned to the pipeline capacity at the western import border crossings according to their relative size at the time.

Conventional Western Canada

The vast majority of natural gas produced in Canada currently is from the WCSB. Therefore, a different approach was used in modeling supplies from this region. The model consists of a series of estimated and reserves accounting equations for forecasting conventional (including from tight formations)[26] wells drilled, reserves added, reserve levels, and expected production-to-reserve ratios in the WCSB. Drilling activity, measured as the number of successful natural gas wells drilled, is estimated directly as a function of various market drivers rather than as a function of expected profitability. No distinction is made between wells for exploration and development. Next, an econometrically specified finding rate is applied to the successful wells to determine reserve additions; a reserves accounting procedure yields reserve estimates (beginning of year reserves). Finally an estimated extraction rate determines production potential [production-to-reserves ratio (PRR)].

Wells Determination

The total number of successful conventional natural gas wells drilled in Western Canada each year is forecasted econometrically as a function of the Canadian natural gas wellhead price, remaining undiscovered resources, last year's production-to-reserve ratio, and a proxy term for the drilling cost per well, as follows:

$$\begin{aligned} \mathrm{SUCWELL_t} &= \exp(-1.85639) * \mathrm{CN\_PRC00_t^{1.09939}} * \mathrm{URRCAN_t^{1.57373}} \\ &\quad * \mathrm{CST\_PRXYLAG}^{-0.86063} * \exp(33.6237 * \mathrm{CURPRRCAN_{t\text{-}1}}) \end{aligned} \tag{20}$$

where,

---

[24]A significant amount of natural gas flows into Minnesota from Canada on an annual basis only to be routed back to Canada through Michigan. The levels of gas in this category are specified exogenously (Appendix E, FLOW_THRU_IN) and split into peak and off-peak levels based on average (1990-2009 historically based shares for general Canadian imports (PKSHR_ICAN).

[25]All of the gas from the MacKenzie Delta is not necessarily targeted for the U.S. market directly. Although it is anticipated that the additional supply in the Canadian system will reduce prices and increase the demand for Canadian gas in the United States. The methodology for representing natural gas production in the MacKenzie Delta and the associated pipeline is described in the section titled "Alaskan Natural Gas Routine."

[26]Since current data tend to combine statistics for drilling and production from conventional sources and that from tight gas formations, the model does not distinguish the two at present. The conventional resource estimate was increased by 1.5 percent per year as a rough estimate of the future contribution from resource appreciation and from tight formations until more reliable estimates can be generated. For the rest of the discussion on Canada, the use of the term "conventional" should be assumed to include gas from tight formations.

$SUCWELL_t$ = total conventional successful gas wells completed in Western Canada in year t

CN_PRC00_t = average Western Canada wellhead price per Mcf of natural gas in 2000 US dollars in year t

$URRCAN_t$ = remaining conventional undiscovered recoverable gas resources in the beginning of year t in Western Canada in (Bcf), specified below

CST_PRXYLAG = proxy term to reflect the change in drilling costs per well, projected into the future based on projections for the average lower 48 drilling costs the previous forecast year

CURPRRCAN = expected production-to-reserve ratio from the previous forecast year, specified below

Parameter values and details about the estimation of this equation can be found in Table F11 of Appendix F. The number of wells is restricted to increase by no more than 30 percent annually.

Reserve Additions

The reserve additions algorithm calculates units of gas added to Western Canadian Sedimentary Basin proved reserves. The methodology for conversion of gas resources into proved reserves is a critically important aspect of supply modeling. The actual process through which gas becomes proved reserves is a highly complex one. This section presents a methodology that is representative of the major phases that occur; although, by necessity, it is a simplification from a highly complex reality.

Gas reserve additions are calculated using a finding rate equation. Typical finding rate equations relate reserves added to 1) wells or feet drilled in such a way that reserve additions per well decline as more wells are drilled, and/or 2) remaining resources in such a way that reserve additions per well decline as remaining resources deplete. The reason for this is, all else being equal, the larger prospects typically are drilled first. Consequently, the finding rate can be expected to decline as a region matures, although the rate of decline and the functional forms are a subject of considerable debate. In previous versions of the model the finding rate (reserves added per well) was assumption based, while the current version is econometrically estimated using the following:

$$\begin{aligned} FRCAN_t = {} & \exp\{(1-0.428588)*-25.3204\}*URRCAN_t^{2.13897} * \\ & FRLAG^{0.428588}*URRCAN_{t-1}^{--0.428588*2.13897}] \end{aligned} \qquad (21)$$

where,

$FRCAN_t$ = finding rate in year t (Bcf per well)

FRLAG = finding rate in year t-1 (Bcf per well)

$URRCAN_t$ = remaining conventional gas recoverable resources in year t in Western Canada in (Bcf)

Parameter values and details about the estimation of this equation can be found in Table F12 of Appendix F. Remaining conventional plus tight gas recoverable resources are initialized in 2004 and set each year thereafter as follows:

$$URRCAN_t = RESBASE * (1 + RESTECH)^T - CUMRCAN \tag{22}$$

where,

RESBASE	=	initial recoverable resources in 2004 (set at 92,800 Bcf) [27]
RESTECH	=	assumed rate of increase, primarily due to the contribution from tight gas formations, but also attributable to technological improvement (1.5 percent or 0.015)
$CUMRCAN_t$	=	cumulative reserves added since initial year of 2004 in Bcf
T	=	the forecast year (t) minus the base year of 2004.

Total reserve additions in period t are given by:

$$RESADCAN_t = FRCAN_t * SUCWELL_t \tag{23}$$

where,

$RESADCAN_t$	=	reserve additions in year t, in BCF
$FRCAN_{t-1}$	=	finding rate in the previous year, in BCF per well
$SUCWELL_t$	=	successful gas wells drilled in year t

Total end-of-year proved reserves for each period equal proved reserves from the previous period plus new reserve additions less production.

$$RESBOYCAN_{t+1} = CURRESCAN_t + RESADCAN_t - OGPRDCAN_t \tag{24}$$

where,

$RESBOYCAN_{t+1}$	=	beginning of year reserves for year t+1, in BCF
$CURRESCAN_t$	=	beginning of year reserves for t, in BCF
$RESADCAN_t$	=	reserve additions in year t, in BCF
$OGPRDCAN_t$	=	production in year t, in BCF
t	=	forecast year

When rapid and slow technological progress cases are run, the forecasted values for the number of successful wells and for the expected production-to-reserve ratio for new wells are adjusted accordingly.

Gas Production

Production is commonly modeled using a production-to-reserves ratio. A major advantage to this approach is its transparency. Additionally, the performance of this function in the aggregate is

[27] Source: National Energy Board, "Canada's Conventional Natural Gas Resources: A Status Report," Table 1.1A, April 2004.

consistent with its application on the micro level. The production-to-reserves ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves.

Conventional gas production in the WCSB in year t is determined in the NGTDM through a market equilibrium mechanism using a supply curve based on an expected production level provided by the OGSM. The realized extraction is likely to be different. The expected or normal operating level of production is set as the product of the beginning-of-year reserves (RESBOYCAN) and an expected extraction rate under normal operating conditions. This expected production-to-reserve ratio is estimated as follows:

$$PRRATCAN_t = \frac{e^{-72.1364+0.117911*\ln SUCWELL_t+0.041469*\ln FRCAN_t+0.03437*RLYR}}{1+e^{-72.1364+0.117911*\ln SUCWEL_t+0.041469*\ln FRCAN_t+0.03437*RLYR}} * \left(\frac{PRRATCAN_{t-1}}{1-PRRATCAN_{t-1}}\right)^{0.916835} \quad (25)$$
$$* \, e^{-0.916835*(-72.1364+0.117911*\ln SUCWELL_{t-1}+0.041469*\ln FRCAN_{t-1}+0.03437*(RLYR-1))}$$

where,

$PRRATCAN_t$	=	expected production-to-reserve natural gas ratio in Western Canada for conventional and tight gas
$FRCAN_t$	=	finding rate in year t, in BCF per well
$SUCWELL_t$	=	successful gas wells drilled in year t
RLYR	=	calendar year

Parameter values and details about the estimation of this equation can be found in Table F13 of Appendix F. The resulting production-to-reserve ratio is limited, so as not to increase or decrease more than 5 percent from one year to the next and to stay within the range of 0.7 to 0.12.

The potential or expected production level is used within the NGTDM to build a supply curve for conventional and tight natural gas production in Western Canada. The form of this supply curve is effectively the same as the one used to represent non-associated natural gas production in lower 48 regions. This curve is described later in this chapter, with the exceptions related to Canada noted. A primary difference is that the supply curve for the lower 48 States represents non-associated natural gas production net of lease and plant fuel consumption; whereas the Western Canada supply curve represents total conventional and tight natural gas production inclusive of lease and plant fuel consumption.

Canada Shale and Coalbed

Natural gas produced from other unconventional sources (coal beds and shale) in Western Canada (PRD2) is based on an assumed production profile, with the area under the curve equal to the assumed ultimate recovery (CUR_ULTRES). The production level is initially specified in terms of the forecast year and is set using one functional form before reaching its peak production level and a second functional form after reaching its peak production level. Before reaching peak production, the production levels are assumed to follow a quadratic form, where the level of production is zero in the first year (LSTYR0) and reaches its peak level (PKPRD) in the peak year (PKIYR). The area under the assumed production function equals the assumed technically recoverable resource level (CUR_ULTRES) times the assumed percentage (PERRES) produced before hitting the peak level. After peak production the production path is assumed to decline linearly to the last year (LSTYR) when production is again zero. The two curves meet in the peak year (PKIYR) when both have a value equal to the peak production level (PKPRD). The actual production volumes are adjusted to reflect assumed technological improvement and by a factor that depends on the difference between an assumed price trajectory and the actual price projected in the model. The specifics follow:

Before Peak Production

Assumptions:

production function

$$\mathrm{PRD2} = \mathrm{PARMA}*(\mathrm{PRDIYR}-\mathrm{PKIYR})^2 + \mathrm{PARMB} \tag{26}$$

area under the production function

$$\mathrm{CUR\_ULTRES} * \mathrm{PERRES}$$

$$\int_{\mathrm{LSTYR0}}^{\mathrm{PKIYR}} [\mathrm{PARMA} * (\mathrm{PRDIYR} - \mathrm{PKIYR})^2 + \mathrm{PARMB}]\, d\mathrm{PRDIYR} \tag{27}$$

production in year LSTYR0:

$$0 = \mathrm{PARMA}*(\mathrm{LSTYR0} - \mathrm{PKIYR})^2 + \mathrm{PARMB} \tag{28}$$

production in peak year when PRDIYR = PKIYR

$$\mathrm{PKPRD} = \mathrm{PARMA}*(\mathrm{PKIYR}-\mathrm{PKIYR})^2 + \mathrm{PARMB} = \mathrm{PARMB} \tag{29}$$

Derived from above:

$$\mathrm{PARMA} = \frac{-3}{2} * \frac{\mathrm{CUR\_ULTRES} * \mathrm{PERRES}}{(\mathrm{PKIYR} - \mathrm{LSTYRO})^3} \tag{30}$$

$$\mathrm{PARMB} = -\mathrm{PARMA}*(\mathrm{LSTYRO}-\mathrm{PKIYR})^2 \tag{31}$$

After Peak Production

Assumptions:

production function

$$\mathrm{PRD2} = (\mathrm{PARMC}*\mathrm{PRDIYR}) + \mathrm{PARMD} \tag{32}$$

area under the production function

$$\mathrm{CUR\_ULTRES}*(1-\mathrm{PERRES}) = \int_{\mathrm{PKIYR}}^{\mathrm{LSTYR}} [(\mathrm{PARMC}*\mathrm{PRDIYR}) + \mathrm{PARMD}]\, d\mathrm{PRDIYR} \tag{33}$$

production in peak year when PRDIYR = PKIYR

$$\text{PKPRD} = \text{PARMB} = (\text{PARMC* PKIYR}) + \text{PARMD} \tag{34}$$

production in last year LSTYR

$$0 = (\text{PARMC*LSTYR}) + \text{PARMD} \tag{35}$$

Derived from above:

$$\text{PARMC} = \frac{-\text{PARMB}^2}{2\text{*CUR\_ULTRES*}(1-\text{PERRES})} \tag{36}$$

$$\text{LSTYR} = \frac{2\text{*CUR\_ULTRES*}(1-\text{PERRES})}{\text{PARMB}} + \text{PKIYR} \tag{37}$$

$$\text{PARMD} = -\text{PARMC*LSTYR} \tag{38}$$

given,

$$\text{CUR\_ULTRES} = \text{ULTRES*}(1+\text{RESTECH})^{(\text{MODYR}-\text{RESBASE})}\text{*}(1+\text{RESADJ}) \tag{39}$$

and,

PRD2	=	Unadjusted Canada unconventional gas production (Bcf)
PKPRD	=	Peak production level in year PKIYR
CUR_ULTRES	=	Estimate of ultimate recovery of natural gas from unconventional Canada sources in the current forecast year (Bcf)
ULTRES	=	Estimate of ultimate recovery of natural gas from unconventional Canada sources in the year RESBASE (8,000 Bcf for coalbed in 2008 and 153,000 Bcf for shale in 2011, based on assumed resource levels used in EIA's International Natural Gas Model for the *International Energy Outlook 2010*.
RESBASE	=	Year associated with CUR_ULTRES
RESTECH	=	Technology factor to increase resource estimate over time (1.0)
MODYR	=	Current forecast year
RESADJ	=	Scenario specific resource adjustment factor (default value of 0.0)
PERRES	=	Percent of ultimate resource produced before the peak year of production (0.50, fraction)
PKIYR	=	Assumed peak year of production (2045)
LSTYR0	=	Last year of zero production (2004)
PRDIYR	=	Implied year of production along cumulative production path after price adjustment

The actual production is set by taking the unadjusted unconventional gas production (PRD2) and multiplying it by a price adjustment factor, as well as a technology factor. The price adjustment factor (PRCADJ) is based on the degree to which the actual price in the previous forecast year compares against a prespecified expected price path (exprc), represented by the functional form: exprc = (2.0 + [0.08*(MODYR-2008)]. The price adjustment factor is set to the price in the previous forecast year divided by the expected price, all raised to the 0.1 power. Technology is assumed to progressively increase production by 1 percent per year (TECHGRW) more than it would have been otherwise (e.g., in the fifth forecast year production is increased by 5 percent above what it would have been otherwise). [28] Once the production is established for a given forecast year, the value of PRDIYR is adjusted to reflect the actual production in the previous year and incremented by 1 for the next forecast year.

The remaining forecast elements used in representing the Canada gas market are set exogenously in the NGTDM. When required, such annual forecasts are split into peak and off-peak values using historically based or assumed peak shares that are held constant throughout the forecast. For example, the level of natural gas exports (Appendix E, CANEXP) are currently set exogenously to NEMS, are distinguished by seven Canada/U.S. border crossings, and are split between peak and off-peak periods by applying average (1992 to 2009, Appendix E, PKSHR_ECAN) historical shares to the assumed annual levels. While most Canadian import levels into the U.S. are set endogenously, the flow from Eastern Canada into the East North Central region is secondary to the flow going in the opposite direction and is therefore set exogenously (Appendix E, Q23TO3). "Fixed" supply values for the entire Eastern Canada region are set exogenously (Appendix E, CN_FIXSUP)[29] and split into peak and off-peak periods using PKSHR_PROD (Appendix E).

Mexico

The Mexico model is largely based on exogenously specified assumptions about consumption and production growth rates and LNG import levels. For the most part, natural gas imports from Mexico are set exogenously for each of the three border crossing points with the United States, with the exception of any gas that is imported into Baja, Mexico, in liquid form only to be exported to the United States. Exports to Mexico from the United States are established before the NGTDM equilibrates and represents the required level to balance the assumed consumption in (and exports from) Mexico against domestic production and LNG imports. The supply levels are also largely assumption based, but are set to vary to a degree with changes in the expected wellhead price in the United States. Peak and off-peak values for imports from and exports to Mexico are based on average historical shares (1994 or 1991 to 2009, PKSHR_IMEX and PKSHR_EMEX, respectively).

Mexican gas trade is a complex issue, as a range of non-economic factors will influence, if not determine, future flows of gas between the United States and Mexico. Uncertainty surrounding Mexican/U.S. trade is great enough that not only is the magnitude of flow for any future year in doubt, but also the direction of net flows. Despite the uncertainty and the significant influence of non-economic factors that influence Mexican gas trade with the United States, a methodology to anticipate the path of future Mexican imports from, and exports to, the United States has been incorporated into the NGTDM. This outlook is generated using assumptions regarding regional supply from indigenous production and/or liquefied natural gas (LNG) and regional/sectoral demand growth for natural gas in Mexico.

[28] If a rapid or slow technology case is being run, this value is increased or decreased accordingly.
[29] Eastern Canada is expected to continue to provide only a small share of the total production in Canada and is almost exclusively offshore.

Assumptions for the growth rate of consumption (Appendix E, PEMEX_GFAC, IND_GFAC, ELE_GFAC, RC_GFAC) were based on the projections from the *International Energy Outlook 2010*. Assumptions about base level domestic production (PRD_GFAC) are based in part on the same source and analyst judgment. The production growth rate is adjusted using an additive factor based on the degree to which the average lower 48 wellhead price varies from a set base price, as follows:

$$PRC\_FAC = MIN\left\{\left(\frac{OGWPRNG}{3.66}\right)^{0.03125} - 1, \quad 0.05\right\} \tag{40}$$

where,

PRC_FAC	=	Factor to add to assumed base level production growth rate (PRD_GFAC)
OGWPRNG	=	Lower 48 average natural gas wellhead price in the current forecast year (1987$/Mcf)
3.66	=	Fixed base price, approximately equal to the average lower 48 natural gas wellhead price over the projection period based on *AEO2010* reference case results (1987$/Mcf), [set in the code and converted at $6.14 (2008$/Mcf)]
0.03125	=	An assumed parameter
0.05	=	Assumed minimum price factor

The volumes of LNG imported into Mexico for use in the country are initially set exogenously (Appendix E, MEXLNG). However, these values are scaled back if the projected total volumes available to North America (see below) are not sufficient to accommodate these levels. LNG imports into Baja destined for the U.S. are set endogenously with the LNG import volumes for the rest of North America, as discussed below. Finally, any excess supply in Mexico is assumed to be available for export to the United States, and any shortfall is assumed to be met by imports from the United States. [30]

Liquefied Natural Gas

LNG imports are set at the beginning of each NEMS iteration within the NGTDM by evaluating seasonal supply curves, based on outputs from EIA's International Natural Gas Model (INGM), at associated regasification tailgate prices set in the previous NEMS iteration. LNG exports from the lower 48 States are assumed to be zero for the forecast period. [31] LNG exports to Japan from Alaska are set exogenously by OGSM through Spring of 2013 when the Kenai Peninsula LNG plant's export license will expire. The NGTDM does not assume or project additional LNG exports from Alaska.[32] LNG import levels are established for each region, and period (peak and

[30]A minimum import level from Mexico is set exogenously (DEXP_FRMEX, Appendix E), as well as a maximum decline from historical levels for exports to Mexico (DFAC_TOMEX, Appendix E).

[31]The capability to project LNG exports in the model was not included in the *AEO2011* analysis largely due to resource constraints, which continue to be tight. While a very preliminary analysis was done using the International Natural Gas Model that showed the economic viability of a liquefaction project in the Gulf of Mexico to be questionable under preliminary reference case conditions, a more thorough analysis is warranted.

[32]TransCanada and ExxonMobil filed an open season plan for an Alaska Pipeline Project which includes an option for shipping

off-peak) The basic process is as follows for each NEMS iteration (except for the first step): 1) at the beginning of each forecast year set up LNG supply curves for eastern and western North America for each period (peak and off-peak), 2) using the supply curves and the quantity-weighted average regasification tailgate price from the previous NEMS iteration, determine the amount of LNG available for import into North America, 3) subtract the volumes that are exogenously set and dedicated to the Mexico market (unless they exceed the total), and 4) allocate the remaining amount to the associated LNG terminals using a share based on the regasification capacity, the volumes imported last year, and the relative prices.

The LNG import supply curves are developed off of a base price/quantity pair (Appendix E, LNGPPT, LNGQPT) from a reference case run of the INGM, using the same, or very similar, world oil price assumptions. The quantities equal the sum of the LNG imports into east or west North America in the associated period; and the prices equal the quantity-weighted average tailgate price at the regasification terminals. The mathematical specification of the curve is exactly like the one used for domestic production described earlier in this chapter, except the assumed elasticities are represented with different variables and have different values.[33] This representation represents a first cut at integrating the information from INGM in the domestic projections.[34] The formulation for these LNG supply curves will likely be revised in future NEMS to better capture the market dynamics as represented in the INGM.

Once the North American LNG import volumes are established, the exogenously specified LNG imports into Mexico are subtracted,[35] along with the sum of any assumed minimum level (Appendix E, LNGMIN) for each of the representative terminals in the U.S., Canada, and Baja, Mexico (as shown in **Table 2-1**). The remainder (TOTQ) is shared out to the terminals and then added to the terminal's assumed minimum import level to arrive at the final LNG import level by terminal and season. The shares are initially set as follows and then normalized to total to 1.0:

$$LSHR_{n,r} = \left\{ \frac{QLNGLAG_{n,r} - (LNGMIN_r * SH_{r,n})}{TOTQ_{n,c}} * PERQ + \frac{LNGCAP_r - LNGMIN_r}{TOTCAP_c} * (1 - PERQ) \right\} * \left\{ \frac{PLNG_{n,r}}{AVGPR_{n,c}} \right\}^{BETA} \quad (41)$$

where,

$LSHR_{n,r}$ = Initial share (before normalization) of LNG imports going to terminal r in period n from the east or west coast, fraction

$TOTQ_{n,c}$ = The level of LNG imports in the east or west coast to be shared out for a period n to the associated U.S. regasification regions

gas to Valdez for export as LNG. Previous EIA analysis indicated that the option for a pipeline to the lower 48 States is likely to provide a greater netback to the producers and is therefore a more viable option. This analysis and model assumption will be reviewed in the future.

[33]For LNG the variables are called PARM_LNGxx, instead of PARM_SUPxx and are also traceable using Appendix E.

[34]As first implemented, the resulting LNG import volumes were somewhat erratic, so a five-year moving average was applied to the quantity inputs to smooth out the trajectory and more closely approximate a trend line.

[35]If the total available LNG import levels exceed the assumed LNG imports into Mexico, the volumes into Mexico are adjusted accordingly, not to be set below assumed minimums (Appendix E, MEXLNGMIN).

$QLNGLAG_{n,r}$ = LNG import level last year (Bcf)
$LNGMIN_r$ = Minimum annual LNG import level (Bcf) (Appendix E)
$SH_{r,n}$ = Fraction of LNG imported in period n last year
$LNGCAP_r$ = Beginning of year LNG sendout capacity[36] (Bcf) (Appendix E)
$TOTCAP_c$ = Total LNG sendout capacity on the east or west coast (Bcf)
PERQ = Assumed parameter (0.5)
$PLNG_{n,r}$ = Regasification tailgate price (1987$/Mcf)
$AVGPR_{n,r}$ = Average regasification tailgate price on the east or west coast (1987$/Mcf)
BETA = Assumed parameter (1.2)
r = Regasification terminal number (See Table 2-1)
n = Network or period (peak or off-peak)
c = East or west coast

Table 2-1. LNG Regasification Regions

Number	Regasification Terminal/Region
1	Everett, MA
2	Cove Point, MD
3	Elba Island, GA
4	Lake Charles, LA
5	New England
6	Middle Atlantic
7	South Atlantic
8	Florida/Bahamas

Number	Regasification Regions
9	Alabama/Mississippi
10	Louisiana/Texas
11	California
12	Washington/Oregon
13	Eastern Canada
14	Western Canada
15	Baja into the U.S.
--	--

Source: Office of Integrated Analysis and Forecasting, U.S. Energy Information Administration

Alaska Natural Gas Routine

The NEMS demand modules provide a forecast of natural gas consumption for the total Pacific Census Division, which includes Alaska. Currently natural gas that is produced in Alaska cannot be transported to the lower 48 States via pipeline. Therefore, the production and consumption of natural gas in Alaska is handled separately within the NGTDM from the contiguous States. Annual estimates of contiguous Pacific Division consumption levels are derived within the NGTDM by first estimating Alaska natural gas consumption for all sectors, and then subtracting these from the core market consumption levels in the Pacific Division provided by the NEMS demand modules. The use of natural gas in compressed natural gas vehicles in Alaska is assumed to be negligible or nonexistent. The Electricity Market Module provides a value for

[36]Send-out capacity is the maximum annual volume of gas that can be delivered by a regasification facility into the pipeline.

natural gas consumption in Alaska by electric generators. The series of equations for specifying the consumption of gas by Alaska residential and commercial customers follows:

$$\begin{aligned}AK\_RN_y &= \exp\{-2.677 + (0.888 * \ln(AK\_RN_{y-1})) - (0.185 * \ln(AK\_RN_{y-2})) \\ &\quad + (0.626 * \ln(AK\_POP_y))\}\end{aligned} \tag{42}$$

$$AK\_CN_y = 0.932946 + (0.937471 * AK\_CN_{y-1}) \tag{43}$$

$$\begin{aligned}(res):\ AKQTY\_F_{s=1,y} &= \{e^{(6.983794*(1-0.364042))} * (AKQTY\_F_{s=1,y\text{-}1} * 1000)^{0.364042} * \\ &\quad * AK\_RN_y^{(0.601932*(1-0.364042))}\}/1000.\end{aligned} \tag{44}$$

$$\begin{aligned}(com):AKQTY\_F_{s=2,y} &= \{e^{(9.425307*(1-0.736334))} * (AKQTY\_F_{s=2,y-1} * 1000)^{0.736334} * \\ &\quad AK\_CN_y^{0.205020} * (AK\_CN_{y-1} * 1000)^{(-0.736334*0.205020)}\}/1000.\end{aligned} \tag{45}$$

where,

$AKQTY\_F_{s=1}$	=	consumption of natural gas by residential (s=1) customers in Alaska in year y (MMcf, converted to Bcf, Table F1, Appendix F1)
$AKQTY\_F_{s=2}$	=	consumption of natural gas by commercial (s=2) customers in Alaska in the current forecast year y (MMcf, converted to Bcf, Table F1, Appendix F1)
AK_RN	=	number of residential customers in year y (thousands, Table F1, Appendix F)
AK_CN_y	=	number of commercial customers in year y (thousands, Table F2, Appendix F)
AK_POP	=	exogenously specified projection of the population in Alaska (thousands, Appendix E)

Gas consumption by Alaska industrial customers is set exogenously, as follows:

$$(ind):\ AKQTY\_F_{s=3,y} = AK\_QIND\_S_y \tag{46}$$

where,

$AKQTY\_F_{s=3,y}$	=	consumption of natural gas by industrial customers in year y (s=3), (Bcf)
AK_QIND_S	=	consumption of natural gas by industrial customers in southern Alaska (Bcf), the sum of consumption at the Agrium fertilizer plant (assumed to close in 2007, Appendix E) and at the Kenai LNG liquefaction facility (assumed to close in 2013, Appendix E)
s	=	sector
y	=	year

The production of gas in Alaska is basically set equal to the sum of the volumes consumed and transported out of Alaska, so depends on: 1) whether a pipeline is constructed from Alaska to

Alberta, 2) whether a gas-to-liquids plant is built in Alaska, and 3) consumption in and exports from Alaska. The production of gas related to the Alaska pipeline equals the volumes delivered to Alberta (which depend on assumptions about the pipeline capacity) plus what is consumed for related lease, plant, and pipeline operations (calculated as delivered volume divided by 1 minus the percent used for lease, plant, and pipeline operations). If the Petroleum Market Module (PMM) determines that a gas-to-liquids facility will be built in Alaska, then the natural gas consumed in the process (AKGTL_NGCNS, set in the PMM) is added to production in the north, along with the associated lease and plant fuel consumed. The production volumes related to the pipeline and the GTL plant are summed together ($N.AK_2$ below). Other production in North Alaska that is not related to the pipeline or GTL is largely lease and plant fuel associated with the crude oil extraction processes; whereas gas is produced in the south to satisfy consumption and export requirements. The quantity of lease and plant fuel not related to the pipeline or GTL in Alaska ($N.AK_1$ below) is assigned separately, includes lease and plant fuel used in the north and south, and is added to the other production ($N.AK_2$ below) to arrive at total North Alaska production. The details follow:

$$\begin{aligned}(S.AK):\ AK\_PROD_{r=1} = {} & AK\_CONS\_S + EXPJAP + QALK\_LAP\_S + \\ & QALK\_PIP\_S - AK\_DISCR\end{aligned} \tag{47}$$

$$\begin{aligned}(N.AK_1):\ AK\_PROD_{r=2} = QALK\_LAP\_N = {} & (0.0943884 * QALK\_LAP\_NLAG \\ & + (0.038873 * \textstyle\sum_{s=1}^{3} oOGPRCOAK_{s,y})\end{aligned} \tag{48}$$

$$\begin{aligned}(N.AK_2):\ AK\_PROD_{r=3} = {} & \frac{QAK\_ALB_y}{1. - AK\_PCTLSE_{r=3} - AK\_PCTPLT_{r=3} - AK\_PCTPIP_{r=3}} + \\ & AKGTL\_NGCNS_t + AKGTL\_LAP\end{aligned} \tag{49}$$

where,

$$AK\_CONS\_S = \sum_{s=1}^{4} (AKQTY\_F_s + AKQTY\_I_s) \tag{50}$$

$$QALK\_LAP\_S = 0.0 \qquad \text{(total is assigned to the North)} \tag{51}$$

$$QALK\_PIP\_S = (AK\_CONS\_S + EXPJAP) * AK\_PCTPIP_2 \tag{52}$$

$$AKGTL\_LAP = oAKGTL\_NGCNS_t * (AK\_PCTLSE_3 + AK\_PCTPLT_3) \tag{53}$$

where,

AK_PROD_r	=	dry gas production in Alaska (Bcf)
AK_CONS_S	=	total gas delivered to customers in South Alaska (Bcf)
$AKQTY\_F_s$	=	total gas delivered to core customers in Alaska in sector s (Bcf)
$AKQTY\_I_s$	=	total gas delivered to non-core customers in Alaska in sector s (Bcf)

EXPJAP = quantity of gas liquefied and exported to Japan (from OGSM in Bcf)

QALK_LAP_N = quantity of gas consumed in Alaska for lease and plant operations, excluding that related to the Alaska pipeline and GTL (Bcf)

QALK_LAP_NLAG = quantity of gas consumed for lease and plant operations in the previous year, excluding that related to the pipeline and GTL (Bcf)

$oOGPRCOAK_{s,y}$ = crude oil production in Alaska by sector

$QALK\_PIP_r$ = quantity of gas consumed as pipeline fuel (Bcf)

AK_DISCR = discrepancy, the average (2006-2008) historically based difference in reported supply levels and consumption levels in Alaska (Bcf)

QAK_ALB_t = gas produced on North Slope entering Alberta via pipeline (Bcf)

AK_PCTLSE_r = (for r=1) not used, (for r=2) lease and plant consumption as a percent of gas consumption, (for r=3) lease consumption as a percent of gas production (fraction, Appendix E)

AK_PCTPLT_r = (for r=1 and r=2) not used, (for r=3) plant fuel as a percent of gas production (fraction, Appendix E)

AK_PCTPIP_r = (for r=1) not used, (for r=2) pipeline fuel as a percent of gas consumption, (for r=3) pipeline fuel as a percent of gas production (fraction, Appendix E)

$AKGTL\_NGCNS_t$ = natural gas consumed in a gas-to-liquids plant in the North Slope (from PMM in Bcf)

AKGTL_LAP = lease and plant consumption associated with the gas for a gas-to-liquids plant (Bcf)

s = sectors (1=residential, 2=commercial, 3=industrial, 4=transportation, 5=electric generators)

r = region (1 = south, 2 = north not associated with a pipeline to Alberta or gas-to-liquids process, 3 = north associated with a pipeline to Alberta and/or a gas-to-liquids plant

Lease, plant, and pipeline fuel consumption are calculated as follows. For south Alaska, the calculation of pipeline fuel (QALK_PIP_S) and lease and plant fuel (QALK_LAP_S) are shown above. For the Alaska pipeline, all three components are set to the associated production times the percentage of lease (AK_PCTLSE_3), plant (AK_PCTPLT_3), or pipeline fuel (AK_PCTPIP_3). For the gas-to-liquids process, lease and plant fuel (AKGTL_LAP) is calculated as shown above and pipeline fuel is considered negligible. For the rest of north Alaska, pipeline fuel consumption is assumed to be negligible, while lease and plant fuel not associated with the pipeline or GTL (QALK_LAP_N) is set based on an estimated equation shown previously (Table F10, Appendix F).

Estimates for natural gas wellhead and delivered prices in Alaska are estimated in the NGTDM for proper accounting, but have a very limited impact on the NEMS system. The average Alaska wellhead price (AK_WPRC) over the North and South regions (not accounting for the impact if a pipeline ultimately is connected to Alberta) is set using the following estimated equation:

$$AK\_WPRC_1 = WPRLAG^{0.934077} * oIT\_WOP_{y,1}{}^{(0.280960*(1-0.934077))} \quad (54)$$

where,

AK_WPRC_1 = natural gas wellhead price in Alaska, presuming no pipeline to Alberta (1987$/Mcf) (Table F1, Appendix F)

WPRLAG = AK_WPRC in the previous forecast year ($/Mcf)

$oIT\_WOP_{y,1}$ = world oil price (1987$ per barrel)

The price for natural gas associated with a pipeline to Alberta is exogenously specified ($FR\_PMINWPR_1$, Appendix E) and does not vary by forecast year. The average wellhead price for the State is calculated as the quantity-weighted average of AK_WPRC and $FR\_PMINWPR_1$. Delivered prices in Alaska are set equal to the wellhead price (AK_WPRC) resulting from the equation above plus a fixed, exogenously specified markup (Appendix E -- AK_RM, AK_CM, AK_IN, AK_EM).

Within the model, the commencement of construction of the Alaska to Alberta pipeline is restricted to the years beyond an earliest start date (FR_PMINYR, Appendix E) and can only occur if a pipeline from the MacKenzie Delta to Alberta is not under construction. The same is true for the MacKenzie Delta pipeline relative to construction of the Alaska pipeline. Otherwise, the structural representation of the MacKenzie Delta pipeline is nearly identical to that of the Alaska pipeline, with different numerical values for model parameters. Therefore, the following description applies to both pipelines. Within the model the same variable names are used to specify the supporting data for the two pipelines, with an index of 1 for Alaska and an index of 2 for the MacKenzie Delta pipeline.

The decision to build a pipeline is triggered if the estimated cost to supply the gas to the lower 48 States is lower than an average of the lower 48 average wellhead price over the planning period of FR_PPLNYR (Appendix E) years.[37] Construction is assumed to take FR_PCNSYR (Appendix E) years. Initial pipeline capacity is assumed to accommodate a throughput delivered to Alberta of FR_PVOL (Appendix E). The first year of operation, the volume is assumed to be half of its ultimate throughput. If the trigger price exceeds the minimum price by FR_PADDTAR (Appendix E) after the initial pipeline is built, then the capacity will be expanded the following year by a fraction (FR_PEXPFAC, Appendix E) of the original capacity.

The expected cost to move the gas to the lower 48 is set as the sum of the wellhead price,[38] the charge for treating the gas, and the fuel costs (FR_PMINWPR, Appendix E), plus the pipeline tariff for moving the gas to Alberta and an assumed differential between the price in Alberta and the average lower 48 wellhead price (ALB_TO_L48, Appendix E). A risk premium is also included to largely reflect the expected initial price drop as a result of the introduction of the pipeline, as well as some of the uncertainties in the necessary capital outlays and in the ultimate

[37]The prices are weighted, with a greater emphasis on the prices in the recent past. An additional check is made that the estimated cost is lower than the lower 48 price in the last two years of the planning period and lower than a weighted average of the expected prices in the three years after the planning period, during the construction period.

[38]The required wellhead price in the MacKenzie Delta is progressively adjusted in response to changes in the U.S. national average drilling cost per well projections and across the forecast horizon in a higher or lower technology case, such that by the last year (2035) the price is higher or lower than the price in the reference case by a fraction equal to 0.25 times the technology factor adjustment rate (e.g., 0.50 for *AEO2011*).

selling price (FR_PRISK, Appendix E).[39] The cost-of-service based calculation for the pipeline tariff (NGFRPIPE_TAR) to move gas from each production source to Alberta is presented at the end of Chapter 6.

[39]If there is an annual decline in the average lower 48 wellhead price over the planning period for the Alaska pipeline, an additional adjustment is made to the expected cost (although it is not a cost item), equivalent to half of the drop in price averaged over the planning period, to account for the additional concern created by declining prices.

3. Overview of Solution Methodology

The previous chapter described the function of the NGTDM within the NEMS and the transformation and representation of supply and demand elements within the NGTDM. This chapter will present an overview of the NGTDM model structure and of the methodologies used to represent the natural gas transmission and distribution industries. First, a detailed description of the network used in the NGTDM to represent the U.S. natural gas pipeline system is presented. Next, a general description of the interrelationships between the submodules within the NGTDM is presented, along with an overview of the solution methodology used by each submodule.

NGTDM Regions and the Pipeline Flow Network

General Description of the NGTDM Network

In the NGTDM, a transmission and distribution network (**Figure 3-1**) simulates the interregional flow of gas in the contiguous United States and Canada in either the peak (December through March) or off-peak (April through November) period. This network is a simplified representation of the physical natural gas pipeline system and establishes the possible interregional transfers to move gas from supply sources to end-users. Each NGTDM region contains one transshipment node, a junction point representing flows coming into and out of the region. Nodes have also been defined at the Canadian and Mexican borders, as well as in eastern and western Canada. Arcs connecting the transshipment nodes are defined to represent flows between these nodes; and thus, to represent interregional flows. Each of these interregional arcs represents an aggregation of pipelines that are capable of moving gas from one region into another region. Bidirectional flows are allowed in cases where the aggregation includes some pipelines flowing one direction and other pipelines flowing in the opposite direction.[40] Bidirectional flows can also be the result of directional flow shifts within a single pipeline system due to seasonal variations in flows. Arcs leading from or to international borders generally[41] represent imports or exports. The arcs which are designated as "secondary" in **Figure 3-1** generally represent relatively low flow volumes and are handled somewhat differently and separately from those designated as "primary."

Flows are further represented by establishing arcs from the transshipment node to each demand sector/subregion represented in the NGTDM region. Demand in a particular NGTDM region can only be satisfied by gas flowing from that same region's transshipment node. Similarly, arcs are also established from supply points into transshipment nodes. The supply from each NGTDM/OGSM region is directly available to only one transshipment node, through which it must first pass if it is to be made available to the interstate market (at an adjoining transshipment

[40]Historically, one out of each pair of bidirectional arcs in Figure 3-1 represents a relatively small amount of gas flow during the year. These arcs are referred to as "the bidirectional arcs" and are identified as the secondary arcs in Figure 3-1, excluding 3 to 15, 5 to 10, 15 to E. Canada, 20 to 7, 21 to 11, 22 to 12, and Alaska to W. Canada. The flows along these arcs are initially set at the last historical level and are only increased (proportionately) when a known (or likely) planned capacity expansion occurs.

[41]Some natural gas flows across the Canadian border into the United States, only to flow back across the border without changing ownership or truly being imported. In addition, any natural gas that might flow from Alaska to the lower 48 states would cross the Canadian/U.S. border, but not be considered as an import.

node). During a peak period, one of the supply sources feeding into each transshipment node represents net storage withdrawals in the region during the peak period. Conversely during the off-peak period, one of the demand nodes represents net storage injections in the region during the off-peak period.

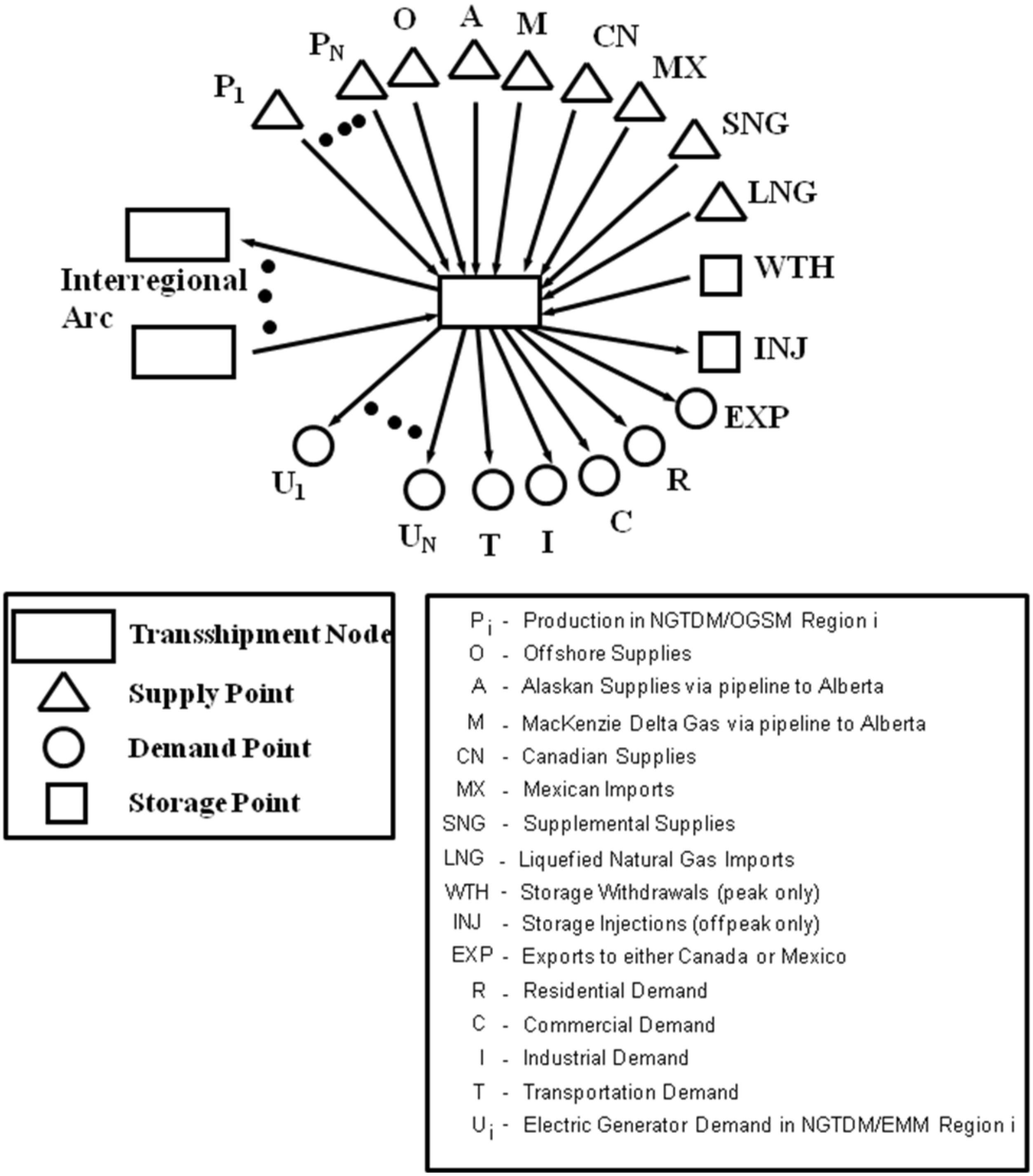
Figure 3-1. Natural Gas Transmission and Distribution Module Network

Figure 3-2 shows an illustration of all possible flows into and out of a transshipment node. Each transshipment node has one or more arcs to represent flows from or to other transshipment nodes. The transshipment node also has an arc representing flow to each end-use sector in the region (residential, commercial, industrial, electric generators, and transportation), including separate arcs to each electric generator subregion.[42] Exports and (in the off-peak period) net storage injections are also represented as flow out of a transshipment node. Each transshipment node can have one or more arcs flowing in from each supply source represented within the region. These supply points represent U.S. or Canadian onshore or U.S. offshore production,

[42]Conceptually within the model, the flow of gas to each end-use sector passes through a common city gate point before reaching the end-user.

liquefied natural gas imports, gas produced in Alaska and transported via pipeline, Mexican imports, (in the peak period) net storage withdrawals in the region, or supplemental gas supplies.

Figure 3-2. Transshipment Node



Two items accounted for but not presented in **Figure 3-2** are discrepancies or balancing items (i.e., average historically observed differences between independently reported natural gas supply and disposition levels (DISCR for the United States, CN_DISCR for Canada) and backstop supplies.[43]

Many of the types of supply listed above are relatively low in volume and are set independently of current prices and before the NGTDM determines a market equilibrium solution. As a result, these sources of supply are handled differently within the model. Structurally within the model only the price responsive sources of supply (i.e., onshore and offshore lower 48 U.S. production, Western Canadian Sedimentary Basin (WCSB) production, and storage withdrawals) are explicitly represented with supply nodes and connecting arcs to the transshipment nodes when the NGTDM is determining a market equilibrium solution.

Once the types of end-use destinations and supply sources into and out of each transshipment node are defined, a general network structure is created. Each transshipment node does not necessarily have all supply source types flowing in, or all demand source types flowing out. For instance, some transshipment nodes will have liquefied natural gas available while others will not. The specific end-use sectors and supply types specified for each transshipment node in the network are listed in **Table 3-1**. This table also provides the mapping of Electricity Market Module regions and Oil and Gas Supply Module regions to NGTDM regions (**Figure 2-3** and **Figure 2-5** in Chapter 2). The transshipment node numbers in the U.S. align with the NGTDM regions in **Figure 3-1**. Transshipment nodes 13 through 19 are pass-through nodes for the border crossings on the Canada/U.S. border, going from east to west.

As described earlier, the NGTDM determines the flow and price of natural gas in both a peak and off-peak period. The basic network structure separately represents the flow of gas during the two periods within the Interstate Transmission Submodule. Conceptually this can be thought of as two parallel networks, with three areas of overlap. First, pipeline expansion is determined only in the peak period network (with the exception of pipelines going into Florida from the East South Central Division). These levels are then used as constraints for pipeline flow in the off-peak period. Second, net withdrawals from storage in the peak period establish the net amount of natural gas that will be injected in the off-peak period, within a given forecast year. Similarly, the price of gas withdrawn in the peak period is the sum of the price of the gas when it was injected in the off-peak, plus an established storage tariff. Third, the supply curves provided by the Oil and Gas Supply Module are specified on an annual basis. Although, these curves are used to approximate peak and off-peak supply curves, the model is constrained to solve on the annual supply curve (i.e., when the annual curve is evaluated at the quantity-weighted average annual wellhead price, the resulting quantity should equal the sum of the production in the peak and off-peak periods). The details of how this is accomplished are provided in Chapter 4.

[43]Backstop supplies are allowed when the flow out of a transshipment node exceeds the maximum flow into a transshipment node. A high price is assigned to this supply source and it is generally expected not to be required (or desired). Chapter 4 provides a more detailed description of the setting and use of backstop supplies in the NGTDM.

Table 3-1. Demand and Supply Types at Each Transshipment Node in the Network

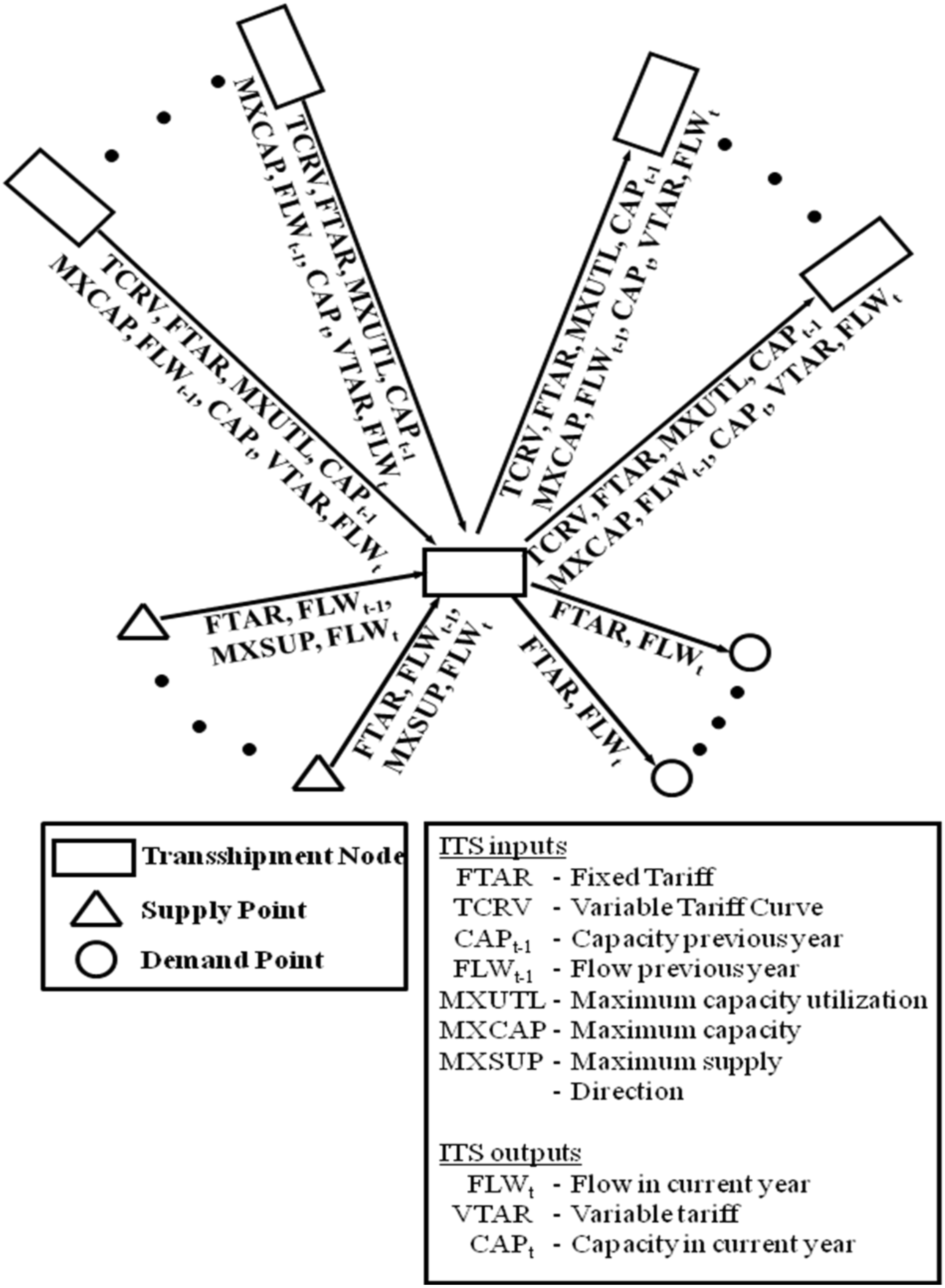
Transshipment Node	Demand Types	Supply Types
1	R, C, I, T, U(1)	P(1/1), LNG Everett Mass., LNG generic, SNG
2	R, C, I, T, U(2), INJ	P(2/1), WTH, LNG generic, SNG
3	R, C, I, T, U(3), U(4), INJ	P(3/1), WTH, SNG
4	R, C, I, T, U(5), INJ	P(4/3), P(4/5), SNG, WTH, LNG generic
5	R, C, I, T, U(6), U(7), INJ	P(5/1), LNG Cove Pt Maryland, LNG Elba Island Georgia, Atlantic Offshore, WTH, LNG generic, SNG
6	R, C, I, T, U(9), U(10), INJ	P(6/1), P(6/2), WTH, LNG generic, SNG
7	R, C, I, T, U(11), INJ	P(7/2), P(7/3), P(7/4), LNG Lake Charles Louisiana, Offshore Louisiana, Gulf of Mexico, WTH, LNG generic, SNG
8	R, C, I, T, U(12), U(13), INJ	P(8/5), WTH, SNG
9	R, C, I, T, U(15), INJ	P(9/6), WTH, LNG generic, SNG
10	R, C, I, T, U(6), U(8), INJ	P(10/2), WTH, SNG
11	R, C, I, T, U(14), INJ	P(11/4), P(11/5), WTH, SNG
12	R, C, I, T, U(16), INJ	P(12/6), Pacific Offshore, WTH, LNG generic, SNG
13 – 19	--	--
20	Mexican Exports (TX)	Mexican Imports (TX)
21	Mexican Exports (AZ/NM)	Mexican Imports (AZ/NM)
22	Mexican Exports (CA)	Mexican Imports (CA)
23	Eastern Canadian consumption, INJ	Eastern Canadian supply, WTH
24	Western Canadian consumption, INJ	Western Canadian supply, WTH, Alaskan Supply via a pipeline, MacKenzie Valley gas via a pipeline
P(x/y) – production in region defined in Figure 2-5 for NGTDM region x and OGSM region y U(z) – electric generator consumption in region z, defined in Figure 2-3		

Specifications of a Network Arc

Each arc of the network has associated variable inputs and outputs. The variables that define an interregional arc in the Interstate Transmission Submodule (ITS) are the pipeline direction, available capacity from the previous forecast year, the "fixed" tariffs and/or tariff curve, the flow on the arc from the previous year, the maximum capacity level, and the maximum utilization of the capacity (**Figure 3-3**). While a model solution is determined (i.e., the quantity of the natural gas flow along each interregional arc is determined), the "variable" or quantity dependent tariff and the required capacity to support the flow are also determined in the process.

For the peak period, the maximum capacity build levels are set to a factor above the 1990 levels. The factor is set high enough so that this constraint is rarely, if ever, binding. However, the structure could be used to limit growth along a particular path. In the off-peak period the maximum capacity levels are set to the capacity level determined in the peak period. The maximum utilization rate along each arc is used to capture the impact that varying demand loads over a season have on the utilization along an arc.

Figure 3-3. Variables Defined and Determined for Network Arc



For the peak period, the maximum utilization rate is calculated based on an estimate of the ratio of January-to-peak period consumption requirements. For the off-peak the maximum utilization rates are set exogenously (HOPUTZ, Appendix E). Capacity and flow levels from the previous forecast year are used as input to the solution algorithm for the current forecast year. In some cases, capacity that is newly available in the current forecast year will be exogenously set (PLANPCAP, Appendix E) as “planned” (i.e., highly probable that it will be built by the given forecast year based on project announcements). Any additional capacity beyond the planned level is determined during the solution process and is checked against maximum capacity levels and adjusted accordingly. Each of the interregional arcs has an associated “fixed” and “variable” tariff, to represent usage and reservation fees, respectively. The variable tariff is established by applying the flow level along the arc to the associated tariff supply curve, established by the Pipeline Tariff Submodule. During the solution process in the Interstate Transmission Submodule, the resulting tariff in the peak or off-peak period is added to the price at the source node to arrive at a price for the gas along the interregional arc right before it reaches its destination node. Through an iterative process, the relative values of these prices for all of the arcs entering a node are used as the basis for reevaluating the flow along each of these arcs.[44]

For the arcs from the transshipment nodes to the final delivery points, the variables defined are tariffs and flows (or consumption). The tariffs here represent the sum of several charges or adjustments, including interstate pipeline tariffs in the region, intrastate pipeline tariffs, and distributor markups. Associated with each of these arcs is the flow along the arc, which is equal to the amount of natural gas consumed by the represented sector. For arcs from supply points to transshipment nodes, the input variables are the production levels from the previous forecast year, a tariff, and the maximum limit on supplies or production. In this case the tariffs theoretically represent gathering charges, but are currently assumed to be zero.[45] Maximum supply levels are set at a percentage above a baseline or “expected” production level (described in Chapter 4). Although capacity limits can be set for the arcs to and from end-use sectors and supply points, respectively, the current version of the module does not impose such limits on the flows along these arcs.

Note that any of the above variables may have a value of zero, if appropriate. For instance, some pipeline arcs may be defined in the network that currently have zero capacity, yet where new capacity is expected in the future. On the other hand, some arcs such as those to end-use sectors are defined with infinite pipeline capacity because the model does not forecast limits on the flow of gas from transshipment nodes to end users.

Overview of the NGTDM Submodules and Their Interrelationships

The NEMS generates an annual forecast of the outlook for U.S. energy markets for the years 1990 through 2030. For the historical years, many of the modules in NEMS do not execute, but

[44]During the off-peak period in a previous version of the module, only the usage fee was used as a basis for determining the relative flow along the arcs entering a node. However, the total tariff was ultimately used when setting delivered prices.

[45]Ultimately the gathering charges are reflected in the delivered prices when the model is benchmarked to historically reported city gate prices.

simply assign historically published values to the model's output variables. The NGTDM similarly assigns historical values to most of the known module outputs for these years. However, some of the required outputs from the module are not known (e.g., the flow of natural gas between regions on a seasonal basis). Therefore, the model is run in a modified form to fill in such unknown, but required values. Through this process historical values are generated for the unknown parameters that are consistent with the known historically based values (e.g., the unknown seasonal interregional flows sum to the known annual totals).

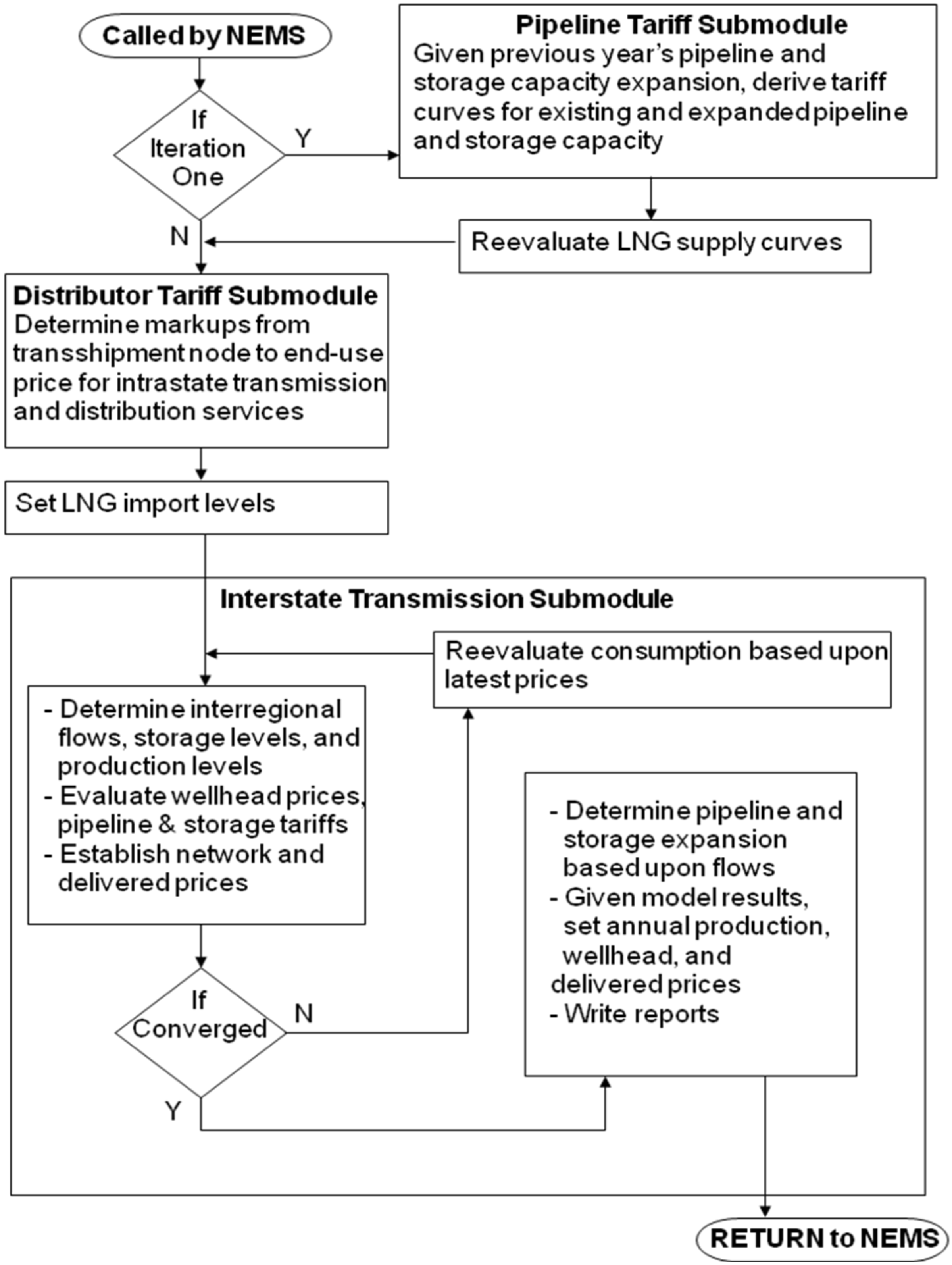
Although the NGTDM is executed for each iteration of each forecast year solved by the NEMS, it is not necessary that all of the individual components of the module be executed for all iterations. Of the NGTDM's three components or submodules, the Pipeline Tariff Submodule is executed only once per forecast year since the submodule's input values do not change from one iteration of NEMS to the next. However, the Interstate Transmission Submodule and the Distributor Tariff Submodule are executed during every iteration for each forecast year because their input values can change by iteration. Within the Interstate Transmission Submodule an iterative process is used. The basic solution algorithm is repeated multiple times until the resulting wellhead prices and production levels from one iteration are within a user-specified tolerance of the resulting values from the previous iteration, and equilibrium is reached. A process diagram of the NGTDM is provided in **Figure 3-4**, with the general calling sequence.

The Interstate Transmission Submodule is the primary submodule of the NGTDM. One of its functions is to forecast interregional pipeline and underground storage expansions and produce annual pipeline load profiles based on seasonal loads. Using this information from the previous forecast year and other data, the Pipeline Tariff Submodule uses an accounting process to derive revenue requirements for the current forecast year. This submodule builds pipeline and storage tariff curves based on these revenue requirements for use in the Interstate Transmission Submodule. These curves extend beyond the level of the current year's capacity and provide a means for assessing whether the demand for additional capacity, based on a higher tariff, is sufficient to warrant expansion of the capacity. The Distributor Tariff Submodule provides distributor tariffs for use in the Interstate Transmission Submodule. The Distributor Tariff Submodule must be called in each iteration because some of the distributor tariffs are based on consumption levels that may change from iteration to iteration. Finally, using the information provided by these other NGTDM submodules and other NEMS modules, the Interstate Transmission Submodule solves for natural gas prices and quantities that reflect a market equilibrium for the current forecast year. A brief summary of each of the NGTDM submodules follows.

Interstate Transmission Submodule

The Interstate Transmission Submodule (ITS) is the main integrating module of the NGTDM. One of its major functions is to simulate the natural gas price determination process. The ITS brings together the major economic factors that influence regional natural gas trade on a seasonal basis in the United States, the balancing of the demand for and the domestic supply of natural gas, including competition from imported natural gas. These are examined in combination with the relative prices associated with moving the gas from the producer to the end-user where and

Figure 3-4. NGTDM Process Diagram



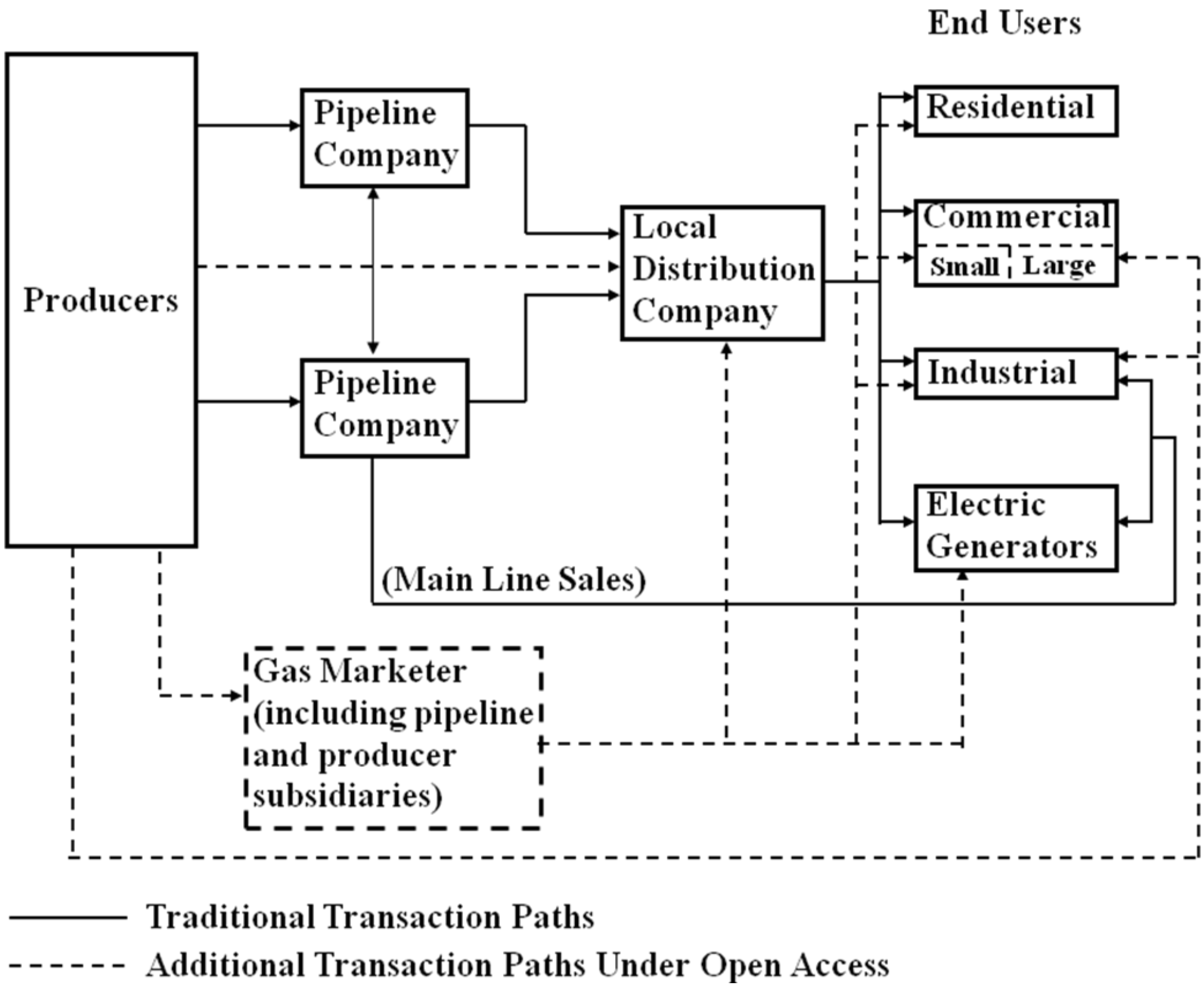
when (peak versus off-peak) it is needed. In the process, the ITS models the decision-making process for expanding pipeline and/or seasonal storage capacity in the U.S. gas market, determining the amount of pipeline and storage capacity to be added between or within regions in the NGTDM. Storage serves as the primary link between the two seasonal periods represented.

The ITS employs an iterative heuristic algorithm to establish a market equilibrium solution. Given the consumption levels from other NEMS modules, the basic process followed by the ITS involves first establishing the backward flow of natural gas in each period from the consumers, through the network, to the producers, based primarily on the relative prices offered for the gas (from the previous ITS iteration). This process is performed for the peak period first since the net withdrawals from storage during the peak period will establish the net injections during the off-peak period. Second, using the model's supply curves, wellhead prices are set corresponding to the desired production volumes. Also, using the pipeline and storage tariff curves from the Pipeline Tariff Submodule, pipeline and storage tariffs are set corresponding to the associated flow of gas, as determined in the first step. These prices are then translated from the producers, back through the network, to the city gate and the end-users, by adding the appropriate tariffs along the way. A regional storage tariff is added to the price of gas injected into storage in the off-peak to arrive at the price of the gas when withdrawn in the peak period. Delivered prices are derived for residential, commercial, electric generation, and transportation customers, as well as for both the core and non-core industrial sectors, using the distributor tariffs provided by the Distributor Tariff Submodule. At this point consumption levels can be reevaluated given the resulting set of delivered prices. Either way, the process is repeated until the solution has converged.

In the end, the ITS derives average seasonal (and ultimately annual) natural gas prices (wellhead, city gate, and delivered), and the associated production and flows, that reflect an interregional market equilibrium among the competing participants in the market. In the process of determining interregional flows and storage injections/withdrawals, the ITS also forecasts pipeline and storage capacity additions. In the calculations for the next forecast year, the Pipeline Tariff Submodule will adjust the requirements to account for the associated expansion costs. Other primary outputs of the module include lease, plant, and pipeline fuel use, Canadian import levels, and net storage withdrawals in the peak period.

The historical evolution of the price determination process simulated by the ITS is depicted schematically in **Figure 3-5**. At one point, the marketing chain was very straightforward, with end-users and local distribution companies contracting with pipeline companies, and the pipeline companies in turn contracting with producers. Prices typically reflected average costs of providing service plus some regulator-specified rate of return. Although this approach is still used as a basis for setting pipeline tariffs, more pricing flexibility has been introduced, particularly in the interstate pipeline industry and more recently by local distributors. Pipeline companies are also offering a range of services under competitive and market-based pricing arrangements. Additionally, newer players—for example marketers of spot gas and brokers for pipeline capacity—have entered the market, creating new links connecting suppliers with end-users. The marketing links are expected to become increasingly complex in the future.

Figure 3-5. Principal Buyer/Seller Transaction Paths for Natural Gas Marketing



The level of competition for pipeline services (generally a function of the number of pipelines having access to a customer and the amount of capacity available) drives the prices for interruptible transmission service and is having an effect on firm service prices. Currently, there are significant differences across regions in pipeline capacity utilization.[46] These regional differences are evolving as new pipeline capacity has been and is being constructed to relieve capacity constraints in the Northeast, to expand markets in the Midwest and the Southeast, and to move more gas out of the Rocky Mountain region and the Gulf of Mexico. As capacity changes take place, prices of services should adjust accordingly to reflect new market conditions.

[46]Further information can be found on the U.S. Energy Information Administration web page under "Pipeline Capacity and Usage" www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html.

Federal and State initiatives are reducing barriers to market entry and are encouraging the development of more competitive markets for pipeline and distribution services. Mechanisms used to make the transmission sector more competitive include the widespread capacity releasing programs, market-based rates, and the formation of market centers with deregulated upstream pipeline services. The ITS is not designed to model any specific type of program, but to simulate the overall impact of the movement towards market based pricing of transmission services.

Pipeline Tariff Submodule

The primary purpose of the Pipeline Tariff Submodule (PTS) is to provide volume dependent curves for computing tariffs for interstate transportation and storage services within the Interstate Transmission Submodule. These curves extend beyond current capacity levels and relate incremental pipeline or storage capacity expansion to corresponding estimated rates. The underlying basis for each tariff curve in the model is a forecast of the associated regulated revenue requirement. An accounting system is used to track costs and compute revenue requirements associated with both reservation and usage fees under a current typical regulated rate design. Other than an assortment of macroeconomic indicators, the primary input to the PTS from other modules/submodules in NEMS is the level of pipeline and storage capacity expansions in the previous forecast year. Once an expansion is projected to occur, the submodule calculates the resulting impact on the revenue requirement. The PTS currently assumes rolled-in (or average), not incremental rates for new capacity (i.e., the cost of any additional capacity is lumped in with the remaining costs of existing capacity when deriving a single tariff for all the customers along a pipeline segment).

Transportation revenue requirements (and associated tariff curves) are established for interregional arcs defined by the NGTDM network. These network tariff curves reflect an aggregation of the revenue requirements for individual pipeline companies represented by the network arc. Storage tariff curves are defined at regional NGTDM network nodes, and similarly reflect an aggregation of individual company storage revenue requirements. Note that these services are unbundled and do not include the price of gas, except for the cushion gas used to maintain minimum gas pressure. Furthermore, the submodule cannot address competition for pipeline or storage services along an aggregate arc or within an aggregate region, respectively. It should also be noted that the PTS deals only with the interstate market, and thus does not capture the impacts of State-specific regulations for intrastate pipelines. Intrastate transportation charges are accounted for within the Distributor Tariff Submodule.

Pipeline tariffs for transportation and storage services represent a more significant portion of the price of gas to industrial and electric generator end-users than to other sectors. Consumers of natural gas are grouped generally into two categories: (1) those that need firm or guaranteed service because gas is their only fuel option or because they are willing to pay for security of supply, and (2) those that do not need guaranteed service because they can either periodically terminate operations or use fuels other than natural gas. The first group of customers (core customers) is assumed to purchase firm transportation services, while the latter group (non-core customers) is assumed to purchase non-firm service (e.g., interruptible service, released capacity). Pipeline companies guarantee to their core customers that they will provide peak day service up to the maximum capacity specified under their contracts even though these customers may not actually request transport of gas on any given day. In return for this service guarantee, these customers pay monthly reservation fees (or demand charges). These reservation fees are paid in addition to charges for transportation service based on the quantity of gas actually transported (usage fees or commodity charges). The pipeline tariff curves generated by the PTS are used within the ITS when determining the relative cost of purchasing and moving gas from one source versus another in the peak and off-peak seasons. They are also used when setting the price of gas along the NGTDM network and ultimately to the end-users.

The actual rates or tariffs that pipelines are allowed to charge are largely regulated by the Federal Energy Regulatory Commission (FERC). FERC's ratemaking traditionally allows (but does not necessarily guarantee) a pipeline company to recover its costs, including what the regulators consider a fair rate of return on capital. Furthermore, FERC not only has jurisdiction over how cost components are allocated to reservation and usage categories, but also how reservation and usage costs are allocated across the various classes of transmission (or storage) services offered (e.g., firm versus non-firm service). Previous versions of the NGTDM (and therefore the PTS) included representations of natural gas moved (or stored) using firm and non-firm service. However, in an effort to simplify the module, this distinction has been removed in favor of moving from an annual to a seasonal model. The impact of the distinction of firm versus non-firm service on core and non-core delivered prices is indirectly captured in the markup established in the Distributor Tariff Submodule. More recent initiatives by FERC have allowed for more flexible processes for setting rates when a service provider can adequately demonstrate that it does not possess significant market power. The use of volume dependent tariff curves partially serves to capture the impact of alternate rate setting mechanisms. Additionally, various rate making policy options discussed by FERC would allow peak-season rates to rise substantially above the 100-percent load factor rate (also known as the full cost-of-service rate). In capacity-constrained markets, the basis differential between markets connected via the constrained pipeline route will generally be above the full cost of service pipeline rates. The NGTDM's ultimate purpose is to project market prices; it uses cost-of-service rates as a means in the process of establishing market prices.

Distributor Tariff Submodule

The primary purpose of the Distributor Tariff Submodule (DTS) is to determine the price markup from the regional market hub to the end-user. For most customers, this consists of (1) distributor markups charged by local distribution companies for the distribution of natural gas from the city gate to the end user and (2) markups charged by intrastate pipeline companies for intrastate transportation services. Intrastate pipeline tariffs are specified exogenously to the model and are currently set to zero (INTRAST_TAR, Appendix E). However, these tariffs are accounted for in the module indirectly. For most industrial and electric generator customers, gas is not purchased through a local distribution company, so they are not specifically charged a distributor tariff. In this case, the "distributor tariff" represents the difference between the average price paid by local distribution companies at the city gate and the price paid by the average industrial or electric generator customer. Distributor tariffs are distinguished within the DTS by sector (residential, commercial, industrial, transportation, and electric generator), region (NGTDM/EMM regions for electric generators and NGTDM regions for the rest), seasons (peak or off-peak), and as appropriate by service type or class (core or non-core).

Distribution markups represent a significant portion of the price of gas to residential, commercial, and transportation customers, and less so to the industrial and electric generation sectors. Each sector has different distribution service requirements, and frequently different transportation needs. For example, the core customers in the model (residential, transportation, commercial and some industrial and electric generator customers) are assumed to require guaranteed on-demand (firm) service because natural gas is largely their only fuel option. In contrast, large portions of the industrial and electric generator sectors may not rely solely on guaranteed service because they can either periodically terminate operations or switch to other fuels. These customers are referred to as non-core. They can elect to receive some gas supplies through a lower priority (and lower cost) interruptible transportation service. While not specifically represented in the model, during periods of peak demand, services to these sectors can be interrupted in order to meet the natural gas requirements of core customers. In addition, these customers frequently select to bypass the local distribution company pipelines and hook up directly to interstate or intrastate pipelines.

The rates that local distribution companies and intrastate carriers are allowed to charge are regulated by State authorities. State ratemaking traditionally allows (but does not necessarily guarantee) local distribution companies and intrastate carriers to recover their costs, including what the regulators consider a fair return on capital. These rates are derived from the cost of providing service to the end-use customer. The State authority determines which expenses can be passed through to customers and establishes an allowed rate of return. These measures provide the basis for distinguishing rate differences among customer classes and type of service by allocating costs to these classes and services based on a rate design. The DTS does not project distributor tariffs through a rate base calculation as is done in the PTS, partially due to limits on data availability.[47] In most cases, projected distributor tariffs in the model depend initially on base year values, which are established by subtracting historical city gate prices from historical delivered prices, and generally reflect an average over recent historical years.

Distributor tariffs for all but the transportation sector are set using econometrically estimated equations.[48] Transportation sector markups, representing sales for natural gas vehicles, are set separately for fleet and personal vehicles and account for distribution to delivery stations, retail markups, and federal and state motor fuels taxes. In addition, the NGTDM assesses the potential construction of infrastructure to support fueling compressed natural gas vehicles.

[47] In theory these cost components could be compiled from rate filings to state Public Utility Commissions; however, such an extensive data collection effort is beyond the available resources.

[48] An econometric approach was used largely as a result of data limitations. EIA data surveys do not collect the cost components required to derive revenue requirements and cost-of-service for local distribution companies and intrastate carriers. These cost components can be compiled from rate filings to Public Utility Commissions; however, an extensive data collection effort is beyond the scope of NEMS at this time.

4. Interstate Transmission Submodule Solution Methodology

As a key component of the NGTDM, the Interstate Transmission Submodule (ITS) determines the market equilibrium between supply and demand of natural gas within the North American pipeline system. This translates into finding the price such that the quantity of gas that consumers would desire to purchase equals the quantity that producers would be willing to sell, accounting for the transmission and distribution costs, pipeline fuel use, capacity expansion costs and limitations, and mass balances. To accomplish this, two seasonal periods were represented within the module--a peak and an off-peak period. The network structures within each period consist of an identical system of pipelines, and are connected through common supply sources and storage nodes. Thus, two interconnected networks (peak and off-peak) serve as the framework for processing key inputs and balancing the market to generate the desired outputs. A heuristic approach is used to systematically move through the two networks solving for production levels, network flows, pipeline and storage capacity requirements,[49] supply and citygate prices, and ultimately delivered prices until mass balance and convergence are achieved. (The methodology used for calculating distributor tariffs is presented in Chapter 5.) Primary input requirements include seasonal consumption levels, capacity expansion cost curves, annual natural gas supply levels and/or curves, a representation of pipeline and storage tariffs, as well as values for pipeline and storage starting capacities, and network flows and prices from the previous year. Some of the inputs are provided by other NEMS modules, some are exogenously defined and provided in input files, and others are generated by the module in previous years or iterations and used as starting values. Wellhead, import, and delivered prices, supply quantities, and resulting flow patterns are obtained as output from the ITS and sent to other NGTDM submodules or other NEMS modules after some processing. Network characteristics, input requirements, and the heuristic process are presented more fully below.

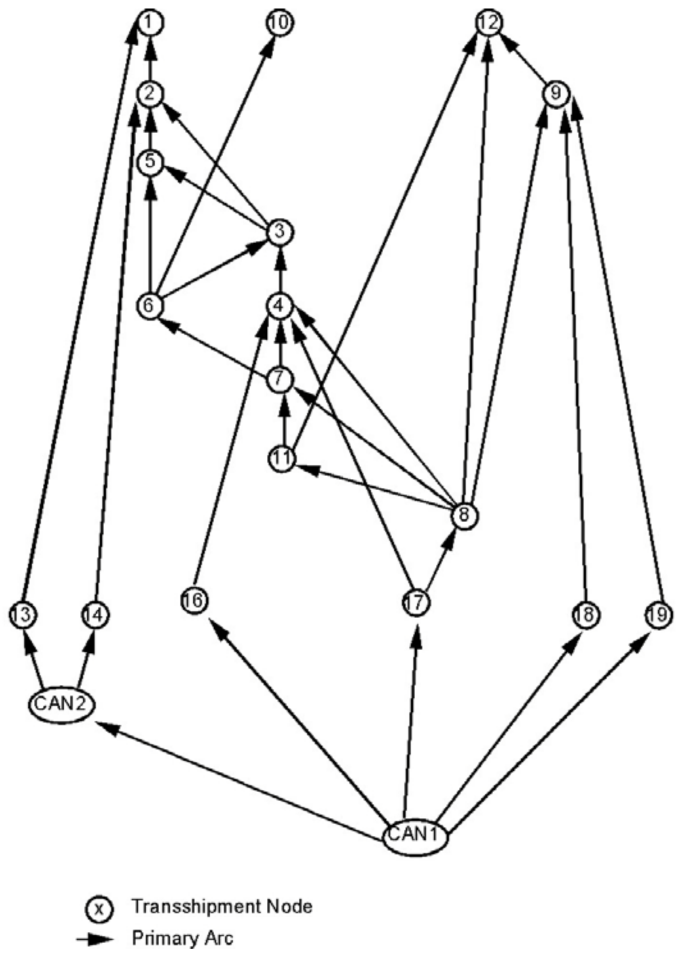
Network Characteristics in the ITS

As described in an earlier chapter, the NGTDM network consists of 12 NGTDM regions (or transshipment nodes) in the lower 48 states, three Mexican border crossing nodes, seven Canadian border crossing nodes, and two Canadian supply/demand regions. Interregional arcs connecting the nodes represent an aggregation of pipelines that are capable of moving gas from one region (or transshipment node) into another. These arcs have been classified as either primary flow arcs or secondary flow arcs. The primary flow arcs (see **Figure 3-1**) represent major flow corridors for the transmission of natural gas. Secondary arcs represent either flow in the opposite direction from the primary flow (historically about 3 percent of the total flow) or relatively low flow volumes that are set exogenously or outside the ITS equilibration routine (e.g. Mexican imports and exports). In the ITS, this North American natural gas pipeline flow network has been restructured into a hierarchical, acyclic network representing just the primary flow of natural gas (**Figure 4-1**). The representation of flows along secondary arcs is described in the Solution Process section below. A hierarchical, acyclic network structure allows for the

[49]In reality, capacity expansion decisions are made based on expectations of future demand requirements, allowing for regulatory approvals and construction lead times. In the model, additional capacity is available immediately, once it is determined that it is needed. The implicit assumption is that decision makers exercised perfect foresight and that planning and construction for the pipeline actually started before the pipeline came online.

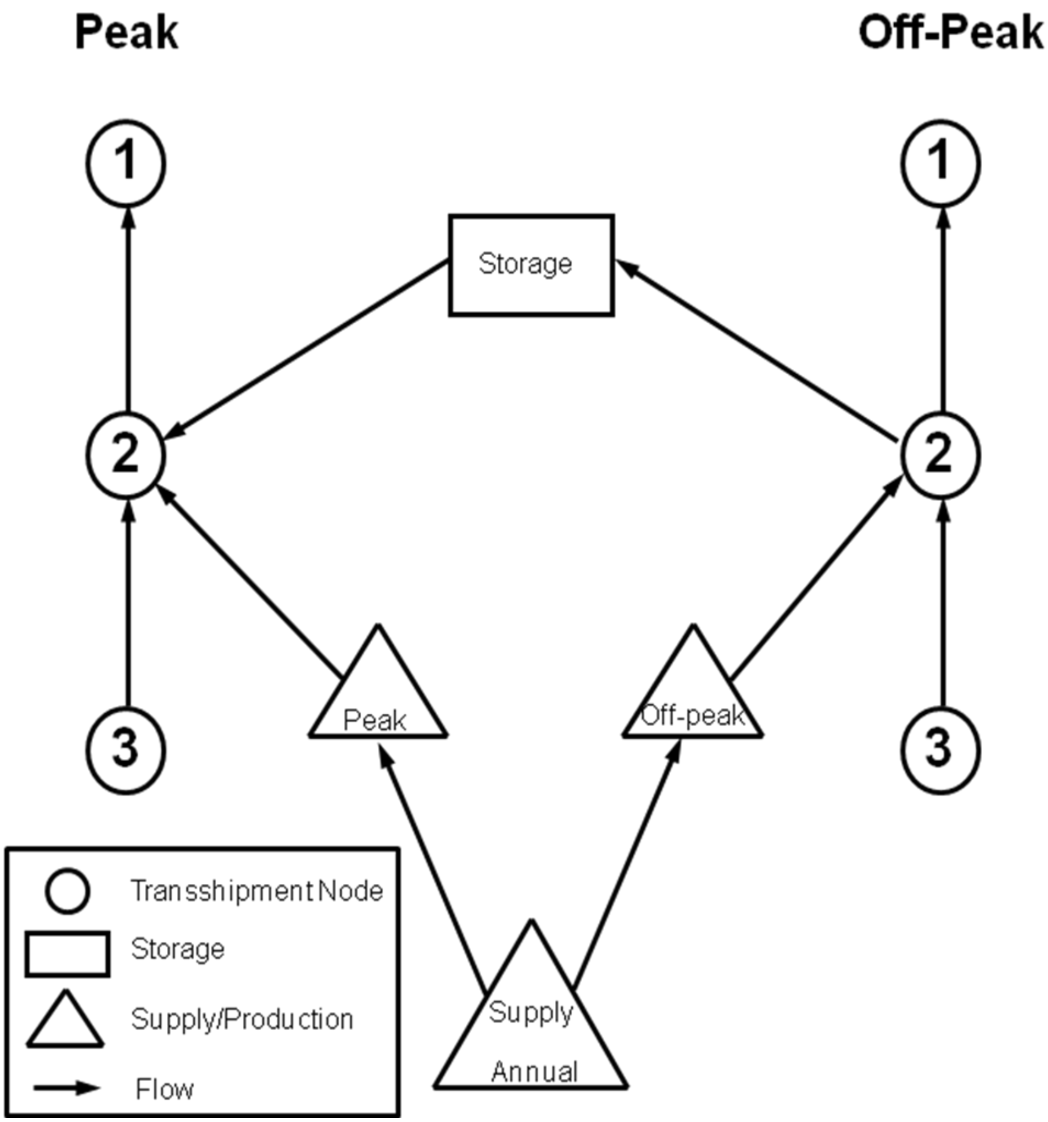
systematic representation of the flow of natural gas (and its associated prices) from the supply sources, represented towards the bottom of the network, up through the network to the end-use consumer at the upper end of the network.

Figure 4-1. Network "Tree" of Hierarchical, Acyclic Network of Primary Arcs



In the ITS, two interconnected acyclic networks are used to represent natural gas flow to end-use markets during the peak period (PK) and flow to end-use markets during the off-peak period (OP). These networks are connected regionally through common supply sources and storage nodes (**Figure 4-2**). Storage within the module only represents the transfer of natural gas produced in the off-peak period to meet the higher demands in the peak period. Therefore, net storage injections are included only in the off-peak period, while net storage withdrawals occur only in the peak period. Within a given forecast year, the withdrawal level from storage in the peak period establishes the level of gas injected in the off-peak period. Annual supply sources provide natural gas to both networks based on the combined network production requirements and corresponding annual supply availability in each region.

Figure 4-2. Simplified Example of Supply and Storage Links Across Networks



Input Requirements of the ITS

The following is a list of the key inputs required during ITS processing:

- Seasonal end-use consumption or demand curves for each NGTDM region and Canada
- Seasonal imports (except Canada) and exports by border crossing
- Canadian import capacities by border crossing
- Total natural gas production in eastern Canada and unconventional production in western Canada, by season.
- Natural gas flow by pipeline from Alaska to Alberta.
- Natural gas flow by pipeline from the MacKenzie Delta to Alberta.

- Regional supply curve parameters for U.S. nonassociated and western Canadian conventional natural gas supply[50]
- Seasonal supply quantities for U.S. associated-dissolved gas, synthetic gas, and other supplemental supplies by NGTDM region
- Seasonal network flow patterns from the previous year, by arc (including flows from storage, variable supply sources, and pipeline arcs)
- Seasonal network prices from the previous year, by arc (including flows from storage, variable supply sources, and pipeline arcs)
- Pipeline capacities, by arc
- Seasonal maximum pipeline utilizations, by arc
- Seasonal pipeline (and storage) tariffs representing variable costs or usage fees, by arc (and region)
- Pipeline capacity expansion/tariff curves for the peak network, by arc
- Storage capacity expansion/tariff curves for the peak network, by region
- Seasonal distributor tariffs by sector and region

Many of the inputs are provided by other NEMS submodules, some are defined from data within the ITS, and others are ITS model results from operation in the previous year. For example, supply curve parameters for lower 48 nonassociated onshore and offshore natural gas production and lower 48 associated-dissolved gas production are provided by the Oil and Gas Supply Module (OGSM). In contrast, Canadian data are set within the NGTDM as direct input to the ITS. U.S. end-use consumption levels are provided by NEMS demand modules; pipeline and storage capacity expansion/tariff curve parameters are provided by the Pipeline Tariff Submodule (PTS, see chapter 6); and seasonal distributor tariffs are defined by the Distributor Tariff Submodule (DTS, see Chapter 5). Seasonal network flow patterns and prices are determined within the ITS. They are initially set based on historical data, and then from model results in the previous model year.

Because the ITS is a seasonal model, most of the input requirements are on a seasonal level. In most cases, however, the information provided is not represented in the form defined above and needs to be processed into the required form. For example, regional end-use consumption levels are initially defined by sector on an annual basis. The ITS disaggregates each of these sector-specific quantities into a seasonal peak and off-peak representation, and then aggregates across sectors within each season to set a total consumption level. Also, regional fixed supplies and some of the import/export levels represent annual values. A simple methodology has been developed to disaggregate the annual information into peak and off-peak quantities using item-specific peak sharing factors (e.g., PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, PKSHR_SUPLM, PKSHR_ILNG, and PKSHR_YR). For more detail on these inputs see Chapter 2. A similar method is used to approximate the consumption and supply in the peak month of each period. This information is used to verify that sufficient sustained[51] capacity is available for the peak day in each period; and if not, it is used as a basis for adding

[50]These supply sources are referred to as the "variable" supplies because they are allowed to change in response to price changes during the ITS solution process. A few of the "fixed" supplies are adjusted each NEMS iteration, generally in response to price, but are held constant within the ITS solution process.

[51]"Sustained" capacity refers to levels that can operationally be sustained throughout the year, as opposed to "peak" capacity which can be realized at high pressures and would not generally be maintained other than at peak demand periods.

additional capacity. The assumption reflected in the model is that, if there is sufficient sustained capacity to handle the peak month, line packing[52] and propane injection can be used to accommodate a peak day in this month.

Heuristic Process

The basic process used to determine supply and delivered prices in the ITS involves starting from the top of the hierarchical, acyclic network or “tree” (as shown in **Figure 4-1**) with end-use consumption levels, systematically moving down each network (in the opposite direction from the primary flow of gas) to define seasonal flows along network arcs that will satisfy the consumption, evaluating wellhead prices for the desired production levels, and then moving up each network (in the direction of the primary flow of gas) to define transmission, node, storage, and delivered prices.

While progressively moving down the peak or off-peak network, net regional demands are assigned for each node on each network. Net regional demands are defined as the sum of consumption in the region plus the gas that is exiting the region to satisfy consumption elsewhere, net of fixed[53] supplies in the region. The consumption categories represented in net regional demands include end-use consumption in the region, exports, pipeline fuel consumption, secondary and primary flows out of the region, and for the off-peak period, net injections into regional storage facilities. Regional fixed supplies include imports (except conventional gas from Western Canada), secondary flows into the region, and the regions associated-dissolved production, supplemental supplies, and other fixed supplies. The net regional demands at a node will be satisfied by the gas flowing along the primary arcs into the node, the local “variable” supply flowing into the node, and for the peak period, the gas withdrawn from the regional storage facilities on a net basis.

Starting with the node(s) at the top of the network tree (i.e., nodes 1, 10, and 12 in **Figure 4-1**), the model uses a sharing algorithm to determine the percent of the represented region’s net demand that is satisfied by each arc going into the node. The resulting shares are used to define flows along each arc (supply, storage, and interregional pipeline) into the region (or node). The interregional flows then become additional consumption requirements (i.e., primary flows out of a region) at the corresponding source node (region). If the arc going into the original node is from a supply or storage[54] source, then the flow represents the production or storage withdrawal level, respectively. The sharing algorithm is systematically applied (going down the network tree) to each regional node until flows have been defined for all arcs along a network, such that consumption in each region is satisfied.

Once flows are established for each network (and pipeline tariffs are set by applying the flow levels to the pipeline tariff curves), resulting production levels for the variable supplies are used to determine regional wellhead prices and, ultimately, storage, node, and delivered prices. By

[52]Line packing is a means of storing gas within a pipeline for a short period of time by compressing the gas.
[53]Fixed supplies are those supply sources that are not allowed to vary in response to changes in the natural gas price during the ITS solution process.
[54]For the peak period networks only.

systematically moving up each network tree, regional wellhead prices are used with pipeline tariffs, while adjusting for price impacts from pipeline fuel consumption, to calculate regional node prices for each season. Next, intraregional and intrastate markups are added to the regional/seasonal node prices, followed by the addition of corresponding seasonal, sectoral distributor tariffs, to generate delivered prices. Seasonal prices are then converted to annual delivered prices using quantity-weighted averaging. To speed overall NEMS convergence,[55] the delivered prices can be applied to representative demand curves to approximate the demand response to a change in the price and to generate a new set of consumption levels. This process of going up and down the network tree is repeated until convergence is reached.

The order in which the networks are solved differs depending on whether movement is down or up the network tree. When proceeding down the network trees, the peak network flows are established first, followed by the off-peak network flows. This order has been established for two reasons. First, capacity expansion is decided based on peak flow requirements.[56] This in turn is used to define the upper limits on flows along arcs in the off-peak network. Second, net storage injections (represented as consumption) in the off-peak season cannot be defined until net storage withdrawals (represented as supplies) in the peak season are established. When going up the network trees, prices are determined for the off-peak network first, followed by the peak network. This order has been established mainly because the price of fuel withdrawn from storage in the peak season is based on the cost of fuel injected into storage in the off-peak season plus a storage tariff.

If net demands exceed available supplies on a network in a region, then a backstop supply is made available at a higher price than other local supply. The higher price is passed up the network tree to discourage (or decrease) demands from being met via this supply route. Thus, network flows respond by shifting away from the backstop region until backstop supply is no longer needed.

Movement down and up each network tree (defined as a cycle) continues within a NEMS iteration until the ITS converges. Convergence is achieved when the regional seasonal supply prices determined during the current cycle down the network tree are within a designated minimum percentage tolerance from the supply prices established the previous cycle down the network tree. In addition, the absolute change in production between cycles within supply regions with relatively small production levels are checked in establishing convergence. In addition, the presence of backstop will prevent convergence from being declared. Once convergence is achieved, only one last movement up each network tree is required to define final regional/seasonal node and delivered prices. If convergence is not achieved, then a set of "relaxed" supply prices is determined by weighting regional production results from both the current and the previous cycle down the network tree, and obtaining corresponding new annual and seasonal supply prices from the supply curves in each region based on these "relaxed" production levels. The concept of "relaxation" is a means of speeding convergence by solving

[55]At various times, NEMS has not readily converged and various approaches have been taken to improve the process. If the NGTDM can anticipate the potential demand response to a price change from one iteration to the next, and accordingly moderate the price change, the NEMS will theoretically converge to an equilibrium solution in less iterations.

[56]Pipeline capacity into region 10 (Florida) is allowed to expand in either the peak or off-peak period because the region experiences its peak usage of natural gas in what is generally the off-peak period for consumption in the rest of the country.

for quantities (or prices) in the current iteration based on a weighted-average of the prices (or quantities) from the previous two iterations, rather than just using the previous iteration's values.[57]

The following subsections describe many of these procedures in greater detail, including: net node demands, pipeline fuel consumption, sharing algorithm, wellhead prices, tariffs, arc, node, and storage prices, backstop, convergence, and delivered and import prices. A simple flow diagram of the overall process is presented in **Figure 4-3**.

Net Node Demands

Seasonal net demands at a node are defined as total seasonal demands in the region, net of seasonal fixed supplies entering the region. Regional demands consist of primary flows exiting the region (including net storage injections in the off-peak), pipeline fuel consumption, end-use consumption, discrepancies (or historical balancing item), Canadian consumption, exports, and other secondary flows exiting the region. Fixed supplies include associated-dissolved gas, Alaskan gas supplies to Alberta, synthetic natural gas, other supplemental supplies, LNG imports, fixed Canadian supplies (including MacKenzie Delta gas), and other secondary flows entering the region. Seasonal net node demands are represented by the following equations:

Peak:

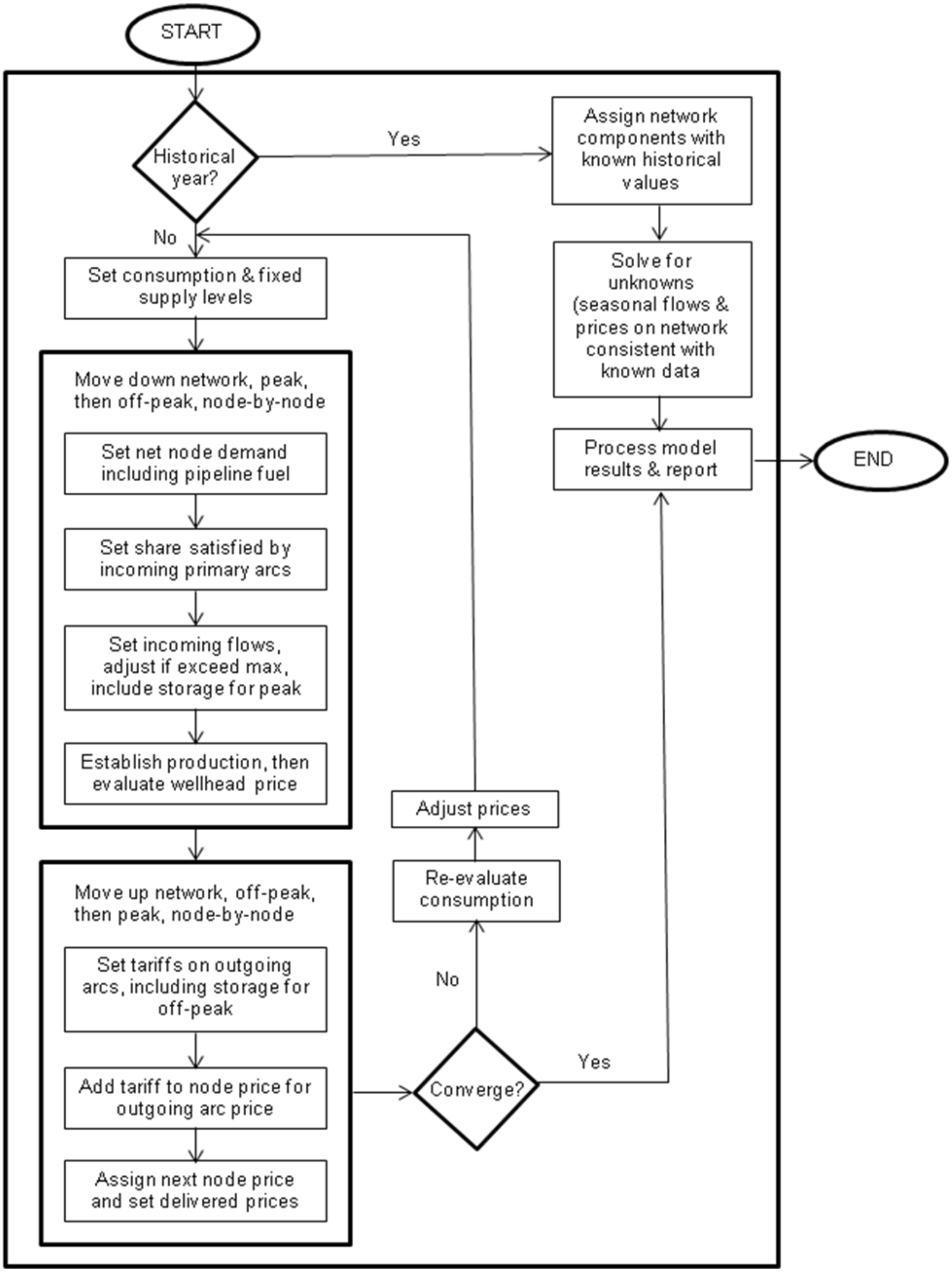
$$\begin{aligned}NODE\_DMD_{PK,r} = {} & PFUEL_{PK,r} + FLOW_{PK,a} + NODE\_CDMD_{PK,r} \\ & \sum_{nonu}(PKSHR\_DMD_{nonu,r} * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \\ & \sum_{jutil \subset r}(PKSHR\_UDMD_{jutil} * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil})\end{aligned} \qquad (55)$$

$$\begin{aligned}NODE\_CDMD_{PK,r} = {} & YEAR\_CDMD_{PK,r} - (PKSHR\_PROD_{s} * ZADGPRD_{s}) - \\ & (PKSHR\_ILNG * OGQNGIMP_{L,t})\end{aligned} \qquad (56)$$

$$\begin{aligned}YEAR\_CDMD_{PK,r} = {} & DISCR_{PK,r,t} + CN\_DISCR_{PK,cn} \\ & ((PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\ & (PK1 * SAFLOW_{a,t}) - (PK2 * SAFLOW_{a',t}) - \\ & (PKSHR\_YR * QAK\_ALB_{t}) - (PKSHR\_SUPLM * ZTOTSUP_{r}) - \\ & (PKSHR\_PROD_{s} * CN\_FIXSUP_{cn,t})\end{aligned} \qquad (57)$$

[57]The model typically solves within 3 to 6 cycles.

Figure 4-3. Interstate Transmission Submodule System



Off-Peak:

$$
\begin{aligned}
&NODE\_DMD_{OP,r} = PFUEL_{OP,r} + FLOW_{OP,a} + FLOW_{PK,st} + NODE\_CDMD_{OP,r} + \\
&\sum_{nonu}((1-PKSHR\_DMD_{nonu,r}) * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \\
&\sum_{jutil \subset r}((1-PKSHR\_UDMD_{jutil}) * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil})) +
\end{aligned} \tag{58}
$$

$$
\begin{aligned}
&NODE\_CDMD_{OP,r} = YEAR\_CDMD_{OP,r} - ((1-PKSHR\_PROD_s) * ZADGPRD_s) - \\
&((1-PKSHR\_ILNG) * OGQNGIMP_{L,t})
\end{aligned} \tag{59}
$$

$$
\begin{aligned}
&YEAR\_CDMD_{OP,r} = DISCR_{OP,r,t} + CN\_DISCR_{OP,cn} + \\
&((1-PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\
&((1-PK1) * SAFLOW_{a,t}) - ((1-PK2) * SAFLOW_{a',t}) - \\
&((1-PKSHR\_YR) * QAK\_ALB_t) - \\
&((1-PKSHR\_SUPLM) * ZTOTSUP_r) - \\
&((1-PKSHR\_PROD_s) * CN\_FIXSUP_{cn,t})
\end{aligned} \tag{60}
$$

where,

$NODE\_DMD_{n,r}$	=	net node demands in region r, for network n (Bcf)
$NODE\_CDMD_{n,r}$	=	net node demands remaining constant each NEMS iteration in region r, for network n (Bcf)
$YEAR\_CDMD_{n,r}$	=	net node demands remaining constant within a forecast year in region r, for network n (Bcf)
$PFUEL_{n,r}$	=	Pipeline fuel consumption in region r, for network n (Bcf)
$FLOW_{n,a}$	=	Seasonal flow on network n, along arc a [out of region r] (Bcf)
$ZNGQTY\_F_{nonu,r}$	=	Core demands in region r, by nonelectric sectors nonu (Bcf)
$ZNGQTY\_I_{nonu,r}$	=	Noncore demands in region r, by nonelectric sectors nonu(Bcf)
$ZNGUQTY\_F_{jutil}$	=	Core utility demands in NGTDM/EMM subregion jutil [subset of region r] (Bcf)
$ZNGUQTY\_I_{jutil}$	=	Noncore utility demands in NGTDM/EMM subregion jutil [subset of region r] (Bcf)
$ZADGPRD_s$	=	Onshore and offshore associated-dissolved gas production in supply subregion s (Bcf)
$DISCR_{n,r,t}$	=	Lower 48 discrepancy in region r, for network n, in forecast year t (Bcf)[58]

[58]Projected lower 48 discrepancies are primarily based on the average historical level from 1990 to 2009. Discrepancies are adjusted in the STEO years to account for STEO discrepancy (Appendix E, STDISCR) and annual net storage withdrawal

$CN\_DISCR_{n,cn}$ = Canada discrepancy in Canadian region cn, for network n (Bcf)
$CN\_DMD_{cn,t}$ = Canada demand in Canadian region cn, in forecast year t (Bcf, Appendix E)
$SAFLOW_{a,t}$ = Secondary flows out of region r, along arc a [includes Canadian and Mexican exports, Canadian gas that flows through the U.S., and lower 48 bidirectional flows] (Bcf)
$SAFLOW_{a',t}$ = Secondary flows into region r, along arc a' [includes Mexican imports, Canadian imports into the East North Central Census Division, Canadian gas that flows through the U.S., and lower 48 bidirectional flows] (Bcf)
QAK_ALB_t = Natural gas flow from Alaska into Alberta via pipeline (Bcf)
$ZTOTSUP_r$ = Total supply from SNG liquids, SNG coal, and other supplemental in forecast year t (Bcf)
$OGQNGIMP_{L,t}$ = LNG imports from LNG region L, in forecast year t (Bcf)
$CN\_FIXSUP_{cn,t}$ = Fixed supply from Canadian region cn, in forecast year t (Bcf, Appendix E)
PK1, PK2 = Fraction of either in-flow or out-flow volumes corresponding to peak season (composed of PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, or PKSHR_YR)
$PKSHR\_DMD_{nonu,r}$ = Average (2001-2009) fraction of annual consumption in each nonelectric sector in region r corresponding to the peak season
$PKSHR\_UDMD_{jutil}$ = Average (1994-2009, except New England 1997-2009) fraction of annual consumption in the electric generator sector in region r corresponding to the peak season
$PKSHR\_PROD_s$ = Average (1994-2009) fraction of annual production in supply region s corresponding to the peak season (fraction, Appendix E)
PKSHR_CDMD = Fraction of annual Canadian demand corresponding to the peak season (fraction, Appendix E)
PKSHR_YR = Fraction of the year represented by the peak season
PKSHR_SUPLM = Average (1990-2009) fraction of supplemental supply corresponding to the peak season
PKSHR_ILNG = Fraction of LNG imports corresponding to the peak season
PKSHR_ECAN = Fraction of Canadian exports transferred in peak season
PKSHR_ICAN = Fraction of Canadian imports transferred in peak season
PKSHR_EMEX = Fraction of Mexican exports transferred in peak season
PKSHR_IMEX = Fraction of Mexican imports transferred in peak season
r = region/node
n = network (peak or off-peak)
PK,OP = Peak and off-peak network, respectively
nonu = Nonelectric sector ID: residential, commercial, industrial, transportation
jutil = Utility sector subregion ID in region r
a,a' = Arc ID for arc entering (a') or exiting (a) region r

(Appendix E, NNETWITH) forecasts, and differences between NEMS and STEO total consumption levels Appendix E, STENDCON). These adjustments are phased out over a user-specified number of years (Appendix E, STPHAS_YR).

s = Supply subregion ID into region r (1-21)
cn = Canadian supply subregion ID in region r (1-2)
L = LNG import region ID into region r (1-12)
st = Arc ID corresponding to storage supply into region r
t = Current forecast year

Pipeline Fuel Use and Intraregional Flows

Pipeline fuel consumption represents the natural gas consumed by compressors to transmit gas along pipelines within a region. In the ITS, pipeline fuel consumption is modeled as a regional demand component. It is estimated for each region on each network using a historically based factor, corresponding net demands, and a multiplicative scaling factor. The scaling factor is used to calibrate the results to equal the most recent national *Short-Term Energy Outlook (STEO)* forecast[59] for pipeline fuel consumption (Appendix E, STQGPTR), net of pipeline fuel consumption in Alaska (QALK_PIP), and is phased out by a user-specified year (Appendix E, STPHAS_YR). The following equation applies:

$$PFUEL_{n,r} = PFUEL\_FAC_{n,r} * NODE\_DMD_{n,r} * SCALE\_PF \tag{61}$$

where,

$PFUEL_{n,r}$ = Pipeline fuel consumption in region r, for network n (Bcf)
$PFUEL\_FAC_{n,r}$ = Average (2004-2009) historical pipeline fuel factor in region r, for network n (calculated historically for each region as equal PFUEL/NODE_DMD)
$NODE\_DMD_{n,r}$ = Net demands (excluding pipeline fuel) in region r, for network n (Bcf)
$SCALE\_PF$ = STEO benchmark factor for pipeline fuel consumption
n = network (peak and off-peak)
r = region/node

After pipeline fuel consumption is calculated for each node on the network, the regional/seasonal value is added to net demand at the respective node. Flows into a node ($FLOW_{n,a}$) are then defined using net demands and a sharing algorithm (described below). The regional pipeline fuel quantity (net of intraregional pipeline fuel consumption) [60] is distributed over the pipeline arcs entering the region. This is accomplished by sharing the net pipeline fuel quantity over all of the interregional pipeline arcs entering the region, based on their relative levels of natural gas flow:

[59] EIA produces a separate quarterly forecast for primary national energy statistics over the next several years. For certain forecast items, the NEMS is calibrated to produce an equivalent (within 2 to 5 percent) result for these years. For *AEO2011*, the years calibrated to *STEO* results were 2010 and 2011.

[60] Currently, intraregional pipeline fuel consumption (INTRA_PFUEL) is set equal to the regional pipeline fuel consumption level (PFUEL); therefore, pipeline fuel consumption along an arc (ARC_PFUEL) is set to zero. The original design was to allocate pipeline fuel according to flow levels on arcs and within a region. It was later determined that assigning all of the pipeline fuel to a region would simplify benchmarking the results to the STEO and would not change the later calculation of the price impacts of pipeline fuel use.

$$ARC\_PFUEL_{n,a} = (PFUEL_{n,r} - INTRA\_PFUEL_{n,r}) * \frac{FLOW_{n,a}}{TFLOW} \quad (62)$$

where,

$ARC\_PFUEL_{n,a}$	=	Pipeline fuel consumption along arc a (into region r), for network n (Bcf)
$PFUEL_{n,r}$	=	Pipeline fuel consumption in region r, for network n (Bcf)
$INTRA\_PFUEL_{n,r}$	=	Intraregional pipeline fuel consumption in region r, for network n (Bcf)
$FLOW_{n,a}$	=	Interregional pipeline flow along arc a (into region r), for network n (Bcf)
TFLOW	=	Total interregional pipeline flow [into region r] (Bcf)
n	=	network (peak and off-peak)
r	=	region/node
a	=	arc

Pipeline fuel consumption along an interregional arc and within a region on an intrastate pipeline will have an impact on pipeline tariffs and node prices. This will be discussed later in the Arc, Node, and Storage Prices subsection.

The flows of natural gas on the interstate pipeline system within each NGTDM region (as opposed to between two NGTDM regions) are established for the purpose of setting the associated revenue requirements and tariffs. The charge for moving gas within a region (INTRAREG_TAR), but on the interstate pipeline system, is taken into account when setting city gate prices, described below. The algorithm for setting intraregional flows is similar to the method used for setting pipeline fuel consumption. For each region in the historical years, a factor is calculated reflective of the relationship between the net node demand and the intraregional flow. This factor is applied to the net node demand in each forecast year to approximate the associated intraregional flow. Pipeline fuel consumption is excluded from the net node demand for this calculation, as follows:

Calculation of intraregional flow factor based on data for an historical year:

$$FLO\_FAC_{n,r} = INTRA\_FLO_{n,r} \; / \; (NODE\_DMD_{n,r} - PFUEL_{n,r}) \quad (63)$$

Forecast of intraregional flow:

$$INTRA\_FLO_{n,r} = FLO\_FAC_{n,r} * (NODE\_DMD_{n,r} - PFUEL_{n,r}) \quad (64)$$

where,

$INTRA\_FLO_{n,a}$	=	Intraregional, interstate pipeline flow within region r, for network n (Bcf)
$PFUEL_{n,r}$	=	Pipeline fuel consumption in region r, for network n (Bcf)
$NODE\_DMD_{n,r}$	=	Net demands (with pipeline fuel) in region r, for network n (Bcf)

$FLO\_FAC_{n,r}$ = Average (1990 - 2009) historical relationship between net node demand and intraregional flow
n = network (peak and off-peak)
r = region/node

Historical annual intraregional flows are set for the peak and off-peak periods based on the peak and off-peak share of net node demand in each region.

Sharing Algorithm, Flows, and Capacity Expansion

Moving systematically downward from node to node through the acyclic network, the sharing algorithm is allocates net demands ($NODE\_DMD_{n,r}$) across all arcs feeding into the node. These "inflow" arcs carry flows from local supply sources, storage (net withdrawals during peak period only), or other regions (interregional arcs). If any of the resulting flows exceed their corresponding maximum levels,[61] then the excess flows are reallocated to the unconstrained arcs, and new shares are calculated accordingly. At each node within a network, the sharing algorithm determines the percent of net demand ($SHR_{n,a,t}$) that is satisfied by each of the arcs entering the region.

The sharing algorithm (shown below) dictates that the share ($SHR_{n,a,t}$) of demand for one arc into a node is a function of the share defined in the previous model year[62] and the ratio of the price on the one arc relative to the average of the prices on all of the arcs into the node, as defined the previous cycle up the network tree. These prices ($ARC\_SHRPR_{n,a}$) represents the unit cost associated with an arc going into a node, and is defined as the sum of the unit cost at the source node ($NODE\_SHRPR_{n,r}$) *and* the tariff charge along the arc ($ARC\_SHRFEE_{n,a}$). (A description of how these components are developed is presented later.) The variable γ is an assumed parameter that is always positive. This parameter can be used to prevent (or control) broad shifts in flow patterns from one forecast year to the next. Larger values of γ increase the sensitivity of $SHR_{n,a,t}$ to relative prices; a very large value of γ would result in behavior equivalent to cost minimization. The algorithm is presented below:

$$SHR_{n,a,t} = \frac{ARC\_SHRPR_{n,a}^{-\gamma}}{\frac{\sum_{b} ARC\_SHRPR_{n,b}^{-\gamma}}{N}} * SHR_{n,a,t-1} \tag{65}$$

where,

$SHR_{n,a,t}$, $SHR_{n,a,t-1}$ = The fraction of demand represented along inflow arc a on network n, in year t (or year t-1) [Note: The value for year t-1 has a lower limit set to 0.01]

[61] Maximum flows include potential pipeline or storage capacity additions, and maximum production levels.

[62] When planned pipeline capacity is added at the beginning of a forecast year, the value of SHR_{t-1} is adjusted to reflect a percent usage (PCTADJSHR, Appendix E) of the new capacity. This adjustment is based on the assumption that last year's share would have been higher if not constrained by the existing capacity levels.

$ARC\_SHRPR_{n,a\ or\ b}$	=	The last price calculated for natural gas from inflow arc a (or b) on network n [i.e., from the previous cycle while moving up the network] (87$/Mcf)
N	=	Total number of arcs into a node
γ	=	Coefficient defining degree of influence of relative prices (represented as GAMMAFAC, Appendix E)
t	=	forecast year
n	=	network (peak or off-peak)
a	=	arc into a region
r	=	region/node
b	=	set of arcs into a region

[Note: The resulting shares ($SHR_{n,a,t}$) along arcs going into a node are then normalized to ensure that they add to one.]

Seasonal flows are generated for each arc using the resulting shares and net node demands, as follows:

$$FLOW_{n,a} = SHR_{n,a,t} * NODE\_DMD_{n,r} \tag{66}$$

where,

$FLOW_{n,a}$	=	Interregional flow (into region r) along arc a, for network n (Bcf)
$SHR_{n,a,t}$	=	The fraction of demand represented along inflow arc a on network n, in year t
$NODE\_DMD_{n,r}$	=	Net node demands in region r, for network n (Bcf)
n	=	network (peak or off-peak)
a	=	arc into a region
r	=	region/node

These flows must not exceed the maximum flow limits ($MAXFLO_{n,a}$) defined for each arc on each network. The algorithm used to define maximum flows may differ depending on the type of arc (storage, pipeline, supply, Canadian imports) and the network being referenced. For example, maximum flows for all *peak* network arcs are a function of the maximum permissible annual capacity levels ($MAXPCAP_{PK,a}$) and peak utilization factors. However, maximum *pipeline* flows along the *off-peak* network arcs are a function of the annual capacity defined by peak flows and off-peak utilization factors. Thus, maximum flows along the off-peak network depend on whether or not capacity was added during the peak period. Also, maximum flows from *supply* sources in the off-peak network are limited by maximum annual capacity levels and off-peak utilization. (Note: *storage* arcs do not enter nodes on the off-peak network; therefore, maximum flows are not defined there.) The following equations define maximum flow limits and maximum annual capacity limits:

Maximum peak flows (note: for storage arcs, PKSHR_YR=1):

$$MAXFLO_{PK,a} = MAXPCAP_{PK,a} * (PKSHR\_YR * PKUTZ_a) \tag{67}$$

with $MAXPCAP_{PK,a}$ defined by type as follows:

for *Supply*[63]:

$$MAXPCAP_{PK,a} = ZOGRESNG_s * ZOGPRRNG_s * MAXPRRFAC * (1 - (PCTLP_r * SCALE\_LP_t)) \tag{68}$$

for *Pipeline*:

$$MAXPCAP_{PK,a} = PTMAXPCAP_{i,j} \tag{69}$$

for *Storage*:

$$MAXPCAP_{PK,a} = PTMAXPSTR_{st} \tag{70}$$

for *Canadian imports*:

$$MAXPCAP_{PK,a} = CURPCAP_{a,t} \tag{71}$$

Maximum off-peak pipeline flows:

$$MAXFLO_{OP,a} = MAXPCAP_{OP,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \tag{72}$$

with MAXPCAPOP,a is defined as follows for

either *current capacity:*

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} \tag{73}$$

or *current capacity* plus *capacity additions*,

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} + ((1 + XBLD) * \left(\frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} - CURPCAP_{a,t}\right)) \tag{74}$$

or, for *pipeline arc entering region 10 (Florida), peak maximum capacity*,

$$MAXPCAP_{OP,a} = MAXPCAP_{PK,a} \tag{75}$$

[63]In historical years, historical production values are used in place of the product of ZOGRESNG and ZOGPRRNG.

Maximum off-peak flows from supply sources:

$$MAXFLO_{OP,a} = MAXPCAP_{PK,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \quad (76)$$

where,

$MAXFLO_{n,a}$	=	Maximum flow on arc a, in network n [PK-peak or OP-off-peak] (Bcf)
$MAXPCAP_{n,a}$	=	Maximum annual physical capacity along arc a for network n (Bcf)
$CURPCAP_{a,t}$	=	Current annual physical capacity along arc a in year t (Bcf)
$ZOGRESNG_s$	=	Natural gas reserve levels for supply source s [defined by OGSM] (Bcf)
$ZOGPRRNG_s$	=	Expected natural gas production-to-reserves ratio for supply source s [defined by OGSM] (fraction)
MAXPRRFAC	=	Factor to set maximum production-to-reserves ratio [MAXPRRCAN for Canada] (Appendix E)
$PCTLP_t$	=	Average (1996-2009) fraction of production consumed as lease and plant fuel in forecast year t
$SCALE\_LP_t$	=	Scale factor for STEO year percent lease and plant consumption for forecast year t to force regional lease and plant consumption forecast to total to STEO forecast.
$PTMAXPCAP_{i,j}$	=	Maximum pipeline capacity along arc defined by source node i and destination node j [defined by PTS] (Bcf)
$PTMAXPSTR_{st}$	=	Maximum storage capacity for storage source st [defined by PTS] (Bcf)
$FLOW_{PK,a}$	=	Flow along arc a for the peak network (Bcf)
PKSHR_YR	=	Fraction of the year represented by peak season
$PKUTZ_a$	=	Pipeline utilization along arc a for the peak season (fraction, Appendix E)
$OPUTZ_a$	=	Pipeline utilization along arc a for the off-peak season (fraction, Appendix E)
XBLD	=	Percent increase over capacity builds to account for weather (fraction, Appendix E)
a	=	arc
t	=	forecast year
n	=	network (peak or off-peak)
PK, OP	=	peak and off-peak network, respectively
s,st	=	supply or storage source
i,j	=	regional source (i) and destination (j) link on arc a

If the model has been restricted from building capacity through a specified forecast year (Appendix E, NOBLDYR), then the maximum pipeline and storage flow for either network will be based only on current capacity and utilization for that year.

If the flows defined by the sharing algorithm above exceed these maximum levels, then the excess flow is reallocated along adjacent arcs that have excess capacity. This is achieved by determining the flow distribution of the qualifying adjacent arcs, and distributing the excess flow according to this distribution. These adjacent arcs are checked again for excess flow; if excess flow is found, the reallocation process is performed again on all arcs with space remaining. This applies to supply and pipeline arcs on all networks, as well as storage withdrawal arcs on the peak network. To handle the event where insufficient space or supply is available on all inflowing arcs to meet demand, a backstop supply ($BKSTOP_{n,r}$) is available at an incremental price ($RBKSTOP\_PADJ_{n,r}$). The intent is to dissuade use of the particular route, or to potentially lower demands. Backstop pricing will be defined in another section below.

With the exception of import and export arcs,[64] the resulting interregional flows defined by the sharing algorithm for the peak network are used to determine if *pipeline* capacity expansion should occur. Similarly, the resulting storage withdrawal quantities in the peak season define the *storage* capacity expansion levels. Thus, initially capacity expansion is represented by the difference between new capacity levels ($ACTPCAP_a$) and current capacity ($CURPCAP_{a,t}$, previous model year capacity plus planned additions). In the module, these initial new capacity levels are defined as follows:

Storage:

$$ACTPCAP_a = \frac{FLOW_{PK,a}}{PKUTZ_a} \tag{77}$$

Pipeline:

$$ACTPCAP_a = MAXPCAP_{OP,a} \tag{78}$$

Pipeline arc entering region 10 (Florida):

$$ACTPCAP_a = \text{MAX between } \frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} \text{ and } \frac{FLOW_{OP,a}}{(1 - PKSHR\_YR) * OPUTZ_a} \tag{79}$$

where,

$ACTPCAP_a$	=	Annual physical capacity along an arc a (Bcf)
$MAXPCAP_{OP,a}$	=	Maximum annual physical capacity along pipeline arc a for network n [see equation above] (Bcf)
$FLOW_{n,a}$	=	Flow along arc a on network n (Bcf)
$PKUTZ_a$	=	Maximum peak utilization of capacity along arc a (fraction, Appendix E)
$OPUTZ_a$	=	Maximum off-peak utilization of capacity along arc a (fraction, Appendix E)
PKSHR_YR	=	Fraction of the year represented by the peak season
a	=	pipeline and storage arc
n	=	network (peak or off-peak)

[64]For *AEO2011* capacity expansion on Canadian import arcs were set exogenously (PLANPCAP, Appendix E).

PK = peak season
OP = off-peak season

A second check and potential adjustment are made to these capacity levels to insure that capacity is sufficient to handle estimated flow in the peak month of each period.[65] Since capacity is defined as sustained capacity, it is assumed that the peak month flows should be in accordance with the maximum capacity requirements of the system, short of line packing, propane injections, and planning for the potential of above average temperature months.[66] Peak month consumption and supply levels are set at an assumed fraction of the corresponding period levels. Based on historical relationships, an initial guess is made at the fraction of each period's net storage withdrawals removed during the peak month. With this information, peak month flows are set at the same time flows are set for each period, while coming down the network tree, and following a similar process. At each node a net monthly demand is set equal to the sum of the monthly flows going out of the node, plus the monthly consumption at the node, minus the monthly supply and net storage withdrawals. The period shares are then used to set initial monthly flows, as follows:

$$MTHFLW_{n,a} = MTH\_NETNOD_{n,r} * \frac{SHR_{n,a,t}}{\sum_{c} SHR_{n,c,t}} \tag{80}$$

where,

$MTHFLW_{n,a}$ = Monthly flow along pipeline arc a (Bcf)
$MTH\_NETNOD_{n,r}$ = Monthly net demand at node r (Bcf)
$SHR_{n,a,t}$ = Fraction of demand represented along inflow arc a
c = set of arcs into a region representing pipeline arcs
n = network (peak or off-peak)
a = arc into a region
r = region/node
t = forecast year

These monthly flows are then compared against a monthly capacity estimate for each pipeline arc and reallocated to the other available arcs if capacity is exceeded, using a method similar to what is done when flows for a period exceed maximum capacity. These adjusted monthly flows are used later in defining the net node demand for nodes lower in the network tree. Monthly capacity is estimated by starting with the previously set ACTPCAP for the pipeline arc divided by the number of months in the year, to arrive at an initial monthly capacity estimate (MTH_CAP). This number is increased if the total of the monthly capacity entering a node exceeds the monthly net node demand, as follows:

$$MTH\_CAPADD_{n,a} = MTH\_TCAPADD_{n} * \frac{INIT\_CAPADD_{n,a}}{\sum_{c} INIT\_CAPADD_{n,c}} \tag{81}$$

[65] Currently this is only done in the model for the peak period of the year.
[66] To represent that the pipeline system is built to accommodate consumption levels outside the normal range due to colder than normal temperatures, the net monthly demand levels are increased by an assumed percentage (XBLD, Appendix E).

where,

$MTH\_CAPADD_{n,a}$ = Additional added monthly capacity to accommodate monthly flow estimates (Bcf)

$MTH\_TCAPADD_{n}$ = Total initial monthly capacity entering a node minus monthly net node demand (Bcf), if value is negative then it is set to zero

$INIT\_CAPADD_{n,a}$ = MTHFLWa - MTH_CAPa, if value is negative then it is set to zero (Bcf)

n = network (peak or off-peak)

a = arc into a region

c = set of arcs into a region representing pipeline arcs

The additional added monthly capacity is multiplied by the number of months in the year and added to the originally estimated pipeline capacity levels for each arc (ACTPCAP). Finally, if the net node demand is not close to zero at the lowest node on the network tree (node number 24 in western Canada), then monthly storage levels are adjusted proportionally throughout the network to balance the system for the next time quantities are brought down the network tree.

Wellhead and Henry Hub Prices

Ultimately, all of the network-specific consumption levels are transferred down the network trees and into supply nodes, where corresponding supply prices are calculated. The Oil and Gas Supply Module (OGSM) provides only annual price/quantity supply curve parameters for each supply subregion. Because this alone will not provide a wellhead price differential between seasons, a special methodology has been developed to approximate seasonal prices that are consistent with the annual supply curve. First, in effect the quantity axis of the annual supply curve is scaled to correspond to seasonal volumes (based on the period's share of the year); and the resulting curves are used to approximate seasonal prices. (Operationally within the model this is done by converting seasonal production values to annual equivalents and applying these volumes to the annual supply curve to arrive at seasonal prices.) Finally, the resulting seasonal prices are scaled to ensure that the quantity-weighted average annual wellhead price equals the price obtained from the annual supply curve when evaluated using total annual production. To obtain seasonal wellhead prices, the following methodology is used. Taking one supply region at a time, the model estimates equivalent annual production levels (ANNSUP) for each season.

Peak:

$$ANNSUP = \frac{NODE\_QSUP_{PK,s}}{PKSHR\_YR} \tag{82}$$

Off-peak:

$$ANNSUP = \frac{NODE\_QSUP_{OP,s}}{(1 - PKSHR\_YR)} \tag{83}$$

where,

ANNSUP = Equivalent annual production level (Bcf)

$NODE\_QSUP_{n,s}$ = Seasonal (n=PK-peak or OP-off-peak) production level for supply region s (Bcf)

PKSHR_YR	=	Fraction of year represented by peak season
PK	=	peak season
OP	=	off-peak season
s	=	supply region

Next, estimated seasonal prices ($SPSUP_n$) are obtained using these equivalent annual production levels and the annual supply curve function. These initial seasonal prices are then averaged, using quantity weights, to generate an equivalent *average* annual supply price ($SPAVG_s$). An *actual* annual price ($PSUP_s$) is also generated, by evaluating the price on the annual supply function for a quantity equal to the sum of the seasonal production levels. The *average* annual supply price is then compared to the *actual* price. The corresponding ratio (FSF) is used to adjust the estimated seasonal prices to generate final seasonal supply prices ($NODE\_PSUP_{n,s}$) for a region.

For a *supply source* s,

$$FSF = \frac{PSUP_s}{SPAVG_s} \tag{84}$$

and,

$$NODE\_PSUP_{n,s} = SPSUP_n * FSF \tag{85}$$

where,

FSF	=	Scaling factor for seasonal prices
$PSUP_s$	=	Annual supply price from the annual supply curve for supply region s (87$/Mcf)
$SPAVG_s$	=	Quantity-weighted average annual supply price using peak and off-peak prices and production levels for supply region s (87$/Mcf)
$NODE\_PSUP_{n,s}$	=	Adjusted seasonal supply prices for supply region s (87$/Mcf)
$SPSUP_n$	=	Estimated seasonal supply prices [for supply region s] (87$/Mcf)
n	=	network (peak or off-peak)
s	=	supply source

During the STEO years (2010 and 2011 for *AEO2011*), national average wellhead prices (lower 48 only) generated by the model are compared to the national STEO wellhead price forecast to generate a benchmark factor ($SCALE\_WPR_t$). This factor is used to adjust the regional (annual and seasonal) lower 48 wellhead prices to equal STEO results. This benchmark factor is only applied for the STEO years. The benchmark factor is applied as follows:

Annual:

$$PSUP_s = PSUP_s * SCALE\_WPR_t \tag{86}$$

Seasonal:

$$NODE\_PSUP_{n,s} = NODE\_PSUP_{n,s} * SCALE\_WPR_t \tag{87}$$

where,

$PSUP_s$ = Annual supply price from the annual supply curve for supply region s (87$/Mcf)
$NODE\_PSUP_{n,s}$ = Adjusted seasonal supply prices for supply region s (87$/Mcf)
$SCALE\_WPR_t$ = STEO benchmark factor for wellhead price in year t
n = network (peak or off-peak)
s = supply source
t = forecast year

A similar adjustment is made for the Canadian supply price, with an additional multiplicative factor applied (STSCAL_CAN, Appendix E) which is set to align Canadian import levels with STEO results.

While the NGTDM does not explicitly represent the Henry Hub within its modeling structure, the module reports a projected value for reporting purposes. The price at the Henry Hub is set using an econometrically estimated equation as a function of the lower 48 average natural gas wellhead price, as follows:

$$oOGHHPRNG_t = 1.00439 * e^{0.090246} * oOGWPRNG_{s=13,t}^{1.00119} \quad (88)$$

where,

$oOGHHPRNG_t$ = Natural gas price at the Henry Hub (87$/MMBtu)
$oOGWPRNG_{s,t}$ = Average natural gas wellhead price for supply region 13, representing the lower 48 average (87$/Mcf)
s = supply source/region
t = forecast year

Details about the generation of this estimated equation and associated parameters are provided in **Table F9**, Appendix F.

Arc Fees (Tariffs)

Fees (or tariffs) along arcs are used in conjunction with supply, storage, and node prices to determine competing arc prices that, in turn, are used to determine network flows, transshipment node prices, and delivered prices. Arc fees exist in the form of pipeline tariffs, storage fees, and gathering charges. Pipeline tariffs are transportation rates along interregional arcs, and reflect the average rate charged over all of the pipelines represented along an arc. Storage fees represent the charges applied for storing, injecting, and withdrawing natural gas that is injected in the off-peak period for use in the peak period, and are applied along arcs connecting the storage sites to the peak network. Gathering charges are applied to the arcs going from the supply points to the transshipment nodes.

Pipeline and storage tariffs consist of both a fixed (volume independent) term and a variable (volume dependent) term. For pipelines the fixed term ($ARC\_FIXTAR_{n,a,t}$) is set in the PTS at the beginning of each forecast year to represent pipeline usage fees and does not vary in response to changes in flow in the current year. For storage, the fixed term establishes a minimum and is set to $0.001 per Mcf. The variable term is obtained from tariff/capacity curves provided by two PTS functions and represents reservation fees for pipelines and all charges for storage. These two functions are NGPIPE_VARTAR and X1NGSTR_VARTAR. When determining network flows a different set of tariffs ($ARC_SHRFEE_{n,a}$) are used than are used when setting delivered prices ($ARC_ENDFEE_{n,a}$).

In the peak period ARC_SHRFEE equals ARC_ENDFEE and the total tariff (reservation plus usage fee). In the off-peak period, ARC_ENDFEE represents the total tariff as well, but ARC_SHRFEE represents the fee that drives the flow decision. In previous AEOs this was set to just the usage fee. The assumption behind this structure was that delivered prices will ultimately reflect reservation charges, but that during the off-peak period in particular, decisions regarding the purchase and transport of gas are made largely independently of where pipeline is reserved and the associated fees. For *AEO2011* the ARC_SHRFEE was set similarly to ARC_ENDFEE because the usage fees seemed to be underestimating off-peak market prices. (This decision will be reexamined in the future.) During the peak period, the gas is more likely to flow along routes where pipeline is reserved; therefore the flow decision is more greatly influenced by the relative reservation fees.[67] The following arc tariff equations apply:

Pipeline:

$$\begin{aligned} ARC\_ENDFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n,a,i,j,FLOW_{n,a}) \\ ARC\_SHRFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n,a,i,j,FLOW_{n,a}) \end{aligned} \tag{89}$$

Storage:

$$\begin{aligned} ARC\_SHRFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + X1NGSTR\_VARTAR(st,FLOW_{n,a}) \\ ARC\_ENDFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + X1NGSTR\_VARTAR(st,FLOW_{n,a}) \end{aligned} \tag{90}$$

where,

$ARC\_SHRFEE_{n,a}$	=	Total arc fees along arc a for network n [used with sharing algorithm] (87$/Mcf)
$ARC\_ENDFEE_{n,a}$	=	Total arc fees along arc a for network n [used with delivered pricing] (87$/Mcf)
$ARC\_FIXTAR_{n,a,t}$	=	Fixed (or usage) fees along an arc a for a network n in time t (87$/Mcf)
NGPIPE_VARTAR	=	PTS function to define pipeline tariffs representing reservation fees for specified arc at given flow level
X1NGSTR_VARTAR	=	PTS function to define storage fees at specified storage region for given storage level

[67]Reservation fees are frequently considered "sunk" costs and are not expected to influence short-term purchasing decisions as much, but still must ultimately be paid by the end-user. Therefore within the ITS, the arc prices used in determining flows can have tariff components defined differently than their counterparts (arc and node prices) ultimately used to establish delivered prices.

$FLOW_{n,a}$ = Flow of natural gas on the arc in the given period
n = network (peak or off-peak)
a = arc
i, j = from transshipment node i to transshipment node j

A methodology for defining gathering charges has not been developed but may be developed in a separate effort at a later date.[68] In order to accommodate this, the supply arc indices in the variable $ARC\_FIXTAR_{n,a}$ have been reserved for this information (currently set to 0). Since the historical wellhead price represents a first-purchase price, the cost of gathering is frequently already included and no further charge should be added.

Arc, Node, and Storage Prices

Prices at the transshipment nodes (or node prices) represent intermediate prices that are used to determine regional delivered prices. Node prices (along with tariffs) are also used to help make model decisions, primarily within the flow-sharing algorithm. In both cases it is not required (as described above) to set delivered or arc prices using the same price components or methods used to define prices needed to establish flows along the networks (e.g., in setting $ARC\_SHRPR_{n,a}$ in the share equation). Thus, *process-specific* node prices ($NODE\_ENDPR_{n,r}$ and $NODE\_SHRPR_{n,r}$) are generated using *process-specific* arc prices ($ARC\_ENDPR_{n,a}$ and $ARC\_SHRPR_{n,a}$) which, in turn, are generated using *process-specific* arc fees/tariffs ($ARC\_ENDFEE_{n,a}$ and $ARC\_SHRFEE_{n,a}$).

The following equations define the methodology used to calculate arc prices. Arc prices are first defined as the average node price at the source node plus the arc fee (pipeline tariff, storage fee, or gathering charge). Next, the arc prices along pipeline arcs are adjusted to account for the cost of pipeline fuel consumption. These equations are as follows:

$$ARC\_SHRPR_{n,a} = NODE\_SHRPR_{n,rs} + ARC\_SHRFEE_{n,a}$$

$$ARC\_ENDPR_{n,a} = NODE\_ENDPR_{n,rs} + ARC\_ENDFEE_{n,a} \qquad (91)$$

with the adjustment accomplished through the assignment statements:

$$ARC\_SHRPR_{n,a} = \frac{(ARC\_SHRPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})}$$

$$ARC\_ENDPR_{n,a} = \frac{(ARC\_ENDPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})} \qquad (92)$$

[68]In a previous version of the NGTDM, "gathering" charges were used to benchmark the regional wellhead prices to historical values. It is possible that they may be used (at least in part) to fulfill the same purpose in the ITS. In the past an effort was made, with little success, to derive representative gathering charges. Currently, the gathering charge portion of the tariff along the supply arcs is assumed to be zero.

where,

$ARC\_SHRPR_{n,a}$	=	Price calculated for natural gas along inflow arc a for network n [used with sharing algorithm] (87$/Mcf)
$ARC\_ENDPR_{n,a}$	=	Price calculated for natural gas along inflow arc a for network n [used with delivered pricing] (87$/Mcf)
$NODE\_SHRPR_{n,r}$	=	Node price for region i on network n [used with sharing algorithm] (87$/Mcf)
$NODE\_ENDPR_{n,r}$	=	Node price for region i on network n [used with delivered pricing] (87$/Mcf
$ARC\_SHRFEE_{n,a}$	=	Tariff along inflow arc a for network n [used with sharing algorithm] (87$/Mcf)
$ARC\_ENDFEE_{n,a}$	=	Tariff along inflow arc a for network n [used with delivered pricing] (87$/Mcf)
$ARC\_PFUEL_{n,a}$	=	Pipeline fuel consumption along arc a, for network n (Bcf)
$FLOW_{n,a}$	=	Network n flow along arc a (Bcf)
n	=	network (peak or off-peak)
a	=	arc
rs	=	region corresponding to source link on arc a

Although each type of node price may be calculated differently (e.g., average prices for delivered price calculation, marginal prices for flow sharing calculation, or some combination of these for each), the current model uses the quantity-weighted averaging approach to establish node prices for both the delivered pricing and flow sharing algorithm pricing. Prices from all arcs entering a node are included in the average. Node prices then are adjusted to account for intraregional pipeline fuel consumption. The following equations apply:

$$NODE\_SHRPR_{n,rd} = \frac{\Sigma_a (ARC\_SHRPR_{n,a} * FLOW_{n,a})}{\Sigma_a (FLOW_{n,a} - ARC\_PFUEL_{n,a})}$$

$$NODE\_ENDPR_{n,rd} = \frac{\Sigma_a (ARC\_ENDPR_{n,a} * FLOW_{n,a})}{\Sigma_a (FLOW_{n,a} - ARC\_PFUEL_{n,a})} \tag{93}$$

and,

$$NODE\_SHRPR_{n,rd} = \frac{(NODE\_SHRPR_{n,rd} * NODE\_DMD_{n,rd})}{(NODE\_DMD_{n,rd} - INTRA\_PFUEL_{n,rd})}$$

$$NODE\_ENDPR_{n,rd} = \frac{(NODE\_ENDPR_{n,rd} * NODE\_DMD_{n,rd})}{(NODE\_DMD_{n,rd} - INTRA\_PFUEL_{n,rd})} \tag{94}$$

where,

$NODE\_SHRPR_{n,r}$ = Node price for region r on network n [used with flow sharing algorithm] (87$/Mcf)
$NODE\_ENDPR_{n,r}$ = Node price for region r on network n [used with delivered pricing] (87$/Mcf)
$ARC\_SHRPR_{n,a}$ = Price calculated for natural gas along inflow arc a for network n [used with flow sharing algorithm] (87$/Mcf)
$ARC\_ENDPR_{n,a}$ = Price calculated for natural gas along inflow arc a for network n [used with delivered pricing] (87$/Mcf)
$FLOW_{n,a}$ = Network n flow along arc a (Bcf)
$ARC\_PFUEL_{n,a}$ = Pipeline fuel consumed along the pipeline arc a, network n (Bcf)
$INTRA\_PFUEL_{n,r}$ = Intraregional pipeline fuel consumption in region r, network n (Bcf)
$NODE\_DMD_{n,r}$ = Net node demands (w/ pipeline fuel) in region r, network n (Bcf)
n = network (peak or off-peak)
a = arc
rd = region r destination link along arc a

Once node prices are established for the off-peak network, the cost of the gas injected into storage can be modeled. Thus, for every region where storage is available, the storage node price is set equal to the off-peak regional node price. This applies for both the delivered pricing and the flow sharing algorithm pricing:

$$NODE\_SHRPR_{PK,i} = NODE\_SHRPR_{OP,r}$$

$$NODE\_ENDPR_{PK,i} = NODE\_ENDPR_{OP,r} \qquad (95)$$

where,
$NODE\_SHRPR_{PK,i}$ = Price at node i [used with flow sharing algorithm] (87$/Mcf)
$NODE\_SHRPR_{OP,r}$ = Price at node r in off-peak network [used with flow sharing algorithm] (87$/Mcf)
$NODE\_ENDPR_{PK,ii}$ = Price at node i [used with delivered pricing] (87$/Mcf)
$NODE\_ENDPR_{OP,r}$ = Price at node r in off-peak network [used with delivered pricing] (87$/Mcf)
PK, OP = peak and off-peak network, respectively
i = node ID for storage
r = region ID where storage exists

Backstop Price Adjustment

Backstop supply[69] is activated when seasonal net demand within a region exceeds total available supply for that region. When backstop occurs, the corresponding *share* node price ($NODE\_SHRPR_{n,r}$) is adjusted upward in an effort to reduce the demand for gas from this

[69]Backstop supply can be thought of as a high-priced alternative supply when no other options are available. Within the model, it also plays an operational role in sending a price signal when equilibrating the network that additional supplies are unavailable along a particular path in the network.

source. If this initial price adjustment ($BKSTOP\_PADJ_{n,r}$) is not sufficient to eliminate backstop, on the next cycle down the network tree, an additional adjustment ($RBKSTOP\_PADJ_{n,r}$) is added to the original adjustment, creating a cumulative price adjustment. This process continues until the backstop quantity is reduced to zero, or until the maximum number of ITS cycles has been completed. If backstop is eliminated, then the cumulative price adjustment level is maintained, as long as backstop does not resurface, and until ITS convergence is achieved. Maintaining a backstop adjustment is necessary because complete removal of this high-price signal would cause demand for this source to increase again, and backstop would return. However, if the need for backstop supply recurs following a cycle which did not need backstop supply, then the price adjustment ($BKSTOP\_PADJ_{n,r}$) factor is reduced by one-half and added to the cumulative adjustment variable, with the process continuing as described above. The objective is to eliminate the need for backstop supply while keeping the associated price at a minimum. The node prices are adjusted as follows:

$$NODE\_SHRPR_{n,r} = NODE\_SHRPR_{n,r} + RBKSTOP\_PADJ_{n,r} \tag{96}$$

$$RBKSTOP\_PADJ_{n,r} = RBKSTOP\_PADJ_{n,r} + BKSTOP\_PADJ_{n,r} \tag{97}$$

where,

$NODE\_SHRPR_{n,r}$	=	Node price for region r on network n [used with flow sharing algorithm] (87$/Mcf)
$RBKSTOP\_PADJ_{n,r}$	=	Cumulative price adjustment due to backstop (87$/Mcf)
$BKSTOP\_PADJ_{n,r}$	=	Incremental backstop price adjustment (87$/Mcf)
n	=	network (peak or off-peak)
r	=	region

Currently, this cumulative backstop adjustment ($RBKSTOP\_PADJ_{n,r}$) is maintained for each NEMS iteration and set to zero only on the first NEMS iteration of each model year. Also, it is not used to adjust the NODE_ENDPR because it is an adjustment for making flow allocation decisions, not for pricing gas for the end-user.

ITS Convergence

The ITS is considered to have converged when the regional/seasonal wellhead prices are within a defined percentage tolerance (PSUP_DELTA) of the prices set during the last ITS cycle and, for those supply regions with relatively small production levels (QSUP_SMALL), production is within a defined tolerance (QSUP_DELTA) of the production set during the last ITS cycle. If convergence does not occur, then a new wellhead price is determined based on a user-specified weighting of the seasonal production levels determined during the current cycle and during the previous cycle down the network. The the new production levels are defined as follows:

$$\begin{aligned} NODE\_QSUP_{n,s} = {} & (QSUP\_WT * NODE\_QSUP_{n,s}) + \\ & ((1 - QSUP\_WT) * NODE\_QSUPPREV_{n,s}) \end{aligned} \tag{98}$$

where,

$NODE\_QSUP_{n,s}$	=	Production level at supply source s on network n for current ITS cycle (Bcf)
$NODE\_QSUPPREV_{n,s}$	=	Production level at supply source s on network n for previous ITS cycle (Bcf)
QSUP_WT	=	Weighting applied to production level for current ITS cycle (Appendix E)
n	=	network (peak or off-peak)
s	=	supply source

Seasonal prices ($NODE\_PSUP_{n,s}$) for these quantities are then determined using the same methodology defined above for obtaining wellhead prices.

End-Use Sector Prices

The NGTDM provides regional end-use or delivered prices for the Electricity Market Module (electric generation sector) and the other NEMS demand modules (nonelectric sectors). For the nonelectric sectors (residential, commercial, industrial, and transportation), prices are established at the NGTDM region and then averaged (when necessary) using quantity-weights to obtain prices at the Census Division level. For the electric generation sector, prices are provided on a seasonal basis and are determined for core and noncore services at two different regional levels: the Census Division level and the NGTDM/EMM level (Chapter 2, **Figure 2-3**).

The first step toward generating these delivered prices is to translate regional, seasonal node prices into corresponding city gate prices ($CGPR_{n,r}$). To accomplish this, seasonal intraregional and intrastate tariffs are added to corresponding regional end-use node prices (NODE_ENDPR). This sum is then adjusted using a city gate benchmark factor ($CGBENCH_{n,r}$) which represents the average difference between historical city gate prices and model results for the historical years of the model. These equations are defined below:

$$\begin{aligned} CGPR_{n,r} = {} & NODE\_ENDPR_{n,r} + INTRAREG\_TAR_{n,r} + \\ & INTRAST\_TAR_{r} + CGBENCH_{n,r} \end{aligned} \qquad (99)$$

such that:

$$CGBENCH_{n,r} = avg(HCG\_BENCH_{n,r,HISYR}) = avg(HCGPR_{n,r,HISYR} - CGPR_{n,r}) \qquad (100)$$

where,

$CGPR_{n,r}$	=	City gate price in region r on network n in each HISYR (87\$/Mcf)
$NODE\_ENDPR_{n,r}$	=	Node price for region r on network n (87\$/Mcf)
$INTRAREG\_TAR_{n,r}$	=	Intraregional tariff for region r on network n (87\$/Mcf)
$INTRAST\_TAR_{r}$	=	Intrastate tariff in region r (87\$/Mcf)
$CGBENCH_{n,r}$	=	City gate benchmark factor for region r on network n (87\$/Mcf)
$HCG\_BENCH_{n,r,HISYR}$	=	City gate benchmark factors for region r on network n in historical years HISYR (87\$/Mcf)

$HCGPR_{n,r,HISYR}$	=	Historical city gate price in region r on network n in historical year HISYR (87$/Mcf)
n	=	network (peak and off-peak)
r	=	region (lower 48 only)
HISYR	=	historical year, over which average is taken (2004-2008, excluding the outlier year of 2006)
avg	=	straight average of indicated value over indicated historical years of the model.

The intraregional tariffs are the sum of a usage fee (INTRAREG_FIXTAR), provided by the Pipeline Tariff Submodule, and a reservation fee that is set using the same function NGPIPE_VARTAR that is used in setting interregional tariffs and was described previously. The benchmark factor represents an adjustment to calibrate city gate prices to historical values.

Seasonal distributor tariffs are then added to the city gate prices to get seasonal, sectoral delivered prices by the NGTDM regions for nonelectric sectors and by the NGTDM/EMM subregions for the electric generation sector. The prices for residential, commercial, and electric generation sectors (core and noncore) are then adjusted using STEO benchmark factors ($SCALE\_FPR_{sec,t}$, $SCALE\_IPR_{sec,t}$)[70] to calibrate the results to equal the corresponding national STEO delivered prices. Each seasonal sector price is then averaged to get an annual, sectoral delivered price for each representative region. The following equations apply.

Nonelectric Sectors (except core transportation):

$$NGPR\_SF_{n,sec,r} = CGPR_{n,r} + DTAR\_SF_{n,sec,r} + SCALE\_FPR_{sec,t}$$
$$NGPR\_SI_{n,sec,r} = CGPR_{n,r} + DTAR\_SI_{n,sec,r} + SCALE\_IPR_{sec,t} \tag{101}$$

$$\begin{aligned} NGPR\_F_{sec,r} = {} & NGPR\_SF_{PK,sec,r} * PKSHR\_DMD_{sec,r} + \\ & NGPR\_SF_{OP,sec,r} * (1. - PKSHR\_DMD_{sec,r}) \end{aligned}$$
$$\begin{aligned} NGPR\_I_{sec,r} = {} & NGPR\_SI_{PK,sec,r} * PKSHR\_DMD_{sec,r} + \\ & NGPR\_SI_{OP,sec,r} * (1. - PKSHR\_DMD_{sec,r}) \end{aligned} \tag{102}$$

where,

$NGPR\_SF_{n,sec,r}$	=	Seasonal (n) core nonelectric sector (sec) price in region r (87$/Mcf)
$NGPR\_SI_{n,sec,r}$	=	Seasonal (n) noncore nonelectric sector (sec) price in region r (87$/Mcf)
$NGPR\_F_{sec,r}$	=	Annual core nonelectric sector (sec) price in region r (87$/Mcf)
$NGPR\_I_{sec,r}$	=	Annual noncore nonelectric sector (sec) price in region r (87$/Mcf)

[70]The STEO scale factors are linearly phased out over a user-specified number of years (Appendix E, STPHAS_YR) after the last STEO year. STEO benchmarking is not done for the industrial price, because of differences in the definition of the price in the STEO versus the price in the AEO, nor for the transportation sector since the STEO does not include a comparable value.

$CGPR_{n,r}$ = City gate price in region r on network n (87$/Mcf)
$DTAR\_SF_{n.sec,r}$ = Seasonal (n) distributor tariff to core nonelectric sector (sec) in region r (87$/Mcf)
$DTAR\_SI_{n.\,sec,r}$ = Seasonal (n) distributor tariff to noncore nonelectric sector (sec) in region r (87$/Mcf)
$PKSHR\_DMD_{sec,r}$ = Average (2001-2009) fraction of annual consumption for nonelectric sector in peak season for region r
$SCALE\_FPR_{sec,t}$ = STEO benchmark factor for core delivered prices for sector sec, in year t (87$/Mcf)
$SCALE\_IPR_{sec,t}$ = STEO benchmark factor for noncore delivered prices for sector sec, in year t (87$/Mcf)
n = network (peak or off-peak)
sec = nonelectric sector
r = region (lower 48 only)

Electric Generation Sector:

$$NGUPR\_SF_{n,j} = CGPR_{n,r} + UDTAR\_SF_{n,j} + SCALE\_FPR_{sec,t}$$

$$NGUPR\_SI_{n,j} = CGPR_{n,r} + UDTAR\_SI_{n,j} + SCALE\_IPR_{sec,t} \tag{103}$$

$$NGUPR\_F_{j} = NGUPR\_SF_{PK,j} * PKSHR\_UDMD_{j} + NGUPR\_SF_{OP,j} * (1. - PKSHR\_UDMD_{j})$$

$$NGUPR\_I_{j} = NGUPR\_SI_{PK,j} * PKSHR\_UDMD_{j} + NGUPR\_SI_{OP,j} * (1. - PKSHR\_UDMD_{j}) \tag{104}$$

where,

$NGUPR\_SF_{n,j}$ = Seasonal (n) core utility sector price in region j (87$/Mcf)
$NGUPR\_SI_{n,j}$ = Seasonal (n) noncore utility sector price in region j (87$/Mcf)
$NGUPR\_F_{j}$ = Annual core utility sector price in region j (87$/Mcf)
$NGUPR\_I_{j}$ = Annual noncore utility sector price in region j (87$/Mcf)
$CGPR_{n,r}$ = City gate price in region r on network n (87$/Mcf)
$UDTAR\_SF_{n,j}$ = Seasonal (n) distributor tariff to core utility sector in region j (87$/Mcf)
$UDTAR\_SI_{n,j}$ = Seasonal (n) distributor tariff to noncore utility sector in region j (87$/Mcf)
$PKSHR\_UDMD_{j}$ = Average (1994-2009, except for New England 1997-2009) fraction of annual consumption for the electric generator sector in peak season, for region j
$SCALE\_FPR_{sec,t}$ = STEO benchmark factor for core delivered prices for sector sec, in year t (87$/Mcf)
$SCALE\_IPR_{sec,t}$ = STEO benchmark factor for noncore delivered prices for sector sec, in year t (87$/Mcf)

n = network (peak PK or off-peak OP)
sec = utility sector (electric generation only)
r = region (lower 48 only)
j = NGTDM/EMM subregion

For *AEO2011*, the natural gas price that was finally sent to the Electricity Market Module for both core and noncore customers was the quantity-weighted average of the core and noncore prices derived from the above equations. This was done to alleviate some difficulties within the Electricity Market Module as selections were being made between different types of natural gas generation equipment.

Core Transportation Sector:

A somewhat different methodology is used to determine natural gas delivered prices for the core (F) transportation sector. The core transportation sector consists of a personal vehicles component and a fleet vehicles component. Like the other nonelectric sectors, seasonal distributor tariffs are added to the regional city gate prices to determine seasonal delivered prices for both components. Annual core prices are then established for each component in a region by averaging the corresponding seasonal prices, as follows:

$$NGPR\_TRPV\_SF_{n,r} = CGPR_{n,r} + DTAR\_TRPV\_SF_{n,r} + SCALE\_FPR_{sec,t}$$
$$NGPR\_TRFV\_SF_{n,r} = CGPR_{n,r} + DTAR\_TRFV\_SF_{n,r} + SCALE\_FPR_{sec,t} \quad (105)$$

$$NGPR\_TRPV\_F_{r} = NGPR\_TRPV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + NGPR\_TRPV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r})$$
$$NGPR\_TRFV\_F_{r} = NGPR\_TRFV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + NGPR\_TRFV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r}) \quad (106)$$

where,

$NGPR\_TRPV\_SF_{n,r}$ = Seasonal (n) price of natural gas used by personal vehicles (core) in region r (87$/Mcf)
$NGPR\_TRFV\_SF_{n,r}$ = Seasonal (n) price of natural gas used by fleet vehicles (core) in region r (87$/Mcf)
$DTAR\_TRPV\_SF_{n,r}$ = Seasonal (n) distributor tariff to core transportation (personal vehicles) sector in region r (87$/Mcf)
$DTAR\_TRFV\_SF_{n,r}$ = Seasonal (n) distributor tariff to core transportation (fleet vehicles) sector in region r (87$/Mcf)
$CGPR_{n,r}$ = City gate price in region r on network n (87$/Mcf)
$NGPR\_TRPV\_F_{r}$ = Annual price of natural gas used by personal vehicles (core) in region r (87$/Mcf)
$NGPR\_TRFV\_F_{r}$ = Annual price of natural gas used by fleet vehicles (core) in region r (87$/Mcf)

$PKSHR\_DMD_{sec,r}$	=	Fraction of annual consumption for the transportation sector (sec=4) in the peak season for region r (set to PKSHR_YR)
$SCALE\_FPR_{sec,t}$	=	STEO benchmark factor for core delivered prices for sector sec, in year t (set to 0 for transportation sector), (87$/Mcf)
n	=	network (peak PK or off-peak OP)
sec	=	transportation sector =4
r	=	region (lower 48 only)

Once the personal vehicles price for natural gas is established, the two core component prices are averaged (using quantity weights) to produce an annual core price for each region ($NGPR\_F_{sec=4,r}$). Seasonal core prices are also determined by quantity-weighted averaging of the two seasonal components ($NGPR\_SF_{n,sec=4,r}$).

Regional delivered prices can be used within the ITS cycle to approximate a demand response. The submodule can then be resolved with adjusted consumption levels in an effort to speed NEMS convergence. Finally, once the ITS has converged, regional prices are averaged using quantity weights to compute Census Division prices, which are sent to the corresponding NEMS modules.

Import Prices

The price associated with Canadian imports at each of the module's border crossing points is established during the ITS convergence process. Each of these border-crossing points is represented by a node in the network. The import price for a given season and border crossing is therefore equal to the price at the associated node. For reporting purposes, these node prices are averaged using quantity weights to derive an average annual Canadian import price. The prices for imports at the three Mexican border crossings are set to the average wellhead price in the nearest NGTDM region plus a markup (or markdown) that is based on the difference between similar import and wellhead prices historically. The structure for setting LNG import prices is similar to setting Mexican import prices, although regional city gate prices are used instead of wellhead prices. For the facilities for which historical prices are not available (i.e., generic new facilities), an assumption was made about the difference between the regional city gate price and the LNG import price (LNGDIFF, Appendix E).

5. Distributor Tariff Submodule Solution Methodology

This chapter discusses the solution methodology for the Distributor Tariff Submodule (DTS) of the Natural Gas Transmission and Distribution Module (NGTDM). Within each region, the DTS develops seasonal, market-specific distributor tariffs (or city gate to end-use markups) that are applied to projected seasonal city gate prices to derive end-use or delivered prices. Since most industrial and electric generator customers do not purchase their gas through local distribution companies, their "distributor tariff" represents the difference between the average price paid by local distribution companies at the city gate and the average price paid by the industrial or electric generator customer.[71] Distributor tariffs are defined for both core and noncore markets within the industrial and electric generator sectors, while residential, commercial, and transportation sectors have distributor tariffs defined only for the core market, since noncore customer consumption in these sectors is assumed to be insignificant and set to zero. The core transportation sector is composed of two categories of compressed natural gas (CNG) consumers (fleet vehicles and personal vehicles); therefore, separate distributor tariffs are developed for each of these two categories.

For the residential, commercial, industrial, and electric generation sectors distributor tariffs are based on econometrically estimated equations and are driven in part by sectoral consumption levels.[72] This general approach was taken since data are not reasonably obtainable to develop a detailed cost-based accounting methodology similar to the approach used for interstate pipeline tariffs in the Pipeline Tariff Submodule. Distribution charges for CNG in vehicles are set to the sum of historical tariffs for delivering natural gas to refueling stations, federal and state motor fuels taxes and credits, and estimates of dispensing charges. The specific methodologies used to calculate each sector's distributor tariffs are discussed in the remainder of this chapter.

Residential and Commercial Sectors

Residential and commercial distributor tariffs are projected using econometrically estimated equations. The primary explanatory variables are floorspace and commercial natural gas consumption per floorspace for the commercial tariff, and number of households and natural gas consumption per household for the residential sector tariff. In both cases distributor tariffs are estimated separately for the peak and off-peak periods, as follows:

[71] It is not unusual for these "markups" to be negative.

[72] Historical distributor tariffs for a sector in a particular region/season can be estimated by taking the difference between the average sectoral delivered price and the average city gate price in the region/season (Appendix E, HCGPR).

Residential peak

$$\mathrm{DTAR\_SF}_{s=1,r,n=1} = e^{\mathrm{PRSREGPK19}_{r,n=1}} * \mathrm{NUMRS}_{r,t}^{0.162972} * \left(\frac{\mathrm{BASQTY\_SF}_{s=1,r,n=1} + \mathrm{BASQTY\_SI}_{s=1,r,n=1}}{\mathrm{NUMRS}_{r,t}}\right)^{-0.607267} * \tag{107}$$

$$\mathrm{DTAR\_SFPREV}_{s=1,r,n=1}^{0.231296} * e^{(-0.231296*\mathrm{PRSREGPK19}_{r,n=1})} * \mathrm{NUMRS}_{r,t-1}^{-0.231296*0.162972} * \left(\frac{\mathrm{BASQTY\_SFPREV}_{s=1,r,n=1} + \mathrm{BASQTY\_SIPREV}_{s=1,r,n=1}}{\mathrm{NUMRS}_{r,t-1}}\right)^{(-0.231296*-0.607267)}$$

Residential off-peak

$$\mathrm{DTAR\_SF}_{s=1,r,n=2} = e^{\mathrm{PRSREGPK19}_{r,n=2}} * \mathrm{NUMRS}_{r,t}^{0.282301} * \left(\frac{\mathrm{BASQTY\_SF}_{s=1,r,n=2} + \mathrm{BASQTY\_SI}_{s=1,r,n=2}}{\mathrm{NUMRS}_{r,t}}\right)^{-0.814968} * \tag{108}$$

$$\mathrm{DTAR\_SFPREV}_{s=1,r,n=2}^{0.231296} * e^{(-0.202612*\mathrm{PRSREGPK19}_{r,n=2})} * \mathrm{NUMRS}_{r,t-1}^{-0.202612*0.282301} * \left(\frac{\mathrm{BASQTY\_SFPREV}_{s=1,r,n=2} + \mathrm{BASQTY\_SIPREV}_{s=1,r,n=2}}{\mathrm{NUMRS}_{r,t-1}}\right)^{(-0.202612*-0.814968)}$$

Commercial peak

$$\mathrm{DTAR\_SF}_{s=2,r,n=2} = e^{\mathrm{PCMREGPK13}_{r,n=1}} * \mathrm{FLRSPC12}_{r,t}^{0.218189} * \left(\frac{\mathrm{BASQTY\_SF}_{s=2,r,n=1} + \mathrm{BASQTY\_SI}_{s=2,r,n=1}}{\mathrm{FLRSPC12}_{r,t}}\right)^{-0.217322} * \tag{109}$$

$$\mathrm{DTAR\_SFPREV}_{s=2,r,n=1}^{0.284608} * e^{(-0.284608*\mathrm{PCMREGPK13}_{r,n=1})} * \mathrm{FLRSPC12}_{r,t-1}^{-0.284608*0.218189} \left(\frac{\mathrm{BASQTY\_SFPREV}_{s=2,r,n=1} + \mathrm{BASQTY\_SIPREV}_{s=2,r,n=1}}{\mathrm{FLRSPC12}_{r,t-1}}\right)^{(-0.284608*-0.217322)}$$

Commercial off-peak

$$\text{DTAR\_SF}_{s=2,r,n=2} = e^{\text{PCMREGPK13}_{r,n=2}} * \text{FLRSPC12}_{r,t}^{0.530831} * \left(\frac{\text{BASQTY\_SF}_{s=2,r,n=2} + \text{BASQTY\_SI}_{s=2,r,n=2}}{\text{FLRSPC12}_{r,t}}\right)^{-0.613588} * \text{DTAR\_SFPREV}_{s=2,r,n=2}^{0.166956} * e^{(-0.166956*\text{PCMREGPK13}_{r,n=2})} * \text{FLRSPC12}_{r,t-1}^{-0.166956*0.530831} \left(\frac{\text{BASQTY\_SFPREV}_{s=2,r,n=2} + \text{BASQTY\_SIPREV}_{s=2,r,n=2}}{\text{FLRSPC12}_{r,t-1}}\right)^{(-0.166956*-0.613588)} \quad (110)$$

where,

$$\text{NUMRS}_{r,t} = \text{oRSGASCUST}_{cd,t} * \text{RECS\_ALIGN}_r * \text{NUM\_REGSHR}_r \quad (111)$$

and,

$$\text{FLRSPC12}_{r,t} = (\text{MC\_COMMFLSP}_{1,cd,t} - \text{MC\_COMMFLSP}_{8,cd,t}) * \text{SHARE}_r \quad (112)$$

where,

$\text{DTAR\_SF}_{s,r,n}$	=	core distributor tariff in current forecast year for sector s, region r, and network n (1987$/Mcf)
$\text{DTAR\_SFPREV}_{s,r,n}$	=	core distributor tariff in previous forecast year (1987$/Mcf). [For first forecast year set at the 2008 historical value.]
$\text{BASQTY\_SF}_{s,r,n}$	=	sector (s) level firm gas consumption for region r, and network n (Bcf)
$\text{BASQTY\_SI}_{s,r,n}$	=	sector (s) level nonfirm gas consumption for region r, and network n (Bcf) (assumed at 0 for residential and commercial)
$\text{BASQTY\_SFPREV}_{s,r,n}$	=	sector (s) level gas consumption for region r, and network n in previous year (Bcf) (assumed at 0 for residential and commercial)
$\text{BASQTY\_SIPREV}_{s,r,n}$	=	sector (s) level nonfirm gas consumption for region r, and network n in previous year (Bcf)
NUMRS	=	number of residential customers in year t
$\text{PRSREGPK19}_{r,n}$	=	residential, regional, period specific, constant term (Table F6, Appendix F)
$\text{PCMREGPK13}_{r,n}$	=	commercial, regional, peak specific, constant term (Table F7, Appendix F)
$\text{oRSGASCUST}_{cd,t-1}$	=	number of residential gas customers by census division in the previous forecast year (from NEMS residential demand module)
RECS_ALIGN_r	=	factor to align residential customer count data from EIA's 2005 Residential Consumption Survey (RECS), the data on which oRSGASCUST is based, with similar data from the EIA's Natural Gas Annual, the data on which the DTAR_SF estimation is based.
NUM_REGSHR_r	=	share of residential customers in NGTDM region r relative to the number in the larger or equal sized associated census division, set to values in last historical year, 2008. (fraction, Appendix E)

$FLRSPC12_r$	=	commercial floorspace by NGTDM region (total net of for manufacturing) (billion square feet)
$MC\_COMMFLSP_{1,cd,t}$	=	commercial floorspace by Census Division (total, including manufacturing)
$MC\_COMMFLSP_{8,cd,t}$	=	commercial floorspace by Census Division (manufacturing)
$SHARE_r$	=	assumed fraction of the associated census division's commercial floorspace within each of the 12 NGTDM regions based on population data (1.0, 1.0, 1.0, 1.0, 0.66, 1.0, 1.0, 0.59, 0.24, 0.34, 0.41, 0.75)
s	=	sector (=1 for residential, =2 for commercial)
cd	=	census division
r	=	region (12 NGTDM regions)
n	=	network (=1 for peak, =2 for off-peak)
t	=	forecast year (e.g., 2010)

Parameter values and details about the estimation of these equations can be found in Tables F6 and F7 of Appendix F.

Industrial Sector

For the industrial sector, a single distributor tariff (i.e., no distinction between core and noncore) is estimated for each season and region as a function of the industrial consumption level in that season and region. Next, core seasonal tariffs are set by assuming a differential between the core price and the estimated distributor tariff for the season and region, based on historical estimates. The noncore price is set to insure that the quantity-weighted average of the core and noncore price in a season and region will equal the originally estimated tariff for that season and region. Historical prices for the industrial sector are estimated based on the data that are available from the Manufacturing Energy Consumption Survey (MECS) (Table F5, Appendix F). The industrial prices within EIA's Natural Gas Annual only represent industrial customers who purchase gas through their local distribution company, a small percentage of the total; whereas the prices in the MECS represent a much larger percentage of the total industrial sector. The equation for the single seasonal/regional industrial distributor tariff follows:

$$\begin{aligned} TAR = {} & 0.199135 + PINREG15_r + PIN\_REGPK15_{r,n} + \\ & (-0.000317443 * QCUR_n) + (0.423561 * TARLAG_n) \\ & - 0.423561 * [0.199135 + PIN\_REG15_r + PIN\_REGPK15_{r,n} + \\ & (-0.000317443 * QLAG_n)] \end{aligned} \tag{113}$$

The core and noncore distributor tariffs are set using:

$$DTAR\_SF_{s=3,r,n} = TAR + FDIFF_{cr} \tag{114}$$

$$DTAR\_SI_{s=3.r,.n} = \frac{(TAR * QCUR_n) - (DTAR\_SF_{s=3,r,n} * BASQTY\_SF_{s=3,r,n})}{BASQTY\_SI_{s=3,r,n}} \qquad (115)$$

where,

TAR	=	seasonal distributor tariff for industrial sector in region r (87$/Mcf)
$TARLAG_n$	=	seasonal distributor tariff for the industrial sector (s=3) in region r in the previous forecast year (87$/Mcf)
$FDIFF_{cr}$	=	historical average difference between core and average industrial price (1987$/Mcf, Appendix E)
PIN_REG15_r	=	estimated constant term (Table F4, Appendix F)
$PIN\_REGPK15_{r,n}$	=	estimated coefficient, set to zero for the off-peak period and for any region where the coefficient is not statistically significant
$DTAR\_SF_{n,s,r}$	=	seasonal distributor tariff for the core industrial sector (s=3) in region r (87$/Mcf)
$DTAR\_SI_{n,s,r}$	=	seasonal distributor tariff for the noncore industrial sector (s=3) in region r (87$/Mcf)
$DTAR\_SFPREV_{n,s,r}$	=	seasonal distributor tariff for the core industrial sector (s=3) in region r (87$/Mcf) in the previous forecast year [In the first forecast year set to the estimated average historical value from 2006 to 2009 [Table F5, Appendix F] (87$/Mcf)]
$BASQTY\_SF_{n,s=3,r}$	=	seasonal core natural gas consumption for industrial sector(s=3) in the current forecast year (Bcf)
$BASQTY\_SI_{n,s=3,r}$	=	seasonal noncore natural gas consumption for industrial sector (s=3) in the current forecast year (Bcf)
$QCUR_n$	=	sum of BASQTY_SF and BASQTY_SI for industrial in a particular season and region
$QLAG_n$	=	sum of BASQTY_SFPREV and BASQTY_SIPREV for industrial in a particular season and region, the value of QCUR in the last forecast year
s	=	end-use sector index (s=3 for industrial sector)
n	=	network (peak or off-peak)
r	=	NGTDM region
cr	=	the census region associated with the NGTDM region

Parameter values and details about the estimation of these two equations can be found in Table F4 and F5, Appendix F.

Electric Generation Sector

Distributor tariffs for the electric generation sector do not represent a charge imposed by a local distribution company; rather they represent the difference between the average city gate price in each NGTDM region and the natural gas price paid on average by electric generators in each NGTDM/EMM region, and are often negative. A single markup or tariff (i.e., no distinction between core and noncore) is projected for each season and region using econometrically estimated equations, as was done for the industrial sector. However, the current version of the model (as used for *AEO2011*) assigns this same value to both the core and noncore segments.[73] The estimated equations for the distributor tariffs for electric generators are a function of natural gas consumption by the sector relative to consumption by the other sectors. The greater the electric consumption share, the greater the price difference between the electric sector and the average, as they will need to reserve more space on the pipeline system. The specific equations follow:

$$\begin{aligned} UDTAR\_SF_{n,j} = {} & (-0.153777 + 0.0299295) + PELREG31_{n,j} + \\ & (0.000000704 * qelec_{n,j}) + (0.281378 * UDTAR\_SFPREV_{n,j}) \\ & - 0.281378 * [(-0.153777 + 0.0299295) + PELREG31_{n,j} + \\ & (0.000000704 * qeleclag_{n,j})] \end{aligned} \tag{116}$$

where,

$$qelec_{n,j} = (BASUQTY\_SF_{n,j} + BASUQTY\_SI_{n,j}) * 1000 \tag{117}$$

$$qeleclag_{n,j} = (BASUQTY\_SFPREV_{n,j} + BASUQTY\_SIPREV_{n,j}) * 1000 \tag{118}$$

$UDTAR\_SI_{n,j}$ = $UDTAR\_SF_{n,j}$ for all n and j,

where,

$UDTAR\_SF_{n,j}$ = seasonal core electric generation sector distributor tariff, current forecast year ($/Mcf)

$UDTAR\_SI_{n,j}$ = seasonal noncore electric generation sector distributor tariff, current forecast year ($/Mcf)

$UDTAR\_SFPREV_{n,j}$ = seasonal core electric generation sector distributor tariff, previous forecast year ($/Mcf)

$BASUQTY\_SF_{n,j}$ = core electric generator gas consumption, current forecast year (Bcf)

$BASUQTY\_SI_{n,j}$ = noncore electric generator gas consumption, current forecast year (Bcf)

$BASUQTY\_SFPREV_{n,j}$ = core electric generator gas consumption in previous forecast year (Bcf)

$BASUQTY\_SIPREV_{n,j}$ = noncore electric generator gas consumption in previous forecast year (Bcf)

$PELREG31_{n=1,j}$ = $PELREG31_j$ in code, regional constant terms for peak period (Table F8, Appendix F)

$PELREG31_{n=2,j}$ = $PELREG32_j$ in code, regional constant terms for off-peak period (Table F8, Appendix F)

n = network (peak=1 or off-peak=2)

j = NGTDM/EMM region (see chapter 2)

[73] This distinction was eliminated several years ago because of operational concerns in the Electricity Market Module. In addition, there are some remaining issues concerning the historical data necessary to generate separate price series for the two segments.

Parameter values and details about the estimation of these two equations can be found in Table F8, Appendix F.

Transportation Sector

Consumers of compressed natural gas (CNG) have been classified into two end-use categories within the core transportation sector: fleet vehicles and personal vehicles (i.e., CNG sold at retail). A distributor tariff is set for both categories to capture 1) the cost of the natural gas delivered to the dispensing station above the city gate price, 2) the per-unit cost or charge for dispensing the gas, and 3) federal and state motor fuels taxes and credits.

For both categories, the distribution charge for the CNG delivered to the station is based on the historical difference between the price reported for the transportation sector in EIA's *Natural Gas Annual* (which should reflect this delivered price) and the city gate price. Similarly federal and state motor fuels taxes are assumed to be the same for both categories and held constant in nominal dollars.[74] The Highway Bill of 2005 raised the motor fuels tax for CNG.[75] The model adjusts the distribution costs accordingly. A potential difference in the pricing for the two categories is the assumed per-unit dispensing charge. Currently the refueling options available for personal natural gas vehicles are largely limited to the same refueling facilities used by fleet vehicles. Therefore, the assumption in the model is that the dispensing charge will be similar for fleet and personal vehicles ($RETAIL\_COST_2$) unless there is a step increase in the number of retail stations selling natural gas in response to an expected increase in the number of personal vehicles. In such a case, an additional markup is added to the natural gas price to personal vehicles to account for the profit of the builder (RET_MARK), as described below. The distributor tariffs for CNG vehicles are set as follows:

$$\begin{aligned} DTAR\_TRFV\_SF_{n,r} = \{ & HDTAR\_SF_{n,s=4,r,EHISYR} \\ & * (1 - TRN\_DECL)^{YR-DECL}\} + RETAIL\_COST_2 \\ & + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \end{aligned} \tag{119}$$

$$\begin{aligned} DTAR\_TRPV\_SF_{n,r} = \{ & HDTAR\_SF_{n,s=4,r,EHISYR} \\ & * (1 - TRN\_DECL)^{YR-DECL}\} + RETAIL\_COST_2 \\ & + CNG\_RETAIL\_MARKUP_r + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \end{aligned} \tag{120}$$

where,

[74]Motor vehicle fuel taxes are assumed constant in current year dollars throughout the forecast to reflect current laws. Within the model these taxes are specified in 1987 dollars.

[75]The Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU), Section 1113. The bill also allowed for an excise tax credit of $0.50 per gasoline gallon equivalent to be paid to the seller of the CNG through September of 2009. The model assumes that the subsidy will be passed through to consumers.

$DTAR\_TRFV\_SF_{n,r}$ = distributor tariff for the fleet vehicle transportation sector (87$/Mcf)
$DTAR\_TRPV\_SF_{n,r}$ = distributor tariff for the personal vehicle transportation sector (87$/Mcf)
$HDTAR\_SF_{n,s,r,EHISYR}$ = historical (2009) distributor tariff for the transportation sector to deliver the CNG to the station[76] (87$/ Mcf)
TRN_DECL = fleet vehicle distributor decline rate, set to zero for *AEO2011* (fraction, Appendix E)
YR_DECL = difference between the current year and the last historical year over which the decline rate is applied
$RETAIL\_COST_2$ = assumed additional charge related to providing the dispensing service to customers, at a fleet refueling station (87$/Mcf, Appendix E)
$CNG\_RETAIL\_MARKUP_r$ = markup for natural gas sold at retail stations (described below)
$STAX_r$ = State motor vehicle fuel tax for CNG (current year $/Mcf, Appendix E)
FTAX = Federal motor vehicle fuel tax minus federal excise motor fuel credit for CNG (current year $/Mcf, Appendix E)
MC_PCWGDP_t = GDP conversion from current year dollars to 87 dollars [from the NEMS macroeconomic module]
n = network (peak or off-peak)
s = end-use sector index (s=4 for transportation sector)
r = NGTDM region
EHISYR = index defining last year that historical data are available
t = forecast year

A new algorithm was developed for *AEO2010* which projects whether construction of CNG fueling stations is economically viable in any of the NGTDM regions and, if so, sets the added charge that will result. In addition, the model provides the NEMS Transportation Sector Module with a projection of the fraction of retail refueling stations that sell natural gas. This is a key driver in the transportation module for projecting the number of compressed natural gas vehicles purchased and the resulting consumption level. While demand for CNG for personal vehicles is increased when fueling infrastructure is built, at the same time the viability of fueling infrastructure depends on sufficient demand to support it. A reduced form of the NEMS Transportation Sector Module was created for use in the NGTDM to estimate the increase in demand for CNG due to infrastructure construction, in order to project the revenue from a infrastructure building project, and then to assess its viability.

The basic algorithm involves 1) assuming a set increase in the number of stations selling CNG, 2) assuming CNG will be priced at a discount to the price of motor gasoline once it starts penetrating, 3) estimating the expected demand for CNG given the increased supply availability and price, 4) calculating the expected revenue per station that will cover capital expenditures

[76]EIA published, annual, State level data are used to set regional historical end-use prices for CNG vehicles. Since monthly data are not available for this sector, seasonal differentials for the industrial sector are applied to annual CNG data to approximate seasonal CNG prices.

(i.e., discounting for taxes, gas purchase costs, and other operating costs), 5) checking the revenue against infrastructure costs to determine viability, and 6) if viable, assuming the infrastructure will be added and the retail price changed accordingly.

The algorithm starts by testing the effects of building a large number of CNG stations (i.e., primarily by offering CNG at existing gasoline stations). The increase in availability that is tested is assumed to be a proportion of the number of gasoline stations in the region, as follows:

$$TOTPUMPS = NSTAT_r * (MAX\_CNG\_BUILD + CNGAVAIL_{t-1}) \tag{121}$$

where,

TOTPUMPS	=	the number of retail stations selling CNG in the region
$NSTAT_r$	=	the number of gasoline stations in the region at the beginning of the projection period (Appendix E)
$CNGAVAIL_{t-1}$	=	fraction of total retail refueling stations selling CNG last year
MAX_CNG_BUILD	=	assumed fraction of stations that can add CNG refueling this year (Appendix E).
r	=	census division
t	=	year

The assumed regional retail markup to cover capital costs if CNG infrastructure is built is set as follows:

$$TEST\_MARKUP_r = \text{minimum}\{5.0, MAX\_CNGMARKUP\} \tag{122}$$

where,

$$\begin{aligned} MAX\_CNGMARKUP_r = 0.75 * \{PMGTR_{r,t-1} - \\ (PGFTRPV_{r,t-1} - CNG\_RETAIL\_MARKUP_r)\} \end{aligned} \tag{123}$$

where,

$TEST\_MARKUP_r$	=	assumed regional retail markup (87$/MMBtu)
$MAX\_CNG\_MARKUP_r$	=	assumed maximum markup that can be added to base line cost of dispensing CNG to cover capital expenditures (87$/MMBtu) [Note: base line costs include taxes and fuel and basic operating costs]
$PMGTR_r$	=	retail price of motor gasoline (87$/MMBtu)
PMGFTRPV	=	retail price of CNG (87$/MMBtu)
$CNG\_RETAIL\_MARKUP_r$	=	retail CNG markup above base line costs added last year (87$/MMBtu)
0.75	=	assumed economic rent that can be captured relative to the difference between the retail price of motor gasoline and the retail price of CNG (fraction)
5.0	=	assumed minimum retail CNG markup (87$/MMBtu)

For each model year and region, the present value of projected revenue is determined with the following equation:

$$REVENUE = \sum_{n=1}^{CNG\_HRZ} \frac{TEST\_MARKUP_r * DEMAND * 1000000}{TOTPUMPS * (1 + CNG\_WACC)^n} \quad (124)$$

where,

REVENUE	=	the net revenue per station (above the basic operating expenses) after infrastructure is added in the region (1987 dollars)
CNG_HRZ	=	the time horizon for the revenue calculation, corresponding to the number of years over which the capital investment is assumed to need to be recovered (Appendix E)
$TEST\_MARKUP_r$	=	assumed regional retail markup above baseline costs (87$/MMBtu)
DEMAND	=	estimated consumption of CNG by personal vehicles if the infrastructure is added and the implied retail price is charged (trillion BTU), described at the end of this section
TOTPUMPS	=	the number of retail stations selling CNG in the region
CNG_WACC	=	assumed weighted average cost of capital for financing the added CNG infrastructure (Appendix E)

The model compares the present value of the projected revenue per station from an infrastructure build to the assumed cost of a station (CNG_BUILDCOST, Appendix E) to make the decision of whether stations are built or not. The cost of a station reflects the estimated cost of building a single pumping location in an existing retrial refueling station, considering the tax value of depreciation and a payback number of years (CNG_HRZ, Appendix E) and an assumed weighted average cost of capital (CNG_WACC, Appendix E). If the revenue is sufficient in a region then the availability of CNG stations in that region are increased and the retail markup is set to the markup that was tested. The equations for new retail markup and availability when stations have been built are given in the following:

$$CNGAVAIL_{r,t} = CNGAVAIL_{r,t-1} + MAX\_CNG\_BUILD \quad (125)$$

$$RET\_MARK_r = TEST\_MARKUP \quad (126)$$

where,

$CNGAVAIL_{r,t}$	=	fraction of regional retail refueling stations selling CNG
MAX_CNG_BUILD	=	incremental fraction of retail refueling stations selling CNG with added infrastructure in the year
RET_MARK_r	=	CNG retail markup above baseline costs (87$/MMBtu)
TEST_MARKUP	=	assumed CNG retail markup above baseline costs, based on the difference between baseline CNG costs and motor gasoline prices (87$/MMBtu)
r	=	Census Division
t	=	year

These variables stay at last year's values if no stations have been built. The retail markup by NGTDM region (CNG_RETAIL_MARKUP), as used in the transportation sector distributor tariff equation, is set by assigning the retail markup (RET_MARK) from the associated Census Division.

The demand response for CNG use in personal vehicles was estimated by doing multiple runs of the Transportation Sector Module. The key variable that was varied was the availability of CNG refueling stations. Test runs were made over a range of availability values for nine different cases. The cases were defined with three different motor gasoline to CNG price differentials (a maximum, a minimum, and the average between the two) in combination with three different CNG vehicle purchase subsidies ($0, $20,000, $40,000 in 2009 dollars per vehicle).[77] For each of the resulting nine sets of runs the CNG demand response in the Pacific Census Division was estimated as a function of station availability in a log-linear form with a constant term. The demand response in the Pacific Division was estimated by linearly interpolating between the points in the resulting three dimensional grid for a given availability (fraction of stations offering CNG), price differential between CNG and motor gasoline, and allowed subsidy for purchasing a CNG vehicle. The estimated consumption levels in the other Census Divisions were set by scaling the Pacific Division consumption based on size (as measured by total transportation energy demand) relative to the Pacific Division.

[77]Based on current laws and regulations in the *AEO2011* Reference Case, the subsidy is set to $0. A nonzero subsidy option was included for potential scenario analyses.

6. Pipeline Tariff Submodule Solution Methodology

The Pipeline Tariff Submodule (PTS) sets rates charged for storage services and interstate pipeline transportation. The rates developed are based on actual costs for transportation and storage services. These cost-based rates are used as a basis for developing tariff curves for the Interstate Transmission Submodule (ITS). The PTS tariff calculation is divided into two phases: an historical year initialization phase and a forecast year update phase. Each of these two phases includes the following steps: (1) determine the various components, in nominal dollars, of the total cost-of-service, (2) classify these components as fixed and variable costs based on the rate design (for transportation), (3) allocate these fixed and variable costs to rate components (reservation and usage costs) based on the rate design (for transportation), and (4) for transportation: compute rates for services during peak and off-peak time periods; for storage: compute annual regional tariffs. For the historical year phase, the cost of service is developed from historical financial data on 28 major U.S. interstate pipeline companies; while for the forecast year update phase the costs are estimated using a set of econometric equations and an accounting algorithm. The pipeline tariff calculations are described first, followed by the storage tariff calculations, and finally a description of the calculation of the tariffs for moving gas by pipeline from Alaska and from the MacKenzie Delta to Alberta. A general overview of the methodology for deriving rates is presented in the following box. The PTS system diagram is presented in **Figure 6-1**.

The purpose of the historical year initialization phase is to provide an initial set of transportation revenue requirements and tariffs. The last historical year for the PTS is currently 2006, which need not align with the last historical year for the rest of the NGTDM. Ultimately the ITS requires pipeline and storage tariffs; whether they are based on historical or projected financial data is mechanically irrelevant. The historical year information is developed from existing pipeline company transportation data. The historical year initialization process draws heavily on three databases: (1) a pipeline financial database (1990-2006) of 28 major interstate natural gas pipelines developed by Foster Associates,[83] (2) "a competitive profile of natural gas services" database developed by Foster Associates,[84] and (3) a pipeline capacity database developed by the former Office of Oil and Gas, EIA.[85] The first database represents the existing physical U.S. interstate pipeline and storage system, which includes production processing, gathering, transmission, storage, and other. The physical system is at a more disaggregate level than the NGTDM network. This database provides detailed company-level financial, cost, and rate base parameters. It contains information on capital structure, rate base, and revenue requirements by major line item of the cost of service for the historical years of the model. The second Foster database contains

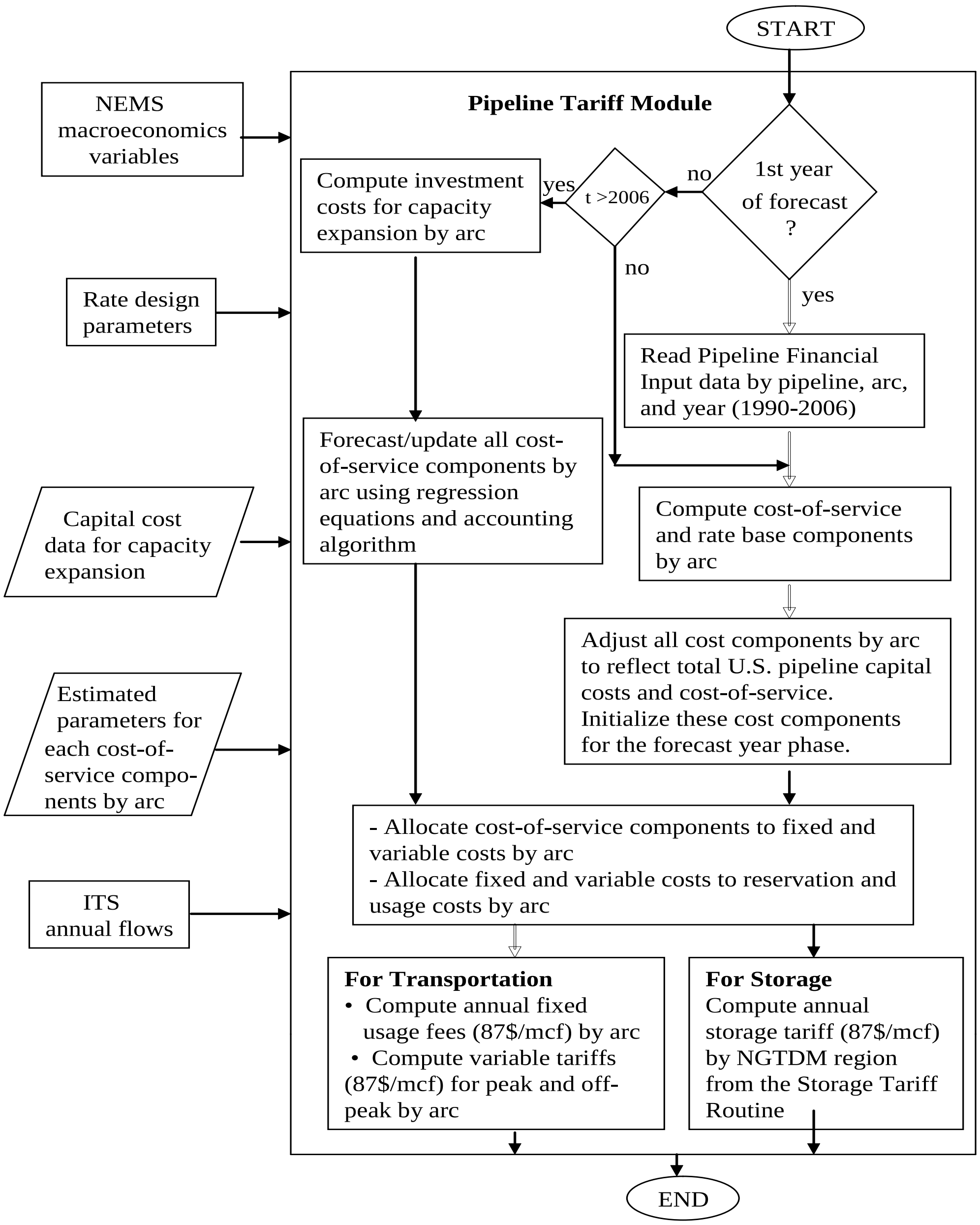
[83]Foster Financial Reports, 28 Major Interstate Natural Gas Pipelines, 2000, 2004 and 2007 Editions, Foster Associates, Inc., Bethesda, Maryland. The primary sources of data for these reports are FERC Form 2 and the monthly FERC Form 11 pipeline company filings. These reports can be purchased from Foster Associates.

[84]Competitive Profile of Natural Gas Services, Individual Pipelines, December 1997, Foster Associates, Inc., Bethesda, Maryland. Volumes III and IV of this report contain detailed information on the major interstate pipelines, including a pipeline system map, capacity, rates, gas plant accounts, rate base, capitalization, cost of service, etc. This report can be purchased from Foster Associates.

[85]A spreadsheet compiled by James Tobin of the Office of Oil and Gas containing historical and proposed state-to-state pipeline construction project costs, mileage, capacity levels and additions by year from 1996 to 2011, by pipeline company (data as of August 16, 2007).

detailed data on gross and net plant in service and depreciation, depletion, and amortization for individual plants (production processing and gathering plants, gas storage plants, gas transmission plants, and other plants) and is used to compute sharing factors by pipeline company and year to single out financial cost data for transmission plants from the "total plants" data in the first database.

Figure 6-1. Pipeline Tariff Submodule System Diagram



The third database contains information on pipeline financial construction projects by pipeline company, state-to-state transfer, and year (1996-2011). This database is used to determine factors to allocate the pipeline company financial data to the NGTDM interstate pipeline arcs based on capacity level in each historical year. These three databases are pre-processed offline to generate the pipeline transmission financial data by pipeline company, NGTDM interstate arc, and historical year (1990-2006) used as input into the PTS.

PTS Process for Deriving Rates

For Each Pipeline Arc

- Read historical financial database for 28 major interstate natural gas pipelines by pipeline company, arc, and historical year (1990-2006).

- Derive the total pipeline cost of service (TCOS)
  - Historical years
  - Aggregate pipeline TCOS items to network arcs
    - Adjust TCOS components to reflect all U.S. pipelines based on annual "Pipeline Economics" special reports in the Oil & Gas Journal
  - Forecast years
    - Include capital costs for capacity expansion
    - Estimate TCOS components from forecasting equations and accounting algorithm

- Allocate total cost of service to fixed and variable costs based on rate design

- Allocate costs to rate components (reservation and usage costs) based on rate design

- Compute rates for services for peak and off-peak time periods

For Each Storage Region:

- Derive the total storage cost of service (STCOS)

  - Historical years: read regional financial data for 33 storage facilities by node (NGTDM region) and historical year (1990-1998)
  - Forecast years:
    - Estimate STCOS components from forecasting equations and accounting algorithm
    - Adjust STCOS to reflect total U.S. storage facilities based on annual storage capacity data reported by EIA

- Compute annual regional storage rates for services

Historical Year Initialization Phase

The following section discusses two separate processes that occur during the historical year initialization phase: (1) the computation and initialization of the cost-of-service components, and (2) the computation of rates for services. The computation of historical year cost-of-service components and rates for services involves four distinct procedures as outlined in the above box and discussed below. Rates are calculated in nominal dollars and then converted to real dollars for use in the ITS.

Computation and Initialization of Pipeline Cost-of-Service Components

In the historical year initialization phase of the PTS, rates are computed using the following process: (Step 1) derivation and initialization of the total cost-of-service components, (Step 2) classification of cost-of-service components as fixed and variable costs, (Step 3) allocation of fixed and variable costs to rate components (reservation and usage costs) based on rate design, and (Step 4) computation of rates at the arc level for transportation services.

Step 1: Derivation and Initialization of the Total Cost-of-Service Components

The total cost-of-service for existing capacity on an arc consists of a just and reasonable return on the rate base plus total normal operating expenses. Derivations of return on rate base and total normal operating expenses are presented in the following subsections. The total cost of service is computed as follows:

$$TCOS_{a,t} = TRRB_{a,t} + TNOE_{a,t} \tag{127}$$

where,

$TCOS_{a,t}$ = total cost-of-service (dollars)
$TRRB_{a,t}$ = total return on rate base (dollars)
$TNOE_{a,t}$ = total normal operating expenses (dollars)
a = arc
t = historical year

Just and Reasonable Return. In order to compute the return portion of the cost-of-service at the arc level, the determination of capital structure and adjusted rate base is necessary. Capital structure is important because it determines the cost of capital to the pipeline companies associated with a network arc. The weighted average cost of capital is applied to the rate base to determine the return component of the cost-of-service, as follows:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \tag{128}$$

where,

$TRRB_{a,t}$ = total return on rate base after taxes (dollars)
$WAROR_{a,t}$ = weighted-average after-tax return on capital (fraction)
$APRB_{a,t}$ = adjusted pipeline rate base (dollars)
a = arc
t = historical year

In addition, the return on rate base $TRRB_{a,t}$ is broken out into the three components as shown below.

$$PFEN_{a,t} = \sum_{p} [(PFES_{a,p,t} / TOTCAP_{a,p,t}) * PFER_{a,p,t} * APRB_{a,p,t}] \quad (129)$$

$$CMEN_{a,t} = \sum_{p} [(CMES_{a,p,t} / TOTCAP_{a,p,t}) * CMER_{a,p,t} * APRB_{a,p,t}] \quad (130)$$

$$LTDN_{a,t} = \sum_{p} [(LTDS_{a,p,t} / TOTCAP_{a,p,t}) * LTDR_{a,p,t} * APRB_{a,p,t}] \quad (131)$$

such that,

$$TRRB_{a,t} = (PFEN_{a,t} + CMEN_{a,t} + LTDN_{a,t}) \quad (132)$$

where,

$PFEN_{a,t}$ = total return on preferred stock (dollars)
$PFES_{a,p,t}$ = value of preferred stock (dollars)
$TOTCAP_{a,p,t}$ = total capitalization (dollars)
$PFER_{a,p,t}$ = coupon rate for preferred stock (fraction) [read as D_PFER]
$APRB_{a,p,t}$ = adjusted pipeline rate base (dollars) [read as D_APRB]
$CMEN_{a,t}$ = total return on common stock equity (dollars)
$CMES_{a,p,t}$ = value of common stock equity (dollars)
$CMER_{a,p,t}$ = common equity rate of return (fraction) [read as D_CMER]
$LTDN_{a,t}$ = total return on long-term debt (dollars)
$LTDS_{a,p,t}$ = value of long-term debt (dollars)
$LTDR_{a,p,t}$ = long-term debt rate (fraction) [read as D_LTDR]
p = pipeline company
a = arc
t = historical year

Note that the first terms (fractions) in parentheses on the right hand side of equations 129 to 131 represent the capital structure ratios for each pipeline company associated with a network arc. These fractions are computed exogenously and read in along with the rates of return and the adjusted rate base. The total returns on preferred stock, common equity, and long-term debt at the arc level are computed immediately after all the input variables are read in. The capital structure ratios are exogenously determined as follows:

$$GPFESTR_{a,p,t} = PFES_{a,p,t} / TOTCAP_{a,p,t} \quad (133)$$

$$GCMESTR_{a,p,t} = CMES_{a,p,t} / TOTCAP_{a,p,t} \quad (134)$$

$$GLTDSTR_{a,p,t} = LTDS_{a,p,t} / TOTCAP_{a,p,t} \quad (135)$$

where,

$GPFESTR_{a,p,t}$ = capital structure ratio for preferred stock for existing pipeline (fraction) [read as D_GPFES]

$GCMESTR_{a,p,t}$ = capital structure ratio for common equity for existing pipeline (fraction) [read as D_GCMES]
$GLTDSTR_{a,p,t}$ = capital structure ratio for long-term debt for existing pipeline (fraction) [read as D_GLTDS]
$PFES_{a,p,t}$ = value of preferred stock (dollars)
$CMES_{a,p,t}$ = value of common stock (dollars)
$LTDS_{a,p,t}$ = value of long-term debt (dollars)
$TOTCAP_{a,p,t}$ = total capitalization (dollars), equal to the sum of value of preferred stock, common stock equity, and long-term debt
p = pipeline company
a = arc
t = historical year

In the financial database, the estimated capital (capitalization) for each interstate pipeline is by definition equal to its adjusted rate base. Hence, the estimated capital $TOTCAP_{a,p,t}$ defined in the above equations is equal to the adjusted rate base $APRB_{a,p,t}$.

$$TOTCAP_{a,p,t} = APRB_{a,p,t} \tag{136}$$

where,

$TOTCAP_{a,p,t}$ = total capitalization (dollars)
$APRB_{a,p,t}$ = adjusted rate base (dollars)
a = arc
p = pipeline company
t = historical year

Substituting the adjusted rate base $APRB_{a,t}$ for the estimated capital $TOTCAP_{a,t}$ in equations 133 to 135, the values of preferred stock, common stock, and long-term debt by pipeline and arc can be computed by applying the capital structure ratios to the adjusted rate base, as follows:

$$\begin{aligned} PFES_{a,p,t} &= GPFESTR_{a,p,t} * APRB_{a,p,t} \\ CMES_{a,p,t} &= GCMESTR_{a,p,t} * APRB_{a,p,t} \\ LTDS_{a,p,t} &= GLTDSTR_{a,p,t} * APRB_{a,p,t} \\ GPFESTR_{a,p,t} &+ GCMESTR_{a,p,t} + GLTDSTR_{a,p,t} = 1.0 \end{aligned} \tag{137}$$

where,

$PFES_{a,p,t}$ = value of preferred stock in nominal dollars
$CMES_{a,p,t}$ = value of common equity in nominal dollars
$LTDS_{a,p,t}$ = long-term debt in nominal dollars
$GPFESTR_{a,p,t}$ = capital structure ratio for preferred stock for existing pipeline (fraction)
$GCMESTR_{a,p,t}$ = capital structure ratio of common stock for existing pipeline (fraction)
$GLTDSTR_{a,p,t}$ = capital structure ratio of long term debt for existing pipeline (fraction)

$APRB_{a,p,t}$ = adjusted rate base (dollars)
p = pipeline
a = arc
t = forecast year

The cost of capital at the arc level ($WAROR_{a,t}$) is computed as the weighted average cost of capital for preferred stock, common stock equity, and long-term debt for all pipeline companies associated with that arc, as follows:

$$WAROR_{a,t} = \sum_{p} [(PFES_{a,p,t} * PFER_{a,p,t} + CMES_{a,p,t} * CMER_{a,p,t} + LTDS_{a,p,t} * LTDR_{a,p,t})] / APRB_{a,t} \tag{138}$$

$$APRB_{a,t} = PFES_{a,t} + CMES_{a,t} + LTDS_{a,t} \tag{139}$$

where,

$WAROR_{a,t}$ = weighted-average after-tax return on capital (fraction)
$PFES_{a,p,t}$ = value of preferred stock (dollars)
$PFER_{a,p,t}$ = preferred stock rate (fraction)
$CMES_{a,p,t}$ = value of common stock equity (dollars)
$CMER_{a,p,t}$ = common equity rate of return (fraction)
$LTDS_{a,p,t}$ = value of long-term debt (dollars)
$LTDR_{a,p,t}$ = long-term debt rate (fraction)
$APRB_{a,p,t}$ = adjusted rate base (dollars)
p = pipeline
a = arc
t = historical year

The adjusted rate base by pipeline and arc is computed as the sum of net plant in service and total cash working capital (which includes plant held for future use, materials and supplies, and other working capital) minus accumulated deferred income taxes. This rate base is computed offline and read in by the PTS. The computation is as follows:

$$APRB_{a,p,t} = NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t} \tag{140}$$

where,

$APRB_{a,p,t}$ = adjusted rate base (dollars)
$NPIS_{a,p,t}$ = net capital cost of plant in service (dollars) [read as D_NPIS]
$CWC_{a,p,t}$ = total cash working capital (dollars) [read as D_CWC]
$ADIT_{a,p,t}$ = accumulated deferred income taxes (dollars) [read as D_ADIT]
p = pipeline company
a = arc
t = historical year

The net plant in service by pipeline and arc is the original capital cost of plant in service minus the accumulated depreciation. It is computed offline and then read in by the PTS. The computation is as follows:

$$NPIS_{a,p,t} = GPIS_{a,p,t} - ADDA_{a,p,t} \tag{141}$$

where,

$NPIS_{a,p,t}$	=	net capital cost of plant in service (dollars)
$GPIS_{a,p,t}$	=	original capital cost of plant in service (dollars) [read as D_GPIS]
$ADDA_{a,p,t}$	=	accumulated depreciation, depletion, and amortization (dollars) [read as D_ADDA]
p	=	pipeline company
a	=	arc
t	=	historical year

The adjusted rate base at the arc level is computed as follows:

$$\begin{aligned} APRB_{a,,t} &= \sum_p APRB_{a,p,t} = \sum_p (NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t}) \\ &= (NPIS_{a,t} + CWC_{a,t} - ADIT_{a,t}) \end{aligned} \tag{142}$$

with,

$$\begin{aligned} NPIS_{a,,t} &= \sum_p (GPIS_{a,p,t} - ADDA_{a,p,t}) \\ &= (GPIS_{a,t} - ADDA_{a,t}) \end{aligned} \tag{143}$$

where,

$APRB_{a,p,t}$	=	adjusted rate base (dollars) at the arc level
$NPIS_{a,p,t}$	=	net capital cost of plant in service (dollars) at the arc level
$CWC_{a,t}$	=	total cash working capital (dollars) at the arc level
$ADIT_{a,t}$	=	accumulated deferred income taxes (dollars) at the arc level
$GPIS_{a,p,t}$	=	original capital cost of plant in service (dollars) at the arc level
$ADDA_{a,t}$	=	accumulated depreciation, depletion, and amortization (dollars) at the arc level
p	=	pipeline company
a	=	arc
t	=	historical year

Total Normal Operating Expenses. Total normal operating expense line items include depreciation, taxes, and total operating and maintenance expenses. Total operating and maintenance expenses include administrative and general expenses, customer expenses, and other operating and maintenance expenses. In the PTS, taxes are disaggregated further into Federal, State, and other taxes and deferred income taxes. The equation for total normal operating expenses at the arc level is given as follows:

$$TNOE_{a,t} = \sum_p (DDA_{a,p,t} + TOTAX_{a,p,t} + TOM_{a,p,t}) \tag{144}$$

where,

$TNOE_{a,t}$	=	total normal operating expenses (dollars)
$DDA_{a,p,t}$	=	depreciation, depletion, and amortization costs (dollars) [read as D_DDA]

$TOTAX_{a,p,t}$ = total Federal and State income tax liability (dollars)
$TOM_{a,p,t}$ = total operating and maintenance expense (dollars) [read as D_TOM]
p = pipeline
a = arc
t = historical year

Depreciation, depletion, and amortization costs, and total operating and maintenance expense are available directly from the financial database. The equations to compute these costs at the arc level are as follows:

$$DDA_{a,t} = \sum_{p} DDA_{a,p,t} \tag{145}$$

$$TOM_{a,t} = \sum_{p} TOM_{a,p,t} \tag{146}$$

Total taxes at the arc level are computed as the sum of Federal and State income taxes, other taxes, and deferred income taxes, as follows:

$$TOTAX_{a,t} = \sum_{p} (FSIT_{a,p,t} + OTTAX_{a,p,t} + DIT_{a,p,t}) \tag{147}$$

$$FSIT_{a,t} = \sum_{p} FSIT_{a,p,t} = \sum_{p} (FIT_{a,p,t} + SIT_{a,p,t}) \tag{148}$$

where,

$TOTAX_{a,t}$ = total Federal and State income tax liability (dollars)
$FSIT_{a,p,t}$ = Federal and State income tax (dollars)
$OTTAX_{a,p,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes and deferred income tax (dollars) [read as D_OTTAX]
$DIT_{a,p,t}$ = deferred income taxes (dollars) [read as D_DIT]
$FIT_{a,p,t}$ = Federal income tax (dollars)
$SIT_{a,p,t}$ = State income tax (dollars)
p = pipeline company
a = arc
t = historical year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the Federal tax rate. The after-tax profit at the arc level is determined as follows:

$$ATP_{a,t} = \sum_{p} (PFER_{a,p,t} * PFES_{a,p,t} + CMER_{a,p,t} * CMES_{a,p,t}) \tag{149}$$

where,

$ATP_{a,t}$ = after-tax profit (dollars) at the arc level
$PFER_{a,p,t}$ = preferred stock rate (fraction)
$PFES_{a,p,t}$ = value of preferred stock (dollars)

$CMER_{a,p,t}$ = common equity rate of return (fraction)
$CMES_{a,p,t}$ = value of common stock equity (dollars)
a = arc
t = historical year

and the Federal income taxes at the arc level are,

$$FIT_{a,t} = \frac{FRATE * ATP_{a,t}}{(1. - FRATE)} \tag{150}$$

where,

$FIT_{a,t}$ = Federal income tax (dollars) at the arc level
FRATE = Federal income tax rate (fraction) (Appendix E)
$ATP_{a,t}$ = after-tax profit (dollars)

State income taxes are computed by multiplying the sum of taxable profit and the associated Federal income tax by a weighted-average State tax rate associated with each pipeline company. The weighted-average State tax rate is based on peak service volumes in each State delivered by the pipeline company. State income taxes at the arc level are computed as follows:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{151}$$

where,

$SIT_{a,t}$ = State income tax (dollars) at the arc level
SRATE = average State income tax rate (fraction) (Appendix E)
$FIT_{a,t}$ = Federal income tax (dollars) at the arc level
$ATP_{a,t}$ = after-tax profits (dollars) at the arc level

Thus, total taxes at the arc level can be expressed by the following equation:

$$TOTAX_{a,t} = (FSIT_{a,t} + OTTAX_{a,t} + DIT_{a,t}) \tag{152}$$

where,

$TOTAX_{a,t}$ = total Federal and State income tax liability (dollars) at the arc level
$FSIT_{a,t}$ = Federal and State income tax (dollars) at the arc level
$OTTAX_{a,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes and deferred income taxes (dollars), at the arc level
$DIT_{a,t}$ = deferred income taxes (dollars) at the arc level
a = arc
t = historical year

All other taxes and deferred income taxes at the arc level are expressed as follows:

$$OTTAX_{a,t} = \sum_{p} OTTAX_{a,p,t} \tag{153}$$

$$DIT_{a,t} = \sum_{p} DIT_{a,p,t} \tag{154}$$

Adjustment from 28 major pipelines to total U.S. Note that all cost-of-service and rate base components computed so far are based on the financial database of 28 major interstate pipelines. According to the U.S. natural gas pipeline construction and financial reports filed with the FERC and published in the Oil and Gas Journal,[86] there were more than 100 interstate natural gas pipelines operating in the United States in 2006. The total annual gross plant in service and operating revenues for all these pipelines are much higher than those for the 28 major interstate pipelines in the financial database. All the cost-of-service and rate base components at the arc level computed in the above sections are scaled up as follows: For the capital costs and adjusted rate base components,

$$\begin{aligned}
GPIS_{a,t} &= GPIS_{a,t} * HFAC_GPIS_t \\
ADDA_{a,t} &= ADDA_{a,t} * HFAC_GPIS_t \\
NPIS_{a,t} &= NPIS_{a,t} * HFAC_GPIS_t \\
CWC_{a,t} &= CWC_{a,t} * HFAC_GPIS_t \\
ADIT_{a,t} &= ADIT_{a,t} * HFAC_GPIS_t \\
APRB_{a,t} &= APRB_{a,t} * HFAC_GPIS_t
\end{aligned} \tag{155}$$

For the cost-of-service components,

$$\begin{aligned}
PFEN_{a,t} &= PFEN_{a,t} * HFAC_REV_t \\
CMEN_{a,t} &= CMEN_{a,t} * HFAC_REV_t \\
LTDN_{a,t} &= LTDN_{a,t} * HFAC_REV_t \\
DDA_{a,t} &= DDA_{a,t} * HFAC_REV_t \\
FSIT_{a,t} &= FSIT_{a,t} * HFAC_REV_t \\
OTTAX_{a,t} &= OTTAX_{a,t} * HFAC_REV_t \\
DIT_{a,t} &= DIT_{a,t} * HFAC_REV_t \\
TOM_{a,t} &= TOM_{a,t} * HFAC_REV_t
\end{aligned} \tag{156}$$

where,

$GPIS_{a,t}$	=	original capital cost of plant in service (dollars)
$HFAC\_GPIS_t$	=	adjustment factor for capital costs to total U.S. (Appendix E)
$ADDA_{a,t}$	=	accumulated depreciation, depletion, and amortization (dollars)
$NPIS_{a,t}$	=	net capital cost of plant in service (dollars)
$CWC_{a,t}$	=	total cash working capital (dollars)
$ADIT_{a,t}$	=	accumulated deferred income taxes (dollars)
$APRB_{a,t}$	=	adjusted pipeline rate base (dollars)
$PFEN_{a,t}$	=	total return on preferred stock (dollars)

[86] *Pipeline Economics*, Oil and Gas Journal, 1994, 1995, 1997, 1999, 2001, 2002, 2003, 2004, 2005, 2006.

$HFAC\_REV_t$	=	adjustment factor for operation revenues to total U.S. (Appendix E)
$CMEN_{a,t}$	=	total return on common stock equity (dollars)
$LTDN_{a,t}$	=	total return on long-term debt (dollars)
$DDA_{a,t}$	=	depreciation, depletion, and amortization costs (dollars)
$FSIT_{a,t}$	=	Federal and State income tax (dollars)
$OTTAX_{a,t}$	=	all other taxes assessed by Federal, State, or local governments except income taxes and deferred income taxes (dollars)
$DIT_{a,t}$	=	deferred income taxes (dollars)
$TOM_{a,t}$	=	total operations and maintenance expense (dollars)
a	=	arc
t	=	historical year

Except for the Federal and State income taxes and returns on capital, all the cost-of-service and rate base components computed at the arc level above are also used as initial values in the forecast year update phase that starts in 2007.

Step 2: Classification of Cost-of-Service Line Items as Fixed and Variable Costs

The PTS breaks each line item of the cost of service (computed in Step 1) into fixed and variable costs. Fixed costs are independent of storage/transportation usage, while variable costs are a function of usage. Fixed and variable costs are computed by multiplying each line item of the cost of service by the percentage of the cost that is fixed and the percentage of the cost that is variable. The classification of fixed and variable costs is defined by the user as part of the scenario specification. The classification of line item cost Ri to fixed and variable cost is determined as follows:

$$R_{i,f} = ALL_f * R_i / 100 \qquad (157)$$

$$R_{i,v} = ALL_v * R_i / 100 \qquad (158)$$

where,

$R_{i,f}$	=	fixed cost portion of line item Ri (dollars)
ALL_f	=	percentage of line item Ri representing fixed cost
R_i	=	total cost of line item i (dollars)
$R_{i,v}$	=	variable cost portion of line item Ri (dollars)
ALL_v	=	percentage of line item Ri representing variable cost
i	=	line item index
f,v	=	fixed or variable
100	=	ALLf + ALLv

An example of this procedure is illustrated in **Table 6-1**.

The resulting fixed and variable costs at the arc level are obtained by summing all line items for each cost category from the above equations, as follows:

$$FC_a = \sum_i R_{i,f} \quad (159)$$

$$VC_a = \sum_i R_{i,v} \quad (160)$$

where,

FC_a = total fixed cost (dollars) at the arc level
VC_a = total variable cost (dollars) at the arc level
a = arc

Table 6-1. Illustration of Fixed and Variable Cost Classification

Cost of Service Line Item	Total (dollars)	Cost Allocation Factors (percent) Fixed	Variable	Cost Component (dollars) Fixed	Variable
Total Return					
Preferred Stock	1,000	100	0	1,000	0
Common Stock	30,000	100	0	30,000	0
Long-Term Debt	29,000	100	0	29,000	0
Normal Operating Expenses					
Depreciation	30,000	100	0	30,000	0
Taxes					
Federal Tax	25,000	100	0	25,000	0
State Tax	5,000	100	0	5,000	0
Other Tax	1,000	100	0	1,000	0
Deferred Income Taxes	1,000	100	0	1,000	0
	105,000	60	40	63,000	42,000
Total Operations & Maintenance					
Total Cost-of-Service	227,000			185,000	42,000

Step 3: Allocation of Fixed and Variable Costs to Rate Components

Allocation of fixed and variable costs to rate components is conducted only for transportation services because storage service is modeled in a more simplified manner using a one-part rate. The rate design to be used within the PTS is specified by input parameters, which can be modified by the user to reflect changes in rate design over time. The PTS allocates the fixed and variable costs computed in Step 2 to rate components as specified by the rate design. For transportation service, the components of the rate consist of a reservation and a usage fee. The reservation fee is a charge assessed based on the amount of capacity reserved. It typically is a monthly fee that does not vary with throughput. The usage fee is a charge assessed for each unit of gas that moves through the system.

The actual reservation and usage fees that pipelines are allowed to charge are regulated by the Federal Energy Regulatory Commission (FERC). How costs are allocated determines the extent of differences in the rates charged for different classes of customers for different types of services. In general, if more fixed costs are allocated to usage fees, more costs are recovered based on throughput.

Costs are assigned either to the reservation fee or to the usage fee according to the rate design specified for the pipeline company. The rate design can vary among pipeline companies. Three typical rate designs are described in **Table 6-2**. The PTS provides two options for specifying the rate design. In the first option, a rate design for each pipeline company can be specified for each forecast year. This option permits different rate designs to be used for different pipeline companies while also allowing individual company rate designs to change over time. Since pipeline company data subsequently are aggregated to network arcs, the composite rate design at the arc-level is the quantity-weighted average of the pipeline company rate designs. The second option permits a global specification of the rate design, where all pipeline companies have the same rate design for a specific time period but can switch to another rate design in a different time period.

Table 6-2. Approaches to Rate Design

Modified Fixed Variable (Three-Part Rate)	Modified Fixed Variable (Two-Part Rate)	Straight Fixed Variable (Two-Part Rate)
• Two-part reservation fee. - Return on equity and related taxes are held at risk to achieving throughput targets by allocating these costs to the usage fee. Of the remaining fixed costs, 50 percent are recovered from a peak day reservation fee and 50 percent are recovered through an annual reservation fee.	• Reservation fee based on peak day requirements - all fixed costs except return on equity and related taxes recovered through this fee.	• One-part capacity reservation fee. All fixed costs are recovered through the reservation fee, which is assessed based on peak day capacity requirements.
• Variable costs allocated to the usage fee. In addition, return on equity and related taxes are also recovered through the usage fee.	• Variable costs plus return on equity and related taxes are recovered through the usage fee.	• Variable costs are recovered through the usage fee.

The allocation of fixed costs to reservation and usage fees entails multiplying each fixed cost line item of the total cost of service by the corresponding fixed cost rate design classification factor. A similar process is carried out for variable costs. This procedure is illustrated in **Tables 6-3a and 6-3b** and is generalized in the equations that follow. The classification of transportation line item costs $R_{i,f}$ and $R_{i,v}$ to reservation and usage cost is determined as follows:

$$R_{i,f,r} = ALL_{f,r} * R_{i,f} / 100 \tag{161}$$

$$R_{i,f,u} = ALL_{f,u} * R_{i,f} / 100 \tag{162}$$

$$R_{i,v,r} = ALL_{v,r} * R_{i,v} / 100 \tag{163}$$

$$R_{i,v,u} = ALL_{v,u} * R_{i,v} / 100 \tag{164}$$

Table 6-3a. Illustration of Allocation of Fixed Costs to Rate Components

Cost of Service Line Item	Total (dollars)	Allocation Factors (percent) Reservation	Usage	Cost Assigned to Rate Component (dollars) Reservation	Usage
Total Return					
Preferred Stock	1,000	100	0	0	1,000
Common Stock	30,000	100	0	0	30,000
Long-Term Debt	29,000	100	0	29,000	0
Normal Operating Expenses					
Depreciation	30,000	100	0	30,000	0
Taxes					
Federal Tax	25,000	0	100	0	25,000
State Tax	5,000	0	100	0	5,000
Other Tax	1,000	100	0	1,000	0
Deferred Income Taxes	1,000	100	0	1,000	0
Total Operations & Maintenance	63,000	100	0	63,000	0
Total Cost-of-Service	185,000			124,000	61,000

Table 6-3b. Illustration of Allocation of Variable Costs to Rate Components

Cost of Service Line Item	Total (dollars)	Allocation Factors (percent) Reservation	Usage	Cost Assigned to Rate Component (dollars) Reservation	Usage
Total Return					
Preferred Stock	0	0	100	0	0
Common Stock	0	0	100	0	0
Long-Term Debt	0	0	100	0	0
Normal Operating Expenses					
Depreciation	0	0	100	0	0
Taxes					
Federal Tax	0	0	100	0	0
State Tax	0	0	100	0	0
Other Tax	0	0	100	0	0
Deferred Income Taxes	0	0	100	0	0
Total Operations & Maintenance	42,000	0	100	0	42,000
Total Cost-of-Service	42,000			0	42,000

where,

R = line item cost (dollars)

ALL = percentage of reservation or usage line item R representing fixed or variable cost (Appendix E -- AFR, AVR, AFU=1-AFR, AVU=1-AVR)

100 = $ALL_{f,r} + ALL_{f,u}$

$100 = ALL_{v,r} + ALL_{v,u}$
i = line item number index
f = fixed cost index
v = variable cost index
r = reservation cost index
u = usage cost index

At this stage in the procedure, the line items comprising the fixed and variable cost components of the reservation and usage fees can be summed to obtain total reservation and usage components of the rates.

$$RCOST_a = \sum_i (R_{i,f,r} + R_{i,v,r}) \qquad (165)$$

$$UCOST_a = \sum_i (R_{i,f,u} + R_{i,v,u}) \qquad (166)$$

where,

$RCOST_a$ = total reservation cost (dollars) at the arc level
$UCOST_a$ = total usage cost (dollars) at the arc level
a = arc

After ratemaking Steps 1, 2 and 3 are completed for each arc by historical year, the rates are computed below.

Computation of Rates for Historical Years

The reservation and usage costs-of-service (RCOST and UCOST) developed above are used separately to develop two types of rates at the arc level: *variable tariffs* and *annual fixed usage fees*.

Variable Tariff Curves

Variable tariffs are proportional to reservation charges and are broken up into peak and off-peak time periods. Variable tariffs are derived directly from variable tariff curves which are developed based on reservation costs, utilization rates, annual flows, and other parameters.

In the PTS code, these variable tariff curves are defined by FUNCTION (NGPIPE_VARTAR) which is used by the ITS to compute the variable peak and off-peak tariffs by arc and by forecast year. The pipeline tariff curves are a function of peak or off-peak flow and are specified using a base point [price and quantity (PNOD, QNOD)] and an assumed price elasticity, as follows:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA\_PIPE} \qquad (167)$$

such that,

For peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR\_YR}{(QNOD_{a,t} * MC\_PCWGDP_{t})} \tag{168}$$

$$QNOD_{a,t} = PT\,NETFLOW_{a,t} \tag{169}$$

For off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_{t})} \tag{170}$$

$$QNOD_{a,t} = PT\,NETFLOW_{a,t} \tag{171}$$

where,

$NGPIPE\_VARTAR_{a,t}$	=	function to define pipeline tariffs (87$/Mcf)
$PNOD_{a,t}$	=	base point, price (87$/Mcf)
$QNOD_{a,t}$	=	base point, quantity (Bcf)
$Q_{a,t}$	=	flow along pipeline arc (Bcf), dependent variable for the function
ALPHA_PIPE	=	price elasticity for pipeline tariff curve for current capacity
$RCOST_{a,t}$	=	reservation cost-of-service (dollars)
$PTNETFLOW_{a,t}$	=	natural gas network flow (throughput, Bcf)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
MC_PCWGDP_{t}	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	historical year

Annual Fixed Usage Fees

The annual fixed usage fees (volumetric charges) are derived directly from the usage costs, utilization rates for peak and off-peak time periods, and annual arc capacity. These fees are computed as the average fees over each historical year, as follows:

$$\begin{aligned} FIXTAR_{a,t} = UCOST_{a,t} / [(&PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + \\ &(1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_{t}] \end{aligned} \tag{172}$$

where,

$FIXTAR_{a,t}$	=	annual fixed usage fees for existing and new capacity (87$/Mcf)
$UCOST_{a,t}$	=	annual usage cost of service for existing and new capacity (dollars)

$PKSHR\_YR$ = portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$ = peak pipeline utilization (fraction)
$PTCURPCAP_{a,t}$ = current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$ = off-peak pipeline utilization (fraction)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = historical year

Canadian Tariffs

In the historical year phase, Canadian tariffs are set to the historical differences between the import prices and the Western Canada Sedimentary Basin (WCSB) wellhead price.

Computation of Storage Rates

The annual storage tariff for each NGTDM region and year is defined as a function of storage flow and is specified using a base point [price and quantity (PNOD, QNOD)] and an assumed price elasticity, as follows:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA\_STR} \quad (173)$$

such that,

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC\_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP\_ADJ_{r,t} * ADJ\_STR \quad (174)$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \quad (175)$$

where,

$X1NGSTR\_VARTAR_{r,t}$ = function to define storage tariffs (87$/Mcf)
$Q_{r,t}$ = peak period net storage withdrawals (Bcf)
$PNOD_{r,t}$ = base point, price (87$/Mcf)
$QNOD_{r,t}$ = base point, quantity (Bcf)
$ALPHA\_STR$ = price elasticity for storage tariff curve (ratio, Appendix E)

$STCOS_{r,t}$ = existing storage capacity cost of service, computed from historical cost-of-service components
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
$STRATIO_{r,t}$ = portion of revenue requirement obtained by moving gas from the off-peak to the peak period (fraction, Appendix E)
$STCAP\_ADJ_{r,t}$ = adjustment factor for the cost of service to total U.S. (ratio), defined as annual storage working gas capacity divided by

Foster storage working gas capacity

ADJ_STR = storage tariff curve adjustment factor (fraction, Appendix E)
$PTSTUTZ_{r,t}$ = storage utilization (fraction)
$PTCURPSTR_{r,t}$ = annual storage working gas capacity (Bcf)
r = NGTDM region
t = historical year

Forecast Year Update Phase

The purpose of the forecast year update phase is to project, for each arc and subsequent year of the forecast period, the cost-of-service components that are used to develop rates for the peak and off-peak periods. For each year, the PTS forecasts the adjusted rate base, cost of capital, return on rate base, depreciation, taxes, and operation and maintenance expenses. The forecasting relationships are discussed in detail below.

After all of the components of the cost-of-service at the arc level are forecast, the PTS proceeds to: (1) classify the components of the cost of service as fixed and variable costs, (2) allocate fixed and variable costs to rate components (reservation and usage costs) based on the rate design, and (3) compute arc-specific rates (variable and fixed tariffs) for peak and off-peak periods.

Investment Costs for Generic Pipelines

The PTS projects the capital costs to expand pipeline capacity at the arc level, as opposed to determining the costs of expansion for individual pipelines. The PTS represents arc-specific generic pipelines to generate the cost of capacity expansion by arc. Thus, the PTS tracks costs attributable to capacity added during the forecast period separately from the costs attributable to facilities in service in the historical years. The PTS estimates the capital costs associated with the level of capacity expansion forecast by the ITS in the previous forecast year based on exogenously specified estimates for the average pipeline capital costs at the arc level ($AVG\_CAPCOST_a$) associated with expanding capacity for compression, looping, and new pipeline. These average capital costs per unit of expansion (2005 dollars per Mcf) were computed based on a pipeline construction project cost database[87] compiled by the Office of Oil and Gas. These costs are adjusted for inflation from 2007 throughout the forecast period (i.e., they are held constant in real terms).

The average capital cost to expand capacity on a network arc is estimated given the level of capacity additions in year t provided by the ITS and the associated assumed average unit capital cost. This average unit capital cost represents the investment cost for a generic pipeline associated with a given arc, as follows:

$$CCOST_{a,t} = AVG\_CAPCOST_a * MC\_PCWGDP_t / MC\_PCWGDP_{2000} \qquad (176)$$

[87] A spreadsheet compiled by James Tobin of EIA's Office of Oil and Gas containing historical and proposed state-to-state pipeline construction project costs, mileage, and capacity levels and additions by year from 1996 to 2011, by pipeline company (data as of August 16, 2007).

where,

$CCOST_{a,t}$ = average pipeline capital cost per unit of expanded capacity (nominal dollars per Mcf)
$AVG\_CAPCOST_{a}$ = average pipeline capital cost per unit of expanded capacity in 2000 dollars per Mcf (Appendix E, AVGCOST)
MC_PCWGDP_{t} = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

The new capacity expansion expenditures allowed in the rate base within a forecast year are derived from the above average unit capital cost and the amount of incremental capacity additions determined by the ITS for each arc, as follows:

$$NCAE_{a,t} = CCOST_{a,t} * CAPADD_{a,t} * 1{,}000{,}000 * (1 + PCNT\_R) \quad (177)$$

where,

$NCAE_{a,t}$ = capital cost to expand capacity on a network arc (dollars)
$CCOST_{a,t}$ = average capital cost per unit of expansion (dollars per Mcf)
$CAPADD_{a,t}$ = capacity additions for an arc as determined in the ITS (Bcf/yr)
PCNT_R = assumed average percentage (fraction) for pipeline replacement costs (Appendix E)
t = forecast year

To account for additional costs due to pipeline replacements, the PTS increases the capital costs to expand capacity by a small percentage (PCNT_R). Once the capital cost of new plant in service is computed by arc in year t, this amount is used in an accounting algorithm for the computation of gross plant in service for new capacity expansion, along with its depreciation, depletion, and amortization. These will in turn be used in the computation of updated cost-of-service components for the existing and new capacity for an arc.

Forecasting Cost-of-Service [88]

The primary purpose in forecasting cost-of-service is to capture major changes in the composition of the revenue requirements and major changes in cost trends through the forecast period. These changes may be caused by capacity expansion or maintenance and life extension of nearly depreciated plants, as well as by changes in the cost and availability of capital.

The projection of the cost-of-service is approached from the viewpoint of a long-run marginal cost analysis for gas pipeline systems. This differs from the determination of cost-of-service for the purpose of a rate case. Costs that are viewed as fixed for the purposes of a rate case actually vary in the long-run with one or more external measures of size or activity levels in the industry. For example, capital investments for replacement and refurbishment of existing facilities are a long-run marginal cost of the pipeline system. Once in place,

[88] All cost components in the forecast equations in this section are in nominal dollars, unless explicitly stated otherwise.

however, the capital investments are viewed as fixed costs for the purposes of rate cases. The same is true of operations and maintenance expenses that, except for short-run variable costs such as fuel, are most commonly classified as fixed costs in rate cases. For example, customer expenses logically vary over time based on the number of customers served and the cost of serving each customer. The unit cost of serving each customer, itself, depends on changes in the rate base and individual cost-of-service components, the extent and/or complexity of service provided to each customer, and the efficiency of the technology level employed in providing the service.

The long-run marginal cost approach generally projects total costs as the product of unit cost for the activity multiplied by the incidence of the activity. Unit costs are projected from cost-of-service components combined with time trends describing changes in level of service, complexity, or technology. The level of activity is projected in terms of variables external to the PTS (e.g., annual throughput) that are both logically and empirically related to the incurrence of costs. Implementation of the long-run marginal cost approach involves forecasting relationships developed through empirical studies of historical change in pipeline costs, accounting algorithms, exogenous assumptions, and inputs from other NEMS modules. These forecasting algorithms may be classified into three distinct areas, as follows:

- The projection of adjusted rate base and cost of capital for the combined existing and new capacity.
- The projection of components of the revenue requirements.
- The computation of variable and fixed rates for peak and off-peak periods.

The empirically derived forecasting algorithms discussed below are determined for each network arc.

Projection of Adjusted Rate Base and Cost of Capital

The approach for projecting adjusted rate base and cost of capital at the arc level is summarized in **Table 6-4**. Long-run marginal capital costs of pipeline companies reflect changes in the AA utility bond index rate. Once projected, the adjusted rate base is translated into capital-related components of the revenue requirements based on projections of the cost of capital, total operating and maintenance expenses, and algorithms for depreciation and tax effects.

The projected adjusted rate base for the combined existing and new pipelines at the arc level in year t is computed as the amount of gross plant in service in year t minus previous year's accumulated depreciation, depletion, and amortization plus total cash working capital minus accumulated deferred income taxes in year t.

$$APRB_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} + CWC_{a,t} - ADIT_{a,t} \tag{178}$$

where,

$APRB_{a,t}$ = adjusted rate base in dollars

$GPIS_{a,t}$ = total capital cost of plant in service (gross plant in service) in dollars

Table 6-4. Approach to Projection of Rate Base and Capital Costs

Projection Component	**Approach**
1. Adjusted Rate Base	
a. Gross plant in service in year t	
I. Capital cost of existing plant in service	Gross plant in service in the last historical year (2006)
II. Capacity expansion costs for new capacity	Accounting algorithm [equation 180]
b. Accumulated Depreciation, Depletion & Amortization	Accounting algorithm [equations 186, 187, 189] and empirically estimated for existing capacity [equation 188]
c. Cash and other working capital	User defined option for the combined existing and new capacity [equation 190]
d. Accumulated deferred income taxes	Empirically estimated for the combined existing and new capacity [equation 141]
f. Depreciation, depletion, and amortization	Existing Capacity: empirically estimated [equation 188] New Capacity: accounting algorithm [equation 189]
2. Cost of Capital	
a. Long-term debt rate	Projected AA utility bond yields adjusted by historical average deviation constant for long-term debt rate
b. Preferred equity rate	Projected AA utility bond yields adjusted by historical average deviation constant for preferred equity rate
c. Common equity return	Projected AA utility bond yields adjusted by historical average deviation constant for common equity return
3. Capital Structure	Held constant at average historical values

$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
$CWC_{a,t}$ = total cash working capital including other cash working capital in dollars
$ADIT_{a,t}$ = accumulated deferred income taxes in dollars
a = arc
t = forecast year

All the variables in the above equation represent the aggregate variables for all interstate pipelines associated with an arc. The aggregate variables on the right hand side of the adjusted rate base equation are forecast by the equations below. First, total (existing and new) gross plant in service in the forecast year is determined as the sum of existing gross plant in service and new capacity expansion expenditures added to existing gross plant in service. New capacity expansion can be compression, looping, and new pipelines. For simplification, the replacement, refurbishment, retirement, and cost associated with new facilities for complying with Order 636 are not accounted for in projecting total gross plant in service in year t. Total gross plant in service for a network arc is forecast as follows:

$$GPIS_{a,t} = GPIS\_E_{a,t} + GPIS\_N_{a,t} \quad (179)$$

where,

$GPIS_{a,t}$	=	total capital cost of plant in service (gross plant in service) in dollars
$GPIS\_E_{a,t}$	=	gross plant in service in the last historical year (2006)
$GPIS\_N_{a,t}$	=	capital cost of new plant in service in dollars
a	=	arc
t	=	forecast year

In the above equation, the capital cost of existing plant in service ($GPIS\_E_{a,t}$) reflects the amount of gross plant in service in the last historical year (2006). The capital cost of new plant in service ($GPIS\_N_{a,t}$) in year t is computed as the accumulated new capacity expansion expenditures from 2007 to year t and is determined by the following equation:

$$GPIS\_N_{a,t} = \sum_{s=2004}^{t} NCAE_{a,s} \quad (180)$$

where,

$GPIS\_N_{a,t}$	=	gross plant in service for new capacity expansion in dollars
$NCAE_{a,s}$	=	new capacity expansion expenditures occurring in year s after 2006 (in dollars) [equation 177]
s	=	the year new expansion occurred
a	=	arc
t	=	forecast year

Next, net plant in service in year t is determined as the difference between total capital cost of plant in service (gross plant in service) in year t and previous year’s accumulated depreciation, depletion, and amortization.

$$NPIS_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} \quad (181)$$

where,

$NPIS_{a,t}$	=	total net plant in service in dollars
$GPIS_{a,t}$	=	total capital cost of plant in service (gross plant in service) in dollars
$ADDA_{a,t}$	=	accumulated depreciation, depletion, and amortization in dollars
a	=	arc
t	=	forecast year

Accumulated depreciation, depletion, and amortization for the combined existing and new capacity in year t is determined by the following equation:

$$ADDA_{a,t} = ADDA\_E_{a,t} + ADDA\_N_{a,t} \quad (182)$$

where,

$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
$ADDA\_E_{a,t}$ = accumulated depreciation, depletion, and amortization for existing capacity in dollars
$ADDA\_N_{a,t}$ = accumulated depreciation, depletion, and amortization for new capacity in dollars
a = arc
t = forecast year

With this and the relationship between the capital costs of existing and new plants in service from equation 179, total net plant in service ($NPIS_{a,t}$) is set equal to the sum of net plant in service for existing pipelines and new capacity expansions, as follows:

$$NPIS_{a,t} = NPIS\_E_{a,t} + NPIS\_N_{a,t} \tag{183}$$

$$NPIS\_E_{a,t} = GPIS\_E_{a,t} - ADDA\_E_{a,t-1} \tag{184}$$

$$NPIS\_N_{a,t} = GPIS\_N_{a,t} - ADDA\_N_{a,t-1} \tag{185}$$

where,

$NPIS_{a,t}$ = total net plant in service in dollars
$NPIS\_E_{a,t}$ = net plant in service for existing capacity in dollars
$NPIS\_N_{a,t}$ = net plant in service for new capacity in dollars
$GPIS\_E_{a,t}$ = gross plant in service in the last historical year (2006)
$ADDA\_E_{a,t}$ = accumulated depreciation, depletion, and amortization for existing capacity in dollars
$ADDA\_N_{a,t}$ = accumulated depreciation, depletion, and amortization for new capacity in dollars
GPIS_N = gross plant in service for new capacity in dollars
a = arc
t = forecast year

Accumulated depreciation, depletion, and amortization for a network arc in year t is determined as the sum of previous year's accumulated depreciation, depletion, and amortization and current year's depreciation, depletion, and amortization.

$$ADDA_{a,t} = ADDA_{a,t-1} + DDA_{a,t} \tag{186}$$

where,

$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
$DDA_{a,t}$ = annual depreciation, depletion, and amortization costs in dollars
a = arc
t = forecast year

Annual depreciation, depletion, and amortization for a network arc in year t equal the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with the arc.

$$DDA_{a,t} = DDA\_E_{a,t} + DDA\_N_{a,t} \quad (187)$$

where,

$DDA_{a,t}$	=	annual depreciation, depletion, and amortization in dollars
$DDA\_E_{a,t}$	=	depreciation, depletion, and amortization costs for existing capacity in dollars
$DDA\_N_{a,t}$	=	depreciation, depletion, and amortization costs for new capacity in dollars
a	=	arc
t	=	forecast year

A regression equation is used to determine the annual depreciation, depletion, and amortization for existing capacity associated with an arc, while an accounting algorithm is used for new capacity. For existing capacity, this expense is forecast as follows:

$$DDA\_E_{a,t} = \beta_{0,a} + \beta_1 * NPIS\_E_{a,t-1} + \beta_2 * NEWCAP\_E_{a,t} \quad (188)$$

where,

$DDA\_E_{a,t}$	=	annual depreciation, depletion, and amortization costs for existing capacity in nominal dollars
$\beta_{0,a}$	=	DDA_C_a, constant term estimated by arc (Appendix F, Table F3.3, $\beta_{0,a} = B\_ARC_{xx\_yy}$)
β_1	=	DDA_NPIS, estimated coefficient for net plant in service for existing capacity (Appendix F, Table F3.3)
β_2	=	DDA_NEWCAP, estimated coefficient for the change in gross plant in service for existing capacity (Appendix F, Table F3.3)
$NPIS\_E_{a,t}$	=	net plant in service for existing capacity (dollars)
$NEWCAP\_E_{a,t}$	=	change in gross plant in service for existing capacity between t and t-1 (dollars)
a	=	arc
t	=	forecast year

The accounting algorithm used to define the annual depreciation, depletion, and amortization for new capacity assumes straight-line depreciation over a 30-year life, as follows:

$$DDA\_N_{a,t} = GPIS\_N_{a,t} / 30 \quad (189)$$

where,

$DDA\_N_{a,t}$	=	annual depreciation, depletion, and amortization for new capacity in dollars
$GPIS\_N_{a,t}$	=	gross plant in service for new capacity in dollars [equation 180]
30	=	30 years of plant life
a	=	arc
t	=	forecast year

Next, total cash working capital ($CWC_{a,t}$) for the combined existing and new capacity by arc in the adjusted rate base equation consists of cash working capital, material and supplies, and other components that vary by company. Total cash working capital for pipeline transmission for existing and new capacity at the arc level is deflated using the chain weighted GDP price index with 2005 as a base. This level of cash working capital ($R\_CWC_{a,t}$) is determined using a log-linear specification with correction for serial correlation given the economies in cash management in gas transmission. The estimated equation used for R_CWC (Appendix F, Table F3) is determined as a function of total operation and maintenance expenses, as defined below:

$$R\_CWC_{a,t} = CWC\_K * e^{(\beta_{0,a}*(1-\rho)+CWC\_TOM*\log(R\_TOM_{a,t})+\rho*\log(R\_CWC_{a,t-1})-\rho*CWC\_TOM*\log(R\_TOM_{a,t-1}))} \tag{190}$$

where,

$R\_CWC_{a,t}$	=	total pipeline transmission cash working capital for existing and new capacity (2005 real dollars)
$\beta_{0,a}$	=	CWC_C_a, estimated arc specific constant for gas transported from node to node (Appendix F, Table F3.2, $\beta_{0,a} = B\_ARC_{xx\_yy}$)
CWC_TOM	=	estimated R_TOM coefficient (Appendix F, Table F3.2)
$R\_TOM_{a,t}$	=	total operation and maintenance expenses in 2005 real dollars
CWC_K	=	correction factor estimated in stage 2 of the regression equation estimation process (Appendix F, Table F3)
ρ	=	autocorrelation coefficient from estimation (Appendix F, Table F3.2 -- CWC_RHO)
a	=	arc
t	=	forecast year

Last, the level of accumulated deferred income taxes for the combined existing and new capacity on a network arc in year t in the adjusted rate base equation depends on income tax regulations in effect, differences in tax and book depreciation, and the time vintage of past construction. The level of accumulated deferred income taxes for the combined existing and new capacity is derived as follows:

$$\begin{aligned} ADIT_{a,t} = {} & \beta_{0,a} + \beta_1 * \ NEWCAP_{a,t} + \beta_2 * \ NEWCAP_{a,t} + \\ & \beta_3 * \ NEWCAP_{a,t} + ADIT_{a,t-1} \end{aligned} \tag{191}$$

where,

$ADIT_{a,t}$	=	accumulated deferred income taxes in dollars
$\beta_{0,a}$	=	ADIT_Ca, constant term estimated by arc (Appendix F, Table F3.5, $\beta_{0,a} = B\_ARC_{xx\_yy}$)
β_1	=	BNEWCAP_PRE2003, estimated coefficient on the change in gross plant in service in the pre-2003 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
β_2	=	BNEWCAP_2003_2004, estimated coefficient on the change in gross plant in service for the years 2003/2004 because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.

β_3 = BNEWCAP_POST2004, estimated coefficient on the change in gross plant in service in the post-2004 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
$NEWCAP_{a,t}$ = change in gross plant in service for the combined existing and new capacity between years t and t-1 (in dollars)
a = arc
t = forecast year

Cost of capital. The capital-related components of the revenue requirement at the arc level depend upon the size of the adjusted rate base and the cost of capital to the pipeline companies associated with that arc. In turn, the company level costs of capital depend upon the rates of return on debt, preferred stock and common equity, and the amounts of debt and equity in the overall capitalization. Cost of capital for a company is the weighted average after-tax rate of return (WAROR) which is a function of long-term debt, preferred stock, and common equity. The rate of return variables for preferred stock, common equity, and debt are related to forecast macroeconomic variables. For the combined existing and new capacity at the arc level, it is assumed that these rates will vary as a function of the yield on AA utility bonds (provided by the Macroeconomic Activity Module as a percent) in year t adjusted by a historical average deviation constant, as follows:

$$PFER_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_PFER_a \tag{192}$$

$$CMER_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_CMER_a \tag{193}$$

$$LTDR_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_LTDR_a \tag{194}$$

where,
$PFER_{a,t}$ = rate of return for preferred stock
$CMER_{a,t}$ = common equity rate of return
$LTDR_{a,t}$ = long-term debt rate
$MC\_RMPUAANS_t$ = AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPPUAA, percentage)
ADJ_PFER_a = historical average deviation constant (fraction) for rate of return for preferred stock (1994-2003, over 28 major gas pipeline companies) (D_PFER/100., Appendix E)
ADJ_CMER_a = historical average deviation constant (fraction) for rate of return for common equity (1994-2003, over 28 major gas pipeline companies) (D_CMER/100., Appendix E)
ADJ_LTDR_a = historical average deviation constant (fraction) for long term debt rate (1994-2003, over 28 major gas pipeline companies) (D_LTDR/100., Appendix E)
a = arc
t = forecast year

The weighted average cost of capital in the forecast year is computed as the sum of the capital-weighted rates of return for preferred stock, common equity, and debt, as follows:

$$WAROR_{a,t} = \frac{(PFER_{a,t} * PFES_{a,t}) + (CMER_{a,t} * CMES_{a,t}) + (LTDR_{a,t} * LTDS_{a,t})}{TOTCAP_{a,t}} \tag{195}$$

$$TOTCAP_{a,t} = (PFES_{a,t} + CMES_{a,t} + LTDS_{a,t}) \tag{196}$$

where,

$WAROR_{a,t}$	=	weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$	=	rate or return for preferred stock (fraction)
$PFES_{a,t}$	=	value of preferred stock (dollars)
$CMER_{a,t}$	=	common equity rate of return (fraction)
$CMES_{a,t}$	=	value of common stock (dollars)
$LTDR_{a,t}$	=	long-term debt rate (fraction)
$LTDS_{a,t}$	=	value of long-term debt (dollars)
$TOTCAP_{a,t}$	=	sum of the value of long-term debt, preferred stock, and common stock equity dollars)
a	=	arc
t	=	forecast year

The above equation can be written as a function of the rates of return and capital structure ratios as follows:

$$WAROR_{a,t} = (PFER_{a,t} * GPFESTR_{a,t}) + (CMER_{a,t} * GCMESTR_{a,t}) + (LTDR_{a,t} * GLTDSTR_{a,t}) \tag{197}$$

where,

$$GPFESTR_{a,t} = PFES_{a,t} / TOTCAP_{a,t} \tag{198}$$

$$GCMESTR_{a,t} = CMES_{a,t} / TOTCAP_{a,t} \tag{199}$$

$$GLTDSTR_{a,t} = LTDS_{a,t} / TOTCAP_{a,t} \tag{200}$$

and,

$WAROR_{a,t}$	=	weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$	=	coupon rate for preferred stock (fraction)
$CMER_{a,t}$	=	common equity rate of return (fraction)
$LTDR_{a,t}$	=	long-term debt rate (fraction)
$GPFESTR_{a}$	=	ratio of preferred stock to estimated capital for existing and new capacity (fraction) [referred to as capital structure for preferred stock]
$GCMESTR_{a}$	=	ratio of common stock to estimated capital for existing and new capacity (fraction)[referred to as capital structure for common stock]
$GLTDSTR_{a}$	=	ratio of long term debt to estimated capital for existing and new capacity (fraction)[referred to as capital structure for long term debt]
$PFES_{a,t}$	=	value of preferred stock (dollars)
$CMES_{a,t}$	=	value of common stock (dollars)
$LTDS_{a,t}$	=	value of long-term debt (dollars)

$TOTCAP_{a,t}$ = estimated capital equal to the sum of the value of preferred stock, common stock equity, and long-term debt (dollars)
a = arc
t = forecast year

In the financial database, the estimated capital for each interstate pipeline is by definition equal to its adjusted rate base. Hence, the estimated capital ($TOTCAP_{a,t}$) defined in equation 196 is equal to the adjusted rate base ($APRB_{a,t}$) defined in equation 178:

$$TOTCAP_{a,t} = APRB_{a,t} \tag{201}$$

where,

$TOTCAP_{a,t}$ = estimated capital in dollars
$APRB_{a,t}$ = adjusted rate base in dollars
a = arc
t = forecast year

Substituting the adjusted rate base variable $APRB_{a,t}$ for the estimated capital $TOTCAP_{a,t}$ in equations 198 to 200, the values of preferred stock, common stock, and long term debt by arc can be derived as functions of the capital structure ratios and the adjusted rate base. Capital structure is the percent of total capitalization (adjusted rate base) represented by each of the three capital components: preferred equity, common equity, and long-term debt. The percentages of total capitalization due to common stock, preferred stock, and long-term debt are considered fixed throughout the forecast. Assuming that the total capitalization fractions remain the same over the forecast horizon, the values of preferred stock, common stock, and long-term debt can be derived as follows:

$$\begin{aligned} PFES_{a,t} &= GPFESTR_a * APRB_{a,t} \\ CMES_{a,t} &= GCMESTR_a * APRB_{a,t} \\ LTDS_{a,t} &= GLTDSTR_a * APRB_{a,t} \end{aligned} \tag{202}$$

where,

$PFES_{a,t}$ = value of preferred stock in nominal dollars
$CMES_{a,t}$ = value of common equity in nominal dollars
$LTDS_{a,t}$ = long-term debt in nominal dollars
$GPFESTR_a$ = ratio of preferred stock to adjusted rate base for existing and new capacity (fraction) [referred to as capital structure for preferred stock]
$GCMESTR_a$ = ratio of common stock to adjusted rate base for existing and new capacity (fraction)[referred to as capital structure for common stock]
$GLTDSTR_a$ = ratio of long term debt to adjusted rate base for existing and new capacity (fraction)[referred to as capital structure for long term debt]
$APRB_{a,t}$ = adjusted pipeline rate base (dollars)
a = arc
t = forecast year

In the forecast year update phase, the capital structures ($GPFESTR_a$, $GCMESTR_a$, and $GLTDSTR_a$) at the arc level in the above equations are held constant over the forecast period. They are defined below as the average adjusted rate base weighted capital structures over all pipelines associated with an arc and over the historical time period (1997-2006).

$$GPFESTR_a = \frac{\sum_{t=1997}^{2006} \sum_p (GPFESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_p APRB_{a,p,t}} \tag{203}$$

$$GCMESTR_a = \frac{\sum_{t=1997}^{2006} \sum_p (GCMESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_p APRB_{a,p,t}} \tag{204}$$

$$GLTDSTR_a = \frac{\sum_{t=1997}^{2006} \sum_p (GLTDSTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_p APRB_{a,p,t}} \tag{205}$$

where,

$GPFESTR_a$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period

$GCMESTR_a$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period

$GLTDSTR_a$ = historical average capital structure for long term debt for existing and new capacity (fraction), held constant over the forecast period

$GPFESTR_{a,p,t}$ = capital structure for preferred stock (fraction) by pipeline company in the historical years (1997-2006) (Appendix E, D_PFES)

$GCMESTR_{a,p,t}$ = capital structure for common stock (fraction) by pipeline company in the historical years (1997-2006) (Appendix E, D_CMES)

$GLTDSTR_{a,p,t}$ = capital structure for long term debt (fraction) by pipeline company in the historical years (1997-2006) (Appendix E,D_LTDS)

$APRB_{a,p,t}$ = adjusted rate base (capitalization) by pipeline company in the historical years (1997-2006) (Appendix E, D_APRB)

p = pipeline company

a = arc

t = historical year

The weighted average cost of capital in the forecast year in equation 197 is forecast as follows:

$$WAROR_{a,t} = (PFER_{a,t} * GPFESTR_{a}) + (CMER_{a,t} * GCMESTR_{a}) + (LTDR_{a,t} * GLTDSTR_{a}) \quad (206)$$

where,

$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$ = coupon rate for preferred stock (fraction), function of AA utility bond rate [equation 192]
$CMER_{a,t}$ = common equity rate of return (fraction), function of AA utility bond rate [equation 193]
$LTDR_{a,t}$ = long-term debt rate (fraction), function of AA utility bond rate [equation 194]
$GPFESTR_{a}$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$GCMESTR_{a}$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$GLTDSTR_{a}$ = historical average capital structure for long term debt for existing and new capacity (fraction), held constant over the forecast period
a = arc
t = forecast year

The weighted-average after-tax rate of return on capital ($WAROR_{a,t}$) is applied to the adjusted rate base ($APRB_{a,t}$) to project the total return on rate base (after taxes), also known as the after-tax operating income, which is a major component of the revenue requirement.

Projection of Revenue Requirement Components

The approach to the projection of revenue requirement components is summarized in **Table 6-5**. Given the rate base, rates of return, and capitalization structure projections discussed above, the revenue requirement components are relatively straightforward to project. The capital-related components include total return on rate base (after taxes); Federal and State income taxes; deferred income taxes; other taxes; and depreciation, depletion, and amortization costs. Other components include total operating and maintenance expenses, and regulatory amortization, which is small and thus assumed to be negligible in the forecast period. The total operating and maintenance expense variable includes expenses for transmission of gas for others; administrative and general expenses; and sales, customer accounts and other expenses. The total cost of service (revenue requirement) at the arc level for a forecast year is determined as follows:

$$TCOS_{a,t} = TRRB_{a,t} + DDA_{a,t} + TOTAX_{a,t} + TOM_{a,t} \quad (207)$$

where,

Table 6-5. Approach to Projection of Revenue Requirements

Projection Component	Approach
1. Capital-Related Costs	
a. Total return on rate base	Direct calculation from projected rate base and rates of return
b. Federal/State income taxes	Accounting algorithms based on tax rates
c. Deferred income taxes	Difference in the accumulated deferred income taxes between years t and t-1
2. Depreciation, Depletion, and Amortization	Estimated equation and accounting algorithm
3. Total Operating and Maintenance Expenses	Estimated equation
4. Other Taxes	Previous year's other taxes adjusted to inflation rate and growth in capacity

$TCOS_{a,t}$ = total cost-of-service or revenue requirement for existing and new capacity (dollars)
$TRRB_{a,t}$ = total return on rate base for existing and new capacity after taxes (dollars)
$DDA_{a,t}$ = depreciation, depletion, and amortization for existing and new capacity (dollars)
$TOTAX_{a,t}$ = total Federal and State income tax liability for existing and new capacity (dollars)
$TOM_{a,t}$ = total operating and maintenance expenses for existing and new capacity (dollars)
a = arc
t = forecast year

The total return on rate base for existing and new capacity is computed from the projected weighted cost of capital and estimated rate base, as follows:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \tag{208}$$

where,

$TRRB_{a,t}$ = total return on rate base (after taxes) for existing and new capacity in dollars
$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital for existing and new capacity (fraction)
$APRB_{a,t}$ = adjusted pipeline rate base for existing and new capacity in dollars
a = arc
t = forecast year

The return on rate base for existing and new capacity on an arc can be broken out into the three components:

$$PFEN_{a,t} = GPFESTR_a * PFER_{a,t} * APRB_{a,t} \tag{209}$$

$$CMEN_{a,t} = GCMESTR_a * CMER_{a,t} * APRB_{a,t} \tag{210}$$

$$LTDN_{a,t} = GLTDSTR_a * LTDR_{a,t} * APRB_{a,t} \tag{211}$$

where,

$PFEN_{a,t}$	=	total return on preferred stock for existing and new capacity (dollars)
$GPFESTR_a$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$PFER_{a,t}$	=	coupon rate for preferred stock for existing and new capacity (fraction)
$APRB_{a,t}$	=	adjusted rate base for existing and new capacity (dollars)
$CMEN_{a,t}$	=	total return on common stock equity for existing and new capacity (dollars)
$GCMESTR_a$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$CMER_{a,t}$	=	common equity rate of return for existing and new capacity (fraction)
$LTDN_{a,t}$	=	total return on long-term debt for existing and new capacity (dollars)
$GLTDSTR_a$	=	historical average capital structure ratio for long term debt for existing and new capacity (fraction), held constant over the forecast period
$LTDR_{a,t}$	=	long-term debt rate for existing and new capacity (fraction)
a	=	arc
t	=	forecast year

Next, annual depreciation, depletion, and amortization $DDA_{a,t}$ for a network arc in year t is calculated as the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with the arc. $DDA_{a,t}$ is defined earlier in equation 187.

Next, total taxes consist of Federal income taxes, State income taxes, deferred income taxes, and other taxes. Federal income taxes and State income taxes are calculated using average tax rates. The equation for total taxes is as follows:

$$TOTAX_{a,t} = FSIT_{a,t} + DIT_{a,t} + OTTAX_{a,t} \tag{212}$$

$$FSIT_{a,t} = FIT_{a,t} + SIT_{a,t} \tag{213}$$

where,

$TOTAX_{a,t}$	=	total Federal and State income tax liability for existing and new capacity (dollars)
$FSIT_{a,t}$	=	Federal and State income tax for existing and new capacity (dollars)
$FIT_{a,t}$	=	Federal income tax for existing and new capacity (dollars)

$SIT_{a,t}$ = State income tax for existing and new capacity (dollars)
$DIT_{a,t}$ = deferred income taxes for existing and new capacity (dollars)
$OTTAX_{a,t}$ = all other Federal, State, or local taxes for existing and new capacity (dollars)
a = arc
t = forecast year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the Federal tax rate. The after-tax profit is determined as follows:

$$ATP_{a,t} = APRB_{a,t} * (PFER_{a,t} * GPFESTR_a + CMER_{a,t} * GCMESTR_a) \tag{214}$$

where,

$ATP_{a,t}$ = after-tax profit for existing and new capacity (dollars)
$APRB_{a,t}$ = adjusted pipeline rate base for existing and new capacity (dollars)
$PFER_{a,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)
$GPFESTR_a$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$CMER_{a,t}$ = common equity rate of return for existing and new capacity (fraction)
$GCMESTR_a$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
a = arc
t = forecast year

and the Federal income taxes are:

$$FIT_{a,t} = (FRATE * ATP_{a,t} / 1. - FRATE) \tag{215}$$

where,

$FIT_{a,t}$ = Federal income tax for existing and new capacity (dollars)
FRATE = Federal income tax rate (fraction, Appendix E)
$ATP_{a,t}$ = after-tax profit for existing and new capacity (dollars)
a = arc
t = forecast year

State income taxes are computed by multiplying the sum of taxable profit and the associated Federal income tax by a weighted-average State tax rate associated with each pipeline company. The weighted-average State tax rate is based on peak service volumes in each State served by the pipeline company. State income taxes are computed as follows:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{216}$$

where,

$SIT_{a,t}$ = State income tax for existing and new capacity (dollars)
SRATE = average State income tax rate (fraction, Appendix E)
$FIT_{a,t}$ = Federal income tax for existing and new capacity (dollars)
$ATP_{a,t}$ = after-tax profits for existing and new capacity (dollars)
a = arc
t = forecast year

Deferred income taxes for existing and new capacity at the arc level are the differences in the accumulated deferred income taxes between year t and year t-1.

$$DIT_{a,t} = ADIT_{a,t} - ADIT_{a,t-1} \tag{217}$$

where,

$DIT_{a,t}$ = deferred income taxes for existing and new capacity (dollars)
$ADIT_{a,t}$ = accumulated deferred income taxes for existing and new capacity (dollars)
a = arc
t = forecast year

Other taxes consist of a combination of ad valorem taxes (which grow with company revenue), property taxes (which grow in proportion to gross plant), and all other taxes (assumed constant in real terms). Other taxes in year t are determined as the previous year's other taxes adjusted for inflation and capacity expansion.

$$OTTAX_{a,t} = OTTAX_{a,t-1} * EXPFAC_{a,t} * (MC\_PCWGDP_t / MC\_PCWGDP_{t-1}) \tag{218}$$

where,

$OTTAX_{a,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes for existing and new capacity (dollars)
$EXPFAC_{a,t}$ = capacity expansion factor (see below)
MC_PCWGDPt = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

The capacity expansion factor is expressed as follows:

$$EXPFAC_{a,t} = PTCURPCAP_{a,t} / PTCURPCAP_{a,t-1} \tag{219}$$

where,

$EXPFAC_{a,t}$ = capacity expansion factor (growth in capacity)
$PTCURPCAP_{a,t}$ = current pipeline capacity (Bcf) for existing and new capacity
a = arc
t = forecast year

Last, the total operating and maintenance costs for existing and new capacity by arc ($R\_TOM_{a,t}$) are determined using a log-linear form, given the economies of scale inherent in gas transmission. The estimated equation used for R_TOM (Appendix F, Table F3) is determined as a function of gross plant in service, $GPIS_a$, a level of accumulated depreciation relative to gross plant in service, $DEPSHR_a$, and a time trend, TECHYEAR, that proxies the state of technology, as defined below:

$$R\_TOM_{a,t} = TOM\_K * e^{(\beta_{0,a} * (1-\rho) + G2 + G3 + G4 + G5 + G6 - \rho * (G7 + G8 + G4 + G9))} \tag{220}$$

where,

$R\_TOM_{a,t}$	=	total operating and maintenance cost for existing and new capacity (2005 real dollars)
TOM_K	=	correction factor estimated in stage 2 of the regression equation estimation process (Appendix F, Table F3)
$\beta_{0,a}$	=	TOM_C, constant term estimated by arc (Appendix F, Table F3.6, $\beta_{0,a} = B\_ARC_{xx\_yy}$)
G_2	=	$\beta_1 * \log(GPIS_{a,t-1})$
G_3	=	$\beta_2 * DEPSHR_{a,t-1}$
G_4	=	$\beta_3 * 2006.0$
G_5	=	$\beta_4 * (TECHYEAR-2006.0)$
G_6	=	$\rho * \log(R\_TOM_{a,t-1})$
G_7	=	$\beta_1 * \log(GPIS_{a,t-2})$
G_8	=	$\beta_2 * DEPSHR_{a,t-2}$
G_9	=	$\beta_4 * (TECHYEAR - 1.0- 2006.0)$
log	=	natural logarithm operator
ρ	=	estimated autocorrelation coefficient (Appendix F, Table F3.6 -- TOM_RHO)
β_1	=	TOM_GPIS_1, estimated coefficient on the change in gross plant in service (Appendix F, Table F3.6)
β_2	=	TOM_DEPSHR, estimated coefficient for the accumulated depreciation of the plant relative to the GPIS (Appendix F, Table F3.6)
β_3	=	TOM_BYEAR, estimated coefficient for the time trend variable TECHYEAR (Appendix F, Table F3.6)
β_4	=	TOM_BYEAR_EIA = TOM_BYEAR, estimated future rate of decline in R_TOM due to technology improvements and efficiency gains. EIA assumes that this coefficient is the same as the coefficient for the time trend variable TECHYEAR (Appendix F, Table F3.6)
$DEPSHR_{a,t}$	=	level of the accumulated depreciation of the plant relative to the gross plant in service for existing and new capacity at the beginning of year t. This variable is a proxy for the age of the capital stock.
$GPIS_{a,t}$	=	capital cost of plant in service for existing and new capacity in dollars (not deflated)
TECHYEAR	=	MODYEAR (time trend in 4 digit Julian units, the minimum value of this variable in the sample being 1997, otherwise TECHYEAR=0 if less than 1997)
a	=	arc
t	=	forecast year

For consistency the total operating and maintenance costs are converted to nominal dollars:

$$TOM_{a,t} = R\_TOM_{a,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{2000}} \tag{221}$$

where,

$TOM_{a,t}$ = total operating and maintenance costs for existing and new capacity (nominal dollars)
$R\_TOM_{a,t}$ = total operating and maintenance costs for existing and new capacity (2005 real dollars)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

Once all four components ($TRRB_{a,t}$, $DDA_{a,t}$, $TOTAX_{a,t}$, $TOM_{a,t}$) of the cost-of-service $TCOST_{a,t}$ of equation 207 are computed by arc in year t, each of them will be disaggregated into fixed and variable costs which in turn will be disaggregated further into reservation and usage costs using the allocation factors for a straight fixed variable (SFV) rate design summarized in **Table 6-6**.[89] Note that the return on rate base ($TRRB_{a,t}$) has three components ($PFEN_{a,t}$, $CMEN_{a,t}$, and $LTDN_{a,t}$ [equations 209, 210, and 211]).

Disaggregation of Cost-of-Service Components into Fixed and Variable Costs

Let $Item_{i,a,t}$ be a cost-of-service component (i=cost component index, a=arc, and t=forecast year). Using the first group of rate design allocation factors ξi (**Table 6-6**), all the components of cost-of-service computed in the above section can be split into fixed and variable costs, and then summed over the cost categories to determine fixed and variable costs-of-service as follows:

$$FC_{a,t} = \sum_i (\xi_i * Item_{i,a,t}) \tag{222}$$

$$VC_{a,t} = \sum_i [(1.0 - \xi_i) * Item_{i,a,t}] \tag{223}$$

$$TCOS_{a,t} = FC_{a,t} + VC_{a,t} \tag{224}$$

where,

$TCOS_{a,t}$ = total cost-of-service for existing and new capacity (dollars)
$FC_{a,t}$ = fixed cost for existing and new capacity (dollars)
$VC_{a,t}$ = variable cost for existing and new capacity (dollars)
$Item_{i,a,t}$ = cost-of-service component index at the arc level
ξ_i = first group of allocation factors (ratios) to disaggregate the cost-of-service components into fixed and variable costs

[89] The allocation factors of SFV rate design are given in percent in this table for illustration purposes. They are converted into ratios immediately after they are read in from the input file by dividing by 100.

Table 6-6. Percentage Allocation Factors for a Straight Fixed Variable (SFV) Rate Design

Cost-of-service Items (percentage) [$Item_{i,a,t}$, i=cost component index, a=arc, t=year]	**Break up cost-of-service items into fixed and variable costs**		**Break up fixed cost items into reservation and usage costs**		**Break up variable cost items into reservation and usage costs**	
$Item_{i,a,t}$	**$FC_{i,a,t}$**	**$VC_{i,a,t}$**	**$RFC_{i,a,t}$**	**$UFC_{i,a,t}$**	**$RVC_{i,a,t}$**	**$UVC_{i,a,t}$**
Cost Allocation Factors	**ξ_i**	**$100 - \xi_i$**	**λ_i**	**$100 - \lambda_i$**	**μ_i**	**$100-\mu_i$**
After-tax Operating Income						
Return on Preferred Stocks	100	0	100	0	0	100
Return on Common Stocks	100	0	100	0	0	100
Return on Long-Term Debt	100	0	100	0	0	100
Normal Operating Expenses						
Depreciation	100	0	100	0	0	100
Income Taxes	100	0	100	0	0	100
Deferred Income Taxes	100	0	100	0	0	100
Other Taxes	100	0	100	0	0	100
Total O&M	60	40	100	0	0	100

ξ_i = first group of allocation factors (ratios) to disaggregate the cost-of-service components into fixed and variable costs
i = subscript to designate a cost-of-service component (i=1 for PFEN, i=2 for CMEN, i=3 for LTDN, i=4 for DDA, i=5 for FSIT, i=6 for DIT, i=7 for OTTAX, and i=8 for TOM)
a = arc
t = forecast year

Disaggregation of Fixed and Variable Costs into Reservation and Usage Costs

Each type of cost-of-service component (fixed or variable) in the above equations can be further disaggregated into reservation and usage costs using the second and third groups of rate design allocation factors λi and μi (**Table 6-6**), as follows:

$$RFC_{a,t} = \sum_{i} (\lambda_i * \xi_i * Item_{i,a,t}) \tag{225}$$

$$UFC_{a,t} = \sum_{i} [(1.0 - \lambda_i) * \xi_i * Item_{i,a,t}] \tag{226}$$

$$RVC_{a,t} = \sum_{i} [\mu_i * (1.0 - \xi_i) * Item_{i,a,t}] \tag{227}$$

$$UVC_{a,t} = \sum_i [(1.0 - \mu_i) * (1.0 - \xi_i) * Item_{i,a,t}] \quad (228)$$

$$TCOS_{a,t} = RFC_{a,t} + UFC_{a,t} + RVC_{a,t} + UVC_{a,t} \quad (229)$$

where,

TCOSa,t	=	total cost-of-service for existing and new capacity (dollars)
RFCa,t	=	fixed reservation cost for existing and new capacity (dollars)
UFCa,t	=	fixed usage cost for existing and new capacity (dollars)
RVCa,t	=	variable reservation cost for existing and new capacity (dollars)
UVCa,t	=	variable usage cost for existing and new capacity (dollars)
Itemi,a,t	=	cost-of-service component index at the arc level
ξi	=	first group of allocation factors to disaggregate cost-of-service components into fixed and variable costs
λi	=	second group of allocation factors to disaggregate fixed costs into reservation and usage costs
μi	=	third group of allocation factors to disaggregate variable costs into reservation and usage costs
i	=	subscript to designate a cost-of-service component (i=1 for PFEN, i=2 for CMEN, i=3 for LTDN, i=4 for DDA, i=5 for FSIT, i=6 for DIT, i=7 for OTTAX, and i=8 for TOM)
a	=	arc
t	=	forecast year

The summation of fixed and variable reservation costs (RFC and RVC) yields the total reservation cost (RCOST). This can be disaggregated further into peak and off-peak reservation costs, which are used to develop variable tariffs for peak and off-peak time periods. The summation of fixed and variable usage costs (UFC and UVC), which yields the total usage cost (UCOST), is used to compute the annual average fixed usage fees. Both types of rates are developed in the next section. The equations for the reservation and usage costs can be expressed as follows:

$$RCOST_{a,t} = (RFC_{a,t} + RVC_{a,t}) \quad (230)$$

$$UCOST_{a,t} = (UFC_{a,t} + UVC_{a,t}) \quad (231)$$

where,

$RCOST_{a,t}$	=	reservation cost for existing and new capacity (dollars)
$UCOST_{a,t}$	=	annual usage cost for existing and new capacity (dollars)
$RFC_{a,t}$	=	fixed reservation cost for existing and new capacity (dollars)
$UFC_{a,t}$	=	fixed usage cost for existing and new capacity (dollars)
$RVC_{a,t}$	=	variable reservation cost for existing and new capacity (dollars)
$UVC_{a,t}$	=	variable usage cost for existing and new capacity (dollars)
a	=	arc
t	=	forecast period

As **Table 6-6** indicates, all the fixed costs are included in the reservation costs and all the variable costs are included in the usage costs.

Computation of Rates for Forecast Years

The reservation and usage costs-of-service RCOST and UCOST determined above are used separately to develop two types of rates at the arc level: variable tariffs and annual fixed usage fees. The determination of both rates is described below.

Variable Tariff Curves

Variable tariffs are proportional to reservation charges and are broken up into peak and off-peak time periods. Variable tariffs are derived directly from variable tariff curves which are developed based on reservation costs, utilization rates, annual flows, and other curve parameters.

In the PTS code, these variable curves are defined by a FUNCTION (NGPIPE_VARTAR) which is called by the ITS to compute the variable tariffs for peak and off-peak by arc and by forecast year. In this pipeline function, the tariff curves are segmented such that tariffs associated with *current capacity* and *capacity expansion* are represented by separate but similar equations. A uniform functional form is used to define these tariff curves for both the *current capacity* and *capacity expansion segments* of the tariff curves. It is defined as a function of a base point [price and quantity (PNOD, QNOD)] using different *process-specific* parameters, peak or off-peak flow, and a price elasticity. This functional form is presented below:

current capacity segment:

$$\text{NGPIPE\_VARTAR}_{a,t} = \text{PNOD}_{a,t} * (\text{Q}_{a,t} / \text{QNOD}_{a,t})^{\text{ALPHA\_PIPE}} \tag{232}$$

capacity expansion segment:

$$\text{NGPIPE\_VARTAR}_{a,t} = \text{PNOD}_{a,t} * (\text{Q}_{a,t} / \text{QNOD}_{a,t})^{\text{ALPHA2\_PIPE}} \tag{233}$$

such that,

for peak transmission tariffs:

$$\text{PNOD}_{a,t} = \frac{\text{RCOST}_{a,t} * \text{PKSHR\_YR}}{(\text{QNOD}_{a,t} * \text{MC\_PCWGDP}_t)} \tag{234}$$

$$\text{QNOD}_{a,t} = \text{PTNETFLOW}_{a,t} \tag{235}$$

for off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{236}$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \tag{237}$$

where,

$NGPIPE\_VARTAR_{a,t}$	=	function to define pipeline tariffs (87$/Mcf)
$PNOD_{a,t}$	=	base point, price (87$/Mcf)
$QNOD_{a,t}$	=	base point, quantity (Bcf)
$Q_{a,t}$	=	flow along pipeline arc (Bcf)
ALPHA_PIPE	=	price elasticity for pipeline tariff curve for current capacity (Appendix E)
ALPHA2_PIPE	=	price elasticity for pipeline tariff curve for capacity expansion segment (Appendix E)
$RCOST_{a,t}$	=	reservation cost-of-service (million dollars)
$PTNETFLOW_{a,t}$	=	natural gas network flow (throughput, Bcf)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	forecast year

Annual Fixed Usage Fees

The annual fixed usage fees (volumetric charges) are derived directly from the usage costs, peak and off-peak utilization rates, and annual arc capacity. These fees are computed as the average fees over each forecast year, as follows:

$$FIXTAR_{a,t} = UCOST_{a,t} / [(PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_t] \tag{238}$$

where,

$FIXTAR_{a,t}$	=	annual fixed usage fees for existing and new capacity (87$/Mcf)
$UCOST_{a,t}$	=	annual usage cost for existing and new capacity (million dollars)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$	=	peak pipeline utilization (fraction)
$PTCURPCAP_{a,t}$	=	current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$	=	off-peak pipeline utilization (fraction)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	forecast year

As can be seen from the allocation factors in **Table 6-6**, usage costs (UCOST) are less than 10 percent of reservation costs (RCOST). Therefore, annual fixed usage fees which are proportional to usage costs are expected to be less than 10 percent of the variable tariffs. In general, these fixed fees are within the range of 5 percent of the variable tariffs which are charged to firm customers.

Canadian Fixed and Variable Tariffs

Fixed and variables tariffs along Canadian import arcs are defined using input data. Fixed tariffs are obtained directly from the data (Appendix E, $ARC\_FIXTAR_{n,a,t}$), while variables tariffs are calculated in the FUNCTION subroutine (NGPIPE_VARTAR) and are based on pipeline utilization and a maximum expected tariff, CNMAXTAR. If the pipeline utilization along a Canadian arc for any time period (peak or off-peak) is less than 50 percent, then the pipeline tariff is set to a low level (70 percent of CNMAXTAR). If the Canadian pipeline utilization is between 50 and 90 percent, then the pipeline tariff is set to a level between 70 and 80 percent of CNMAXTAR. The sliding scale is determined using the corresponding utilization factor, as follows:

$$\begin{aligned} NGPIPE\_VARTAR_{a,t} = {} & CNMAXTAR - [CNMAXTAR * (1.0 - 0.9) * 2.0] - \\ & [CNMAXTAR * (0.9 - CANUTIL_{a,t}) * 0.25] \end{aligned} \tag{239}$$

If the Canadian pipeline utilization is greater than 90 percent, then the pipeline tariff is set to between 80 and 100 percent of CNMAXTAR. This is accomplished again using Canadian pipeline utilization, as follows:

$$\begin{aligned} NGPIPE\_VARTAR_{a,t} = {} & CNMAXTAR - \\ & [CNMAXTAR * (1.0 - CANUTIL_{a,t}) * 2.0] \end{aligned} \tag{240}$$

where,

$$CANUTIL_{a,t} = \frac{Q_{a,t}}{QNOD_{a,t}} \tag{241}$$

for peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * PKSHR\_YR * PTPKUTZ_{a,t} \tag{242}$$

for off-peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} \tag{243}$$

and,

$NGPIPE\_VARTAR_{a,t}$	=	function to define pipeline tariffs (87$/Mcf)
CNMAXTAR	=	maximum effective tariff (87$/Mcf, ARC_VARTAR, Appendix E)

$CANUTIL_{a,t}$ = pipeline utilization (fraction)
$QNOD_{a,t}$ = base point, quantity (Bcf)
$Q_{a,t}$ = flow along pipeline arc (Bcf)
PKSHR_YR = portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$ = peak pipeline utilization (fraction)
$PTCURPCAP_{a,t}$ = current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$ = off-peak pipeline utilization (fraction)
a = arc
t = forecast year

For the eastern and western Canadian storage regions, the "variable" tariff is set to zero and only the assumed "fixed" tariff (Appendix E, ARC_FIXTAR) is applied.

Storage Tariff Routine Methodology

Background

This section describes the methodology used to assign a storage tariff for each of the 12 NGTDM regions. All variables and equations presented below are used for the forecast time period (1999-2030). If the time period t is less than 1999, the associated variables are set to the initial values read in from the input file (Foster's storage financial database[90] by region and year, 1990-1998).

This section starts with the presentation of the natural gas storage cost-of-service equation by region. The equation sums four components to be forecast: after-tax[91] total return on rate base (operating income); total taxes; depreciation, depletion, and amortization; and total operating and maintenance expenses. Once these four components are computed, the regional storage cost of service is projected and, with the associated effective storage capacity provided by the ITS, a storage tariff curve can be established (as described at the end of this section).

Cost-of-Service by Storage Region

The cost-of-service (or revenue requirement) for existing and new storage capacity in an NGTDM region can be written as follows:

$$STCOS_{r,t} = STBTOI_{r,t} + STDDA_{r,t} + STTOTAX_{r,t} + STTOM_{r,t} \qquad (244)$$

where,

$STCOS_{r,t}$ = total cost-of-service or revenue requirement for existing and new capacity (dollars)

[90] Natural Gas Storage Financial Data, compiled by Foster Associates, Inc., Bethesda, Maryland for EIA under purchase order #01-99EI36663 in December of 1999. This data set includes financial information on 33 major storage companies. The primary source of the data is FERC Form 2 (or Form 2A for the smaller pipelines). These data can be purchased from Foster Associates.

[91] 'After-tax' in this section refers to 'after taxes have been taken out.'

$STBTOI_{r,t}$ = total return on rate base for existing and new capacity (after-tax operating income) (dollars)
$STDDA_{r,t}$ = depreciation, depletion, and amortization for existing and new capacity (dollars)
$STTOTAX_{r,t}$ = total Federal and State income tax liability for existing and new capacity (dollars)
$STTOM_{r,t}$ = total operating and maintenance expenses for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

The storage cost-of-service by region is first computed in nominal dollars and subsequently converted to 1987$ for use in the computation of a base for regional storage tariff, PNOD (87$/Mcf). PNOD is used in the development of a regional storage tariff curve. An approach is developed to project the storage cost-of-service in nominal dollars by NGTDM region in year t and is provided in **Table 6-7**.

Table 6-7. Approach to Projection of Storage Cost-of-Service

Projection Component	**Approach**
1. Capital-Related Costs	
a. Total return in rate base	Direct calculation from projected rate base and rates of return
b. Federal/State income taxes	Accounting algorithms based on tax rates
c. Deferred income taxes	Difference in the accumulated deferred income taxes between years t and t-1
2. Depreciation, Depletion, and Amortization	Estimated equation and accounting algorithm
3. Total Operating and Maintenance Expenses	Estimated equation

Computation of total return on rate base (after-tax operating income), STBTOIr,t

The total return on rate base for existing and new capacity is computed from the projected weighted cost of capital and estimated rate base, as follows:

$$STBTOI_{r,t} = STWAROR_{r,t} * STAPRB_{r,t} \tag{245}$$

where,

$STBTOI_{r,t}$ = total return on rate base (after-tax operating income) for existing and new capacity in dollars
$STWAROR_{r,t}$ = weighted-average after-tax rate of return on capital for existing and new capacity (fraction)
$STAPRB_{r,t}$ = adjusted storage rate base for existing and new capacity in dollars
r = NGTDM region
t = forecast year

The return on rate base for existing and new storage capacity in an NGTDM region can be broken out into three components as shown below.

$$STPFEN_{r,t} = STGPFESTR_r * STPFER_{r,t} * STAPRB_{r,t} \quad (246)$$

$$STCMEN_{r,t} = STGCMESTR_r * STCMER_{r,t} * STAPRB_{r,t} \quad (247)$$

$$STLTDN_{r,t} = STGLTDSTR_r * STLTDR_{r,t} * STAPRB_{r,t} \quad (248)$$

where,

$STPFEN_{r,t}$ = total return on preferred stock for existing and new capacity (dollars)

$STPFER_{r,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)

$STGPFESTR_r$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period

$STAPRB_{r,t}$ = adjusted rate base for existing and new capacity (dollars)

$STCMEN_{r,t}$ = total return on common stock equity for existing and new capacity (dollars)

$STGCMESTR_r$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period

$STCMER_{r,t}$ = common equity rate of return for existing and new capacity (fraction)

$STLTDN_{r,t}$ = total return on long-term debt for existing and new capacity (dollars)

$STGLTDSTR_r$ = historical average capital structure ratio for long term debt for existing and new capacity (fraction), held constant over the forecast period

$STLTDR_{r,t}$ = long-term debt rate for existing and new capacity (fraction)

r = NGTDM region

t = forecast year

Note that the total return on rate base is the sum of the above equations and can be expressed as:

$$STBTOI_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t} + STLTDN_{r,t}) \quad (249)$$

It can be seen from the above equations that the weighted average rate of return on capital for existing and new storage capacity, $STWAROR_{r,t}$, can be determined as follows:

$$STWAROR_{r,t} = STPFER_{r,t} * STGPFESTR_r + STCMER_{r,t} * STGCMESTR_r + STLTDR_{r,t} * STGLTDSTR_r \quad (250)$$

The historical average capital structure ratios $STGPFESTR_r$, $STGCMESTR_r$, and $STGLTDSTR_r$ in the above equation are computed as follows:

$$STGPFESTR_r = \frac{\sum_{t=1990}^{1998} STPFES_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \quad (251)$$

$$STGCMESTR_r = \frac{\sum_{t=1990}^{1998} STCMES_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \quad (252)$$

$$STGLTDSTR_r = \frac{\sum_{t=1990}^{1998} STLTDS_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \quad (253)$$

where,

$STGPFESTR_r$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STGCMESTR_r$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$STGLTDSTR_r$	=	historical average capital structure ratio for long term debt for existing and new capacity (fraction), held constant over the forecast period
$STPFES_{r,t}$	=	value of preferred stock for existing capacity (dollars) [read in as D_PFES]
$STCMES_{r,t}$	=	value of common stock equity for existing capacity (dollars) [read in as D_CMES]
$STLTDS_{r,t}$	=	value of long-term debt for existing capacity (dollars) [read in as D_LTDS]
$STAPRB_{r,t}$	=	adjusted rate base for existing capacity (dollars) [read in as D_APRB]
r	=	NGTDM region
t	=	forecast year

In the STWAROR equation, the rate of return variables for preferred stock, common equity, and debt ($STPFER_{r,t}$, $STCMER_{r,t}$, and $STLTDR_{r,t}$) are related to forecast macroeconomic variables. These rates of return can be determined as a function of nominal AA utility bond index rate (provided by the Macroeconomic Module) and a regional historical average constant deviation as follows:

$$STPFER_{r,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_STPFER_r \quad (254)$$

$$STCMER_{r,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_STCMER_r \quad (255)$$

$$STLTDR_{r,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_STLTDR_r \quad (256)$$

where,

$STPFER_{r,t}$	=	rate of return for preferred stock
$STCMER_{r,t}$	=	common equity rate of return
$STLTDR_{r,t}$	=	long-term debt rate
$MC\_RMPUAANS_t$	=	AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPUAA, percentage)
ADJ_STPFER_r	=	historical weighted average deviation constant (fraction) for preferred stock rate of return (1990-1998)
ADJ_STCMER_r	=	historical weighted average deviation constant (fraction) for common equity rate of return (1990-1998)
ADJ_STLTDR_r	=	historical weighted average deviation constant (fraction) for long term debt rate (1990-1998)
r	=	NGTDM region
t	=	forecast year

The historical weighted average deviation constants by NGTDM region are computed as follows:

$$ADJ\_STLTDR_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STLTDN_{r,t}}{STLTDS_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \quad (257)$$

$$ADJ\_STPFER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STPFEN_{r,t}}{STPFES_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \quad (258)$$

$$ADJ\_STCMER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STCMEN_{r,t}}{STCMES_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \quad (259)$$

where,

ADJ_STLTDR_r	=	historical weighted average deviation constant (fraction) for long term debt rate
ADJ_STCMER_r	=	historical weighted average deviation constant (fraction) for common equity rate of return
ADJ_STPFER_r	=	historical weighted average deviation constant (fraction) for preferred stock rate of return

$STPFEN_{r,t}$ = total return on preferred stock for existing capacity (dollars) [read in as D_PFEN]
$STCMEN_{r,t}$ = total return on common stock equity for existing capacity (dollars) [read in as D_CMEN]
$STLTDN_{r,t}$ = total return on long-term debt for existing capacity (dollars) [read in as D_LTDN]
$STPFES_{r,t}$ = value of preferred stock for existing capacity (dollars) [read in as D_PFES]
$STCMES_{r}$ = value of common stock equity for existing capacity (dollars) [read in as D_CMES]
$STLTDS_{r}$ = value of long-term debt for existing capacity (dollars) [read in as D_LTDS]
$MC\_RMPUAANS_{t}$ = AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPPUAA, percentage)
$STGPIS_{r,t}$ = original capital cost of plant in service (dollars) [read in as D_GPIS]
r = NGTDM region
t = forecast year

Computation of adjusted rate base, $STAPRB_{r,t}$[92]

The adjusted rate base for existing and new storage facilities in an NGTDM region has three components and can be written as follows:

$$STAPRB_{r,t} = STNPIS_{r,t} + STCWC_{r,t} - STADIT_{r,t} \qquad (260)$$

where,

$STAPRB_{r,t}$ = adjusted storage rate base for existing and new capacity (dollars)
$STNPIS_{r,t}$ = net plant in service for existing and new capacity (dollars)
$STCWC_{r,t}$ = total cash working capital for existing and new capacity (dollars)
$STADIT_{r,t}$ = accumulated deferred income taxes for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

The net plant in service is the level of gross plant in service minus the accumulated depreciation, depletion, and amortization. It is given by the following equation:

$$STNPIS_{r,t} = STGPIS_{r,t} - STADDA_{r,t-1} \qquad (261)$$

[92]In this section, any variable ending with "_E" will signify that the variable is for the existing storage capacity as of the end of 1998, and any variable ending with "_N" will mean that the variable is for the new storage capacity added from 1999 to 2025.

where,

$STNPIS_{r,t}$ = net plant in service for existing and new capacity (dollars)
$STGPIS_{r,t}$ = gross plant in service for existing and new capacity (dollars)
$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

The gross and net plant-in-service variables can be written as the sum of their respective existing and new gross and net plants in service as follows:

$$STGPIS_{r,t} = STGPIS\_E_{r,t} + STGPIS\_N_{r,t} \tag{262}$$

$$STNPIS_{r,t} = STNPIS\_E_{r,t} + STNPIS\_N_{r,t} \tag{263}$$

where,

$STGPIS_{r,t}$ = gross plant in service for existing and new capacity (dollars)
$STNPIS_{r,t}$ = net plant in service for existing and new capacity (dollars)
$STGPIS\_E_{r,t}$ = gross plant in service for existing capacity (dollars)
$STGPIS\_N_{r,t}$ = gross plant in service for new capacity (dollars)
$STNPIS\_E_{r,t}$ = net plant in service for existing capacity (dollars)
$STNPIS\_N_{r,t}$ = net plant in service for new capacity (dollars)
r = NGTDM region
t = forecast year

For the same reason as above, the accumulated depreciation, depletion, and amortization for t-1 can be split into its existing and new accumulated depreciation:

$$STADDA_{r,t-1} = STADDA\_E_{r,t-1} + STADDA\_N_{r,t-1} \tag{264}$$

where,

$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity (dollars)
$STADDA\_E_{r,t}$ = accumulated depreciation, depletion, and amortization for existing capacity (dollars)
$STADDA\_N_{r,t}$ = accumulated depreciation, depletion, and amortization for new capacity (dollars)
r = NGTDM region
t = forecast year

The accumulated depreciation for the current year t is expressed as last year's accumulated depreciation plus this year's depreciation. For the separate existing and new storage capacity, their accumulated depreciation, depletion, and amortization can be expressed separately as follows:

$$STADDA\_E_{r,t} = STADDA\_E_{r,t-1} + STDDA\_E_{r,t} \tag{265}$$

$$STADDA\_N_{r,t} = STADDA\_N_{r,t-1} + STDDA\_N_{r,t} \tag{266}$$

where,

$STADDA\_E_{r,t}$ = accumulated depreciation, depletion, and amortization for existing capacity (dollars)
$STADDA\_N_{r,t}$ = accumulated depreciation, depletion, and amortization for new capacity (dollars)
$STDDA\_E_{r,t}$ = depreciation, depletion, and amortization for existing capacity (dollars)
$STDDA\_N_{r,t}$ = depreciation, depletion, and amortization for new capacity (dollars)
r = NGTDM region
t = forecast year

Total accumulated depreciation, depletion, and amortization for the combined existing and new capacity by storage region in year t is determined as the sum of previous year's accumulated depreciation, depletion, and amortization and current year's depreciation, depletion, and amortization for that total capacity.

$$STADDA_{r,t} = STADDA_{r,t-1} + STDDA_{r,t} \tag{267}$$

where,

$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity in dollars
$STDDA_{r,t}$ = annual depreciation, depletion, and amortization for existing and new capacity in dollars
r = NGTDM region
t = forecast year

Computation of annual depreciation, depletion, and amortization, $STDDA_{r,t}$

Annual depreciation, depletion, and amortization for a storage region in year t is the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with that region.

$$STDDA_{r,t} = STDDA\_E_{r,t} + STDDA\_N_{r,t} \tag{268}$$

where,

$STDDA_{r,t}$ = annual depreciation, depletion, and amortization for existing and new capacity in dollars
$STDDA\_E_{r,t}$ = depreciation, depletion, and amortization costs for existing capacity in dollars
$STDDA\_N_{r,t}$ = depreciation, depletion, and amortization costs for new capacity in dollars
r = NGTDM region
t = forecast year

A regression equation is used to determine the annual depreciation, depletion, and amortization for existing capacity associated with an NGTDM region, while an accounting algorithm is used for new storage capacity. For existing capacity, this depreciation expense by NGTDM region is forecast as follows:

$$\begin{aligned} STDDA\_E_{r,t} = {} & STDDA\_CREG_r + STDDA\_NPIS * STNPIS\_E_{r,t-1} \\ & + STDDA\_NEWCAP * STNEWCAP_{r,t} \end{aligned} \tag{269}$$

where,

$STDDA\_E_{r,t}$	=	annual depreciation, depletion, and amortization costs for existing capacity in dollars
$STDDA\_CREG_r$	=	constant term estimated by region (Appendix F, Table F3)
STDDA_NPIS	=	estimated coefficient for net plant in service for existing capacity (Appendix F, Table F3)
STDDA_NEWCAP	=	estimated coefficient for the change in gross plant in service for existing capacity (Appendix F, Table F3)
$STNPIS\_E_{r,t}$	=	net plant in service for existing capacity (dollars)
$STNEWCAP_{r,t}$	=	change in gross plant in service for existing capacity (dollars)
r	=	NGTDM region
t	=	forecast year

The accounting algorithm used to define the annual depreciation, depletion, and amortization for new capacity assumes straight-line depreciation over a 30-year life, as follows:

$$STDDA\_N_{r,t} = STGPIS\_N_{r,t} / 30 \tag{270}$$

where,

$STDDA\_N_{r,t}$	=	annual depreciation, depletion, and amortization for new capacity in dollars
$STGPIS\_N_{r,t}$	=	gross plant in service for new capacity in dollars
30	=	30 years of plant life
r	=	NGTDM region
t	=	forecast year

In the above equation, the capital cost of new plant in service ($STGPIS\_N_{r,t}$) in year t is computed as the accumulated new capacity expansion expenditures from 1999 to year t and is determined by the following equation:

$$STGPIS\_N_{r,t} = \sum_{s=1999}^{t} STNCAE_{r,s} \tag{271}$$

where,

$STGPIS\_N_{r,t}$	=	gross plant in service for new capacity expansion in dollars
$STNCAE_{r,s}$	=	new capacity expansion expenditures occurring in year s after 1998 (in dollars)
s	=	the year new expansion occurred
r	=	NGTDM region
t	=	forecast year

The new capacity expansion expenditures allowed in the rate base within a forecast year are derived for each NGTDM region from the amount of incremental capacity additions determined by the ITS:

$$STNCAE_{r,t} = STCCOST_{r,t} * STCAPADD_{r,t} * 1{,}000{,}000. \quad (272)$$

where,

$STNCAE_{r,t}$	=	total capital cost to expand capacity for an NGTDM region (dollars)
$STCCOST_{r,t}$	=	capital cost per unit of natural gas storage expansion (dollars per Mcf)
$STCAPADD_{r,t}$	=	storage capacity additions as determined in the ITS (Bcf/yr)
r	=	NGTDM region
t	=	forecast year

The capital cost per unit of natural gas storage expansion in an NGTDM region ($STCCOST_{r,t}$) is computed as its 1998 unit capital cost times a function of a capacity expansion factor relative to the 1998 storage capacity. This expansion factor represents a relative change in capacity since 1998. Whenever the ITS forecasts storage capacity additions in year t in an NGTDM region, the increased capacity is computed for that region from 1998 and the unit capital cost is computed. Hence, the capital cost to expand capacity in an NGTDM region can be estimated from any amount of capacity additions in year t provided by the ITS and the associated unit capital cost. This capital cost represents the investment cost for generic storage companies associated with that region. The unit capital cost ($STCCOST_{r,t}$) is computed by the following equations:

$$STCCOST_{r,t} = STCCOST\_CREG_r * e^{(BETAREG_r * STEXPFAC98_r)} * (1.0 + STCSTFAC) \quad (273)$$

where,

$STCCOST_{r,t}$	=	capital cost per unit of natural gas storage expansion (dollars per Mcf)
$STCCOST\_CREG_r$	=	1998 capital cost per unit of natural gas storage expansion (1998 dollars per Mcf)
$BETAREG_r$	=	expansion factor parameter (set to STCCOST_BETAREG, Appendix E)
$STEXPFAC98_r$	=	relative change in storage capacity since 1998
STCSTFAC	=	factor to set a particular storage region's expansion cost, based on an average [Appendix E]
r	=	NGTDM region
t	=	forecast year

The relative change in storage capacity is computed as follows:

$$STEXPFAC98_r = \frac{PTCURPSTR_{r,t}}{PTCURPSTR_{r,1998}} - 1.0 \quad (274)$$

where,

$PTCURPSTR_{r,t}$	=	current storage capacity (Bcf)
$PTCURPSTR_{r,1998}$	=	1998 storage capacity (Bcf)
r	=	NGTDM region
t	=	forecast year

Computation of total cash working capital, $STCWC_{r,t}$

The total cash working capital represents the level of working capital at the beginning of year t deflated using the chain weighted GDP price index with 1996 as a base year. This cash working capital variable is expressed as a non-linear function of total gas storage capacity (base gas capacity plus working gas capacity) as follows:

$$R\_STCWC_{r,t} = e^{(STCWC\_CREG_r * (1-\rho))} * DSTTCAP_{r,t-1}^{STCWC\_TOTCAP} * R\_STCWC_{r,t-1}^{\rho} * DSTTCAP_{r,t-2}^{-\rho * STCWC\_TOTCAP} \quad (275)$$

where,

$R\_STCWC_{r,t}$	=	total cash working capital at the beginning of year t for existing and new capacity (1996 real dollars)
$STCWC\_CREG_r$	=	constant term, estimated by region (Appendix F, Table F3)
ρ	=	autocorrelation coefficient from estimation (Appendix F, Table F3 — STCWC_RHO)
$DSTTCAP_{r,t}$	=	total gas storage capacity (Bcf)
STCWC_TOTCAP	=	estimated DSTTCAP coefficient (Appendix F, Table F3)
r	=	NGTDM region
t	=	forecast year

This total cash working capital in 1996 real dollars is converted to nominal dollars to be consistent with the convention used in this submodule.

$$STCWC_{r,t} = R\_STCWC_{r,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{1996}} \quad (276)$$

where,

$STCWC_{r,t}$	=	total cash working capital at the beginning of year t for existing and new capacity (nominal dollars)
$R\_STCWC_{r,t}$	=	total cash working capital at the beginning of year t for existing and new capacity (1996 real dollars)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
r	=	NGTDM region
t	=	forecast year

Computation of accumulated deferred income taxes, $STADIT_{r,t}$

The level of accumulated deferred income taxes for the combined existing and new capacity in year t in the adjusted rate base equation is a stock (not a flow) and depends on income tax regulations in effect, differences in tax, and book depreciation. It can be expressed as a linear function of its own lagged variable and the change in the level of gross plant in service between time t and t-1. The forecasting equation can be written as follows:

$$\begin{aligned} STADIT_{r,t} = {} & STADIT\_C + (STADIT\_ADIT * STADIT_{r,t-1}) + \\ & (STADIT\_NEWCAP * NEWCAP_{r,t}) \end{aligned} \tag{277}$$

where,

$STADIT_{r,t}$	=	accumulated deferred income taxes in dollars
STADIT_C	=	constant term from estimation (Appendix F, Table F3)
STADIT_ADIT	=	estimated coefficient for lagged accumulated deferred income taxes (Appendix F, Table F3)
STADIT_NEWCAP	=	estimated coefficient for change in gross plant in service (Appendix F, Table F3)
$NEWCAP_{r,t}$	=	change in gross plant in service for the combined existing and new capacity between years t and t-1 (in dollars)
r	=	NGTDM region
t	=	forecast year

Computation of Total Taxes, $STTOTAX_{r,t}$

Total taxes consist of Federal income taxes, State income taxes, deferred income taxes, and other taxes. Federal income taxes and State income taxes are calculated using average tax rates. The equation for total taxes is as follows:

$$STTOTAX_{r,t} = STFSIT_{r,t} + STDIT_{r,t} + STOTTAX_{r,t} \tag{278}$$

$$STFSIT_{r,t} = STFIT_{r,t} + STSIT_{r,t} \tag{279}$$

where,

$STTOTAX_{r,t}$	=	total Federal and State income tax liability for existing and new capacity (dollars)
$STFSIT_{r,t}$	=	Federal and State income tax for existing and new capacity (dollars)
$STFIT_{r,t}$	=	Federal income tax for existing and new capacity (dollars)
$STSIT_{r,t}$	=	State income tax for existing and new capacity (dollars)
$STDIT_{r,t}$	=	deferred income taxes for existing and new capacity (dollars)
STOTTAX	=	all other taxes assessed by Federal, State, or local governments for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the Federal tax rate. The after-tax profit is the operating income excluding the total long-term debt, which is determined as follows:

$$STATP_{r,t} = STAPRB_{r,t} * (STPFER_{r,t} * STGPFESTR_r + STCMER_{r,t} * STGCMESTR_r) \quad (280)$$

$$STATP_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t}) \quad (281)$$

where,

$STATP_{r,t}$	=	after-tax profit for existing and new capacity (dollars)
$STAPRB_{r,t}$	=	adjusted pipeline rate base for existing and new capacity (dollars)
$STPFER_{r,t}$	=	coupon rate for preferred stock for existing and new capacity (fraction)
$STGPFESTR_r$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STCMER_{r,t}$	=	common equity rate of return for existing and new capacity (fraction)
$STGCMESTR_r$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$STPFEN_{r,t}$	=	total return on preferred stock for existing and new capacity (dollars)
$STCMEN_{r,t}$	=	total return on common stock equity for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

and the Federal income taxes are

$$STFIT_{r,t} = (FRATE * STATP_{r,t}) / (1. - FRATE) \quad (282)$$

where,

$STFIT_{r,t}$	=	Federal income tax for existing and new capacity (dollars)
FRATE	=	Federal income tax rate (fraction, Appendix E)
$STATP_{r,t}$	=	after-tax profit for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

State income taxes are computed by multiplying the sum of taxable profit and the associated Federal income tax by a weighted-average State tax rate associated with each NGTDM region. State income taxes are computed as follows:

$$STSIT_{r,t} = SRATE * (STFIT_{r,t} + STATP_{r,t}) \quad (283)$$

where,

$STSIT_{r,t}$	=	State income tax for existing and new capacity (dollars)
SRATE	=	average State income tax rate (fraction, Appendix E)
$STFIT_{r,t}$	=	Federal income tax for existing and new capacity (dollars)
$STATP_{r,t}$	=	after-tax profits for existing and new capacity (dollars)

r = NGTDM region
t = forecast year

Deferred income taxes for existing and new capacity at the arc level are the differences in the accumulated deferred income taxes between year t and year t-1.

$$STDIT_{r,t} = STADIT_{r,t} - STADIT_{r,t-1} \tag{284}$$

where,

$STDIT_{r,t}$ = deferred income taxes for existing and new capacity (dollars)
$STADIT_{r,t}$ = accumulated deferred income taxes for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

Other taxes consist of a combination of ad valorem taxes (which grow with company revenue), property taxes (which grow in proportion to gross plant), and all other taxes (assumed constant in real terms). Other taxes in year t are determined as the previous year's other taxes adjusted for inflation.

$$STOTTAX_{r,t} = STOTTAX_{r,t-1} * (MC\_PCWGDP_t / MC\_PCWGDP_{t-1}) \tag{285}$$

where,

$STOTTAX_{r,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes for existing and new capacity (dollars) [read in as D_OTTAXr,t , t=1990-1998]
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
r = NGTDM region
t = forecast year

Computation of total operating and maintenance expenses, $STTOM_{r,t}$

The total operating and maintenance costs (including administrative costs) for existing and new capacity in an NGTDM region are determined in 1996 real dollars using a log-linear form with correction for serial correlation. The estimated equation is determined as a function of working gas storage capacity for region r at the beginning of period t. In developing the estimations, the impact of regulatory change and the differences between producing and consuming regions were analyzed.[93] Because their impacts were not supported by the data, they were not accounted for in the estimations. The final estimating equation is:

$$\begin{aligned} R\_STTOM_{r,t} = {} & e^{(STTOM\_C*(1-\rho))} * DSTWCAP_{r,t-1}^{STTOM\_WORKCAP} * \\ & R\_STTOM_{r,t-1}^{\rho} * DSTWCAP_{r,t-2}^{-\rho*STTOM\_WORKCAP} \end{aligned} \tag{286}$$

[93]The gas storage industry changed substantially when in 1994 FERC Order 636 required jurisdictional pipeline companies to operate their storage facilities on an open-access basis. The primary customers and use of storage in producing regions are significantly different from consuming regions.

where,

$R\_STTOM_{r,t}$ = total operating and maintenance cost for existing and new capacity (1996 real dollars)
STTOM_C = constant term from estimation (Appendix F, Table F3)
ρ = autocorrelation coefficient from estimation (Appendix F, Table F3 -- STTOM_RHO)
$DSTWCAP_{r,t}$ = level of gas working capacity for region r during year t
STTOM_WORKCAP = estimated DSTWCAP coefficient (Appendix F, Table F3)
r = NGTDM region
t = forecast year

Finally, the total operating and maintenance costs are converted to nominal dollars to be consistent with the convention used in this submodule.

$$STTOM_{r,t} = R\_STTOM_{r,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{1996}} \tag{287}$$

where,

$STTOM_{r,t}$ = total operating and maintenance costs for existing and new capacity (nominal dollars)
$R\_STTOM_{r,t}$ = total operating and maintenance costs for existing and new capacity (1996 real dollars)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
r = NGTDM region
t = forecast year

Computation of Storage Tariff

The regional storage tariff depends on the storage cost of service, current working gas capacity, utilization rate, natural gas storage activity, and other factors. The functional form is similar to the pipeline tariff curve, in that it will be built from a regional base point [price and quantity (PNOD,QNOD)]. The base regional storage tariff ($PNOD_{r,t}$) is determined as a function of the cost of service ($STCOS_{r,t}$ (equation 244)) and other factors discussed below. $QNOD_{r,t}$ is set to an effective working gas storage capacity by region, which is defined as a regional working gas capacity times its utilization rate. Hence, once the storage cost of service is computed by region, the base point can be established. Minor adjustments to the storage tariff routine will be necessary in order to obtain the desired results.

In the model, the storage cost of service used represents only a portion of the total storage cost of service, the revenue collected from the customers for withdrawing during the peak period the quantity of natural gas stored during the off-peak period. This portion is defined as a user-set percentage (STRATIO, Appendix E) representing the portion (ratio) of revenue requirement obtained by storage companies for storing gas during the off-peak and withdrawing it for the customers during the peak period. This would include charges for injections, withdrawals, and reserving capacity.

The cost of service $STCOS_{r,t}$ is computed using the Foster storage financial database which represents only the storage facilities owned by the interstate natural gas pipelines in the U.S. which have filed a Form 2 financial report with the FERC. Therefore, an adjustment to this cost of service to account for all the storage companies by region is needed. For example, at the national level, the Foster database shows the underground storage working gas capacity at 2.3 Tcf in 1998 and the EIA storage gas capacity data show much higher working gas capacity at 3.8 Tcf. Thus, the average adjustment factor to obtain the "actual" cost of service across all regions in the U.S. is 165 percent. This adjustment factor, $STCAP\_ADJ_{r,t}$, varies from region to region.

To complete the design of the storage tariff computation, two more factors need to be incorporated: the regional storage tariff curve adjustment factor and the regional efficiency factor for storage operations, which makes the storage tariff more competitive in the long-run.

Hence, the regional average storage tariff charged to customers for moving natural gas stored during the off-peak period and withdrawn during the peak period can be computed as follows:

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC\_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP\_ADJ_{r,t} * ADJ\_STR * (1.0 - STR\_EFF/100.)^t \tag{288}$$

where,

$$STCAP\_ADJ_{r,t} = \frac{PTCURPSTR_{r,t}}{FS\_PTCURPSTR_{r,t}} \tag{289}$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \tag{290}$$

and,

$PNOD_{r,t}$	=	base point, price (87$/Mcf)
$STCOS_{r,t}$	=	storage cost of service for existing and new capacity (dollars)
$QNOD_{r,t}$	=	base point, quantity (Bcf)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
$STRATIO_{r,t}$	=	portion of revenue requirement obtained by moving gas from the off-peak to the peak period (fraction, Appendix E)
$STCAP\_ADJ_{r,t}$	=	adjustment factor for the cost of service to total U.S. (ratio)
ADJ_STR	=	storage tariff curve adjustment factor (fraction, Appendix E)
STR_EFF	=	efficiency factor (percent) for storage operations (Appendix E)
$PTSTUTZ_{r,t}$	=	storage utilization (fraction)
$PTCURPSTR_{r,t}$	=	current storage capacity (Bcf)

$FS\_PTCURPSTR_{r,t}$	=	Foster storage working gas capacity (Bcf) [read in as D_WCAP]
r	=	NGTDM region
t	=	forecast year

Finally, the storage tariff curve by region can be expressed as a function of a base point [price and quantity (PNOD, QNOD)], storage flow, and a price elasticity, as follows:

current capacity segment:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA\_STR} \tag{291}$$

capacity expansion segment:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA2\_STR} \tag{292}$$

where,

$X1NGSTR\_VARTAR_{r,t}$	=	function to define storage tariffs (87$/Mcf)
$PNOD_{r,t}$	=	base point, price (87$/Mcf)
$QNOD_{r,t}$	=	base point, quantity (Bcf)
$Q_{r,t}$	=	regional storage flow (Bcf)
ALPHA_STR	=	price elasticity for storage tariff curve for current capacity (Appendix E)
ALPHA2_STR	=	price elasticity for storage tariff curve for capacity expansion segment (Appendix E)
r	=	NGTDM region
t	=	forecast year

Alaska and MacKenzie Delta Pipeline Tariff Routine

A single routine (FUNCTION NGFRPIPE_TAR) estimates the potential per-unit pipeline tariff for moving natural gas from either the North Slope of Alaska or the MacKenzie Delta to the market hub in Alberta, Canada for the years beyond the specified in-service date. The tariff estimates are based on a simple cost-of-service rate base methodology, given the infrastructure's initial capital cost at the beginning of the construction period (FR_CAPITL0 in billion dollars, Appendix E), the assumed number of years for the project to be completed (FRPCNSYR, Appendix E), the associated discount rate for the project (FR_DISCRT, Appendix E), the initial capacity (a function of delivered volume FR_PVOL, Appendix E), and the number of years over which the final cost of capitalization is assumed completely amortized (INVEST_YR=15). The input values vary depending on whether the tariff being calculated is associated with a pipeline for Alaska or for MacKenzie Delta gas. The cost of service consists of the following four components: depreciation, depletion, and amortization; after-tax operating income (known as the return on rate base); total operating and maintenance expenses; and total income taxes. The computation of each of the four components in nominal dollars per Mcf is described below:

Depreciation, depletion, and amortization, FR_DDA_t

The depreciation is computed as the final cost of capitalization at the start of operations divided by the amortization period. The depreciation equation is provided below:

$$FR\_DDA_t = FR\_CAPITL1 / INVEST\_YR \tag{293}$$

where,

FR_DDA_t	=	depreciation, depletion, and amortization costs (thousand nominal dollars)
FR_CAPITL1	=	final cost of capitalization at the start of operations (thousand nominal dollars)
INVEST_YR	=	investment period allowing recovery (parameter, INVEST_YR=15)
t	=	forecast year

The structure of the final cost of capitalization, FR_CAPITL1, is computed as follows:

$$\begin{aligned} FR\_CAPITL1 = FR\_CAPIT0 / FR\_PCNSYR \; * \\ [(1+r) + (1+r)^2 + ... + (1+r)^{FR\_PCNSYR}] \end{aligned} \tag{294}$$

where,

FR_CAPITL1	=	final cost of capitalization at the start of operations (thousand nominal dollars)
FR_CAPITL0	=	initial capitalization (thousand FR_CAPYR dollars), where FR_CAPYR is the year dollars associated with this assumed capital cost (Appendix E)
FR_PCNSYR	=	number of construction years (Appendix E)
r	=	cost of debt, fraction, which is equal to the nominal 10-year Treasury bill (MC_RMTCM10Y or TNOTE, in percent) plus a debt premium in percent (debt premium set to FR_DISCRT, Appendix E)

The net plant in service is tied to the depreciation by the following formulas:

$$\begin{aligned} FR\_NPIS_t &= FR\_GPIS_t - FR\_ADDA_t \\ FR\_ADDA_t &= FR\_ADDA_{t-1} + FR\_DDA_t \end{aligned} \tag{295}$$

where,

FR_GPIS_t	=	original capital cost of plant in service (gross plant in service) in thousand nominal dollars, set to FR_CAPITL1.
FR_NPIS_t	=	net plant in service (thousand nominal dollars)
FR_ADDA_t	=	accumulated depreciation, depletion, and amortization in thousand nominal dollars
t	=	forecast year

After-tax operating income (return on rate base), FR_TRRB_t

This after-tax operating income also known as the return on rate base is computed as the net plant in service times an annual rate of return (FR_ROR, Appendix E). The net plant in service, FR_NPIS_t, gets updated each year and is equal to the initial gross plant in service minus accumulated depreciation. Net plant in service becomes the adjusted rate base when other capital related costs such as materials and supplies, cash working capital, and accumulated deferred income taxes are equal to zero.

The return on rate base is computed as follows:

$$FR\_TRRB_t = WACC_t * FR\_NPIS_t \tag{296}$$

where,

$$\begin{aligned} WACC_t = {} & FR\_DEBTRATIO * COST\_OF\_DEBT_t + \\ & (1.0 - FR\_DEBTRATIO) * COST\_OF\_EQUITY_t \end{aligned} \tag{297}$$

and

$$COST\_OF\_DEBT_t = (TNOTE_t + FR\_DISCRT) / 100. \tag{298}$$

$$COST\_OF\_EQUITY_t = (TNOTE_t / 100. \tag{299}$$

where,

FR_TRRB_t	=	after-tax operating income or return on rate base (thousand nominal dollars)
$WACC_t$	=	weighted average cost of capital (fraction), nominal
FR_NPIS_t	=	net plant in service (thousand nominal dollars)
$COST\_OF\_DEBT_t$	=	cost of debt (fraction)
$COST\_OF\_EQUITY_t$	=	cost of equity (fraction)
$TNOTE_t$	=	nominal 10-year Treasury bill rate, ($MC\_RMTCM10Y_t$, percent) provided by the Macroeconomic Activity Module
FR_DISCRT	=	user-set debt premium, percent (Appendix E)
FR_ROR_PREM	=	user-set risk premium, percent (Appendix E)
t	=	forecast year

Total taxes, FR_TAXES_t

Total taxes consist of Federal and State income taxes and taxes other than income taxes. Each tax category is computed based on a percentage times net profit. These percentages are drawn from the Foster financial report's 28 major interstate natural gas pipeline companies. The percentage for income taxes (FR_TXR) is computed as the average over five years (1992-1996) of tax to net operating income ratio from the Foster report. Likewise, the percentage (FR_OTXR) for taxes other than income taxes is computed as the average over five years (1992-1996) of taxes other than income taxes to net operating income ratio from the same report. Total taxes are computed as follows:

$$FR\_TAXES_t = (FR\_TXR + FR\_OTXR) * FR\_NETPFT_t \tag{300}$$

where,

FR_TAXES_t = total taxes (thousand nominal dollars)
FR_NETPFT_t = net profit (thousand nominal dollars)
FR_TXR = 5-year average Lower 48 pipeline income tax rate, as a proxy (Appendix E)
FR_OTXR = 5-year average Lower 48 pipeline other income tax rate, as a proxy (Appendix E)
t = forecast year

Net profit, FR_NETPFT, is computed as the return on rate base (FR_TRRB_t) minus the long-term debt (FR_LTD_t), which is calculated as the return on rate base times long-term debt rate times the debt to capital structure ratio. The net profit and long-term debt equations are provided below:

$$FR\_NETPFT_t = (FR\_TRRB_t - FR\_LTD_t) \tag{301}$$

$$FR\_LTD_t = FR\_DEBTRATIO * (TNOTE_t + FR\_DISCRT) / 100.0 * FR\_NPIS_t \tag{302}$$

where,

FR_LTD_t = long-term debt (thousand nominal dollars)
FR_NPIS_t = net plant in service (thousand nominal dollars)
$FR\_DEBTRATIO$ = 5-year average Lower 48 pipeline debt structure ratio (Appendix E)
FR_NETPFT_t = net profit (thousand nominal dollars)
FR_TRRB_t = return on rate base (thousand nominal dollars)
$TNOTE_t$ = nominal 10-year Treasury bill, (MC_RMTCM10Y, percent) provided by the Macroeconomic Activity Module
FR_DISCRT = user-set debt premium, percent (Appendix E)
t = forecast year

In the above equations, the long-term debt rate is assumed equal to the 10-year Treasury bill plus a debt premium, which represents a risk premium generally charged by financial institutions. When 10-year Treasury bill rates are needed for years beyond the last forecast year (LASTYR), the variable $TNOTE_t$ becomes the average over a number of years (FR_ESTNYR, Appendix E) of the 10-year Treasury bill rates for the last forecast years.

Cost of Service, FR_COS_t

The cost of service is the sum of four cost-of-service components computed above, as follows:

$$FR\_COS_t = (FR\_TRRB_t + FR\_DDA_t + FR\_TAXES_t + FR\_TOM_{FR\_CAPYR} * (MC\_PCWGDP_t / MC\_PCWGDP_{FR\_CAPYR}) * FR\_PVOL * 1.1484 * 1000.0) \quad (303)$$

where,

FR_COS_t	=	cost of service (thousand nominal dollars)
FR_TRRB_t	=	return on rate base (thousand nominal dollars)
FR_DDA_t	=	depreciation (thousand nominal dollars)
FR_TAXES_t	=	total taxes (thousand nominal dollars)
FR_TOMFR_CAPYR	=	total operating and maintenance expenses (in nominal dollars per Mcf, set constant in real terms) (Appendix E)
MC_PCWGDP_t	=	GDP price deflator (from Macroeconomic Activity Module)
FR_PVOL	=	maximum volume delivered to Alberta in dry terms (Bcf/year)
1.1484	=	factor to convert delivered dry volume to wet gas volume entering the pipeline as a proxy for the pipeline capacity
t	=	forecast year

Hence, the annual pipeline tariff in nominal dollars is computed by dividing the above cost of service by total pipeline capacity, as follows:

$$COS_t = FR\_COS_t / (FR\_PVOL * 1.1484 * 1000.0) \quad (304)$$

where,

COS_t	=	per-unit cost of service or annual pipeline tariff (nominal dollars/Mcf)
t	=	forecast year

To convert this nominal tariff to real 1987$/Mcf, the GDP implicit price deflator variable provided by the Macroeconomic Activity Module is needed. The real tariff equation is written as follows:

$$COSR_t = COS_t / MC\_PCWGDP_t \quad (305)$$

where,

$COSR_t$	=	annual real pipeline tariff (1987 dollars/Mcf)
MC_PCWGDP_t	=	GDP price deflator (from Macroeconomic Activity Module)
t	=	forecast year

Last, the annual average tariff is computed as the average over a number of years (FR_AVGTARYR, Appendix E) of the first successive annual cost of services.

7. Model Assumptions, Inputs, and Outputs

This last chapter summarizes the model and data assumptions used by the Natural Gas Transmission and Distribution Module (NGTDM) and lists the primary data inputs to and outputs from the NGTDM.

Assumptions

This section presents a brief summary of the assumptions used within the NGTDM. Generally, there are two types of data assumptions that affect the NGTDM solution values. The first type can be derived based on historical data (past events), and the second type is based on experience and/or events that are likely to occur (expert or analyst judgment). A discussion of the rationale behind assumed values based on analyst judgment is beyond the scope of this report. Most of the FORTRAN variables related to model input assumptions, both those derived from known sources and those derived through analyst judgment, are identified in this chapter, with background information and actual values referenced in Appendix E.

The assumptions summarized in this section are mentioned in Chapters 2 through 6. They are used in NGTDM equations as starting values, coefficients, factors, shares, bounds, or user specified parameters. Six general categories of data assumptions have been defined: classification of market services, demand, transmission and distribution service pricing, pipeline tariffs and associated regulation, pipeline capacity and utilization, and supply (including imports). These assumptions, along with their variable names, are summarized below.

Market Service Classification

Nonelectric sector natural gas customers are classified as either core or noncore customers, with core customers defined as the type of customer that is expected to generally transport their gas under firm (or near firm) transportation agreements and noncore customers to generally transport their gas under non-firm (interruptible or short-term capacity release) transportation agreements. The residential, commercial, and transportation (natural gas vehicles) sectors are assumed to be core customers. The transportation sector is further subdivided into fleet and personal vehicle customers. Industrial and electric generator end users fall into both categories, with industrial boilers and refineries assumed to be noncore and all other industrial users assumed to be core, and gas steam units or gas combined cycle units assumed to be core and all other electric generators assumed to be noncore. Currently the core/noncore distinction for electric generators is not being used in the model.

Demand

The peak period is defined *(using PKOPMON)* to run from December through March, with the off-peak period filling up the remainder of the year.

The Alaskan natural gas consumption levels for residential and commercial sectors are primarily defined as a function of the number of customers *(AK_RN, AK_CM, Tables F1, F2)*, which in turn are set based on an exogenous projection of the population in Alaska *(AK_POP)*. Alaskan gas consumption is disaggregated into North and South Alaska in order to separately compute the natural gas production forecasts in these regions. Lease, plant, and pipeline fuel related to an Alaska pipeline or a gas-to-liquids facility are set at an assumed percentage of their associated gas volumes *(AK_PCTPLT, AK_PCTPIP, AK_PCTLSE)*. The remaining lease and plant fuel is assumed to be consumed in the North and set based on historical trends. The amount of gas consumed by other sectors in North Alaska is small enough to assume as zero and to allow for the setting of South Alaska volumes equal to the totals for the State. Industrial consumption in South Alaska is set to the exogenously specified sum of the level of gas consumed at the Agrium fertilizer plant and at the liquefied natural gas plant *(AK_QIND_S)*. Pipeline fuel in the South is set as a percentage *(AK_PCTPIP)* of consumption and exports. Production in the south is set to total consumption levels in the region. In the north production equals the flow along an Alaska pipeline to Alberta, any gas needed to support the production of gas-to-liquids, associated lease, plant, and pipeline fuel for these two applications, and the other calculated lease and plant fuel. The forecast for reporting discrepancy in Alaska *(AK_DISCR)* is set to an average historical value. To compute natural gas prices by end-use sector for Alaska, fixed markups derived from historical data *(AK_RM, AK_CM, AK_IN, AK_EM)* are added to the average Alaskan natural gas wellhead price over the North and South regions. The wellhead price is set using a simple estimated equation *(AK_F)*. Historically based percentages and markups are held constant throughout the forecast period.

The shares *(NG_CENSHR)* for disaggregating nonelectric Census Division demands to NGTDM regions are held constant throughout the forecast period and are based on average historical relationships *(SQRS, SQCM, SQIN, SQTR)*. Similarly, the shares for disaggregating end-use consumption levels to peak and off-peak periods are held constant throughout the forecast, and are directly *(United States -- PKSHR_DMD, PKSHR_UDMD_F, PKSHR_UDMD_I)* or partially *(Canada -- PKSHR_CDMD)* historically based. Canadian consumption levels are set exogenously *(CN_DMD)* based on another published forecast, and adjusted if the associated world oil price changes. Consumption, base level production, and domestically consumed LNG imports into Mexico are set exogenously *(PEMEX_GFAC, IND_GFAC, ELE_GFAC, RC_GFAC, PRD_GFAC, MEXLNG)*. After the base level production is adjusted based on the average U.S. wellhead price, exports to Mexico are set to balance supply and consumption. Historically based shares *(PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, PKSHR_ILNG)* are applied to projected/historical values for natural gas exports and imports *(SEXP, SIMP, CANEXP, Q23TO3, FLO_THRU_IN,OGQNGEXP)*. These historical based shares are generated from monthly historical data *(QRS, QCM, QIN, QEU, MON_QEXP, MON_QIMP)*.

Lease and plant fuel consumption in each NGTDM region is computed as an historically derived percentage *(using SQLP)* of dry gas production *(PCTLP)* in each NGTDM/OGSM region. These percentages are held constant throughout the forecast period. Pipeline fuel use is derived using historically *(SQPF)* based factors *(PFUEL_FAC)* relating pipeline fuel use to the quantity of natural gas exiting a regional node. Values for the most recent historical year are derived from monthly-published figures *(QLP_LHIS, NQPF_TOT)*.

Pricing of Distribution Services

End-use prices for residential, commercial, industrial, transportation, and electric generation customers are derived by adding markups to the regional hub price of natural gas. Each regional end-use markup consists of an intraregional tariff *(INTRAREG_TAR)*, an intrastate tariff *(INTRAST_TAR)*, a distribution tariff *(endogenously defined)*, and a city gate benchmark factor [endogenously defined based on historical seasonal city gate prices (HCGPR)]. Historical distributor tariffs are derived for all sectors as the difference between historical city gate and end-use prices *(SPRS, SPCM, SPIN, SPEU, SPTR, PRS, PCM PIN, PEU)*.[94] Historical industrial end-use prices are derived in the module using an econometrically estimated equation (Table F5).[95] The residential, commercial, industrial, and electric generator distributor tariffs are also based on econometrically estimated equations (Tables F4, F6, F7, and F8). The distributor tariff for the personal (PV) and fleet vehicle (FV) components of the transportation sector are set using historical data, a decline rate *(TRN_DECL)*, state and federal taxes *(STAX, FTAX)*, and assumed dispensing costs/charges *(RETAIL_COST)*, and for personal vehicles at retail stations, a capital cost recovery markup *(CNG_RETAIL_MARKUP)*.

Prices for exports (and fixed volume imports) are based on historical differences between border prices *(SPIM, SPEX, MON_PIMP, MON_PEXP)* and their closest market hub price (as determined in the module when executed during the historical years).

Pipeline and Storage Tariffs and Regulation

Peak and off-peak transportation rates for interstate pipeline services (both between NGTDM regions and within a region) are calculated assuming that the costs of new pipeline capacity will be rolled into the existing rate base. Peak and off-peak market transmission service rates are based on a cost-of-service/rate-of-return calculation for current pipeline capacity times an assumed utilization rate *(PKUTZ, OPUTZ)*. To reflect recent regulatory changes related to alternative ratemaking and capacity release developments, these tariffs are discounted (based on an assumed price elasticity) as pipeline utilization rates decline.

In the computation of natural gas pipeline transportation and storage rates, the Pipeline Tariff Submodule uses a set of data assumptions based on historical data or expert judgment. These include the following:

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[94]All historical prices are converted from nominal to real 1987 dollars using a price deflator *(GDP_B87)*.

[95]Traditionally industrial prices have been derived by collecting sales data from local distribution companies. More recently, industrial customers have not relied on LDCs to purchase their gas. As a result, annually published industrial natural gas prices only represent a rather small portion of the total population. In the module, these published prices are adjusted using an econometrically estimated equation based on EIA's survey of manufacturers to derive a more representative set of industrial prices.

- Factors *(AFX, AFR, AVR)* to allocate each company's line item costs into the fixed and variable cost components of the reservation and usage fees
- Capacity reservation shares used to allocate cost of service components to portions of the pipeline network
- Average pipeline capital cost (2005 dollars) per unit of expanded capacity by arc *(AVGCOST)* used to derive total capital costs to expand pipeline capacity
- Storage capacity expansion cost parameters *(STCCOST_CREG, STCCOST_BETAREG, STCSTFAC)* used to derive total capital costs to expand regional storage capacity
- Input coefficients *(ALPHA_PIPE, ALPH2_PIPE, ALPHA_STR, ALPHA2_STR, ADJ_STR, STR_EFF)* for transportation and storage rates
- Pipeline tariff curve parameters by arc *(PKSHR_YR, PTPKUTZ, PTOPUTZ, ALPHA_PIPE, ALPHA2_PIPE)*
- Storage tariff curve parameters by region *(STRATIO, STCAP_ADJ, PTSTUTZ, ADJ_STR, STR_EFF, ALPHA_STR, ALPHA2_STR)*

In order to determine when a pipeline from either Alaska or the MacKenzie Delta to Alberta could be economic, the model estimates the tariff that would be charged on both pipelines should they be built, based on a number of assumed values. A simple cost-of-service/rate-of-return calculation is used, incorporating the following: initial capitalization *(FR_CAPITLO)*, return on debt *(FR_DISCRT)* and return on equity *(FR_ROR_PREM)* (both specified as a premium added to the 10-year Treasury bill rate), total debt as a fraction of total capital *(FR_DEBTRATIO)*, operation and maintenance expenses *(FR_TOM0)*, federal income tax rate *(FR_TXR)*, other tax rate *(FR_OTXR)*, levelized cost period *(FR_AVGTARYR)*, and depreciation period *(INVEST_YR)*. In order to establish the ultimate charge for the gas in the lower 48 States assumptions were made for the minimum wellhead price *(FR_PMINWPC)* including production, treatment, and fuel costs, as well as the average differential between Alberta and the lower 48 *(ALB_TO_L48)* and a risk premium *(FR_PRISK)* to reflect cost and market uncertainties. The market price in the lower 48 states must be maintained over a planning horizon *(FR_PPLNYR)* before construction would begin. Construction is assumed to take a set number of years *(FR_PCNSYR)* and result in a given initial capacity based on initial delivered volumes *(FR_PVOL)*. An additional expansion is assumed on the condition of an increase in the market price *(FR_PADDTAR, FR_PEXPFAC)*.

Pipeline and Storage Capacity and Utilization

Historical and planned interregional, intraregional, and Canadian pipeline capacities are assigned in the module for the historical years and the first few years *(NOBLDYR)* into the forecast *(ACTPCAP, PTACTPCAP, PLANPCAP, SPLANPCAP, PER_YROPEN, CNPER_YROPEN)*. The flow of natural gas along these pipeline corridors in the peak and off-peak periods of the historical years is set, starting with historical shares *(HPKSHR_FLOW)*, to be consistent with the annual flows *(HAFLOW, SAFLOW)* and other known seasonal network volumes (e.g., consumption, production).

A similar assignment is used for storage capacities *(PLANPCAP, ADDYR)*. The module only represents net storage withdrawals in the peak period and net storage injections in the off-peak period, which are known historically *(HNETWTH, HNETINJ, SNETWTH, NWTH_TOT, NINJ_TOT)*.

For the forecast years, the use of both pipeline and storage capacity in each seasonal period is limited by exogenously set maximum utilization rates *(PKUTZ, OPUTZ, SUTZ)*, although these are currently not active for pipelines. They were originally intended to reflect an expected variant in the load throughout a season. Adjustments are now being made within the module, during the flow sharing algorithm, to reflect the seasonal load variation.

The decision concerning the share of gas that will come from each incoming source into a region for the purpose of satisfying the regions consumption levels (and some of the consumption upstream) is based on the relative costs of the incoming sources and assumed parameters *(GAMMAFAC, MUFAC)*. During the process of deciding the flow of gas through the network, an iterative process is used that requires a set of assumed parameters for assessing and responding to nonconvergence *(PSUP_DELTA, QSUP_DELTA, QSUP_SMALL, QSUP_WT, MAXCYCLE)*.

Supply

The supply curves for domestic lower 48 nonassociated dry gas production and for conventional and tight gas production from the WCSB are based on an expected production level, the former of which is set in the OGSM. Expected production from the WCSB is set in the NGTDM using a series of three econometric equations for new successful wells drilled, quantity proved per well drilled, and expected quantity produced per current level proved, and is dependent on resource assumptions *(RESBASE, RESTECH)*. A set of parameters *(PARM_SUPCRV3, PARM_SUPCRV5, SUPCRV, PARM_SUPELAS)* defines the price change from a base or expected price as production deviates from this expected level. These supply curves are limited by minimum and maximum levels, calculated as a factor *(PARM_MINPR, MAXPRRFAC, MAXPRRCAN)* times the expected production levels. Domestic associated-dissolved gas production is provided by the Oil and Gas Supply Module. Eastern Canadian production from other than the WCSB is set exogenously *(CN_FIXSUP)*. Natural gas production in Canada from both coal beds and shale is based on assumed production withdrawal profiles from their perspective resource base totals *(ULTRES, ULTSHL)* at an assumed exogenously specified price path and is adjusted relative to how much the actual western Canadian price differs from the assumed. Production from the frontier areas in Canada (i.e., the MacKenzie Delta) is set based on the assumed size of the pipeline to transport the gas to Alberta, should the pipeline be built. Production from Alaska is a function of the consumption in Alaska and the potential capacity of a pipeline from Alaska to Alberta and/or a gas-to-liquids facility.

Imports from Mexico and Canada at each border crossing point are represented as follows: (1) Mexican imports are set exogenously *(EXP_FRMEX)* with the exception of LNG imported into Baja for U.S. markets; (2) Canadian imports are set endogenously (except for the imports into the East North Central region, *(Q23TO3)* and limited to Canadian pipeline capacities *(ACTPCAP, CNPER_YROPEN)*, which are set in the module, and expand largely in response to the introduction of Alaskan gas into the Alberta system. Total gas imports from Canada exclude the amount of gas that travels into the United States and then back into Canada *(FLO_THRU_IN)*.

Liquefied natural gas imports are represented with an east and west supply curves to North America generated based on output results from EIA's International Natural Gas Model and shared to representative regional terminals based on regasification capacity, last year's imports, and relative prices. Regasification capacity is set based on known facilities, either already constructed or highly likely to be *(LNGCAP)*.

The three supplemental production categories (synthetic production of natural gas from coal and liquids and other supplemental fuels) are represented as constant supplies within the Interstate Transmission Submodule, with the exception of any production from potential new coal-to-gas plants. Synthetic production from the existing coal plant is set exogenously *(SNGCOAL)*. Forecast values for the other two categories are held constant throughout the forecast and are set to historical values *(SNGLIQ, SUPPLM)* within the module. The algorithm for determining the potential construction of new coal-to-gas plants uses an extensive set of detailed cost figures to estimate the total investment and operating costs of a plant (including accounting for emissions costs, electricity credits, and lower costs over time due to learning) for use within a discounted cash flow calculation. If positive cash flow is estimated to occur the number of generic plants built is based on a Mansfield-Blackman market penetration algorithm. Throughout the forecast, the annual synthetic gas production levels are split into seasonal periods using an historically *(NSUPLM_TOT)* based share *(PKSHR_SUPLM)*.

The supply component uses an assortment of input values in defining historical production levels and prices (or revenues) by the regions and categories required by the module *(QOF_ALST, QOF_ALFD, QOF_LAST, QOF_LAFD, QOF_CA, ROF_CA, QOF_LA, ROF_LA, QOF_TX, ROF_TX, AL_ONSH, AL_OFST, AL_OFFD, LA_ONSH, LA_OFST, lA_OFFD , ADW, NAW, TGD, MISC_ST, MISC_GAS, MISC_OIL, SMKT_PRD, SDRY_PRD, HQSUP, HPSUP, WHP_LHIS, SPWH)*. A set of seasonal shares *(PKSHR_PROD)* have been defined based on historical values *(MONMKT_PRD)* to split production levels of supply sources that are nonvariant with price *(CN_FIXSUP and others)* into peak and off-peak categories.

Discrepancies that exist between historical supply and disposition level data are modeled at historical levels *(SBAL_ITM)* in the NGTDM and kept constant throughout the forecast years at average historical levels *(DISCR, CN_DISCR)*.

Model Inputs

The NGTDM inputs are grouped into six categories: mapping and control variables, annual historical values, monthly historical values, Alaskan and Canadian demand/supply variables, supply inputs, pipeline and storage financial and regulatory inputs, pipeline and storage capacity and utilization related inputs, end-use pricing inputs, and miscellaneous inputs. Short input data descriptions and identification of variable names that provide more detail (via Appendix E) on the sources and transformation of the input data are provided below.

Mapping and Control Variables

- Variables for mapping from States to regions *(SNUM_ID, SCH_ID, SCEN_DIV, SITM_REG, SNG_EM, SNG_OG, SIM_EX, MAP_PRDST)*
- Variables for mapping import/export borders to States and to nodes *(CAN_XMAPUS, CAN_XMAPCN, MEX_XMAP, CAN_XMAP)*
- Variables for handling and mapping arcs and nodes *(PROC_ORD,ARC_2NODE, NODE_2ARC, ARC_LOOP, SARC_2NODE, SNODE_2ARC, NODE_ANGTS, CAN_XMAPUS)*
- Variables for mapping supply regions *(NODE_SNGCOAL, MAPLNG_NG, OCSMAP, PMMMAP_NG, SUPSUB_NG, SUPSUB_OG)*
- Variables for mapping demand regions *(EMMSUB_NG, EMMSUB_EL, NGCENMAP)*

Annual Historical Values

- Offshore natural gas production and revenue data (QOF_ALST, QOF_ALFD, QOF_LAST, QOF_LAFD, QOF_CA, ROF_CA, QOF_LA, ROF_LA, QOF_TX, ROF_TX, QOF_AL, ROF_AL, QOF_MS, ROF_MS, QOF_GM, ROF_GM, PRICE_CA, PRICE_LA, PRICE_AL, PRICE_TX, GOF_LA, GOF_AL, GOF_TX, GOF_CA, AL_ONSH, AL_OFST, AL_OFFD, LA_ONSH, LA_OFST, LA_OFFD, AL_ONSH2, AL_OFST2, AL_ADJ)
- State-level supply prices *(SPIM, SPWH)*
- State/sub-state-level natural gas production and other supply/storage data *(ADW, NAW, TGD, TGW, MISC_ST, MISC_GAS, MISC_OIL, SMKT_PRD, SDRY_PRD, SIMP, SNET_WTH, SUPPLM)*
- State-level consumption levels *(SBAL_ITM, SEXP, SQPF, SQLP, SQRS, SQCM, SQIN, SQEU, SQTR)*
- State-level end-use prices *(SPEX, SPRS, SPCM, SPIN, SPEU, SPTR)*
- Miscellaneous *(GDP_B87, OGHHPRNG)*

Monthly Historical Values

- State-level natural gas production data *(MONMKT_PRD)*
- Import/export volumes and prices by source *(MON_QIMP, MON_PIMP, MON_QEXP, MON_PEXP, HQIMP)*
- Storage data *(NWTH_TOT, NINJ_TOT, HNETWTH, HNETINJ)*
- State-level consumption and prices *(CON & PRC -- QRS, QCM, QIN, QEU, PRS, PCM, PIN, PEU)*
- Electric power gas consumption and prices *(CON_ELCD, PRC_EPMCD, CON_EPMGR, PRC_EPMGR)*
- Miscellaneous monthly/seasonal data *(NQPF_TOT, NSUPLM_TOT, WHP_LHIS, QLP_LHIS, HCGPR)*

Alaskan, Canadian, & Mexican Demand/Supply Variables

- Alaskan lease, plant, and pipeline fuel parameters *(AK_PCTPLT, AK_PCTPIP, AK_PCTLSE)*
- Alaskan consumption parameters *(AK_QIND_S, AK_RN, AK_CM, AK_POP, AK_HDD, HI_RN)*
- Alaskan pricing parameters *(AK_RM, AK_CM, AK_IN, AK_EM)*
- Canadian production and end-use consumption *(CN_FIXSUP, CN_DMD, PKSHR_PROD, PKSHR_CDMD)*
- Exogenously specified Canadian import/export related volumes *(CANEXP, Q23TO3, FLO_THRU_IN)*
- Historical western Canadian production and wellhead prices *(HQSUP, HPSUP)*
- Unconventional western Canadian production parameters *(ULTRES, ULTSHL, RESBASE, PKIYR, LSTYR0, PERRES, RESTECH, TECHGRW)*
- Mexican production, LNG imports, and end-use consumption *(PEMEX_GFAC, IND_GFAC,ELE_GFAC,RC_GFAC, PRD_GFAC, MEXLNG)*

Supply Inputs

- Liquefied natural gas supply curves and pricing *(LNGCAP, PARM_LNGCRV3, PARM_LNGCRV5,PARM_LNGELAS, LNGPPT, LNGQPT, LNGMIN,PERQ, BETA,LNGTAR)*
- Supply curve parameters *(SUPCRV, PARM_MINPR, PARM_SUPCRV3, PARM_SUPCRV5, PARM_SUPELAS, MAXPRRFAC, MAXPRRNG, PARM_MINPR)*
- Synthetic natural gas projection *(SNGCOAL, SNGLIQ, NRCI_INV, NRCI_LABOR_NRCI_OPER,INFL_RT, FEDTAX_RT, STTAX_RT, INS_FAC, TAX_FAC, MAINT_FAC, OTH_FAC,BEQ_OPRAVG, BEQ_OPRHRSK, EMRP_OPRAVG, EMRP_OPRHRSK, EQUITY_OPRAVG, EQUITY_OPRHRSK, BEQ_BLDAVG, BEQ_BLDHRSK, EMRP_BLDAVG, EMRP_BLDHRSK, EQUITY_BLDAVG, EQUITY_BLDHRSK, BA_PREM, PCLADJ, CTG_CAPYR$, PRJSDECOM, CTG_BLDYRS, CTG_PRJLIFE, CTG_OSBLFAC, CTG_PCTENV, CTG_PCTCNTG, CTG_PCTLND, CTG_PCTSPECL, CTG_PCTWC, CTG_STAFF_LCFAC, CTG_OH_LCFAC, CTG_FSIYR, CTG_INCBLD, CTG_DCLCAPCST, CTG_DCLOPRCST, CTG_BASHHV, CTG_BASCOL, CTG_BCLTON, CTG_BASSIZ, CTG_BASCGS, CTG_BASCGSCO2, CTG_BASCGG, CTG_BASCGGCO2,CTG_NCL, CTG_NAM, CTG_CO2,LABORLOC, CTG_PUCAP, XBM_ISBL, XBM_LABOR, CTG_BLDX, CTG_IINDX, CTG_SINVST)*

Pipeline and Storage Financial and Regulatory Inputs

- Rate design specification *(AFX_PFEN, AFR_PFEN, AVR_PFEN, AFX_CMEN, AFR_CMEN, AVR_CMEN, AFX_LTDN, AFR_LTDN, AVR_LTDN, AFX_DDA, AFR_DDA, AVR_DDA, AFX_FSIT, AFR_FSIT, AVR_FSIT, AFX_DIT, AFR_DIT, AVR_DIT, AFX_OTTAX, AFR_OTTAX, AVR_OTTAX, AFX_TOM, AFR_TOM, AVR_TOM)*
- Pipeline rate base, cost, and volume parameters *(D_TOM, D_DDA, D_OTTAX, D_DIT, D_GPIS, D_ADDA, D_NPIS, D_CWC, D_ADIT, D_APRB, D_GPFES, D_GCMES, D_GLTDS, D_PFER, D_CMER, D_LTDR)*
- Storage rate base, cost, and volume parameters *(D_TOM, D_DDA, D_ADDA, D_OTTAX, D_FSIT, D_DIT, D_LTDN, D_PFEN, D_CMEN, D_GPIS, D_NPIS, D_CWC, D_ADIT, D_APRB, D_LTDS, D_PFES, D_CMES, D_TCAP, D_WCAP)*
- Pipeline and storage revenue requirement forecasting equation parameters *(Table F3)*
- Rate of return set for generic pipeline companies *(MC_RMPUAANS, ADJ_PFER, ADJ_CMER, ADJ_LTDR)*
- Rate of return set for existing and new storage capacity *(MC_RMPUAANS, ADJ_STPFER, ADJ_STCMER, ADJ_STLTDR)*
- Federal and State income tax rates *(FRATE, SRATE)*
- Depreciation schedule *(30 year life)*
- Pipeline capacity expansion cost parameter for capital cost equations *(AVGCOST)*
- Pipeline capacity replacement cost parameter *(PCNT_R)*
- Storage capacity expansion cost parameters for capital cost equations *(STCCOST_CREG, STCCOST_BETAREG, STCSTFAC)*
- Parameters for interstate pipeline transportation rates *(PKSHR_YR, PTPKUTZ, PTOPUTZ, ALPHA_PIPE, ALPHA2_PIPE)*
- Canadian pipeline and storage tariff parameters *(ARC_FIXTAR, ARC_VARTAR, CN_FIXSHR)*
- Parameters for storage rates *(STRATIO, STCAP_ADJ, PTSTUTZ, ADJ_STR, STR_EFF, ALPHA_STR, ALPHA2_STR)*
- Parameters for Alaska-to-Alberta and MacKenzie Delta-to-Alberta pipelines *(FR_CAPITL0, FR_CAPYR, FR_PCNSYR, FR_DISCRT, FR_PVOL, INVEST_YR,FR_ROR_PREM, FR_TOM0, FR_DEBTRATIO, FR_TXR, FR_OTXR, FR_ESTNYR, FR_AVGTARYR)*

Pipeline and Storage Capacity and Utilization Related Inputs

- Canadian natural gas pipeline capacity and planned capacity additions *(ACTPCAP, PTACTPCAP, PLANPCAP, CNPER_YROPEN)*
- Maximum peak and off-peak primary and secondary pipeline utilizations *(PKUTZ, OPUTZ, SUTZ, MAXUTZ, XBLD)*
- Interregional planned pipeline capacity additions along primary and secondary arcs (PLANPCAP, SPLANPCAP, PER_YROPEN)
- Maximum storage utilization (PKUTZ)
- Existing storage capacity and planned additions *(PLANPCAP, ADDYR)*
- Net storage withdrawals (peak) and injections (off-peak) in Canada *(HNETWTH, HNETINJ)*
- Historical flow data *(HPKSHR_FLOW, HAFLOW, SAFLOW)*
- Alaska-to-Alberta and MacKenzie Delta-to-Alberta pipeline *(FR_PMINYR, FR_PVOL, FR_PCNSYR, FR_PPLNYR, FR_PEXPFAC, FR_PADDTAR, FR_PMINWPR, FR_PRISK, FR_PDRPFAC, FR_PTREAT, FR_PFUEL)*

End-Use Pricing Inputs

- Residential, commercial, industrial, and electric generator distributor tariffs *(OPTIND, OPTCOM, OPTRES, OPTELP, OPTELO, RECS_ALIGN, NUM_REGSHR, HHDD)*
- Intrastate and intraregional tariffs *(INTRAST_TAR, INTRAREG_TAR)*
- Historical city gate prices *(HCGPR)*

- State and Federal taxes, costs to dispense, and other compressed natural gas pricing and infrastructure development parameters *(STAX, FTAX, RETAIL_COST, NSTAT, TRN_DECL, MAX_CNG_BUILD, CNG_HRZ, CNG_WACC, CNG_BUILDCOST)*

Miscellaneous

- Network processing control variables *(MAXCYCLE, NOBLDYR,ALPHAFAC, GAMMAFAC, PSUP_DELTA, QSUP_DELTA, QSUP_SMALL, QSUP_WT, PCT_FLO, SHR_OPT, PCTADJSHR)*
- Miscellaneous control variables *(PKOPMON, NGDBGRPT, SHR_OPT, NOBLDYR)*
- STEO input data *(STEOYRS, STQGPTR, STQLPIN, STOGWPRNG, STPNGRS, STPNGIN, STPNGCM, STPNGEL, STOGPRSUP, NNETWITH, STDISCR, STENDCON, STSCAL_CAN, STINPUT_SCAL, STSCAL_PFUEL, STSCAL_LPLT, STSCAL_WPR, STSCAL_DISCR, STSCAL_SUPLM, STSCAL_NETSTR, STSCAL_FPR, STSCAL_IPR, STPHAS_YR, STLNGIMP)*

Model Outputs

Once a set of solution values are determined within the NGTDM, those values required by other modules of NEMS are passed accordingly. In addition, the NGTDM module results are presented in a series of internal and external reports, as outlined below.

Outputs to NEMS Modules

The NGTDM passes its solution values to different NEMS modules as follows:

- Pipeline fuel consumption and lease and plant fuel consumption by Census Division (to NEMS PROPER and REPORTS)
- Natural gas wellhead prices by Oil and Gas Supply Module region (to NEMS REPORTS, Oil and Gas Supply Module, and Petroleum Market Module)
- Core and noncore natural gas prices by sector and Census Division (to NEMS PROPER and REPORTS, and NEMS demand modules)
- Fraction of retail fueling stations that sell compressed natural gas (to Transportation Sector Module)
- Dry natural gas production and supplemental gas supplies by Oil and Gas Supply Module region (NEMS REPORTS and Oil and Gas Supply Module)
- Peak/off-peak, core/ noncore natural gas prices to electric generators by NGTDM/Electricity Market Module region (to NEMS PROPER and REPORTS and Electricity Market Module)
- Coal consumed, electricity generated, and CO2 produced in the process of converting coal into pipeline quality synthetic gas in newly constructed plants (to Coal Market Module, Electricity Market Module, and NEMS PROPER)
- Dry natural gas production by PADD region (to Petroleum Market Module)
- Nonassociated dry natural gas production by NGTDM/Oil and Gas Supply Module region (to NEMS REPORTS and Oil and Gas Supply Module)
- Natural gas imports, exports, and associated prices by border crossing (to NEMS REPORTS)

Internal Reports

The NGTDM produces reports designed to assist in the analysis of NGTDM model results. These reports are controlled with a user-defined variable (NGDBGRPT), include the following information, and are written to the indicated output file:

- Primary peak and off-peak flows, shares, and maximum constraints going into each node (NGOBAL)
- Historical and forecast values historically based factors applied in the module (NGOBENCH)
- Intermediate results from the Distributor Tariff Submodule (NGODTM)
- Intermediate results from the Pipeline Tariff Submodule (NGOPTM)
- Convergence tracking and error message report (NGOERR)
- Aggregate/average historical values for most model elements (NGOHIST)
- Node and arc level prices and quantities along the network by cycle (NGOTREE)

External Reports

In addition to the reports described above, the NGTDM produces external reports to support recurring publications. These reports contain the following information:

- Natural gas end-use prices and consumption levels by end-use sector, type of service (core and noncore), and Census Division (and for the United States)
- Natural gas used to in a gas-to-liquids conversion process in Alaska
- Natural gas wellhead prices and production levels by NGTDM region (and the average for the lower 48 States), including a price for the Henry Hub
- Natural gas end-use and city gate prices and margins
- Natural gas import and export volumes and import prices by source or destination
- Pipeline fuel consumption by NGTDM region (and for the United States)
- Natural gas pipeline capacity (entering and exiting a region) by NGTDM region and by Census Division
- Natural gas flows (entering and exiting a region) by NGTDM region and Census Division
- Natural gas pipeline capacity between NGTDM regions
- Natural gas flows between NGTDM regions
- Natural gas underground storage and pipeline capacity by NGTDM region
- Unaccounted for natural gas[96]

[96]Unaccounted for natural gas is a balancing item between the amount of natural gas consumed and the amount supplied. It includes reporting discrepancies, net storage withdrawals (in historical years), and differences due to convergence tolerance levels.

Appendix A. NGTDM Model Abstract

Model Name: Natural Gas Transmission and Distribution Module

Acronym: NGTDM

Title: Natural Gas Transmission and Distribution Module

Purpose: The NGTDM is the component of the National Energy Modeling System (NEMS) that represents the mid-term natural gas market. The purpose of the NGTDM is to derive natural gas supply and end-use prices and flow patterns for movements of natural gas through the regional interstate network. The prices and flow patterns are derived by obtaining a market equilibrium across the three main components of the natural gas market: the supply component, the demand component, and the transmission and distribution network that links them.

Status: ACTIVE

Use: BASIC

Sponsor:

- Office of Energy Analysis
- Office of Petroleum, Gas, and Biofuels Analysis, EI-33
- Model Contact: Joe Benneche
- Telephone: (202) 586-6132

Documentation: Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, June 2011).

Previous Documentation: Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, June 2010).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, June 2009).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, January 2009).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, October 2007).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, August 2006).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, May 2005).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, March 2004)

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, May 2003)

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, January 2002).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, January 2001).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, January 2000).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, February 1999).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National*

Energy Modeling System (NEMS), DOE/EIA-M062/1 (Washington, DC, December 1997).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062/1 (Washington, DC, December 1996).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062/1 (Washington, DC, December 1995).

Energy Information Administration, *Model Documentation, Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System, Volume II: Model Developer's Report*, DOE/EIA-M062/2 (Washington, DC, January 1995).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062/1 (Washington, DC, February 1995).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062/1 (Washington, DC, February 1994).

Reviews Conducted:

Paul R. Carpenter, PhD, The Brattle Group. "Draft Review of Final Design Proposal Seasonal/North American Natural Gas Transmission Model." Cambridge, MA, August 15, 1996.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Natural Gas Annual Flow Module (AFM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, Aug 25, 1992.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Capacity Expansion Module (CEM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, Apr 30, 1993.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Pipeline Tariff Module (PTM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, Apr 30, 1993.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Distributor Tariff Module (DTM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, Apr 30, 1993.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Final Review of the National Energy Modeling System (NEMS) Natural Gas Transmission and Distribution Model (NGTDM)." Boston, MA, Jan 4, 1995.

Archival: The NGTDM is archived as a component of the NEMS on compact disc storage compatible with the PC multiprocessor computing platform upon completion of the NEMS production runs to generate the *Annual Energy Outlook 2011*, DOE/EIA-0383(2011). The archive package can be downloaded from ftp://ftp.eia.doe.gov/pub/forecasts/aeo.

Energy System Covered: The NGTDM models the U.S. natural gas transmission and distribution network that links the suppliers (including importers) and consumers of natural gas, and in so doing determines the regional market clearing natural gas end-use and supply (including border) prices.

Coverage: Geographic: Demand regions are the 12 NGTDM regions, which are based on the nine Census Divisions with Census Division 5 split further into South Atlantic and Florida, Census Division 8 split further into Mountain and Arizona/New Mexico, and Census Division 9 split further into California and Pacific with Alaska and Hawaii handled separately. Production is represented in the lower 48 at 17 onshore and 3 offshore regions. Import/export border crossings include three at the Mexican border, seven at the Canadian border, and 12 liquefied natural gas import terminals. In a separate component, potential liquefied natural gas production and liquefaction for U.S. import is represented for 14 international ports. A simplified Canadian representation is subdivided into an eastern and western region, with potential LNG import facilities on both shores. Consumption, production, and LNG imports to serve the Mexico gas market are largely assumption based and serve to set the level of exports to Mexico from the United States.

Time Unit/Frequency: Annually through 2035, including a peak (December through March) and off-peak forecast.

Product(s): Natural gas

Economic Sector(s): Residential, commercial, industrial, electric generators and transportation

Data Input Sources:

(Non-DOE)

- The Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU), Section 1113.
  — Federal vehicle natural gas (VNG) taxes

- Canadian Association of Petroleum Producers Statistical Handbook
  — Historical Canadian supply and consumption data
- Mineral Management Service.
  — Revenues and volumes for offshore production in Texas, California, and Louisiana
- Foster Pipeline and Storage Financial Cost Data
  — pipeline and storage financial data
- Data Resources Inc., U.S. Quarterly Model
  — Various macroeconomic data
- *Oil and Gas Journal*, "Pipeline Economics"
  — Pipeline annual capitalization and operating revenues
- Board of Governors of the Federal Reserve System Statistical Release, "Selected Interest Rates and Bond Prices"
  — Real average yield on 10 year U.S. government bonds
- Hart Energy Network's Motor Fuels Information Center at www.hartenergynetowrk.com/motorfuels/state/doc/glance/glnctax.htm
  — compressed natural gas vehicle taxes by state
- National Oceanic and Atmospheric Association
  — State level heating degree days
- U.S. Census
  — State level population data for heating degree day weights
- Natural Gas Week
  — Canada storage withdrawal and capacity data
- PEMEX Prospective de Gas Natural
  — Historical Mexico raw gas production by region
- Informes y Publicaciones, Anuario Estadísticas, Estadísticas Operativas, Producción de gas natural
  — Historical Mexico raw gas production by region
- Sener Prospectiva del Mercado de gas natural 2006-2015
  — Mexico LNG import projections

Data Input Sources:

(DOE) Forms and/or Publications:

- U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216.
  — Annual estimate of gas production for associated-dissolved and nonassociated categories by State/sub-state.
- Natural Gas Annual, DOE/EIA-0131.
  — By state -- natural gas consumption by sector, dry production, imports, exports, storage injections and withdrawals, balancing item, state transfers, number of residential customers, fraction of industrial market represented by historical prices, and wellhead, city gate, and end-use prices.
  — Supplemental supplies
- Natural Gas Monthly, DOE/EIA-0130.
  — By month and state – natural gas consumption by sector, marketed production, net storage withdrawals, end-use prices by sector, city gate prices

- — By month – quantity and price of imports and exports by country, wellhead prices, lease and plant consumption, pipeline consumption, supplemental supplies
- State Energy Data System (SEDS).
  - — State level annual delivered natural gas prices when not available in the Natural Gas Annual.
- Electric Power Monthly, DOE/EIA-0226.
  - — Monthly volume and price paid for natural gas by electric generators
- *Annual Energy Review*, DOE/EIA-0384
  - — Gross domestic product and implicit price deflator
- EIA-846, "Manufacturing Energy Consumption Survey"
  - — Base year average annual core industrial end-use prices
- *Short-Term Energy Outlook*, DOE/EIA-0131.
  - — National natural gas projections for first two years beyond history
  - — Historical natural gas prices at the Henry Hub
- Department of Energy, *Natural Gas Imports and Exports*, Office of Fossil Energy
  - — Import and export volumes and prices by border location
- Department of Energy, Alternate Fuels & Advanced Vehicles Data Center, including *Alternate Fuel Price Report*, Office of Energy Efficiency and Renewable Energy
  - — Sample of retail prices paid for compressed natural gas for vehicles
  - — State motor fuel taxes
- EIA-191, "Underground Gas Storage Report"
  - — Used in part to develop working gas storage capacity data
- EIA-457, "Residential Energy Consumption Survey"
  - — Number of residential natural gas customers
- International Energy Outlook, DOE/EIA-0484.
  - — Projection of natural gas consumption in Canada and Mexico.
- International Energy Annual, DOE/EIA-0484.
  - — Historical natural gas data on Canada and Mexico.

Models and other:

- National Energy Modeling System (NEMS)
  - — Domestic supply and demand representations are provided interactively as inputs to the NGTDM from other NEMS models
- International Natural Gas Model (INGM)
  - — Provides information for setting LNG supply curves exogenously in the NGTDM

General Output Descriptions:

- Average natural gas end-use prices levels by sector and region
- Average natural gas production volumes and prices by region
- Average natural gas import and export volumes and prices by region and type
- Pipeline fuel consumption by region
- Lease and plant fuel consumption by region

- Lease and plant fuel consumption by region
- Flow of gas between regions by peak and off-peak period
- Pipeline capacity additions and utilization levels by arc
- Storage capacity additions by region

Related Models: NEMS (part of)

Model Features:

- Model Structure: Modular; three major components: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS).
  - — ITS Integrating submodule of the NGTDM. Simulates the natural gas price determination process by bringing together all major economic and technological factors that influence regional natural gas trade in the United States. Determines natural gas production and imports, flows and prices, pipeline capacity expansion and utilization, storage capacity expansion and utilization for a simplified network representing the interstate natural gas pipeline system
  - — PTS Develops parameters for setting tariffs in the ITM for transportation and storage services provided by interstate pipeline companies
  - — DTS Develops markups for distribution services provided by LDC's and intrastate pipeline companies.

- Modeling Technique:
  - — ITS, Heuristic algorithm, operates iteratively until supply/demand convergence is realized across the network
  - — PTS, Econometric estimation and accounting algorithm
  - — DTS, Econometric estimation
  - — Canada and Mexico supplies based on a combination of estimated equations and basic assumptions.

Model Interfaces: NEMS

Computing Environment:

- Hardware Used: Personal Computer
- Operating System: UNIX simulation
- Language/Software Used: FORTRAN
- Storage Requirement: 2,700K bytes for input data storage; 1,100K bytes for source code storage; and 17,500K bytes for compiled code storage
- Estimated Run Time: Varies from NEMS iteration and from computer processor, but rarely exceeds a quarter of a second per iteration and generally is less than 5 hundredths of a second.

Status of Evaluation Efforts:

Model developer's report entitled "Natural Gas Transmission and Distribution Model, Model Developer's Report for the National Energy Modeling System," dated November 14, 1994.

Date of Last Update: January 2011.

Appendix B. References

Alaska Department of Natural Resources, Division of Oil and Gas, *Alaska Oil and Gas Report*, November 2009.

Carpenter, Paul R., "Review of the Gas Analysis Modeling System (GAMS), Final Report of Findings and Recommendations" (Boston: Incentives Research, Inc., August 1991).

Decision Focus Incorporate, *Generalized Equilibrium Modeling: The Methodology of the SRI-GULF Energy Model* (Palo Alto, CA, May 1977).

Energy Information Administration, "Analytical Framework for a Natural Gas Transmission and Distribution Forecasting System," prepared by SAIC for the Analysis and Forecasting Branch within the Reserves and Natural Gas Division of the Office of Oil and Gas (Washington, DC, March 1991).

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Energy Information Administration, Office of Integrated Analysis and Forecasting, "Component Design Report, Capacity Expansion Module for the Natural Gas Transmission and Distribution Model of the National Energy Modeling System" (Washington, DC, December 29, 1992).

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Energy Information Administration, *Natural Gas 1994: Issues and Trends* DOE/EIA-0560(94) (Washington, DC, July 1994).

Energy Information Administration, *Natural Gas 1995: Issues and Trends* DOE/EIA-0560(95) (Washington, DC, November 1995).

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Energy Information Administration, Office of Integrated Analysis and Forecasting, "Requirements for a National Energy Modeling System," (Working Paper) (Washington, DC, May 1992).

Forbes, Kevin, Science Applications International Corporation, "Efficiency in the Natural Gas Industry," Task 93-095 Deliverable under Contract No. DE-AC01-92-EI21944 for Natural Gas Analysis Branch of the Energy Information Administration, January 31, 1995.

Foster's Associates Inc., *Foster financial report of 28 Major Interstate Natural Gas Pipelines, 1996*.

Gas Technology Institute, "Liquefied Natural Gas (LNG) Methodology Enhancements in NEMS," report submitted to Energy Information Administration, March 2003.

Interstate Natural Gas Association of America (INGAA), "Availability, Economics & Production Potential of North American Unconventional Natural Gas Supplies," November 2008, written by ICF.

National Energy Board, *Canada's Energy Future: Scenarios for Supply and Demand to 2025*, 2003

Oil and Gas Journal, "Pipeline Economics," published annually in various editions.

Woolridge, Jeffrey M., Introductory Econometrics: A Modern Approach, South-Western College Publishing, 2000.

Appendix C. NEMS Model Documentation Reports

The National Energy Modeling System is documented in a series of 15 model documentation reports, most of which are updated on an annual basis. Copies of these reports are available by contacting the National Energy Information Center, 202/586-8800.

Energy Information Administration, *National Energy Modeling System Integrating Module Documentation Report*, DOE/EIA-M057.

Energy Information Administration, *Model Documentation Report: Macroeconomic Activity Module of the National Energy Modeling System*.

Energy Information Administration, *Documentation of the D.R.I. Model of the U.S. Economy*.

Energy Information Administration, *National Energy Modeling System International Energy Model Documentation Report*.

Energy Information Administration, *World Oil Refining, Logistics, and Demand Model Documentation Report*.

Energy Information Administration, *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation Report: Transportation Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Documentation of the Electricity Market Module*.

Energy Information Administration, *Documentation of the Oil and Gas Supply Module*.

Energy Information Administration, *EIA Model Documentation: Petroleum Market Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation: Coal Market Module*.

Energy Information Administration, *Model Documentation Report: Renewable Fuels Module*.

Appendix D. Model Equations

This appendix presents the mapping of each equation (by equation number) in the documentation with the subroutine in the NGTDM code where the equation is used or referenced.

Chapter 2 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
1	NGDMD_CRVF* (core), NGDMD_CRVI* (noncore)
2-19	NGSUP_PR*
20-25	NGOUT_CAN
26-39	NGCAN_FXADJ
40	NGOUT_MEX
41	NGSETLNG_INGM
42-54	NGTDM_DMDALK

Chapter 4 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
55, 58	NGSET_NODEDMD, NGDOWN_TREE
56, 59	NGSET_NODECDMD
57, 60	NGSET_YEARCDMD
61, 62	NGDOWN_TREE
63	NGSET_INTRAFLO
64	NGSET_INTRAFLO
65	NGSHR_CALC
66	NGDOWN_TREE
67	NGSET_MAXFLO*
68-71	NGSET_MAXPCAP
72-76	NGSET_MAXFLO*
77-79	NGSET_ACTPCAP
80-81	NGSHR_MTHCHK
82-85	NGSET_SUPPR
86-87	NGSTEO_BENCHWPR
88	NGSTEO_BENCHWPR
89-90	NGSET_ARCFEE

91-94	NGUP_TREE
95	NGSET_STORPR
96-97	NGUP_TREE
98	NGCHK_CONVNG
99	NGSET_SECPR
100	NGSET_BENCH, HNGSET_CGPR
101-106	NGSET_SECPR

Chapter 5 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
107-118	NGDTM_FORECAST_DTARF
119-120	NGDTM_FORECAST_TRNF
121-126	NGTDM_CNGBUILD

Chapter 6 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
127-132, 136-154, 203-205	NGPREAD
133-135, 155-156	NGPIPREAD
176-194, 206, 208-221	NGPSET_PLCOS_COMPONENTS
157-166, 172, 207, 222-231, 238	NGPSET_PLINE_COSTS
167-171, 232-237, 238-243	NGPIPE_VARTAR*
251-253	NGSTREAD
244-250, 254-256, 260-287	NGPSET_STCOS_COMPONENTS
257-259	NGPST_DEVCONST
173-175, 288-292	X1NGSTR_VARTAR*
195-202	(accounting relationships, not part of code)
293-205	NGFRPIPE_TAR*

Appendix E. Model Input Variable Mapped to Data Input Files

This appendix provides a list of the FORTRAN variables, and their associated input files, that are assigned values through FORTRAN READ statements in the source code of the NGTDM. Information about all of these variables and their assigned values (including sources, derivations, units, and definitions) are provided in the indicated input files of the NGTDM. The data file names and versions used for the *AEO2011* are identified below. These files are located on the EIA NEMS-F8 NT server. Electronic copies of these input files are available as part of the NEMS2011 archive package. The archive package can be downloaded from ftp://ftp.eia.doe.gov/pub/forecasts/aeo. In addition, the files are available upon request from Joe Benneche at (202) 586-6132 or Joseph.Benneche@eia.doe.gov.

ngcan.txt	V1.68	nghismn.txt	V1.30	ngptar.txt	V1.26
ngcap.txt	V1.32	nglngdat.txt	V1.79	nguser.txt	V1.150
ngdtar.txt	V1.38	ngmap.txt	V1.7		
nghisan.txt	V1.35	ngmisc.txt	V1.155		

Variable	File
ACTPCAP	NGCAN
ACTPCAP	NGCAP
ADDYR	NGCAP
ADJ_PIP	NGPTAR
ADJ_STR	NGPTAR
ADW	NGHISAN
AFR_CMEN	NGPTAR
AFR_DDA	NGPTAR
AFR_DIT	NGPTAR
AFR_FSIT	NGPTAR
AFR_LTDN	NGPTAR
AFR_OTTAX	NGPTAR
AFR_PFEN	NGPTAR
AFR_TOM	NGPTAR
AFX_CMEN	NGPTAR
AFX_DDA	NGPTAR
AFX_DIT	NGPTAR
AFX_FSIT	NGPTAR
AFX_LTDN	NGPTAR
AFX_OTTAX	NGPTAR
AFX_PFEN	NGPTAR
AFX_TOM	NGPTAR
AK_C	NGMISC
AK_CM	NGMISC
AK_CN	NGMISC
AK_D	NGMISC
AK_E	NGMISC
AK_EM	NGMISC
AK_ENDCONS_N	NGMISC
AK_F	NGMISC
AK_G	NGMISC
AK_HDD	NGMISC
AK_IN	NGMISC
AK_PCTLSE	NGMISC
AK_PCTPIP	NGMISC
AK_PCTPLT	NGMISC
AK_POP	NGMISC
AK_QIND_S	NGMISC
AK_RM	NGMISC
AK_RN	NGMISC
AKPIP1	NGMISC
AKPIP2	NGMISC
AL_ADJ	NGHISAN
AL_OFFD	NGHISAN
AL_OFST	NGHISAN
AL_OFST2	NGHISAN
AL_ONSH	NGHISAN
AL_ONSH2	NGHISAN
ALB_TO_L48	NGMISC
ALNGA	NGLNGDAT
ALNGB	NGLNGDAT
ALPHA_PIPE	NGPTAR
ALPHA_STR	NGPTAR
ALPHA2_PIPE	NGPTAR
ALPHA2_STR	NGPTAR
ALPHAFAC	NGUSER

Variable	File
ANUM	NGMAP
ARC_FIXTAR	NGCAN
ARC_VARTAR	NGCAN
AVGCOST	NGPTAR
AVR_CMEN	NGPTAR
AVR_DDA	NGPTAR
AVR_DIT	NGPTAR
AVR_FSIT	NGPTAR
AVR_LTDN	NGPTAR
AVR_OTTAX	NGPTAR
AVR_PFEN	NGPTAR
AVR_TOM	NGPTAR
BA_PREM	NGMISC
BAJA_CAP	NGMISC
BAJA_FIX	NGMISC
BAJA_LAG	NGMISC
BAJA_MAX	NGMISC
BAJA_PRC	NGMISC
BAJA_STAGE	NGMISC
BAJA_STEP	NGMISC
BEQ_BLDAVG	NGMISC
BEQ_BLDHRSK	NGMISC
BEQ_OPRAVG	NGMISC
BEQ_OPRHRSK	NGMISC
BNEWCAP_2003_2004	NGPTAR
BNEWCAP_POST2004	NGPTAR
BNEWCAP_PRE2003	NGPTAR
BPPRC	NGCAN
BPPRCGR	NGCAN
CAN_XMAPCN	NGMAP
CAN_XMAPUS	NGMAP
CANEXP	NGCAN
CM_ADJ	NGDTAR
CM_ALP	NGDTAR
CM_LNQ	NGDTAR
CM_PKALP	NGDTAR
CM_RHO	NGDTAR
CN_DMD	NGCAN
CN_FIXSHR	NGCAN
CN_FIXSUP	NGCAN
CN_OILSND	NGCAN
CN_UNPRC	NGCAN
CN_WOP	NGCAN
CNCAPSW	NGUSER
CNG_BUILDCOST	NGDTAR
CNG_HRZ	NGDTAR
CNG_MARKUP	NGDTAR
CNG_RETAIL_MARKUP	NGDTAR
CNG_WACC	NGDTAR
CNPER_YROPEN	NGCAP
CNPLANYR	NGCAN
CON	NGHISMN
CON_ELCD	NGHISMN
CON_EPMGR	NGHISMN
CONNOL_ELAS	NGCAN

Variable	File	Variable	File
CTG_BASCGG	NGMISC	D_DIT	NGPTAR
CTG_BASCGGCO2	NGMISC	D_FLO	NGPTAR
CTG_BASCGS	NGMISC	D_FSIT	NGPTAR
CTG_BASCGSCO2	NGMISC	D_GCMES	NGPTAR
CTG_BASCOL	NGMISC	D_GLTDS	NGPTAR
CTG_BASHHV	NGMISC	D_GPFES	NGPTAR
CTG_BASSIZ	NGMISC	D_GPIS	NGPTAR
CTG_BCLTON	NGMISC	D_GPIS	NGPTAR
CTG_BLDX	NGMISC	D_LTDN	NGPTAR
CTG_BLDX	NGMISC	D_LTDR	NGPTAR
CTG_BLDYRS	NGMISC	D_LTDR	NGPTAR
CTG_CAPYR$	NGMISC	D_LTDS	NGPTAR
CTG_CO2	NGMISC	DMAP	NGMAP
CTG_DCLCAPCST	NGMISC	D_MXPKFLO	NGPTAR
CTG_DCLOPRCST	NGMISC	D_NPIS	NGPTAR
CTG_FSTYR	NGMISC	D_NPIS	NGPTAR
CTG_IINDX	NGMISC	D_OTTAX	NGPTAR
CTG_INCBLD	NGMISC	D_OTTAX	NGPTAR
CTG_INVLOC	NGMISC	D_PFEN	NGPTAR
CTG_NAM	NGMISC	D_PFER	NGPTAR
CTG_NCL	NGMISC	D_PFER	NGPTAR
CTG_OH_LCFAC	NGMISC	D_PFES	NGPTAR
CTG_OSBLFAC	NGMISC	D_TCAP	NGPTAR
CTG_PCTCNTG	NGMISC	D_TOM	NGPTAR
CTG_PCTENV	NGMISC	D_TOM	NGPTAR
CTG_PCTLND	NGMISC	D_WCAP	NGPTAR
CTG_PCTSPECL	NGMISC	DDA_NEWCAP	NGPTAR
CTG_PCTWC	NGMISC	DDA_NPIS	NGPTAR
CTG_PRJLIFE	NGMISC	DECL_GASREQ	NGCAN
CTG_PUCAP	NGMISC	DEXP_FRMEX	NGMISC
CTG_SINVST	NGMISC	DFAC_TOMEX	NGMISC
CTG_STAFF_LCFAC	NGMISC	DFR	NGCAN
CWC_DISC	NGPTAR	DFR	NGCAN
CWC_K	NGPTAR	DMASP	NGCAN
CWC_RHO	NGPTAR	DMASP	NGCAN
CWC_TOM	NGPTAR	EL_ALP	NGDTAR
D_ADDA	NGPTAR	EL_CNST	NGDTAR
D_ADDA	NGPTAR	EL_PARM	NGDTAR
D_ADIT	NGPTAR	EL_RESID	NGDTAR
D_ADIT	NGPTAR	EL_RHO	NGDTAR
D_APRB	NGPTAR	ELE_GFAC	NGMISC
D_APRB	NGPTAR	EMMSUB_EL	NGMAP
D_CMEN	NGPTAR	EMMSUB_NG	NGMAP
D_CMER	NGPTAR	EMRP_BLDAVG	NGMISC
D_CMER	NGPTAR	EMRP_BLDHRSK	NGMISC
D_CMES	NGPTAR	EMRP_OPRAVG	NGMISC
D_CONST	NGPTAR	EMRP_OPRHRSK	NGMISC
D_CONST	NGPTAR	EQUITY_BLDAVG	NGMISC
D_CONST	NGPTAR	EQUITY_BLDHRSK	NGMISC
D_CONST	NGPTAR	EQUITY_OPRAVG	NGMISC
D_CWC	NGPTAR	EQUITY_OPRHRSK	NGMISC
D_CWC	NGPTAR	EXP_A	NGPTAR
D_DDA	NGPTAR	EXP_B	NGPTAR
D_DDA	NGPTAR	EXP_C	NGPTAR
D_DIT	NGPTAR	EXP_FRMEX	NGMISC

Variable	File	Variable	File
FDGOM	NGHISMN	HELE_SHR	NGMISC
FDIFF	NGDTAR	HFAC_GPIS	NGPTAR
FE_CCOST	NGMISC	HFAC_REV	NGPTAR
FE_EXPFAC	NGMISC	HHDD	NGDTAR
FE_FR_TOM	NGMISC	HI_RN	NGMISC
FE_PFUEL_FAC	NGMISC	HIND_SHR	NGMISC
FE_R_STTOM	NGMISC	HISTRESCAN	NGCAN
FE_R_TOM	NGMISC	HISTWELCAN	NGCAN
FE_STCCOST	NGMISC	HNETINJ	NGCAN
FE_STEXPFAC	NGMISC	HNETWTH	NGCAN
FEDTAX_RT	NGMISC	HNETWTH	NGHISMN
FIXLNGFLG	NGMAP	HPEMEX_SHR	NGMISC
FLO_THRU_IN	NGCAN	HPIMP	NGHISAN
FMASP	NGCAN	HPKSHR_FLOW	NGMISC
FMASP	NGCAN	HPKUTZ	NGCAP
FR_AVGTARYR	NGMISC	HPRC	NGHISMN
FR_BETA	NGMISC	HPSUP	NGCAN
FR_CAPITL0	NGMISC	HQIMP	NGHISAN
FR_CAPYR	NGMISC	HQSUP	NGCAN
FR_DEBTRATIO	NGMISC	HQTY	NGHISMN
FR_DISCRT	NGMISC	HRC_SHR	NGMISC
FR_ESTNYR	NGMISC	HW_ADJ	NGDTAR
FR_OTXR	NGMISC	HW_BETA0	NGDTAR
FR_PADDTAR	NGMISC	HW_BETA1	NGDTAR
FR_PCNSYR	NGMISC	HW_RHO	NGDTAR
FR_PDRPFAC	NGMISC	HYEAR	NGHISAN
FR_PEXPFAC	NGMISC	ICNBYR	NGCAN
FR_PFUEL	NGMISC	IEA_CON	NGMISC
FR_PMINWPR	NGMISC	IEA_PRD	NGMISC
FR_PMINYR	NGMISC	IMASP	NGCAN
FR_PPLNYR	NGMISC	IMASP	NGCAN
FR_PRISK	NGMISC	IMP_TOMEX	NGMISC
FR_PTREAT	NGMISC	IN_ALP	NGDTAR
FR_PVOL	NGMISC	IN_CNST	NGDTAR
FR_ROR_PREM	NGMISC	IN_DIST	NGDTAR
FR_TOM0	NGMISC	IN_LNQ	NGDTAR
FR_TXR	NGMISC	IN_PKALP	NGDTAR
FRATE	NGPTAR	IN_RHO	NGDTAR
FREE_YRS	NGDTAR	IND_GFAC	NGMISC
FRMETH	NGCAN	INFL_RT	NGMISC
FSRGN	NGMAP	INIT_GASREQ	NGCAN
FSTYR_GOM	NGHISAN	INS_FAC	NGMISC
FTAX	NGDTAR	INTRAREG_TAR	NGDTAR
FUTWTS	NGMISC	INTRAST_TAR	NGDTAR
GAMMAFAC	NGUSER	IPR	NGCAN
GDP_B87	NGMISC	IRES	NGCAN
GOF_AL	NGHISAN	IRG	NGCAN
GOF_CA	NGHISAN	IRIGA	NGCAN
GOF_LA	NGHISAN	IRIGA	NGCAN
GOF_TX	NGHISAN	JNETWTH	NGHISMN
HAFLOW	NGMISC	LA_OFFD	NGHISAN
HCG_BENCH	NGDTAR	LA_OFST	NGHISAN
HCGPR	NGHISAN	LA_ONSH	NGHISAN
HCUMSUCWEL	NGCAN	LABORLOC	NGMISC
HDYWHTLAG	NGDTAR	LEVELYRS	NGPTAR

Variable	File	Variable	File
LNG_XMAP	NGMAP	NGDBGRPT	NGUSER
LNGA	NGLNGDAT	NIND_SHR	NGMISC
LNGB	NGLNGDAT	NINJ_TOT	NGHISMN
LNGCAP	NGLNGDAT	NLNGA	NGLNGDAT
LNGCRVOPT	NGLNGDAT	NLNGB	NGLNGDAT
LNGDATA	NGMISC	NLNGPTS	NGLNGDAT
LNGDIF_GULF	NGLNGDAT	NNETWITH	NGUSER
LNGDIFF	NGMISC	NOBLDYR	NGUSER
LNGFIX	NGLNGDAT	NODE_ANGTS	NGMAP
LNGMIN	NGLNGDAT	NODE_SNGCOAL	NGMAP
LNGPPT	NGLNGDAT	NONU_ELAS_F	NGDTAR
LNGPS	NGLNGDAT	NONU_ELAS_I	NGDTAR
LNGQPT	NGLNGDAT	NPEMEX_SHR	NGMISC
LNGQS	NGLNGDAT	NPROC	NGMAP
LNGTAR	NGLNGDAT	NQPF_TOT	NGHISMN
LSTYR_MMS	NGHISAN	NRC_SHR	NGMISC
MAINT_FAC	NGMISC	NRCI_INV	NGMISC
MAP_NG	NGMAP	NRCI_LABOR	NGMISC
MAP_NRG_CRG	NGDTAR	NRCI_OPER	NGMISC
MAP_OG	NGMAP	NSRGN	NGMAP
MAP_PRDST	NGHISMN	NSTAT	NGDTAR
MAP_STSUB	NGHISAN	NSTSTOR	NGHISMN
MAPLNG_NEW	NGMAP	NSUPLM_TOT	NGHISMN
MAPLNG_NG	NGMAP	NUM_REGSHR	NGDTAR
MAX_CNG_BUILD	NGDTAR	NUMRS	NGDTAR
MAXCYCLE	NGUSER	NWTH_TOT	NGHISMN
MAXPLNG	NGLNGDAT	NYR_MISS	NGHISAN
MAXPRRFAC	NGMISC	OCSMAP	NGMAP
MAXPRRNG	NGMISC	oEL_MRKUP_BETA	NGDTAR
MAXUTZ	NGCAP	oEL_MRKUP_BETA	NGDTAR
MBAJA	NGMISC	OEQGCELGR	NGMISC
MDPIP1	NGMISC	OEQGFELGR	NGMISC
MDPIP2	NGMISC	OEQGIELGR	NGMISC
MEX_XMAP	NGMAP	OF_LAST	NGHISAN
MEX_XMAP	NGMAP	OOGHHPRNG	NGMISC
MEXEXP_SHR	NGMISC	OOGQNGEXP	NGMISC
MEXIMP_SHR	NGMISC	OPPK	NGCAP
MEXLNG	NGMISC	OPTCOM	NGDTAR
MEXLNGMIN	NGLNGDAT	OPTELO	NGDTAR
MISC_GAS	NGHISAN	OPTELP	NGDTAR
MISC_OIL	NGHISAN	OPTIND	NGDTAR
MISC_ST	NGHISAN	OPTRES	NGDTAR
MON_PEXP	NGHISMN	OQGCELGR	NGMISC
MON_PIMP	NGHISMN	OQGFEL	NGMISC
MON_QEXP	NGHISMN	OQGFELGR	NGMISC
MON_QIMP	NGHISMN	OQGIEL	NGMISC
MONMKT_PRD	NGHISMN	OQGIELGR	NGMISC
MSPLIT_STSUB	NGHISAN	OQNGEL	NGMISC
MUFAC	NGUSER	OSQGFELGR	NGMISC
NAW	NGHISAN	OSQGIELGR	NGMISC
NCNMX	NGCAN	OTH_FAC	NGMISC
NELE_SHR	NGMISC	PARM_LNGCRV3	NGLNGDAT
NG_CENMAP	NGMAP	PARM_LNGCRV5	NGLNGDAT
NGCFEL	NGHISMN	PARM_LNGELAS	NGLNGDAT
NGDBGCNTL	NGUSER	PARM_MINPR	NGUSER

Variable	File	Variable	File
PARM_SUPCRV3	NGUSER	QOF_GM	NGHISAN
PARM_SUPCRV5	NGUSER	QOF_LA	NGHISAN
PARM_SUPELAS	NGUSER	QOF_LAFD	NGHISAN
PCLADJ	NGMISC	QOF_MS	NGHISAN
PCNT_R	NGPTAR	QOF_TX	NGHISAN
PCT_AL	NGHISAN	QSUP_DELTA	NGUSER
PCT_LA	NGHISAN	QSUP_SMALL	NGUSER
PCT_MS	NGHISAN	QSUP_WT	NGUSER
PCT_TX	NGHISAN	RC_GFAC	NGMISC
PCTADJSHR	NGUSER	RECS_ALIGN	NGDTAR
PCTFLO	NGUSER	RESBASE	NGCAN
PEAK	NGCAP	RESBASYR	NGCAN
PEMEX_GFAC	NGMISC	RESTECH	NGCAN
PEMEX_PRD	NGMISC	RETAIL_COST	NGDTAR
PER_YROPEN	NGCAP	REV	NGHISMN
PERFDTX	NGHISAN	RGRWTH	NGCAN
PERMG	NGDTAR	RGRWTH	NGCAN
PIPE_FACTOR	NGPTAR	ROF_AL	NGHISAN
PKOPMON	NGMISC	ROF_CA	NGHISAN
PKSHR_CDMD	NGCAN	ROF_GM	NGHISAN
PKSHR_PROD	NGCAN	ROF_LA	NGHISAN
PLANPCAP	NGCAP	ROF_MS	NGHISAN
PLANPCAP	NGCAP	ROF_TX	NGHISAN
PMMMAP_NG	NGMAP	RS_ADJ	NGDTAR
PNGIMP	NGLNGDAT	RS_ALP	NGDTAR
PRAT	NGCAN	RS_COST	NGDTAR
PRAT	NGCAN	RS_LNQ	NGDTAR
PRC_EPMCD	NGHISMN	RS_PARM	NGDTAR
PRC_EPMGR	NGHISMN	RS_PKALP	NGDTAR
PRCWTS	NGMISC	RS_RHO	NGDTAR
PRCWTS2	NGMISC	SCEN_DIV	NGHISAN
PRD_GFAC	NGMISC	SCH_ID	NGHISAN
PRD_MLHIS	NGHISMN	SELE_SHR	NGMISC
PRICE_AL	NGHISAN	SHR_OPT	NGUSER
PRICE_CA	NGHISAN	SIM_EX	NGHISAN
PRICE_LA	NGHISAN	SIND_SHR	NGMISC
PRICE_TX	NGHISAN	SITM_RG	NGHISAN
PRJSDECOM	NGMISC	SNG_EM	NGHISAN
PRMETH	NGCAN	SNG_OG	NGHISAN
PROC_ORD	NGMAP	SNGCOAL	NGHISAN
PSUP_DELTA	NGUSER	SNGCOAL	NGMISC
PTCURPCAP	NGCAP	SNGLIQ	NGHISAN
PTMAXPCAP	NGCAN	SPCNEWFAC	NGPTAR
PTMBYR	NGPTAR	SPCNODID	NGPTAR
PTMSTBYR	NGPTAR	SPCNODID	NGPTAR
PUTL_POW	NGHISAN	SPCNODN	NGPTAR
Q23TO3	NGCAN	SPCPNODBAS	NGPTAR
QAK_ALB	NGMISC	SPEMEX_SHR	NGMISC
QLP_LHIS	NGHISMN	SPIN_PER	NGHISAN
QMD_ALB	NGMISC	SRATE	NGPTAR
QNGIMP	NGLNGDAT	SRC_SHR	NGMISC
QOF_AL	NGHISAN	STADIT_ADIT	NGPTAR
QOF_ALFD	NGHISAN	STADIT_C	NGPTAR
QOF_ALST	NGHISAN	STADIT_NEWCAP	NGPTAR
QOF_CA	NGHISAN	STAX	NGDTAR

Variable	File	Variable	File
STCCOST_BETAREG	NGPTAR	STSTATE	NGHISMN
STCCOST_CREG	NGPTAR	STTAX_RT	NGMISC
STCWC_CREG	NGPTAR	STTOM_C	NGPTAR
STCWC_RHO	NGPTAR	STTOM_RHO	NGPTAR
STCWC_TOTCAP	NGPTAR	STTOM_WORKCAP	NGPTAR
STDDA_CREG	NGPTAR	STTOM_YR	NGPTAR
STDDA_NEWCAP	NGPTAR	SUPARRAY	NGMAP
STDDA_NPIS	NGPTAR	SUPCRV	NGUSER
STDISCR	NGUSER	SUPREG	NGMAP
STENDCON	NGUSER	SUPSUB_NG	NGMAP
STEOYRS	NGUSER	SUPSUB_OG	NGMAP
STEP_CN	NGCAN	SUPTYPE	NGMAP
STEP_MX	NGCAN	SUTZ	NGCAP
STLNGIMP	NGUSER	SUTZ	NGCAP
STLNGRG	NGUSER	TAX_FAC	NGMISC
STLNGRGN	NGUSER	TFD	NGDTAR
STLNGYR	NGUSER	TFDYR	NGDTAR
STLNGYRN	NGUSER	TOM_BYEAR	NGPTAR
STOGPRSUP	NGUSER	TOM_BYEAR_EIA	NGPTAR
STOGWPRNG	NGUSER	TOM_DEPSHR	NGPTAR
STPHAS_YR	NGUSER	TOM_GPIS1	NGPTAR
STPIN_FLG	NGUSER	TOM_K	NGPTAR
STPNGCM	NGUSER	TOM_RHO	NGPTAR
STPNGEL	NGUSER	TOM_YR	NGPTAR
STPNGIN	NGUSER	TRN_DECL	NGDTAR
STPNGRS	NGUSER	TTRNCAN	NGCAN
STQGPTR	NGUSER	URES	NGCAN
STQLPIN	NGUSER	URES	NGCAN
STR_EFF	NGPTAR	URG	NGCAN
STR_FACTOR	NGPTAR	URG	NGCAN
STRATIO	NGPTAR	UTIL_ELAS_F	NGDTAR
STSCAL_CAN	NGUSER	UTIL_ELAS_I	NGDTAR
STSCAL_DISCR	NGUSER	WHP_LHIS	NGHISMN
STSCAL_FPR	NGUSER	WLMETH	NGCAN
STSCAL_IPR	NGUSER	WPR4CAST_FLG	NGUSER
STSCAL_LPLT	NGUSER	XBLD	NGCAP
STSCAL_NETSTR	NGUSER	XBM_ISBL	NGMISC
STSCAL_PFUEL	NGUSER	XBM_LABOR	NGMISC
STSCAL_SUPLM	NGUSER	YDCL_GASREQ	NGCAN
STSCAL_WPR	NGUSER		

Appendix F. Derived Data

Table F1

Data: Parameter estimates for the Alaskan natural gas consumption equations for the residential and commercial sectors and the Alaskan natural gas wellhead price.

Author: Tony Radich, EIA, June 2007, reestimated by Margaret Leddy, EIA, July 2009

Source: *Natural Gas Annual*, DOE/EIA-0131.

Derivation: Annual data from 1974 through 2008 were transformed into logarithmic form, tested for unit roots, and examined for simple correlations. When originally estimated, heating degree day quantity was calculated using a five-year average, but was statistically insignificant in both the residential and commercial cases and dropped from the final estimations. Lags of dependent variables were added as needed to remove serial correlation from residuals. Heteroskedasticity-consistent standard error estimators were also used as needed.

Residential Natural Gas Consumption

The forecast equation for residential natural gas consumption is estimated below:

$$LN\_CONS\_RES = (\beta_0*(1-\beta_{-1}) + (\beta_1*(1-\beta_{-1})*LN\_RES\_CUST) + (\beta_{-1}*(LN\_CONS\_RES(-1)*1000)))/1000.$$

where,

LN_CONS_RES = natural log of Alaska residential natural gas consumption in MMcf

LN_RES_CUST = natural log of thousands of Alaska residential gas customers. See the forecast equation for Alaska residential gas customers in Table F2.

(-1) = first lag

All variables are annual from 1974 through 2008.

Regression Diagnostics and Parameters Estimates:

Dependent Variable: LN_CONS_RES
Method: Least Squares
Date: 07/03/07
Sample (adjusted): 1974 – 2008
Included observations: 35 after adjustments
Newey-West HAC Standard Errors & Covariance (lag truncation=3)

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
C	6.983794	0.608314	11.48058	0.0000	β_0
LN_RES_CUST	0.601932	0.136919	4.396257	0.0001	β_1
AR(-1)	0.364042	0.117856	3.088872	0.0041	β_{-1}

R-squared	0.788754	Mean dependent var	9.486861
Adjusted R-squared	0.775552	S.D. dependent var	0.329138
S.E. of regression	0.155932	Akaike info criterion	-0.79697
Sum squared resid	0.778077	Schwarz criterion	-0.66366
Log likelihood	16.94702	Hannan-Quinn criter.	-0.75095
F-statistic	59.74123	Durbin-Watson stat	1.957789
Prob(F-statistic)	0.00000		

The equation for the Alaska residential natural gas consumption translates into the following forecast equation in the code:

AKQTY_F(1) = (exp(6.983794 * (1 - 0.364042)) * (AK_RN(t))**(0.601932 * (1 - 0.364042)) * (PREV_AKQTY(1,t-1)*1000)** (0.364042))/1000.

where,

AKQTY_F(1) = residential Alaskan natural gas consumption, (Bcf)
PREV_AKQTY(1,t-1) = previous year's residential Alaskan natural gas consumption, (Bcf)
AK_RN(t) = residential consumers (thousands) at current year. See Table F2

Commercial Natural Gas Consumption

The forecast equation for commercial natural gas consumption is estimated below:

LN_CONS_COM = $(\beta_0*(1 - \beta_{-1}) + (\beta_1$*LN_COM_CUST) + $(-\beta_{-1}* \beta_1)$*LN_COM_CUST(-1) + $(\beta_{-1}*$ LN_CONS_COM(-1)*1000))/1000.

where,

LN_CONS_COM = natural log of Alaska commercial natural gas consumption in MMcf
LN_COM_CUST = natural log of thousands of Alaska commercial gas customers. See the forecast equation in Table F2.
(-1) = first lag

All variables are annual from 1974 through 2008.

Regression Diagnostics and Parameters Estimates:

Dependent Variable: LN_CONS_COM
Method: Least Squares
Date: 07/22/09 Time: 09:36
Sample (adjusted): 1974 2008
Included observations: 35 after adjustments
Convergence achieved after 9 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=3)

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
C	9.425307	0.229458	41.07648	0.0000	β_0
LN_COM_CUST	0.205020	0.115140	1.780615	0.0845	β_1
AR(1)	0.736334	0.092185	7.987556	0.0000	β_{-1}

R-squared	0.696834	Mean dependent var	9.885287
Adjusted R-squared	0.677886	S.D. dependent var	0.213360
S.E. of regression	0.121093	Akaike info criterion	-1.302700
Sum squared resid	0.469232	Schwarz criterion	-1.169385
Log likelihood	25.79725	Hannan-Quinn criter.	-1.256680
F-statistic	36.77630	Durbin-Watson stat	1.680652
Prob(F-statistic)	0.000000		

The equation in the code for the Alaska commercial natural gas consumption follows:

AKQTY_F(2) = (exp(9.425307 * (1 - 0.736334)) * (AK_CN(t)**(0.205020)) * (AK_CN(t-1)**(-0.736334 * 0.205020)) * (PREV_AKQTY(2,t-1)*1000.)**(0.736334)))/1000.

where,

AKQTY_F(2) = commercial Alaskan natural gas consumption, (Bcf)

PREV_AKQTY(2,t-1) = previous year's commercial Alaskan natural gas consumption, (Bcf)

AK_CN(t) = commercial consumers (thousands) at current year. See Table F2

Natural Gas Wellhead Price

The forecast equation for natural gas wellhead price is determined below:

$$\ln AK\_WPRC_t = \beta_{-1}*\ln AK\_WPRC_{t-1} + \beta_1*(1-\beta_{-1})*\ln IRAC87$$

Dependent Variable: LN_WELLHEAD_PRICE
Method: Least Squares
Date: 07/22/09 Time: 13:25
Sample (adjusted): 1974 2008
Included observations: 35 after adjustments
Convergence achieved after 6 iterations

	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
LN_IRAC87	0.280760	0.101743	2.759499	0.0094	β_1
AR(1)	0.934077	0.040455	23.08940	0.0000	β_{-1}

R-squared	0.881227	Mean dependent var	0.135244
Adjusted R-squared	0.877628	S.D. dependent var	0.540629
S.E. of regression	0.189122	Akaike info criterion	-0.437408
Sum squared resid	1.180310	Schwarz criterion	-0.348531
Log likelihood	9.654637	Hannan-Quinn criter.	-0.406727
Durbin-Watson stat	2.121742		

Inverted AR Roots .93

The forecast equation becomes:

$$AK\_WPRC_t = AK\_WPRC_{t-1}^{0.934077} * oIT\_WOP_{y,1}^{(0.280760*(1-0.934077))}$$

where,

AK_WPRC_t	=	average natural gas wellhead price (1987$/Mcf) in year t.
AK_F	=	Parameters for Alaskan natural gas wellhead price (Appendix E).
$oIT\_WOP_{y,1}$ or IRAC87	=	World oil price (International Refinery Acquisition Cost) (1987$/barrel)
t	=	year index

Data used in estimating parameters in Tables F1 and F2

	(mmcf) Res_Cons	(mmcf) Com_Con	1987$/Mcf Res_Price	1987$/Mcf Com_Price	1987$/Mcf Wellhead Price	Thousand Population	HDD, Alaska	Thousand Res_ Cust	Thousand Com_ Cust	(2000=1) GDP defl	87$/bbl IRAC	Mbbl oil_prod
1973	5024	12277	3.61	1.79	0.34	336.4	12865	23	3	0.3185	9.38	
1974	4163	13106	3.33	1.83	0.36	348.1	12655	22	4	0.3473	26.39	
1975	10393	14415	3.14	1.87	0.58	384.1	12391	25	4	0.38	26.83	
1976	10917	14191	3	1.89	0.71	409.8	11930	28	4	0.402	24.55	
1977	11282	14564	2.93	2.29	0.68	418	12521	30	5	0.4275	24.88	
1978	12166	15208	2.82	2.11	0.83	411.6	11400	33	5	0.4576	23.31	
1979	7313	15862	2.53	1.52	0.77	413.7	11149	36	6	0.4955	32.01	
1980	7917	16513	2.34	1.44	0.99	419.8	10765	37	6	0.5404	45.9	
1981	7904	16149	2.41	1.73	0.77	434.3	11248	40	6	0.5912	45.87	587337
1982	10554	24232	2.09	1.86	0.74	464.3	11669	48	7	0.6273	39.15	618910
1983	10434	24693	2.62	2.18	0.82	499.1	10587	55	8	0.6521	32.89	625527
1984	11833	24654	2.69	2.24	0.79	524	12161	63	10	0.6766	31.25	630401
1985	13256	20344	2.95	2.48	0.78	543.9	11237	65	10	0.6971	28.34	666233
1986	12091	20874	3.34	2.6	0.51	550.7	11398	66	11	0.7125	14.38	681310
1987	12256	20224	3.21	2.41	0.94	541.3	11704	67.648	11.484	0.732	18.13	715955
1988	12529	20842	3.35	2.51	1.23	535	11116	68.612	11.649	0.7569	14.08	738143
1989	13589	21738	3.38	2.39	1.27	538.9	10884	69.54	11.806	0.7856	16.85	683979
1990	14165	21622	3.4	2.36	1.24	553.17	11101	70.808	11.921	0.8159	19.52	647309
1991	13562	20897	3.62	2.51	1.28	569.05	11582	72.565	12.071	0.8444	16.21	656349
1992	14350	21299	3.21	2.24	1.19	586.72	11846	74.268	12.204	0.8639	15.42	627322
1993	13858	20003	3.28	2.3	1.18	596.91	11281	75.842	12.359	0.8838	13.37	577495
1994	14895	20698	2.92	2.01	1.03	600.62	11902	77.67	12.475	0.9026	12.58	568951
1995	15231	24979	2.88	1.8	1.3	601.58	10427	79.474	12.584	0.9211	13.62	541654
1996	16179	27315	2.67	1.81	1.26	605.21	11498	81.348	12.732	0.9385	16.1	509999
1997	15146	26908	2.89	1.87	1.4	609.66	11165	83.596	12.945	0.9541	14.22	472949
1998	15617	27079	2.78	1.83	1	617.08	11078	86.243	13.176	0.9647	9.14	428850
1999	17634	27667	2.72	1.63	1.02	622	12227	88.924	13.409	0.9787	12.91	383199
2000	15987	26485	2.62	1.51	1.29	627.53	10908	91.297	13.711	1	20.28	355199
2001	16818	15849	3.02	2.26	1.42	632.24	12227	93.896	14.002	1.024	15.73	351411
2002	16191	15691	3.1	2.4	1.5	640.54	10908	97.077	14.342	1.0419	16.66	359335
2003	16853	17270	3.02	2.46	1.66	647.75	10174	100.4	14.502	1.064	19.06	355582
2004	18200	18373	3.26	2.77	2.29	656.83	10296	104.36	13.999	1.0946	24.01	332465
2005	18029	16903	3.71	3.19	3.08	663.25	10103	108.4	14.12	1.13	31.65	315420
2006	20616	18544	4.29	2.98	3.64	670.05	11269	112.27	14.384	1.1657	37.06	270486
2007	19843	18756	5.31	4.63	3.44	668.74	10815	115.5	13.408	1.1966	41.01	263595
2008	21440	18717.5	5.21	4.73	3.88	671.31	11640	118	13	1.225	55.44	249874

Table F2

Data: Equations for the number of residential and commercial customers in Alaska

Author: Tony Radich, EIA, June, 2007 and Margaret Leddy, July 2009.

Source: *Natural Gas Annual* (1985-2000), DOE/EIA-0131, see Table F1.

Derivation:

a. Residential customers

Since 1967, the number of residential households has increased steadily, mirroring the population growth in Alaska. Because the current year's population is highly dependent on the previous year's value, the number of residential consumers was estimated based on its lag values. The forecast equation is determined as follows:

$$NRS_t = \beta_0 + \beta_{-1} * NRS_{t-1} + \beta_{-2} * NRS_{t-2} + \beta_1 * POP$$

where,

NRS = natural log of thousands of Alaska residential gas customers (AK_RN in code)
POP = natural log of Alaska population in thousands (AK_POP in code, Appendix E)
t = year

Regression Diagnostics and Parameters Estimates:

Dependent Variable: NRS
Method: Least Squares
Date: 07/03/07
Sample (adjusted): 1969-2005
Included observations: 37 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
C	-2.677338	0.946058	-2.829994	0.0079	β_0
NRS(-1)	0.887724	0.166407	5.334659	0.0000	β_{-1}
NRS(-2)	-0.184504	0.141213	-1.306569	0.2004	β_{-2}
POP	0.626436	0.201686	3.105990	0.0039	β_1

R-squared	0.995802	Mean dependent var	3.950822
Adjusted R-squared	0.995421	S.D. dependent var	0.602330
S.E. of regression	0.040760	Akaike info criterion	-3.460402
Sum squared resid	0.054827	Schwarz criterion	-3.286248
Log likelihood	68.01743	F-statistic	2609.424
Durbin-Watson stat	1.656152	Prob(F-statistic)	0.000000

This translates into the following forecast equation in the code:

$$AK\_RN_t = \exp[-2.677 + (0.888*\log(AK\_RN_{t-1})) - (0.185*\log(AK\_RN_{t-2})) + (0.626*\log(AK\_POP_t))]$$

b. Commercial customers

The number of commercial consumers, based on billing units, also showed a strong relationship to its lag value. The forecast equation was determined using data from 1985 to 2008 as follows:

$$COM\_CUST_t = \beta 0 + \beta_{-1} * COM\_CUST_{t-1}$$

where,

COM_CUST = number of Alaska commercial gas customers in year t, in thousands(AK_CM in the code)

t = year

Regression Diagnostics and Parameters Estimates:

Dependent Variable: COM_CUST
Method: Least Squares
07/14/09
Sample (adjusted): 1974-2008
Included observations: 35 after adjustments
Newey-West HAC Standard Errors & Covariance (lag truncation=3)

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
C	0.932946	0.294368	3.169323	0.0033	β_0
COM_CUST(-1)	0.937471	0.023830	39.33956	0.0000	β_{-1}

R-squared	0.982050	Mean dependent var	10.63666
Adjusted R-squared	0.981506	S.D. dependent var	3.534514
S.E. of regression	0.480669	Akaike info criterion	1.428171
Sum squared resid	7.624424	Schwarz criterion	1.517048
Log likelihood	-22.99300	Hannan-Quinn criter.	1.458852
F-statistic	1805.422	Durbin-Watson	1.859586
Prob(F-statistic)	0.000000		

This translates into the following forecast equation in the code:

$$AK\_CN_t = 0.932946 + (0.937471 * AK\_CN_{t-1})$$

Table F3

Data: Coefficients for the following Pipeline Tariff Submodule forecasting equations for pipeline and storage: total cash working capital for the combined existing and new capacity; depreciation, depletion, and amortization expenses for existing capacity; accumulated deferred income taxes for the combined existing and new capacity; and total operating and maintenance expense for the combined existing and new capacity.

Author: Science Applications International Corporation (SAIC)

Source: Foster Pipeline Financial Data, 1997-2006
Foster Storage Financial Data, 1990-1998

Variables:

For Transportation:

R_CWC	=	total pipeline transmission cash working capital for existing and new capacity (2005 real dollars)
DDA_E	=	annual depreciation, depletion, and amortization costs for existing capacity (nominal dollars)
NPIS_E	=	net plant in service for existing capacity in dollars (nominal dollars)
NEWCAP_E	=	change in existing gross plant in service (nominal dollars) between t and t-1 (set to zero during the forecast year phase since $GPIS\_E_{a,t}$ = $GPIS\_E_{a,t+1}$ for year t >= 2007)
ADIT	=	accumulated deferred income taxes (nominal dollars)
NEWCAP	=	change in gross plant in service between t and t-1 (nominal dollars)
R_TOM	=	total operating and maintenance cost for existing and new capacity (2005 real dollars)
GPIS	=	capital cost of plant in service for existing and new capacity (nominal dollars)
DEPSHR	=	level of the accumulated depreciation of the plant relative to the gross plant in service for existing and new capacity at the beginning of year t. This variable is a proxy for the age of the capital stock.
TECHYEAR	=	MODYEAR (time trend in Julian units, the minimum value of this variable in the sample being 1997, otherwise TECHYEAR=0 if less than 1997)
a	=	arc
t	=	forecast year

For Storage:

R_STCWC	=	total cash working capital at the beginning of year t for existing and new capacity (1996 real dollars)
DSTTCAP	=	total gas storage capacity (Bcf)
STDDA_E	=	annual depreciation, depletion, and amortization costs for existing capacity (nominal dollars)

STNPIS_E = net plant in service for existing capacity (nominal dollars)
STNEWCAP = change in gross plant in service for existing capacity (nominal dollars)
STADIT = accumulated deferred income taxes (nominal dollars)
NEWCAP = change in gross plant in service for the combined existing and new capacity between years t and t-1 (nominal dollars)
R_STTOM = total operating and maintenance cost for existing and new capacity (1996 real dollars)
DSTWCAP = level of gas working capacity for region r during year t (Bcf)
r = NGTDM region
t = forecast year

References: For transportation: "Memorandum describing the estimated and forecast equations for TOM, DDA, CWC, and ADIT for the new PTM," by SAIC, June 23-July 22, 2008.
For storage: "Memorandum describing the estimated and forecast equations for TOM, DDA, CWC, and ADIT for the new PTM," by SAIC, May 31, 2000.

Derivation: Estimations were done by using an accounting algorithm in combination with estimation software. Projections are based on a series of econometric equations which have been estimated using the Time Series Package (TSP) software. Equations were estimated by arc for pipelines and by NGTDM region for storage, as follows: total cash working capital for the combined existing and new capacity; depreciation, depletion, and amortization expenses for existing capacity; accumulated deferred income taxes for the combined existing and new capacity; and total operating and maintenance expense for the combined existing and new capacity. These equations are defined as follows:

(1) Total Cash Working Capital for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model.

Because of economies in cash management, a log-linear specification between total operating and maintenance expenses, R_TOM_a, and the level of cash working capital, R_CWC_a was assumed. To control for arc specific effects, a binary variable was created for each of the arcs. The associated coefficient represents the arc specific constant term.

The underlying notion of this equation is the working capital represents funds to maintain the capital stock and is therefore driven by changes in R_TOM

The forecasting equation is presented in two stages.

Stage 1:

$$\mathrm{Ln(R\_CWC_{a,t}) = CWC\_C_a * (1-\rho) + CWC\_TOM * Ln(R\_TOM_{a,t})} +$$
$$\mathrm{\rho * Ln(R\_CWC_{a,t-1}) - \rho * CWC\_TOM * Ln(R\_TOM_{a,t-1})}$$

Stage 2:

$$\mathrm{R\_CWC_{a,t} = CWC\_K * exp(Ln(R\_CWC_{a,t}))}$$

where,

R_CWC	=	total pipeline transmission cash working capital for existing and new capacity (2005 real dollars)
CWC_C_a	=	estimated arc specific constant for gas transported from node to node (see Table F3.2)
CWC_TOM	=	estimated R_TOM coefficient (see Table F3.2)
R_TOM	=	total operation and maintenance expenses in 2005 real dollars
CWC_K	=	correction factor estimated in stage 2 of the regression equation estimation process
ρ	=	autocorrelation coefficient from estimation (see Table F3.2 -- CWC_RHO)

Ln is a natural logarithm operator and CWC_K is the correction factor estimated in equation two.

The results of this regression are reported below:

Dependent variable: R_CWC
Number of observations: 396

Mean of dep. var.	= 18503.0	LM het. Test	= 135.638 [.000]
Std. dev. of dep. var.	= 283454.4	Durbin-Watson	= 2.29318 [<1.00]
Sum of squared residuals	= .116124E+11	Jarque-Bera test	= 6902.15 [.000]
Variance of residuals	= .293986E+08	Ramsey's RESET2	= .849453 [.357]
Std. error of regression	= 5422.05	Schwarz B.I.C.	= 3969.29
R-squared	= .963435	Log likelihood	= -3966.30
Adjusted R-squared	= .963435		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
CWC_K	1.01813	8.31E-03	122.551	[.000]

For Storage:

$$\mathrm{R\_STCWC_{r,t} = e^{(\beta_{0,r} * (1-\rho))} * DSTTCAP_{r,t-1}^{\beta_1}} *$$
$$\mathrm{R\_STCWC_{r,t-1}^{\rho} * DSTTCAP_{r,t-2}^{-\rho * \beta_1}}$$

where,

$\beta_{0,a}$	=	constant term estimated by region (see Table F3.1, $\beta_{0,r}$ = REG_r)
	=	STCWC_CREG (Appendix E)

β_1 = 1.07386
= STCWC_TOTCAP (Appendix E)
t-statistic = (2.8)
ρ = 0.668332
= STCWC_RHO (Appendix E)
t-statistic = (6.8)
DW = 1.53
R-Squared = 0.99

(2) Total Depreciation, Depletion, and Amortization for Existing Capacity

(a) existing capacity (up to 2000 for pipeline and up to 1998 for storage)

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. A linear specification was chosen given that DDA_E is generally believed to be proportional to the level of net plant. The forecasting equation was estimated with a correction for first order serial correlation.

$$\text{DDA\_E}_{a,t} = \text{DDA\_C}_a * \text{ARC}_a + \text{DDA\_NPIS} * \text{NPIS}_{a,t-1} + \text{DDA\_NEWCAP} * \text{NEWCAP\_E}_{a,t}$$

where,

DDA_C_a = constant term estimated by arc for the binary variable ARC_a (see Table F3.3, $\text{DDA\_C}_a = \text{B\_ARC}_{xx\_yy}$)
ARC_a = binary variable created for each arc to control for arc specific effects
DDA_NPIS = estimated coefficient (see Table F3.3)
DDA_NEWCAP = estimated coefficient (see Table F3.3)

The standard errors in Table F3.3 are computed from heteroscedastic-consistent matrix (Robust-White). The results of this regression are reported below:

Dependent variable: DDA_E
Number of observations: 446

Mean of dep. var.	= 25154.4	R-squared	= .995361
Std. dev. of dep. var.	= 33518.3	Adjusted R-squared	= .994761
Sum of squared residuals	= .231907E+10	LM het. Test	= 30.7086 [.000]
Variance of residuals	= .588597E+07	Durbin-Watson	= 2.06651 [<1.00]
Std. error of regression	= 2426.10		

For Storage:

$$\text{STDDA\_E}_{r,t} = \beta_{0,r} + \beta_1 * \text{STNPIS\_E}_{r,t-1} + \beta_2 * \text{STNEWCAP}_{r,t}$$

where,

$\beta_{0,a}$ = constant term estimated by region (see Table F3.4, $\beta_{0,r}$ = REG_r)
= STDDA_CREG (Appendix E)
β_1, β_2 = (0.032004, 0.028197)
= STDDA_NPIS, STDDA_NEWCAP (Appendix E)
t-statistic = (10.3) (16.9)
DW = 1.62
R-Squared = 0.97

(b) new capacity (generic pipelines and storage)

A regression equation is not used for the new capacity; instead, an accounting algorithm is used (presented in Chapter 6).

(3) Accumulated Deferred Income Taxes for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. To control for arc specific effects, a binary variable ARC_a was created for each of the arcs. The associated coefficient represents the arc specific constant term.

Because the level of deferred income taxes is a stock (and not a flow) it was hypothesized that a formulation that focused on the change in the level of accumulated deferred income taxes from the previous year, $deltaADIT_{a,t}$, would be appropriate. Specifically, a linear relationship between the change in ADIT and the change in the level of gross plant in service, $NEWCAP_{a,t}$, and the change in tax policy, POLICY_CHG, was assumed. The form of the estimating equation is:

$$\text{delta}\,ADIT_{a,t} = ADIT\_C_a * ARC_a + \beta_1 * NEWCAP_{a,t} + \beta_2 * NEWCAP_{a,t} + \beta_3 * NEWCAP_{a,t}$$

where,

$ADIT\_C_a$ = constant term estimated by arc for the binary variable ARC_a (see Table F3.5, $ADIT\_C_a$ = $B\_ARC_{xx\_yy}$)
β_1 = BNEWCAP_PRE2003, estimated coefficient on the change in gross plant in service in the pre-2003 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
β_2 = BNEWCAP_2003_2004, estimated coefficient on the change in gross plant in service for the years 2003 and 2004 because of changes in tax policy (Appendix F, Table F3.5). It is zero otherwise.
β_3 = BNEWCAP_POST2004, estimated coefficient on the change in gross plant in service in the post-2004 period because of changes in tax policy (Appendix F, Table F3.5). It is zero otherwise.

The estimation results are:

Dependent variable: DELTAADIT
Number of observations: 396

Mean of dep. var.	= 6493.50	R-squared	= .464802
Std. dev. of dep. var.	= 17140.8	Adjusted R-squared	= .383664
Sum of squared residuals	= .621120E+11	LM het. test	= 4.03824 [.044]
Variance of residuals	= .181084E+09	Durbin-Watson	= 2.44866 [<1.00]
Std. error of regression	= 13456.8		

For Storage:

$$STADIT_{r,t} = \beta_0 + \beta_1 * STADIT_{r,t-1} + \beta_2 * NEWCAP_{r,t}$$

where,

β_0	=	-212.535
	=	STADIT_C (Appendix E)
β_1, β_2	=	(0.921962, 0.212610)
	=	STADIT_ADIT, STADIT_NEWCAP (Appendix E)
t-statistic	=	(58.8) (8.4)
DW	=	1.69
R-Squared	=	0.98

(4) Total Operating and Maintenance Expense for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. To control for arc specific effects, a binary variable ARC_a was created for each of the arcs. The associated coefficient represents the arc specific constant term.

The forecasting equation is presented in two stages.

Stage 1:

$$\begin{aligned} Ln(R\_TOM_{a,t}) = {} & TOM\_C_a * ARC_a * (1-\rho) + TOM\_GPIS1 * Ln(GPIS_{a,t-1}) \\ & + TOM\_DEPSHR * DEPSHR_{a,t-1} + TOM\_BYEAR * 2006 \\ & + TOM\_BYEAR\_EIA * (TECHYEAR - 2006.0) + \rho * Ln(R\_TOM_{a,t-1}) \\ & - \rho * (TOM\_GPIS1 * Ln(GPIS_{a,t-2}) + TOM\_DESHR * DEPSHR_{a,t-2} \\ & + TOM\_BYEAR * 2006 + TOM\_BYEAR\_EIA * (TECHYEAR - 1 - 2006.0)) \end{aligned}$$

Stage 2:

$$R\_TOM_{a,t} = TOM\_K * \exp(Ln(R\_TOM_{a,t}))$$

where Ln is a natural logarithm operator and TOM_K is the correction factor estimated in equation two, and where,

TOM_C_a	=	constant term estimated by arc for the binary variable ARCa (see Table F3.6, TOM_Ca = B_ARCxx_yy)
ARC_a	=	binary variable created for each arc to control for arc specific effects
TOM_GPIS1	=	estimated coefficient (see Table F3.6)
TOM_DEPSHR	=	estimated coefficient (see Table F3.6)
TOM_BYEAR	=	estimated coefficient (see Table F3.6)
TOM_BYEAR_EIA	=	future rate of decline in R_TOM due to technology improvements and efficiency gains. EIA assumes that this rate is the same as TOM_BYEAR (see Table F3.6)
ρ	=	first-order autocorrelation, TOM_RHO (see Table F3.6)

The results of this regression are reported below:

Dependent variable: R_TOM
Number of observations: 396

Mean of dep. var.	= 52822.9	LM het. test	= 28.7074 [.000]
Std. dev. of dep. var.	= 76354.9	Durbin-Watson	= 2.01148 [<1.00]
Sum of squared residuals	= .668483E+11	Jarque-Bera test	= 13559.1 [.000]
Variance of residuals	= .169236E+09	Ramsey's RESET2	= 4.03086 [.045]
Std. error of regression	= 13009.1	Schwarz B.I.C.	= 4215.86
R-squared	= .971019	Log likelihood	= -4312.87
Adjusted R-squared	= .971019		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
TOM_K	0.940181	6.691E-03	140.504	[.000]

For Storage:

$$R\_STTOM_{r,t} = e^{(\beta_0 * (1-\rho))} * DSTWCAP_{r,t-1}^{\beta_1} * R\_STTOM_{r,t-1}^{\rho} * DSTWCAP_{r,t-2}^{-\rho * \beta_1}$$

where,

β_0	=	-6.6702
	=	STTOM_C (Appendix E)
β_1	=	1.44442
	=	STTOM_WORCAP (Appendix E)
t-statistic	=	(33.6)
ρ	=	0.761238
	=	STTOM_RHO (Appendix E)
t-statistic	=	(10.2)
DW	=	1.39
R-Squared	=	0.99

Table F3.1. Summary Statistics for Storage Total Cash Working Capital Equation

Variable	Coefficient	Standard Error	t-statistic
REG2	-2.30334	5.25413	-.438386
REG3	-1.51115	5.33882	-.283049
REG4	-2.11195	5.19899	-.406224
REG5	-2.07950	5.06766	-.410346
REG6	-1.24091	4.97239	-.249559
REG7	-1.63716	5.27950	-.310097
REG8	-2.48339	4.68793	-.529740
REG9	-3.23625	4.09158	-.790954
REG11	-2.15877	4.33364	-.498143

Table F3.2. Summary Statistics for Pipeline Total Cash Working Capital Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
CWC_TOM	0.381679	.062976	6.06073	[.000]
B_ARC01_01	4.83845	.644360	7.50892	[.000]
B_ARC02_01	5.19554	.644074	8.06668	[.000]
B_ARC02_02	6.37816	.781655	8.15982	[.000]
B_ARC02_03	4.38403	.594344	7.37625	[.000]
B_ARC02_05	5.02364	.684640	7.33764	[.000]
B_ARC03_02	5.51162	.651682	8.45754	[.000]
B_ARC03_03	6.10201	.772378	7.90028	[.000]
B_ARC03_04	4.10475	.572836	7.16566	[.000]
B_ARC03_05	4.69978	.665214	7.06507	[.000]
B_ARC03_15	4.99465	.600910	8.31180	[.000]
B_ARC04_03	5.56047	.718330	7.74083	[.000]
B_ARC04_04	6.15095	.783539	7.85021	[.000]
B_ARC04_07	4.26747	.590736	7.22400	[.000]
B_ARC04_08	4.12216	.611516	6.74089	[.000]
B_ARC05_02	5.50272	.732227	7.51505	[.000]
B_ARC05_03	4.93360	.667589	7.39018	[.000]
B_ARC05_05	6.03791	.774677	7.79409	[.000]
B_ARC05_06	3.27334	.516303	6.33995	[.000]
B_ARC06_03	5.80098	.714338	8.12078	[.000]
B_ARC06_05	5.76939	.741907	7.77644	[.000]
B_ARC06_06	6.73455	.807246	8.34262	[.000]
B_ARC06_07	3.52000	.555549	6.33606	[.000]
B_ARC06_10	4.64811	.665947	6.97970	[.000]
B_ARC07_04	5.60946	.732039	7.66279	[.000]
B_ARC07_06	6.35683	.778573	8.16471	[.000]
B_ARC07_07	6.81298	.828208	8.22616	[.000]
B_ARC07_08	3.60827	.543296	6.64144	[.000]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC07_11	5.89640	.708385	8.32373	[.000]
B_ARC07_21	4.85140	.621031	7.81185	[.000]
B_ARC08_04	4.94307	.678799	7.28208	[.000]
B_ARC08_07	3.97367	.579267	6.85982	[.000]
B_ARC08_08	5.58162	.723678	7.71286	[.000]
B_ARC08_09	5.19274	.635784	8.16746	[.000]
B_ARC08_11	5.12277	.637835	8.03148	[.000]
B_ARC08_12	4.29097	.593945	7.22452	[.000]
B_ARC09_08	4.10222	.576694	7.11333	[.000]
B_ARC09_09	5.44178	.684020	7.95558	[.000]
B_ARC09_12	4.96229	.600227	8.26735	[.000]
B_ARC09_20	2.63716	.448339	5.88207	[.000]
B_ARC11_07	5.58226	.687702	8.11726	[.000]
B_ARC11_08	4.36952	.548152	7.97137	[.000]
B_ARC11_11	6.13044	.728452	8.41571	[.000]
B_ARC11_12	5.93253	.710336	8.35173	[.000]
B_ARC11_22	4.33062	.545420	7.93998	[.000]
B_ARC15_02	5.09861	.583090	8.74412	[.000]
B_ARC16_04	5.03673	.592859	8.49567	[.000]
B_ARC17_04	4.17798	.576943	7.24158	[.000]
B_ARC19_09	5.14500	.618100	8.32389	[.000]
B_ARC20_09	4.58498	.624006	7.34766	[.000]
B_ARC21_07	4.26846	.563536	7.57441	[.000]
CWC_RHO	0.527389	.048379	10.9011	[.000]

Table F3.3. Summary Statistics for Pipeline Depreciation, Depletion, and Amortization Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
DDA_NEWCAP	.725948E-02	.200846E-02	3.61446	[.000]
DDA_NPIS	.023390	.103991E-02	22.4923	[.000]
B_ARC01_01	4699.58	862.825	5.44674	[.000]
B_ARC02_01	5081.37	853.478	5.95372	[.000]
B_ARC02_02	43769.1	1954.50	22.3940	[.000]
B_ARC02_03	2050.29	814.056	2.51861	[.012]
B_ARC02_05	7876.12	880.047	8.94965	[.000]
B_ARC03_02	5973.21	842.863	7.08681	[.000]
B_ARC03_03	33063.3	1489.77	22.1936	[.000]
B_ARC03_04	1032.74	809.439	1.27588	[.202]
B_ARC03_05	2386.89	845.864	2.82184	[.005]
B_ARC03_15	7652.92	864.810	8.84924	[.000]
B_ARC04_03	19729.5	1118.66	17.6368	[.000]
B_ARC04_04	35522.7	2267.45	15.6663	[.000]
B_ARC04_07	1919.97	811.222	2.36677	[.018]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC04_08	747.069	822.607	.908172	[.364]
B_ARC05_02	15678.2	1114.41	14.0686	[.000]
B_ARC05_03	6452.49	855.092	7.54596	[.000]
B_ARC05_05	45000.5	1771.82	25.3979	[.000]
B_ARC05_06	446.742	809.035	.552191	[.581]
B_ARC06_03	11967.8	942.879	12.6928	[.000]
B_ARC06_05	22576.3	1243.19	18.1599	[.000]
B_ARC06_06	67252.9	2892.23	23.2530	[.000]
B_ARC06_07	1134.14	809.115	1.40170	[.161]
B_ARC06_10	15821.4	989.531	15.9888	[.000]
B_ARC07_04	15041.4	984.735	15.2746	[.000]
B_ARC07_06	48087.6	1908.12	25.2015	[.000]
B_ARC07_07	80361.2	3384.54	23.7436	[.000]
B_ARC07_08	833.829	809.565	1.02997	[.303]
B_ARC07_11	4732.17	928.814	5.09486	[.000]
B_ARC07_21	1452.16	922.486	1.57418	[.115]
B_ARC08_04	4920.06	1022.86	4.81008	[.000]
B_ARC08_07	1425.79	811.348	1.75731	[.079]
B_ARC08_08	34661.3	1694.49	20.4553	[.000]
B_ARC08_09	5962.90	873.649	6.82528	[.000]
B_ARC08_11	1088.95	824.202	1.32122	[.186]
B_ARC08_12	7610.79	899.215	8.46382	[.000]
B_ARC09_08	2857.54	814.127	3.50994	[.000]
B_ARC09_09	15070.9	1021.78	14.7496	[.000]
B_ARC09_12	3120.00	833.569	3.74295	[.000]
B_ARC09_20	279.322	917.025	.304595	[.761]
B_ARC11_07	4022.68	871.680	4.61485	[.000]
B_ARC11_08	325.210	809.288	.401846	[.688]
B_ARC11_11	5616.89	1025.31	5.47822	[.000]
B_ARC11_12	4041.93	940.189	4.29906	[.000]
B_ARC11_22	259.293	809.060	.320487	[.749]
B_ARC15_02	2125.53	812.198	2.61701	[.009]
B_ARC16_04	8017.53	871.030	9.20465	[.000]
B_ARC17_04	3316.38	860.323	3.85481	[.000]
B_ARC19_09	4216.02	853.774	4.93810	[.000]
B_ARC20_09	6238.31	834.249	7.47776	[.000]
B_ARC21_07	666.813	810.034	.823192	[.410]

Table F3.4. Summary Statistics for Storage Depreciation, Depletion, and Amortization Equation

Variable	Coefficient	St-Error	t-statistic
REG2	4485.56	1204.28	3.72467
REG3	6267.52	1806.17	3.47006
REG4	3552.55	728.230	4.87833
REG5	2075.31	646.561	3.20976
REG6	1560.07	383.150	4.07169
REG7	4522.42	1268.87	3.56412
REG8	1102.49	622.420	1.77129
REG9	65.2731	10.1903	6.40542
REG11	134.692	494.392	.272439

Table F3.5. Summary Statistics for Pipeline Accumulated Deferred Income Tax Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
BNEWCAP_PRE2003	.067242	.023235	2.89405	[.004]
BNEWCAP_2003_2004	.132014	.013088	10.0865	[.000]
BNEWCAP_POST2004	.109336	.028196	3.87766	[.000]
B_ARC01_01	3529.80	4775.58	.739134	[.460]
B_ARC02_01	2793.71	4766.40	.586125	[.558]
B_ARC02_02	15255.3	5318.30	2.86844	[.004]
B_ARC02_03	767.648	4758.23	.161331	[.872]
B_ARC02_05	2479.86	4768.91	.520005	[.603]
B_ARC03_02	1663.09	4761.98	.349243	[.727]
B_ARC03_03	6184.51	4966.65	1.24521	[.213]
B_ARC03_04	-14.6495	4757.75	-.307908E-02	[.998]
B_ARC03_05	3183.89	4761.49	.668676	[.504]
B_ARC03_15	2531.19	4759.07	.531866	[.595]
B_ARC04_03	3660.65	4780.00	.765826	[.444]
B_ARC04_04	6076.87	4900.20	1.24013	[.215]
B_ARC04_07	-391.339	4757.90	-.082250	[.934]
B_ARC04_08	1798.04	4758.19	.377884	[.706]
B_ARC05_02	6654.17	4801.91	1.38573	[.166]
B_ARC05_03	1842.90	4762.25	.386982	[.699]
B_ARC05_05	6344.87	5220.98	1.21526	[.224]
B_ARC05_06	148.421	4757.73	.031196	[.975]
B_ARC06_03	2475.65	4775.18	.518441	[.604]
B_ARC06_05	5193.49	4996.38	1.03945	[.299]
B_ARC06_06	24991.1	5803.11	4.30650	[.000]
B_ARC06_07	-259.276	4757.72	-.054496	[.957]
B_ARC06_10	13015.7	4862.80	2.67659	[.007]
B_ARC07_04	189.221	4776.34	.039616	[.968]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC07_06	14166.3	5012.13	2.82640	[.005]
B_ARC07_07	16102.7	5680.52	2.83472	[.005]
B_ARC07_08	118.047	4758.11	.024810	[.980]
B_ARC07_11	-434.842	4808.84	-.090426	[.928]
B_ARC07_21	495.934	5498.36	.090197	[.928]
B_ARC08_04	4679.95	4780.56	.978955	[.328]
B_ARC08_07	365.793	4762.84	.076801	[.939]
B_ARC08_08	5133.64	5235.92	.980466	[.327]
B_ARC08_09	-3672.71	4770.23	-.769923	[.441]
B_ARC08_11	-1856.45	4762.76	-.389784	[.697]
B_ARC08_12	795.831	4808.51	.165505	[.869]
B_ARC09_08	537.433	4759.95	.112907	[.910]
B_ARC09_09	-1812.27	4829.76	-.375230	[.707]
B_ARC09_12	-2803.40	4761.86	-.588719	[.556]
B_ARC09_20	55.5366	5493.73	.010109	[.992]
B_ARC11_07	-1137.92	4772.21	-.238448	[.812]
B_ARC11_08	276.612	4757.86	.058138	[.954]
B_ARC11_11	7.99239	4874.89	.163950E-02	[.999]
B_ARC11_12	-1079.76	4825.77	-.223750	[.823]
B_ARC11_22	337.987	4759.18	.071018	[.943]
B_ARC15_02	429.875	4758.19	.090344	[.928]
B_ARC16_04	2744.23	4759.07	.576631	[.564]
B_ARC17_04	935.795	4757.97	.196680	[.844]
B_ARC19_09	-3806.27	4762.95	-.799141	[.424]
B_ARC20_09	1173.22	4768.48	.246037	[.806]
B_ARC21_07	586.673	4759.84	.123255	[.902]

Table F3.6. Summary Statistics for Pipeline Total Operating and Maintenance Expense Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
TOM_GPIS1	.256869	.114518	2.24304	[.025]
TOM_DEPSHR	1.69807	.429440	3.95415	[.000]
TOM_BYEAR	-.019974	.718590E-02	-2.77955	[.005]
B_ARC01_01	45.8116	13.5505	3.38081	[.001]
B_ARC02_01	45.7428	13.5502	3.37580	[.001]
B_ARC02_02	47.4313	13.4380	3.52963	[.000]
B_ARC02_03	45.3570	13.6230	3.32944	[.001]
B_ARC02_05	46.3936	13.5393	3.42658	[.001]
B_ARC03_02	45.8277	13.5539	3.38115	[.001]
B_ARC03_03	47.1662	13.4461	3.50779	[.000]
B_ARC03_04	44.5365	13.6401	3.26512	[.001]
B_ARC03_05	45.9318	13.5464	3.39071	[.001]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC03_15	45.1262	13.5508	3.33015	[.001]
B_ARC04_03	46.5137	13.4799	3.45060	[.001]
B_ARC04_04	47.4725	13.4290	3.53508	[.000]
B_ARC04_07	45.0325	13.6249	3.30516	[.001]
B_ARC04_08	45.6096	13.5965	3.35451	[.001]
B_ARC05_02	46.8361	13.4859	3.47298	[.001]
B_ARC05_03	46.2316	13.5556	3.41052	[.001]
B_ARC05_05	47.2881	13.4422	3.51788	[.000]
B_ARC05_06	44.2555	13.6969	3.23105	[.001]
B_ARC06_03	46.4249	13.4976	3.43948	[.001]
B_ARC06_05	46.9210	13.4730	3.48260	[.000]
B_ARC06_06	47.6072	13.4045	3.55157	[.000]
B_ARC06_07	44.5090	13.6696	3.25606	[.001]
B_ARC06_10	46.0547	13.5171	3.40715	[.001]
B_ARC07_04	46.6884	13.4905	3.46084	[.001]
B_ARC07_06	47.2664	13.4316	3.51904	[.000]
B_ARC07_07	47.8651	13.3928	3.57395	[.000]
B_ARC07_08	44.7096	13.6750	3.26944	[.001]
B_ARC07_11	46.7847	13.5263	3.45880	[.001]
B_ARC07_21	45.4067	13.6138	3.33535	[.001]
B_ARC08_04	46.3290	13.5124	3.42864	[.001]
B_ARC08_07	45.1349	13.6437	3.30810	[.001]
B_ARC08_08	46.8373	13.4658	3.47825	[.001]
B_ARC08_09	45.7056	13.5495	3.37323	[.001]
B_ARC08_11	45.9766	13.5925	3.38250	[.001]
B_ARC08_12	45.1596	13.5537	3.33190	[.001]
B_ARC09_08	44.9927	13.6211	3.30317	[.001]
B_ARC09_09	46.2997	13.5103	3.42699	[.001]
B_ARC09_12	45.2655	13.5793	3.33342	[.001]
B_ARC09_20	43.2644	13.7686	3.14226	[.002]
B_ARC11_07	46.4472	13.5409	3.43015	[.001]
B_ARC11_08	44.9105	13.6898	3.28058	[.001]
B_ARC11_11	47.0985	13.5107	3.48603	[.000]
B_ARC11_12	46.8744	13.5270	3.46526	[.001]
B_ARC11_22	44.8071	13.7118	3.26778	[.001]
B_ARC15_02	44.8267	13.6116	3.29327	[.001]
B_ARC16_04	45.0068	13.5491	3.32175	[.001]
B_ARC17_04	44.8832	13.5582	3.31042	[.001]
B_ARC19_09	45.4861	13.5613	3.35412	[.001]
B_ARC20_09	45.5729	13.5745	3.35725	[.001]
B_ARC21_07	44.6298	13.6465	3.27041	[.001]
TOM_RHO	.297716	.052442	5.67707	[.000]

Table F4

Data: Equation for industrial distribution tariffs

Author: Ernest Zampelli, SAIC, 2009.

Source: The source for the peak and off-peak consumption data used in this estimation was the Natural Gas Monthly, DOE/EIA-0130. State level city gate prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM regions) prices. The quantity-weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. Prices for the estimations were derived as described in Table F5.

Variables:

$TIN_{r,n,t}$ = industrial distributor tariff in region r, network n (1987 dollars per Mcf) [$DTAR\_SF_3$]
$PREG_r$ = 1, if observation is in region r during peak period (n=1), =0 otherwise
$QIND_{r,t}$ = industrial gas consumption in region r in year t (MMcf) [$BASQTY\_SF_3$+$BASQTY\_SI_3$]
r = NGTDM region
t = year
α_0, α_r, $\alpha_{r,n}$ = estimated parameters for regional constants [$PINREG15_r$ and $PINREGPK15_{r,n}$]
β = estimated parameter for consumption
ρ = autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The industrial distributor tariff equation was estimated using backcasted data for the 12 NGTDM regions over the 1990 to 2008 time period. The equation was estimated in linear form with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 5.0. The form of the estimating equation follows:

$$\begin{aligned} \ln TIN_{r,n,t} = {} & \alpha_0 + \sum_r (\alpha_r + \alpha_{r,pk}) * REG_{r,pk} + \beta * QIND_{r,t} + \rho * TIN_{r,t-1} \\ & - \rho * (\sum_r (\alpha_r + \alpha_{r,pk}) * REG_{r,pk} + \beta * QIND_{r,t-1}) \end{aligned}$$

Regression Diagnostics and Parameter Estimates:

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

Dependent variable: TIN87
Number of observations: 456

Mean of dep. var.	= .282327		R-squared	= .711027	
Std. dev. of dep. var.	= 1.68053		Adjusted R-squared	= .703199	
Sum of squared residuals	= 371.429		Durbin-Watson	= 1.96827	

Variance of residuals	=	.838440	Schwarz B.I.C.	=	640.302
Std. error of regression	=	.915663	Log likelihood	=	-600.506

Parameter	Estimate	Standard Error	t-statistic	P-value	Code Variable
WT	.199135	.041539	4.79396	[.000]	
NE	.664368	.178794	3.71584	[.000]	$PINREG15_1$
WNCNTL	-.565428	.069519	-8.13339	[.000]	$PINREG15_4$
ESCNTL	-.248102	.053509	-4.63666	[.000]	$PINREG15_6$
AZNM	.395943	.093005	4.25725	[.000]	$PINREG15_{11}$
CA	.605914	.097865	6.19132	[.000]	$PINREG15_{12}$
MIDATL_PK	.418090	.101754	4.10881	[.000]	$PINREGPK15_2$
WNCNTL_PK	.354066	.079415	4.45840	[.000]	$PINREGPK15_4$
ESCNTL_PK	.203711	.074239	2.74398	[.006]	$PINREGPK15_6$
WSCNTL_PK	-.411782	.068533	-6.00852	[.000]	$PINREGPK15_7$
WAOR_PK	.263996	.092401	2.85709	[.004]	$PINREGPK15_9$
QIND	-.317443E-03	.482650E-04	-6.57708	[.000]	
RHO	.423561	.043665	9.70021	[.000]	

Standard Errors computed from analytic second derivatives (Newton)

Data used for estimation

		New Engl.	Mid Atl.	E.N. Central	W.N. Central	S.Atl Fl	E.S. Central	W.S. Central	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
		1	2	3	4	5	6	7	8	9	10	11	12
1990 QIN	peak	25.238	156.14	453.96	140.9	185.23	152.15	948.57	56.599	46.146	30.06	13.198	177.12
1990 QIN	off-peak	56.095	270.87	730.76	245.05	351.31	272.39	1987.3	93.839	81.168	54.881	24.473	388.08
1991 QIN	peak	39.282	168.91	481.69	149.95	171.26	158.54	979.32	66.408	47.282	30.235	14.3	201.54
1991 QIN	off-peak	82.376	282.18	729.31	254.99	330.64	288.33	2003.6	109.22	87.502	53.163	24.25	401.08
1992 QIN	peak	54.227	204.09	498.51	155.99	185.1	166.54	1018.4	74.334	49.691	29.904	13.778	217.12
1992 QIN	off-peak	108.78	354.7	777.87	263.94	353.2	304.97	1942.1	128.69	88.594	54.925	23.066	377.45
1993 QIN	peak	61.814	224.11	529.31	166.97	185.5	176.42	1045.5	83.593	54.178	34.299	13.167	214.7
1993 QIN	off-peak	123.32	366.69	786.37	283.17	358.16	305.77	2109.2	148.52	98.713	66.051	25.02	445.02
1994 QIN	peak	60.862	243.6	553.36	190.76	182.9	170.14	1088.8	91.076	58.07	42.837	13.711	210.07
1994 QIN	off-peak	111.77	398.1	795.93	320.33	380.72	299.53	2069.5	149.79	112.1	84.036	30.899	446.68
1995 QIN	peak	67.612	274.81	564.08	174.94	198.2	181.21	1094.8	92.348	62.974	49.496	18.42	216.02
1995 QIN	off-peak	117.09	462.71	842.05	302.97	408.65	323.96	2206	154.12	115.93	83.981	30.338	471.9
1996 QIN	peak	54.363	285.51	578.99	166.26	193.94	178.95	1196.9	93.314	66.644	46.056	17.943	231.69
1996 QIN	off-peak	112.99	481.59	876.22	283.25	385.99	324.38	2332	168.08	135.35	90.666	31.894	461.85
1997 QIN	peak	48.405	234.18	527.5	180.9	213.68	185.66	1158.6	77.997	70.675	41.903	18.414	232.69
1997 QIN	off-peak	86.131	402.1	814.07	291.91	398.91	334.13	2246.7	136.03	130.89	83.234	35.325	487.2
1998 QIN	peak	52.54	226.19	506.96	165.78	200.57	186.74	1119.4	94.347	83.184	40.685	18.07	232.48
1998 QIN	off-peak	95.549	375.1	771.51	298.64	370.18	328.87	2140.8	154.17	152.69	81.23	35.135	513.67
1999 QIN	peak	55.157	197.85	523.25	160.89	221.22	201	1023.2	77.398	81.611	43.813	18.686	203.63
1999 QIN	off-peak	100.84	332.74	804.58	274.65	340.85	366.69	2032.3	146.67	150.74	90.394	34.188	522.78
2000 QIN	peak	54.493	152.64	539.34	163.07	194.49	200.21	1080.9	87.687	57.099	35.056	17.259	218.27
2000 QIN	off-peak	86.042	262.25	788.24	285.56	364.74	347.3	2230.3	139.76	102.92	69.631	33.847	558.47
2001 QIN	peak	49.565	139.45	480.99	150.12	155.17	168.54	1051.7	104.16	50.923	30.792	19.007	211.11
2001 QIN	off-peak	85.579	228.74	699.46	258.24	303.54	299.32	1974.5	167.1	93.96	63.919	35.375	455.88
2002 QIN	peak	52.54	144.33	470.45	121.75	173.22	176.85	1011.8	91.637	51.527	28.746	14.516	241.23
2002 QIN	off-peak	81.724	234.44	758.81	221.6	328.78	305.4	2005.8	169.31	86.7	54.823	26.005	499.44
2003 QIN	peak	39.744	139.83	481.39	158.53	175.69	176.28	982.91	89.808	47.009	25.345	13.858	252.4
2003 QIN	off-peak	46.063	215.76	678.89	260.18	298.39	286.67	1906.9	146.28	86.394	47.99	25.8	527.13

		New Engl.	Mid Atl.	E.N. Central	W.N. Central	S.Atl Fl	E.S. Central	W.S. Central	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
		1	2	3	4	5	6	7	8	9	10	11	12
2004 QIN	peak	37.198	136.43	491.51	156.64	176.4	173.92	973.99	91.339	49.641	23.374	16.187	271.43
2004 QIN	off-peak	45.242	214.24	688.46	265.89	305.66	303.33	1907	146.72	89.858	40.229	26.574	564.84
2005 QIN	peak	40.728	135.24	478.91	158.08	172.16	168.5	808.09	93.829	48.327	23.015	14.013	267.71
2005 QIN	off-peak	45.586	205.31	681.74	260.6	290.89	283.02	1538.7	159.82	88.192	40.118	27.785	514.11
2006 QIN	peak	35.807	124.55	429.28	162.89	161.04	157.39	787.35	97.212	50.66	24.302	13.762	244.48
2006 QIN	off-peak	47.391	207.44	673.41	298.82	305.01	292.01	1573.2	151.07	90.187	45.419	22.924	488.02
2007 QIN	peak	39.898	129.41	455.49	173.06	161.02	166.6	834.3	97.509	51.108	23.489	13.67	243.44
2007 QIN	off-peak	47.76	206.79	665.3	304.43	293.52	287.93	1612	156.13	91.117	42.303	23.336	490.16
2008 QIN	peak	41.994	131.75	450.39	195.27	158.12	162.98	834.03	101.53	55.157	25.683	13.962	255.11
2008 QIN	off-peak	45.87	195.97	644.85	323.08	290.82	281.62	1594.9	157.55	89.092	45.653	24.509	509.07
1990 TIN	peak	1.099	0.6688	0.3058	-0.1288	0.7025	0.1655	-0.5898	0.0125	0.6006	0.5055	0.3569	0.7677
1990 TIN	off-peak	0.2422	0.2975	0.3219	-0.2679	0.3332	0.0103	-0.8011	-0.6182	0.3989	0.6069	0.4618	0.4976
1991 TIN	peak	1.1651	0.7854	0.3182	-0.1239	0.6413	0.1569	-0.6598	-0.2375	0.5443	0.4694	0.4572	0.9729
1991 TIN	off-peak	0.2206	0.1636	0.1991	-0.3464	0.1277	-0.0513	-0.6584	-0.7412	0.4784	0.5472	0.3259	0.5807
1992 TIN	peak	1.2819	0.6984	0.2446	-0.0567	0.628	0.1737	-0.6297	-0.1706	0.5218	0.5658	1.2426	1.078
1992 TIN	off-peak	-0.1136	-0.164	-0.0413	-0.3214	0.0843	-0.1326	-0.5803	-0.9941	0.5634	0.4786	0.9993	0.2713
1993 TIN	peak	1.1049	0.5098	0.1875	-0.0766	0.6265	0.1938	-0.5649	-0.1407	0.4983	0.5495	0.7831	0.3072
1993 TIN	off-peak	-0.5318	-0.1649	0.0392	-0.3932	0.0085	-0.1049	-0.4782	-0.5373	0.4175	0.689	0.6653	-0.1804
1994 TIN	peak	1.1511	0.6644	0.3775	0.043	0.5115	0.3493	-0.4724	-0.4511	0.4197	0.0552	0.989	0.4388
1994 TIN	off-peak	-0.7697	0.0425	0.2089	-0.4502	-0.1338	-0.0533	-0.3722	-0.6965	0.1884	0.2237	0.5148	0.1871
1995 TIN	peak	0.9682	0.5415	0.1336	0.0336	0.5657	0.368	-0.5873	-0.1514	0.2735	-0.0042	1.0843	1.3996
1995 TIN	off-peak	-0.6908	0.1533	-0.0909	-0.4184	0.0587	-0.091	-0.5336	-0.1512	0.2563	0.1373	0.8486	0.7801
1996 TIN	peak	1.0885	0.4724	-0.0801	0.1501	0.3852	-0.0597	-0.2293	0.0624	0.3147	0.0629	0.7245	0.7635
1996 TIN	off-peak	-0.5643	-0.1022	-0.0573	-0.4768	0.0265	0.0109	-0.287	0.0885	0.0274	0.2877	0.6701	0.549
1997 TIN	peak	0.9536	0.5591	0.1766	-0.1368	0.4308	0.1911	-0.4936	0.04	0.5014	-0.2748	0.3125	1.0975
1997 TIN	off-peak	-0.3627	-0.9394	-0.1531	-0.7348	-0.0943	-0.0291	-0.2262	0.2046	0.0767	0.1115	0.1918	0.4767
1998 TIN	peak	0.7314	0.029	0.1798	-0.0513	0.1833	0.0944	-0.2879	-0.1103	0.1663	-0.0655	0.544	1.0797
1998 TIN	off-peak	-0.8255	-0.5106	0.0985	-0.5266	-0.3471	-0.2757	-0.1983	0.0953	0.0643	-0.0713	0.176	0.4421
1999 TIN	peak	0.381	0.1165	0.1777	-0.0447	-0.0503	0.1269	-0.4494	0.5426	0.1491	0.6896	0.5158	0.6471
1999 TIN	off-peak	-0.8161	-0.787	-0.2143	-0.5001	-0.4758	-0.2064	-0.2569	0.2023	0.0292	-0.0932	0.0834	0.2283
2000 TIN	peak	0.4368	0.3257	-0.1319	-0.1978	-0.0355	-0.0918	-0.5133	0.3527	0.5765	-0.0681	-0.0613	0.6967
2000 TIN	off-peak	-0.6324	-0.5654	-0.2139	-0.637	-0.4437	-0.2846	-0.3444	0.3139	-0.0557	0.2312	-0.0438	0.5583
2001 TIN	peak	-0.0298	0.5579	0.0726	-0.3949	-0.0079	-0.2461	-0.7083	0.157	-0.2738	-0.3584	-0.0328	-0.4836
2001 TIN	off-peak	-0.1169	0.2263	0.2662	-0.493	-0.4109	-0.0722	-0.3964	0.7435	0.3807	0.8896	0.7614	0.8027
2002 TIN	peak	0.6619	0.4506	-0.1471	-0.2	-0.0309	0.19	-0.5569	0.8717	0.7349	0.8584	1.2169	1.054
2002 TIN	off-peak	-0.875	0.1446	-0.447	-0.351	-0.4161	-0.0017	-0.4194	0.9103	-0.0871	0.4439	0.6581	0.6936
2003 TIN	peak	0.7842	1.1901	0.0288	-0.3011	0.018	0.3513	-0.222	0.5963	0.2737	-0.4933	0.3882	1.0483
2003 TIN	off-peak	0.2361	0.7713	0.1791	-0.4924	-0.4897	-0.3577	-0.2159	0.6595	0.1605	0.5482	0.6927	0.8708
2004 TIN	peak	1.2662	0.958	0.1488	-0.1974	0.0588	0.1299	-0.4422	0.2895	0.3958	0.1907	0.4129	1.176
2004 TIN	off-peak	0.17	0.2825	-0.2684	-0.6077	-0.4935	-0.1755	-0.1804	0.2801	0.0213	0.433	0.4578	0.4561
2005 TIN	peak	1.1769	0.9548	-0.071	0.0804	0.1706	0.2596	-0.513	0.4996	0.5463	-0.0684	0.4173	1.3857
2005 TIN	off-peak	6.2644	0.1607	-0.6005	-0.8601	-0.6412	-0.2335	-0.2605	0.2672	0.0206	-0.6922	0.4917	0.3082
2006 TIN	peak	0.7955	0.6048	-0.3683	0.1022	-0.2335	0.0381	-0.6599	0.3446	0.3204	0.599	0.3567	1.2178
2006 TIN	off-peak	0.2617	-0.7368	-0.1778	-0.7105	-0.4412	-0.3876	-0.4774	0.2411	0.1519	1.1891	1.1094	0.9437
2007 TIN	peak	1.3417	0.2697	-0.3644	0.0452	0.1393	-0.1848	-0.7233	-0.0415	0.6403	0.7626	0.7061	0.907
2007 TIN	off-peak	0.2215	-0.0402	-0.1513	-0.3497	-0.1962	-0.1132	-0.7936	0.3232	0.5507	0.9501	0.8721	0.8912
2008 TIN	peak	1.1063	0.3597	-0.1709	0.1381	0.1855	-0.1638	-0.62	0.1363	0.8461	1.0509	0.5912	0.9421
2008 TIN	off-peak	0.5047	0.3785	0.2288	-0.1025	-0.0856	-0.255	-0.6044	0.071	-0.1388	1.2117	1.1816	1.1883

Table F5

Data: Historical industrial sector natural gas prices by type of service, NGTDM region.

Derivation: The historical industrial natural gas prices published in the *Natural Gas Annual (NGA)* only reflect gas purchased through local distribution companies. In order to approximate the average price to all industrial customers by service type and NGTDM region (HPGFINGR, HPGIINGR), data available at the Census Region level[97] from the Manufacturing Energy Consumption Survey (MECS)[98] for the years 1988, 1991, 1994, 1998, and 2002 were used to estimate an equation for the regional MECS price as a function of the regional NGA industrial price and the regional supply price (quantity-weighted average of the gas wellhead price and import price). The procedure is outlined below.

1) Assign average Census Division industrial price using econometrically derived equation:

$$\mathrm{PIN\_NG}_{nr} = 1.00187 * \exp(0.039682) * \mathrm{PW\_NRG}_{nr}^{0.231404} * \mathrm{HPIN}_{nr}^{0.726227}$$

from estimating the following equation

$$\ln\mathrm{PIN\_NG}_{nr} = \beta_0 + \beta_1 * \ln\mathrm{PW\_NRG}_{nr} + \beta_2 * \mathrm{HPIN}_{nr}$$

2) Assign prices to the NGTDM regions that represent subregions of Census Divisions by multiplying the Census Division price from step 1 by the subregion price (as published in the NGA), divided by the Census Division price (as published in the NGA). For the Pacific Division, the industrial price in Alaska from the NGA, with quantity weights, is used to approximate a Pacific Division price for the lower-48 (i.e., CA, WA, and OR), before this step is performed.

3) Core industrial prices are derived by applying an historical, regional, average average-to-firm price markup (FDIFF, in 1987$/Mcf, Northeast 0.11, North Central 0.14, South 0.67, West 0.39) to the established average regional industrial price (from step 2). Noncore prices are calculated so that the quantity-weighted average of the core and noncore prices equal the original regional estimate. The data used to generate the average-to-firm markups are presented below.

4) Finally, the peak and off-peak prices from the NGA are scaled to align with the core and noncore prices generated from step 3 on an average annual basis, to arrive at peak/off-peak, core/noncore industrial prices for the NGTDM regions.

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[97] Through a special request, the Census Bureau generated MECS data by Census Region and by service type (core versus noncore) based on an assumption of which industrial classifications are more likely to consume most of their purchased natural gas in boilers (core) or non-boiler applications (noncore).

[98] A request was issued to the Census Bureau to obtain similar data from other MECS surveys to improve this estimation.

	Prices (87$/mcf)			Consumption (Bcf)		
	1988	**1991**	**1994**	**1988**	**1991**	**1994**
Core						
Northeast	3.39	3.05	3.04	335	299	310
North Central	3.04	2.37	2.42	864	759	935
South	2.91	2.40	2.53	643	625	699
West	3.21	2.70	2.55	217	204	227
Noncore						
Northeast	3.05	2.78	2.67	148	146	187
North Central	2.60	2.01	2.17	537	648	747
South	1.96	1.57	1.75	2517	2592	2970
West	2.54	2.19	1.91	347	440	528

	Price (87$/mcf)				
	1988	1991	1994	1998	2002
Northeast	3.297223	3.018058	2.941269	2.834076	3.498869
North Central	2.880355	2.247968	2.351399	2.247715	2.985983
South	2.162684	1.766014	1.939298	1.947017	2.634691
West	2.804912	2.398525	2.133228	2.217645	2.831414

Variables:

PIN_NG = Industrial natural gas prices by NGTDM region (1987$/Mcf)
PW_CDV = Average supply price by Census Division (1987$/Mcf)
PI_CDV = Industrial natural gas price from the NGA by Census Division (1987$/Mcf)
FDIFF = Average (1988, 1991, 1994) difference between the firm industrial price and the average industrial price by Census Region (1987$/Mcf)
PIN_FNG = Industrial core natural gas prices by NGTDM region (1987$/Mcf)
PIN_ING = Industrial noncore natural gas prices by NGTDM region (1987$/Mcf)
HPGFINGR = Industrial core natural gas prices by period and NGTDM region (1987$/Mcf)
HPGIINGR = Industrial noncore natural gas prices by period and NGTDM region (1987$/Mcf)

Regression Diagnostics and Parameter Estimates:

```
Dependent variable: LNMECS87
 Number of observations:  20

       Mean of dep. var. = .921802          LM het. test = .021529 [.883]
   Std. dev. of dep. var. = .190034        Durbin-Watson = 1.22472 [<.086]
 Sum of squared residuals = .067807      Jarque-Bera test = .977466 [.613]
    Variance of residuals = .398866E-02   Ramsey's RESET2 = .044807 [.835]
```

Std. error of regression = .063156		F (zero slopes) = 77.5121 [.000]	
R-squared = .901177		Schwarz B.I.C. = -23.9958	
Adjusted R-squared = .889550		Log likelihood = 28.4894	

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value	Symbol
C	.039682	.072242	.549291	[.590]	β_0
LNSUPPLYP87	.231404	.105606	2.19120	[.043]	β_1
LNNGAP87	.726227	.073700	9.85385	[.000]	β_2

Form of Forecasting Equation:

$$MECS87 = 1.00187 * e^{0.039682} SUPPLYP87^{0.231404} NGAP87^{0.726227}$$

where:

*MECS*87 = Manufacturer's Energy Consumption Survey in US$87

*SUPPLYP*87 = supply price in US$87

*NGAP*87 = natural gas annual price in US$87

The term 1.00187 is an adjustment factor that is applied in cases where the value of "y" is predicted from an estimated equation where the dependent variable is the natural log of y. The adjustment is due to the fact that generally predictions of "y" using the first equation only tend to be biased downward. It is calculated by estimating the historical values of the dependent variable as a function of the estimated values for the same.

Table F6

Data: Equations for residential distribution tariffs

Author: Ernest Zampelli, SAIC, with summer intern Ben Laughlin, 2010.

Source: The source for the peak and off-peak data used in this estimation was the *Natural Gas Monthly*, DOE/EIA-0130. State level city gate and residential prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM regions) prices. The quantity-weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. The source for the number of residential customers was the Natural Gas Annual, DOE/EIA-0131.

Variables:

$TRS_{r,n,t}$ = residential distributor tariff in the period n for region r (1987 dollars per Mcf) [DTAR_SF$_1$]

REG_r = 1, if observation is in region r, =0 otherwise

$QRS\_NUMR_{r,n,t}$ = residential gas consumption per customer in the period for region r in year t (Bcf per thousand customers) [(BASQTY_SF$_1$+BASQTY_SI$_1$)/NUMRS]

$NUMRS_{r,t}$ = number of residential customers (thousands)

r = NGTDM region

n = network (1=peak, 2=off-peak)

t = year

$\alpha_{r,n}$ = estimated parameters for regional dummy variables [PRSREGPK19]

$\beta_{1,n}$, $\beta_{2,n}$ = estimated parameters

ρ_n = autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Residential distributor tariff equations for the peak and off-peak periods were estimated using panel data for the 12 NGTDM regions over the 1990 to 2009 time period. The equations were estimated in log-linear form with corrections for cross sectional heteroscedasticity and first order serial correlation using EViews. The general form for both estimating equations follows:

$$\ln TRS_{r,n,t} = \sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QRS\_NUMR_{r,n,t} + \beta_{2,n} * \ln NUMRS_{r,t} +$$

$$\rho_n * \ln TRS_{r,n,t-1} - \rho_n * (\sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QRS\_NUMR_{r,n,t-1} + \beta_{2,n} * \ln NUMRS_{r,t}$$

Regression Diagnostics and Parameter Estimates for the Peak Period:

Dependent Variable: LNTRS87
Method: Least Squares
Date: 07/22/10 Time: 16:32
Sample (adjusted): 2 240
Included observations: 239 after adjustments
Convergence achieved after 7 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=4)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQRS_NUMR	-0.607267	0.094552	-6.422580	0.0000
LN_NUMRS	0.162972	0.090462	1.801551	0.0730
REGION=1	-6.947036	1.103041	-6.298074	0.0000
REGION=2	-7.422527	1.201445	-6.178001	0.0000
REGION=3	-8.021596	1.217912	-6.586353	0.0000
REGION=4	-7.864109	1.156385	-6.800599	0.0000
REGION=5	-7.473760	1.153979	-6.476514	0.0000
REGION=6	-7.664540	1.121958	-6.831398	0.0000
REGION=7	-8.052452	1.177230	-6.840170	0.0000
REGION=8	-7.987073	1.121141	-7.124058	0.0000
REGION=9	-7.308704	1.060240	-6.893446	0.0000
REGION=10	-7.283411	1.060717	-6.866500	0.0000
REGION=11	-7.523595	1.085943	-6.928169	0.0000
REGION=12	-7.954022	1.209662	-6.575410	0.0000
AR(1), ρ	0.231296	0.068422	3.380459	0.0009

R-squared	0.911539	Mean dependent var	0.940050
Adjusted R-squared	0.906010	S.D. dependent var	0.384204
S.E. of regression	0.117789	Akaike info criterion	-1.379145
Sum squared resid	3.107810	Schwarz criterion	-1.160957
Log likelihood	179.8078	Hannan-Quinn criter.	-1.291221
Durbin-Watson stat	1.994101		

Regression Diagnostics and Parameter Estimates for the Off-peak Period:

Dependent Variable: LNTRS87
Method: Least Squares
Date: 07/22/10 Time: 16:31
Sample: 241 480
Included observations: 240
Convergence achieved after 6 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=4)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQRS_NUMR	-0.814968	0.085444	-9.538040	0.0000
LN_NUMRS	0.282301	0.111488	2.532127	0.0120
REGION=1	-11.06556	1.189130	-9.305589	0.0000
REGION=2	-11.46569	1.331512	-8.611025	0.0000
REGION=3	-11.99084	1.365602	-8.780628	0.0000
REGION=4	-11.81121	1.265735	-9.331497	0.0000
REGION=5	-11.52214	1.266859	-9.095045	0.0000
REGION=6	-11.67063	1.209285	-9.650856	0.0000

REGION=7	-11.86662	1.278193	-9.283902	0.0000
REGION=8	-11.80703	1.229651	-9.601944	0.0000
REGION=9	-11.19628	1.140432	-9.817580	0.0000
REGION=10	-10.93813	1.060071	-10.31830	0.0000
REGION=11	-11.32604	1.134872	-9.980016	0.0000
REGION=12	-12.06455	1.327790	-9.086182	0.0000
AR(1), ρ	0.202612	0.083183	2.435748	0.0156

R-squared	0.905922	Mean dependent var	1.272962
Adjusted R-squared	0.900069	S.D. dependent var	0.368928
S.E. of regression	0.116625	Akaike info criterion	-1.399238
Sum squared resid	3.060333	Schwarz criterion	-1.181698
Log likelihood	182.9086	Hannan-Quinn criter.	-1.311585
Durbin-Watson stat	2.010275		

Data used for peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TRS87	1.3013	1.0730	0.4048	0.3961	1.0185	0.6054	0.6114	0.4041	1.0087	1.4535	1.0112	0.9513
1990	NUMRS	14.4242	15.9210	16.2206	15.2533	15.2427	14.6570	15.5148	14.5549	13.5724	13.0339	13.7708	15.9587
1990	QRS_NUMR	-9.8137	-9.8268	-9.5457	-9.6821	-9.9747	-9.9839	-10.1121	-9.8411	-9.9340	-11.0881	-10.1387	-10.2906
1991	TRS87	1.3496	1.1217	0.4383	0.4061	0.9869	0.7178	0.6539	0.4200	0.8813	1.5632	1.0210	1.0692
1991	NUMRS	14.4330	15.9914	16.2352	15.2651	15.2648	14.6832	15.5257	14.5850	13.6744	13.0546	13.8374	15.9747
1991	QRS_NUMR	-9.8481	-9.8694	-9.4866	-9.5907	-9.9350	-9.9281	-10.0510	-9.7635	-9.9330	-11.1596	-10.1994	-10.4037
1992	TRS87	1.3843	1.1746	0.4187	0.4769	1.0595	0.7357	0.6413	0.4536	0.9455	1.5313	0.9832	1.0246
1992	NUMRS	14.4423	16.0036	16.2475	15.2807	15.3133	14.7090	15.5316	14.6128	13.6913	13.0644	13.8095	15.9800
1992	QRS_NUMR	-9.7463	-9.7981	-9.4989	-9.6974	-9.8973	-9.9207	-10.0994	-9.8291	-9.9947	-11.0110	-10.1482	-10.4125
1993	TRS87	1.3820	1.1496	0.4725	0.4174	1.0268	0.6689	0.5867	0.4285	0.9412	1.6365	0.9866	1.0188
1993	NUMRS	14.4511	15.9482	16.2628	15.3088	15.3177	14.7384	15.5461	14.6431	13.7500	13.0915	13.8235	15.9853
1993	QRS_NUMR	-9.7174	-9.6990	-9.4326	-9.5707	-9.8014	-9.8673	-10.0340	-9.7353	-9.8164	-11.1386	-10.1938	-10.3689
1994	TRS87	1.4626	1.2113	0.5602	0.5377	1.0417	0.7789	0.6270	0.3148	1.0047	1.5705	1.0989	1.0644
1994	NUMRS	14.4669	15.9546	16.2793	15.3186	15.3552	14.7660	15.5493	14.6859	13.8117	13.1179	13.8590	15.9927
1994	QRS_NUMR	-9.6833	-9.6305	-9.4214	-9.5819	-9.8242	-9.8557	-10.0686	-9.8535	-9.9180	-11.0983	-10.2387	-10.3976
1995	TRS87	1.4777	1.2395	0.4181	0.5394	1.0357	0.7752	0.6719	0.4867	1.0564	1.5497	1.1641	1.2479
1995	NUMRS	14.4722	15.9635	16.2956	15.3296	15.3786	14.7928	15.5719	14.7298	13.8644	13.1468	13.8953	16.0011
1995	QRS_NUMR	-9.8144	-9.7202	-9.4542	-9.6281	-9.8344	-9.8930	-10.1371	-9.9560	-10.0186	-11.0584	-10.4061	-10.5225
1996	TRS87	1.3476	1.0818	0.1781	0.5158	0.8316	0.3859	0.5277	0.3350	0.9486	1.4764	0.8042	1.0371
1996	NUMRS	14.4787	15.9705	16.3101	15.3458	15.4097	14.8172	15.5827	14.7820	13.9172	13.1648	13.9272	16.0128
1996	QRS_NUMR	-9.7463	-9.6610	-9.3922	-9.5186	-9.7506	-9.8066	-10.0178	-9.8489	-9.8830	-10.9631	-10.3015	-10.5316
1997	TRS87	1.4246	1.2644	0.5200	0.5224	1.0685	0.7789	0.5464	0.2708	0.8759	1.5913	0.8229	0.9658
1997	NUMRS	14.4942	15.9815	16.3246	15.3617	15.4343	14.8403	15.5943	14.8138	13.9636	13.1859	13.9709	16.0228
1997	QRS_NUMR	-9.8196	-9.7484	-9.4966	-9.6504	-9.9177	-9.9457	-10.0575	-9.8098	-9.9762	-11.2669	-10.1617	-10.4781
1998	TRS87	1.4327	1.2917	0.4904	0.6157	0.9988	0.8608	0.7975	0.5630	0.9999	1.6068	0.9482	1.2250
1998	NUMRS	14.4989	15.9974	16.3359	15.3965	15.4742	14.8582	15.6056	14.8560	14.0103	13.2044	14.0129	16.0361
1998	QRS_NUMR	-9.9191	-9.8890	-9.6541	-9.7858	-10.0032	-10.0339	-10.1671	-9.8718	-9.9315	-11.2087	-10.1565	-10.3678
1999	TRS87	1.5129	1.2759	0.4744	0.6043	0.7784	0.8467	0.7095	0.7222	0.9247	1.6374	1.0753	1.1647
1999	NUMRS	14.5139	15.9997	16.3533	15.3897	15.5150	14.8715	15.6069	14.8947	14.0632	13.2297	14.0591	16.0522
1999	QRS_NUMR	-9.9349	-9.7629	-9.5478	-9.7411	-10.0050	-10.0386	-10.3070	-9.9509	-9.9094	-11.3010	-10.3344	-10.3496
2000	TRS87	1.2459	0.9658	0.2874	0.5682	1.0392	0.6611	0.4867	0.4600	0.8809	1.5769	0.8454	1.0239
2000	NUMRS	14.5479	16.0179	16.3707	15.4080	15.5191	14.8989	15.6219	14.9377	14.1061	13.2568	14.0976	16.0564
2000	QRS_NUMR	-9.8027	-9.7135	-9.5247	-9.7105	-9.8176	-9.9435	-10.2082	-9.9300	-9.9268	-11.1472	-10.3574	-10.4820
2001	TRS87	1.1669	0.8359	0.4220	0.5104	0.9910	0.7410	0.6233	0.5086	0.9195	1.6954	0.7993	0.7641
2001	NUMRS	14.5525	16.0404	16.3786	15.4165	15.5482	14.9102	15.6258	14.9727	14.1408	13.2883	14.1309	16.0808
2001	QRS_NUMR	-9.8536	-9.7796	-9.5948	-9.6984	-9.9725	-9.9584	-10.1280	-9.8815	-9.8992	-11.1316	-10.2740	-10.4422
2002	TRS87	1.3252	1.0061	0.1798	0.5499	1.1709	0.9131	0.7894	0.6021	1.3468	1.7721	1.2823	1.0116
2002	NUMRS	14.5638	16.0403	16.3942	15.4318	15.5633	14.9165	15.6392	15.0026	14.1702	13.3108	14.1679	16.0935
2002	QRS_NUMR	-9.9004	-9.8433	-9.6303	-9.9500	-9.9503	-9.9813	-10.1525	-9.8950	-10.0019	-11.2021	-10.3534	-10.5047
2003	TRS87	1.0640	0.9727	0.2343	0.3112	0.9532	0.7328	0.4904	0.2461	0.8771	1.7006	0.9723	0.9677
2003	NUMRS	14.5811	16.0513	16.3998	15.4423	15.5781	14.9256	15.6478	15.0353	14.2350	13.3332	14.1914	16.1013
2003	QRS_NUMR	-9.7270	-9.6751	-9.5145	-9.7046	-9.8285	-9.9254	-10.1285	-9.9871	-10.1089	-11.1387	-10.4292	-10.5824
2004	TRS87	1.4448	1.1049	0.4562	0.5844	1.1471	0.9384	0.7348	0.4769	0.9936	1.8242	1.0512	0.9869
2004	NUMRS	14.5756	16.0534	16.4051	15.4520	15.5898	14.9327	15.6576	15.0708	14.2355	13.3677	14.2230	16.1165

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
2004	QRS_NUMR	-9.8007	-9.7289	-9.5665	-9.7569	-9.8660	-10.0182	-10.2595	-9.9870	-10.0385	-11.2037	-10.3556	-10.5074
2005	TRS87	1.3379	1.0112	0.5253	0.5977	1.1991	1.1059	0.8346	0.6471	1.0996	1.8538	1.0791	1.0613
2005	NUMRS	14.5778	16.0534	16.4355	15.4628	15.6158	14.9387	15.6603	15.1071	14.2811	13.3940	14.2685	16.1330
2005	QRS_NUMR	-9.7550	-9.7055	-9.5980	-9.7940	-9.9176	-10.0749	-10.2975	-10.0114	-10.0741	-11.2697	-10.4966	-10.6082
2006	TRS87	1.4382	1.0702	0.5922	0.7802	1.3712	1.1594	0.9223	0.6719	1.1872	1.9608	1.2392	1.0536
2006	NUMRS	14.6041	16.0667	16.4213	15.4743	15.6183	14.9404	15.6673	15.1360	14.3135	13.4197	14.2995	16.1530
2006	QRS_NUMR	-9.9612	-9.9080	-9.7920	-9.9646	-10.1252	-10.2239	-10.4576	-10.0484	-10.0769	-11.3045	-10.5704	-10.6089
2007	TRS87	1.4864	1.0909	0.4472	0.6683	1.2977	0.9723	0.6249	0.3350	1.3113	1.8413	1.2638	0.9427
2007	NUMRS	14.6116	16.0784	16.4269	15.4747	15.6430	14.9418	15.6896	15.1576	14.3400	13.4342	14.3264	16.1636
2007	QRS_NUMR	-9.8358	-9.7697	-9.6440	-9.8083	-10.0464	-10.1692	-10.2719	-9.9694	-10.0544	-11.4291	-10.4542	-10.5827
2008	TRS87	1.3928	1.1184	0.4855	0.5188	1.2655	0.9639	0.6981	0.2994	1.1499	1.7733	1.1499	0.9547
2008	NUMRS	14.6286	16.0706	16.4277	15.4811	15.6491	14.9374	15.6981	15.1769	14.3588	13.4288	14.3374	16.1708
2008	QRS_NUMR	-9.8906	-9.7897	-9.5915	-9.7199	-10.0515	-10.0780	-10.2801	-9.9503	-10.0494	-11.3525	-10.4683	-10.5638
2009	TRS87	1.6335	1.2695	0.7903	0.8171	1.2355	1.1304	0.9066	0.5545	1.2369	1.9854	1.2550	1.0463
2009	NUMRS	14.5832	16.0687	16.4454	15.4815	15.6506	14.9563	15.6793	15.1583	14.3126	13.4289	14.3197	16.1646
2009	QRS_NUMR	-9.9948	-9.7392	-9.6625	-9.7911	-9.9657	-10.1392	-10.3138	-10.0136	-9.9490	-11.4385	-10.5687	-10.6136

Data used for off-peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TRS87	1.4572	1.3623	0.7696	0.7120	1.2790	1.0152	1.1575	0.5134	1.2202	1.8083	1.4110	0.9509
1990	NUMRS	14.4242	15.9210	16.2206	15.2533	15.2427	14.6570	15.5148	14.5549	13.5724	13.0339	13.7708	15.9587
1990	QRS_NUMR	-10.1737	-10.1963	-9.9287	-10.1549	-10.4345	-10.4700	-10.5254	-10.1992	-10.3260	-11.2459	-10.7420	-10.5401
1991	TRS87	1.4697	1.3661	0.7622	0.7571	1.2565	1.0811	1.1499	0.5218	1.1378	1.8672	1.3903	1.1285
1991	NUMRS	14.4330	15.9914	16.2352	15.2651	15.2648	14.6832	15.5257	14.5850	13.6744	13.0546	13.8374	15.9747
1991	QRS_NUMR	-10.2129	-10.2794	-9.9370	-10.1508	-10.4257	-10.5158	-10.5282	-10.1586	-10.2602	-11.2210	-10.6974	-10.4672
1992	TRS87	1.3002	1.2934	0.6785	0.7367	1.1210	0.9490	1.1311	0.3660	1.1894	1.8746	1.3697	1.0112
1992	NUMRS	14.4423	16.0036	16.2475	15.2807	15.3133	14.7090	15.5316	14.6128	13.6913	13.0644	13.8095	15.9800
1992	QRS_NUMR	-10.0309	-10.1508	-9.8551	-10.1300	-10.3308	-10.4581	-10.5444	-10.2928	-10.4391	-11.1796	-10.7692	-10.5941
1993	TRS87	1.2436	1.3337	0.8002	0.7756	1.2006	0.9381	1.0325	0.5110	1.0770	1.9327	1.3486	1.0533
1993	NUMRS	14.4511	15.9482	16.2628	15.3088	15.3177	14.7384	15.5461	14.6431	13.7500	13.0915	13.8235	15.9853
1993	QRS_NUMR	-10.0770	-10.1454	-9.8863	-10.0785	-10.3702	-10.4200	-10.4423	-10.1556	-10.2861	-11.1613	-10.7189	-10.5619
1994	TRS87	1.3990	1.5250	0.9030	0.7509	1.3126	1.1703	1.2499	0.5446	1.1378	1.9370	1.3880	1.1716
1994	NUMRS	14.4669	15.9546	16.2793	15.3186	15.3552	14.7660	15.5493	14.6859	13.8117	13.1179	13.8590	15.9927
1994	QRS_NUMR	-10.2330	-10.2089	-10.0332	-10.2796	-10.5232	-10.6547	-10.6284	-10.2230	-10.3182	-11.2742	-10.7146	-10.4615
1995	TRS87	1.3676	1.5059	0.6355	0.7971	1.2447	1.0378	1.2093	0.6871	1.2250	1.9244	1.4344	1.2686
1995	NUMRS	14.4722	15.9635	16.2956	15.3296	15.3786	14.7928	15.5719	14.7298	13.8644	13.1468	13.8953	16.0011
1995	QRS_NUMR	-10.2486	-10.2046	-9.8990	-10.1283	-10.4491	-10.5672	-10.6332	-10.1208	-10.3370	-11.2799	-10.7640	-10.5265
1996	TRS87	1.2179	1.4156	0.7251	0.8011	1.2945	1.0420	1.1490	0.5939	1.0515	1.9081	1.2404	1.1641
1996	NUMRS	14.4787	15.9705	16.3101	15.3458	15.4097	14.8172	15.5827	14.7820	13.9172	13.1648	13.9272	16.0128
1996	QRS_NUMR	-10.1759	-10.0992	-9.8632	-10.1027	-10.3690	-10.4690	-10.5870	-10.1797	-10.2427	-11.1834	-10.7557	-10.5586
1997	TRS87	1.3737	1.2977	0.6896	0.7006	1.3048	1.1594	1.1628	0.7333	0.9636	1.9840	1.4978	1.1817
1997	NUMRS	14.4942	15.9815	16.3246	15.3617	15.4343	14.8403	15.5943	14.8138	13.9636	13.1859	13.9709	16.0228
1997	QRS_NUMR	-10.1844	-10.1359	-9.9058	-10.1853	-10.3817	-10.5536	-10.5969	-10.2171	-10.2644	-11.3449	-10.8543	-10.6133
1998	TRS87	1.3538	1.4852	0.8912	0.9517	1.4389	1.2096	1.3172	0.9817	1.0821	1.9462	1.6148	1.2596
1998	NUMRS	14.4989	15.9974	16.3359	15.3965	15.4742	14.8582	15.6056	14.8560	14.0103	13.2044	14.0129	16.0361
1998	QRS_NUMR	-10.3094	-10.2789	-10.1529	-10.3891	-10.6234	-10.7340	-10.8047	-10.2558	-10.3918	-11.2958	-10.8069	-10.4719
1999	TRS87	1.0889	1.3689	0.7701	0.9219	1.3943	1.1805	1.2698	0.9010	1.0445	1.9481	1.4173	1.0852
1999	NUMRS	14.5139	15.9997	16.3533	15.3897	15.5150	14.8715	15.6069	14.8947	14.0632	13.2297	14.0591	16.0522
1999	QRS_NUMR	-10.2181	-10.2620	-10.1580	-10.3818	-10.6582	-10.7539	-10.8316	-10.2372	-10.2219	-11.2957	-10.7622	-10.4560
2000	TRS87	1.2021	1.1666	0.7641	0.9369	1.2873	1.2075	1.2439	0.7683	1.0360	1.9498	1.0543	1.1401
2000	NUMRS	14.5479	16.0179	16.3707	15.4080	15.5191	14.8989	15.6219	14.9377	14.1061	13.2568	14.0976	16.0564
2000	QRS_NUMR	-10.2939	-10.2010	-10.0886	-10.3475	-10.4772	-10.7147	-10.7695	-10.2952	-10.2961	-11.3271	-10.7458	-10.5203
2001	TRS87	1.5986	1.5336	0.8858	1.1518	1.4931	1.4535	1.3543	1.2768	1.4339	2.1949	1.5484	1.1171
2001	NUMRS	14.5525	16.0404	16.3786	15.4165	15.5482	14.9102	15.6258	14.9727	14.1408	13.2883	14.1309	16.0808
2001	QRS_NUMR	-10.3591	-10.3157	-10.2289	-10.4221	-10.6404	-10.8037	-10.8797	-10.3798	-10.1673	-11.3560	-10.9661	-10.6333
2002	TRS87	1.1783	1.3180	0.4898	0.9135	1.4253	1.3279	1.2407	0.9776	1.3118	2.0916	1.6413	1.0325
2002	NUMRS	14.5638	16.0403	16.3942	15.4318	15.5633	14.9165	15.6392	15.0026	14.1702	13.3108	14.1679	16.0935
2002	QRS_NUMR	-10.2894	-10.2494	-10.0372	-10.4213	-10.5565	-10.7848	-10.8196	-10.2990	-10.3072	-11.3809	-11.0132	-10.5959
2003	TRS87	1.6186	1.5151	0.9115	1.0726	1.5988	1.4413	1.5072	0.9738	1.0335	2.2077	1.6160	1.0526
2003	NUMRS	14.5811	16.0513	16.3998	15.4423	15.5781	14.9256	15.6478	15.0353	14.2350	13.3332	14.1914	16.1013
2003	QRS_NUMR	-10.2544	-10.2498	-10.1390	-10.4069	-10.6046	-10.8938	-10.9634	-10.3580	-10.3962	-11.4032	-10.9974	-10.5834
2004	TRS87	1.4646	1.4598	0.8796	1.1230	1.6372	1.4839	1.5330	0.9555	1.1681	2.1940	1.6409	0.9058
2004	NUMRS	14.5756	16.0534	16.4051	15.4520	15.5898	14.9327	15.6576	15.0708	14.2355	13.3677	14.2230	16.1165
2004	QRS_NUMR	-10.3369	-10.3011	-10.2379	-10.5061	-10.6721	-10.9527	-10.9803	-10.3803	-10.4749	-11.3955	-11.0150	-10.6372
2005	TRS87	1.2565	1.3067	0.8920	1.0574	1.5239	1.4063	1.5061	0.9768	1.1534	2.0852	1.4960	0.9310

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
2005	NUMRS	14.5778	16.0534	16.4355	15.4628	15.6158	14.9387	15.6603	15.1071	14.2811	13.3940	14.2685	16.1330
2005	QRS_NUMR	-10.3301	-10.3133	-10.2901	-10.5292	-10.6477	-10.8541	-10.9974	-10.4205	-10.4464	-11.3454	-11.0278	-10.6804
2006	TRS87	1.5839	1.4591	0.9431	1.1597	1.7837	1.5063	1.6380	0.8924	1.4159	2.2101	1.8361	1.1429
2006	NUMRS	14.6041	16.0667	16.4213	15.4743	15.6183	14.9404	15.6673	15.1360	14.3135	13.4197	14.2995	16.1530
2006	QRS_NUMR	-10.4060	-10.4084	-10.2527	-10.5223	-10.6889	-10.9109	-11.0536	-10.4466	-10.4555	-11.4250	-11.0867	-10.6868
2007	TRS87	1.5611	1.4748	1.0919	1.3310	1.7778	1.4913	1.5573	0.9662	1.4900	2.1891	1.8070	1.1891
2007	NUMRS	14.6116	16.0784	16.4269	15.4747	15.6430	14.9418	15.6896	15.1576	14.3400	13.4342	14.3264	16.1636
2007	QRS_NUMR	-10.3719	-10.3408	-10.3127	-10.5771	-10.6998	-10.9956	-11.0435	-10.4942	-10.4203	-11.4010	-11.1591	-10.7360
2008	TRS87	1.4298	1.4639	1.2161	1.2273	1.6152	1.4734	1.4704	0.7659	0.9869	2.0844	1.8111	1.2459
2008	NUMRS	14.6286	16.0706	16.4277	15.4811	15.6491	14.9374	15.6981	15.1769	14.3588	13.4288	14.3374	16.1708
2008	QRS_NUMR	-10.3753	-10.3351	-10.2613	-10.4774	-10.6242	-10.8958	-11.0306	-10.4334	-10.3485	-11.3981	-11.1367	-10.7886
2009	TRS87	1.7502	1.6044	1.1547	1.2444	1.8710	1.6198	1.6156	0.9761	1.5667	2.3046	1.8086	1.1597
2009	NUMRS	14.5832	16.0687	16.4454	15.4815	15.6506	14.9563	15.6793	15.1583	14.3126	13.4289	14.3197	16.1646
2009	QRS_NUMR	-10.4626	-10.3705	-10.2891	-10.5011	-10.7517	-10.9740	-10.9774	-10.3727	-10.3909	-11.4718	-11.0855	-10.7547

Table F7

Data: Equation for commercial distribution tariffs

Author: Ernest Zampelli, SAIC, with Ben Laughlin, EIA Intern, 2010.

Source: The source for the peak and off-peak data used in this estimation was the *Natural Gas Monthly*, DOE/EIA-0130. State level city gate and commercial prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM regions) prices. The quantity-weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. Historical commercial floorspace data by census division were extracted from the NEMS model and allocated to NGTDM region using Census population figures.

Variables:

$TCM_{r,n,t}$ = commercial distributor tariff in region r, network n (1987 dollars per Mcf) [$DTAR\_SF_2$]

REG_r = 1, if observation is in region r, =0 otherwise

$QCM\_FLRr_{r,n,t}$ = commercial gas consumption per floorspace for region r in year t (Bcf) [($BASQTY\_SF_2$+$BASQTY\_SI_2$)/FLRSPC12]

$FLR_{r,t}$ = commercial floorspace for region r in year t (estimated in thousand square feet) [FLRSPC12]

r = NGTDM region

n = network (1=peak, 2=off-peak)

t = year

$\alpha_{r,n}$ = estimated parameters for regional dummy variables [PCMREGPK13]

$\beta_{1,n}$,$\beta_{2,n}$ = estimated parameters

ρ_n = autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The commercial distributor tariff equation was estimated using panel data for the 12 NGTDM regions over the 1990 to 2009 time period. The equation was estimated in log-linear form with corrections for cross sectional heteroscedasticity and first order serial correlation using EViews. The form of the estimated equation follows:

$$\begin{aligned} \ln TCM_{r,n,t} = & \sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QCM\_FLR_{r,n,t} + \beta_{2,n} * \ln FLR_{r,t} + \\ & \rho_n * \ln TCM_{r,n,t-1} - \rho_n * (\sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QCM\_FLR_{r,n,t-1} + \beta_{2,n} * \ln NUMCM_{r,t-1}) \end{aligned}$$

Regression Diagnostics and Parameter Estimates for the Peak Period

Dependent Variable: LNTCM87
Method: Least Squares
Date: 07/23/10 Time: 08:03
Sample (adjusted): 2 240
Included observations: 239 after adjustments
Convergence achieved after 9 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=4)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQCM_FLR	-0.217322	0.129951	-1.672341	0.0959
LNFLR	0.218189	0.121009	1.803081	0.0727
REGION=1	-4.498378	1.340720	-3.355196	0.0009
REGION=2	-4.852790	1.408476	-3.445420	0.0007
REGION=3	-5.471895	1.435476	-3.811903	0.0002
REGION=4	-5.266668	1.364229	-3.860545	0.0001
REGION=5	-5.054427	1.410819	-3.582619	0.0004
REGION=6	-4.975067	1.349163	-3.687521	0.0003
REGION=7	-5.517942	1.406269	-3.923816	0.0001
REGION=8	-5.253175	1.305366	-4.024293	0.0001
REGION=9	-4.795673	1.307829	-3.666896	0.0003
REGION=10	-5.051970	1.397162	-3.615881	0.0004
REGION=11	-4.899262	1.299003	-3.771555	0.0002
REGION=12	-4.817270	1.405236	-3.428085	0.0007
AR(1)	0.284608	0.083893	3.392527	0.0008

R-squared	0.809134	Mean dependent var	0.594811
Adjusted R-squared	0.797204	S.D. dependent var	0.347177
S.E. of regression	0.156344	Akaike info criterion	-0.812814
Sum squared resid	5.475313	Schwarz criterion	-0.594626
Log likelihood	112.1313	Hannan-Quinn criter.	-0.724890
Durbin-Watson stat	1.979180		

Regression Diagnostics and Parameter Estimates for the Off-Peak Period

Dependent Variable: LNTCM87
Method: Least Squares
Date: 07/23/10 Time: 08:04
Sample: 241 480
Included observations: 240
Convergence achieved after 6 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=4)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQCM_FLRSPC	-0.613588	0.209576	-2.927752	0.0038
LNFLRSPC	0.530831	0.213552	2.485719	0.0137
REGION=1	-13.87098	1.869814	-7.418373	0.0000
REGION=2	-14.12193	2.052895	-6.879033	0.0000
REGION=3	-14.49560	2.085660	-6.950127	0.0000
REGION=4	-14.29389	1.944700	-7.350175	0.0000
REGION=5	-14.37939	2.005218	-7.170990	0.0000
REGION=6	-13.98336	1.889625	-7.400073	0.0000

REGION=7	-14.50539	2.000913	-7.249384	0.0000
REGION=8	-13.81237	1.894236	-7.291790	0.0000
REGION=9	-13.71773	1.813711	-7.563346	0.0000
REGION=10	-14.29647	1.877570	-7.614347	0.0000
REGION=11	-13.50724	1.778116	-7.596376	0.0000
REGION=12	-14.05762	2.001953	-7.021954	0.0000
AR(1)	0.166956	0.091737	1.819954	0.0701

R-squared	0.603286	Mean dependent var	0.577749
Adjusted R-squared	0.578601	S.D. dependent var	0.335016
S.E. of regression	0.217477	Akaike info criterion	-0.152989
Sum squared resid	10.64162	Schwarz criterion	0.064551
Log likelihood	33.35864	Hannan-Quinn criter.	-0.065336
Durbin-Watson stat	1.997625		

Data used for peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TCM87	1.03354	0.782073	0.14842	0.042101	0.696143	0.430483	0.206201	0.028587	0.679555	0.735248	0.541161	0.904218
1990	QCM_FLR	-10.80819	-10.27518	-10.02571	-10.0121	-10.87259	-10.66464	-10.6939	-10.05054	-10.88697	-12.19567	-10.64772	-10.65706
1990	FLR	14.73416	15.69451	15.92281	15.07962	15.5246	14.82673	15.50667	14.31229	14.34193	14.8613	13.94832	15.48136
1991	TCM87	1.008688	0.80245	0.200489	0.090754	0.643432	0.518198	0.224742	0.058269	0.615186	0.76314	0.578297	1.0654
1991	QCM_FLR	-10.78194	-10.22102	-9.971767	-9.929256	-10.76971	-10.60622	-10.60989	-9.986422	-10.86598	-12.15423	-10.671	-10.80858
1991	FLR	14.74157	15.70491	15.93733	15.09204	15.55072	14.84239	15.51601	14.33424	14.36901	14.88742	13.97028	15.50845
1992	TCM87	1.074661	0.861201	0.193921	0.170586	0.711478	0.563608	0.322083	0.08526	0.658556	0.709021	0.549277	1.072268
1992	QCM_FLR	-10.67296	-10.15695	-9.984192	-10.02488	-10.69684	-10.61159	-10.66214	-10.05214	-10.96197	-12.10189	-10.66952	-10.77438
1992	FLR	14.74724	15.71275	15.94971	15.10304	15.57115	14.85401	15.52609	14.35083	14.38809	14.90785	13.98686	15.52753
1993	TCM87	1.017041	0.82242	0.265436	0.131905	0.680062	0.514618	0.288931	0.130151	0.625404	0.920283	0.581657	1.135587
1993	QCM_FLR	-10.61099	-10.14154	-9.926096	-9.900956	-10.64854	-10.54903	-10.68735	-9.946373	-10.76914	-12.1597	-10.7212	-10.84729
1993	FLR	14.75353	15.71675	15.96006	15.1135	15.58787	14.86603	15.53845	14.36863	14.40303	14.92458	14.00466	15.54246
1994	TCM87	1.17619	0.949339	0.377751	0.309688	0.710004	0.648673	0.266969	-0.037702	0.720762	0.729961	0.702602	1.439124
1994	QCM_FLR	-10.35558	-10.09798	-9.894967	-9.90904	-10.65618	-10.51963	-10.67386	-10.01784	-10.85795	-12.16941	-10.77524	-10.88982
1994	FLR	14.75796	15.72214	15.97161	15.12337	15.60436	14.88037	15.55029	14.39101	14.41575	14.94106	14.02705	15.55519
1995	TCM87	1.130434	0.950885	0.228728	0.249201	0.708036	0.628075	0.276115	0.18648	0.783445	0.727065	0.781616	1.382788
1995	QCM_FLR	-10.43041	-10.10463	-9.908138	-9.943346	-10.64013	-10.52523	-10.63409	-10.10654	-10.91288	-12.16089	-10.87959	-10.88643
1995	FLR	14.76406	15.72657	15.98518	15.1362	15.6225	14.89741	15.56682	14.41638	14.42795	14.9592	14.05242	15.56738
1996	TCM87	0.984697	0.874218	-0.04919	0.27079	0.548121	0.135405	0.138892	-0.019183	0.64815	0.639219	0.322808	1.107572
1996	QCM_FLR	-10.34278	-9.983987	-9.842353	-9.848968	-10.62702	-10.44972	-10.65972	-10.0069	-10.77339	-12.14789	-10.81071	-11.03641
1996	FLR	14.77156	15.73278	15.99937	15.15122	15.6444	14.91814	15.58439	14.44409	14.44094	14.98111	14.08013	15.58038
1997	TCM87	1.108893	0.927428	0.336472	0.222343	0.738598	0.559616	0.195567	-0.139262	0.475613	0.667316	0.360468	1.096276
1997	QCM_FLR	-10.30902	-10.00031	-9.948278	-9.98826	-10.68835	-10.55067	-10.5866	-9.999211	-10.86226	-12.31262	-10.71917	-10.94718
1997	FLR	14.78041	15.73888	16.01425	15.16549	15.6683	14.9417	15.60114	14.47542	14.45301	15.00501	14.11146	15.59244
1998	TCM87	1.06264	0.691646	0.300845	0.277632	0.718327	0.675492	0.447247	0.275356	0.617345	0.823298	0.609222	1.234308
1998	QCM_FLR	-10.39582	-9.992437	-10.09763	-10.06498	-10.71608	-10.66425	-10.75371	-10.09564	-10.80522	-12.32806	-10.73728	-10.96726
1998	FLR	14.79058	15.74669	16.03036	15.1816	15.69627	14.96628	15.62199	14.50829	14.46986	15.03297	14.14433	15.60929
1999	TCM87	1.021371	0.608678	0.291176	0.29565	0.561899	0.642906	0.280657	0.464363	0.58389	0.822859	0.687632	1.094604
1999	QCM_FLR	-10.59798	-9.933422	-10.01313	-10.06831	-10.72396	-10.66884	-10.76822	-10.20156	-10.74532	-12.35381	-10.84215	-10.95635
1999	FLR	14.80814	15.7567	16.04907	15.20068	15.72808	14.99202	15.64769	14.55063	14.49341	15.06479	14.18667	15.63284
2000	TCM87	0.813593	1.010509	0.002996	0.24686	0.687129	0.403463	-0.115411	0.111541	0.594431	0.690143	0.144966	0.967744
2000	QCM_FLR	-10.52122	-9.982545	-9.976626	-10.04653	-10.673	-10.60803	-10.71636	-10.16844	-10.7873	-12.1577	-10.87075	-11.04346
2000	FLR	14.82306	15.76907	16.06954	15.22189	15.76349	15.01802	15.67919	14.59011	14.51777	15.10019	14.22614	15.65721
2001	TCM87	0.740985	0.905432	0.128393	0.191446	0.771034	0.570414	-0.071496	0.242946	0.535908	1.127524	0.222343	0.726582
2001	QCM_FLR	-10.5722	-10.07162	-10.03531	-10.04857	-10.79009	-10.65373	-10.74992	-10.12952	-10.76708	-12.16264	-10.87023	-11.06204
2001	FLR	14.84233	15.78239	16.08961	15.2449	15.79681	15.04719	15.70677	14.6275	14.54296	15.13352	14.26353	15.6824
2002	TCM87	0.995102	0.442118	0.1415	0.203757	0.764072	0.731887	0.350657	0.360468	1.055705	1.118742	0.911479	0.885419
2002	QCM_FLR	-10.63463	-10.05163	-10.1255	-10.27543	-10.77561	-10.70046	-10.66041	-10.1548	-10.89604	-12.07748	-10.91055	-11.1448
2002	FLR	14.86432	15.79755	16.10825	15.26372	15.82963	15.0726	15.73421	14.66104	14.56744	15.16634	14.29707	15.70687
2003	TCM87	0.735728	0.82154	-0.043952	-0.009041	0.517006	0.508623	0.024693	-0.149661	0.515813	1.028547	0.442761	0.789366
2003	QCM_FLR	-10.60418	-9.934664	-9.984421	-10.07127	-10.73325	-10.63397	-10.67996	-10.25794	-10.94268	-12.1272	-10.99802	-11.08346
2003	FLR	14.87915	15.81076	16.124	15.28423	15.8558	15.09277	15.75895	14.68954	14.58792	15.1925	14.32557	15.72736
2004	TCM87	1.160334	0.913487	0.180653	0.280657	0.752359	0.666803	0.349952	0.094401	0.834213	1.166582	0.519984	0.799757
2004	QCM_FLR	-10.65883	-9.927092	-10.04934	-10.10882	-10.72775	-10.70777	-10.79844	-10.24872	-10.90133	-12.10691	-10.9337	-11.14323
2004	FLR	14.8915	15.82207	16.13839	15.30039	15.88185	15.11195	15.78199	14.71552	14.60498	15.21855	14.35156	15.74441
2005	TCM87	1.066433	0.756122	0.198031	0.318454	0.733329	0.942738	0.486738	0.366724	0.740985	1.011964	0.555608	0.914689
2005	QCM_FLR	-10.65271	-10.03913	-10.07135	-10.17298	-10.75486	-10.78261	-10.93415	-10.27977	-10.90604	-12.12498	-11.03518	-11.20321
2005	FLR	14.90435	15.83166	16.15338	15.31553	15.90631	15.13114	15.80292	14.74137	14.62178	15.24301	14.37741	15.76122
2006	TCM87	1.111199	0.781158	0.364643	0.509224	0.94585	0.92267	0.485508	0.423305	0.945461	1.307792	0.771034	0.947789
2006	QCM_FLR	-10.80154	-10.20122	-10.25512	-10.32185	-10.91544	-10.88917	-11.06584	-10.31421	-10.89834	-12.28774	-11.06119	-11.18639
2006	FLR	14.92068	15.84244	16.17045	15.33077	15.93231	15.15151	15.82449	14.7725	14.63929	15.26902	14.40853	15.77872
2007	TCM87	1.20627	0.597737	0.206201	0.408128	0.905028	0.699626	0.105261	0.038259	1.04486	1.032116	0.782988	0.732368
2007	QCM_FLR	-10.64449	-10.08287	-10.14895	-10.20875	-10.86095	-10.87075	-10.94939	-10.26239	-10.87505	-12.31859	-11.02282	-11.12961
2007	FLR	14.93262	15.85366	16.18633	15.34587	15.95991	15.1722	15.84616	14.80524	14.65694	15.29661	14.44127	15.79638
2008	TCM87	1.045212	0.580538	0.099845	0.245296	0.81978	0.683602	0.142367	-0.042908	0.821101	1.002101	0.560758	0.797958
2008	QCM_FLR	-10.70065	-10.08087	-10.08169	-10.10907	-10.88544	-10.82181	-10.96436	-10.25204	-10.86054	-12.33066	-11.05978	-11.13563

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
2008	FLR	14.946	15.86429	16.20345	15.36096	15.98527	15.19212	15.87062	14.83697	14.67404	15.32198	14.473	15.81347
2009	TCM87	1.185096	0.609222	0.404798	0.444686	0.78527	0.897719	0.447886	0.214305	0.950499	1.03176	0.65752	0.783445
2009	QCM_FLR	-10.72952	-10.06608	-10.12776	-10.18844	-10.85652	-10.88899	-10.99863	-10.33785	-10.83499	-12.34896	-11.17492	-11.19006
2009	FLR	14.95814	15.87473	16.21753	15.37525	16.00654	15.20937	15.88914	14.86197	14.68849	15.34324	14.49801	15.82793

Data used for off-peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TCM87	0.81978	0.711969	0.379805	-0.177931	0.630207	0.528862	0.183155	-0.185125	0.738121	0.738121	0.564177	0.534151
1990	QCM_FLR	-10.90124	-10.34489	-10.31414	-10.18253	-10.96697	-10.85666	-10.5901	-10.29073	-11.02909	-11.77349	-10.73081	-10.38875
1990	FLR	14.73416	15.69451	15.92281	15.07962	15.5246	14.82673	15.50667	14.31229	14.34193	14.8613	13.94832	15.48136
1991	TCM87	0.818016	0.702602	0.413433	-0.080126	0.578858	0.560758	0.221542	-0.176737	0.702602	0.730443	0.666803	0.728514
1991	QCM_FLR	-10.9393	-10.37896	-10.37715	-10.1497	-10.89713	-10.89184	-10.59688	-10.25007	-10.93988	-11.7143	-10.73172	-10.31648
1991	FLR	14.74157	15.70491	15.93733	15.09204	15.55072	14.84239	15.51601	14.33424	14.36901	14.88742	13.97028	15.50845
1992	TCM87	0.513422	0.700123	0.262364	-0.125563	0.429832	0.430483	0.087095	-0.55687	0.782073	0.693147	0.491031	0.436318
1992	QCM_FLR	-10.7426	-10.30278	-10.2948	-10.18815	-10.82841	-10.83675	-10.55567	-10.36185	-11.10669	-11.68164	-10.67683	-10.38468
1992	FLR	14.74724	15.71275	15.94971	15.10304	15.57115	14.85401	15.52609	14.35083	14.38809	14.90785	13.98686	15.52753
1993	TCM87	0.14842	0.671924	0.438255	0.059212	0.506215	0.442761	0.132781	-0.125563	0.677526	0.946238	0.567584	0.850151
1993	QCM_FLR	-10.76579	-10.33389	-10.30689	-10.20689	-10.84683	-10.79649	-10.57541	-10.22038	-11.00829	-11.6948	-10.64436	-10.5797
1993	FLR	14.75353	15.71675	15.96006	15.1135	15.58787	14.86603	15.53845	14.36863	14.40303	14.92458	14.00466	15.54246
1994	TCM87	0.365337	0.90987	0.555608	-0.142716	0.559044	0.620576	0.367417	-0.015114	0.703098	0.845439	0.733329	1.214022
1994	QCM_FLR	-10.57619	-10.34363	-10.38704	-10.28376	-10.88405	-10.89237	-10.6291	-10.23104	-10.98642	-11.76509	-10.68369	-10.49269
1994	FLR	14.75796	15.72214	15.97161	15.12337	15.60436	14.88037	15.55029	14.39101	14.41575	14.94106	14.02705	15.55519
1995	TCM87	0.436318	0.880456	0.265436	0.051643	0.555034	0.525911	0.170586	0.276115	0.815365	0.727065	0.758935	1.09293
1995	QCM_FLR	-10.55041	-10.25587	-10.26514	-10.18332	-10.83986	-10.85856	-10.48104	-10.1478	-10.98213	-11.78257	-10.71065	-10.41359
1995	FLR	14.76406	15.72657	15.98518	15.1362	15.6225	14.89741	15.56682	14.41638	14.42795	14.9592	14.05242	15.56738
1996	TCM87	0.249201	0.760338	0.35977	0.07139	0.596085	0.65024	0.157858	0.025668	0.590561	0.832474	0.407463	0.910675
1996	QCM_FLR	-10.42864	-10.23423	-10.23524	-10.16125	-10.79765	-10.7675	-10.6159	-10.19003	-10.89767	-11.76986	-10.70743	-10.61657
1996	FLR	14.77156	15.73278	15.99937	15.15122	15.6444	14.91814	15.58439	14.44409	14.44094	14.98111	14.08013	15.58038
1997	TCM87	0.528273	0.00995	0.335043	-0.191161	0.695644	0.690143	0.358374	0.178146	0.483043	0.875885	0.522359	0.909468
1997	QCM_FLR	-10.32009	-9.960956	-10.25067	-10.28505	-10.78882	-10.73029	-10.48983	-10.22183	-10.87255	-11.91702	-10.78638	-10.5713
1997	FLR	14.78041	15.73888	16.01425	15.16549	15.6683	14.9417	15.60114	14.47542	14.45301	15.00501	14.11146	15.59244
1998	TCM87	0.385262	0.413433	0.524729	0.175633	0.744315	0.607044	0.510426	0.574364	0.617885	0.809151	0.828115	1.053615
1998	QCM_FLR	-10.47149	-10.05141	-10.4248	-10.4753	-10.83441	-10.90459	-10.71362	-10.26044	-10.98847	-11.91034	-10.78333	-10.41553
1998	FLR	14.79058	15.74669	16.03036	15.1816	15.69627	14.96628	15.62199	14.50829	14.46986	15.03297	14.14433	15.60929
1999	TCM87	-0.357674	0.32573	-0.375693	-0.036332	-0.640274	-0.603769	-0.41871	-0.502592	-0.576051	-0.82022	-0.599386	-0.945073
1999	QCM_FLR	10.5712	9.960255	10.44113	10.47538	10.90767	10.88557	10.76356	10.30853	10.88778	12.00961	10.78357	10.69796
1999	FLR	-14.80814	-15.7567	-16.04907	-15.20068	-15.72808	-14.99202	-15.64769	-14.55063	-14.49341	-15.06479	-14.18667	-15.63284
2000	TCM87	-0.209487	-0.500875	0.370183	0.173953	0.585005	0.626473	0.235072	0.237441	0.323532	0.661657	0.157004	0.856116
2000	QCM_FLR	-10.64719	-9.928819	-10.38156	-10.45832	-10.87819	-10.97466	-10.67225	-10.32453	-10.89739	-11.73493	-10.80875	-10.6644
2000	FLR	14.82306	15.76907	16.06954	15.22189	15.76349	15.01802	15.67919	14.59011	14.51777	15.10019	14.22614	15.65721
2001	TCM87	0.731406	0.951272	0.576051	0.491031	0.907855	0.963937	0.452985	1.003202	1.0936	1.363026	0.74479	0.817133
2001	QCM_FLR	-10.75139	-10.03607	-10.51336	-10.54833	-10.92828	-11.03404	-10.86342	-10.44685	-10.81949	-11.73978	-10.91398	-10.69869
2001	FLR	14.84233	15.78239	16.08961	15.2449	15.79681	15.04719	15.70677	14.6275	14.54296	15.13352	14.26353	15.6824
2002	TCM87	0.274597	0.290428	0.260825	0.303063	0.662688	0.824175	0.306749	0.540579	0.836381	1.101608	0.853564	0.605408
2002	QCM_FLR	-10.69804	-9.993283	-10.3539	-10.51929	-10.95871	-11.03534	-10.62712	-10.39477	-11.01604	-11.64437	-10.9786	-10.73535
2002	FLR	14.86432	15.79755	16.10825	15.26372	15.82963	15.0726	15.73421	14.66104	14.56744	15.16634	14.29707	15.70687
2003	TCM87	1.125579	0.783445	0.50742	0.407463	0.793897	0.764537	0.682592	0.541161	0.463734	1.20147	0.724646	0.72222
2003	QCM_FLR	-10.81744	-10.1338	-10.46123	-10.54033	-10.94377	-11.05512	-10.73289	-10.43014	-11.01381	-11.70079	-10.98742	-10.85435
2003	FLR	14.87915	15.81076	16.124	15.28423	15.8558	15.09277	15.75895	14.68954	14.58792	15.1925	14.32557	15.72736
2004	TCM87	0.826366	0.740508	0.386622	0.363948	0.710004	0.814479	0.650761	0.490419	0.78982	1.18142	0.762207	0.394067
2004	QCM_FLR	-10.95466	-10.09444	-10.51966	-10.58474	-10.97447	-11.05178	-10.85089	-10.47832	-11.07644	-11.69623	-11.01532	-10.84808
2004	FLR	14.8915	15.82207	16.13839	15.30039	15.88185	15.11195	15.78199	14.71552	14.60498	15.21855	14.35156	15.74441
2005	TCM87	0.592774	0.527093	0.255417	0.180653	0.463734	0.789366	0.541161	0.444045	0.519984	0.941569	0.456792	0.432432
2005	QCM_FLR	-10.98257	-10.26062	-10.56394	-10.64246	-10.98874	-11.04146	-10.96842	-10.46439	-11.03032	-11.68515	-11.05266	-10.82296
2005	FLR	14.90435	15.83166	16.15338	15.31553	15.90631	15.13114	15.80292	14.74137	14.62178	15.24301	14.37741	15.76122
2006	TCM87	0.993622	0.35347	0.404131	0.408128	1.02029	0.916291	0.787548	0.463734	1.059178	1.178039	1.137512	0.795704
2006	QCM_FLR	-11.02975	-10.27795	-10.52172	-10.61187	-11.00399	-11.10895	-11.03871	-10.49775	-11.02842	-11.83787	-11.08461	-10.78475
2006	FLR	14.92068	15.84244	16.17045	15.33077	15.93231	15.15151	15.82449	14.7725	14.63929	15.26902	14.40853	15.77872
2007	TCM87	0.947789	0.405465	0.552159	0.579418	0.841998	0.852712	0.614104	0.594983	1.112186	1.178963	1.042042	0.792993
2007	QCM_FLR	-10.95062	-10.22291	-10.57512	-10.66478	-11.02575	-11.14991	-11.02351	-10.57283	-10.9986	-11.84828	-11.14366	-10.8093
2007	FLR	14.93262	15.85366	16.18633	15.34587	15.95991	15.1722	15.84616	14.80524	14.65694	15.29661	14.44127	15.79638
2008	TCM87	0.863312	0.539413	0.779325	0.496524	0.636577	0.909065	0.30822	0.239017	0.279146	1.082483	1.0431	0.923068
2008	QCM_FLR	-10.97875	-10.23502	-10.54087	-10.56937	-10.98552	-11.13943	-10.98381	-10.51688	-10.95221	-11.88835	-11.1648	-10.83484
2008	FLR	14.946	15.86429	16.20345	15.36096	15.98527	15.19212	15.87062	14.83697	14.67404	15.32198	14.473	15.81347
2009	TCM87	1.102272	0.518198	0.387301	0.436318	1.070213	1.057443	0.848012	0.623261	1.21075	1.154047	1.091588	0.718815
2009	QCM_FLR	-11.06186	-10.26981	-10.53377	-10.60598	-11.07528	-11.17901	-10.98755	-10.53441	-11.04401	-11.92348	-11.15915	-10.84407
2009	FLR	14.95814	15.87473	16.21753	15.37525	16.00654	15.20937	15.88914	14.86197	14.68849	15.34324	14.49801	15.82793

Table F8

Data: Equation for electric generator distribution tariffs or markups.

Author: Ernest Zampelli, SAIC, 2008.

Source: The original source for the natural gas prices to electric generators used with city gate prices to calculate markups was the *Electric Power Monthly*, DOE/EIA-0226. The original source for the rest of the data used was the *Natural Gas Monthly*, DOE/EIA-0130. State level city gate and electric generator prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM and 16 NGTDM/EMM regions, respectively) prices. The quantity-weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. The consumption data were generated within the historical routines in the NEMS system based on state level data from the original source and therefore may differ from the original source.

Variables:

$MARKUP_{r,t}$ = electric generator distributor tariff (or markup) in region r, year t (1987 dollars per Mcf) [UDTAR_SF]

$QELEC_{r,t}$ = electric generator consumption of natural gas [sum of BASUQTY_SF and BASUQTY_SI]

REG_r = 1, if observation is in region r, =0 otherwise

$\beta_{0.r}$ = coefficient on REGr [PELREG20 or PELREG25 equivalent to the product of REGr and β0r]

β_0, β_1 = Estimated parameters

ρ = autocorrelation coefficient

r = NGTDM/EMM region

t = year

n = season (1=peak, 2=off-peak)

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and/or in the model code.]

Derivation: The equation used for the peak and off-peak electric markups was estimated using panel data for the 16 EMM regions over the 1990 to 2009 time period and two periods. The equations were estimated in linear form allowing for region and period-specific intercepts and with corrections for cross sectional heteroscedasticity and first order serial correlation using EViews. Because the reported point estimates of the parameters yielded projections of the electric generator distributor tariffs that were considered inconsistent with analyst's expectations (i.e., that did not align well with more recent historical levels), the constant term in each equation was increased by one half of a standard deviation of the error, well within the 95% confidence interval limits for the parameters.

$$\mathrm{MARKUP}_{n,r,t} = \beta_{0,n} + \sum_r \beta_{0,n,r}\mathrm{REG}_r + \beta_{1,n}\mathrm{QELEC}_{n,r,t} + \rho * \mathrm{MARKUP}_{n,r,t-1}$$
$$- \rho_n * (\beta_{0,n} + \sum_r \beta_{0,n,r}\mathrm{REG}_r + \beta_{1,n}\mathrm{QELEC}_{n,r,t-1})$$

Regression Diagnostics and Parameter Estimates

This table reports the results of the estimation of the electric generator tariff equation allowing for different intercepts for each region/peak and off-peak period pairing.

Dependent Variable: TEU87
Method: Least Squares
Date: 08/03/10 Time: 08:58
Sample (adjusted): 2 640
Included observations: 639 after adjustments
Convergence achieved after 6 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=6)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.153777	0.059859	-2.569001	0.0104
R1N1	-0.569051	0.187530	-3.034454	0.0025
R1N2	-1.377838	0.165891	-8.305701	0.0000
R2N2	-0.836857	0.142380	-5.877619	0.0000
R4N1	-0.993607	0.123113	-8.070659	0.0000
R4N2	-0.966333	0.122853	-7.865788	0.0000
R5N2	-0.553732	0.118913	-4.656614	0.0000
R6N2	-0.549285	0.066117	-8.307780	0.0000
R7N2	-0.495265	0.150436	-3.292203	0.0011
R9N2	-0.349100	0.143640	-2.430379	0.0154
R10N1	-0.453206	0.099193	-4.568931	0.0000
R10N2	-0.625117	0.089210	-7.007262	0.0000
R11N1	-0.553142	0.115808	-4.776368	0.0000
R11N2	-1.148493	0.338392	-3.393968	0.0007
QELEC	7.04E-07	2.61E-07	2.703306	0.0071
AR(1), ρ	0.281378	0.048877	5.756867	0.0000

R-squared	0.337021	Mean dependent var	-0.341534
Adjusted R-squared	0.321059	S.D. dependent var	0.704578
S.E. of regression	0.580558	Akaike info criterion	1.775065
Sum squared resid	209.9805	Schwarz criterion	1.886738
Log likelihood	-551.1334	Hannan-Quinn criter.	1.818414
F-statistic	21.11324	Durbin-Watson stat	2.010879
Prob(F-statistic)	0.000000		

Data used for estimation

YEAR	REG	TEU87	QELEC	TEU87	QELEC	REG	TEU87	QELEC	TEU87	QELEC
		peak	peak	off-peak	off-peak		peak	peak	off-peak	off-peak
1990	1	-0.373	5477.792	-0.689	78029.21	9	0.202	112.733	-0.07	733.267
1991	1	-0.285	10403.05	-0.948	90079.95	9	-0.07	88	-1.004	350
1992	1	-0.431	4216.713	-0.879	124801.3	9	-0.031	85	-0.434	474
1993	1	-0.595	16036.8	-1.384	109778.2	9	-0.079	54	-1.686	1745
1994	1	-0.626	11368.83	-1.836	146989.2	9	0.061	118.826	-1.354	1249.174

YEAR	REG	TEU87	QELEC	TEU87	QELEC	REG	TEU87	QELEC	TEU87	QELEC
1995	1	-0.898	30834.64	-1.78	164613.4	9	0.142	380.87	-0.344	2539.13
1996	1	-0.544	30441.67	-1.507	152519.3	9	-0.009	471.804	-0.227	1934.196
1997	1	-0.647	51998.01	-0.985	152213	9	-0.044	478.75	-0.447	3349.25
1998	1	-0.527	58556.68	-1.476	124108.3	9	0.343	644.785	-0.557	11348.22
1999	1	-2.145	26046.15	-2.22	154448.8	9	-0.129	904	-0.324	10655
2000	1	-2.864	48405.54	-2.915	151491.4	9	-0.248	2628.278	0.356	6823.722
2001	1	-0.25	75437.73	-1.985	192119.3	9	-0.921	655.664	-0.514	6254.336
2002	1	-0.665	106724.8	-1.482	233054.2	9	-0.82	4669.191	-0.453	11638.81
2003	1	-0.218	93391.41	-0.622	249761.6	9	0.321	2993.909	-0.332	6293.09
2004	1	0.075	104596.4	-1.357	248623.6	9	-0.117	1886.401	-0.005	5208.599
2005	1	0.103	96665.48	-0.938	258176.5	9	0.616	5315.032	-0.031	17492.97
2006	1	-1.356	101914.5	-1.654	267822.5	9	-0.905	3080.886	-0.662	15897.11
2007	1	-0.079	103940.7	-1.287	277224.3	9	-0.312	6110.758	-0.597	20556.24
2008	1	0.252	101929.7	-0.739	250712.3	9	-0.071	4028.149	0.085	9966.851
2009	1	-0.906	113848.8	-1.615	238725.2	9	-1.09	3550.858	-0.92	8518.142
1990	2	-0.091	56008.69	-0.827	254571.3	10	-0.78	11836.17	-0.971	58827.83
1991	2	-0.157	64743.73	-0.898	267021.3	10	-0.812	15655.99	-1.021	51891.01
1992	2	-0.277	86805.72	-0.846	297436.3	10	-0.931	16384.83	-0.943	42633.17
1993	2	-0.302	83314.7	-0.87	308035.3	10	-0.715	8031.323	-0.744	38079.68
1994	2	-0.503	70013.87	-0.815	393282.2	10	-0.56	16516.63	-0.983	71653.38
1995	2	-0.444	134962.2	-0.675	487430.7	10	-0.607	30614.88	-0.86	89503.12
1996	2	0.171	62217.58	-0.622	411604.4	10	0.692	14569.8	-0.618	76325.2
1997	2	-0.502	111473	-1.339	456865	10	-0.684	14076	-0.592	70928
1998	2	-0.397	108447	-0.742	433440	10	-0.615	15754.85	-0.793	88350.15
1999	2	-0.284	108384.3	-0.864	496415.8	10	-0.541	28160.57	-0.566	103466.4
2000	2	0.037	120397.1	-0.692	408934.9	10	-0.559	34598.51	-0.28	108258.5
2001	2	0.566	114874.5	-0.896	393543.5	10	-1.737	40322.03	-1.047	177977
2002	2	-0.56	140725.3	-0.283	435593.6	10	-0.807	79041.83	-0.438	197026.2
2003	2	0.591	111812	-0.135	320290	10	0.211	58740.21	-0.426	123469.8
2004	2	0.17	121153.9	-0.097	354346.2	10	-0.434	59686.33	-0.333	164801.7
2005	2	0.356	116582	0.151	393216	10	0.674	56009.41	0.03	184339.6
2006	2	-0.916	137123.6	-1.023	482526.4	10	-1.223	46339.27	-0.933	239106.8
2007	2	-0.366	171300.2	-0.902	538288.8	10	-0.589	82203.64	-0.851	276528.3
2008	2	0.118	189873.8	-0.029	520375.2	10	-0.307	95446.84	-0.201	236164.2
2009	2	-1.209	212035.5	-1.426	544876.5	10	-1.263	121736.6	-1.046	292033.4
1990	3	0.477	150	-0.356	1103	11	-0.5	383955.5	-0.588	1244416
1991	3	-0.539	453	-0.68	2784	11	-0.471	381862.6	-0.474	1224830
1992	3	-0.597	933	-0.9	2023	11	-0.4	396487	-0.439	1151983
1993	3	-0.491	1267	0.237	1469	11	-0.39	381623.1	-0.41	1254746
1994	3	1.015	845.443	0.864	2122.557	11	-0.384	386224	-0.37	1266091
1995	3	-0.197	851.772	-0.584	6606.229	11	-0.555	426659.9	-0.507	1298862
1996	3	0.336	446.384	-0.27	2455.616	11	-0.183	387316.8	-0.302	1250172
1997	3	0.397	390	-0.063	3100	11	-0.628	378754.8	-0.27	1292336
1998	3	0.447	904.887	0.156	7075.113	11	-0.241	393644.6	-0.113	1588856
1999	3	0.282	2043.821	-0.556	9343.18	11	-0.407	449100.1	-0.214	1535106
2000	3	-0.057	2424.521	0.069	7697.479	11	-0.173	505656.9	-0.106	1587056
2001	3	1.586	1313.623	2.199	9230.377	11	-0.469	473726.6	-0.291	1475389
2002	3	-0.291	5156.494	-0.457	17565.51	11	-0.5	527764.5	-0.314	1583531
2003	3	-0.134	5862.449	0.086	12911.55	11	0.169	520349.9	0.035	1422995
2004	3	-0.037	5929.066	-0.26	12328.93	11	-0.229	496203.2	-0.024	1383611
2005	3	0.204	6165.703	-0.088	21775.3	11	0.066	497927.9	-0.046	1544522
2006	3	-0.931	4535.418	-0.126	18648.58	11	-0.645	474470.1	-0.286	1534773
2007	3	-0.287	9500.535	-0.174	27791.47	11	-0.524	541641.6	-0.532	1506612
2008	3	0.267	8165.851	1.186	15327.15	11	-0.454	571748.9	-0.527	1451966

YEAR	REG	TEU87	QELEC	TEU87	QELEC	REG	TEU87	QELEC	TEU87	QELEC
2009	3	-0.925	12502.88	-1.185	25454.13	11	-1.02	550137.3	-0.832	1434106
1990	4	-1.817	31429.56	-1.347	72129.44	12	-0.595	108.33	-0.957	376.67
1991	4	-1.348	31578.48	-1.253	77733.52	12	0.711	74.782	1.56	268.218
1992	4	-1.418	44851.64	-1.497	68893.36	12	1.405	51.828	-0.004	250.172
1993	4	-1.241	35502.96	-1.283	87438.03	12	0.845	112.683	0.455	242.317
1994	4	-0.907	45192.25	-1.022	104732.8	12	-0.713	189.751	-0.878	571.249
1995	4	-1.128	47723.8	-1.258	132765.2	12	5.098	93.277	1.118	422.723
1996	4	-1.342	41181.18	-1.264	136386.8	12	3.806	267.156	1.572	471.844
1997	4	-1.893	58116.89	-1.709	149975.1	12	-1.3	713.689	-0.673	1580.311
1998	4	-1.426	57722.75	-1.106	185009.2	12	-0.003	834	-1.099	1726
1999	4	-1.017	56206.06	-1.275	181599.9	12	-1.421	661.7	-1.291	1543.3
2000	4	-0.795	62974.71	-0.843	154818.3	12	-1.468	858	-1.035	2886
2001	4	-1.38	55546.81	-0.777	164441.2	12	-0.705	2966.774	-0.578	10398.23
2002	4	-0.447	64369.93	-0.624	219275	12	0.762	1841.396	0.58	4757.604
2003	4	-0.951	58171.08	-0.766	128116.9	12	-0.093	3115.147	-0.2	9223.853
2004	4	-1.009	67560.77	-1.245	140486.2	12	-0.73	3432.394	-0.513	9186.606
2005	4	-1.006	62452.09	-1.464	220560.9	12	-0.394	3310.012	-0.31	8903.987
2006	4	-1.683	43653.99	-0.841	179495	12	-0.645	2908.668	-0.985	8073.332
2007	4	-0.72	70883.59	-0.594	207352.4	12	-0.109	4028.414	-0.17	11499.59
2008	4	-0.447	70728.65	0.307	132756.4	12	0.074	4134.663	0.213	9996.337
2009	4	-0.718	63267.38	-1.036	128803.6	12	-0.835	3748.62	-0.598	9380.38
1990	5	-0.591	6513.661	-0.868	37663.33	13	-0.406	7475.622	-1.168	30674.38
1991	5	-0.577	8386.246	-0.945	54605.75	13	-0.725	8442.727	-1.35	32877.27
1992	5	-0.477	6564.392	-0.855	19551.61	13	-0.779	11631.35	-1.39	41860.65
1993	5	-0.404	5430.949	-0.708	31682.05	13	-0.202	16816.29	-0.642	41179.71
1994	5	-0.379	6607.164	-1.018	37455.84	13	-0.624	16133.88	-1.112	66494.13
1995	5	-0.49	9284.483	-0.854	48442.52	13	-0.717	25685.17	-0.801	67311.83
1996	5	-0.145	6701.926	-0.869	33308.07	13	-0.188	22187.69	-0.468	78930.31
1997	5	-0.485	7062.148	-1.058	40882.85	13	-0.467	22608.37	-0.311	83926.64
1998	5	-0.275	6673.499	-0.839	73116.5	13	-0.385	28588.31	0.006	94087.7
1999	5	-0.392	11064.86	-0.741	67943.15	13	-0.072	35234.71	-0.007	102074.3
2000	5	-0.33	14452.84	-0.533	73293.16	13	1.265	53316.27	0.455	141533.7
2001	5	-0.658	12855.91	-0.609	68365.09	13	1.211	71984.5	1.291	137618.5
2002	5	-0.502	14525.6	-0.627	61418.4	13	0.473	56705.46	0.332	146509.5
2003	5	0.365	12441.34	-0.24	51685.66	13	0.415	52597.99	0.28	155741
2004	5	0.111	15715.84	-0.398	45414.16	13	-0.132	62488.94	0.094	167248.1
2005	5	0.574	22234.67	-0.68	82644.33	13	0.01	68457.95	0.123	184153
2006	5	-0.07	16733.13	-0.368	93896.87	13	-0.452	76476.9	-0.827	212270.1
2007	5	0.162	36287.14	-0.307	106214.9	13	-0.652	91240.94	-0.624	260458.1
2008	5	0.254	40233.62	-0.079	81822.38	13	-0.092	100212.7	0.03	242283.3
2009	5	-0.488	30968.19	-0.602	68794.81	13	-0.614	101870	-0.415	254915
1990	6	0.123	5736.463	-0.57	45691.54	14	-0.12	12451.51	-0.552	37300.48
1991	6	-0.259	9603.718	-0.824	55953.28	14	-0.39	10503.82	-0.595	40932.18
1992	6	-0.1	13896.39	-0.568	40156.62	14	-0.093	11060.75	-0.151	42418.25
1993	6	-0.168	18359.31	-0.714	46145.68	14	0.047	11955.11	-0.095	36309.89
1994	6	-0.247	18000.7	-0.969	60320.31	14	-0.143	13658.88	-0.164	44792.13
1995	6	-0.142	25663.08	-0.677	78174.92	14	-0.125	13662.47	-0.176	40548.53
1996	6	-0.021	14490.55	-0.611	57460.45	14	0.394	11768.99	0.121	45934.01
1997	6	-0.455	11760.21	-0.704	48107.79	14	0.084	12934.19	-0.122	54012.81
1998	6	-0.031	10607.77	-0.703	82748.23	14	0.076	18095.38	-0.132	69705.62
1999	6	-0.088	18558	-0.702	88756	14	-0.042	22906.24	-0.124	74796.77
2000	6	-0.661	18429.81	-0.196	77524.2	14	0.368	33129.53	0.148	109635.5
2001	6	1.04	11727.8	-0.54	83846.2	14	0.489	49709.35	-0.107	128357.6
2002	6	-0.542	31719.6	-1.034	113421.4	14	0.286	50972.55	-0.266	131697.5

YEAR	REG	TEU87	QELEC	TEU87	QELEC	REG	TEU87	QELEC	TEU87	QELEC
2003	6	0.025	22153.38	-0.48	65724.62	14	0.355	52509.88	0.372	155480.1
2004	6	-0.342	31824.06	-0.621	96166.94	14	0.239	73750.1	0.265	197387.9
2005	6	-0.163	42401.81	-0.379	132210.2	14	0.716	70105.91	0.66	188586.1
2006	6	-1.163	38068.46	-0.523	135358.5	14	-0.245	80424.6	-0.312	223227.4
2007	6	-0.056	50933.98	-0.522	170925	14	-0.019	88519	-0.567	252688
2008	6	0.475	47926.71	-0.042	144152.3	14	-0.166	103157.1	0.523	249401.9
2009	6	-1.173	60839.04	-0.951	177359	14	-0.482	95551.13	-0.231	239102.9
1990	7	0.373	94	-0.127	1838	15	-0.398	2163.144	-0.413	5411.857
1991	7	0.18	86	-0.214	752	15	-0.111	2385.528	-0.415	10360.47
1992	7	0.599	40	-0.404	1122	15	-0.184	6807.541	0.497	19222.46
1993	7	0.601	112.963	-0.408	2913.037	15	0.499	26265.15	-0.027	18996.85
1994	7	0.485	268.321	-0.153	1070.679	15	-0.333	26457.18	-0.207	42886.82
1995	7	1.584	368.214	-0.26	10727.79	15	-0.285	17894.08	-0.113	41866.93
1996	7	1.371	208.809	-0.706	5566.191	15	0.58	1662.173	-0.161	66420.83
1997	7	0.181	323.943	-0.941	16729.06	15	0.104	7462.426	0.902	44431.57
1998	7	-1.064	845	-0.463	32505	15	-0.372	16440.47	-0.323	76776.53
1999	7	-0.867	683	-1.1	31822	15	-0.098	12471.85	-0.158	69827.15
2000	7	0.814	676	-0.777	41357	15	0.166	30435.15	0.56	113414.9
2001	7	-0.394	1813.314	-1.357	32851.69	15	0.213	55816.64	0.531	112908.4
2002	7	-0.472	12366.93	-0.961	44221.07	15	-0.439	30135.98	-0.949	65269.01
2003	7	-0.114	8131.998	-0.605	24126	15	-0.518	41637.16	-1.075	90642.84
2004	7	-0.437	11419.18	-0.718	34506.82	15	-0.675	46265.81	-0.82	108536.2
2005	7	0.062	17548.92	-0.107	54718.08	15	-0.387	48284.78	-0.701	105522.2
2006	7	-1.522	20942.52	-0.854	74464.48	15	-1.054	36728.14	-1.325	97256.86
2007	7	-0.527	27945.63	-0.963	93780.37	15	-0.7	45077.4	-0.962	113719.6
2008	7	0.218	24032.35	-0.327	72283.65	15	-0.536	62191.23	-0.708	129025.8
2009	7	-1.494	36520.59	-1.208	106465.4	15	-1.093	61018.65	-1.443	133252.4
1990	8	-0.111	53532.49	-0.081	135631.5	16	0.519	154426.4	0.106	474358.6
1991	8	-0.347	57488.14	-0.233	143844.9	16	0.314	200566.8	0.049	427968.1
1992	8	-0.559	54243.96	-0.149	149075	16	0.129	227147.9	0.029	535783.1
1993	8	-0.41	47776.24	-0.304	140451.8	16	0.261	244498.6	0.09	428566.4
1994	8	-0.538	53104.2	-0.412	158386.8	16	-0.027	238089.7	0.013	572584.3
1995	8	-0.384	80269.09	-0.369	289028.9	16	0.403	181126.9	0.103	421776.1
1996	8	-0.203	70158.84	-0.441	267108.2	16	0.446	116542	0.08	408493
1997	8	-1.335	88892.73	-0.917	249964.3	16	0.344	129870	0.036	465952
1998	8	-0.996	80991.75	-0.831	242778.3	16	0.378	206154	0.294	442932
1999	8	-0.436	83337	-0.25	282249	16	0.305	279871.4	0.035	443299.6
2000	8	-0.699	109654.3	-0.233	254590.7	16	3.086	234992	0.621	658384
2001	8	-0.608	88541.95	-0.013	285769.1	16	1.745	313453.9	1.712	659873.1
2002	8	0.223	114050.8	0.133	407817.2	16	0.606	229522.8	0.335	497104.2
2003	8	0.241	134894.4	0.056	400204.6	16	0.438	222017.6	0.166	483325.4
2004	8	-0.203	145665.3	0.002	440175.8	16	0.003	230285.1	-0.041	540231.9
2005	8	-0.598	153085.3	-0.367	477324.7	16	0.559	216351.5	-0.172	472817.5
2006	8	-0.21	162821.4	0.462	578937.6	16	-0.409	211302.6	0.249	559533.4
2007	8	0.835	177456.6	0.931	595511.4	16	0.046	236827.2	-0.076	597458.9
2008	8	0.396	198930.3	0.309	598335.6	16	0.092	279011.8	0.08	578855.2
2009	8	1.253	232426	1.368	677572	16	0.123	255257.8	0.146	557431.3

Table F9

Data: Equation for natural gas price at the Henry Hub

Author: Eddie Thomas, EI-83, 2008

Source: Annual natural gas wellhead prices and chain-type GDP price deflators data from EIA's *Annual Energy Review 2007*, DOE/EIA-0384(2007), published June 2008. Henry Hub spot price data from EIA's Short-Term Energy Outlook database series NGHHUUS; the annual Henry Hub prices equal the arithmetic average of the monthly data.

Variables:

HHPRICE	=	Henry Hub spot natural gas price (1987 dollars per MMBtu)
EIAPRICE	=	Average U.S. natural gas wellhead price (1987 dollars per Mcf)
HHPRICE_HAT	=	estimated values for Henry Hub price (1987 dollars per MMBtu)
α	=	estimated parameter
α_0	=	constant term
const2	=	constant term

Derivation: Using TSP version 5.0 and annual price data from 1995 through 2007, the first equation was estimated in log-linear form using ordinary least squares. The second equation estimates an adjustment factor that is applied in cases where the value of "y" is predicted from an estimated equation where the dependent variable is the natural log of y. The adjustment is due to the fact that generally predictions of "y" using the first equation only tend to be biased downward.

1) $\ln HHPRICE = \alpha_0 + (\alpha * \ln EIAPRICE)$
2) $HHPRICE = \beta * HHPRICE\_HAT$

Regression Diagnostics and Parameter Estimates

First Equation

Dependent variable: lnHHPRICE
Current sample: 1 to 13
Number of observations: 13

Mean of dep. var.	= 1.00473	LM het. test	= .317007 [.573]
Std. dev. of dep. var.	= .447616	Durbin-Watson	= 2.74129 [<.934]
Sum of squared residuals	= .048856	Jarque-Bera test	= .475878 [.788]
Variance of residuals	= .444143E-02	Ramsey's RESET2	= .103879 [.754]
Std. error of regression	= .066644	F (zero slopes)	= 530.339 [.000]
R-squared	= .979680	Schwarz B.I.C.	= -15.2838
Adjusted R-squared	= .977833	Log likelihood	= 17.8487

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value	Symbol
CONST	.090246	.043801	2.06036	[.064]	α_0
lnEIAPRICE	1.00119	.043475	23.0291	[.000]	α

Second Equation

Dependent variable: HHPRICE
Current sample: 1 to 13
Number of observations: 13

Mean of dep. var.	= 2.98879	LM het. test	= 2.14305 [.143]
Std. dev. of dep. var.	= 1.29996	Durbin-Watson	= 2.97238 [<1.00]
Sum of squared residuals	= .420043	Jarque-Bera test	= .138664 [.933]
Variance of residuals	= .035004	Ramsey's RESET2	= .655186 [.435]
Std. error of regression	= .187092	Schwarz B.I.C.	= -2.58158
R-squared	= .979456	Log likelihood	= 3.86405
Adjusted R-squared	= .979456		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value	Symbol
HHPRICE_HAT	1.00439	.016114	62.3290	[.000]	β

Data used for Estimation:

Year	**Henry Hub Spot Natural Gas Price ($/MMBtu, in 1987 dollars)**	**Average U.S. Wellhead Natural Gas Price ($/Mcf, in 1987 dollars)**
1995	1.34	1.23
1996	2.14	1.70
1997	1.91	1.79
1998	1.58	1.50
1999	1.70	1.65
2000	3.16	2.73
2001	2.83	2.89
2002	2.36	2.09
2003	3.77	3.40
2004	3.95	3.68
2005	5.62	4.79
2006	4.23	4.03
2007	4.26	3.90

Table F10

Data: Lease and plant fuel consumption in Alaska

Author: Margaret Leddy, EIA summer intern

Source: EIA's Petroleum Supply Annual and Natural Gas Annual.

Variables:

LSE_PLT = Lease and plant fuel consumption in Alaska [QALK_LAP_N]

OIL_PROD = Oil production in Alaska (thousand barrels) [OGPRCOAK]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Using EViews and annual price data from 1981 through 2007, the following equation was estimated using ordinary least squares without a constant term:

$$LSE\_PLT_t = \beta_{-1} * LSE\_PLT_{t-1} + \beta_1 * OIL\_PROD_t$$

The intent was to find an equation that demonstrated similar characteristics to the projection by the Alaska Department of Natural Resources in their "Alaska Oil and Gas Report."

Regression Diagnostics and Parameter Estimates

Dependent Variable: LSE_PLT
Method: Least Squares
Date: 07/24/09 Time: 17:34
Sample (adjusted): 1981 2007
Included observations: 27 after adjustments

	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
OIL_PROD	0.038873	0.015357	2.531280	0.0180	β_1
LSE_PLT_PREV	0.943884	0.037324	25.28876	0.0000	β_{-1}

R-squared	0.911327	Mean dependent var	210731.2
Adjusted R-squared	0.907780	S.D. dependent var	86703.97
S.E. of regression	26329.98	Akaike info criterion	23.26599
Sum squared resid	1.73E+10	Schwarz criterion	23.36198
Log likelihood	-312.0909	Hannan-Quinn criter.	23.29453
Durbin-Watson stat	2.407017		

Data used for Estimation:

Year	oil_prod	lse_plt	Year	oil_prod	lse_plt	Year	oil_prod	lse_plt
1981	587337	15249	1990	647309	193875	1999	383199	265504.375
1982	618910	94232	1991	656349	223194.366	2000	355199	269177.988
1983	625527	97828	1992	627322	234716.225	2001	351411	271448.841
1984	630401	111069	1993	577495	237701.556	2002	359335	285476.659
1985	666233	64148	1994	568951	238156.064	2003	355582	300463.487
1986	681310	72686	1995	541654	292810.594	2004	332465	281546.298
1987	715955	116682	1996	509999	295833.863	2005	315420	303215.128
1988	738143	153670	1997	472949	271284.345	2006	270486	257091.267
1989	683979	192239	1998	428850	281871.556	2007	263595	268571.098

Table F11

Data: Western Canada successful conventional gas wells

Author: Ernie Zampelli, SAIC, 2009

Source: Canadian Association of Petroleum Producers, Statistical Handbook. Undiscovered remaining resource estimates from National Energy Board of Canada.

Variables:

GWELLS = Number of successful new natural gas wells drilled in Western Canada [SUCWELL]

PGAS2000 = Average natural gas wellhead price in Alberta (2000 U.S. dollars per Mcf) [CN_PRC00]

REMAIN = Remaining natural gas undiscovered resources in Western Canada (Bcf) [URRCAN]

DRILLCOSTPERGASWELL2000 = U.S. based proxy for drilling cost per gas well (2000 U.S. dollars) [CST_PRXYLAG]

PR_LAG = Production to reserve ratio last forecast year [CURPRRCAN]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Using TSP version 5.0 and annual price data from 1978 through 2005, the following equation was estimated after taking natural logs of all of the variables and by instrumental variables:

$$\ln GWELLS = \beta_0 + \beta_1 * \ln PGAS2000 + \beta_2 * \ln REMAIN + \beta_3 * \ln DRILLCOSTPERGASWELL2000LAG + \beta_4 * PR\_LAG$$

Regression Diagnostics and Parameter Estimates

```
TSP Program File:  canada10_wells_v1.tsp
TSP Output File:  canada10_wells_v1.out
Data File: canada10.xls

Method of estimation = Instrumental Variable

 Dependent variable: LNGWELLS
 Endogenous variables: LNPGAS2000
 Included exogenous variables: C LNREMAIN PR_LAG LNDRILLCOSTPERGASWELL2000LAG
 Excluded exogenous variables: LNRIGS_AVAIL LNRIGS_ACT LNWOP2000
                               LNWOP2000(-1)
 Current sample:  32 to 59
 Number of observations:  28

        Mean of dep. var. = 8.22053  Adjusted R-squared = .868002
   Std. dev. of dep. var. = .770092       Durbin-Watson = 1.47006 [<.460]
 Sum of squared residuals = 1.81489     F (zero slopes) = 44.8913 [.000]
    Variance of residuals = .078908  F (over-id. rest.) = 3.04299 [.049]
 Std. error of regression = .280906              E'PZ*E = .720351
                R-squared = .887557
```

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value	Symbol
C	-1.85639	10.8399	-.171256	[.864]	β_0
LNPGAS2000	1.09939	.275848	3.98551	[.000]	β_1
LNREMAIN	1.57373	.767550	2.05033	[.040]	β_2
PR_LAG	33.6237	5.95568	5.64564	[.000]	β_3
LNDRILLCOSTPERGASWELL2000LAG	-.860630	.413101	-2.08334	[.037]	β_4

where LNGWELLS is the natural log of the number of successful gas wells drilled, C is the constant term, LNPGAS2000 is the natural log of the natural gas wellhead price in US$2000, LNREMAIN is the natural log of remaining natural gas resources, PR_LAG is the one-year lag of the natural gas production to reserves ratio, and LNDRILLCOSTPERGASWELL2000LAG is the one-year lag of the natural log drilling costs per gas well in US$2000.

Data used for Estimation:

OBS	Year	gwells	pgas2000	Remain	drillcostpergaswell2000
3	1949		0.048973961		
4	1950		0.326113924		
5	1951		0.332526561		
6	1952		0.53466758		
7	1953		0.520772302		
8	1954		0.518522266		
9	1955	168	0.508917468		
10	1956	180	0.506220324		
11	1957	194	0.521861883		
12	1958	200	0.481073325		
13	1959	302	0.452683617		
14	1960	292	0.474693506		487885.5568
15	1961	392	0.533594173		445149.9201
16	1962	331	0.529535218		450150.6792
17	1963	338	0.569702785		423745.2977
18	1964	308	0.58367073	247614.5688	473327.0074
19	1965	320	0.567907929	238537.3503	452030.1753
20	1966	342	0.576547139	236436.2237	577347.2558
21	1967	372	0.562604404	232547.9993	590110.0741
22	1968	478	0.537960863	229480.2528	596222.8555
23	1969	524	0.505967348	224686.5834	590148.7629
24	1970	731	0.518371638	219742.8184	583504.0314
25	1971	838	0.506420538	215141.3928	576188.9938
26	1972	1164	0.514557299	211401.9226	522986.1433
27	1973	1656	0.532790308	210506.5381	487525.511
28	1974	1902	0.791608407	207750.6318	544786.1771
29	1975	2080	1.411738215	207326.7494	689458.4496
30	1976	3304	2.237940881	203831.3434	672641.5564
31	1977	3192	2.599391226	201592.1585	733387.9117
32	1978	3319	2.626329384	196792.3469	817752.475
33	1979	3450	2.710346999	191501.0181	894243.9654
34	1980	4241	3.384567857	185756.1549	992546.6758
35	1981	3206	3.221572826	182757.9141	1181643.803
36	1982	2555	3.213342789	177773.8365	1377862.449
37	1983	1374	3.284911566	175254.2284	932534.8506
38	1984	1866	3.129580432	172207.6619	723979.0112
39	1985	2528	2.783743697	164103.9115	729665.916
40	1986	1298	2.102135277	163082.6472	733903.1579
41	1987	1599	1.70904727	162025.2004	519637.6851
42	1988	2300	1.605152553	161045.0253	608099.7173
43	1989	2313	1.6374231	159296.4045	582756.2503
44	1990	2226	1.616410647	154195.8722	577621.032
45	1991	1645	1.413315563	150493.0434	599894.6047
46	1992	908	1.302240063	147472.6695	493273.1377
47	1993	3327	1.450352061	144605.8153	589678.7771
48	1994	5333	1.51784337	141039.5975	592881.5963
49	1995	3325	1.094686059	137038.8014	683668.8164
50	1996	3664	1.255799796	130554.9327	656352.5551
51	1997	4820	1.46778215	128082.3795	763619.5946
52	1998	4955	1.340424158	126038.0859	845430.7986
53	1999	7005	1.702885108	122364.2737	815784.5261
54	2000	9034	3.139760843	117371.83	756939
55	2001	10693	3.517434005	112428.7004	875486.0887
56	2002	9011	2.374637309	105719.0529	951999.7696
57	2003	12911	4.216469412	100440.0085	1039434.608
58	2004	15041	4.506654918	95800	1568071.111
59	2005	15895	6.175733625	89650.7047	1324919.051
60	2006	13850	3.555109614	82089.6695	1161087.791
61	2007	9626	5.155666777	75854.5886	3260771.516
62	2008	8104	6.102395678	69930.7064	

Table F12

Data: Western Canada conventional natural gas finding rate

Author: Ernie Zampelli, SAIC, 2009

Source: Canadian Association of Petroleum Producers, Statistical Handbook. Undiscovered remaining resource estimates from National Energy Board of Canada.

Variables:

FR = Natural gas proved reserves added per successful natural gas well in Western Canada (Bcf/well) [FRCAN]

REMAIN = Remaining natural gas undiscovered resources in Western Canada (Bcf) [URRCAN]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The equation to project the average natural gas finding rate in Western Canada was estimated for the time period 1965-2007 using TSP version 5.0 and aggregated reserves and production data for the provinces in Western Canada. Natural logs were taken of all data before the estimation was performed. The following equation was estimated with correction for first-order serial correlation:

$$\ln FR_t = \beta_0 + \beta_1 * \ln REMAIN_t + \rho * \ln FR_{t-1} - \rho * (\beta_0 + \beta_1 * \ln REMAIN_{t-1})$$

Regression Diagnostics and Parameter Estimates

```
TSP Program File:  canada10_findrate_v1.tsp
TSP Output File:  canada10_findrate_v1.out
Data File:  canada10.xls

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

 Objective function:  Exact ML (keep first obs.)

 CONVERGENCE ACHIEVED AFTER   6 ITERATIONS

 Dependent variable: LNFR
 Current sample:  19 to 61
 Number of observations:  43
        Mean of dep. var. = .258333           R-squared = .523925
   Std. dev. of dep. var. = 1.01511  Adjusted R-squared = .500121
 Sum of squared residuals = 20.6112       Durbin-Watson = 2.19910
    Variance of residuals = .515280      Schwarz B.I.C. = 50.8486
 Std. error of regression = .717830      Log likelihood = -45.2068
```

Parameter	Estimate	Standard Error	t-statistic	P-value	Symbol
C	-25.3204	6.81740	-3.71409	[.000]	β_0
LNREMAIN	2.13897	.569561	3.75547	[.000]	β_1
RHO (ρ)	.428588	.139084	3.08150	[.002]	ρ

Data used for Estimation:

OBS	Year	fr	remain
17	1963	9.28880858	
18	1964	29.47148864	247614.5688
19	1965	6.566020625	238537.3503
20	1966	11.36907719	236436.2237
21	1967	8.246630376	232547.9993
22	1968	10.02859707	229480.2528
23	1969	9.434666031	224686.5834
24	1970	6.294699863	219742.8184
25	1971	4.46237494	215141.3928
26	1972	0.76923067	211401.9226
27	1973	1.664194626	210506.5381
28	1974	0.222861409	207750.6318
29	1975	1.680483654	207326.7494
30	1976	0.677719401	203831.3434
31	1977	1.503700376	201592.1585
32	1978	1.594253932	196792.3469
33	1979	1.665177739	191501.0181
34	1980	0.706965527	185756.1549
35	1981	1.554609357	182757.9141
36	1982	0.986147984	177773.8365
37	1983	2.217297307	175254.2284
38	1984	4.342845874	172207.6619
39	1985	0.403981131	164103.9115
40	1986	0.81467396	163082.6472
41	1987	0.612992558	162025.2004
42	1988	0.760269913	161045.0253
43	1989	2.205158798	159296.4045
44	1990	1.663445103	154195.8722
45	1991	1.836093556	150493.0434
46	1992	3.157328414	147472.6695
47	1993	1.071901954	144605.8153
48	1994	0.750196156	141039.5975
49	1995	1.950035699	137038.8014
50	1996	0.674823472	130554.9327
51	1997	0.424127303	128082.3795
52	1998	0.741435358	126038.0859
53	1999	0.712697173	122364.2737
54	2000	0.547169537	117371.83
55	2001	0.627480361	112428.7004
56	2002	0.585844457	105719.0529
57	2003	0.35938413	100440.0085
58	2004	0.408835536	95800
59	2005	0.475686392	89650.7047
60	2006	0.450186347	82089.6695
61	2007	0.615404342	75854.5886
62	2008		69930.7064

Table F13

Data: Western Canada production-to-reserves ratio

Author: Ernie Zampelli, SAIC, 2009

Source: Canadian Association of Petroleum Producers, Statistical Handbook.

Variables:

PR = Natural gas production-to-reserve ratio in Western Canada [PRRATCAN]

GWELLS = Number of successful new natural gas wells drilled in Western Canada [SUCWELL}

RES_ADD_PER_WELL = Proved natural gas reserves added per successful natural gas well in Western Canada (Bcf/well) [FRCAN]

YEAR = Calendar year [RLYR]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The equation was estimated using TSP version 5.0 for the period from 1978 to 2007 using aggregated data in natural log form (with the exception of YEAR) for the provinces of Western Canada. Because the PR ratio is bounded between zero and one, the dependent variable was measured in logistic form, as follows:

$$\begin{aligned}\ln\left(\frac{PR_t}{1-PR_t}\right) &= \beta_0 + \beta_1 * \ln GWELLS_t + \beta_2 * \ln RES\_ADD\_PER\_WELL_t + \beta_3 * YEAR \\ &+ \rho * \ln\left(\frac{PR_{t-1}}{1-PR_{t-1}}\right) \\ &- \rho * (\beta_0 + \beta_1 * \ln GWELLS_t + \beta_2 * \ln RES\_ADD\_PER\_WELL_t + \beta_3 * YEAR)\end{aligned}$$

Regression Diagnostics and Parameter Estimates

```
TSP Program File:  canada10_pr_v1.tsp
TSP Output File:  canada10_pr_v1.out
Data File:  canada10.xls

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

 Objective function:  Exact ML (keep first obs.)

 CONVERGENCE ACHIEVED AFTER   7 ITERATIONS

 Dependent variable: LOGISTIC
 Current sample:  32 to 61
 Number of observations:  30
```

Mean of dep. var.	-2.68213	R-squared	.986473
Std. dev. of dep. var.	.479351	Adjusted R-squared	.984308
Sum of squared residuals	.090398	Durbin-Watson	1.29483
Variance of residuals	.361591E-02	Schwarz B.I.C.	-35.3745
Std. error of regression	.060132	Log likelihood	43.8775

Parameter	Estimate	Standard Error	t-statistic	P-value	Symbol
C	-72.1364	13.7385	-5.25069	[.000]	β_0
LNGWELLS	.117911	.032053	3.67858	[.000]	β_1
LNRES_ADD_PER_WELL	.041469	.017819	2.32723	[.020]	β_2
YEAR	.034370	.690795E-02	4.97536	[.000]	β_3
RHO (ρ)	.916835	.061397	14.9329	[.000]	ρ

Data used for Estimation:

OBS	Year	pr	gwells	res_add_per_well
9	1955		168	
10	1956		180	
11	1957		194	
12	1958		200	
13	1959		302	
14	1960		292	
15	1961		392	
16	1962		331	
17	1963	0.023779341	338	9.28880858
18	1964	0.024979017	308	29.47148864
19	1965	0.022612325	320	6.566020625
20	1966	0.02372014	342	11.36907719
21	1967	0.024985242	372	8.246630376
22	1968	0.027431524	478	10.02859707
23	1969	0.030312333	524	9.434666031
24	1970	0.032625343	731	6.294699863
25	1971	0.034308623	838	4.46237494
26	1972	0.037697554	1164	0.76923067
27	1973	0.041418124	1656	1.664194626
28	1974	0.040851176	1902	0.222861409
29	1975	0.042823468	2080	1.680483654
30	1976	0.042727689	3304	0.677719401
31	1977	0.04464118	3192	1.503700376
32	1978	0.04178307	3319	1.594253932
33	1979	0.042644059	3450	1.665177739
34	1980	0.037495598	4241	0.706965527
35	1981	0.036757207	3206	1.554609357
36	1982	0.036329357	2555	0.986147984
37	1983	0.034484267	1374	2.217297307
38	1984	0.03717602	1866	4.342845874
39	1985	0.038172848	2528	0.403981131
40	1986	0.035340517	1298	0.81467396
41	1987	0.039250307	1599	0.612992558
42	1988	0.046730172	2300	0.760269913
43	1989	0.051076089	2313	2.205158798
44	1990	0.050410254	2226	1.663445103
45	1991	0.054586093	1645	1.836093556
46	1992	0.060679876	908	3.157328414
47	1993	0.068904777	3327	1.071901954
48	1994	0.075709817	5333	0.750196156
49	1995	0.080323276	3325	1.950035699
50	1996	0.082543421	3664	0.674823472
51	1997	0.087979875	4820	0.424127303
52	1998	0.095582952	4955	0.741435358
53	1999	0.102052842	7005	0.712697173
54	2000	0.105232537	9034	0.547169537
55	2001	0.108329697	10693	0.627480361
56	2002	0.107044449	9011	0.585844457
57	2003	0.105846562	12911	0.35938413
58	2004	0.109676418	15041	0.408835536
59	2005	0.110235118	15895	0.475686392
60	2006	0.107756259	13850	0.450186347
61	2007	0.105636132	9626	0.615404342
62	2008	0.101395754	8104	

Appendix G. Variable Cross Reference Table

With the exception of the Pipeline Tariff Submodule (PTS) all of the equations in this model documentation report are the same as those used in the model FORTRAN code. Table G-1 presents cross references between model equation variables defined in this document and in the FORTRAN code for the PTS.

Table G-1. Cross Reference of PTM Variables Between Documentation and Code

Documentation	Code Variable	Equation #
$R_{i,f}$	Not represented	157
$R_{i,v}$	Not represented	158
ALL_f	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	157
ALL_v	AVA_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	158
R_i	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	157, 158
FC_a	Not represented	159
VC_a	Not represented	160
$R_{i,f,r}$	RFC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	161
$R_{i,f,u}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	162
$R_{i,v,r}$	RVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	163
$R_{i,v,u}$	UVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	164
$ALL_{f,r}$	AFR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	161
$ALL_{f,u}$	AFU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	162
$ALL_{v,r}$	AVR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	163
$ALL_{v,u}$	AVU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	164

Documentation	Code Variable	Equation #
ξ_i	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	222, 223, 225-228
$Item_{i,a,t}$	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	222, 223, 225-228
$FC_{a,t}$	Not represented	222
$VC_{a,t}$	Not represented	223
$TCOS_{a,t}$	Not represented	224, 229
$RFC_{a,t}$	RFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	225
$UFC_{a,t}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	225
$RVC_{a,t}$	RVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	227
$UVC_{a,t}$	UVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	228
λ_i	AFR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	225, 226
μ_i	AVR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	227, 228
a - arc, t - year, i - cost-of-service component index		

Appendix H. Coal-to-Gas Submodule

A Coal-to-Gas (CTG) algorithm has been incorporated into the NGTDM to project potential new CTG plants at the census division level and the associated pipeline quality gas production. The Coal-to-Gas process with no carbon sequestration is adopted as the generic facility for the CTG. The CTG_INVEST subroutine calculates the annualized capital costs, operating costs, and other variable costs for a generic coal-to-gas plant producing 100 MMcf/day (Appendix E, CTG_PUCAP) of pipeline quality synthetic gas from coal. The capital costs are converted into a per unit basis by dividing by the plant's assumed output of gas. Capital and operating costs are assumed to decline over the forecast due to technological improvements. To determine whether it is profitable to build a CTG plant, the per unit capital and operating costs plus the coal costs are compared to the average market price of natural gas and electricity. If a CTG plant is profitable, the actual number of plants to be built is set using the Mansfield-Blackman market penetration algorithm. Any new generic plant is assumed to be built in the regions with the greatest level of profitability and to produce pipeline quality natural gas and cogenerated electricity (cogen) for sale to the grid.

Electricity generated by a CTG facility is partially consumed in the facility, while the remainder is assumed to be sold to the grid at wholesale market prices (EWSPRCN, 87$/MWh, from the EMM). Cogeneration for each use is set for a generic facility using assumed ratios of electricity produced to coal consumed (Appendix E, own—CTG_BASECGS, grid—CTG_BASCGG). The revenue from cogen sales is treated as a credit (CGNCRED) by the model to offset the costs (feedstock, fixed, and operation costs) of producing CTG syngas. The annualized transmission cost (CGNTRNS) for cogen sent to the grid is accounted for in the operating cost of the CTG facility.

The primary inputs to the CTG model include a mine-mouth coal price (PCLGAS, 87$/MMBtu, from the Coal Market Module (CMM)) and a regional wholesale equivalent natural gas price (NODE_ENDPR, 87$/Mcf). A carbon tax (JCLIN, 87$/MMBtu from the Integration Module) is added to the coal price as well as a penalty for SO2 and HG. If the CTG plant is deemed to be economic, the final quantity of coal demanded (QCLGAS, Quad Btu/yr) is sent back to the CMM for feedback. The final outputs from the model are coal consumed, gas produced, electricity consumed, and electricity sold to the grid.

Investment decisions for building new CTG facilities are based on the total investment cost of a CTG plant (CTG_INVCST). Actual cash flows associated with the operation of the individual plants are considered, as well as cash flows associated with capital for the construction of new plants. Terms for capital-related financial charges (CAPREC) and fixed operating costs (FXOC) are included.

$$\mathrm{CTG\_INVCST} = \mathrm{CAPREC} + \mathrm{FXOC} \qquad (306)$$

Once a build decision is made, a Mansfield-Blackman algorithm for market penetration is used to determine the limit on the number of plants allowed to build in a given year. The investment costs are further adjusted to account for learning and for resource competition. The methodologies used to calculate the capital-related financial charges and the fixed operating costs, the Mansfield-Blackman model, and investment costs adjustments are presented in detail below.

Capital-Related Financial Charges for Coal-to-Gas

A discounted cash flow calculation is used to determine the annual capital charge for a CTG plant investment. The annual capital recovery charge assumes a discount rate equal to the cost of capital, which includes the cost of equity (CTGCOE) and interest payments on any loans or other debt instruments used as part of capital project financing (CTGCOD) with an assumed interest rate of the Industrial BAA bond rate (MC_RMCORPBAA, from MACRO) plus an additional risk premium (Appendix E, BA_PREM). Together, this translates into the capital recovery factor (CTG_RECRAT) which is calculated on an after-tax basis.

Some of the steps associated with the capital-related financial charge estimates are conducted exogenous to NEMS (Step 0 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant capital-related cost estimation algorithm are:

0) Estimation of the inside battery limit field cost (ISBL)
1) Year-dollar and location adjustments for ISBL Field Costs
2) Estimation of outside battery limit field cost (OSBL) and Total Field Cost
3) Estimation of Total Project Cost
4) Calculate Annual Capital Recovery
5) Convert capital related financial costs to a "per-unit" basis

Step 0 involves several adjustments which must be made prior to input into the NGTDM; steps 1-4 are performed within the NGTDM.

Step 0 - Estimation of ISBL Field Cost
The inside battery limits (CTG_ISBL) field costs include direct costs such as major equipment, bulk materials, direct labor costs for installation, construction subcontracts, and indirect costs such as distributables. The ISBL investment and labor costs were provided for plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in 2004 dollars.

Step 1 - Year-Dollar and Location Adjustments to ISBL Field Costs
Before utilizing the ISBL investment cost information, the raw data must be converted according to the following steps:

a) Adjust the ISBL field and labor costs from 2004 dollars, first to the year-dollar reported by NEMS, using the Nelson-Farrar refining industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 year dollars used internally by the NEMS.

b) Convert the ISBL field costs in 1987 dollars from a PADD III basis (Appendix E, XBM_ISBL) to costs in the NGTDM demand regions using location multipliers (Appendix E, CTG_INVLOC). The location multipliers represent differences in material costs between the various regions.

$$CTG\_ISBL = CTG\_INVLOC * BM\_ISBL / 1000 \tag{307}$$

Step 2 - Estimation of OSBL and Total Field Cost
The outside battery-limit (OSBL) costs for CTG are included in the inside battery-limit costs. The total field cost (CTG_TFCST) is the sum of ISBL and OSBL

$$CTG\_TFCST = (1 - CTG\_OSBLFAC) * CTG\_ISBL \tag{308}$$

The OSBL field cost is estimated as a fraction (Appendix E, CTG_OSBLFAC) of the ISBL costs.

Step 3 - Estimation of Total Project Cost
The total project investment (CTG_TPI) is the sum of the total field cost (Eq. 3) and other one-time costs (CTG_OTC).

$$CTG\_TPI = CTG\_TFCST + CTG\_OTC \tag{309}$$

Other one-time costs include the contractor's cost (such as home office costs), the contractor's fee and a contractor's contingency, the owner's cost (such as pre-startup and startup costs), and the owner's contingency and working capital. The other one-time costs are estimated as a function of total field costs using cost factors (OTCFAC):

$$CTG\_OTC = OTCFAC * CTG\_TFCST \tag{310}$$

where,

$$\begin{aligned} OTCFAC = {} & CTG\_PCTENV + CTG\_PCTCNTG + CTG\_PCTLND + \\ & CTG\_PCTSPECL + CTG\_PCTWC \end{aligned} \tag{311}$$

and,

CTG_PCTENV	=	Home, office, contractor fee
CTG_CNTG	=	Contractor & owner contingency
CTG_PCTLND	=	Land
CTG_PCTSPECL	=	Prepaid royalties, license, start-up costs
CTG_PCTWC	=	Working capital

The total project investment given above represents the total project cost for 'overnight construction.' The total project investment at project completion and startup will be discussed below.

Closely related to the total project investment are the fixed capital investment (CTG_FCI) and total depreciable investment (CTG_TDI). The fixed capital investment is equal to the total project investment less working capital. It is used to estimate capital-related fixed operating costs.

$$\mathrm{WRKCAP} = \mathrm{CTG\_PCTWC} * \mathrm{CTG\_TFCST} \tag{312}$$

Thus,

$$\mathrm{CTG\_FCI} = \mathrm{CTG\_TPI} - \mathrm{WKRCAP} \tag{313}$$

For the CTG plant, the total depreciable investment (CTG_TDI) is assumed to be equal to the total project investment.

Step 4 - Annual Capital Recovery

The annual capital recovery (ACAPRCV) is the difference between the total project investment (TPI) and the recoverable investment (RCI), all in terms of present value (e.g., at startup). The TPI estimated previously is for overnight construction (ONC). In reality, the TPI is spread out through the construction period. Land costs (LC) will occur as a lump-sum payment at the beginning of the project, construction expenses (TPI – WC – LC = FCI - LC) will be distributed during construction, and working capital (WC) expenses will occur as a lump-sum payment at startup. Thus, the TPI at startup (present value) is determined by discounting the construction expenses (assumed as discrete annual disbursements) and adding working capital (WC):

$$\begin{aligned}\mathrm{TPI\_START} = {} & \mathrm{FVI\_CONSTR} * \mathrm{LAND} + \mathrm{FV\_CONSTR} * \\ & (\mathrm{CTG\_FCI} - \mathrm{LAND}) + \mathrm{WRKCAP}\end{aligned} \tag{314}$$

where,

FVI_CONSTR	=	Future-value compounding factor for an instantaneous payment made n years before the startup year
FV_CONSTR	=	Future-value compounding factor for discrete uniform payments made at the beginning of each year starting n years before the startup year.

The future-value factors are a function of the number of compounding periods (n), and the interest rate (r) assumed for compounding. In this case, (n) equals the construction time in years before startup, and the compounding rate used is the cost of capital (CTG_RECRAT).

The recoverable investment (RCI_START) includes the value of the land and the working capital (assumed not to depreciate over the life of the project), as well as the salvage value (PRJSDECOM) of the used equipment:

$$\mathrm{RCI\_START} = \mathrm{PV\_PRJ} * (\mathrm{LAND} + \mathrm{WKRCAP} + \mathrm{PRJSDECOM}) \tag{315}$$

The present value of RCI is subtracted from the TPI at startup to determine the present value of the project investment (PVI):

$$PVI\_START = TPI\_START - RCI\_START \tag{316}$$

Thus, the annual capital recovery (ACAPRCV) is given by:

$$ACAPRCV = LC\_LIFE * PVI\_START \tag{317}$$

where,

LC_LIFE = uniform- value leveling factor for a periodic payment (annuity) made at the end of each year for (n) years in the future

The depreciation tax credit (DTC) is based on the depreciation schedule for the investment and the total depreciable investment (TDI). The simplest method used for depreciation calculations is the straight-line method, where the total depreciable investment is depreciated by a uniform annual amount over the tax life of the investment. Generic equations representing the present value and the levelized value of the annual depreciation charge are:

$$ADEPREC = CTG\_TDI / CTG\_PRJLIFE \tag{318}$$

$$ADEPTAXC = ADEPREC * FEDST\_TAX \tag{319}$$

$$ACAPCHRGAT = ACAPRCV - ADEPTAXC \tag{320}$$

$$DCAPCHRGAT = ACAPCHRGAT / 365 \tag{321}$$

where,

ADEPREC = annual levelized depreciation
ADEPTAXC = levelized depreciation tax credit, after federal and state taxes
ACAPCHRGAT = annual capital charge, after tax credit
DCAPCHRGAT = daily capital charge, after tax credit

Step 5 - Convert Capital Costs to a ‘per-day’, ‘per-capacity’ Basis

The annualized capital-related financial charge is converted to a daily charge, and then converted to a “per-capacity” basis by dividing the result by the operating capacity of the unit being evaluated. The result is a fixed operation cost on a per-mcf basis (CAPREC).

CTG Plant Fixed Operating Costs

Fixed operating costs (FXOC), a component of total product cost, are costs incurred at the plant that do not vary with plant throughput, and any other costs which cannot be controlled at the plant level. These include such items as wages, salaries and benefits; the cost of maintenance, supplies and repairs; laboratory charges; insurance, property taxes and rent; and other overhead costs. These components can be factored from either the operating labor requirement or the capital cost.

Like capital cost estimations, operating cost estimations, involve a number of distinct steps. Some of the steps associated with the FXOC estimate are conducted exogenous to NEMS (Step 0 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant fixed operating cost estimation algorithm are:

0) Estimation of the annual cost of direct operating labor
1) Year-dollar and location adjustment for operating labor costs (OLC)
2) Estimation of total labor-related operating costs (LRC)
3) Estimation of capital-related operating costs (CRC)
4) Convert fixed operating costs to a "per-unit" basis

Step 0 involves several adjustments which must be made prior to input into the NGTDM; steps 1-4 are performed within the NGTDM.

Step 0 – Estimation of Direct Labor Costs
Direct labor costs are reported based on a given processing unit size. Operation and labor costs were provided for plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in 2004 dollars.

Step 1 – Year-Dollar and Location Adjustment for Operating Labor Costs
Before the labor cost data can be utilized, it must be converted via the following steps:

a) Adjust the labor costs from 2004 dollars, first to the year-dollar reported by NEMS using the Nelson-Farrar refining-industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 dollars used internally by the NEMS (Appendix E, XBM_LABOR).

b) Convert the 1987 operating labor costs from a PADD III (Gulf Coast) basis into regional (other U.S. PADDs) costs using regional location factors. The location multiplier (Appendix E, LABORLOC) represents differences in labor costs between the various locations and includes adjustments for construction labor productivity.

$$CTG\_LABOR = LABORLOC * BM\_LABOR \tag{322}$$

Location multipliers are translated to the NGTDM demand regions.

Step 2 - Estimation of Labor-Related Fixed Operating Costs
Fixed operating costs related to the cost of labor include the salaries and wages of supervisory and other staffing at the plant, charges for laboratory services, and payroll benefits and other plant overhead. These labor-related fixed operating costs (FXOC_LABOR) can be factored from the direct operating labor cost. This relationship is expressed by:

$$FXOC\_STAFF = CTG\_LABOR * CTG\_STAFF\_LCFAC \tag{323}$$

$$FXOC\_OH = (CTG\_LABOR + FXOC\_STAFF) * CTG\_OH\_LCFAC \tag{324}$$

$$FXOC\_LABOR = CTG\_LABOR + FXOC\_STAFF + FXOC\_OH \tag{325}$$

where,

FXOC_STAFF = Supervisory and staff salary costs
FXOC_OH = Benefits and overhead

Step 3 - Estimation of Capital-Related Fixed Operating Costs
Capital–related fixed operating costs (FXOC_CAP) include insurance, local taxes, maintenance, supplies, non-labor related plant overhead, and environmental operating costs. These costs can be factored from the fixed capital investment (CTG_FCI). This relationship is expressed by:

$$FXOC\_INS = CTG\_FCI * INS\_FAC \tag{326}$$

$$FXOC\_TAX = CTG\_FCI * TAX\_FAC \tag{327}$$

$$FXOC\_MAINT = CTG\_FCI * MAINT\_FAC \tag{328}$$

$$FXOC\_OTH = CTG\_FCI * OTH\_FAC \tag{329}$$

$$\begin{aligned} FXOC\_CAP = {} & FXOC\_INS + FXOC\_TAX + \\ & FXOC\_MAINT + FXOC\_OTH \end{aligned} \tag{330}$$

where,

INS_FAC = Yearly Insurance
TAX_FAC = Local Tax Rate
MAINT_FAC = Yearly Maintenance
OTH_FAC = Yearly Supplies, Overhead, Etc.

Step 4 - Convert Fixed Operating Costs to a "per-capacity" Basis
On a "per-capacity" basis, the FXOC is the sum of capital-related operating costs and labor-related operating costs, divided by the operating capacity of the unit being evaluated.

Mansfield-Blackman Model for Market Penetration
The Mansfield-Blackman model for market penetration has been incorporated to limit excessive growth of CTG (on a national level) once they become economically feasible.[99] The indices associated with this modeling algorithm are user inputs that define the characteristics of the CTG process. They include an innovation index of the industry (Appendix E, CTG_IINDX), the relative profitability of the investment within the industry (Appendix E, CTG_PINDX), the relative size of the investment (per plant) as a percentage of total company value (Appendix E, CTG_SINVST), and a maximum penetration level (total number of units, Appendix E, CTG_BLDX).[100]

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[99] E. Mansfield, "Technical Change and the Rate of Imitation," *Econometrica*, Vol. 29, No. 4 (1961), pp. 741-765. A.W. Blackman, "The Market Dynamics of Technological Substitution," *Technological Forecasting and Social Change*, Vol. 6 (1974), pp. 41-63.

[100] These have been defined in a memorandum from Andy Kydes (EIA) to Han-Lin Lee (EIA), entitled "Development of a model for optimistic growth rates for the coal-to-liquids (CTG) technology in NEMS," dated March 23, 2002.

$$KFAC = -LOG((CTG\_BLDX / NCTGBLT) - 1) \tag{331}$$

$$PHI = -0.3165 + (0.23221 * CTG\_IINDX) + (0.533 * CTG\_PINDX) - (0.027 * CTG\_SINVST) \tag{332}$$

$$SHRBLD = 1/(1 + EXP(-KFAC - (YR * PHI))) \tag{333}$$

$$CTGBND = CTG\_BLDX * SHRBLD \tag{334}$$

where,

CTG_BLDX = maximum number of plants allowed
NCTGBLT = number of plants already built
SHRBLD = the share of the maximum number of plants that can be built in a given year
CTGBND = the upper bound on the number of plants to build

Investment Cost Adjustments

To represent cost improvements over time (due to learning), a decline rate (CTG_DCLCAPCST) is applied to the original CTG capital costs after builds begin.

$$CTG\_INVADJ = CTG\_INVBAS * (1 - CTG\_DCLCAPCST)^{(YR - CTG\_BASYR)} \tag{335}$$

where,

CTG_INVBAS = the initial CTG investment cost
CTG_BASYR = the first year CTG plants are allowed to build
CTG_INVADJ = the adjusted CTG investment cost

However, once the capacity builds exceed 1.1 bcf/day, a supplemental algorithm is applied to increase costs in response to impending resource depletions (such as competition for water).[101]

$$CTG\_CSTADD = 15 * TANH(0.4 * (MAX(0, (CTGPRODC / 1127308) - 1))) \tag{336}$$

where,

CTGPRODC = current CTG production
CTG_CSTADD = the additional cost

[101] The basic algorithm is defined in a memorandum from Andy Kydes (EIA) to William Brown (EIA), entitled “CTL run-- add to total CTLCST in ADJCTLCST sub,” dated September 29, 2006.

DOE/EIA-M063(2011)

Documentation of the Oil and Gas Supply Module (OGSM)

July 2011

Office of Energy Analysis
U.S. Energy Information Administration
U.S. Department of Energy
Washington, DC 20585

Update Information

This edition of the *Documentation of the Oil and Gas Supply Module* reflects changes made to the oil and gas supply module over the past year for the *Annual Energy Outlook 2011*. The major changes include:

- Texas Railroad Commission District 5 is included in the Southwest region instead of the Gulf Coast region.
- Re-estimation of Lower 48 onshore exploration and development costs.
- Updates to crude oil and natural gas resource estimates for emerging shale plays.
- Addition of play-level resource assumptions for tight gas, shale gas, and coalbed methane (Appendix 2.C).
- Updates to the assumptions used for the announced/nonproducing offshore discoveries.
- Revision of the North Slope New Field Wildcat (NFW) exploration wells drilling rate function. The NFW drilling rate is a function of the low-sulfur light projected crude oil prices and was statically estimated based on Alaska Oil and Gas Conservation Commission well counts and success rates.
- Recalibration of the Alaska oil and gas well drilling and completion costs based on the 2007 American Petroleum Institute Joint Association Survey drilling cost data.
- Updates to oil shale plant configuration, cost of capital calculation, and market penetration algorithms.
- Addition of natural gas processing and coal-to-liquids plants as anthropogenic sources of carbon dioxide (CO_2).

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1. Introduction

The purpose of this report is to define the objectives of the Oil and Gas Supply Module (OGSM), to describe the model's basic approach, and to provide detail on how the model works. This report is intended as a reference document for model analysts, users, and the public. It is prepared in accordance with the U.S. Energy Information Administration's (EIA) legal obligation to provide adequate documentation in support of its statistical and forecast reports (Public Law 93-275, Section 57(b)(2)).

Projected production estimates of U.S. crude oil and natural gas are based on supply functions generated endogenously within the National Energy Modeling System (NEMS) by the OGSM. The OGSM encompasses both conventional and unconventional domestic crude oil and natural gas supply. Crude oil and natural gas projections are further disaggregated by geographic region. The OGSM projects U.S. domestic oil and gas supply for six Lower 48 onshore regions, three offshore regions, and Alaska. The general methodology relies on forecasted profitability to determine exploratory and developmental drilling levels for each region and fuel type. These projected drilling levels translate into reserve additions, as well as a modification of the production capacity for each region.

The OGSM utilizes both exogenous input data and data from other modules within the NEMS. The primary exogenous inputs are resource levels, finding-rate parameters, costs, production profiles, and tax rates - all of which are critical determinants of the expected returns from projected drilling activities. Regional projections of natural gas wellhead prices and production are provided by the Natural Gas Transmission and Distribution Module (NGTDM). Projections of the crude oil wellhead prices at the OGSM regional level come from the Petroleum Market Model (PMM). Important economic factors, namely interest rates and GDP deflators, flow to the OGSM from the Macroeconomic Module. Controlling information (e.g., forecast year) and expectations information (e.g., expected price paths) come from the Integrating Module (i.e. system module).

Outputs from the OGSM go to other oil and gas modules (NGTDM and PMM) and to other modules of the NEMS. To equilibrate supply and demand in the given year, the NGTDM employs short-term supply functions (with the parameters provided by the OGSM) to determine non-associated gas production and natural gas imports. Crude oil production is determined within the OGSM using short-term supply functions. These short-term supply functions reflect potential oil or gas flows to the market for a 1-year period. The gas functions are used by the NGTDM and the oil volumes are used by the PMM for the determination of equilibrium prices and quantities of crude oil and natural gas at the wellhead. The OGSM also provides projections of natural gas production to the PMM to estimate the corresponding level of natural gas liquids production. Other NEMS modules receive projections of selected OGSM variables for various uses. Oil and gas production is passed to the Integrating Module for reporting purposes. Forecasts of oil and gas production are also provided to the Macroeconomic Module to assist in forecasting aggregate measures of output.

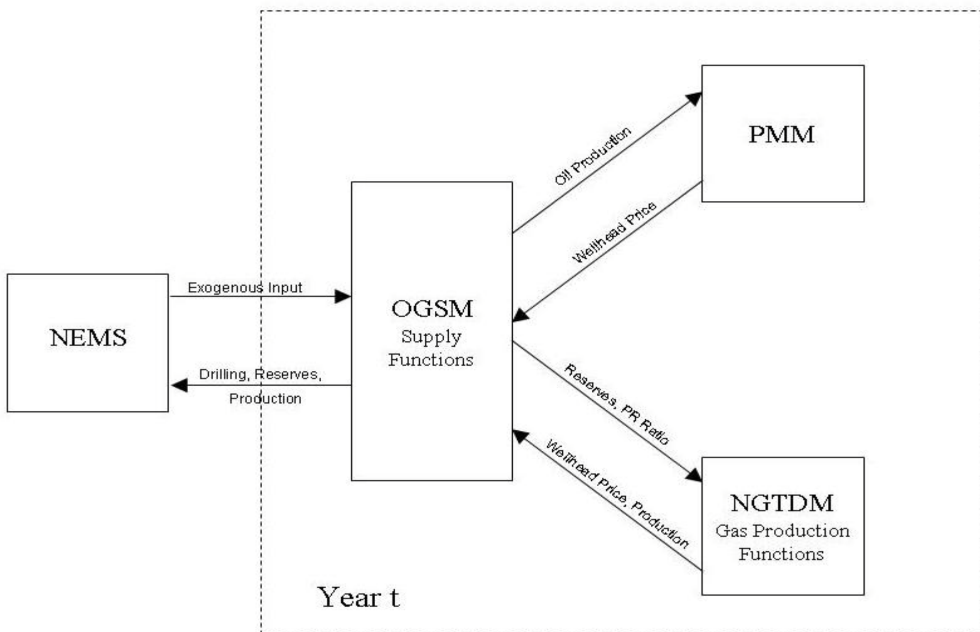
The OGSM is archived as part of the NEMS. The archival package of the NEMS is located under the model acronym NEMS2011. The NEMS version documented is that used to produce the *Annual Energy Outlook 2011 (AEO2011)*. The package is available on the EIA website.[1]

Model Purpose

The OGSM is a comprehensive framework used to analyze oil and gas supply potential and related issues. Its primary function is to produce domestic projections of crude oil and natural gas production as well as natural gas imports and exports in response to price data received endogenously (within the NEMS) from the NGTDM and PMM. Projected natural gas and crude oil wellhead prices are determined within the NGTDM and PMM, respectively. As the supply component only, the OGSM cannot project prices, which are the outcome of the equilibration of both demand and supply.

The basic interaction between the OGSM and the other oil and gas modules is represented in Figure 1-1. The OGSM provides beginning-of-year reserves and the production-to-reserves ratio to the NGTDM for use in its short-term domestic non-associated gas production functions and associated-dissolved natural gas production. The interaction of supply and demand in the NGTDM determines non-associated gas production.

Figure 1-1. OGSM Interface with Other Oil and Gas Modules



[1] ftp://ftp.eia.doe.gov/pub/forecasts/aeo/

The OGSM provides domestic crude oil production to the PMM. The interaction of supply and demand in the PMM determines the level of imports. System control information (e.g., forecast year) and expectations (e.g., expect price paths) come from the Integrating Module. Major exogenous inputs include resource levels, finding-rate parameters, costs, production profiles, and tax rates -- all of which are critical determinants of the oil and gas supply outlook of the OGSM.

The OGSM operates on a regionally disaggregated level, further differentiated by fuel type. The basic geographic regions are Lower 48 onshore, Lower 48 offshore, and Alaska, each of which, in turn, is divided into a number of subregions (see Figure 1-2). The primary fuel types are crude oil and natural gas, which are further disaggregated based on type of deposition, method of extraction, or geologic formation. Crude oil supply includes lease condensate. Natural gas is differentiated by non-associated and associated-dissolved gas.[2] Non-associated natural gas is categorized by fuel type: low-permeability carbonate and sandstone (conventional), high-permeability carbonate and sandstone (tight gas), shale gas, and coalbed methane.

The OGSM provides mid-term (through year 2035) projections and serves as an analytical tool for the assessment of alternative supply policies. One publication that utilizes OGSM forecasts is the *Annual Energy Outlook (AEO)*. Analytical issues that OGSM can address involve policies that affect the profitability of drilling through impacts on certain variables, including:

- drilling and production costs;
- regulatory or legislatively mandated environmental costs;
- key taxation provisions such as severance taxes, State or Federal income taxes, depreciation schedules and tax credits; and
- the rate of penetration for different technologies into the industry by fuel type.

The cash flow approach to the determination of drilling levels enables the OGSM to address some financial issues. In particular, the treatment of financial resources within the OGSM allows for explicit consideration of the financial aspects of upstream capital investment in the petroleum industry.

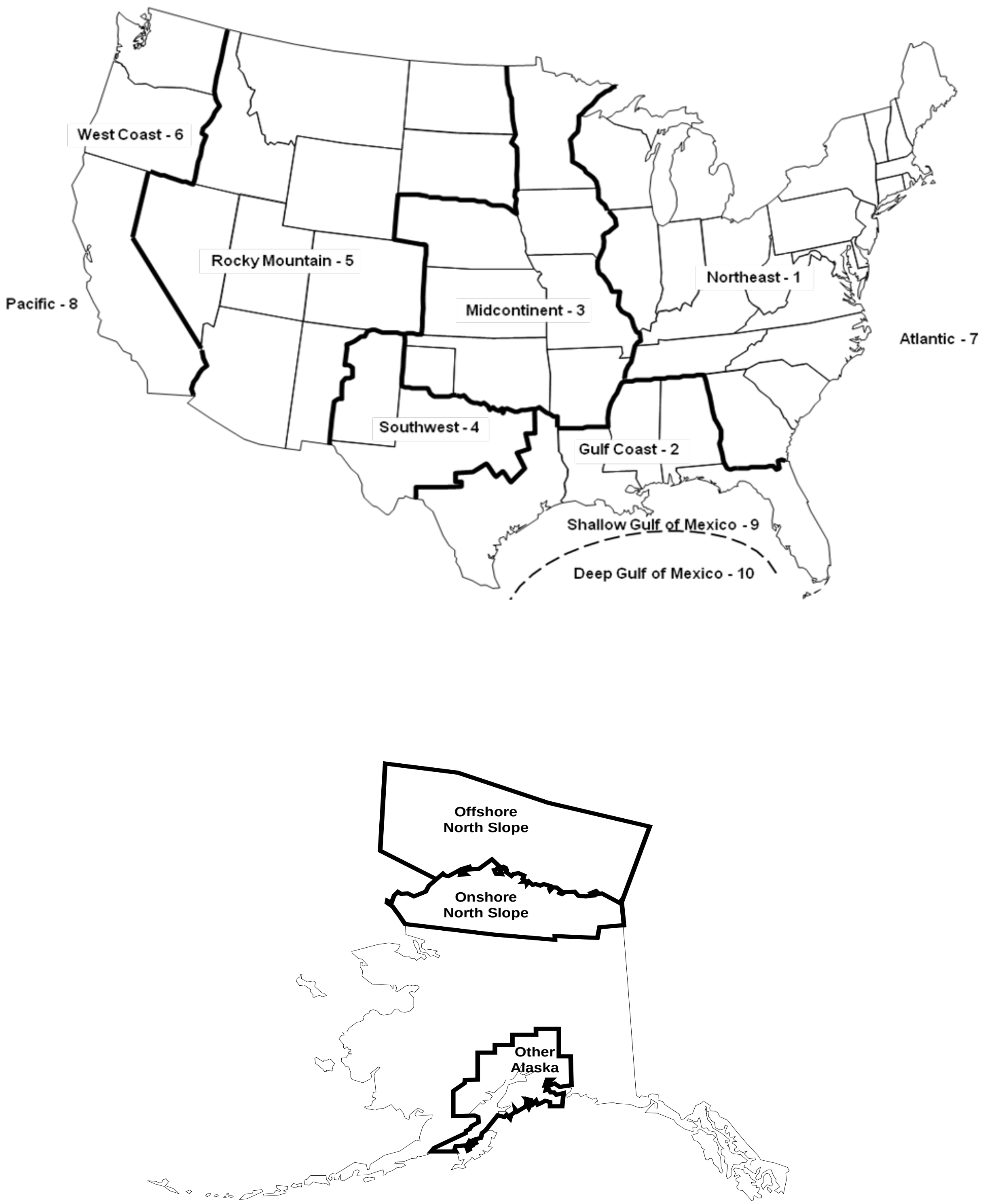
The OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for technically recoverable oil and gas resources for each of the sources of domestic production (i.e., geographic region/fuel type combinations). With some modification, this feature could allow the model to be used for the analysis of issues involving:

- the uncertainty surrounding the technically recoverable oil and gas resource estimates, and
- access restrictions on much of the offshore Lower 48 states, the wilderness areas of the onshore Lower 48 states, and the 1002 Study Area of the Arctic National Wildlife Refuge (ANWR).

[2]Nonassociated (NA) natural gas is gas not in contact with significant quantities of crude oil in a reservoir. Associated-dissolved natural gas consists of the combined volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

In general, the OGSM is used to foster a better understanding of the integral role that the oil and gas extraction industry plays with respect to the entire oil and gas industry, the energy subsector of the U.S. economy, and the total U.S. economy.

Figure 1-2. Oil and Gas Supply Regions

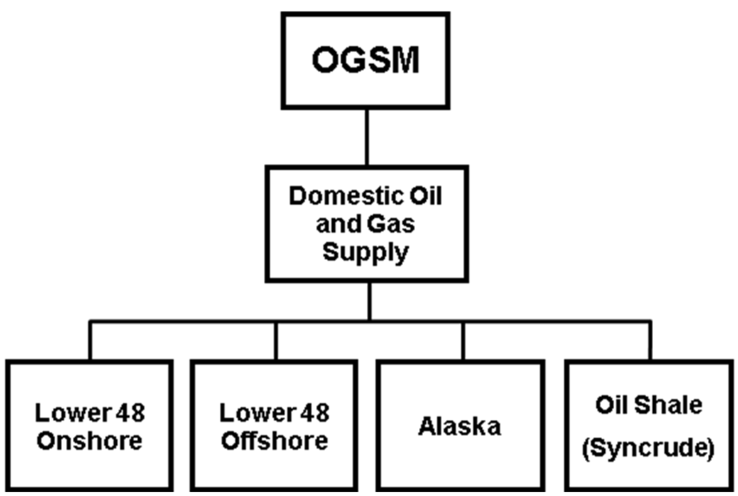


Model Structure

The OGSM consists of a set of submodules (Figure 1-3) and is used to perform supply analysis of domestic oil and gas as part of the NEMS. The OGSM provides crude oil production and parameter estimates representing natural gas supplies by selected fuel types on a regional basis to support the market equilibrium determination conducted within other modules of the NEMS. The oil and gas supplies in each period are balanced against the regionally-derived demand for the produced fuels to solve simultaneously for the market clearing prices and quantities in the wellhead and end-use markets. The description of the market analysis models may be found in the separate methodology documentation reports for the Petroleum Market Module (PMM) and the Natural Gas Transmission and Distribution Model (NGTDM).

The OGSM represents the activities of firms that produce oil and natural gas from domestic fields throughout the United States. The OGSM encompasses domestic crude oil and natural gas supply by both conventional and unconventional recovery techniques. Natural gas is categorized by fuel type: high-permeability carbonate and sandstone (conventional), low-permeability carbonate and sandstone (tight gas), shale gas, and coalbed methane. Unconventional oil includes production of synthetic crude from oil shale (syncrude). Crude oil and natural gas projections are further disaggregated by geographic region. Liquefied natural gas (LNG) imports and pipeline natural gas import/export trade with Canada and Mexico are determined in the NGTDM.

Figure 1-3. Submodules within the Oil and Gas Supply Module



The model's methodology is shaped by the basic principle that the level of investment in a specific activity is determined largely by its expected profitability. Output prices influence oil and gas supplies in distinctly different ways in the OGSM. Quantities supplied as the result of the annual market equilibration in the PMM and the NGTDM are determined as a direct result of the observed market price in that period. Longer-term supply responses are related to investments required for subsequent production of oil and gas. Output prices affect the expected profitability of these investment opportunities as determined by use of a discounted cash flow evaluation of representative prospects. The OGSM incorporates a complete and representative description of the processes by which oil and gas in the technically recoverable resource base[3] convert to proved reserves.[4]

The breadth of supply processes that are encompassed within OGSM result in different methodological approaches for determining crude oil and natural gas production from Lower 48 onshore, Lower 48 offshore, Alaska, and oil shale. The present OGSM consequently comprises four submodules. The Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) models crude oil and natural gas supply from resources in the Lower 48 States. The Offshore Oil and Gas Supply Submodule (OOGSS) models oil and gas exploration and development in the offshore Gulf of Mexico, Pacific, and Atlantic regions. The Alaska Oil and Gas Supply Submodule (AOGSS) models industry supply activity in Alaska. Oil shale (synthetic) is modeled in the Oil Shale Supply Submodule (OSSS). The distinctions of each submodule are explained in individual chapters covering methodology. Following the methodology chapters, four appendices are included: Appendix A provides a description of the discounted cash flow (DCF) calculation; Appendix B is the bibliography; Appendix C contains a model abstract; and Appendix D is an inventory of key output variables.

[3] *Technically recoverable resources* are those volumes considered to be producible with current recovery technology and efficiency but without reference to economic viability. Technically recoverable volumes include proved reserves and inferred reserves as well as undiscovered and other unproved resources. These resources may be recoverable by techniques considered either conventional or unconventional.

[4] *Proved reserves* are the estimated quantities that analyses of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

2. Onshore Lower 48 Oil and Gas Supply Submodule

Introduction

U.S. onshore lower 48 crude oil and natural gas supply projections are determined by the Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS). The general methodology relies on a detailed economic analysis of potential projects in known crude oil and natural gas fields, enhanced oil recovery projects, developing natural gas plays, and undiscovered crude oil and natural gas resources. The projects that are economically viable are developed subject to the availability of resource development constraints which simulate the existing and expected infrastructure of the oil and gas industries. The economic production from the developed projects is aggregated to the regional and the national levels.

OLOGSS utilizes both exogenous input data and data from other modules within the National Energy Modeling System (NEMS). The primary exogenous data includes technical production for each project considered, cost and development constraint data, tax information, and project development data. Regional projections of natural wellhead prices and production are provided by the Natural Gas Transmission and Distribution Model (NGTDM). From the Petroleum Market Module (PMM) come projections of the crude oil wellhead prices at the OGSM regional level.

Model Purpose

OLOGSS is a comprehensive model with which to analyze the crude oil and natural gas supply potential and related economic issues. Its primary purpose is to project production of crude oil and natural gas from the onshore lower 48 in response to price data received from the PMM and the NGTDM. As a supply submodule, OLOGSS does not project prices.

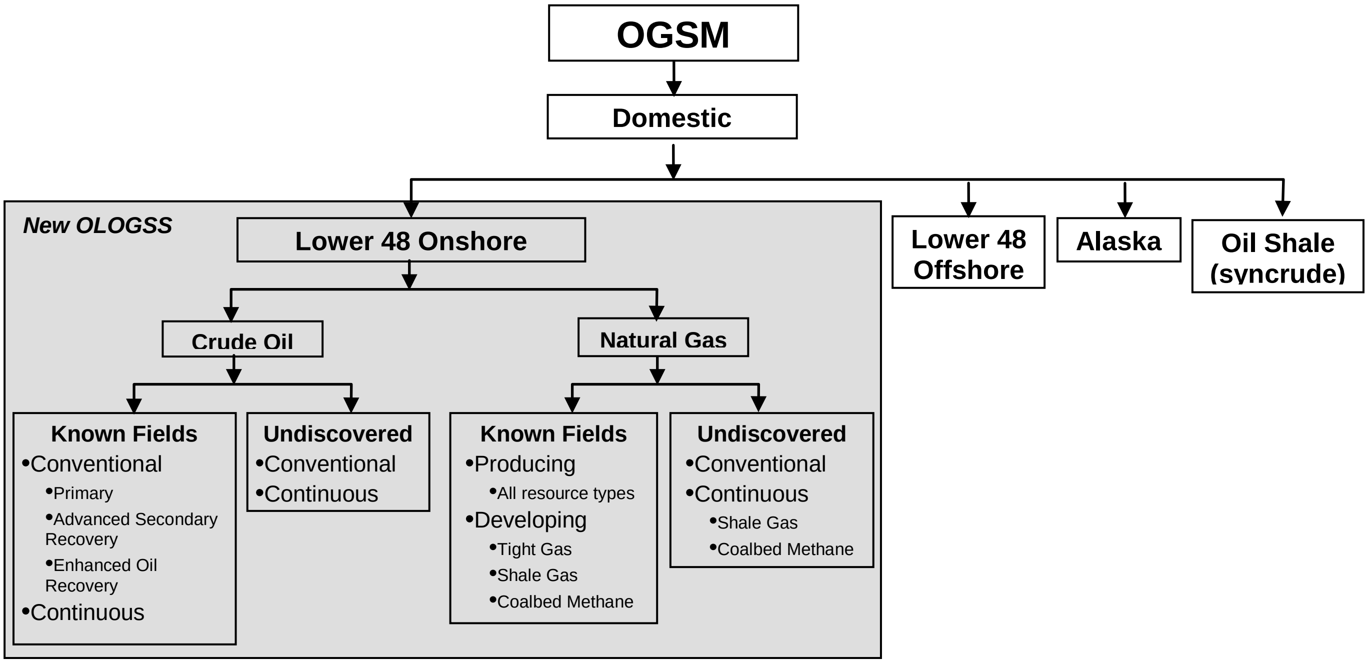
The basic interaction between OLOGSS and the OGSM is illustrated in figure 2-1. As seen in the figure, OLOGSS models the entirety of the domestic crude oil and natural gas production within the onshore lower 48.

Resources Modeled

Crude Oil Resources

Crude oil resources, as illustrated in figure 2-1, are divided into known fields and undiscovered fields. For known resources, exogenous production type curves are used for quantifying the technical production profiles from known fields under primary, secondary, and tertiary recovery processes. Primary resources are also quantified for their advanced secondary recovery (ASR) processes that include the following: waterflooding, infill drilling, horizontal continuity, and horizontal profile modification. Known resources are evaluated for the potential they may possess when employing enhanced oil recovery (EOR) processes such as CO_2 flooding, steam flooding, polymer flooding and profile modification. Known crude oil resources include highly fractured continuous zones such as the Austin chalk formations and the Bakken shale formations.

Figure 2-1: Subcomponents within OGSM



Undiscovered crude oil resources are characterized in a method similar to that used for discovered resources and are evaluated for their potential production from primary and secondary techniques. The potential from an undiscovered resource is defined based on United States Geological Survey (USGS) estimates and is distinguished as either conventional or continuous. Conventional crude oil and natural gas resources are defined as discrete fields with well-defined hydrocarbon-water contacts, where the hydrocarbons are buoyant on a column of water. Conventional resources commonly have relatively high permeability and obvious seals and traps. In contrast, continuous resources commonly are regional in extent, have diffuse boundaries, and are not buoyant on a column of water. Continuous resources have very low permeability, do not have obvious seals and traps, are in close proximity to source rocks, and are abnormally pressured. Included in the category of continuous accumulations are hydrocarbons that occur in tight reservoirs, shale reservoirs, fractured reservoirs, and coal beds.

Natural Gas Resources

Natural gas resources, as illustrated in figure 2-1, are divided into known producing fields, developing natural gas plays, and undiscovered fields. Exogenous production type curves have been used to estimate the technical production from known fields. The undiscovered resources have been characterized based on resource estimates developed by the USGS. Existing databases of developing plays, such as the Marcellus Shale, have been incorporated into the model's resource base. The natural gas resource estimates have been developed from detailed geological characterizations of producing plays.

Processes Modeled

OLOGSS models primary, secondary and tertiary oil recovery processes. For natural gas, OLOGSS models discovered and undiscovered fields, as well as discovered and developing fields. Table 2-1 lists the processes modeled by OLOGSS.

Table 2-1: Processes Modeled by OLOGSS

Crude Oil Processes	Natural Gas Processes
Existing Fields and Reservoirs	Existing Radial Flow
Waterflooding in Undiscovered Resources	Existing Water Drive
CO_2 Flooding	Existing Tight Sands
Steam Flooding	Existing Dry Coal/Shale
Polymer Flooding	Existing Wet Coal/Shale
Infill Drilling	Undiscovered Conventional
Profile Modification	Undiscovered Tight Gas
Horizontal Continuity	Undiscovered Coalbed Methane
Horizontal Profile	Undiscovered Shale Gas
Undiscovered Conventional	Developing Shale Gas
Undiscovered Continuous	Developing Coalbed Methane
	Developing Tight Gas

Major Enhancements

OLOGSS is a play-level model that projects the crude oil and natural gas supply from the onshore lower 48. The modeling procedure includes a comprehensive assessment method for determining the relative economics of various prospects based on future financial considerations, the nature of the undiscovered and discovered resources, prevailing risk factors, and the available technologies. The model evaluates the economics of future exploration and development from the perspective of an operator making an investment decision. Technological advances, including improved drilling and completion practices, as well as advanced production and processing operations are explicitly modeled to determine the direct impacts on supply, reserves, and various economic parameters. The model is able to evaluate the impact of research and development (R&D) on supply and reserves. Furthermore, the model design provides the flexibility to evaluate alternative or new taxes, environmental, or other policy changes in a consistent and comprehensive manner.

OLOGSS provides a variety of levers that allow the user to model developments affecting the profitability of development:

- Development of new technologies
- Rate of market penetration of new technologies
- Costs to implement new technologies
- Impact of new technologies on capital and operating costs
- Regulatory or legislative environmental mandates

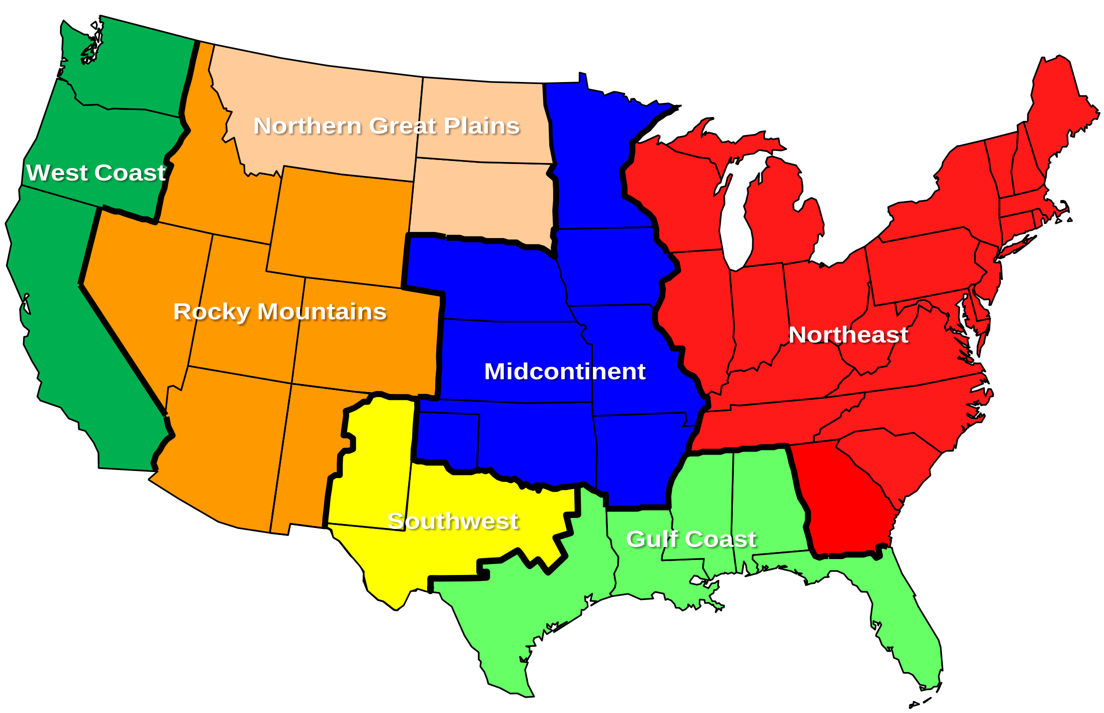
In addition, OLOGSS can quantify the effects of hypothetical developments that affect the resource base. OLOGSS is based on explicit estimates for technically recoverable crude oil and natural gas resources for each source of domestic production (i.e., geographic region/fuel type combinations).

OLOGSS is capable of addressing access issues concerning crude oil and natural gas resources located on federal lands. Undiscovered resources are divided into four categories:

- Officially inaccessible
- Inaccessible due to development constraints
- Accessible with federal lease stipulations
- Accessible under standard lease terms

OLOGSS uses the same geographical regions as the OGSM with one distinction. In order to capture the regional differences in costs and drilling activities in the Rocky Mountain region, the region has been divided into two sub-regions. These regions, along with the original six, are illustrated in figure 2-2. The Rocky Mountain region has been split to add the Northern Great Plains region. The results for these regions are aggregated before being passed to other OGSM or NEMS routines.

Figure 2-2: Seven OLOGSS Regions for Onshore Lower 48



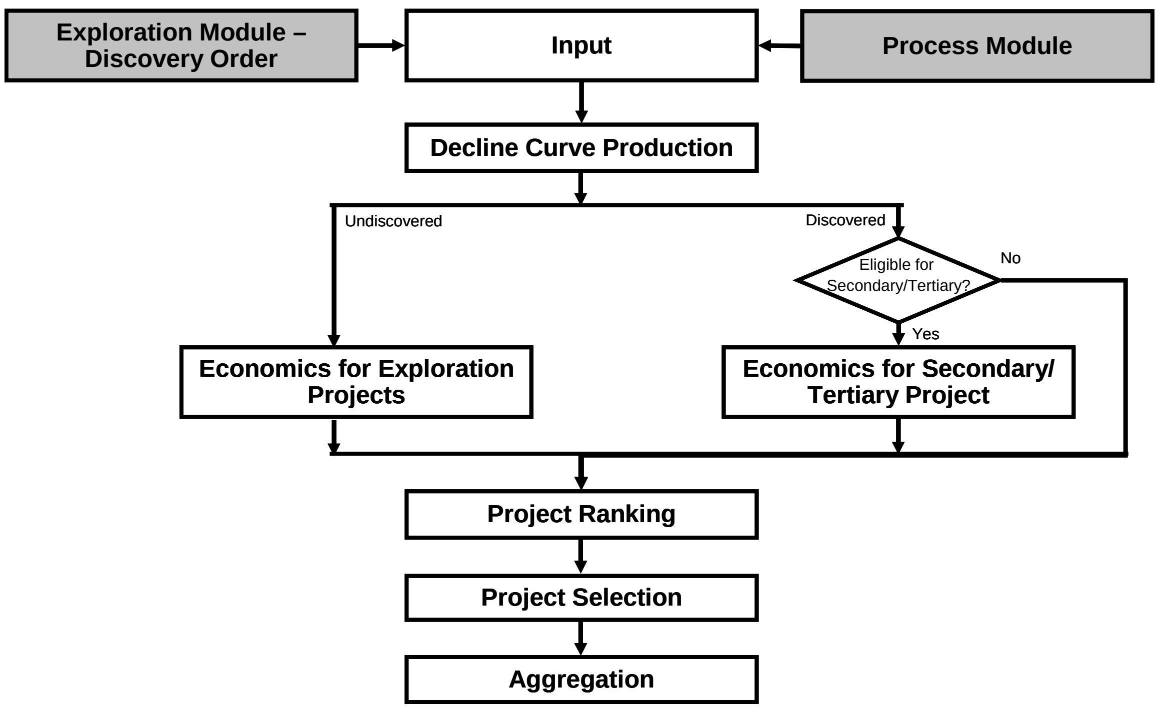
Model Structure

The OLOGSS projects the annual crude oil and natural gas production from existing fields, reserves growth, and exploration. It performs economic evaluation of the projects and ranks the reserves growth and exploration projects for development in a way designed to mimic the way decisions are made by the oil and gas industry. Development decisions and project selection depend upon economic viability and the competition for capital, drilling, and other available development constraints. Finally, the model aggregates production and drilling statistics using geographical and resource categories.

Overall System Logic

Figure 2-3 provides the overall system logic for the OLOGSS timing and economic module. This is the only component of OLOGSS which is integrated into NEMS.

Figure 2-3: OLOGSS Timing Module Overall System Logic



As seen in the figure, there are two primary sources of resource data. The exploration module provides the well-level technical production from the undiscovered projects which may be discovered in the next thirty years. It also determines the discovery order in which the projects will be evaluated by OLOGSS. The process module calculates the well-level technical production from known crude oil and natural gas fields, EOR and advanced secondary recovery (ASR) projects, and developing natural gas plays.

OLOGSS determines the potential domestic production in three phases. As seen in Figure 2-3, the first phase is the evaluation of the known crude oil and natural gas fields using a decline curve analysis. As part of the analysis, each project is subject to a detailed economic analysis used to determine the economic viability and expected life span of the project. In addition, the model applies regional factors used for history matching and resource base coverage. The remaining resources are categorized as either exploration or EOR/ASR. Each year, the exploration projects are subject to economic analysis which determines their economic viability and profitability.

For the EOR/ASR projects, development eligibility is determined before the economic analysis is conducted. The eligibility is based upon the economic life span of the corresponding decline curve project and the process-specific eligibility window. If a project is not currently eligible, it will be re-evaluated in future years. The projects which are eligible are subject to the same type of economic analysis applied to existing and exploration projects in order to determine the viability and relative profitability of the project.

After the economics have been determined for each eligible project, the projects are sorted. The exploration projects maintain their discovery order. The EOR/ASR projects are sorted by their relative profitability. The finalized lists are then considered by the project selection routines.

A project will be selected for development only if it is economically viable and if there are sufficient development resources available to meet the project's requirements. Development resource constraints are used to simulate limits on the availability of infrastructure related to the oil and gas industries. If sufficient resources are not available for an economic project, the project will be reconsidered in future years if it remains economically viable. Other development options are considered in this step, including the waterflooding of undiscovered conventional resources and the extension of CO_2 floods through an increase in total pore volume injected.

The production, reserves, and other key parameters for the timed and developed projects are aggregated at the regional and national levels.

The remainder of this document provides additional details on the logic and particular calculations for each of these steps. These include the decline analysis, economic analysis, timing decisions, project selection, constraints, and modeling of technology.

Known Fields

In this step, the production from existing crude oil and natural gas projects is estimated. A detailed economic analysis is conducted in order to calculate the economically viable production as well as the expected life of each project. The project life is used to determine when a project becomes eligible for EOR and ASR processes.

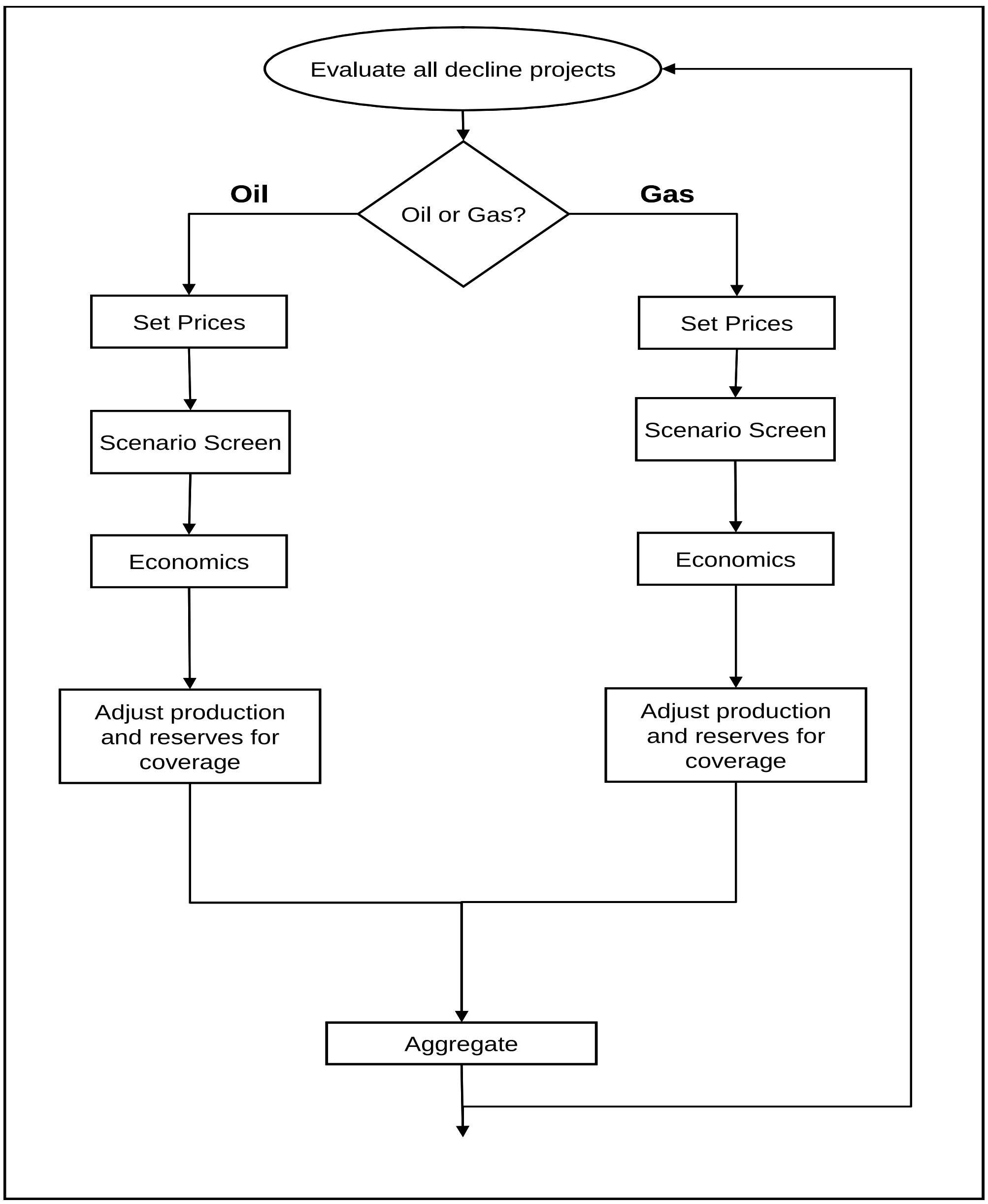
The logic for this process is provided in figure 2-4. For each crude oil project, regional prices are set and the project is screened to determine whether the user has specified any technology and/or economic levers. The screening considers factors including region, process, depth, and several other petro-physical properties. After applicable levers are determined, the project undergoes a detailed economic analysis.

After the analysis, resource coverage factors are applied to the economic production and reserves, and the project results are aggregated at the regional and national levels. In a final step, key parameters including the economic lifespan of the project are stored. A similar process is applied to the existing natural gas fields and reservoirs.

Resource coverage factors are applied in the model to ensure that historical production from existing fields matches that reported by EIA. These factors are calculated at the regional level and applied to production data for the following resources:

- Crude oil (includes lease condensates)
- High-permeability natural gas
- Coalbed methane
- Shale gas
- Tight gas

Figure 2-4: Decline Process Flowchart



Economics

Project Costs

OLOGSS conducts the economic analysis of each project using regional crude oil and natural gas prices. After these prices are set, the model evaluates the base and advanced technology cases for the project. The base case is defined as the current technology and cost scenario for the project; while the advanced case includes technology and/or cost improvements associated with the application of model levers. It is important to note that these cases – for which the assumption are applied to data for the project – are not the same as the *AEO* low, reference, or high technology cases.

For each technology case, the necessary petro-physical properties and other project data are set, the regional dryhole rates are determined, and the process specific depreciation schedule is assigned. The capital and operating costs for the project are then calculated and aggregated for both the base and advanced technology cases.

In the next step, a standard cashflow analysis is conducted, the discounted rate of return is calculated, and the ranking criteria are set for the project. Afterwards, the number and type of wells required for the project, and the last year of actual economic production are set. Finally, the economic variables, including production, development requirements, and other parameters, are stored for project timing and aggregation. All of these steps are illustrated in figure 2-5.

The details of the calculations used in conducting the economic analysis of a project are provided in the following description.

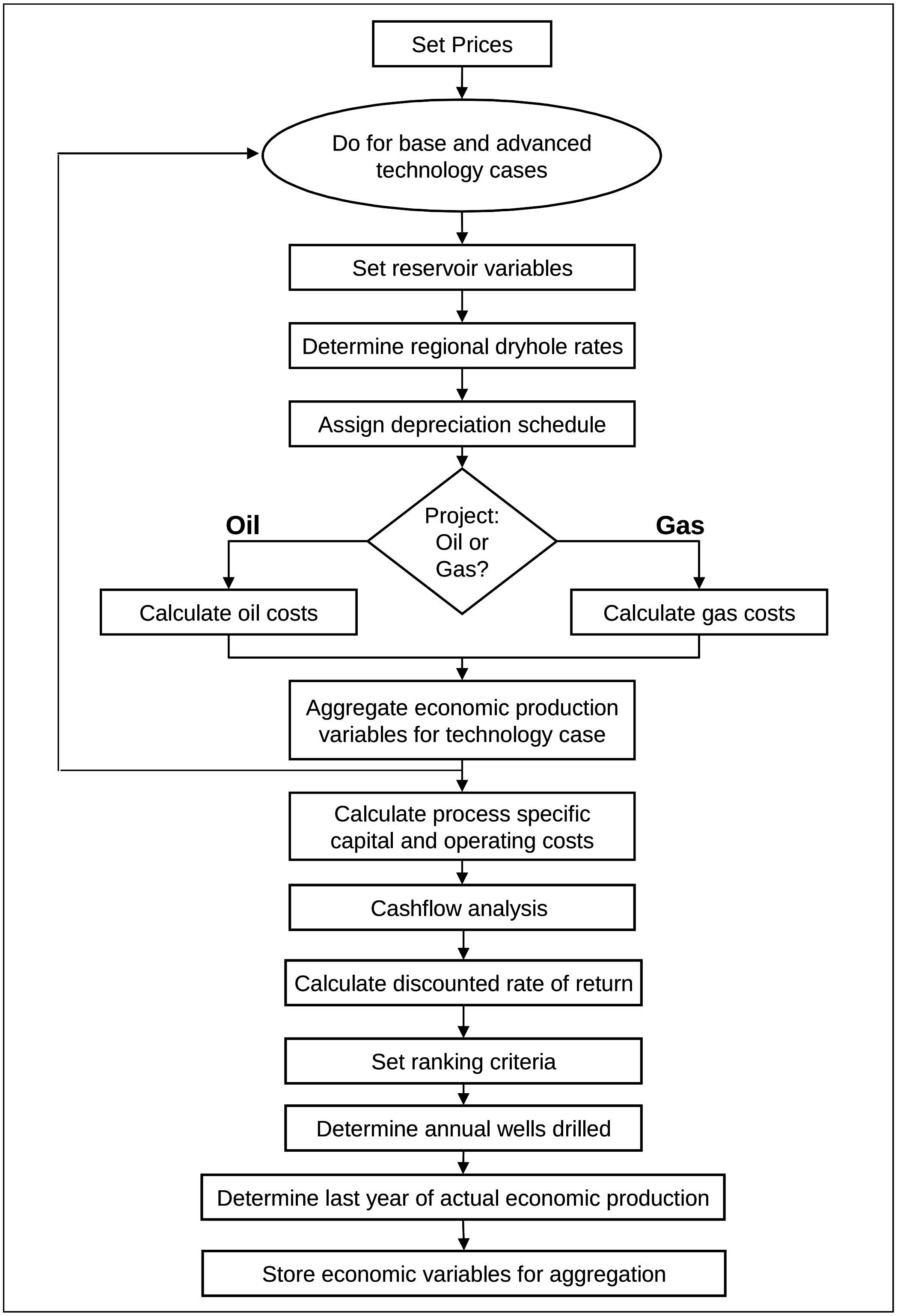
Determine the project shift: The first step is to determine the number of years the project development is shifted, i.e., the numbers of years between the discovery of a project and the start of its development. This will be used to determine the crude oil and natural gas price shift. The number of years is dependent upon both the development schedule – when the project drilling begins – and upon the process.

Determine annual prices: Determine the annual prices used in evaluating the project. Crude oil and natural gas prices in each year use the average price for the previous 5 years.

Begin analysis of base and advanced technology: To capture the impacts of technological improvements on both production and economics, the model divides the project into two categories. The first category – base technology – does not include improvements associated with technology or economic levers. The second category – advanced technology – incorporates the impact of the levers. The division of the project depends on the market penetration algorithm of any applicable technologies.

Determine the dryhole rate for the project: Assigns the regional dryhole rates for undiscovered exploration, undiscovered development, and discovered development. Three types of dryhole rates are used in the model: development in known fields and reservoirs, the first (wildcat) well in an exploration project, and subsequent wells in an exploration project. Specific dryhole rates are used for horizontal drilling and the developing natural gas resources.

Figure 2-5: Economic Analysis Logic



In the advanced case, the dryhole rates may also incorporate technology improvements associated with exploration or drilling success.

$$REGDRYUE_{im} = \left(\frac{SUCEXP_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) * EXPLR\_FAC_{itech} \tag{2-1}$$

$$REGDRYUD_{im} = \left(\frac{SUCEXPD_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-2}$$

$$REGDRYKD_{im} = \left(\frac{SUCDEVE_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-3}$$

If evaluating horizontal continuity or horizontal profile, then,

$$REGDRYKD_{im} = \left(\frac{SUCCHDEV_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-4}$$

If evaluating developing natural gas resources, then,

$$REGDRYUD_{im} = ALATNUM_{ires} * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-5}$$

where

ITECH	=	Technology case number
IM	=	Region number
REGDRYUE	=	Project specific dryhole rate for undiscovered exploration (Wildcat)
REGDRYUD	=	Project specific dryhole rate for undiscovered development
REGDRYKD	=	Project specific dryhole rate for known field development
SUCEXPD	=	Regional dryhole rate for undiscovered development
ALATNUM	=	Variable representing the regional dryhole rate for known field development
SUCDEVE	=	Regional dryhole rate for undiscovered exploration (Wildcat)
SUCCDEVH	=	Dryhole rate for horizontal drilling
DRILL_FAC	=	Technology lever applied to dryhole rate
EXPLR_FAC	=	Technology factor applied to exploratory dryhole rate

Process specific depreciation schedule: The default depreciation schedule is based on an eight-year declining balance depreciation method. The user may select process-specific depreciation schedules for CO2 flooding, steam flooding, or water flooding in the input file.

Calculate the capital and operating costs for the project: The project costs are calculated for each technology case. The costs are specific to crude oil or natural gas resources. The results of the cost calculations, which include technical crude oil and natural gas production, as well as drilling costs, facilities costs, and operating costs, are then aggregated to the project level.

G & G factor: Calculates the geological and geophysical (G&G) factor for each technology case. This is added to the first year cost.

$$GG_{\mathrm{itech}} = GG_{itech} + DRL\_CST_{itech} * INTANG\_M_{itech} * GG\_FAC \tag{2-6}$$

where

GG_{itech}	=	Geophysical and Geological costs for the first year of the project
DRL_CST_{itech}	=	Total drilling cost for the first year of the project
$INTANG\_M_{itech}$	=	Energy Elasticity factor for intangible investments (first year)
GG_FAC	=	Portion of exploratory costs that is G&G costs

After the variables are aggregated, the technology case loop ends. At this point, the process specific capital costs, which apply to the entire project instead of the technology case, are calculated.

Cashflow Analysis: The model then conducts a cashflow analysis on the project and calculates the discounted rate of return. Economic Analysis is conducted using a standard cashflow routine described in Appendix A.

Calculate the discounted rate of return: Determines the projected rate of return for all investments and production. The cumulative investments and discounted after tax cashflow are used to calculate the investment efficiency for the project.

Calculate wells: The annual number of new and existing wells is calculated for the project. The model tracks five drilling categories:

- New production wells drilled
- New injection wells drilled
- Active production wells
- Active injection wells
- Shut in wells

The calculation of the annual well count depends on the number of existing production and injection wells as well as on the process and project-specific requirements to complete each drilling pattern developed.

Determine number of years a project is economic: The model calculates the last year of actual economic production. This is based on both the results of the cashflow analysis and the annual production in year specified by the analysis. The last year of production is used to determine the aggregation range to be used if the project is selected for development.

If the project is economic only in the first year, it will be considered uneconomic and unavailable for development at that time. If this occurs for an existing crude oil or natural gas project, the model will assume that all of the wells will be shut in.

Non-producing decline project: Determines if the existing crude oil or natural gas project is non-producing. If there is no production, then the end point for project aggregation is not calculated. This check applies only to the existing crude oil and natural gas projects

Ranking criteria: Ranks investment efficiency based on the discounted after tax cashflow over tangible and intangible investments.

Determine ranking criterion: The ranking criterion, specified by the user, is the parameter by which the projects will be sorted before development. Ranking criteria options include the project net present value, the rate of return for the project, and the investment efficiency.

Calculating Unit Costs

To conduct the cost analysis, the model calculates price adjustment factors as well as unit costs for all required capital and operating costs. Unit costs include the cost of drilling and completing a single well, producing one barrel of crude oil, or operating one well for a year. These costs are adjusted using the technology levers and CPI indices. After the development schedule for the project is determined and the economic life of a single well is calculated, the technical production and injection are determined for the project. Based on the project's development schedule and the technical production, the annual capital and operating costs are determined. In the final step, the process and resource specific capital and operating costs are calculated for the project. These steps are illustrated in figure 2-6.

The Onshore Lower 48 Oil and Gas Supply Submodule uses detailed project costs for economic calculations. There are three broad categories of costs used by the model: capital costs, operating costs, and other costs. These costs are illustrated in figure 2-7. Capital costs encompass the costs of drilling and equipment necessary for the production of crude oil and natural gas resources. Operating costs are used to calculate the full life cycle economics of the project. Operating costs consist of normal daily expenses and surface maintenance. Other cost parameters include royalty, state and federal taxes, and other required schedules and factors.

The calculations for capital costs and operating costs for both crude oil and natural gas are described in detail below. The capital and operating costs are used in the timing and economic module to calculate the lifecycle economics for all crude oil and natural gas projects.

There are two categories for these costs: costs that are applied to all processes, thus defined as *resource independent*, and the process-specific costs, or *resource dependent* costs. Resource dependent costs are used to calculate the economics for existing, reserves growth, and exploration projects. The capital costs for both crude oil and natural gas are calculated first, followed by the resource independent costs, and then the resource dependent costs.

The resource independent and resource dependent costs applied to each of the crude oil and natural gas processes are detailed in tables 2-2 and 2-3 respectively.

Figure 2-6: Project Cost Calculation Procedure

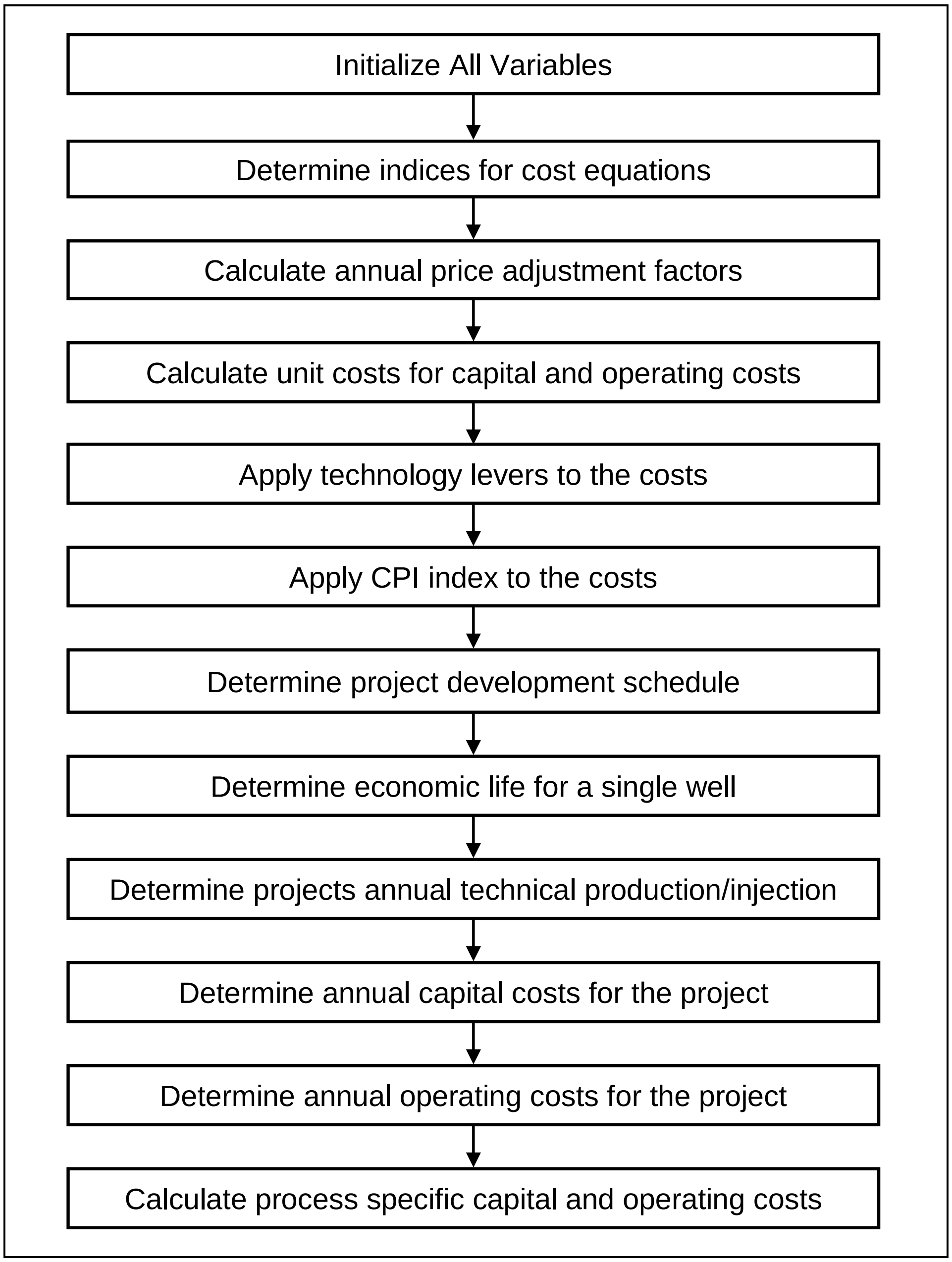


Figure 2-7: Cost Data Types and Requirements

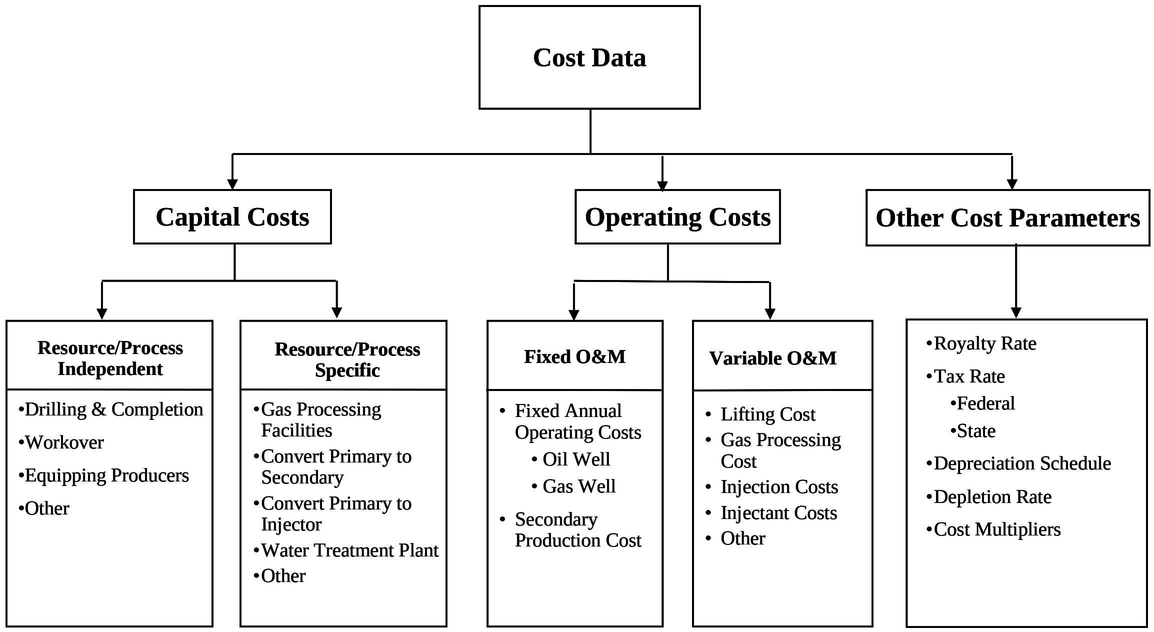


Table 2-2: Costs Applied to Crude Oil Processes

	Capital Cost for Oil	Existing	Water Flooding	CO2 Flooding	Steam Flooding	Polymer Flooding	Infill Drilling	Profile Modification	Undiscovered
Resource Independent	Vertical Drilling Cost	v	v	v	v	V	v	v	v
	Horizontal Drilling Cost								
	Drilling Cost for Dryhole	v	v	v	v	V	v	v	v
	Cost to Equip a Primary Producer		v	v	v	V	v	v	v
	Workover Cost		v	v	v	V	v	v	v
	Facillities Upgrade Cost		v	v	v	V	v	v	
	Fixed Annual Cost for Oil Wells	v	v	v	v	V	v	v	v
	Fixed Annual Cost for Secondary Production		v	v	v	V	v	v	v
	Lifting Cost		v	v	v	V	v	v	v
	O & M Cost for Active Patterns		v			V		v	
	Variable O & M Costs	v	v	v	v	V	v	v	v
	Socondary Workover Cost		v	v	v	V	v	v	v
Resource Dependent	Cost of Water Handling Plant		v			V		v	
	Cost of Chemical Plant					V			
	CO2 Recycle Plant			v					
	Cost of Injectant					V			
	Cost to Convert a Primary to Secondary Well		v	v	v	V	v	v	v
	Cost to Convert a Producer to an Injector		v	v	v	V	v	v	v
	Fixed O & M Cost for Secondary Operations		v	v	v	V	v	v	v
	Cost of a Water Injection Plant		v						
	O & M Cost for Active Patterns per Year		v			V		v	
	Cost to Inject CO2			v					
	King Factor				v				
	Steam Manifolds Cost				v				
	Steam Generators Cost				v				
	Cost to Inject Poloymer					V		v	

Table 2-3: Costs Applied to Natural Gas Processes

	Capital Costs for Gas	Conventional Radial Gas	Water Drive	Tight Sands	Coal/Shale Gas	Undiscovered Conventional
Resource Independent	Vertical Drilling Cost	v	v	v	v	v
	Horizontal Drilling Cost	v	v	v	v	v
	Drilling Cost for Dryhole	v	v	v	v	v
	Gas Facilities Cost	v	v	v	v	v
	Fixed Annual Costs for Gas Wells	v	v	v	v	v
	Gas Stimulation Costs	v	v	v	v	v
	Overhead Costs	v	v	v	v	v
	Variable O & M Cost	v	v	v	v	v
Resource Dependent	Gas Processing and Treatment Facilities	v	v	v	v	v

The following section details the calculations used to calculate the capital and operating costs for each crude oil and natural gas project. The specific coefficients are econometrically estimated according to the corresponding equations in Appendix 2.B.

Cost Multipliers

Cost multipliers are used to capture the impact on capital and operating costs associated with changes in energy prices. OLOGSS calculates cost multipliers for tangible and intangible investments, operating costs, and injectants (polymer and CO_2). The methodology used to calculate the multipliers is based on the National Energy Technology Laboratory (NETL's) Comprehensive Oil and Gas Analysis Model as well as the 1984 Enhanced Oil Recovery Study completed by the National Petroleum Council.

The multipliers for operating costs and injectant are applied while calculating project costs. The investment multipliers are applied during the cashflow analysis. The injectant multipliers are held constant for the analysis period while the others vary with changing crude oil and natural gas prices.

Operating Costs for Crude Oil: Operating costs are adjusted by the change between current crude oil prices and the base crude oil price. If the crude oil price in a given year falls below a pre-established minimum price, the adjustment factor is calculated using the minimum crude oil price.

$$\text{TERM} = \left(\frac{\text{OILPRICE}_{\text{iyr}} - \text{BASEOIL}}{\text{BASEOIL}}\right) \tag{2-7}$$

$$\text{INTANG\_M}_{\text{iyr}} = 1.0 + (\text{OMULT\_INT} * \text{TERM}) \tag{2-8}$$

$$\text{TANG\_M}_{\text{iyr}} = 1.0 + (\text{OMULT\_TANG} * \text{TERM}) \tag{2-9}$$

$$\text{OAM\_M}_{\text{iyr}} = 1.0 + (\text{OMULT\_OAM} * \text{TERM}) \tag{2-10}$$

where

IYR	=	Year
TERM	=	Fractional change in crude oil prices (from base price)
BASEOIL	=	Base crude oil price used for normalization of capital and operating costs
OMULT_INT	=	Coefficient for intangible crude oil investment factor
OMULT_TANG	=	Coefficient for tangible crude oil investment factor
OMULT_OAM	=	Coefficient for O & M factor
INTANG_M	=	Annual energy elasticity factor for intangible investments
TANG_M	=	Annual energy elasticity factor for tangible investments
OAM_M	=	Annual energy elasticity factor for crude oil O & M

Cost Multipliers for Natural Gas:

$$TERM = \left(\frac{GASPRICEC_{iyr} - BASEGAS}{BASEGAS} \right) \quad (2\text{-}11)$$

$$TANG\_M_{iyr} = 1.0 + (GMULT\_TANG * TERM) \quad (2\text{-}12)$$

$$INTANG\_M_{iyr} = 1.0 + (GMULT\_INT * TERM) \quad (2\text{-}13)$$

$$OAM\_M_{iyr} = 1.0 + (GMULT\_OAM * TERM) \quad (2\text{-}14)$$

where

GASPRICEC	=	Annual natural gas price
IYR	=	Year
TERM	=	Fractional change in natural gas prices
BASEGAS	=	Base natural gas price used for normalization of capital and operating costs
GMULT_INT	=	Coefficient for intangible natural gas investment factor
GMULT_TANG	=	Coefficient for tangible natural gas investment factor
GMULT_OAM	=	Coefficient for O & M factor
INTANG_M	=	Annual energy elasticity factor for intangible investments
TANG_M	=	Annual energy elasticity factor for tangible investments
OAM_M	=	Annual energy elasticity factor for crude oil O & M

Cost Multipliers for Injectant:

In the first year of the project:

$$FPLY = 1.0 + (0.3913 * TERM) \quad (2\text{-}15)$$

$$FCO2 = \frac{0.5 + 0.013 * BASEOIL * (1.0 + TERM)}{0.5 + 0.013 * BASEOIL} \quad (2\text{-}16)$$

where

TERM	=	Fractional change in crude oil prices
BASEOIL	=	Base crude oil price used for normalization of capital and operating costs
FPLY	=	Energy elasticity factor for polymer

FCO2 = Energy elasticity factor for natural CO_2 prices

Resource Independent Capital Costs for Crude Oil

Resource independent capital costs are applied to both crude oil and natural gas projects, regardless of the recovery method applied. The major resource independent capital costs are as follows: drilling and completion costs, the cost to equip a new or primary producer, and workover costs.

Drilling and Completion Costs: Drilling and completion costs incorporate the costs to drill and complete a crude oil or natural gas well (including tubing costs), and logging costs. These costs do not include the cost of drilling a dryhole/wildcat during exploration. OLOGSS uses a separate cost estimator, documented below, for dryholes drilled. Vertical well drilling costs include drilling and completion of vertical, tubing, and logging costs. Horizontal well costs include costs for drilling and completing a vertical well and the horizontal laterals.

Horizontal Drilling for Crude Oil:

$$DWC\_W = OIL\_DWCK_{r,d} + (OIL\_DWCA_{r,d} * DEPTH^2) + (OIL\_DWCB_{r,d} * DEPTH^2 * NLAT) + (OIL\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}17)$$

Vertical Drilling for Crude Oil:

$$DWC\_W = OIL\_DWCK_{r,d} + (OIL\_DWCA_{r,d} * DEPTH) + (OIL\_DWCB_{r,d} * DEPTH^2) + (OIL\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}18)$$

where

DWC_W	=	Cost to drill and complete a crude oil well (K$/Well)
r	=	Region number
d	=	Depth category number
OIL_DWCA, B, C, K	=	Coefficients for crude oil well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Horizontal Drilling for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH^2) + (DRY\_DWCB_{r,d} * DEPTH^2 * NLAT) + (DRY\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}19)$$

Vertical Drilling for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH) + (DRY\_DWCB_{r,d} * DEPTH^2) + (DRY\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}20)$$

where

DRY_W	=	Cost to drill a dry well (K$/Well)
R	=	Region number
D	=	Depth category number
DRY_DWCA, B, C, K	=	Coefficients for dry well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Cost to Equip a New Producer: The cost of equipping a primary producing well includes the production equipment costs for primary recovery.

$$NPR\_W = NPRK_{r,d} + (NPRA_{r,d} * DEPTH) + (NPRB_{r,d} * DEPTH^2) + (NPRC_{r,d} * DEPTH^3) \quad (2\text{-}21)$$

where

NPR_W	=	Cost to equip a new producer (K$/Well)
R	=	Region number
D	=	Depth category number
NPRA, B, C, K	=	Coefficients for new producer equipment cost equation
DEPTH	=	Well depth

Workover Costs: Workover, also known as stimulation is done every 2-3 years to increase the productivity of a producing well. In some cases workover or stimulation of a wellbore is required to maintain production rates.

$$WRK\_W = WRKK_{r,d} + (WRKA_{r,d} * DEPTH) + (WRKB_{r,d} * DEPTH^2) + (WRKC_{r,d} * DEPTH^3) \quad (2\text{-}22)$$

Where,

WRK_W	=	Cost for a well workover (K$/Well)
R	=	Region number
D	=	Depth category number
WRKA, B, C, K	=	Coefficients for workover cost equation
DEPTH	=	Well depth

Facilities Upgrade Cost: Additional cost of equipment upgrades incurred when converting a primary producing well to a secondary resource recovery producing well. Facilities upgrade costs consist of plant costs and electricity costs.

$$FAC\_W = FACUPK_{r,d} + (FACUPA_{r,d} * DEPTH) + (FACUPB_{r,d} * DEPTH^2) + (FACUPC_{r,d} * DEPTH^3) \quad (2\text{-}23)$$

where

FAC_W	=	Well facilities upgrade cost (K$/Well)
R	=	Region number
D	=	Depth category number
FACUPA, B, C, K	=	Coefficients for well facilities upgrade cost equation

DEPTH = Well depth

Resource Independent Capital Costs for Natural Gas

Drilling and Completion Costs: Drilling and completion costs incorporate the costs to drill and complete a crude oil or natural gas well (including tubing costs), and logging costs. These costs do not include the cost of drilling a dryhole/wildcat during exploration. OLOGSS uses a separate cost estimator, documented below, for dryholes drilled. Vertical well drilling costs include drilling and completion of vertical, tubing, and logging costs. Horizontal well costs include costs for drilling and completing a vertical well and the horizontal laterals.

Vertical Drilling Costs:

$$DWC\_W = GAS\_DWCK_{r,d} + (GAS\_DWCA_{r,d} * DEPTH) + (GAS\_DWCB_{r,d} * DEPTH^2) + (GAS\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}24)$$

Horizontal Drilling Costs:

$$DWC\_W = GAS\_DWCK_{r,d} + (GAS\_DWCA_{r,d} * DEPTH^2) + (GAS\_DWCB_{r,d} * DEPTH^2 * NLAT) + (GAS\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}25)$$

Where,

DWC_W = Cost to drill and complete a natural gas well (K$/Well)
R = Region number
D = Depth category number
GAS_DWCA, B, C, K = Coefficients for natural gas well drilling cost equation
DEPTH = Well depth
NLAT = Number of laterals
LATLEN = Length of lateral

Vertical Drilling Costs for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH) + (DRY\_DWCB_{r,d} * DEPTH^2) + (DRY\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}26)$$

Horizontal Drilling Costs for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH^2) + (DRY\_DWCB_{r,d} * DEPTH^2 * NLAT) + (DRY\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}27)$$

where

DRY_W = Cost to drill a dry well (K$/Well)
R = Region number
D = Depth category number
DRY_DWCA, B, C, K = Coefficients for dry well drilling cost equation
DEPTH = Well depth
NLAT = Number of laterals
LATLEN = Length of lateral

Facilities Cost: Additional cost of equipment upgrades incurred when converting a primary producing well to a secondary resource recovery producing well. Facilities costs consist of flowlines and connections, production package costs, and storage tank costs.

$$FWC\_W_{iyr} = FACGK_{r,d} + (FACGA_{r,d} * DEPTH) + (FACGB_{r,d} * PEAKDAILY\_RATE) + (FACGC_{r,d} * DEPTH * PEAKDAILY\_RATE) \quad (2\text{-}28)$$

where

FWC_W	=	Facilities cost for a natural gas well (K$/Well)
R	=	Region number
D	=	Depth category number
FACGA, B, C, K	=	Coefficients for facilities cost equation
DEPTH	=	Well depth
PEAKDAILY_RATE	=	Maximum daily natural gas production rate

Fixed Annual Operating Costs: The fixed annual operating costs are applied to natural gas projects in decline curve analysis.

$$FOAMG\_W = OMGK_{r,d} + (OMGA_{r,d} * DEPTH) + (OMGB_{r,d} * PEAKDAILY\_RATE) + (OMGC_{r,d} * DEPTH * PEAKDAILY\_RATE) \quad (2\text{-}29)$$

where

FOAMG_W	=	Fixed annual operating costs for natural gas (K$/Well)
R	=	Region number
D	=	Depth category number
OMGA, B, C, K	=	Coefficients for fixed annual O & M cost equation for natural gas
DEPTH	=	Well depth
PEAKDAILY_RATE	=	Maximum daily natural gas production rate

Resource Independent Annual Operating Costs for Crude Oil

Fixed Operating Costs: The fixed annual operating costs are applied to crude oil projects in decline curve analysis.

$$OMO\_W = OMOK_{r,d} + (OMOA_{r,d} * DEPTH) + (OMOB_{r,d} * DEPTH^2) + (OMOC_{r,d} * DEPTH^3) \quad (2\text{-}30)$$

where

OMO_W	=	Fixed annual operating costs for crude oil wells (K$/Well)
R	=	Region number
D	=	Depth category number
OMOA, B, C, K	=	Coefficients for fixed annual operating cost equation for crude oil
DEPTH	=	Well depth

Annual Costs for Secondary Producers: The direct annual operating expenses include costs in the following major areas: normal daily expenses, surface maintenance, and subsurface maintenance.

$$OPSEC\_W = OPSECK_{r,d} + (OPSECA_{r,d} * DEPTH) + (OPSECB_{r,d} * DEPTH^2) + (OPSECC_{r,d} * DEPTH^3) \quad (2\text{-}31)$$

where

OPSEC_W	=	Fixed annual operating cost for secondary oil operations (K$/Well)
R	=	Region number
D	=	Depth category number
OPSECA, B, C, K	=	Coefficients for fixed annual operating cost for secondary oil operations
DEPTH	=	Well depth

Lifting Costs: Incremental costs are added to a primary and secondary flowing well. These costs include pump operating costs, remedial services, workover rig services and associated labor.

$$OML\_W = OMLK_{r,d} + (OMLA_{r,d} * DEPTH) + (OMLB_{r,d} * DEPTH^2) + (OMLC_{r,d} * DEPTH^3) \quad (2\text{-}32)$$

where

OML_W	=	Variable annual operating cost for lifting (K$/Well)
R	=	Region number
D	=	Depth category number
OMLA, B, C, K	=	Coefficients for variable annual operating cost for lifting equation
DEPTH	=	Well depth

Secondary Workover: Secondary workover, also known as stimulation is done every 2-3 years to increase the productivity of a secondary producing well. In some cases secondary workover or stimulation of a wellbore is required to maintain production rates.

$$SWK\_W = OMSWRK_{r,d} + (OMSWR\ A_{r,d} * DEPTH) + (OMSWR\ B_{r,d} * DEPTH^2) + (OMSWR\ C_{r,d} * DEPTH^3) \quad (2\text{-}33)$$

where

SWK_W	=	Secondary workover costs (K$/Well)
R	=	Region number
D	=	Depth category number
OMSWRA, B, C, K	=	Coefficients for secondary workover costs equation
DEPTH	=	Well depth

Stimulation Costs: Workover, also known as stimulation is done every 2-3 years to increase the productivity of a producing well. In some cases workover or stimulation of a wellbore is required to maintain production rates.

$$\text{STIM\_W} = \left(\frac{\text{STIM\_A} + \text{STIM\_B} * \text{DEPTH}}{1000}\right) \tag{2-34}$$

where

STIM_W	=	Oil stimulation costs (K$/Well)
STIM_A, B	=	Stimulation cost equation coefficients
DEPTH	=	Well depth

Resource Dependent Capital Costs for Crude Oil

Cost to Convert a Primary Well to a Secondary Well: These costs consist of additional costs to equip a primary producing well for secondary recovery. The cost of replacing the old producing well equipment includes costs for drilling and equipping water supply wells but excludes tubing costs.

$$\begin{aligned}\text{PSW\_W} = {} & \text{PSWK}_{r,\,d} + (\text{PSWA}_{r,\,d} * \text{DEPTH}) + (\text{PSWB}_{r,\,d} * \text{DEPTH}^2) \\ & + (\text{PSWC}_{r,\,d} * \text{DEPTH}^3)\end{aligned} \tag{2-35}$$

where

PSW_W	=	Cost to convert a primary well into a secondary well (K$/Well)
R	=	Region number
D	=	Depth category number
PSWA, B, C, K	=	Coefficients for primary to secondary well conversion cost equation
DEPTH	=	Well depth

Cost to Convert a Producer to an Injector: Producing wells may be converted to injection service because of pattern selection and favorable cost comparison against drilling a new well. The conversion procedure consists of removing surface and sub-surface equipment (including tubing), acidizing and cleaning out the wellbore, and installing new 2- 7/8 inch plastic-coated tubing and a waterflood packer (plastic-coated internally and externally).

$$\begin{aligned}\text{PSI\_W} = {} & \text{PSIK}_{r,\,d} + (\text{PSIA}_{r,\,d} * \text{DEPTH}) + (\text{PSIB}_{r,\,d} * \text{DEPTH}^2) \\ & + (\text{PSIC}_{r,\,d} * \text{DEPTH}^3)\end{aligned} \tag{2-36}$$

where

PSI_W	=	Cost to convert a producing well into an injecting well (K$/Well)
R	=	Region number
D	=	Depth category number
PSIA, B, C, K	=	Coefficients for producing to injecting well conversion cost equation
DEPTH	=	Well depth

Cost of Produced Water Handling Plant: The capacity of the water treatment plant is a function of the maximum daily rate of water injected and produced (MBbl) throughout the life of the project.

$$PWP\_F = PWHP * \left(\frac{RMAXW}{365} \right) \tag{2-37}$$

where

PWP_F	=	Cost of the produced water handling plant (K$/Well)
PWHP	=	Produced water handling plant multiplier
RMAXW	=	Maximum pattern level annual water injection rate

Cost of Chemical Handling Plant (Non-Polymer): The capacity of the chemical handling plant is a function of the maximum daily rate of chemicals injected throughout the life of the project.

$$CHM\_F = CHMK * CHMA * \left(\frac{RMAXP}{365} \right)^{CHMB} \tag{2-38}$$

where

CHM_F	=	Cost of chemical handling plant (K$/Well)
CHMB	=	Coefficient for chemical handling plant cost equation
CHMK, A	=	Coefficients for chemical handling plant cost equation
RMAXP	=	Maximum pattern level annual polymer injection rate

Cost of Polymer Handling Plant: The capacity of the polymer handling plant is a function of the maximum daily rate of polymer injected throughout the life of the project.

$$PLY\_F = PLYPK * PLYPA * \left(\frac{RMAXP}{365} \right)^{0.6} \tag{2-39}$$

where

PLY_F	=	Cost of polymer handling plant (K$/Well)
PLYPK, A	=	Coefficients for polymer handling plant cost equation
RMAXP	=	Maximum pattern level annual polymer injection rate

Cost of CO_2 Recycling Plant: The capacity of a recycling/injection plant is a function of the maximum daily injection rate of CO_2 (Mcf) throughout the project life. If the maximum CO_2 rate equals or exceeds 60 MBbl/Day then the costs are divided into two separate plant costs.

$$CO2\_F = CO2rk * \left(\frac{0.75 * RMAXP}{365} \right)^{CO2RB} \tag{2-40}$$

where,

CO2_F	=	Cost of CO_2 recycling plant (K$/Well)
CO2RK, CO2RB	=	Coefficients for CO_2 recycling plant cost equation
RMAXP	=	Maximum pattern level annual CO_2 injection rate

Cost of Steam Manifolds and Pipelines: Cost to install and maintain steam manifolds and pipelines for steam flood enhanced oil recovery project.

$$STMM\_F = TOTPAT * PATSZE * STMMA \quad (2\text{-}41)$$

where

STMM_F	=	Cost for steam manifolds and generation (K$)
TOTPAT	=	Total number of patterns in the project
PATSZE	=	Pattern size (Acres)
STMMA	=	Steam manifold and pipeline cost (per acre)

Resource Dependant Annual Operating Costs for Crude Oil

Injection Costs: Incremental costs are added for secondary injection wells. These costs include pump operating, remedial services, workover rig services, and associated labor.

$$OPINJ\_W = OPINJK_{r,d} + (OPINJA_{r,d} * DEPTH) + (OPINJ\ B_{r,d} * DEPTH^2) + (OPINJ\ C_{r,d} * DEPTH^3) \quad (2\text{-}42)$$

where

OPINJ_W	=	Variable annual operating cost for injection (K$/Well)
R	=	Region number
D	=	Depth category number
OPINJA, B, C, K	=	Coefficients for variable annual operating cost for injection equation
DEPTH	=	Well depth

Injectant Cost: The injectant costs are added for the secondary injection wells. These costs are specific to the recovery method selected for the project. Three injectants are modeled: polymer, CO_2 from natural sources, and CO_2 from industrial sources.

Polymer Cost:

$$POLYCOST = POLYCOST * FPLY \quad (2\text{-}43)$$

where

POLYCOST	=	Cost of polymer ($/Lb)
FPLY	=	Energy elasticity factor for polymer

Natural CO_2 Cost: Cost to drill, produce and ship CO_2 from natural sources, namely CO_2 fields in Western Texas.

$$CO2COST = CO2K + (CO2B * OILPRICEO(1)) \quad (2\text{-}44)$$

$$CO2COST = CO2COST * CO2PR(IST) \quad (2\text{-}45)$$

where

CO2COST	=	Cost of natural CO_2 ($/Mcf)
IST	=	State identifier
CO2K, CO2B	=	Coefficients for natural CO_2 cost equation
OILPRICEO(1)	=	Crude oil price for first year of project analysis
CO2PR	=	State CO_2 cost multiplier used to represent changes in cost associated with transportation outside of the Permian Basin

Industrial CO_2 Cost: Cost to capture and transport CO_2 from industrial sources. These costs include the capture, compression to pipeline pressure, and the transportation to the project site via pipeline. The regional costs, which are specific to the industrial source of CO_2, are exogenously determined and provided in the input file.

Industrial CO_2 sources include

- Hydrogen Plants
- Ammonia Plants
- Ethanol Plants
- Cement Plants
- Hydrogen Refineries
- Power Plants
- Natural Gas Processing Plants
- Coal to Liquids

After unit costs have been calculated for the project, they are adjusted using technology levers as well as CPI multipliers. Two types of levers are applied to the costs. The first is the fractional change in cost associated with a new technology. The second is the incremental cost associated with implementing the new technology. These factors are determined by the model user. As an example,

$$NPR\_W = (NPR\_W * CHG\_FAC\_FAC(ITECH)) + CST\_FAC\_FAC(ITECH) \qquad (2\text{-}46)$$

where,

NPR_W	=	Cost to equip a new oil producer (K$/well)
CHG_FAC_FAC	=	Fractional change in cost associated with technology improvements
CST_FAC_FAC	=	Incremental cost to apply the new technology
ITECH	=	Technology case (Base or Advanced)

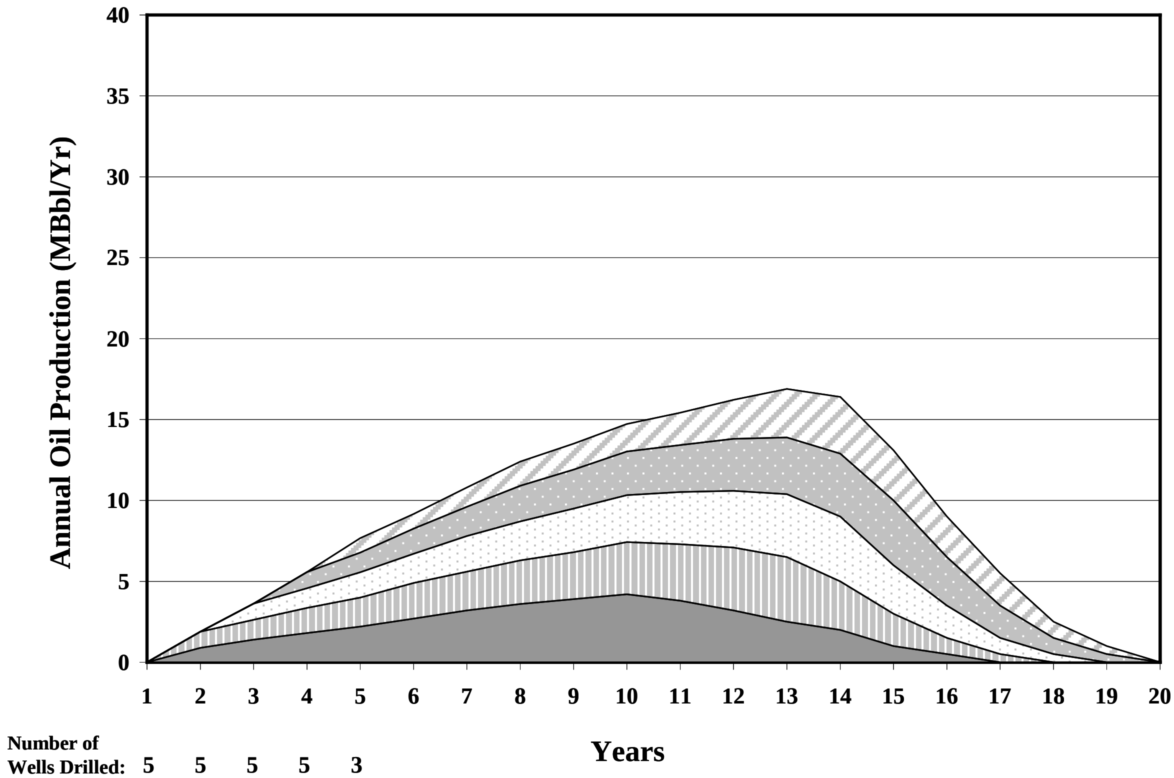
Determining Technical Production

The development schedule algorithms determine how the project's development over time will be modeled. They calculate the number of patterns initiated per year and the economic life of the well. The economic life is the number of years in which the revenue from production exceeds the costs required to produce the crude oil and natural gas.

The model then aggregates the well-level production of crude oil, natural gas, water, and injectant based upon the pattern life and number of wells initiated each year. The resulting profile is the technical production for the project.

Figure 2-8 shows the crude oil production for one project over the course of its life. The graph shows a hypothetical project. In this scenario patterns are initiated for five years. Each shaded area is the annual technical production associated with the initiated patterns.

Figure 2-8: Calculating Project Level Technical Production



The first step in modeling the technical production is to calculate the number of patterns drilled each year. The model uses several factors in calculating the development schedule:

- Potential delays between the discovery of the project and actual initiation
- The process modeled
- The resource access – the number of patterns developed each year is reduced if the resource is subject to cumulative surface use limitations
- The total number of patterns in the project
- The crude oil and natural gas prices
- The user specified maximum and minimum number of patterns developed each year
- The user specified percentage of the project to be developed each year
- The percentage of the project which is using base or advanced technology.

These apply to the EOR/ASR projects as well as the undiscovered and currently developing ones. The projects in existing fields and reservoirs are assumed to have all of their patterns – the number of active wells – developed in the first year of the project.

After calculating the number of patterns initiated each year, the model calculates the number of patterns which are active for each year of the project life.

Production Profile of the Project: For all EOR/ASR, undiscovered, and developing processes, the project level technical production is calculated using well-level production profiles. For infill projects, the production is doubled because the model assumes that there are two producers in each pattern.

$$OILPROD_{iyr1} = OILPROD_{iyr1} + (OPROD_{kyr} * PATN_{iyr}) \quad (2\text{-}47)$$
$$GASPROD_{iyr1} = OILPROD_{iyr1} + (GPROD_{kyr} * PATN_{iyr}) \quad (2\text{-}48)$$
$$NGLPROD_{iyr1} = NGLPROD_{iyr1} + (NPROD_{kyr} * PATN_{iyr}) \quad (2\text{-}49)$$
$$WATPROD_{iyr1} = WATPROD_{iyr1} + (WPROD_{kyr} * PATN_{iyr}) \quad (2\text{-}50)$$
$$TOTINJ_{iyr1} = TOTINJ_{iyr1} + (OINJ_{kyr} * PATN_{iyr}) \quad (2\text{-}51)$$
$$WATINJ_{iyr1} = WATINJ_{iyr1} + (WINJ_{kyr} * PATN_{iyr}) \quad (2\text{-}52)$$
$$TORECY_{iyr1} = TORECY_{iyr1} + (ORECY_{kyr} * PATN_{iyr}) \quad (2\text{-}53)$$
$$SUMP_{iyr1} = SUMP_{iyr1} + PATN_{iyr} \quad (2\text{-}54)$$

where

IYR1	=	Number of years
IYR	=	Year of project development
JYR	=	Number of years the project is developed
KYR	=	Year (well level profile)
LYR	=	Last project year in which pattern level profile is applied
OPROD	=	Pattern level annual crude oil production
GPROD	=	Pattern level annual natural gas production
NPROD	=	Pattern level annual NGLl production
WPROD	=	Pattern level annual water production
WINJ	=	Pattern level annual water injection
OINJ	=	Pattern level annual injectant injection
ORECY	=	Pattern level annual injectant recycled
PATN	=	Number of patterns initiated each year
SUMP	=	Cumulative number of patterns developed
OILPROD	=	Project level annual crude oil production
GASPROD	=	Project level annual natural gas production
NGLPROD	=	Project level annual NGL production
WATPROD	=	Project level annual water production
WATINJ	=	Project level annual water injection
TOTINJ	=	Project level annual injectant injection
TORECY	=	Project level annual injectant recycled

Reviewer's note: The equations above are confusing, because the same variable appears on the LHS and RHS. I'm guessing that the variable is simply being incremented on an annual basis, i.e., that the first equation should read something like

In any case, please clarify what is happening in the equations and use a new variable name on the LHS.

Resource Accounting

OLOGSS incorporates a complete and representative description of the processes by which crude oil and natural gas in the technically recoverable resource base[1] are converted to proved reserves.[2]

OLOGSS distinguishes between drilling for new fields (new field wildcats) and drilling for additional deposits within old fields (other exploratory and developmental wells). This enhancement recognizes important differences in exploratory drilling, both by its nature and in its physical and economic returns. New field wildcats convert resources in previously undiscovered fields[3] into both proved reserves (as new discoveries) and inferred reserves.[4] Other exploratory drilling and developmental drilling add to proved reserves from the stock of inferred reserves. The phenomenon of reserves appreciation is the process by which initial assessments of proved reserves from a new field discovery grow over time through extensions and revisions.

End of Year Reserves: The model calculates two types of end of year (EOY) reserves at the project level: inferred reserves and proved reserves. Inferred reserves are calculated as the total technical production minus the technical production from patterns initiated through a particular year. Proved reserves are calculated as the technical production from wells initiated through a particular year minus the cumulative production from those patterns.

Inferred reserves = total technical production – technical production for wells initiated

$$\mathrm{airsvoil(ires, n)} = \sum_{`i=1}^{\mathrm{max\_yr}} \left[\sum_{j=1}^{\mathrm{ilife}} \left(\mathrm{oprod}(j)\right) \times \mathrm{patn}(i) \right] - \sum_{i=1}^{n} \left[\sum_{j=1}^{\mathrm{ilife}} \left(\mathrm{oprod}(j)\right) \times \mathrm{patn}(i) \right] \qquad (2\text{-}55)$$

$$\mathrm{airsvgas(ires, n)} = \sum_{`i=1}^{\mathrm{max\_yr}} \left[\sum_{j=1}^{\mathrm{ilife}} \left(\mathrm{gprod}(j)\right) \times \mathrm{patn}(i) \right] - \sum_{i=1}^{n} \left[\sum_{j=1}^{\mathrm{ilife}} \left(\mathrm{gprod}(j)\right) \times \mathrm{patn}(i) \right] \qquad (2\text{-}56)$$

Reviewers note: It's not clear what "ires" is above. Also, it looks like all of these equations can be simplified by writing the outer sums from n+1 to max_yr, e.g.,

Proved reserves = technical production for patterns initiated – cumulative production

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[1] *Technically recoverable resources* are those volumes considered to be producible with current recovery technology and efficiency but without reference to economic viability. Technically recoverable volumes include proved reserves, inferred reserves, as well as undiscovered and other unproved resources. These resources may be recoverable by techniques considered either conventional or unconventional.

[2] *Proved reserves* are the estimated quantities that analyses of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[3] *Undiscovered resources* are located outside of oil and gas fields, in which the presence of resources has been confirmed by exploratory drilling, and thus exclude reserves and reserve extensions; however, they include resources from undiscovered pools within confirmed fields to the extent that such resources occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[4] *Inferred reserves* are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

$$\text{aresvoil(ires, n)} = \sum_{`i=1}^{n}\left[\sum_{j=1}^{ilife}\left(\text{oprod}(j)\right)\times \text{patn}(i)\right] - \sum_{i=1}^{n}\left[\sum_{j=1}^{n}\left(\text{oprod}(j)\right)\times \text{patn}(i)\right] \qquad (2\text{-}57)$$

$$\text{aresvgas(ires, n)} = \sum_{`i=1}^{n}\left[\sum_{j=1}^{ilife}\left(\text{gprod}(j)\right)\times \text{patn}(i)\right] - \sum_{i=1}^{n}\left[\sum_{j=1}^{n}\left(\text{gprod}(j)\right)\times \text{patn}(i)\right] \qquad (2\text{-}58)$$

where,

I, J	=	Years
N	=	Current year evaluated
ILIFE	=	Pattern life
MAX_YR	=	Maximum number of years
OPROD	=	Pattern level annual crude oil production
GPROD	=	Pattern level annual natural gas production
PATN	=	Number of patterns developed each year
AIRSVOIL	=	Annual inferred crude oil reserves
AIRSVGAS	=	Annual inferred natural gas reserves
ARESVOIL	=	Annual proved oil reserves
ARESVGAS	=	Annual proved natural gas reserves

For existing crude oil and natural gas projects, the model calculates the proved reserves. For these processes, the proved reserves are defined as the total technical production divided by the life of the project.

Calculating Project Costs

The model uses four drilling categories for the calculation of drilling and facilities costs. These categories are:

- New producers
- New injectors
- Conversions of producers to injectors
- Conversions of primary wells to secondary wells.

The number of ??? in each category required for the pattern is dependent upon the process and the project.

Project Level Process Independent Costs

Drilling costs and facility costs are determined at the project level.

Drilling Costs: Drilling costs are calculated using one of four approaches, depending on the resource and recovery process. These approaches apply to the following resources:

- Undiscovered crude oil and natural gas
- Existing crude oil and natural gas fields
- EOR/ASR projects
- Developing natural gas projects

<u>For undiscovered crude oil and natural gas resources:</u> The first well drilled in the first year of the project is assumed to be a wildcat well. The remaining wells are assumed to be undiscovered development wells. This is reflected in the application of the dryhole rates.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUE_R) * 1.0 * XPP1 \quad (2\text{-}59)$$

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUD_R) * (PATN_{iyr} – 1 * XPP1) \quad (2\text{-}60)$$

For existing crude oil and natural gas fields: As the field is already established, the developmental dryhole rate is used.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYKD_R) * (PATDEV_{ires,iyr, itech} * XPP1) \quad (2\text{-}61)$$

For EOR/ASR Projects: As the project is in an established and known field, the developmental dryhole rate is used.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYKD_R) * (PATN_{iyr} * XPP1) \quad (2\text{-}62)$$

For developing natural gas projects: As the project is currently being developed, it is assumed that the wildcat well(s) have previously been drilled. Therefore, the undiscovered developmental dryhole rate is applied to the project.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUD_R) * (PATN_{iyr} * XPP1) \quad (2\text{-}63)$$

where

IRES	=	Project index number
IYR	=	Year
R	=	Region
PATDEV	=	Number of patterns initiated each year for base and advanced technology cases
PATN	=	Annual number of patterns initiated
DRL_CST2	=	Technology case specific annual drilling cost
DWC_W	=	Cost to drill and complete a well
DRY_W	=	Cost to drill a dryhole
REGDRYUE	=	Dryhole rate for undiscovered exploration (wildcat)
REGDRYUD	=	Dryhole rate for undiscovered development
REGDRYKD	=	Dryhole rate for known fields development
XPP1	=	Number of producing wells drilled per pattern

Facilities Costs: Facilities costs depend on both the process and the resource. Five approaches are used to calculate the facilities costs for the project.

For undiscovered and developing natural gas projects:

$$FACCOST_{iyr} = FACCOST_{iyr} + (FWC\_W * PATN_{iyr} * XPP1) \quad (2\text{-}64)$$

For existing natural gas fields:

$$FACCOST_{iyr} = FACCOST_{iyr} + (FWC\_W * (PATDEV_{IRES,iyr, itech}) * XPP1) \quad (2\text{-}65)$$

For undiscovered continuous crude oil:

$$FACCOST_{iyr} = FACCOST_{iyr} + (NPR\_W * PATN_{iyr} * XPP1) \quad (2\text{-}66)$$

For existing crude oil fields:

$$\begin{aligned} FACCOST_{iyr} = FACCOST_{iyr} &+ (PSW\_W * (PATDEV_{IRES,iyr, itech}) * XPP4) \\ &+ (PSI\_W * PATDEV_{IRES,iyr, itech} * XPP3) \\ &+ (FAC\_W * PATDEV_{IRES,iyr, itech} * (XPP1 + XPP2)) \end{aligned} \quad (2\text{-}67)$$

For undiscovered conventional crude oil and EOR/ASR projects:

$$\begin{aligned} FACCOST_{iyr} = FACCOST_{iyr} &+ (PSW\_W * PATN_{iyr} * XPP4) \\ &+ (PSI\_W * PATN_{iyr} * XPP3) + (FAC\_W * PATN_{iyr} * (XPP1 + XPP2)) \end{aligned} \quad (2\text{-}68)$$

where

IYR	=	Year
IRES	=	Project index number
ITECH	=	Technology case
PATN	=	Number of patterns initiated each year for the technology case being evaluated
PATDEV	=	Number of patterns initiated each year for base and advanced technology cases
XPP1	=	Number of new production wells drilled per pattern
XPP2	=	Number of new injection wells drilled per pattern
XPP3	=	Number of producers converted to injectors per pattern
XPP4	=	Number of primary wells converted to secondary wells per pattern
FAC_W	=	Crude oil well facilities upgrade cost
NPR_W	=	Cost to equip a new producer
PSW_W	=	Cost to convert a primary well to a secondary well
PSI_W	=	Cost to convert a production well to an injection well
FWC_W	=	Natural gas well facilities cost
FACCOST	=	Annual facilities cost for the well

Injectant Cost Added to Operating and Maintenance: The cost of injectant is calculated and added to the operating and maintenance costs.

$$INJ_{iyr} = INJ_{iyr} + INJ\_OAM1 * WATINJ_{iyr} \quad (2\text{-}69)$$

where

IYR	=	Year

INJ	=	Annual injection cost
INJ_OAM1	=	Process specific cost of injection ($/Bbl)
WATINJ	=	Annual project level water injection

Fixed Annual Operating Costs for Crude Oil:
<u>For CO_2 EOR:</u>

$$AOAM_{iyr} = AOAM_{iyr} + OPSEC\_W * SUMP_{iyr} \quad (2\text{-}70)$$

<u>For undiscovered conventional crude oil:</u>

Fixed annual operating costs for secondary oil wells are assumed to be zero.

<u>For all crude oil processes except CO_2 EOR:</u>

$$AOAM_{iyr} = AOAM_{iyr} + (OMO\_W * XPATN_{iyr}) + (OPSEC\_W * XPATN_{iyr}) \quad (2\text{-}71)$$

Fixed Annual Operating Costs for Natural Gas:
<u>For existing natural gas fields:</u>

$$AOAM_{iyr} = AOAM_{iyr} + (FOAMG\_W * OAM\_M_{iyr} * XPATN_{iyr}) \quad (2\text{-}72)$$

<u>For undiscovered and developing natural gas resources:</u>

$$AOAM_{iyr} = AOAM_{iyr} + (FOAMG\_W * OAM\_M_{iyr} * XPATN_{iyr}) * XPP1 \quad (2\text{-}73)$$

where,

AOAM	=	Annual fixed operating an maintenance costs
IYR	=	Year
SUMP	=	Total cumulative patterns initiated
OPSEC_W	=	Fixed annual operating costs for secondary oil wells
OMO_W	=	Fixed annual operating costs for crude oil wells
FOAMG_W	=	Fixed annual operating costs for natural gas wells
OAM_M	=	Energy elasticity factor for operating and maintenance costs
XPATN	=	Annual number of active patterns
XPP1	=	Number of producing wells drilled per pattern

Variable Operating Costs:

$$OAM_{iyr} = OAM_{iyr} + (OILPROD_{iyr} * OIL\_OAM1 * OAM\_M_{iyr}) + (GASPROD_{iyr} * GAS\_OAM1 * OAM\_M_{iyr}) + (WATPROD_{iyr} * WAT\_OAM1 * OAM\_M_{iyr}) \quad (2\text{-}74)$$

$$STIM_{iyr} = STIM_{iyr} + (0.2 * STIM\_W * XPATN_{iyr} * XPP1) \quad (2\text{-}74)$$

For infill drilling: Injectant costs are zero.

$$OAM_{iyr} = OAM_{iyr} + INJ_{iyr} \quad (2\text{-}75)$$

where

OAM	=	Annual variable operating and maintenance costs
OILPROD	=	Annual project level crude oil production
GASPROD	=	Annual project level natural gas production
WATPROD	=	Annual project level water injection
OIL_OAM1	=	Process specific cost of crude oil production ($/Bbl)
GAS_OAM1	=	Process specific cost of natural gas production ($/Mcf)
WAT_OAM1	=	Process specific cost of water production ($/Bbl)
OAM_M	=	Energy elasticity factor for operating and maintenance costs
STIM	=	Project stimulation costs
STIM_W	=	Well stimulation costs
INJ	=	Cost of injection
XPATN	=	Annual number of active patterns
IYR	=	Year
XPP1	=	Number of producing wells drilled per pattern

Cost of Compression (Natural Gas Processes):

Installation costs:

$$COMP_{IYR} = COMP_{IYR} + (COMP\_W*PATN_{IYR}*XPP1) \quad (2\text{-}76)$$

O&M cost for compression:

$$OAM\_COMP_{IYR} = OAM\_COMP_{IYR} + (GASPROD_{IYR} * COMP\_OAM *OAM\_M_{IYR}) \quad (2\text{-}77)$$

where

COMP	=	Cost of installing natural gas compression equipment
COMP_W	=	Natural gas compression cost
PATN	=	Number of patterns initiated each year
IYR	=	Year
XPP1	=	Number of producing wells drilled per pattern
OAM_COMP	=	Operating and maintenance costs for natural gas compression
GASPROD	=	Annual project level natural gas production
COMP_OAM	=	Compressor O & M costs
OAM_M	=	Energy elasticity factor for operating and maintenance costs

Process Dependent Costs

Process-specific facilities and capital costs are calculated at the project level.

Facilities Costs

Profile Model: The facilities cost of a water handling plant is added to the first year facilities costs.

$$FACCOST_1 = FACCOST_1 + PWHP * \left(\frac{RMAX}{365}\right) \tag{2-78}$$

where

$FACCOST_1$	=	First year of project facilities costs
PWHP	=	Produced water handling plant multiplier
RMAX	=	Maximum annual water injection rate

Polymer Model: The facilities cost for a water handling plant is added to the first year facilities costs.

$$FACCOST_1 = FACCOST_1 + PWP\_F \tag{2-79}$$

where

$FACCOST_1$	=	First year of project facilities costs
PWP_F	=	Produced water handling plant

Advanced CO_2: Other costs added to the facilities costs include the facilities cost for a CO_2 handling plant and a recycling plant, the O&M cost for a CO_2 handling plant and recycling plant, injectant cost, O&M and fixed O&M costs for a CO_2 handling plant and a recycling plant. If the plant is developed in a single stage, the costs are added to the first year of the facilities costs. If a second stage is required, the additional costs are added to the sixth year of facilities costs.

$$FACCOST1 = FACCOST1 + \left(CO2RK * \left(\frac{0.75 * RMAX}{365}\right)^{CO2RB}\right) * 1{,}000 \tag{2-80}$$

$$FACCOST6 = FACCOST6 + \left(CO2RK * \left(\frac{0.75 * RMAX}{365}\right)^{CO2RB}\right) * 1{,}000$$

$$INJ_{iyr} = INJ_{iyr} + (TOTINJ_{iyr} - TORECY_{iyr}) * CO2COST \tag{2-81}$$

$$OAM_{iyr} = OAM_{iyr} + (OAM\_M_{iyr} * TORECY_{iyr}) * (CO2OAM + PSW\_W * 0.25) \tag{2-82}$$

$$FOAM_{iyr} = (FOAM_{iyr} + TOTINJ_{iyr}) * 0.40 * FCO2 \tag{2-83}$$

$$TORECY\_CST_{iyr} = TORECY\_CST_{iyr} + (TORECY_{iyr} * CO2OAM2 * OAM\_M_{iyr}) \tag{2-84}$$

where

IYR	=	Year
RMAX	=	Maximum annual volume of recycled CO_2

CO2OAM	=	O & M cost for CO_2 handling plant
CO2OAM2	=	The O & M cost for the project's CO_2 injection plant
CO2RK, CO2RB	=	CO_2 recycling plant cost coefficients
INJ	=	Cost of purchased CO_2
TOTINJ	=	Annual project level volume of injected CO_2
TORECY	=	Annual project level CO_2 recycled volume
CO2COST	=	Cost of CO_2 ($/mcf)
OAM	=	Annual variable operating and maintenance costs
OAM_M	=	Energy elasticity factor for operating and maintenance costs
FOAM	=	Fixed annual operating and maintenance costs
FCO2	=	Energy elasticity factor for CO_2
FACCOST	=	Annual project facilities costs
TORECY_CST	=	The annual cost of operating the CO_2 recycling plant

Steam Model: Facilities and O&M costs for steam generators and recycling.

Recalculate the facilities costs: Facilities costs include the capital cost for injection plants, which is based upon the OOIP of the project, the steam recycling plant, and the steam generators required for the project.

$$\mathrm{FACCOST1} = \mathrm{FACCOST1} + \left(\frac{OOIP * 0.1 * 2.0 * APAT}{TOTPAT}\right) + (\mathrm{RECY\_WAT} * \mathrm{RMAXWAT} + \mathrm{RECY\_OIL} * \mathrm{RMAXOIL}) + (\mathrm{STMMA} * \mathrm{TOTPAT} * \mathrm{PATSIZE}) + (\mathrm{IGEN}_{iyr} - \mathrm{IG}) * \mathrm{STMGA} \tag{2-85}$$

$$\mathrm{OAM}_{iyr} = \mathrm{OAM}_{iyr} + (\mathrm{WAT\_OAM1} * \mathrm{WATPROD}_{iyr} * \mathrm{OAM\_M}_{iyr}) + (\mathrm{OIL\_OAM1} * \mathrm{OILPROD}_{iyr} * \mathrm{OAM\_M}_{iyr}) + (\mathrm{INJ\_OAM1} * \mathrm{WATINJ}_{iyr} * \mathrm{OAM\_M}_{iyr}) \tag{2-86}$$

where

IYR	=	Year
IGEN	=	Number of active steam generators each year
IG	=	Number of active steam generators in previous year
FACCOST	=	Annual project level facilities costs
RMAXWAT	=	Maximum daily water production rate
RMAXOIL	=	Maximum daily crude oil production rate
APAT	=	Number of developed patterns
TOTPAT	=	Total number of patterns in the project
OOIP	=	Original oil in place (mmbbl)
PATSIZE	=	Pattern size (acres)
STMMA	=	Unit cost for steam manifolds
STMGA	=	Unit cost for steam generators
OAM	=	Annual variable operating and maintenance costs
OAM_M	=	Energy elasticity factor for operating and maintenance costs
WAT_OAM1	=	Process specific cost of water production ($/Bbl)
OIL_OAM1	=	Process specific cost of crude oil production ($/Bbl)

INJ_OAM1	=	Process specific cost of water injection ($/Bbl)
OILPROD	=	Annual project level crude oil production
WATPROD	=	Annual project level water production
WATINJ	=	Annual project level water injection
RECY_WAT	=	Recycling plant cost – water factor
RECY_OIL	=	Recycling plant cost – oil factor

Operating and Maintenance Cost

This subroutine calculates the process specific O&M costs.

Profile Model: Add the O&M costs of injected polymer.

$$INJ_{iyr} = INJ_{iyr} + \frac{OAM\_M_{iyr} * TOTINJ_{iyr} * POLYCOST}{1000} \tag{2-87}$$

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \tag{2-88}$$

where

IYR	=	Year
MAX_YR	=	Maximum number of years
INJ	=	Annual Injection cost
OAM_M	=	Energy elasticity factor for operating and maintenance cost
TOTINJ	=	Annual project level injectant injection volume
POLYCOST	=	Polymer cost
OAM	=	Annual variable operating and maintenance cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Polymer: Add the O&M costs of injected polymer.

$$INJ_{iyr} = INJ_{IYR} + \frac{TOTINJ_{iyr} * POLYCOST}{1{,}000} \tag{2-89}$$

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \tag{2-90}$$

where

IYR	=	Year
MAX_YR	=	Maximum number of years
INJ	=	Annual Injection cost
TOTINJ	=	Annual project level injectant injection volume
POLYCOST	=	Polymer cost
OAM	=	Annual variable operating and maintenance cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Waterflood: Add the O&M costs of water injected as well as the cost to convert a primary well to an injection well.

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \quad (2\text{-}91)$$

where

IYR	=	Year
MAX_YR	=	Maximum number of years
OAM	=	Annual variable operating and maintenance cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Existing crude oil fields and reservoirs: Since no new drilling or major investments are expected for decline, facilities and drilling costs are zeroed out.

$$OAM_{iyr} = OAM_{iyr} + ((OIL\_OAM1 * OILPROD_{iyr}) + (GAS\_OAM1 * GASPROD_{iyr}) + (WAT\_OAM1 * WATPROD_{iyr})) * OAM\_M_{iyr} \quad (2\text{-}92)$$

$$AOAM_{iyr} = AOAM_{iyr} + \left(\frac{OPSEC\_W * OAM\_M_{iyr} * SUMP_{iyr}}{5} \right) \quad (2\text{-}93)$$

where

IYR	=	Year
OILPROD	=	Annual project level crude oil production
GASPROD	=	Annual project level natural gas production
WATPROD	=	Annual project level water production
OIL_OAM1	=	Process specific cost of crude oil production ($/Bbl)
GAS_OAM1	=	Process specific cost of natural gas production ($/Mcf)
WAT_OAM1	=	Process specific cost of water production ($/Bbl)
OAM_M	=	Energy elasticity factor for operating and maintenance costs
OPSEC_W	=	Fixed annual operating cost for secondary well operations
SUMP	=	Cumulative patterns developed
AOAM	=	Fixed annual operating and maintenance costs
OAM	=	Variable annual operating and maintenance costs

Overhead Costs: : General and Administrative (G&A) costs on capitalized and expensed items, which consist of administration, accounting, contracting and legal fees/expenses for the project, are calculated according to the following equations:

$$GNA\_EXP_{itech} = GNA\_EXP_{itech} * CHG\_GNA\_FAC_{itech} \quad (2\text{-}94)$$
$$GNA\_CAP_{itech} = GNA\_CAP_{itech} * CHG\_GNA\_FAC_{itech} \quad (2\text{-}95)$$

where

ITECH	=	Technology case (base and advanced) number
GNA_EXP	=	The G&A rate applied to expensed items for the project
GNA_CAP	=	The G&A rate applied to capitalized items for the project
CHG_GNA_FAC	=	Technology case specific change in G&A rates

Timing

Overview of Timing Module

The timing routine determines which of the exploration and EOR/ASR projects are eligible for development in any particular year. Those that are eligible are subject to an economic analysis and passed to the project sort and development routines. The timing routine has two sections. The first applies to exploration projects while the second is applied to EOR/ASR and developing natural gas projects.

Figure 2-9 provides the overall logic for the exploration component of the timing routine. For each project regional crude oil and natural gas prices are obtained. The project is then examined to see if it has previously been timed and developed. The timed projects are no longer available and thus not considered.

The model uses four resource access categories for the undiscovered projects:

- No leasing due to statutory or executive order
- Leasing available but cumulative timing limitations between 3 and 9 months
- Leasing available but with controlled surface use
- Standard leasing terms

Each project has been assigned to a resource access category. If the access category is not available in the year evaluated, the project fails the resource access check.

After the project is evaluated, the number of considered projects is increased. Figure 2-10 shows the timing logic applied to the EOR/ASR projects as well as the developing natural gas projects.

Before the economics are evaluated, the prices are set and the eligibility is determined. The following conditions must be met:

- Project has not been previously timed
- Project must be eligible for timing, re-passed the economic pre-screening routine
- Corresponding decline curve project must have been timed. This does not apply to the developing natural gas projects.

If the project meets all of these criteria, then it is considered eligible for economic analysis. For an EOR/ASR project to be considered for timing, it must be within a process specific EOR/ASR development window. These windows are listed in Table 2-4.

Table 2-4: EOR/ASR Eligibility Ranges

Process	Before Economic Limit	After Economic Limit
CO_2 Flooding	After 2009	10 Years
Steam Flooding	5 Years	10 Years
Polymer Flooding	5 Years	10 Years
Infill Drilling	After 2009	7 Years
Profile Modification	5 Years	7 Years
Horizontal Continuity	5 Years	7 Years
Horizontal Profile	5 Years	7 Years
Waterflood	4 Years	6 Years

The economic viability of the eligible projects is then evaluated. A different analytical approach is applied to CO_2 EOR and all other projects. For non-CO_2 EOR projects the project is screened for applicable technology levers, and the economic analysis is conducted. CO_2 EOR projects are treated differently because of the different CO_2 costs associated with the different sources of industrial and natural CO_2.

For each available source, the economic variables are calculated and stored. These include the source of CO_2 and the project's ranking criterion.

Detailed description of timing module

Exploration projects: The first step in the timing module is to determine which reservoirs are eligible to be timed for conventional and continuous exploration. Prior to evaluation, the constraints, resource access, and technology and economic levers are checked, and the technology case is set.

Calculate economics for EOR/ASR and developing natural gas projects:
This section determines whether an EOR/ASR or developing natural gas project is eligible for economic analysis and timing. The following resources are processes considered in this step.
EOR Processes:

- CO_2 Flooding
- Steam Flooding
- Polymer Flooding
- Profile Modification

ASR Processes:

- Water Flooding
- Infill Drilling
- Horizontal Continuity
- Horizontal Profile

Developing natural gas

- Tight Gas
- Shale Gas
- Coalbed Methane

A project is eligible for timing if the corresponding decline curve project has previously been timed and the year of evaluation is within the eligibility window for the process, as listed in table 2-4.

Project Ranking: Sorts exploration and EOR/ASR projects which are economic for timing. The subroutine matches the discovery order for undiscovered projects and sorts the others by ranking criterion. The criteria include

- Net present value
- Investment efficiency
- Rate of return
- Cumulative discounted after tax cashflow

Selection and Timing: Times the exploration and EOR/ASR projects which are considered in that given year.

Project Selection

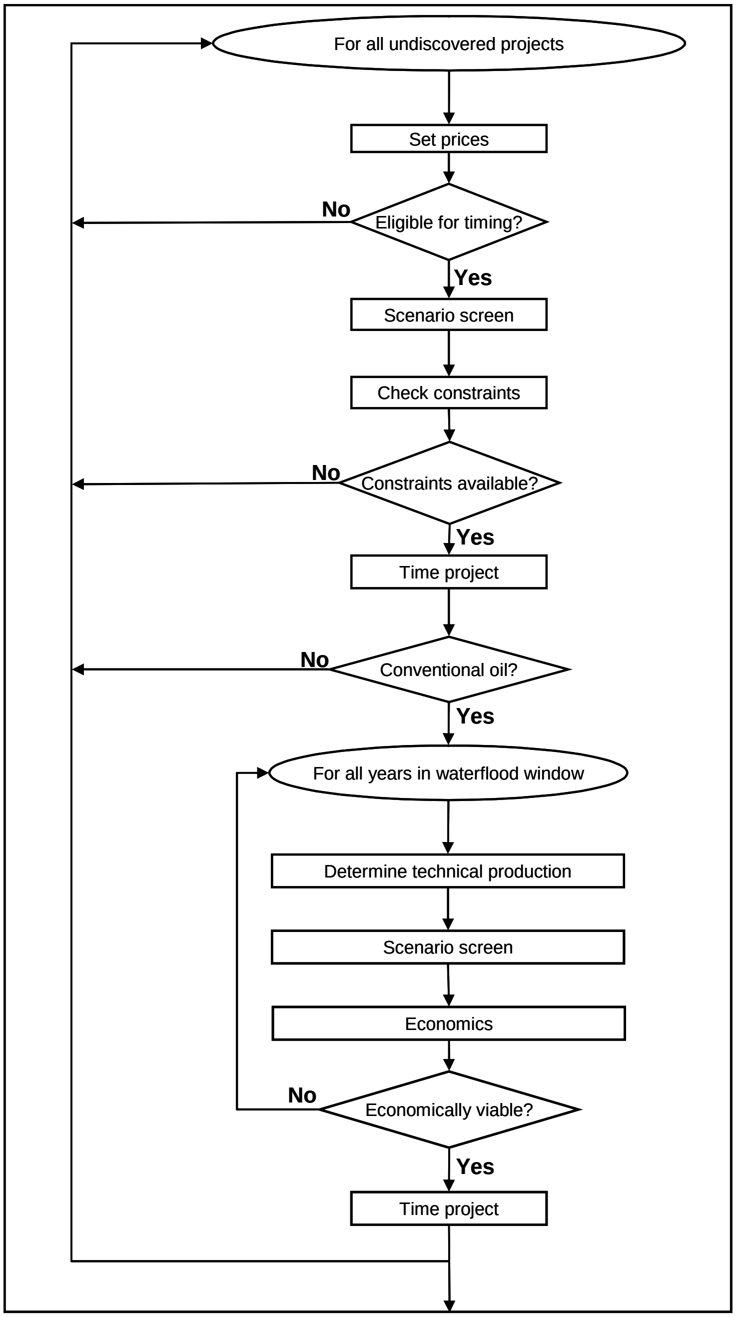
The project selection subroutine determines which exploration, EOR/ASR and developing natural gas projects will be modeled as developed in each year analyzed. In addition, the following development decisions are made:

- Waterflood of conventional undiscovered crude oil projects
- Extension of CO_2 floods as the total CO_2 injected is increased from 0.4 hydrocarbon pore volume (HCPV) to 1.0 HCPV

Overview of Project Selection

The project selection subroutine evaluates undiscovered projects separate from other projects. The logic for the development of exploration projects is provided in figure 2-9.

Figure 2-9: Selecting Undiscovered Projects



As illustrated in the figure the prices are set for the project before its eligibility is checked. Eligibility has the following requirements:

- Project is economically viable
- Project is not previously timed and developed

The projects which are eligible are screened for applicable technologies which impact the drilling success rates. The development constraints required for the project are checked against those that are available in the region.

If sufficient development resources are available, the project is timed and developed. As part of this process, the available development constraints are adjusted, the number of available accumulations is reduced and the results are aggregated. If no undiscovered accumulations remain, then the project is no longer eligible for timing. The projects that are eligible, economically viable, and undeveloped due to lack of development resources, are considered again for future projection years. If the project is conventional crude oil, it is possible to time a waterflood project.

The model evaluates the waterflood potential in a window centered upon the end of the economic life for the undiscovered project. For each year of that window, the technical production is determined for the waterflood project, applicable technology and economic levers are applied, and the economics are considered. If the waterflood project is economic, it is timed. This process is continued until either a waterflood project is timed or the window closes.

The second component of the project selection subroutine is applicable to EOR/ASR projects as well as the developing natural gas projects. The major steps applied to these projects are detailed in figures 2-10 and 2-11.

As seen in the flowchart, the prices are set for the project and the eligibility is checked. As with the undiscovered projects, the subroutine checks the candidate project for both economic viability and eligibility for timing. Afterwards, the project is screened for any applicable technology and economic levers.

If the project is eligible for CO_2 EOR, the economics are re-run for the specific source of CO_2. Afterwards, the availability of resource development constraints is checked for the project. If sufficient drilling and capital resources are available, the project preferences are checked.

The project preferences are rules which govern the competition between projects and selection of projects; these rules are listed below:

- CO_2 EOR and infill drilling are available after 2010
- Profile modification becomes available after 2011
- The annual number of infill drilling and profile modification projects is limited
- Horizontal continuity can compete against any other process except steam flood
- Horizontal profile can compete against any other process except steam flood or profile modification
- Polymer flooding cannot compete against any other process

If the project meets the technology preferences, then it is timed and developed. This process is different for CO_2 EOR and all other processes.

Figure 2-10: Selecting EOR/ASR projects

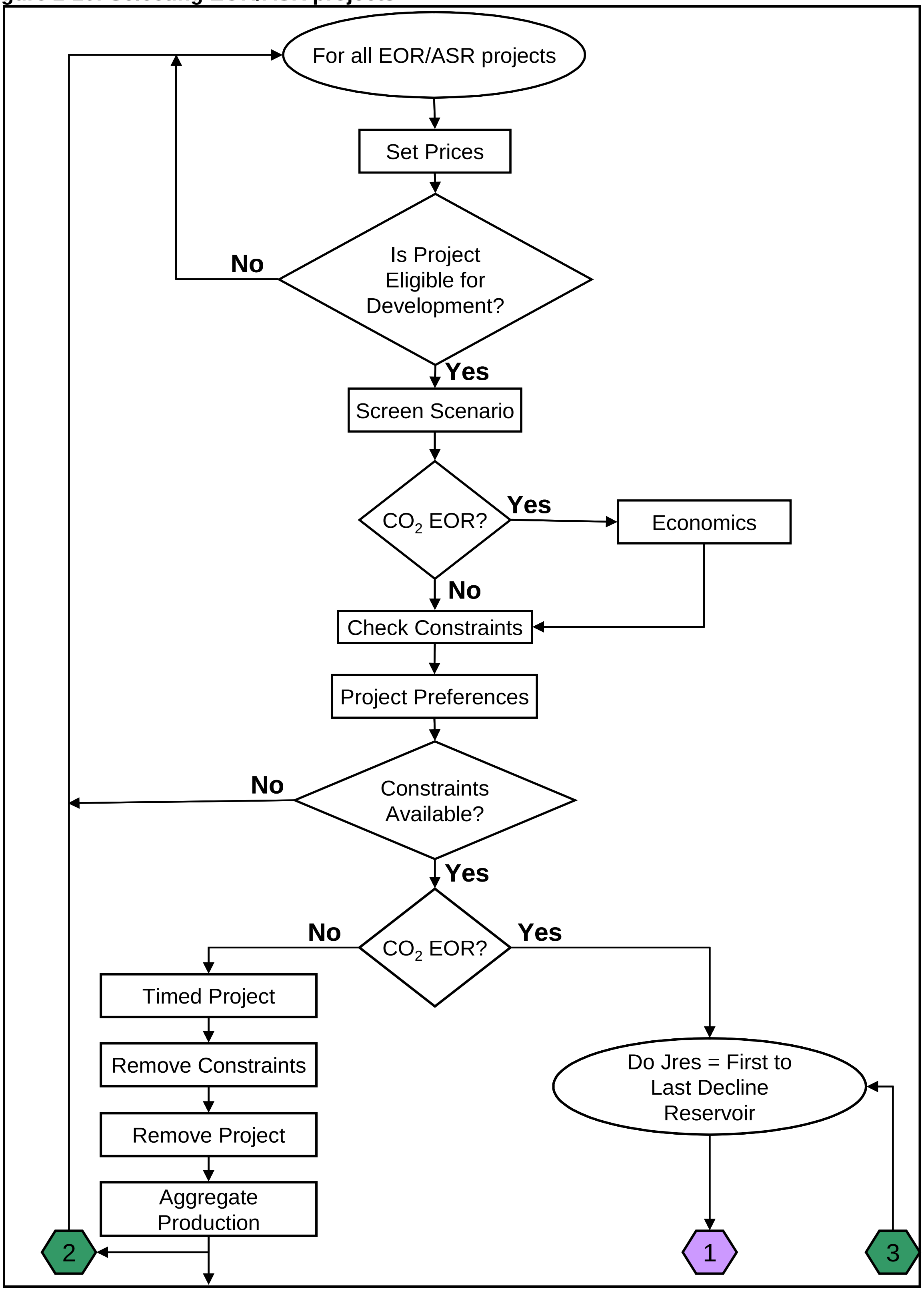
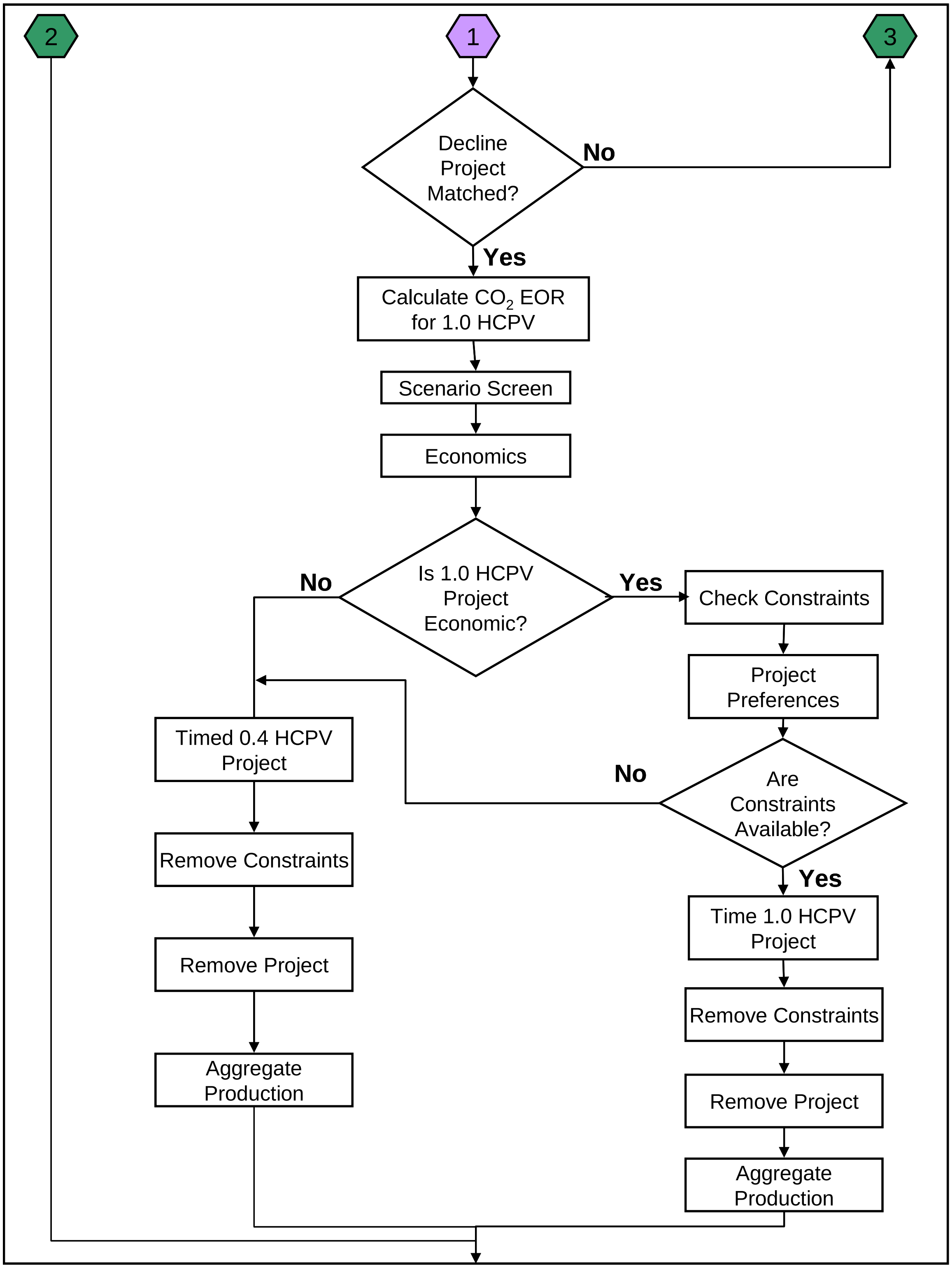


Figure 2-11: Selecting EOR/ASR projects, Continued



For non-CO_2 projects, the constraints are adjusted, the project is removed from the list of eligible projects, and the results are aggregated. It is assumed that most EOR/ASR processes are mutually exclusive and that a reservoir is limited to one process. There are a few exceptions:

- CO_2 EOR and infill drilling can be done in the same reservoir
- CO_2 EOR and horizontal continuity can be done in the same reservoir

For CO_2 EOR projects, a different methodology is used at this step: the decision to increase the total CO_2 injection from 0.4 hydrocarbon pore volume (HCPV) to 1.0 HCPV is made. The model performs the following steps, illustrated in figure 2-10 and continued in figure 2-11.

The CO_2 EOR project is matched to the corresponding decline curve project. Using the project-specific petro-physical properties, the technical production and injection requirements are determined for the 1.0 HCPV project. After applying any applicable technology and economic levers, the model evaluates the project economics. If the 1.0 HCPV project is not economically viable, then the 0.4 HCPV project is timed. If the 1.0 HCPV project is viable, the constraints and project preferences are checked. Assuming that there are sufficient development resources, and competition allows for the development of the project, then the model times the 1.0 HCPV project. If sufficient resources for the 1.0 HCPV project are not available, the model times the 0.4 HCPV project.

Detailed description of project selection

The project selection subroutine analyzes undiscovered crude oil and natural gas projects. If a project is economic and eligible for development, the drilling and capital constraints are examined to determine whether the constraints have been met. The model assumes that the projects for which development resources are available are developed.

Waterflood processing may be considered for undiscovered conventional crude oil projects. The waterflood project will be developed in the first year it is both eligible for implementation and the waterflood project is economically viable.

EOR/ASR Projects

When considering whether a project is eligible for EOR/ASR processing, the model first checks the availability of sufficient development resources are available. Based on the project economics and projected availability of development resources, it also decides whether or not to extend injection in CO_2 EOR projects from 0.4 HCPV to 1.0 HCPV.

If the 1.0 HCPV is economic but insufficient resources are available, the 0.4 HCPV project is selected instead. If the 1.0 HCPV project is uneconomic, the 0.4 HCPV project is selected.

Constraints

Resource development constraints are used during the selection of projects for development in order to mimic the infrastructure limitations of the oil and gas industry. The model assumes that only the projects that do not exceed the constraints available will be developed.

Types of constraints modeled

The development constraints represented in the model include drilling footage availability, rig depth rating, capital constraints, demand for natural gas, carbon dioxide volumes, and resource access.

In the remainder of this section, additional details will be provided for each of these constraints.

Drilling: Drilling constraints are bounding values used to determine the resource production in a given region. OLOGSS uses the following drilling categories:

- Developmental crude oil – applied to EOR/ASR projects
- Developmental natural gas – applied to developing natural gas projects
- Horizontal drilling – applied to horizontal wells
- Dual use – available for either crude oil or natural gas projects
- Conventional crude oil exploration – applied to undiscovered conventional crude oil projects
- Conventional natural gas exploration – applied to undiscovered conventional natural gas projects
- Continuous crude oil exploration – applied to undiscovered continuous crude oil projects
- Continuous natural gas exploration – applied to undiscovered continuous natural gas projects

Except for horizontal drilling, which is calculated as a fraction of the national developmental crude oil footage, all categories are calculated at the national level and apportioned to the regional level. Horizontal drilling is at the national level.

The following equations are used to calculate the national crude oil development drilling. The annual footage available is a function of lagged five year average crude oil prices and the total growth in drilling.

The total growth in drilling is calculated using the following algorithm.
For the first year:

$$\text{TOT\_GROWTH} = 1.0 * \left(1.0 + \frac{\text{DRILL\_OVER}}{100}\right) \tag{2-96}$$

For the remaining years: (2-97)

$$\text{TOT\_GROWTH} = \left(\left(\text{TOT\_GROWTH} * \left(1.0 + \frac{\text{RGR}}{100}\right)\right) - \left(\text{TOT\_GROWTH} * \left(1.0 + \frac{\text{RGR}}{100}\right)\right) * \left(\frac{\text{RRR}}{100}\right)\right) * \left(1.0 * \frac{\text{DRILL\_OVER}}{100}\right)$$

Reviewers note: The equation above would be clearer if it were written as

where

IYR	=	Year evaluated
MAX_YR	=	Maximum number of years
TOT_GROWTH	=	Annual growth change for drilling at the national level (fraction)
DRILL_OVER	=	Percent of drilling constraint available for footage over run
RGR	=	Annual rig development rate (percent)
RRR	=	Annual rig retirement rate (percent)

The national level crude oil and natural gas development footage available for drilling is calculated using the following equations. The coefficients for the drilling footage equations were estimated by least squares using model equations 2.B-16 and 2.B-17 in Appendix 2.B.

$$NAT\_OIL_{IYR} = (OILA0 + OILA1 * OILPRICED_{IYR}) * TOTMUL * TOT\_GROWTH * OIL\_ADJ_{IYR} \tag{2-98}$$

$$NAT\_GAS_{IYR} = (GASA0 + GASA1 * GASPRICED_{IYR}) * TOTMUL * TOT\_GROWTH * GAS\_ADJ_{IYR} \tag{2-99}$$

where

IYR	=	Year evaluated
TOT_GROWTH	=	Final calculated annual growth change for drilling at the national level
NAT_OIL NAT_GAS	=	National development footage available (Thousand Feet)
OILA0,1 GASA0,1	=	Footage equation coefficients
OILPRICED GASPRICED	=	Annual prices used in drilling constraints, five year average
TOTMUL	=	Total drilling constraint multiplier
OIL_ADJ GAS_ADJ	=	Annual crude oil, natural gas developmental drilling availability factors

After the available footage for drilling is calculated at the national level, regional allocations are used to allocate the drilling to each of the OLOGSS regions. The drilling which is not allocated, due to the “drill_trans” factor, is available in any region and represents the drilling which can be transferred among regions. The regional allocations are then subtracted from the national availability.

$$REG\_OIL_{j,iyr} = NAT\_OIL_{IYR} * \left(\frac{PRO\_REGOIL_J}{100}\right) * \left(1.0 - \frac{DRILL\_TRANS}{100}\right) \tag{2-100}$$

where

J	=	Region number
IYR	=	Year

REG_OIL	=	Regional development oil footage (Thousand Feet) available in a specified region
NAT_OIL	=	National development oil footage (Thousand Feet). After allocation, the footage transferrable among regions.
PRO_REGOIL	=	Regional development oil footage allocation (percent)
DRILL_TRANS	=	Percent of footage that is transferable among regions

Footage Constraints: The model determines whether there is sufficient footage available to drill the complete project. The drilling constraint is applied to all projects. Footage requirements are calculated in two stages: vertical drilling and horizontal drilling. The first well for an exploration project is assumed to be a wildcat well and uses a different success rate than the other wells in the project. The vertical drilling is calculated using the following formula.

<u>For non-exploration projects:</u>

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEKD_{itech})) * PATDEV_{irs,ii-itimeyr+1,itech} * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (DEPTH_{itech} * PATDEV_{irs,ii-itiimeyr+1,itech}) * 0.5 * ATOTCONV_{irs,itech} \quad (2\text{-}101)$$

<u>For exploration projects:</u>

For the first year of the project (2-102)

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEUE_{itech})) * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (0.5 * ATOTCONV_{irs,itech}) + (DEPTH_{itech} * (1.0 + SUC\_RATEUD_{itech})) * (PATDEV_{irs,ii-itimeyr+1,itech} - 1 * ATOTPROD_{irs,itech} + ATOTINJ_{ir,itech} + 0.5 * ATOTCONV_{irs,itech})$$

For all other project years (2-103)

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEUD_{itech})) * PATDEV_{irs,ii-itimeyr+1,itech} * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (DEPTH_{itech} * PATDEV_{irs,ii-itimeyr+1,itech} * 0.5 * ATOTCONV_{irs,itech})$$

where

irs	=	Project index number
itech	=	Technology index number
itimeyr	=	Year in which project is evaluated for development
ii	=	Year evaluated
FOOTREQ	=	Footage required for drilling (Thousand Feet)
DEPTH	=	Depth of formation (Feet)
SUC_RATEKD	=	Success rate for known development
SUC_RATEUE	=	Success rate for undiscovered exploration (wildcat)
SUC_RATEUD	=	Success rate for undiscovered development
PATDEV	=	Annual number of patterns developed for base and advanced technology
ATOTPROD	=	Number of new producers drilled per pattern
ATOTINJ	=	Number of new injectors drilled per patterns
ATOTCONV	=	Number of conversions from producing to injection wells per pattern

Add Laterals and Horizontal Wells: The lateral length and the horizontal well length are added to the footage required for drilling.

$$FOOTREQii = FOOTREQii + (ALATNUM_{irs,itech} * ALATLEN_{irs,itech} * (1.0 + SUC\_RATEKD_{itech}) * PATDEV_{irs,ii-itimeyr+1,itech}) \quad (2\text{-}104)$$

where

irs	=	Project index number
itech	=	Technology index number
itimeyr	=	Year in which project is evaluated for development
ii	=	Year evaluated
FOOTREQ	=	Footage required for drilling (Feet)
ALATNUM	=	Number of laterals
ALATLEN	=	Length of laterals (Feet)
SUC_RATEKD	=	Success rate for known development
PATDEV	=	Annual number of patterns developed for base and advanced technology

After determining the footage requirements, the model calculates the footage available for the project. The available footage is specific to the resource, the process, and the constraint options which have been specified by the user. If the footage required to drill the project is greater than the footage available then the project is not feasible.

Rig depth rating: The rig depth rating is used to determine whether a rig is available which can drill to the depth required by the project. OLOGSS uses the nine rig depth categories provided in table 2-5.

Table 2-5 Rig Depth Categories

Depth Category	Minimum Depth (Ft)	Maximum Depth (Ft)
1	1	2,500
2	2,501	5,000
3	5,001	7,500
4	7,501	10,000
5	10,001	12,500
6	12,501	15,000
7	15,001	17,500
8	17,251	20,000
9	20,001	Deeper

The rig depth rating is applied at the national level. The available footage is calculated using the following equation.

$$RDR\_FOOTAGE_{j,\ iyr} = (NAT\_TOT_{iyr} + NAT\_EXP_{iyr} + NAT\_EXPG_{iyr}) * \frac{RDR_j}{100} \quad (2\text{-}106)$$

where

J	=	Rig depth rating category
IYR	=	Year
RDR_FOOTAGE	=	Footage available in this interval (K Ft)

NAT_TOT	=	Total national developmental (crude oil, natural gas, and horizontal) drilling footage available (Thousand feet)
NAT_EXPG	=	National gas exploration drilling constraint
NAT_EXP	=	Total national exploration drilling footage available (Thousand feet)
RDR_j	=	Percentage of rigs which can drill to depth category j

Capital: Crude oil and natural gas companies use different investment and project evaluation criteria based upon their specific cost of capital, the portfolio of investment opportunities available, and their perceived technical risks. OLOGSS uses capital constraints to mimic limitations on the amount of investments the oil and gas industry can make in a given year. The capital constraint is applied at the national level.

Natural Gas Demand: Demand for natural gas is calculated at the regional level by the NGTDM and supplied to OLOGSS.

Carbon Dioxide: For CO_2 miscible flooding, availability of CO_2 gas from natural and industrial sources is a limiting factor in developing the candidate projects. In the Permian Basin, where the majority of the current CO_2 projects are located, the CO_2 pipeline capacity is a major concern.

The CO_2 constraint in OLOGSS incorporates both industrial and natural sources of CO_2. The industrial sources of CO_2 are ammonia plants, hydrogen plants, existing and planned ethanol plants, cement plants, refineries, fossil fuel power plants, and new IGCC plants.

Technology and market constraints prevent the total volumes of CO_2 produced from becoming immediately available. The development of the CO_2 market is divided into 3 periods:
1) technology R&D, 2) infrastructure construction, and 3) market acceptance. The capture technology is under development during the R&D phase, and no CO_2 produced by the technology is assumed available at that time. During the infrastructure development, the required capture equipment, pipelines, and compressors are being constructed, and no CO_2 is assumed available. During the market acceptance phase, the capture technology is being widely implemented and volumes of CO_2 are assumed to become available.

The maximum CO_2 available is achieved when the maximum percentage of the industry that will adopt the technology has adopted it. This provides an upper limit on the volume of CO_2 that will be available. The graph below provides the annual availability of CO_2 from ammonia plants. Availability curves were developed for each source of industrial, as well as natural CO_2.

CO_2 constraints are calculated at the regional level and are source specific.

Resource Access: Restrictions on access to Federal lands constrain the development of undiscovered crude oil and natural gas resources. OLOGSS uses four resource access categories:

- No leasing due to statutory or executive order
- Leasing available but cumulative timing limitations between 3 and 9 months
- Leasing available but with controlled surface use
- Standard leasing terms

The percentage of the undiscovered resource in each category was estimated using data from the Department of Interior's Basin Inventories of Onshore Federal Land's Oil and Gas Resources.

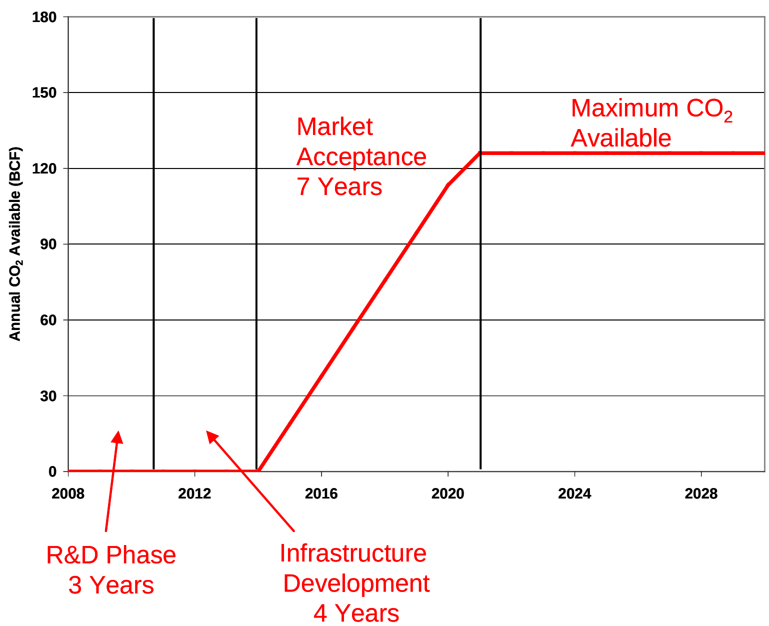


Figure 2-12: CO2 Market Acceptance Curve

Technology

Research and development programs are designed to improve technology to increase the amount of resources recovered from crude oil and natural gas fields. Key areas of study include methods of increasing production, extending reserves, and reducing costs. To optimize the impact of R & D efforts, potential benefits of a new technology are weighed against the costs of research and development. OLOGSS has the capability to model the effects of R & D programs and other technology improvements as they impact the production and economics of a project. This is done in two steps: (1) modeling the implementation of the technology within the oil and gas industry and (2) modeling the costs and benefits for a project that applies this technology.

Impact of technology on economics and recovery

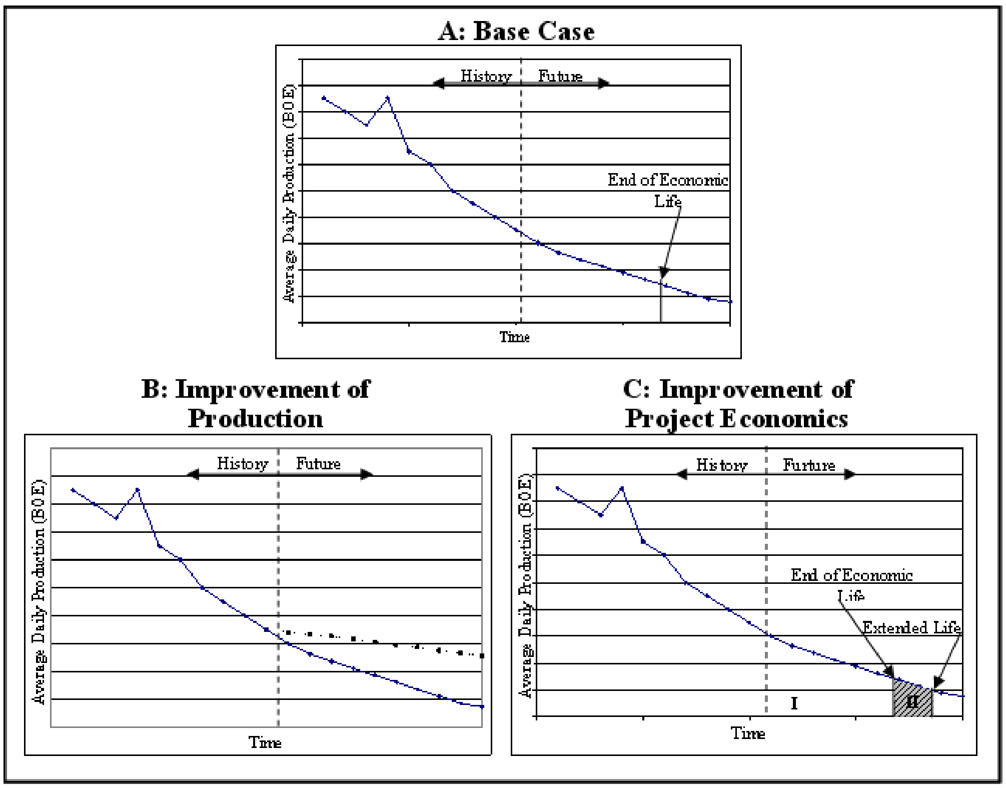
Figure 2-13 illustrates the effects of technology improvement on the production and project economics of a hypothetical well. The graphs plot the daily average production, projected by decline analysis, over the life of the project. Each graph represents a different scenario: (A) base case, (B) production improvement, and (C) economic improvement.

Graph A plots the production for the base case. In the base case, no new technology is applied to the project. The end of the project's economic life, the point at which potential revenues are less than costs of further production, is indicated. At that point, the project would be subject to reserves-growth processes or shut in.

Graph B plots the production for the base case and a production-increasing technology such as skin reduction. The reduction in skin, through well-bore fracturing or acidizing, increases the daily production flow rate. The increase in daily production rate is shown by the dotted line in graph B. The outcome of the production-increasing technology is reserves growth for the well. The amount of reserves growth for the well is shown by the area between the two lines as illustrated in figure 2-13 graph B.

Another example of technology improvement is captured in graph C. In this case a technology is implemented that reduces the cost of operation and maintenance, thereby extending the reservoir life as shown in figure 2-13 graph C.

Figure 2-13: Impact of Economic and Technology Levers

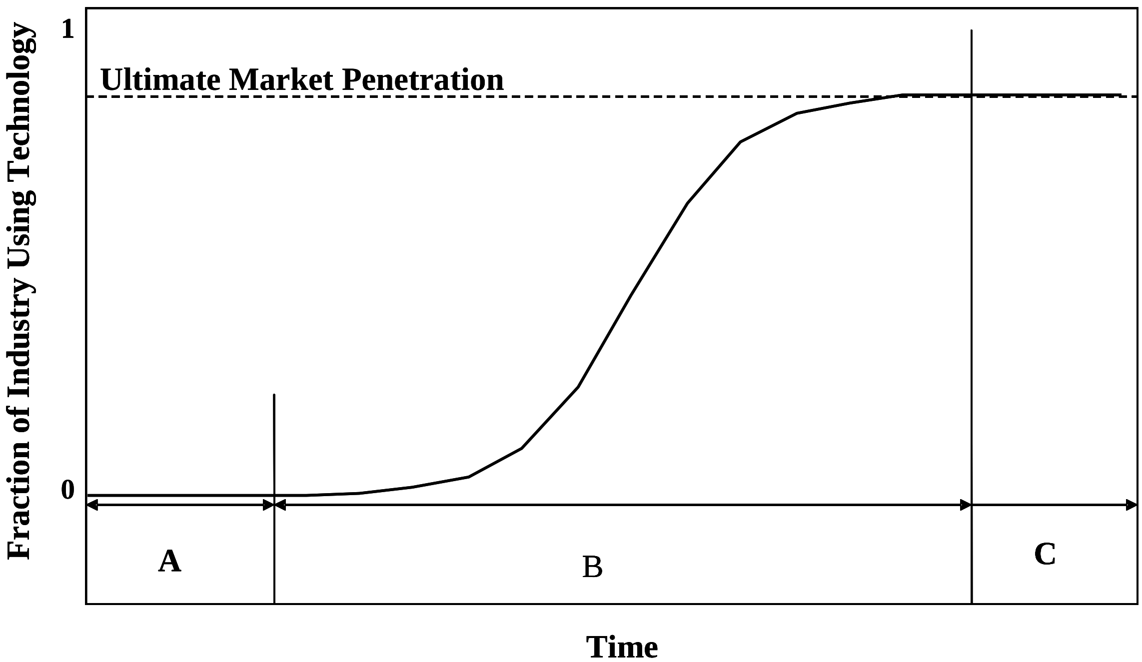


Technology improvements are modeled in OLOGSS using a variety of technology and economic levers. The technology levers, which impact production, are applied to the technical production of the project. The economic levers, which model improvement in project economics, are applied to cashflow calculations. Technology penetration curves are used to model the market penetration of each technology.

The technology-penetration curve is divided into three sections, each of which represents a phase of development. The first section is the research and development phase. In this phase the technology is developed and tested in the laboratory. During these years, the industry may be aware of the technology but has not begun implementation, and therefore does not see a benefit to production or economics. The second section corresponds to the commercialization phase. In the commercialization phase, the technology has successfully left the laboratory and is being adopted by the industry. The third section represents maximum market penetration. This is the ultimate extent to which the technology is adopted by the industry.

Figure 2-14 provides the graph of a generic technology-penetration curve. This graph plots the fraction of industry using the new technology (between 0 and 1) over time. During the research and development phase (A) the fraction of the industry using the technology is 0. This increases during commercialization phase (B) until it reaches the ultimate market penetration. In phase C, the period of maximum market acceptance, the percentage of industry using the technology remains constant.

Figure 2-14: Generic Technology Penetration Curve

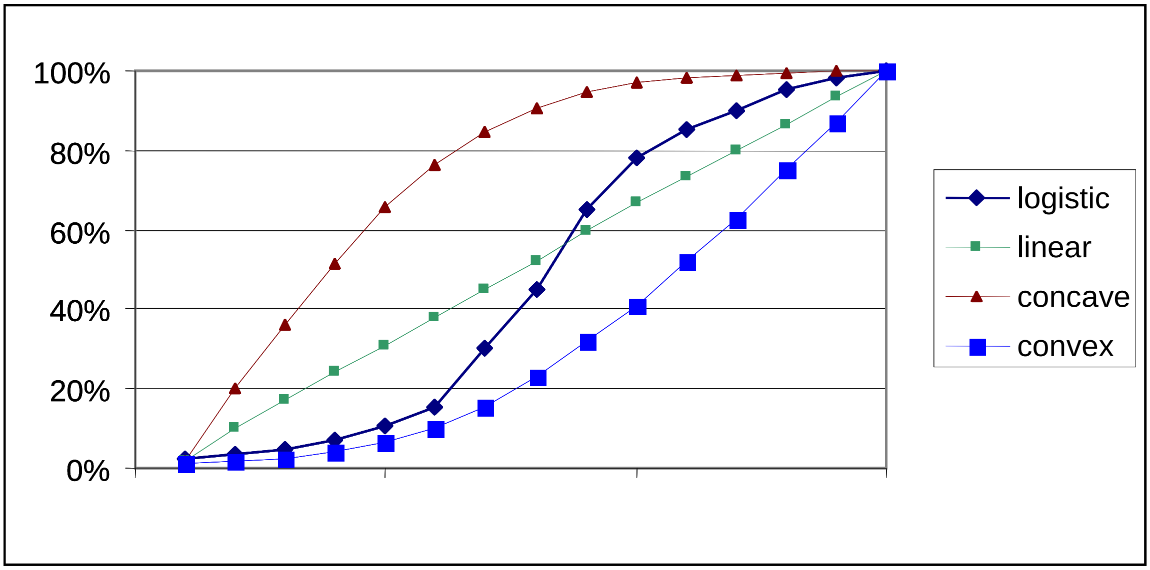


Technology modeling in OLOGSS

The success of the technology program is measured by estimating the probability that the technology development program will be successfully completed. It reflects the pace at which technology performance improves and the probability that the technology project will meet the program goals. There are four possible curve shapes that may represent the adoption of the technology: convex, concave, sigmoid/logistic or linear, as shown in figure 2-15. The convex curve corresponds to rapid initial market penetration followed by slow market penetration. The concave curve corresponds to slow initial market penetration followed by rapid market penetration. The sigmoid/logistic curve represents a slow initial adoption rate followed by rapid increase in adoption and the slow adoption again as the market becomes saturated. The linear curve represents a constant rate of market penetration, and may be used when no other predictions can be made.

The market penetration curve is a function of the relative economic attractiveness of the technology instead of being a time-dependent function. A technology will not be implemented unless the benefits through increased production or cost reductions are greater than the cost to apply the technology. As a result, the market penetration curve provides a limiting value on commercialization instead of a specific penetration path. In addition to the curve, the implementation probability captures the fact that not all technologies that have been proved in the lab are able to be successfully implemented in the field. The implementation probability does not reflect resource access, development constraints, or economic factors.

Figure 2-15: Potential Market Penetration Profiles



The three phases of the technology penetration curve are modeled using three sets of equations. The first set of equations models the research and development phase, the second set models the commercialization phase, and the third set models the maximum market penetration phase.

In summary, technology penetration curves are defined using the following variables:

- Number of years required to develop a technology = Y_d
- First year of commercialization = Y_c
- Number of years to fully penetrate the market = Y_a
- Ultimate market penetration (%) = UP
- Probability of success = P_s
- Probability of implementation = P_i
- Percent of industry implementing the technology (fraction) in year x = Imp_x

Research and Development Phase:
During the research and development phase, the percentage of industry implementing the new technology for a given year is zero.

This equation is used for all values of *market_penetration_profile.*

Commercialization Phase:

The commercialization phase covers the years from the beginning of commercialization through the number of years required to fully develop the technology. The equations used to model this phase depend upon the value of *market_penetration_profile.*

If the *market_penetration_profile* is assumed to be *convex,* then

Step 1: Calculate raw implementation percentage:

$$Imp_{xr} = -0.9 * 0.4^{[(x - Ys) / Ya]} \qquad (2\text{-}105)$$

Step 2: Normalize Imp_x using the following equation:

$$Imp_x = \frac{[(-0.6523) - Imp_x]}{[(-0.6523) - (-0.036)]} \qquad (2\text{-}106)$$

If the *market_penetration_profile* is assumed to be *concave,* then

Step 1: Calculate raw implementation percentage:

$$Imp_x = 0.9 * 0.04^{[1 - \{(x + 1 - Ys)/ Ya\}]} \qquad (2\text{-}107)$$

Step 2: Normalize Imp_x using the following equation:

$$Imp_x = \frac{[(0.04) - Imp_{xr}]}{[(0.04) - (0.74678)]} \qquad (2\text{-}108)$$

If the *market_penetration_profile* is assumed to be *sigmoid,* then

Step 1: Determine midpoint of the sigmoid curve = int $\left(\frac{Y_a}{2}\right)$

Where int$\left(\frac{Y_a}{2}\right)$ = $\left(\frac{Y_a}{2}\right)$ rounded to the nearest integer

Step 2: Assign a value of 0 to the midpoint year of the commercialization period, incrementally increase the values for the years above the midpoint year, and incrementally decrease the values for the years below the midpoint year.

Step 3: Calculate raw implementation percentage:

$$Imp_x = \frac{e^{value_x}}{1 + e^{value_x}} \qquad (2\text{-}109)$$

No normalizing of Imp_x is required for the sigmoid profile.

If the *market_penetration_profile* is assumed to be *linear,* then

Step 1: Calculate the raw implementation percentage:

$$Imp_x = \left[\frac{P_s * P_i * UP}{Y_a + 1} \right] * x_i \qquad (2\text{-}110)$$

No normalizing of Imp_x is required for the linear profile.

Note that the maximum technology penetration is 1.

Ultimate Market Penetration Phase:
For each of the curves generated, the ultimate technology penetration applied per year will be calculated using:

$$Imp_{final} = Imp_x * P_s * P_i \qquad (2\text{-}111)$$

Note that Imp_{final} is not to exceed Ultimate Market Penetration ("UP")

Using these three sets of equations, the industry-wide implementation of a technology improvement can be mapped using a technology-penetration curve.

Levers included in model

Project Level Technology Impact: Adopting a new technology can impact two aspects of a project. It improves the production and/or improves the economics. Technology and economic levers are variables in OLOGSS. The values for these levers are set by the user.

There are two cost variables to which economic levers can be applied in the cashflow calculations: the cost of applying the technology and the cost reductions that result from the technology's implementation. The cost to apply is the incremental cost to apply the technology. The cost reduction is the savings associated with using the new technology. The "cost to apply" levers can be applied at the well and/or project level. The model recognizes the distinction between technologies that are applied at the well level – modeling while drilling - and reservoir characterization and simulation, which affects the entire project. By using both types of levers, users can model the relationship between implementation costs and offsetting cost reductions.

The model assumes that the technology will be implemented only if the cost to apply the technology is less than the increased revenue generated through improved production and cost reductions.

Resource and Filter Levers: Two other types of levers are incorporated into OLOGSS: resource-access levers and technology levers. Resource-access levers allow the user to model changes in resource-access policy. For example, the user can specify that the federal lands in the Santa Maria Basin, which are currently inaccessible due to statutory or executive orders, will be available for exploration in 2015. A series of filter levers is also incorporated in the model. These are used to specifically locate the impact of technology improvement. For example, a technology can be applied only to CO_2 flooding projects in the Rocky Mountain region that are between 5,000 and 7,000 feet deep.

Appendix 2.A: Onshore Lower 48 Data Inventory

Variable Name	Variable Type	Description	Unit
AAPI	Input	API gravity	
AARP	Input	CO_2 source acceptance rate	
ABO	Variable	Current formation volume factor	Bbl/stb
ABOI	Input	Initial formation volume factor	Bbl/stb
ABTU	Variable	BTU content	Btu/Cf
ACER	Input	ACE rate	Percent
ACHGASPROD	Input	Cumulative historical natural gas production	MMcf
ACHOILPROD	Input	Cumulative historical crude oil production	MBbl
ACO2CONT	Input	CO_2 impurity content	%
ADEPTH	Input	Depth	Feet
ADGGLA	Variable	Depletable items in the year (G & G and lease acquisition cost)	K$
ADJGAS	Variable	National natural gas drilling adjustment factor	Fraction
ADJGROSS	Variable	Adjusted gross revenue	K$
ADJOIL	Variable	National crude oil drilling adjustment factor	Fraction
ADOILPRICE	Variable	Adjusted crude oil price	$/Bbl
ADVANCED	Variable	Patterns to be developed using advanced technology	Fraction
AECON_LIFE	Variable	Economic life of the project	Years
AFLP	Input	Portion of reservoir on federal lands	Fraction
AGAS_GRAV	Input	Natural gas gravity	
AGOR	Input	Gas/oil ratio	Mcf/bbl
AH2SCONT	Input	H_2S impurity content	%
AHCPV	Variable	Hydro Carbon Pore Volume	0.4 HCPV
AHEATVAL	Input	Heat content of natural gas	Btu/Cf
AINJINJ	Input	Annual injectant injected	MBbl, Mcf, MLbs
AINJRECY	Variable	Annual injectant recycled	MBbl, Mcf
AIRSVGAS	Variable	End of year inferred natural gas reserves	MMcf
AIRSVOIL	Variable	End of year inferred crude oil reserves	MBbl
ALATLEN	Input	Lateral length	Feet
ALATNUM	Input	Number of laterals	
ALYRGAS	Input	Last year of historical natural gas production	MMcf

ALYROIL	Input	Last year of historical crude oil production	MBbl
AMINT	Variable	Alternative minimum income tax	K$
AMOR	Variable	Intangible investment depreciation amount	K$
AMOR_BASE	Variable	Amortization base	K$
AMORSCHL	Input	Annual fraction amortized	Fraction
AMT	Input	Alternative minimum tax	K$
AMTRATE	Input	Alternative minimum tax rate	K$
AN2CONT	Input	N_2 impurity content	%
ANGL	Input	NGL	bbl/MMcf
ANUMACC	Input	Number of accumulations	
ANWELLGAS	Input	Number of natural gas wells	
ANWELLINJ	Input	Number of injection wells	
ANWELLOIL	Input	Number of crude oil wells	
AOAM	Variable	Annual fixed O & M cost	K$
AOGIP	Variable	Original Gas in Place	Bcf
AOILVIS	Input	Crude Oil viscosity	CP
AOOIP	Variable	Original Oil In Place	MBbl
AORGOOIP	Input	Original OOIP	MBbl
APATSIZ	Input	Pattern size	Acres
APAY	Input	Net pay	Feet
APD	Variable	Annual percent depletion	K$
APERM	Input	Permeability	MD
APHI	Input	Porosity	Percent
APLAY_CDE	Input	Play number	
APRESIN	Variable	Initial pressure	PSIA
APRODCO2	Input	Annual CO_2 production	MMcf
APRODGAS	Input	Annual natural gas production	MMcf
APRODNGL	Input	Annual NGL production	MBbl
APRODOIL	Input	Annual crude oil production	MBbl
APRODWAT	Input	Annual water production	MBbl
APROV	Input	Province	
AREGION	Input	Region number	
ARESACC	Input	Resource Access	
ARESFLAG	Input	Resource flag	
ARESID	Input	Reservoir ID number	
ARESVGAS	Variable	End of year proven natural gas reserves	MMcf
ARESVOIL	Variable	End of year proven crude oil reserves	MBbl
ARRC	Input	Railroad Commission District	
ASC	Input	Reservoir Size Class	
ASGI	Variable	Gas saturation	Percent
ASOC	Input	Current oil saturation	Percent
ASOI	Input	Initial oil saturation	Percent

ASOR	Input	Residual oil saturation	Percent
ASR_ED	Input	Number of years after economic life of ASR	
ASR_ST	Input	Number of years before economic life of ASR	
ASULFOIL	Input	Sulfur content of crude oil	%
ASWI	Input	Initial water saturation	Percent
ATCF	Variable	After tax cashflow	K$
ATEMP	Variable	Reservoir temperature	F°
ATOTACRES	Input	Total area	Acres
ATOTCONV	Input	Number of conversions from producing wells to injecting wells per pattern	
ATOTINJ	Input	Number of new injectors drilled per pattern	
ATOTPAT	Input	Total number of patterns	
ATOTPROD	Input	Number of new producers drilled per pattern	
ATOTPS	Input	Number of primary wells converted to secondary wells per pattern	
AVDP	Input	Dykstra Parsons coefficient	
AWATINJ	Input	Annual water injected	MBbl
AWOR	Input	Water/oil ratio	Bbl/Bbl
BAS_PLAY	Input	Basin number	
BASEGAS	Input	Base natural gas price used for normalization of capital and operating costs	$/Mcf
BASEOIL	Input	Base crude oil price used for normalization of capital and operating costs	K$
BSE_AVAILCO2	Variable	Base annual volume of CO_2 available by region	Bcf
CAP_BASE	Variable	Capital to be depreciated	K$
CAPMUL	Input	Capital constraints multiplier	
CATCF	Variable	Cumulative discounted cashflow	K$
CHG_ANNSEC_FAC	Input	Change in annual secondary operating cost	Fraction
CHG_CHMPNT_FAC	Input	Change in chemical handling plant cost	Fraction
CHG_CMP_FAC	Input	Change in compression cost	Fraction
CHG_CO2PNT_FAC	Input	Change in CO_2 injection/recycling plant cost	Fraction
CHG_COMP_FAC	Input	Change in completion cost	Fraction
CHG_DRL_FAC	Input	Change in drilling cost	Fraction
CHG_FAC_FAC	Input	Change in facilities cost	Fraction

CHG_FACUPG_FAC	Input	Change in facilities upgrade cost	Fraction
CHG_FOAM_FAC	Input	Change in fixed annual O & M cost	Fraction
CHG_GNA_FAC	Input	Change in G & A cost	Fraction
CHG_INJC_FAC	Input	Change in injection cost	Fraction
CHG_INJCONV_FAC	Input	Change in injector conversion cost	Fraction
CHG_INJT_FAC	Input	Change in injectant cost	Fraction
CHG_LFT_FAC	Input	Change in lifting cost	Fraction
CHG_OGAS_FAC	Input	Change in natural gas O & M cost	K$
CHG_OINJ_FAC	Input	Change in injection O & M cost	K$
CHG_OOIL_FAC	Input	Change in oil O & M cost	K$
CHG_OWAT_FAC	Input	Change in water O & M cost	K$
CHG_PLYPNT_FAC	Input	Change in polymer handling plant cost	Fraction
CHG_PRDWAT_FAC	Input	Change in produced water handling plant cost	Fraction
CHG_SECWRK_FAC	Input	Change in secondary workover cost	Fraction
CHG_SECCONV_FAC	Input	Change in secondary conversion cost	Fraction
CHG_STM_FAC	Input	Change in stimulation cost	Fraction
CHG_STMGEN_FAC	Input	Change in steam generation and distribution cost	Fraction
CHG_VOAM_FAC	Input	Change in variable O & M cost	Fraction
.CHG_WRK_FAC	Input	Change in workover cost	Fraction
CHM_F	Variable	Cost for a chemical handling plant	K$
CHMA	Input	Chemical handling plant	
CHMB	Input	Chemical handling plant	
CHMK	Input	Chemical handling plant	
CIDC	Input	Capitalize intangible drilling costs	K$
CO2_F	Variable	Cost for a CO_2 recycling/injection plant	K$
CO2_RAT_ FAC	Input	CO_2 injection factor	
CO2AVAIL	Variable	Total CO_2 available in a region across all sources	Bcf/Yr
CO2BASE	Input	Total Volume of CO_2 Available	Bcf/Yr
CO2COST	Variable	Final cost for CO_2	$/Mcf

CO2B	Input	Constant and coefficient for natural CO_2 cost equation	
CO2K	Input	Constant and coefficient for natural CO_2 cost equation	
CO2MUL	Input	CO_2 availability constraint multiplier	
CO2OAM	Variable	CO_2 variable O & M cost	K$
CO2OM_20	Input	The O & M cost for CO_2 injection < 20 MMcf	K$
CO2OM20	Input	The O & M cost for CO_2 injection > 20 MMcf	K$
CO2PR	Input	State/regional multipliers for natural CO_2 cost	
CO2PRICE	Input	CO_2 price	$/Mcf
CO2RK, CO2RB	Input	CO_2 recycling plant cost	K$
CO2ST	Input	State code for natural CO_2 cost	
COI	Input	Capitalize other intangibles	
COMP	Variable	Compressor cost	K$
COMP_OAM	Variable	Compressor O & M cost	K$
COMP_VC	Input	Compressor O & M costs	K$
COMP_W	Variable	Compression cost to bring natural gas up to pipeline pressure	K$
COMYEAR_FAC	Input	Number of years of technology commercialization for the penetration curve	Years
CONTIN_ FAC	Input	Continuity increase factor	
COST_BHP	Input	Compressor Cost	$/Bhp
COTYPE	Variable	CO_2 source, either industrial or natural	
CPI_2003	Variable	CPI conversion for 2003$	
CPI_2005	Variable	CPI conversion for 2005$	
CPI_AVG	Input	Average CPI from 1990 to 2010	
CPI_FACTOR	Input	CPI factor from 1990 to 2010	
CPI_YEAR	Input	Year for CPI index	
CREDAMT	Input	Flag that allows AMT to be credited in future years	
CREGPR	Input	The CO_2 price by region and source	$/Mcf
CST_ANNSEC_ FAC	Input	Well level cost to apply secondary producer technology	K$
CST_ANNSEC_CSTP	Variable	Project level cost to apply secondary producer technology	K$

CST_CMP_CSTP	Variable	Project level cost to apply compression technology	K$
CST_CMP_FAC	Input	Well level cost to apply compression technology	K$
CST_COMP_ FAC	Input	Well level cost to apply completion technology	K$
CST_COMP_CSTP	Variable	Project level cost to apply completion technology	K$
CST_DRL_ FAC	Input	Well level cost to apply drilling technology	K$
CST_DRL_CSTP	Variable	Project level cost to apply drilling technology	K$
CST_FAC_ FAC	Input	Well level cost to apply facilities technology	K$
CST_FAC_CSTP	Variable	Project level cost to apply facilities technology	K$
CST_FACUPG_ FAC	Input	Well level cost to apply facilities upgrade technology	K$
CST_FACUPG_CSTP	Variable	Project level cost to apply facilities upgrade technology	K$
CST_FOAM_ FAC	Input	Well level cost to apply fixed annual O & M technology	K$
CST_FOAM_CSTP	Variable	Project level cost to apply fixed annual O & M technology	K$
CST_GNA_ FAC	Input	Well level cost to apply G & A technology	K$
CST_GNA_CSTP	Variable	Project level cost to apply G & A technology	K$
CST_INJC_ FAC	Input	Well level cost to apply injection technology	K$
CST_INJC_CSTP	Variable	Project level cost to apply injection technology	K$
CST_INJCONV_ FAC	Input	Well level cost to apply injector conversion technology	K$
CST_INJCONV_CSTP	Variable	Project level cost to apply injector conversion technology	K$
CST_LFT_ FAC	Input	Well level cost to apply lifting technology	K$
CST_LFT_CSTP	Variable	Project level cost to apply lifting technology	K$
CST_SECCONV_ FAC	Input	Well level cost to apply secondary conversion technology	K$

CST_SECCONV_CSTP	Variable	Project level cost to apply secondary conversion technology	K$
CST_SECWRK_ FAC	Input	Well level cost to apply secondary workover technology	K$
CST_SECWRK_CSTP	Variable	Project level cost to apply secondary workover technology	K$
CST_STM_ FAC	Input	Well level cost to apply stimulation technology	K$
CST_STM_CSTP	Variable	Project level cost to apply stimulation technology	K$
CST_VOAM_ FAC	Input	Well level cost to apply variable annual O & M technology	K$
CST_VOAM_CSTP	Variable	Project level cost to apply variable annual O & M technology	K$
CST_WRK_ FAC	Input	Well level cost to apply workover technology	K$
CST_WRK_CSTP	Variable	Project level cost to apply workover technology	K$
CSTP_ANNSEC_ FAC	Input	Project level cost to apply secondary producer technology	K$
CSTP_CMP_ FAC	Input	Project level cost to apply compression technology	K$
CSTP_COMP_ FAC	Input	Project level cost to apply completion technology	K$
CSTP_DRL_ FAC	Input	Project level cost to apply drilling technology	K$
CSTP_FAC_ FAC	Input	Project level cost to apply facilities technology	K$
CSTP_FACUPG_ FAC	Input	Project level cost to apply facilities upgrade technology	K$
CSTP_FOAM_ FAC	Input	Project level cost to apply fixed annual O & M technology	K$
CSTP_GNA_ FAC	Input	Project level cost to apply G & A technology	K$
CSTP_INJC_ FAC	Input	Project level cost to apply injection technology	K$
CSTP_INJCONV_ FAC	Input	Project level cost to apply injector conversion technology	K$
CSTP_LFT_ FAC	Input	Project level cost to apply lifting technology	K$

CSTP_SECCONV_ FAC	Input	Project level cost to apply secondary conversion technology	K$
CSTP_SECWRK_ FAC	Input	Project level cost to apply secondary workover technology	K$
CSTP_STM_ FAC	Input	Project level cost to apply stimulation technology	K$
CSTP_VOAM_ FAC	Input	Project level cost to apply variable annual O & M technology	K$
CSTP_WRK_ FAC	Input	Project level cost to apply workover technology	K$
CUTOIL	Input	Base crude oil price for the adjustment term of price normalization	$/Bbl
DATCF	Variable	Discounted cashflow after taxes	K$
DEP_CRD	Variable	Depletion credit	K$
DEPLET	Variable	Depletion allowance	K$
DEPR	Variable	Depreciation amount	K$
DEPR_OVR	Input	Annual fraction to depreciate	
DEPR_PROC	Input	Process number for override schedule	
DEPR_YR	Input	Number of years for override schedule	
DEPRSCHL	Input	Annual Fraction Depreciated	Fraction
DEPR_SCH	Variable	Process specific depreciation schedule	Years
DGGLA	Variable	Depletion base (G & G and lease acquisition cost)	K$
DISC_DRL	Variable	Discounted drilling cost	K$
DISC_FED	Variable	Discounted federal tax payments	K$
DISC_GAS	Variable	Discounted revenue from natural gas sales	K$
DISC_INV	Variable	Discounted investment rate	K$
DISC_NDRL	Variable	Discounted project facilities costs	K$
DISC_OAM	Variable	Discounted O & M cost	K$
DISC_OIL	Variable	Discounted revenue from crude oil sales	K$
DISC_ROY	Variable	Discounted royalty	K$
DISC_ST	Variable	Discounted state tax rate	K$
DISCLAG	Input	Number of years between discovery and first production	
DISCOUNT_RT	Input	Process discount rates	Percent

DRCAP_D	Variable	Regional dual use drilling footage for crude oil and natural gas development	Ft
DRCAP_G	Variable	Regional natural gas well drilling footage constraints	Ft
DRCAP_O	Variable	Regional crude oil well drilling footage constraints	Ft
DRILL_FAC	Input	Drilling rate factor	
DRILL_OVER	Input	Drilling constraints available for footage over run	%
DRILL_RES	Input	Development drilling constraints available for transfer between crude oil and natural gas	%
DRILL_TRANS	Input	Drilling constraints transfer between regions	%
DRILLCST	Variable	Drill cost by project	K$
DRILLL48	Variable	Successful well drilling costs	1987$ per well
DRL_CST	Variable	Drilling cost	K$
DRY_CST	Variable	Dryhole drilling cost	K$
DRY_DWCA	Estimated	Dryhole well cost	K$
DRY_DWCB	Estimated	Dryhole well cost	K$
DRY_DWCC	Estimated	Dryhole well cost	K$
DRY_DWCD	Input	Maximum depth range for dry well drilling cost equations	Ft
DRY_DWCK	Estimated	Constant for dryhole drilling cost equation	
DRY_DWCM	Input	Minimum depth range for dry well drilling equations	Ft
DRY_W	Variable	Cost to drill a dry well	K$
DRYCST	Variable	Dryhole cost by project	K$
DRYL48	Variable	Dry well drilling costs	1987$ per well
DRYWELLL48	Variable	Dry Lower 48 onshore wells drilled	Wells
DWC_W	Variable	Cost to drill and complete a crude oil well	K$
EADGGLA	Variable	G&G and lease acquisition cost depletion	K$
EADJGROSS	Variable	Adjusted revenue	K$
EAMINT	Variable	Alternative minimum tax	K$
EAMOR	Variable	Amortization	K$
EAOAM	Variable	Fixed annual operating cost	K$
EATCF	Variable	After tax cash flow	K$
ECAP_BASE	Variable	Depreciable/capitalized base	K$

ECATCF	Variable	Cumulative discounted after tax cashflow	K$
ECO2CODE	Variable	CO_2 source code	
ECO2COST	Variable	CO_2 cost	K$
ECO2INJ	Variable	Economic CO_2 injection	Bcf/Yr
ECO2LIM	Variable	Source specific project life for CO_2 EOR projects	
ECO2POL	Variable	Injected CO_2	MMcf
ECO2RANKVAL	Variable	Source specific ranking value for CO_2 EOR projects	
ECO2RCY	Variable	CO_2 recycled	Bcf/Yr
ECOMP	Variable	Compressor tangible capital	K$
EDATCF	Variable	Discounted after tax cashflow	K$
EDEP_CRD	Variable	Adjustment to depreciation base for federal tax credits	K$
EDEPGGLA	Variable	Depletable G & G/lease cost	K$
EDEPLET	Variable	Depletion	K$
EDEPR	Variable	Depreciation	K$
EDGGLA	Variable	Depletion base	K$
EDRYHOLE	Variable	Number of dryholes drilled	
EEC	Input	Expensed environmental costs	K$
EEGGLA	Variable	Expensed G & G and lease acquisition cost	K$
EEORTCA	Variable	Tax credit addback	K$
EEXIST_ECAP	Variable	Environmental existing capital	K$
EEXIST_EOAM	Variable	Environmental existing O & M costs	K$
EFEDCR	Variable	Federal tax credits	K$
EFEDROY	Variable	Federal royalty	K$
EFEDTAX	Variable	Federal tax	K$
EFOAM	Variable	CO_2 FOAM cost	K$
EGACAP	Variable	G & A capitalized	K$
EGAEXP	Variable	G & A expensed	K$
EGASPRICE2	Variable	Natural gas price used in the economics	K$
EGG	Variable	Expensed G & G cost	K$
EGGLA	Variable	Expensed G & G and lease acquisition cost	K$
EGGLAADD	Variable	G & G/lease addback	K$
EGRAVADJ	Variable	Gravity adjustment	K$
EGREMRES	Variable	Remaining proven natural gas reserves	Bcf
EGROSSREV	Variable	Gross revenues	K$
EIA	Variable	Environmental intangible addback	K$

EICAP	Variable	Environmental intangible capital	
EICAP2	Variable	Environmental intangible capital	
EIGEN	Variable	Number of steam generators	
EIGREMRES	Variable	Remaining inferred natural gas reserves	Bcf
EII	Variable	Intangible investment	K$
EIIDRL	Variable	Intangible investment drilling	K$
EINJCOST	Variable	CO_2/Polymer cost	K$
EINJDR	Variable	New injection wells drilled per year	
EINJWELL	Variable	Active injection wells per year	
EINTADD	Variable	Intangible addback	K$
EINTCAP	Variable	Tangible investment drilling	K$
EINVEFF	Variable	Investment efficiency	
EIREMRES	Variable	Remaining inferred crude oil reserves	MMBbl
EITC	Input	Environmental intangible tax credit	K$
EITCAB	Input	Environmental intangible tax credit rate addback	%
EITCR	Input	Environmental intangible tax credit rate	K$
ELA	Variable	Lease and acquisition cost	K$
ELYRGAS	Variable	Last year of historical natural gas production	MMcf
ELYROIL	Variable	Last year of historical crude oil production	MBbl
ENETREV	Variable	Net revenues	K$
ENEW_ECAP	Variable	Environmental new capital	K$
ENEW_EOAM	Variable	Environmental new O & M costs	K$
ENIAT	Variable	Net income after taxes	K$
ENIBT	Variable	Net income before taxes	K$
ENPV	Variable	Net present value	K$
ENV_FAC	Input	Environmental capital cost multiplier	
ENVOP_FAC	Input	Environmental operating cost multiplier	
ENVSCN	Input	Include environmental costs?	
ENYRSI	Variable	Number of years project is economic	
EOAM	Variable	Variable operating and maintenance	K$

EOCA	Variable	Environmental operating cost addback	K$
EOCTC	Input	Environmental operating cost tax credit	K$
EOCTCAB	Input	Environmental operating cost tax credit rate addback	%
EOCTCR	Input	Environmental operating cost tax credit rate	K$
EOILPRICE2	Variable	Crude oil price used in the economics	K$
EORTC	Input	EOR tax credit	K$
EORTCA	Variable	EOR tax credit addback	K$
EORTCAB	Input	EOR tax credit rate addback	%
EORTCP	Input	EOR tax credit phase out crude oil price	K$
EORTCR	Input	EOR tax credit rate	K$
EORTCRP	Input	EOR tax credit applied by year	%
EOTC	Variable	Other tangible capital	K$
EPROC_OAM	Variable	Natural gas processing cost	K$
EPRODDR	Variable	New production wells drilled per year	
EPRODGAS	Variable	Economic natural gas production	MMcf
EPRODOIL	Variable	Economic crude oil production	MBbl
EPRODWAT	Variable	Economic water production	MBbl
EPRODWELL	Variable	Active producing wells per year	
EREMRES	Variable	Remaining proven crude oil reserves	MMBbl
EROR	Variable	Rate of return	
EROY	Variable	Royalty	K$
ESEV	Variable	Severance tax	K$
ESHUTIN	Variable	New shut in wells drilled per year	
ESTIM	Variable	Stimulation cost	K$
ESTTAX	Variable	State tax	K$
ESUMP	Variable	Number of patterns	
ESURFVOL	Variable	Total volume injected	MMcf/ MBbl/ MLbs
ETAXINC	Variable	Net income before taxes	K$
ETCADD	Variable	Tax credit addbacks taken from NIAT	K$
ETCI	Variable	Federal tax credit	K$
ETCIADJ	Variable	Adjustment for federal tax credit	K$

ETI	Variable	Tangible investments	K$
ETOC	Variable	Total operating cost	K$
ETORECY	Variable	CO_2/Surf/Steam recycling volume	Bcf/MBbl/Yr
ETORECY_CST	Variable	CO_2/Surf/Steam recycling cost	Bcf/MBbl/Yr
ETTC	Input	Environmental tangible tax credit	K$
ETTCAB	Input	Environmental tangible tax credit rate addback	%
ETTCR	Input	Environmental tangible tax credit rate	K$
EWATINJ	Variable	Economic water injected	MBbl
EX_CONRES	Variable	Number of exploration reservoirs	
EX_FCRES	Variable	First exploration reservoir	
EXIST_ECAP	Variable	Existing environmental capital cost	K$
EXIST_EOAM	Variable	Existing environmental O & M cost	K$
EXP_ADJ	Input	Fraction of annual crude oil exploration drilling which is made available	Fraction
EXP_ADJG	Input	Fraction of annual natural gas exploration drilling which is made available	Fraction
EXPA0	Estimated	Crude oil exploration well footage A0	
EXPA1	Estimated	Crude oil exploration well footage A1	
EXPAG0	Input	Natural gas exploration well footage A0	
EXPAG1	Input	Natural gas exploration well footage A1	
EXPATN	Variable	Number of active patterns	
EXPCDRCAP	Variable	Regional conventional exploratory drilling footage constraints	Ft
EXPCDRCAPG	Variable	Regional conventional natural gas exploration drilling footage constraint	Ft
EXPGG	Variable	Expensed G & G cost	K$
EXPL_FRAC	Input	Exploration drilling for conventional crude oil	%
EXPL_FRACG	Input	Exploration drilling for conventional natural gas	%

EXPL_MODEL	Input	Selection of exploration models	
EXPLA	Variable	Expensed lease purchase costs	K$
EXPLR_ FAC	Input	Exploration factor	
EXPLR_CHG	Variable	Change in exploration rate	
EXPLSORTIRES	Variable	Sort pointer for exploration	
EXPMUL	Input	Exploration constraint multiplier	
EXPRDL48	Variable	Expected Production	Oil-MMB Gas-BCF
EXPUDRCAP	Variable	Regional continuous exploratory drilling footage constraints	Ft
EXPUDRCAPG	Variable	Regional continuous natural gas exploratory drilling footage constraints	Ft
FAC_W	Variable	Facilities upgrade cost	K$
FACCOST	Variable	Facilities cost	K$
FACGA	Estimated	Natural gas facilities costs	
FACGB	Estimated	Natural gas facilities costs	
FACGC	Estimated	Natural gas facilities costs	
FACGD	Input	Maximum depth range for natural gas facilities costs	Ft
FACGK	Estimated	Constant for natural gas facilities costs	
FACGM	Input	Minimum depth range for natural gas facilities costs	Ft
FACUPA	Estimated	Facilities upgrade cost	
FACUPB	Estimated	Facilities upgrade cost	
FACUPC	Estimated	Facilities upgrade cost	
FACUPD	Input	Maximum depth range for facilities upgrade cost	Ft
FACUPK	Estimated	Constant for facilities upgrade costs	
FACUPM	Input	Minimum depth range for facilities upgrade cost	Ft
FCO2	Variable	Cost multiplier for natural CO_2	
FEDRATE	Input	Federal income tax rate	Percent
FEDTAX	Variable	Federal tax	K$
FEDTAX_CR	Variable	Federal tax credits	K$
FIRST_ASR	Variable	First year a decline reservoir will be considered for ASR	
FIRST_DEC	Variable	First year a decline reservoir will be considered for EOR	

FIRSTCOM_FAC	Input	First year of commercialization for technology on the penetration curve	
FIT	Variable	Federal income tax	K$
FOAM	Variable	CO_2 fixed O & M cost	K$
FOAMG_1	Variable	Fixed annual operating cost for natural gas 1	K$
FOAMG_2	Variable	Fixed annual operating cost for natural gas 2	K$
FOAMG_W	Variable	Fixed operating cost for natural gas wells	K$
FGASPRICE	Input	Fixed natural gas price	$/MCF
FOILPRICE	Input	Fixed crude oil price	$/BBL
FPLY	Variable	Cost multiplier for polymer	
FPRICE	Input	Selection to use fixed prices	
FR1L48	Variable	Finding rates for new field wildcat drilling	Oil-MMB per well Gas-BCF per well
FR2L48	Variable	Finding rates for other exploratory drilling	Oil-MMB per well Gas-BCF per well
FR3L48	Variable	Finding rates for developmental drilling	Oil-MMB per well Gas-BCF per well
FRAC_CO2	Variable	Fraction of CO_2	Fraction
FRAC_H2S	Variable	Fraction of hydrogen sulfide	Fraction
FRAC_N2	Variable	Fraction of nitrogen	Fraction
FRAC_NGL	Variable	NGL yield	Fraction
FWC_W	Variable	Natural gas facilities costs	K$
GA_CAP	Variable	G & A on capital	K$
GA_EXP	Variable	G & A on expenses	K$
GAS_ADJ	Input	Fraction of annual natural gas drilling which is made available	Fraction
GAS_CASE	Input	Filter for all natural gas processes	
GAS_DWCA	Estimated	Horizontal natural gas drilling and completion costs	
GAS_DWCB	Estimated	Horizontal natural gas drilling and completion costs	
GAS_DWCC	Estimated	Horizontal natural gas drilling and completion costs	

GAS_DWCD	Input	Maximum depth range for natural gas well drilling cost equations	Ft
GAS_DWCK	Estimated	Constant for natural gas well drilling cost equations	
GAS_DWCM	Input	Minimum depth range for natural gas well drilling cost equations	Ft
GAS_FILTER	Input	Filter for all natural gas processes	
GAS_OAM	Input	Process specific operating cost for natural gas production	$/Mcf
GAS_SALES	Input	Will produced natural gas be sold?	
GASA0	Estimated	Natural gas footage A0	
GASA1	Estimated	Natural gas footage A1	
GASD0	Input	Natural gas drywell footage A0	
GASD1	Input	Natural gas drywell footage A1	
GASPRICE2	Variable	Natural gas price dummy to shift price track	K$
GASPRICEC	Variable	Annual natural gas prices used by cashflow	K$
GASPRICED	Variable	Annual natural gas prices used in the drilling constraints	K$
GASPRICEO	Variable	Annual natural gas prices used by the model	K$
GASPROD	Variable	Annual natural gas production	MMcf
GG	Variable	G & G cost	K$
GG_FAC	Input	G & G factor	
GGCTC	Input	G & G tangible depleted tax credit	K$
GGCTCAB	Input	G & G tangible tax credit rate addback	%
GGCTCR	Input	G & G tangible depleted tax credit rate	K$
GGETC	Input	G & G intangible depleted tax credit	K$
GGETCAB	Input	G & G intangible tax credit rate addback	%
GGETCR	Input	G & G intangible depleted tax credit rate	K$
GGLA	Variable	G & G and lease acquisition addback	K$
GMULT_INT	Input	Natural gas price adjustment factor, intangible costs	K$

GMULT_OAM	Input	Natural gas price adjustment factor, O & M	K$
GMULT_TANG	Input	Natural gas price adjustment factor, tangible costs	K$
GNA_CAP2	Input	G & A capital multiplier	Fraction
GNA_EXP2	Input	G & A expense multiplier	Fraction
GPROD	Variable	Well level natural gas production	MMcf
GRAVPEN	Variable	Gravity penalty	K$
GREMRES	Variable	Remaining proven natural gas reserves	MMcf
GROSS_REV	Variable	Gross revenue	K$
H_GROWTH	Input	Horizontal growth rate	Percent
H_PERCENT	Input	Crude oil constraint available for horizontal drilling	%
H_SUCCESS	Input	Horizontal development well success rate by region	%
H2SPRICE	Input	H_2S price	$/Metric ton
HOR_ADJ	Input	Fraction of annual horizontal drilling which is made available	Fraction
HOR_VERT	Input	Split between horizontal and vertical drilling	
HORMUL	Input	Horizontal drilling constraint multiplier	
IAMORYR	Input	Number of years in default amortization schedule	
ICAP	Variable	Other intangible costs	K$
ICST	Variable	Intangible cost	K$
IDCA	Variable	Intangible drilling capital addback	K$
IDCTC	Input	Intangible drilling cost tax credit	K$
IDCTCAB	Input	Intangible drilling cost tax credit rate addback	%
IDCTCR	Input	Intangible drilling cost tax credit rate	K$
IDEPRYR	Input	Number of years in default depreciation schedule	
IGREMRES	Variable	Remaining inferred natural gas reserves	MMcf
II_DRL	Variable	Intangible drilling cost	K$
IINFARSV	Variable	Initial inferred AD gas reserves	Bcf
IINFRESV	Variable	Initial inferred reserves	MMBbl
IMP_CAPCR	Input	Capacity for NGL cryogenic expander plant	MMCf/D

IMP_CAPST	Input	Capacity for NGL straight refrigeration	MMCf/D
IMP_CAPSU	Input	Capacity for Claus Sulfur Recovery	Long ton/day
IMP_CAPTE	Input	Natural gas processing plant capacity	MMcf/D
IMP_CO2_LIM	Input	Limit on CO_2 in natural gas	Fraction
IMP_DIS_RATE	Input	Discount rate for natural gas processing plant	
IMP_H2O_LIM	Input	Limit on H_2O in natural gas	Fraction
IMP_H2S_LIM	Input	Limit on H_2S in natural gas	Fraction
IMP_N2_LIM	Input	Limit on N^2 in natural gas	Fraction
IMP_NGL_LIM	Input	Limit on NGL in natural gas	Fraction
IMP_OP_FAC	Input	Natural gas processing operating factor	
IMP_PLT_LFE	Input	Natural gas processing plant life	Years
IMP_THRU	Input	Throughput	
IND_SRCCO2	Input	Use industrial source of CO_2?	
INDUSTRIAL	Variable	Natural or industrial CO_2 source	
INFLFAC	Input	Annual Inflation Factor	
INFR_ADG	Input	Adjustment factor for inferred AD gas reserves	Tcf
INFR_CBM	Input	Adjustment factor for inferred coalbed methane reserves	Tcf
INFR_DNAG	Input	Adjustment factor for inferred deep non-associated gas reserves	Tcf
INFR_OIL	Input	Adjustment factor for inferred crude oil reserves	Bbl?
INFR_SHL	Input	Adjustment factor for inferred shale gas reserves	Tcf
INFR_SNAG	Input	Adjustment factor for inferred shallow non-associated gas reserves	Tcf
INFR_THT	Input	Adjustment factor for inferred tight gas reserves	Tcf
INFARSV	Variable	Inferred AD gas reserves	Bcf
INFRESV	Variable	Inferred reserves, crude oil or natural gas	MMBbl, Bcf
INJ	Variable	Injectant cost	K$
INJ_OAM	Input	Process specific operating cost for injection	$/Bbl
INJ_RATE_FAC	Input	Injection rate increase	fraction
INTADD	Variable	Total intangible addback	K$
INTANG_M	Variable	Intangible cost multiplier	

INTCAP	Variable	Intangible to be capitalized	K$
INVCAP	Variable	Annual total capital investments constraints, used for constraining projects	MM$
IPDR	Input	Independent producer depletion rate	
IRA	Input	Max alternate minimum tax reduction for independents	K$
IREMRES	Variable	Remaining inferred crude oil reserves	MBbl
IUNDARES	Variable	Initial undiscovered resource	MMBbl/Tcf
IUNDRES	Variable	Initial undiscovered resource	MMBbl/Tcf
L48B4YR	Input	First year of analysis	
LA	Variable	Lease and acquisition cost	K$
LACTC	Input	Lease acquisition tangible depleted tax credit	K$
LACTCAB	Input	Lease acquisition tangible credit rate addback	%
LACTCR	Input	Lease acquisition tangible depleted tax credit rate	K$
LAETC	Input	Lease acquisition intangible expensed tax credit	K$
LAETCAB	Input	Lease acquisition intangible tax credit rate addback	%
LAETCR	Input	Lease acquisition intangible expensed tax credit rate	K$
LAST_ASR	Variable	Last year a decline reservoir will be considered for ASR	
LAST_DEC	Variable	Last year a decline reservoir will be considered for EOR	
LBC_FRAC	Input	Lease bonus fraction	Fraction
LEASCST	Variable	Lease cost by project	K$
LEASL48	Variable	Lease equipment costs	1987$/well
MARK_PEN_FAC	Input	Ultimate market penetration	
MAXWELL	Input	Maximum number of dryholes per play per year	
MAX_API_CASE	Input	Maximum API gravity	
MAX_DEPTH_CASE	Input	Maximum depth	
MAX_PERM_CASE	Input	Maximum permeability	
MAX_RATE_CASE	Input	Maximum production rate	
MIN_API_CASE	Input	Minimum API gravity	
MIN_DEPTH_CASE	Input	Minimum depth	
MIN_PERM_CASE	Input	Minimum permeability	
MIN_RATE_CASE	Input	Minimum production rate	
MOB_RAT_ FAC	Input	Change in mobility ratio	
MPRD	Input	Maximum depth range for new producer equations	Ft

N_CPI	Input	Number of years	
N2PRICE	Input	N_2 price	$/Mcf
NAT_AVAILCO2	Input	Annual CO_2 availability by region	Bcf
NAT_DMDGAS	Variable	Annual natural gas demand in region	Bcf/Yr
NAT_DRCAP_D	Variable	National dual use drilling footage for crude oil and natural gas development	Ft
NAT_DRCAP_G	Variable	National natural gas well drilling footage constraints	Ft
NAT_DRCAP_O	Variable	National crude oil well drilling footage constraints	Ft
NAT_DUAL	Variable	National dual use drilling footage for crude oil and natural gas development	Ft
NAT_EXP	Variable	National exploratory drilling constraint	Bcf/Yr
NAT_EXPC	Variable	National conventional exploratory drilling crude oil constraint	MBbl/Yr
NAT_EXPCDRCAP	Variable	National conventional exploratory drilling footage constraints	Ft
NAT_EXPCDRCAPG	Variable	National high-permeability natural gas exploratory drilling footage constraints	Ft
NAT_EXPCG	Variable	National conventional exploratory drilling natural gas constraint	Bcf/Yr
NAT_EXPG	Variable	National natural gas exploration drilling constraint	Bcf/Yr
NAT_EXPU	Variable	National continuous exploratory drilling crude oil constraint	MBbl/Yr
NAT_EXPUDRCAP	Variable	National continuous exploratory drilling footage constraints	Ft
NAT_EXPUDRCAPG	Variable	National continuous natural gas exploratory drilling footage constraints	Ft
NAT_EXPUG	Variable	National continuous exploratory drilling natural gas constraint	Bcf/Yr
NAT_GAS	Variable	National natural gas drilling constraint	Bcf/Yr
NAT_GDR	Variable	National natural gas dry drilling footage	Bcf/Yr

NAT_HGAS	Variable	Annual dry natural gas	MMcf
NAT_HOIL	Variable	Annual crude oil and lease condensates	MBbl
NAT_HOR	Variable	Horizontal drilling constraint	MBbl/Yr
NAT_INVCAP	Input	Annual total capital investment constraint	MM$
NAT_ODR	Variable	National crude oil dry drilling footage	MBbl/Yr
NAT_OIL	Variable	National crude oil drilling constraint	MBbl/Yr
NAT_SRCCO2	Input	Use natural source of CO_2?	
NAT_TOT	Variable	Total national footage	Ft
NET_REV	Variable	Net revenue	K$
NEW_ECAP	Variable	New environmental capital cost	K$
NEW_EOAM	Variable	New environmental O & M cost	K$
NEW_NRES	Variable	New total number of reservoirs	
NGLPRICE	Input	NGL price	$/Gal
NGLPROD	Variable	Annual NGL production	MBbl
NIAT	Variable	Net income after taxes	K$
NIBT	Variable	Net income before taxes	K$
NIBTA	Variable	Net operating income after adjustments before addback	K$
NIL	Input	Net income limitations	K$
NILB	Variable	Net income depletable base	K$
NILL	Input	Net income limitation limit	K$
NOI	Variable	Net operating income	K$
NOM_YEAR	Input	Year for nominal dollars	
NPR_W	Variable	Cost to equip a new producer	K$
NPRA	Estimated	Constant for new producer equipment	
NPRB	Estimated	Constant for new producer equipment	
NPRC	Estimated	Constant for new producer equipment	
NPRK	Estimated	Constant for new producer equipment	
NPRM	Input	Minimum depth range for new producer equations	Ft
NPROD	Variable	Well level NGL production	MMcf
NRDL48	Variable	Proved reserves added by new field discoveries	Oil-MMB Gas-BCF
NREG	Input	Number of regions	

NSHUT	Input	Number of years after economics life in which EOR can be considered	
NTECH	Input	Number of technology impacts	
NUMPACK	Input	Number of packages per play per year	
NWELL	Input	Number of wells in continuous exploration drilling package	
OAM	Variable	Variable O & M cost	K$
OAM_COMP	Variable	Compression O & M	K$
OAM_M	Variable	O & M cost multiplier	
OIA	Variable	Other intangible capital addback	K$
OIL_ADJ	Input	Fraction of annual crude oil drilling which is made available	Fraction
OIL_CASE	Input	Filter for all crude oil processes	
OIL_DWCA	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCB	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCC	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCD	Input	Maximum depth range for crude oil well drilling cost equations	Ft
OIL_DWCK	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCM	Input	Minimum depth range for crude oil well drilling cost equations	Ft
OIL_FILTER	Input	Filter for all crude oil processes	
OIL_OAM	Input	Process specific operating cost for crude oil production	$/Bbl
OIL_RAT_ FAC	Input	Change in crude oil production rate	
OIL_RAT_CHG	Variable	Change in crude oil production rate	
OIL_SALES	Input	Sell crude oil produced from the reservoir?	
OILA0	Estimated	Oil footage A0	
OILA1	Estimated	Oil footage A1	

OILCO2	Input	Fixed crude oil price used for economic pre-screening of industrial CO_2 projects	K$
OILD0	Input	Crude oil drywell footage A0	
OILD1	Input	Crude oil drywell footage A1	
OILPRICEC	Variable	Annual crude oil prices used by cashflow	K$
OILPRICED	Variable	Annual crude oil prices used in the drilling constraints	K$
OILPRICEO	Variable	Annual crude oil prices used by the model	K$
OILPROD	Variable	Annual crude oil production	MBbl
OINJ	Variable	Well level injection	MMcf
OITC	Input	Other intangible tax credit	K$
OITCAB	Input	Other intangible tax credit rate addback	%
OITCR	Input	Other intangible tax credit rate	K$
OMGA	Estimated	Fixed annual cost for natural gas	$/Well
OMGB	Estimated	Fixed annual cost for natural gas	$/Well
OMGC	Estimated	Fixed annual cost for natural gas	$/Well
OMGD	Input	Maximum depth range for fixed annual O & M natural gas cost	Ft
OMGK	Estimated	Constant for fixed annual O & M cost for natural gas	
OMGM	Input	Minimum depth range for fixed annual O & M cost for natural gas	Ft
OML_W	Variable	Variable annual operating cost for lifting	K$
OMLA	Estimated	Lifting cost	$/Well
OMLB	Estimated	Lifting cost	$/Well
OMLC	Estimated	Lifting cost	$/Well
OMLD	Input	Maximum depth range for fixed annual operating cost for crude oil	Ft
OMLK	Estimated	Constant for fixed annual operating cost for crude oil	
OMLM	Input	Minimum depth range for annual operating cost for crude oil	Ft
OMO_W	Variable	Fixed annual operating cost for crude oil	K$

OMOA	Estimated	Fixed annual cost for crude oil	$/Well
OMOB	Estimated	Fixed annual cost for crude oil	$/Well
OMOC	Estimated	Fixed annual cost for crude oil	$/Well
OMOD	Input	Maximum depth range for fixed annual operating cost for crude oil	Ft
OMOK	Estimated	Constant for fixed annual operating cost for crude oil	
OMOM	Input	Minimum depth range for fixed annual operating cost for crude oil	Ft
OMSWRA	Estimated	Secondary workover cost	$/Well
OMSWRB	Estimated	Secondary workover cost	$/Well
OMSWRC	Estimated	Secondary workover cost	$/Well
OMSWRD	Input	Maximum depth range for variable operating cost for secondary workover	Ft
OMSWRK	Estimated	Constant for variable operating cost for secondary workover	
OMSWRM	Input	Minimum depth range for variable operating cost for secondary workover	Ft
OMULT_INT	Input	Crude oil price adjustment factor, intangible costs	
OMULT_OAM	Input	Crude oil price adjustment factor, O & M	
OMULT_TANG	Input	Crude oil price adjustment factor, tangible costs	
OPCOST	Variable	AOAM by project	K$
OPERL48	Variable	Operating Costs	1987$/Well
OPINJ_W	Variable	Variable annual operating cost for injection	K$
OPINJA	Input	Injection cost	$/Well
OPINJB	Input	Injection cost	$/Well
OPINJC	Input	Injection cost	$/Well
OPINJD	Input	Maximum depth range for variable annual operating cost for injection	Ft
OPINJK	Input	Constant for variable annual operating cost for injection	
OPINJM	Input	Minimum depth range for variable annual operating cost for injection	Ft

OPROD	Variable	Well level crude oil production	MBbl
OPSEC_W	Variable	Fixed annual operating cost for secondary operations	K$
OPSECA	Estimated	Annual cost for secondary production	$/Well
OPSECB	Estimated	Annual cost for secondary production	$/Well
OPSECC	Estimated	Annual cost for secondary production	$/Well
OPSECD	Input	Maximum depth range for fixed annual operating cost for secondary operations	Ft
OPSECK	Estimated	Constant for fixed annual operating cost for secondary operations	
OPSECM	Input	Minimum depth range for fixed annual operating cost for secondary operations	Ft
OPT_RPT	Input	Report printing options	
ORECY	Variable	Well level recycled injectant	MBbl
OTC	Variable	Other tangible costs	K$
PATT_DEV	Input	Pattern development	
PATT_DEV_MAX	Input	Maximum pattern development schedule	
PATT_DEV_MIN	Input	Minimum pattern development schedule	
PATDEV	Variable	Annual number of patterns developed for base and advanced technology	
PATN	Variable	Patterns initiated each year	
PATNDCF	Variable	DCF by project	K$
PATTERNS	Variable	Shifted patterns initiated	
PAYCONT_ FAC	Input	Pay continuity factor	
PDR	Input	Percent depletion rate	%
PGGC	Input	Percent of G & G depleted	%
PIIC	Input	Intangible investment to capitalize	%
PLAC	Input	Percent of lease acquisition cost capitalized	%
PLAYNUM	Input	Play number	
PLY_F	Variable	Cost for a polymer handling plant	K$
PLYPA	Input	Polymer handling plant constant	
PLYPK	Input	Polymer handling plant constant	

POLY	Input	Polymer cost	
POLYCOST	Variable	Polymer cost	$/Lb
POTENTIAL	Variable	The number of reservoirs in the resource file	
PRICEYR	Input	First year of prices in price track	K$
PRO_REGEXP	Input	Regional exploration well drilling footage constraint	Ft
PRO_REGEXPG	Input	Regional exploration well drilling footage constraint	Ft
PRO_REGGAS	Input	Regional natural gas well drilling footage constraint	Ft
PRO_REGOIL	Input	Regional crude oil well drilling footage constraint	Ft
PROB_IMP_FAC	Input	Probability of industrial implementation	
PROB_RD_FAC	Input	Probability of successful R & D	
PROC_CST	Variable	Processing cost	$/Mcf
PROC_OAM	Variable	Processing and treating cost	K$
PROCESS_CASE	Input	Filter for crude oil and natural gas processes	
PROCESS_FILTER	Input	Filter for crude oil and natural gas processes	
PROD_IND_ FAC	Input	Production impact	
PROVACC	Input	Year file for resource access	
PROVNUM	Input	Province number	
PRRATL48	Variable	Production to reserves ratio	Fraction
PSHUT	Input	Number of years prior to economic life in which EOR can be considered	
PSI_W	Variable	Cost to convert a primary well to an injection well	K$
PSIA	Estimated	Cost to convert a producer to an injector	
PSIB	Estimated	Cost to convert a producer to an injector	
PSIC	Estimated	Cost to convert a producer to an injector	
PSID	Input	Maximum depth range for producer to injector	Ft
PSIK	Estimated	Constant for producer to injector	
PSIM	Input	Minimum depth range for producer to injector	Ft
PSW_W	Variable	Cost to convert a primary to secondary well	K$

PSWA	Estimated	Cost to convert a primary to secondary well	
PSWB	Estimated	Cost to convert a primary to secondary well	
PSWC	Estimated	Cost to convert a primary to secondary well	
PSWD	Input	Maximum depth range for producer to injector	Ft
PSWK	Estimated	Constant for primary to secondary	
PSWM	Input	Minimum depth range for producer to injector	Ft
PWHP	Input	Produced water handling plant multiplier	K$
PWP_F	Variable	Cost for a produced water handling plant	K$
RDEPTH	Variable	Reservoir depth	ft
RDR	Input	Depth interval	
RDR_FOOTAGE	Variable	Footage available in this interval	Ft
RDR_FT	Variable	Running total of footage used in this bin	Ft
REC_EFF_ FAC	Input	Recovery efficiency factor	
RECY_OIL	Input	Produced water recycling cost	K$
RECY_WAT	Input	Produced water recycling cost	
REG_DUAL	Variable	Regional dual use drilling footage for crude oil and natural gas development	Ft
REG_EXP	Variable	Regional exploratory drilling constraints	MBbl/Yr
REG_EXPC	Variable	Regional conventional crude oil exploratory drilling constraint	MBbl/Yr
REG_EXPCG	Variable	Regional conventional natural gas exploratory drilling constraint	Bcf/Yr
REG_EXPG	Variable	Regional exploratory natural gas drilling constraint	Bcf/Yr
REG_EXPU	Variable	Regional continuous crude oil exploratory drilling constraint	MBbl/Yr
REG_EXPUG	Variable	Regional continuous natural gas exploratory drilling constraint	Bcf/Yr
REG_GAS	Variable	Regional natural gas drilling constraint	Bcf/Yr
REG_HADG	Variable	Regional historical AD gas	MMcf
REG_HCBM	Variable	Regional historical CBM	MMcf

REG_HCNV	Variable	Regional historical high-permeability natural gas	MMcf
REG_HEOIL	Variable	Regional crude oil and lease condensates for continuing EOR	MBbl
REG_HGAS	Variable	Regional dry natural gas	MMcf
REG_HOIL	Variable	Regional crude oil and lease condensates	MBbl
REG_HSHL	Variable	Regional historical shale gas	MMcf
REG_HTHT	Variable	Regional historical tight gas	MMcf
REG_NAT	Input	Regional or national	
REG_OIL	Variable	Regional crude oil drilling constraint	MBbl/Yr
REGDRY	Variable	Regional dryhole rate	
REGDRYE	Variable	Exploration regional dryhole rate	
REGDRYG	Variable	Development natural gas regional dryhole rate	
REGDRYKD	Variable	Regional dryhole rate for discovered development	
REGDRYUD	Variable	Regional dryhole rate for undiscovered development	
REGDRYUE	Variable	Regional dryhole rate for undiscovered exploration	
REGION_CASE	Input	Filter for OLOGSS region	
REGION_FILTER	Input	Filter for OLOGSS region	
REGSCALE_CBM	Input	Regional historical daily CBM gas production for the last year of history	Bcf
REGSCALE_CNV	Input	Regional historical daily high-permeability natural gas production for the last year of history	Bcf
REGSCALE_GAS	Input	Regional historical daily natural gas production for the last year of history	Bcf
REGSCALE_OIL	Input	Regional historical daily crude oil production for the last year of history	MBbl
REGSCALE_SHL	Input	Regional historical daily shale gas production for the last year of history	Bcf
REGSCALE_THT	Input	Regional historical daily tight gas production for the last year of history	Bcf
REM_AMOR	Variable	Remaining amortization base	K$
REM_BASE	Variable	Remaining depreciation base	K$

REMRES	Variable	Remaining proven crude oil reserves	MBbl
RESADL48	Variable	Total additions to proved reserves	Oil-MMB Gas-BCF
RESBOYL48	Variable	End of year reserves for current year	Oil-MMB Gas-BCF
RES_CHR_ FAC	Input	Reservoir characterization cost	$/Cumulative BOE
RES_CHR_CHG	Variable	Reservoir characterization cost	$/Cumulative BOE
RESV_ADGAS	Input	Historical AD gas reserves	Tcf
RESV_CBM	Input	Historical coalbed methane reserves	Tcf
RESV_CONVGAS	Input	Historical high-permeability dry natural gas reserves	Tcf
RESV_OIL	Input	Historical crude oil and lease condensate reserves	BBbl
RESV_SHL	Input	Historical shale gas reserves	Tcf
RESV_THT	Input	Historical tight gas reserves	Tcf
RGR	Input	Annual drilling growth rate	
RIGSL48	Variable	Available rigs	Rigs
RNKVAL	Input	Ranking criteria for the projects	
ROR	Variable	Rate of return	K$
ROYALTY	Variable	Royalty	K$
RREG	Variable	Reservoir region	
RRR	Input	Annual drilling retirement rate	
RUNTYPE	Input	Resources selected to evaluate in the Timing subroutine	
RVALUE	Variable	Reservoir technical crude oil production	MBbl
SCALE_DAY	Input	Number of days in the last year of history	Days
SCALE_GAS	Input	Historical daily natural gas production for the last year of history	Bcf
SCALE_OIL	Input	Historical daily crude oil production for the last year of history	MBbl
SEV_PROC	Variable	Process code	
SEV_TAX	Variable	Severance tax	K$
SFIT	Variable	Alternative minimum tax	K$
SKIN_FAC	Input	Skin factor	
SKIN_CHG	Variable	Change in skin amount	
SMAR	Input	Six month amortization rate	%

SPLIT_ED	Input	Split exploration and development	
SPLIT_OG	Input	Split crude oil and natural gas constraints	
STARTPR	Variable	First year a pattern is initiated	
STATE_TAX	Variable	State tax	K$
STIM	Variable	Stimulation cost	K$
STIM_A, STIM_B	Input	Coefficients for natural gas/oil stimulation cost	K$
STIM_W	Variable	Natural gas well stimulation cost	K$
STIM_YR	Input	Number of years between stimulations of natural gas/oil wells	
STIMFAC	Input	Stimulation efficiency factor	
STL	Variable	State identification number	
STMGA	Input	Steam generator cost multiplier	
STMM_F	Variable	Cost for steam manifolds and generators	K$
STMMA	Input	Steam manifold/pipeline multiplier	
SUCCHDEV	Variable	Horizontal development well success rate by region	Fraction
SUCDEVE	Input	Developmental well dryhole rate by region	%
SUCDEVG	Variable	Final developmental natural gas well success rate by region	Fraction
SUCDEVO	Variable	Final developmental crude oil well success rate by region	Fraction
SUCEXP	Input	Undiscovered exploration well dryhole rate by region	%
SUCEXPD	Input	Exploratory well dryhole rate by region	%
SUCG	Variable	Initial developmental natural gas well success rate by region	Fraction
SUCO	Variable	Initial developmental crude oil well success by region	Fraction
SUCWELLL48	Variable	Successful Lower 48 onshore wells drilled	Wells
SUM_DRY	Variable	Developmental dryholes drilled	
SUM_GAS_CONV	Variable	High-permeability natural gas drilling	MMcf

SUM_GAS_UNCONV	Variable	Low-permeability natural gas drilling	MMcf
SUM_OIL_CONV	Variable	Conventional crude oil drilling	MBbl
SUM_OIL_UNCONV	Variable	Continuous crude oil drilling	MBbl
SUMP	Variable	Total cumulative patterns	
SWK_W	Variable	Secondary workover cost	K$
TANG_FAC_RATE	Input	Percentage of the well costs which are tangible	Percent
TANG_M	Variable	Tangible cost multiplier	
TANG_RATE	Input	Percentage of drilling costs which are tangible	Percent
TCI	Variable	Total capital investments	K$
TCIADJ	Variable	Adjusted capital investments	K$
TCOII	Input	Tax credit on intangible investments	K$
TCOTI	Input	Tax credit on tangible investments	K$
TDTC	Input	Tangible development tax credit	K$
TDTCAB	Input	Tangible development tax credit rate addback	%
TDTCR	Input	Tangible development tax credit rate	K$
TECH01_FAC	Input	WAG ratio applied to CO2EOR	
TECH02_FAC	Input	Recovery Limit	
TECH03_FAC	Input	Vertical Skin Factor for natural gas	
TECH04_FAC	Input	Fracture Half Length	Ft
TECH05_FAC	Input	Fracture Conductivity	Ft
TECH_CO2FLD	Variable	Technical production from CO_2 flood	MBbl
TECH_COAL	Variable	Annual technical coalbed methane gas production	MMcf
TECH_CURVE	Variable	Technology commercialization curve for market penetration	
TECH_CURVE_FAC	Input	Technology commercialization curve for market penetration	
TECH_DECLINE	Variable	Technical decline production	MBbl
TECH_GAS	Variable	Annual technical natural gas production	MMcf
TECH_HORCON	Variable	Technical production from horizontal continuity	MBbl

TECH_HORPRF	Variable	Technical production for horizontal profile	MBbl
TECH_INFILL	Variable	Technical production from infill drilling	MBbl
TECH_NGL	Variable	Annual technical NGL production	MBbl
TECH_OIL	Variable	Annual technical crude oil production	MBbl
TECH_PLYFLD	Variable	Technical production from polymer injection	MBbl
TECH_PRFMOD	Variable	Technical production from profile modification	MBbl
TECH_PRIMARY	Variable	Technical production from primary sources	MBbl
TECH_RADIAL	Variable	Technical production from conventional radial flow	MMcf
TECH_SHALE	Variable	Annual technical shale gas production	MMcf
TECH_STMFLD	Variable	Technical production from steam flood	MBbl
TECH_TIGHT	Variable	Annual technical tight gas production	MMcf
TECH_TIGHTG	Variable	Technical tight gas production	MMcf
TECH_UCOALB	Variable	Technical undiscovered coalbed methane production	MMcf
TECH_UCONTO	Variable	Technical undiscovered continuous crude oil production	MBbl
TECH_UCONVG	Variable	Technical low-permeability natural gas production	MMcf
TECH_UCONVO	Variable	Technical undiscovered conventional crude oil production	MBbl
TECH_UGCOAL	Variable	Annual technical developing coalbed methane gas production	MMcf
TECH_UGSHALE	Variable	Annual technical developing shale gas production	MMcf
TECH_UGTIGHT	Variable	Annual technical developing tight gas production	MMcf
TECH_USHALE	Variable	Technical undiscovered shale gas production	MMcf
TECH_UTIGHT	Variable	Technical undiscovered tight gas production	MMcf
TECH_WATER	Variable	Technical production from waterflood	MBbl

TECH_WTRFLD	Variable	Technical production from waterflood	MBbl
TGGLCD	Variable	Total G & G cost	K$
TI	Variable	Tangible costs	K$
TI_DRL	Variable	Tangible drilling cost	K$
TIMED	Variable	Timing flag	
TIMEDYR	Variable	Year in which the project is timed	
TOC	Variable	Total operating costs	K$
TORECY	Variable	Annual water injection	MBbl
TORECY_CST	Variable	Water injection cost	K$
TOTHWCAP	Variable	Total horizontal drilling footage constraint	Ft
TOTINJ	Variable	Annual water injection	MBbl
TOTMUL	Input	Total drilling constraint multiplier	
TOTSTATE	Variable	Total state severance tax	K$
UCNT	Variable	Number of undiscovered reservoirs	
UDEPTH	Variable	Reservoir depth	K$
UMPCO2	Input	CO_2 ultimate market acceptance	
UNAME	Variable	Reservoir identifier	
UNDARES	Variable	Undiscovered resource, AD gas or lease condensate	Bcf, MMBbl
UNDRES	Variable	Undiscovered resource	MMBbl, Bcf
UREG	Variable	Reservoir region	
USE_AVAILCO2	Variable	Used annual volume of CO_2 by region	Bcf
USE_RDR	Input	Use rig depth rating	
USEAVAIL	Variable	Used annual CO_2 volume by region across all sources	Bcf
USECAP	Variable	Annual total capital investment constraints, used by projects	MM$
UVALUE	Variable	Reservoir undiscovered crude oil production	MBbl
UVALUE2	Variable	Reservoir undiscovered natural gas production	MMcf
VEORCP	Input	Volumetric EOR cutoff	%
VIABLE	Variable	The number of economically viable reservoirs	
VOL_SWP_ FAC	Input	Sweep volume factor	
VOL_SWP_CHG	Variable	Change in sweep volume	
WAT_OAM	Input	Process specific operating cost for water production	$/Bbl
WATINJ	Variable	Annual water injection	MBbl

WATPROD	Variable	Annual water production	MBbl
WELLSL48	Variable	Lower 48 onshore wells drilled	Wells
WINJ	Variable	Well level water injection	MBbl
WPROD	Variable	Well level water production	MBbl
WRK_W	Variable	Cost for well workover	K$
WRKA	Estimated	Constant for workover cost equations	
WRKB	Estimated	Constant for workover cost equations	
WRKC	Estimated	Constant for workover cost equations	
WRKD	Input	Maximum depth range for workover cost	Ft
WRKK	Estimated	Constant for workover cost equations	
WRKM	Input	Minimum depth range for workover cost	Ft
XCAPBASE	Variable	Cumulative cap stream	
XCUMPROD	Variable	Cumulative production	MBbl
XPATN	Variable	Active patterns each year	
XPP1	Variable	Number of new producers drilled per pattern	
XPP2	Variable	Number of new injectors drilled per pattern	
XPP3	Variable	Number of producers converted to injectors	
XPP4	Variable	Number of primary wells converted to secondary wells	
XROY	Input	Royalty rate	Percent
YEARS_STUDY	Input	Number of years of analysis	
YR1	Input	Number of years for tax credit on tangible investments	
YR2	Input	Number of years for tax credit on intangible investments	
YRDI	Input	Years to develop infrastructure	
YRDT	Input	Years to develop technology	
YRMA	Input	Years to reach full capacity	

Appendix 2.B: Cost and Constraint Estimation

The major sections of OLOGSS consist of a series of equations that are used to calculate project economics and the development of crude oil and natural gas resources subject to the availability of regional development constraints. The cost and constraint calculation was assessed as unit costs per well. The product of the cost equation and cost adjustment factor is the actual cost. The actual cost reflects the influence on the resource, region and oil or gas price. The equations, the estimation techniques, and the statistical results for these equations are documented below. The statistical software included within Microsoft Excel was used for the estimations.

Drilling and Completion Costs for Crude Oil

The 2004 – 2007 Joint Association Survey (JAS) data was used to calculate the equation for vertical drilling and completion costs for crude oil. The data was analyzed at a regional level. The independent variables were depth, raised to powers of 1 through 3. Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. The method of estimation used was ordinary least squares. The form of the equation is given below. β1 (the coefficient for depth raised to the first power) is statistically insignificant and is therefore assumed zero.

$$\text{Drilling Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}1)$$

where Drilling Cost = DWC_W
β0 = OIL_DWCK
β1 = OIL_DWCA
β2 = OIL_DWCB
β3 = OIL_DWCC
from equations 2-17 and 2-18 in Chapter 2.

Northeast Region:

Regression Statistics	
Multiple R	0.836438789
R Square	0.699629848
Adjusted R Square	0.691168717
Standard Error	629377.1735
Observations	74

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	6.55076E+13	3.27538E+13	82.6875087	2.86296E-19
Residual	71	2.81242E+13	3.96116E+11		
Total	73	9.36318E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	122428.578	126464.5594	0.968086068	0.336287616	-129734.7159	374591.8719	-129734.7159	374591.8719
β2	0.058292022	0.020819613	2.799860932	0.006580083	0.016778872	0.099805172	0.016778872	0.099805172
β3	5.68014E-07	2.56497E-06	0.221450391	0.825377435	-4.5464E-06	5.68243E-06	-4.5464E-06	5.68243E-06

Gulf Coast Region:

Regression Statistics	
Multiple R	0.927059199
R Square	0.859438758
Adjusted R Square	0.85771408
Standard Error	754021.7218
Observations	166

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	5.66637E+14	2.83318E+14	498.3184388	3.55668E-70
Residual	163	9.26734E+13	5.68549E+11		
Total	165	6.5931E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	171596.0907	99591.43949	1.723000407	0.086784881	-25059.61405	368251.7955	-25059.61405	368251.7955
β2	0.026582707	0.005213357	5.098961204	9.38664E-07	0.016288283	0.036877131	0.016288283	0.036877131
β3	5.10946E-07	3.82305E-07	1.336488894	0.183252113	-2.43962E-07	1.26585E-06	-2.43962E-07	1.26585E-06

Mid-Continent Region:

Regression Statistics	
Multiple R	0.898305188
R Square	0.806952211
Adjusted R Square	0.803343841
Standard Error	865339.0638
Observations	110

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	3.34919E+14	1.67459E+14	223.6334505	6.06832E-39
Residual	107	8.01229E+13	7.48812E+11		
Total	109	4.15042E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	44187.62539	135139.2151	0.326978556	0.744322892	-223710.0994	312085.3502	-223710.0994	312085.3502
β2	0.038468835	0.005870927	6.552429326	2.04023E-09	0.026830407	0.050107263	0.026830407	0.050107263
β3	-9.45921E-07	3.70017E-07	-2.556425591	0.011978314	-1.67944E-06	-2.12405E-07	-1.67944E-06	-2.12405E-07

Southwest Region:

Regression Statistics	
Multiple R	0.927059199
R Square	0.859438758
Adjusted R Square	0.85771408
Standard Error	754021.7218
Observations	166

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	5.66637E+14	2.83318E+14	498.3184388	3.55668E-70
Residual	163	9.26734E+13	5.68549E+11		
Total	165	6.5931E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	171596.0907	99591.43949	1.723000407	0.086784881	-25059.61405	368251.7955	-25059.61405	368251.7955
β2	0.026582707	0.005213357	5.098961204	9.38664E-07	0.016288283	0.036877131	0.016288283	0.036877131
β3	5.10946E-07	3.82305E-07	1.336488894	0.183252113	-2.43962E-07	1.26585E-06	-2.43962E-07	1.26585E-06

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.905358855
R Square	0.819674657
Adjusted R Square	0.81505093
Standard Error	1524859.577
Observations	81

ANOVA

	df	SS	MS	F	Significance F
Regression	2	8.24402E+14	4.12201E+14	177.2757561	9.68755E-30
Residual	78	1.81365E+14	2.3252E+12		
Total	80	1.00577E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	85843.77642	334865.8934	0.256352702	0.798353427	-580822.9949	752510.5477	-580822.9949	752510.5477
β2	0.024046279	0.017681623	1.35995883	0.177760898	-0.011155127	0.059247685	-0.011155127	0.059247685
β3	3.11588E-06	1.35985E-06	2.291329746	0.024643617	4.08613E-07	5.82314E-06	4.08613E-07	5.82314E-06

West Coast Region:

Regression Statistics	
Multiple R	0.829042211
R Square	0.687310988
Adjusted R Square	0.66961161
Standard Error	1192282.08
Observations	57

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1.65605E+14	5.52018E+13	38.83249387	2.05475E-13
Residual	53	7.53414E+13	1.42154E+12		
Total	56	2.40947E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	416130.9988	739996.4118	0.562341914	0.576253925	-1068113.806	1900375.804	-1068113.806	1900375.804
β1	44.24458907	494.4626992	0.089480135	0.929037628	-947.5219666	1036.011145	-947.5219666	1036.011145
β2	0.032683532	0.091113678	0.35871159	0.721235869	-0.150067358	0.215434422	-0.150067358	0.215434422
β3	3.38129E-07	4.76464E-06	0.070966208	0.94369176	-9.21853E-06	9.89479E-06	-9.21853E-06	9.89479E-06

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.847120174
R Square	0.71761259
Adjusted R Square	0.702750095
Standard Error	1967213.576
Observations	61

ANOVA

	df	SS	MS	F	Significance F
Regression	3	5.60561E+14	1.86854E+14	48.2834529	1.1626E-15
Residual	57	2.20586E+14	3.86993E+12		
Total	60	7.81147E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	98507.54357	1384010.586	0.071175426	0.943507284	-2672925.83	2869940.917	-2672925.83	2869940.917
β1	478.7358996	548.203512	0.873281344	0.386173991	-619.0226893	1576.494489	-619.0226893	1576.494489
β2	-0.00832112	0.058193043	-0.142991666	0.886801051	-0.124850678	0.108208438	-0.124850678	0.108208438
β3	6.1159E-07	1.79131E-06	0.34142064	0.7340424	-2.97545E-06	4.19863E-06	-2.97545E-06	4.19863E-06

Drilling and Completion Cost for Oil - Cost Adjustment Factor

The cost adjustment factor for vertical drilling and completion costs for oil was calculated using JAS data through 2007. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Northeast Region:

Regression Statistics	
Multiple R	0.993325966
R Square	0.986696475
Adjusted R Square	0.986411399
Standard Error	0.029280014
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.901997029	2.967332343	3461.175482	4.4887E-131
Residual	140	0.120024694	0.000857319		
Total	143	9.022021723			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309616442	0.009839962	31.46520591	2.3349E-65	0.290162308	0.329070576	0.290162308	0.329070576
β1	0.019837121	0.000434252	45.68110123	5.41725E-86	0.018978581	0.020695661	0.018978581	0.020695661
β2	-0.000142411	5.21769E-06	-27.29392193	6.44605E-58	-0.000152727	-0.000132095	-0.000152727	-0.000132095
β3	3.45898E-07	1.69994E-08	20.34770764	1.18032E-43	3.1229E-07	3.79507E-07	3.1229E-07	3.79507E-07

Gulf Coast Region:

Regression Statistics	
Multiple R	0.975220111
R Square	0.951054265
Adjusted R Square	0.950005428
Standard Error	0.054224144
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	7.998414341	2.666138114	906.7701736	1.76449E-91
Residual	140	0.411636098	0.002940258		
Total	143	8.410050438			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.404677859	0.01822279	22.2072399	1.01029E-47	0.368650426	0.440705292	0.368650426	0.440705292
β1	0.016335847	0.000804199	20.31319148	1.41023E-43	0.014745903	0.017925792	0.014745903	0.017925792
β2	-0.00010587	9.66272E-06	-10.95654411	1.47204E-20	-0.000124974	-8.67663E-05	-0.000124974	-8.67663E-05
β3	2.40517E-07	3.14814E-08	7.639970947	3.10789E-12	1.78277E-07	3.02758E-07	1.78277E-07	3.02758E-07

Mid-Continent Region:

Regression Statistics	
Multiple R	0.973577019
R Square	0.947852212
Adjusted R Square	0.94673476
Standard Error	0.058882142
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.822668656	2.940889552	848.2258794	1.4872E-89
Residual	140	0.485394925	0.003467107		
Total	143	9.308063582			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.309185338	0.019788175	15.62475232	1.738E-32	0.270063053	0.348307623	0.270063053	0.348307623
β1	0.019036286	0.000873282	21.79856116	7.62464E-47	0.017309761	0.020762811	0.017309761	0.020762811
β2	-0.000123667	1.04928E-05	-11.78593913	1.05461E-22	-0.000144412	-0.000102922	-0.000144412	-0.000102922
β3	2.60516E-07	3.41858E-08	7.620611936	3.45556E-12	1.92929E-07	3.28104E-07	1.92929E-07	3.28104E-07

Southwest Region:

Regression Statistics	
Multiple R	0.993452577
R Square	0.986948023
Adjusted R Square	0.986668338
Standard Error	0.030207623
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.66004438	3.220014793	3528.781511	1.1799E-131
Residual	140	0.127750066	0.0009125		
Total	143	9.787794446			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.293837119	0.010151698	28.944627	5.92751E-61	0.273766667	0.313907571	0.273766667	0.313907571
β1	0.020183122	0.00044801	45.05064425	3.35207E-85	0.019297383	0.021068861	0.019297383	0.021068861
β2	-0.000142936	5.38299E-06	-26.55334755	1.63279E-56	-0.000153579	-0.000132294	-0.000153579	-0.000132294
β3	3.44926E-07	1.75379E-08	19.66744699	4.04901E-42	3.10253E-07	3.796E-07	3.10253E-07	3.796E-07

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.993622433
R Square	0.987285538
Adjusted R Square	0.987013086
Standard Error	0.029478386
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.446702681	3.148900894	3623.69457	1.8856E-132
Residual	140	0.121656535	0.000868975		
Total	143	9.568359216			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.297270516	0.009906628	30.00723517	7.63744E-63	0.27768458	0.316856451	0.27768458	0.316856451
β1	0.020126228	0.000437194	46.03497443	1.9664E-86	0.019261872	0.020990585	0.019261872	0.020990585
β2	-0.000143079	5.25304E-06	-27.23739215	8.23219E-58	-0.000153465	-0.000132693	-0.000153465	-0.000132693
β3	3.45557E-07	1.71145E-08	20.19080817	2.6538E-43	3.1172E-07	3.79393E-07	3.1172E-07	3.79393E-07

West Coast Region:

Regression Statistics	
Multiple R	0.993362569
R Square	0.986769193
Adjusted R Square	0.986485676
Standard Error	0.030158697
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.496912448	3.165637483	3480.455028	3.0585E-131
Residual	140	0.127336582	0.000909547		
Total	143	9.62424903			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.297702178	0.010135256	29.37293095	1.01194E-61	0.277664233	0.317740124	0.277664233	0.317740124
β1	0.020091425	0.000447284	44.91872099	4.92225E-85	0.019207121	0.02097573	0.019207121	0.02097573
β2	-0.000142627	5.37427E-06	-26.53879345	1.74092E-56	-0.000153252	-0.000132001	-0.000153252	-0.000132001
β3	3.44597E-07	1.75095E-08	19.68054067	3.78057E-42	3.0998E-07	3.79214E-07	3.0998E-07	3.79214E-07

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.993744864
R Square	0.987528854
Adjusted R Square	0.987261615
Standard Error	0.029293844
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.513146663	3.171048888	3695.304354	4.8762E-133
Residual	140	0.1201381	0.000858129		
Total	143	9.633284764			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.292784596	0.00984461	29.74059899	2.25193E-62	0.273321274	0.312247919	0.273321274	0.312247919
β1	0.020415818	0.000434457	46.99153447	1.31433E-87	0.019556872	0.021274763	0.019556872	0.021274763
β2	-0.000146385	5.22015E-06	-28.04230529	2.6131E-59	-0.000156706	-0.000136065	-0.000156706	-0.000136065
β3	3.5579E-07	1.70074E-08	20.91972526	6.3186E-45	3.22166E-07	3.89415E-07	3.22166E-07	3.89415E-07

Drilling and Completion Costs for Natural Gas

The 2004 – 2007 JAS data was used to calculate the equation for vertical drilling and completion costs for natural gas. The data was analyzed at a regional level. The independent variable was depth. Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. The method of estimation used was ordinary least squares. The form of the equation is given below.

$$\text{Drilling Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}2)$$

where Drilling Cost = DWC_W

β0 = GAS_DWCK

β1 = GAS_DWCA

β2 = GAS_DWCB

β3 = GAS_DWCC

from equations 2-24 and 2-25 in Chapter 2.

Northeast Region:

Regression Statistics	
Multiple R	0.837701882
R Square	0.701744444
Adjusted R Square	0.694887994
Standard Error	1199562.042
Observations	90

ANOVA

	df	SS	MS	F	Significance F
Regression	2	2.94547E+14	1.47274E+14	102.3480792	1.39509E-23
Residual	87	1.25189E+14	1.43895E+12		
Total	89	4.19736E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	197454.5012	290676.607	0.679292714	0.498755704	-380296.7183	775205.7207	-380296.7183	775205.7207
β1	19.31146768	128.263698	0.150560665	0.880670823	-235.6265154	274.2494508	-235.6265154	274.2494508
β2	0.040120878	0.009974857	4.022200679	0.000122494	0.020294769	0.059946987	0.020294769	0.059946987

Gulf Coast Region:

Regression Statistics	
Multiple R	0.842706997
R Square	0.710155083
Adjusted R Square	0.708248209
Standard Error	2573551.438
Observations	307

ANOVA

	df	SS	MS	F	Significance F
Regression	2	4.93318E+15	2.46659E+15	372.4183744	1.77494E-82
Residual	304	2.01344E+15	6.62317E+12		
Total	306	6.94662E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	318882.7578	272026.272	1.172249855	0.242014577	-216410.0169	854175.5325	-216410.0169	854175.5325
β2	0.019032113	0.008289474	2.295937192	0.022359763	0.002720101	0.035344125	0.002720101	0.035344125
β3	1.12638E-06	4.6744E-07	2.409676918	0.016560642	2.06552E-07	2.04621E-06	2.06552E-07	2.04621E-06

Mid-Continent Region:

Regression Statistics	
Multiple R	0.92348831
R Square	0.852830659
Adjusted R Square	0.850494637
Standard Error	1309841.335
Observations	129

ANOVA

	df	SS	MS	F	Significance F
Regression	2	1.25272E+15	6.26359E+14	365.0782904	3.73674E-53
Residual	126	2.16176E+14	1.71568E+12		
Total	128	1.46889E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	355178.8049	240917.4549	1.47427593	0.142901467	-121589.7497	831947.3594	-121589.7497	831947.3594
β1	54.21184769	45.96361807	1.17945127	0.240440741	-36.74880003	145.1724954	-36.74880003	145.1724954
β3	1.20269E-06	1.12352E-07	10.70467954	2.04711E-19	9.80347E-07	1.42503E-06	9.80347E-07	1.42503E-06

Southwest Region:

Regression Statistics	
Multiple R	0.915492169
R Square	0.838125912
Adjusted R Square	0.834866702
Standard Error	1386872.99
Observations	153

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	1.48386E+15	4.94618E+14	257.1561693	1.088E-58
Residual	149	2.86589E+14	1.92342E+12		
Total	152	1.77044E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	91618.176	571133.886	0.160414534	0.872771817	-1036949.89	1220186.242	-1036949.89	1220186.242
β1	376.1968481	269.4896391	1.395960339	0.164802951	-156.3182212	908.7119175	-156.3182212	908.7119175
β2	-0.062403125	0.034837969	-1.791238896	0.075284827	-0.131243411	0.00643716	-0.131243411	0.00643716
β3	5.03882E-06	1.29778E-06	3.88265606	0.000154832	2.4744E-06	7.60325E-06	2.4744E-06	7.60325E-06

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.936745489
R Square	0.877492112
Adjusted R Square	0.87539796
Standard Error	2403080.549
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	4.83951E+15	2.41976E+15	419.0202716	4.54566E-54
Residual	117	6.75651E+14	5.7748E+12		
Total	119	5.51516E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	219733.2637	346024.9678	0.635021412	0.526654367	-465551.0299	905017.5572	-465551.0299	905017.5572
β2	0.032265399	0.013130355	2.457313594	0.015464796	0.00626142	0.058269377	0.00626142	0.058269377
β3	2.6019E-06	7.88034E-07	3.301759413	0.001274492	1.04124E-06	4.16256E-06	1.04124E-06	4.16256E-06

West Coast Region:

Regression Statistics	
Multiple R	0.901854712
R Square	0.813341922
Adjusted R Square	0.795564962
Standard Error	494573.0787
Observations	24

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2.23824E+13	1.11912E+13	45.75258814	2.21815E-08
Residual	21	5.13665E+12	2.44603E+11		
Total	23	2.75191E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	385532.8938	215673.5911	1.787575808	0.088286514	-62984.89058	834050.6782	-62984.89058	834050.6782
β2	0.01799366	0.016370041	1.099182335	0.284130777	-0.016049704	0.052037025	-0.016049704	0.052037025
β3	1.01127E-06	1.49488E-06	0.676491268	0.506112235	-2.0975E-06	4.12005E-06	-2.0975E-06	4.12005E-06

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.856130745
R Square	0.732959853
Adjusted R Square	0.706255838
Standard Error	2157271.229
Observations	23

ANOVA

	df	SS	MS	F	Significance F
Regression	2	2.55472E+14	1.27736E+14	27.44755272	1.84402E-06
Residual	20	9.30764E+13	4.65382E+12		
Total	22	3.48548E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	267619.9291	1118552.942	0.239255487	0.813342236	-2065640.615	2600880.473	-2065640.615	2600880.473
β1	30.61609506	550.5220307	0.055612843	0.956202055	-1117.752735	1178.984925	-1117.752735	1178.984925
β2	0.049406678	0.035529716	1.390573371	0.179635875	-0.024707012	0.123520367	-0.024707012	0.123520367

Drilling and Completion Cost for Gas - Cost Adjustment Factor

The cost adjustment factor for vertical drilling and completion costs for gas was calculated using JAS data through 2007. The initial cost was normalized at various prices from \$1 to \$20 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$5 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Gas Price} + \beta 2 * \text{Gas Price}^2 + \beta 3 * \text{Gas Price}^3$$

Northeast Region:

Regression Statistics	
Multiple R	0.988234523
R Square	0.976607472
Adjusted R Square	0.976106203
Standard Error	0.03924461
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.001833192	3.000611064	1948.272332	6.4218E-114
Residual	140	0.215619522	0.001540139		
Total	143	9.217452714			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.315932281	0.013188706	23.95476038	2.2494E-51	0.289857502	0.34200706	0.289857502	0.34200706
β1	0.195760743	0.005820373	33.63371152	6.11526E-69	0.184253553	0.207267932	0.184253553	0.207267932
β2	-0.013906425	0.000699337	-19.88514708	1.29788E-42	-0.015289053	-0.012523798	-0.015289053	-0.012523798
β3	0.000336178	2.27846E-05	14.75458424	2.61104E-30	0.000291131	0.000381224	0.000291131	0.000381224

Gulf Coast Region:

Regression Statistics	
Multiple R	0.976776879
R Square	0.954093072
Adjusted R Square	0.953109352
Standard Error	0.051120145
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	7.60369517	2.534565057	969.8828784	1.98947E-93
Residual	140	0.365857688	0.002613269		
Total	143	7.969552858			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.343645899	0.017179647	20.00308313	7.02495E-43	0.309680816	0.377610983	0.309680816	0.377610983
β1	0.190338822	0.007581635	25.10524794	1.08342E-53	0.175349523	0.205328121	0.175349523	0.205328121
β2	-0.013965513	0.000910959	-15.33056399	9.3847E-32	-0.015766527	-0.012164498	-0.015766527	-0.012164498
β3	0.000342962	2.96793E-05	11.55560459	4.15963E-22	0.000284285	0.00040164	0.000284285	0.00040164

Mid-continent Region:

Regression Statistics	
Multiple R	0.973577019
R Square	0.947852212
Adjusted R Square	0.94673476
Standard Error	0.058882142
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.822668656	2.940889552	848.2258794	1.4872E-89
Residual	140	0.485394925	0.003467107		
Total	143	9.308063582			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309185338	0.019788175	15.62475232	1.738E-32	0.270063053	0.348307623	0.270063053	0.348307623
β1	0.019036286	0.000873282	21.79856116	7.62464E-47	0.017309761	0.020762811	0.017309761	0.020762811
β2	-0.000123667	1.04928E-05	-11.78593913	1.05461E-22	-0.000144412	-0.000102922	-0.000144412	-0.000102922
β3	2.60516E-07	3.41858E-08	7.620611936	3.45556E-12	1.92929E-07	3.28104E-07	1.92929E-07	3.28104E-07

Southwest Region:

Regression Statistics	
Multiple R	0.966438524
R Square	0.934003421
Adjusted R Square	0.932589209
Standard Error	0.06631093
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.712149531	2.904049844	660.4406967	2.13407E-82
Residual	140	0.615599523	0.004397139		
Total	143	9.327749054			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.323862308	0.022284725	14.53292844	9.46565E-30	0.279804211	0.367920404	0.279804211	0.367920404
β1	0.193832047	0.009834582	19.70923084	3.2532E-42	0.174388551	0.213275544	0.174388551	0.213275544
β2	-0.013820723	0.001181658	-11.69604336	1.80171E-22	-0.016156924	-0.011484522	-0.016156924	-0.011484522
β3	0.000334693	3.84988E-05	8.693602923	8.44808E-15	0.000258579	0.000410807	0.000258579	0.000410807

Rocky Mountains Region:

Regression Statistics	
Multiple R	0.985593617
R Square	0.971394777
Adjusted R Square	0.970781808
Standard Error	0.0421446
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.444274294	2.814758098	1584.737059	8.3614E-108
Residual	140	0.248663418	0.001776167		
Total	143	8.692937712			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.32536782	0.014163288	22.97261928	2.42535E-49	0.29736624	0.353369401	0.29736624	0.353369401
β1	0.194045615	0.006250471	31.04496067	1.21348E-64	0.181688099	0.206403131	0.181688099	0.206403131
β2	-0.01396687	0.000751015	-18.59732564	1.18529E-39	-0.015451667	-0.012482073	-0.015451667	-0.012482073
β3	0.000339698	2.44683E-05	13.88318297	4.22503E-28	0.000291323	0.000388073	0.000291323	0.000388073

West Coast Region:

Regression Statistics	
Multiple R	0.994143406
R Square	0.988321112
Adjusted R Square	0.98807085
Standard Error	0.026802603
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.510960152	2.836986717	3949.147599	4.9307E-135
Residual	140	0.100573131	0.00071838		
Total	143	8.611533284			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.325917293	0.009007393	36.18330938	6.29717E-73	0.308109194	0.343725393	0.308109194	0.343725393
β1	0.193657091	0.003975097	48.71757347	1.12458E-89	0.185798111	0.201516072	0.185798111	0.201516072
β2	-0.013893214	0.000477621	-29.08835053	3.2685E-61	-0.014837497	-0.012948932	-0.014837497	-0.012948932
β3	0.000337413	1.5561E-05	21.68318808	1.35414E-46	0.000306648	0.000368178	0.000306648	0.000368178

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.970035104
R Square	0.940968103
Adjusted R Square	0.939703134
Standard Error	0.057035843
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	7.259587116	2.419862372	743.8663996	8.71707E-86
Residual	140	0.455432229	0.003253087		
Total	143	7.715019345			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.352772153	0.0191677	18.40451098	3.34838E-39	0.31487658	0.390667726	0.31487658	0.390667726
β1	0.189510541	0.008458993	22.40344064	3.85701E-48	0.172786658	0.206234423	0.172786658	0.206234423
β2	-0.014060192	0.001016376	-13.83364754	5.65155E-28	-0.016069622	-0.012050761	-0.016069622	-0.012050761
β3	0.000347364	3.31138E-05	10.49000322	2.34854E-19	0.000281896	0.000412832	0.000281896	0.000412832

Drilling and Completion Costs for Dryholes

The 2004 – 2007 JAS data was used to calculate the equation for vertical drilling and completion costs for dryholes. The data was analyzed at a regional level. The independent variable was depth. Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. The method of estimation used was ordinary least squares. The form of the equation is given bellow.

$$\text{Drilling Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \quad (2.B\text{-}3)$$

where Drilling Cost = DWC_W

β0 = DRY_DWCK

β1 = DRY_DWCA

β2 = DRY_DWCB

β3 = DRY_DWCC

from equations 2-19 and 2-20 in Chapter 2.

Northeast Region:

Regression Statistics	
Multiple R	0.913345218
R Square	0.834199487
Adjusted R Square	0.828851084
Standard Error	1018952.27
Observations	97

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	4.85819E+14	1.6194E+14	155.9716777	3.64706E-36
Residual	93	9.65585E+13	1.03826E+12		
Total	96	5.82378E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	170557.6447	323739.1839	0.526836581	0.599561475	-472323.5706	813438.8601	-472323.5706	813438.8601
β1	256.9930321	233.0025772	1.102962187	0.272889552	-205.7034453	719.6895095	-205.7034453	719.6895095
β2	-0.043428533	0.043117602	-1.007211224	0.31644672	-0.129051459	0.042194394	-0.129051459	0.042194394
β3	5.9031E-06	2.11581E-06	2.789995653	0.006394574	1.70153E-06	1.01047E-05	1.70153E-06	1.01047E-05

Gulf Coast Region:

Regression Statistics	
Multiple R	0.868545327
R Square	0.754370985
Adjusted R Square	0.752096642
Standard Error	2529468.051
Observations	328

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6.36662E+15	2.12221E+15	331.6874692	2.10256E-98
Residual	324	2.07302E+15	6.39821E+12		
Total	327	8.43964E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	118790.7619	515360.6337	0.230500264	0.81784853	-895084.76	1132666.284	-895084.76	1132666.284
β1	126.2333724	241.1698405	0.523421055	0.601039076	-348.2231187	600.6898634	-348.2231187	600.6898634
β2	-0.001057252	0.0294162	-0.035941139	0.971351426	-0.058928115	0.056813612	-0.058928115	0.056813612
β3	2.32104E-06	1.0194E-06	2.276864977	0.02344596	3.15558E-07	4.32653E-06	3.15558E-07	4.32653E-06

Mid-Continent Region:

Regression Statistics	
Multiple R	0.80373002
R Square	0.645981944
Adjusted R Square	0.636056204
Standard Error	904657.9939
Observations	111

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1.59789E+14	5.32631E+13	65.08149035	5.0095E-24
Residual	107	8.75695E+13	8.18406E+11		
Total	110	2.47359E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	163849.8824	309404.7345	0.529564884	0.597510699	-449508.8999	777208.6646	-449508.8999	777208.6646
β1	17.95111978	155.7546455	0.115252548	0.908460959	-290.8142902	326.7165297	-290.8142902	326.7165297
β2	0.022715716	0.021144885	1.074288957	0.285109837	-0.019201551	0.064632983	-0.019201551	0.064632983
β3	-3.50301E-07	7.90957E-07	-0.442882115	0.658745077	-1.91828E-06	1.21768E-06	-1.91828E-06	1.21768E-06

Southwest Region:

Regression Statistics	
Multiple R	0.916003396
R Square	0.839062222
Adjusted R Square	0.835290243
Standard Error	734795.4183
Observations	132

ANOVA

	df	SS	MS	F	Significance F
Regression	3	3.60312E+14	1.20104E+14	222.4461445	1.40193E-50
Residual	128	6.91103E+13	5.39924E+11		
Total	131	4.29423E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	22628.66985	252562.1046	0.089596457	0.928747942	-477108.2352	522365.5749	-477108.2352	522365.5749
β1	262.7649266	164.1391792	1.600866581	0.111871702	-62.01224262	587.5420958	-62.01224262	587.5420958
β2	-0.064989728	0.029352301	-2.21412721	0.02859032	-0.123068227	-0.006911229	-0.123068227	-0.006911229
β3	6.52693E-06	1.49073E-06	4.378340081	2.46095E-05	3.57727E-06	9.4766E-06	3.57727E-06	9.4766E-06

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.908263682
R Square	0.824942917
Adjusted R Square	0.821295894
Standard Error	1868691.311
Observations	99

ANOVA

	df	SS	MS	F	Significance F
Regression	2	1.57976E+15	7.89879E+14	226.1962739	4.70571E-37
Residual	96	3.35233E+14	3.49201E+12		
Total	98	1.91499E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	288056.5506	314517.8483	0.915867103	0.362031526	-336256.4285	912369.5298	-336256.4285	912369.5298
β2	0.018141347	0.017298438	1.048727458	0.296936644	-0.01619578	0.052478474	-0.01619578	0.052478474
β3	3.85847E-06	1.27201E-06	3.033362592	0.003110773	1.33355E-06	6.3834E-06	1.33355E-06	6.3834E-06

West Coast Region:

Regression Statistics	
Multiple R	0.853182771
R Square	0.727920841
Adjusted R Square	0.707514904
Standard Error	907740.218
Observations	44

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.81804E+13	2.93935E+13	35.67201271	2.18647E-11
Residual	40	3.29597E+13	8.23992E+11		
Total	43	1.2114E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	106996.0572	512960.104	0.208585534	0.835830348	-929734.9747	1143727.089	-929734.9747	1143727.089
β1	687.3095347	329.4149478	2.086455212	0.043357214	21.53709715	1353.081972	21.53709715	1353.081972
β2	-0.15898723	0.058188911	-2.732259905	0.009317504	-0.276591406	-0.041383054	-0.276591406	-0.041383054
β3	1.14978E-05	2.91968E-06	3.938046272	0.000320309	5.59694E-06	1.73987E-05	5.59694E-06	1.73987E-05

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.841621294
R Square	0.708326403
Adjusted R Square	0.687977082
Standard Error	2155533.512
Observations	47

ANOVA

	df	SS	MS	F	Significance F
Regression	3	4.85193E+14	1.61731E+14	34.80835607	1.41404E-11
Residual	43	1.99792E+14	4.64632E+12		
Total	46	6.84985E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	122507.9534	1373015.289	0.089225484	0.929317007	-2646441.235	2891457.142	-2646441.235	2891457.142
β1	345.4371452	801.6324436	0.430917122	0.668681154	-1271.20873	1962.08302	-1271.20873	1962.08302
β2	-0.014734575	0.126273194	-0.11668807	0.907650548	-0.269388738	0.239919588	-0.269388738	0.239919588
β3	3.23748E-06	5.69952E-06	0.568026219	0.572971531	-8.2567E-06	1.47317E-05	-8.2567E-06	1.47317E-05

Drilling and Completion Cost for Dry - Cost Adjustment Factor

The cost adjustment factor for vertical drilling and completion costs for dryholes was calculated using JAS data through 2007. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Northeast Region:

Regression Statistics	
Multiple R	0.994846264
R Square	0.989719089
Adjusted R Square	0.989498783
Standard Error	0.026930376
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.774469405	3.258156468	4492.489925	6.5663E-139
Residual	140	0.101534319	0.000725245		
Total	143	9.876003725			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.290689859	0.009050333	32.11924425	1.85582E-66	0.272796865	0.308582854	0.272796865	0.308582854
β1	0.020261651	0.000399405	50.72962235	5.26469E-92	0.019472006	0.021051296	0.019472006	0.021051296
β2	-0.000143294	4.79898E-06	-29.85918012	1.391E-62	-0.000152782	-0.000133806	-0.000152782	-0.000133806
β3	3.45487E-07	1.56352E-08	22.09672004	1.74153E-47	3.14575E-07	3.76399E-07	3.14575E-07	3.76399E-07

Gulf Coast Region:

Regression Statistics	
Multiple R	0.993347128
R Square	0.986738516
Adjusted R Square	0.986454342
Standard Error	0.031666016
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.44539464	3.481798214	3472.296057	3.5967E-131
Residual	140	0.140383119	0.001002737		
Total	143	10.58577776			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.277940175	0.010641812	26.11774938	1.12431E-55	0.256900742	0.298979608	0.256900742	0.298979608
β1	0.020529977	0.000469639	43.71437232	1.71946E-83	0.019601475	0.021458479	0.019601475	0.021458479
β2	-0.000143466	5.64287E-06	-25.42421447	2.53682E-54	-0.000154622	-0.000132309	-0.000154622	-0.000132309
β3	3.43878E-07	1.83846E-08	18.70465533	6.66256E-40	3.07531E-07	3.80226E-07	3.07531E-07	3.80226E-07

Mid-Continent Region:

Regression Statistics	
Multiple R	0.984006541
R Square	0.968268874
Adjusted R Square	0.967588921
Standard Error	0.048034262
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.856909541	3.285636514	1424.023848	1.1869E-104
Residual	140	0.323020652	0.00230729		
Total	143	10.17993019			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.289971748	0.016142592	17.96314638	3.67032E-38	0.258056977	0.32188652	0.258056977	0.32188652
β1	0.020266191	0.000712397	28.44789972	4.71502E-60	0.018857744	0.021674637	0.018857744	0.021674637
β2	-0.000143007	8.55969E-06	-16.70702184	3.8001E-35	-0.00015993	-0.000126084	-0.00015993	-0.000126084
β3	3.44462E-07	2.78877E-08	12.35174476	3.63124E-24	2.89326E-07	3.99597E-07	2.89326E-07	3.99597E-07

Southwest Region:

Regression Statistics	
Multiple R	0.993309425
R Square	0.986663613
Adjusted R Square	0.986377833
Standard Error	0.031536315
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.30103457	3.43367819	3452.531986	5.3348E-131
Residual	140	0.139235479	0.000994539		
Total	143	10.44027005			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.278136296	0.010598224	26.24367047	6.42248E-56	0.257183038	0.299089554	0.257183038	0.299089554
β1	0.020381432	0.000467715	43.57656163	2.59609E-83	0.019456733	0.02130613	0.019456733	0.02130613
β2	-0.00014194	5.61976E-06	-25.25738215	5.41293E-54	-0.000153051	-0.00013083	-0.000153051	-0.00013083
β3	3.38578E-07	1.83093E-08	18.49210412	2.08785E-39	3.0238E-07	3.74777E-07	3.0238E-07	3.74777E-07

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.9949703
R Square	0.9899658
Adjusted R Squar	0.9897508
Standard Error	0.0266287
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.79418782	3.2647293	4604.11	1.199E-139
Residual	140	0.09927263	0.0007091		
Total	143	9.89346045			

	Coefficients	Standard Erro	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.2902761	0.00894897	32.436833	5.504E-67	0.27258355	0.3079687	0.2725836	0.3079687
β1	0.0202676	0.00039493	51.319418	1.133E-92	0.01948684	0.0210484	0.0194868	0.0210484
β2	-0.0001433	4.7452E-06	-30.194046	3.595E-63	-0.0001527	-0.0001339	-0.0001527	-0.0001339
β3	3.454E-07	1.546E-08	22.340389	5.253E-48	3.1482E-07	3.76E-07	3.148E-07	3.76E-07

West Coast Region:

Regression Statistics	
Multiple R	0.992483684
R Square	0.985023864
Adjusted R Square	0.984702946
Standard Error	0.032081124
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.477071064	3.159023688	3069.401798	1.7868E-127
Residual	140	0.144087788	0.001029198		
Total	143	9.621158852			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.297817853	0.010781315	27.62351924	1.55941E-58	0.276502615	0.31913309	0.276502615	0.31913309
β1	0.020092432	0.000475796	42.22913162	1.54864E-81	0.019151759	0.021033105	0.019151759	0.021033105
β2	-0.000142719	5.71684E-06	-24.96465108	2.06229E-53	-0.000154021	-0.000131416	-0.000154021	-0.000131416
β3	3.44906E-07	1.86256E-08	18.51777816	1.81824E-39	3.08082E-07	3.81729E-07	3.08082E-07	3.81729E-07

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.993525621
R Square	0.987093159
Adjusted R Square	0.986816584
Standard Error	0.031179889
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.40915184	3.469717279	3568.986978	5.3943E-132
Residual	140	0.136105966	0.000972185		
Total	143	10.5452578			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.281568556	0.010478442	26.87122338	4.04796E-57	0.260852113	0.302284998	0.260852113	0.302284998
β1	0.020437386	0.000462429	44.19569691	4.11395E-84	0.019523138	0.021351633	0.019523138	0.021351633
β2	-0.000142671	5.55624E-06	-25.67758357	8.07391E-55	-0.000153656	-0.000131686	-0.000153656	-0.000131686
β3	3.42012E-07	1.81024E-08	18.89319503	2.43032E-40	3.06223E-07	3.77802E-07	3.06223E-07	3.77802E-07

Drilling and Completion Costs for Horizontal Wells

The costs of horizontal drilling for crude oil, natural gas, and dryholes are based upon cost estimates developed for the Department of Energy's Comprehensive Oil and Gas Analysis Model. The form of the equation is as follows:

$$Cost = \beta0 + \beta1 * Depth^2 + \beta2 * Depth^2 * nlat + \beta3 * Depth^2 * nlat * latlen \qquad (2.B\text{-}4)$$

Where, nlat is the number of laterals per pattern and latlen is the length of those laterals. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Regression Statistics	
Multiple R	1
R Square	1
Adjusted R Square	1
Standard Error	3.12352E-12
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	147,510,801.46	49,170,267.15	5.04E+30	0.00
Residual	116	0.00	0.00		
Total	119	147,510,801.46			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	172.88	4.37E-13	3.95E+14	0.00	172.88	172.88	172.88	172.88
β1	8.07E-06	8.81E-21	9.16E+14	0.00	8.07E-06	8.07E-06	8.07E-06	8.07E-06
β2	1.15E-06	3.20E-21	3.60E+14	0.00	1.15E-06	1.15E-06	1.15E-06	1.15E-06
β3	9.22E-10	1.48E-24	6.23E+14	0.00	9.22E-10	9.22E-10	9.22E-10	9.22E-10

Cost to Equip a Primary Producer

The cost to equip a primary producer was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). The cost to equip a primary producer is equal to the grand total cost minus the producing equipment subtotal. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \quad (2.B\text{-}5)$$

where Cost = NPR_W

β0 = NPRK

β1 = NPRA

β2 = NPRB

β3 = NPRC

from equation 2-21 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS regions 2 and 4:

Regression Statistics	
Multiple R	0.921
R Square	0.849
Adjusted R Square	0.697
Standard Error	621.17
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2,163,010.81	2,163,010.81	5.61	0.254415
Residual	1	385,858.01	385,858.01		
Total	2	2,548,868.81			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	51,315.4034	760.7805	67.4510	0.0094	41,648.8117	60,981.9952	41,648.8117	60,981.9952
β1	0.3404	0.1438	2.3676	0.2544	-1.4864	2.1672	-1.4864	2.1672

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.995
R Square	0.990
Adjusted R Square	0.981
Standard Error	1,193.14
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	145,656,740.81	145,656,740.81	102.32	0.06
Residual	1	1,423,576.87	1,423,576.87		
Total	2	147,080,317.68			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	45,821.717	1,461.289	31.357	0.020	27,254.360	64,389.074	27,254.360	64,389.074
β1	2.793	0.276	10.115	0.063	-0.716	6.302	-0.716	6.302

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9998
R Square	0.9995
Adjusted R Square	0.9990
Standard Error	224.46
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	105,460,601.42	105,460,601.42	2,093.17	0.01
Residual	1	50,383.23	50,383.23		
Total	2	105,510,984.64			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	62,709.378	274.909	228.110	0.003	59,216.346	66,202.411	59,216.346	66,202.411
β1	2.377	0.052	45.751	0.014	1.717	3.037	1.717	3.037

West Coast, applied to OLOGSS regions 6:

Regression Statistics	
Multiple R	0.9095
R Square	0.8272
Adjusted R Square	0.7408
Standard Error	2,257.74
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	48,812,671.60	48,812,671.60	9.58	0.09
Residual	2	10,194,785.98	5,097,392.99		
Total	3	59,007,457.58			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	106,959.788	2,219.144	48.199	0.000	97,411.576	116,508.001	97,411.576	116,508.001
β1	0.910	0.294	3.095	0.090	-0.355	2.174	-0.355	2.174

Cost to Equip a Primary Producer - Cost Adjustment Factor

The cost adjustment factor for the cost to equip a primary producer was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994410537
R Square	0.988852316
Adjusted R Square	0.988613437
Standard Error	0.026443679
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.683975313	2.894658438	4139.554242	1.896E-136
Residual	140	0.097897541	0.000699268		
Total	143	8.781872854			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.31969898	0.008886772	35.97470366	1.30857E-72	0.302129355	0.337268604	0.302129355	0.337268604
β1	0.01951727	0.000392187	49.76527469	6.72079E-91	0.018741896	0.020292644	0.018741896	0.020292644
β2	-0.000139868	4.71225E-06	-29.68181785	2.86084E-62	-0.000149185	-0.000130552	-0.000149185	-0.000130552
β3	3.39583E-07	1.53527E-08	22.11882142	1.56166E-47	3.0923E-07	3.69936E-07	3.0923E-07	3.69936E-07

South Texas, Applied to OLOGSS Regions 2:

Regression Statistics	
Multiple R	0.994238324
R Square	0.988509845
Adjusted R Square	0.988263627
Standard Error	0.026795052
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.647535343	2.882511781	4014.781289	1.5764E-135
Residual	140	0.100516472	0.000717975		
Total	143	8.748051814			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.320349357	0.009004856	35.57517997	5.36201E-72	0.302546274	0.33815244	0.302546274	0.33815244
β1	0.019534419	0.000397398	49.15583863	3.4382E-90	0.018748742	0.020320096	0.018748742	0.020320096
β2	-0.000140302	4.77487E-06	-29.38344709	9.69188E-62	-0.000149742	-0.000130862	-0.000149742	-0.000130862
β3	3.41163E-07	1.55567E-08	21.9303828	3.96368E-47	3.10407E-07	3.7192E-07	3.10407E-07	3.7192E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994150147
R Square	0.988334515
Adjusted R Square	0.98808454
Standard Error	0.026852947
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.552894405	2.850964802	3953.738464	4.5499E-135
Residual	140	0.100951309	0.000721081		
Total	143	8.653845713			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.322462264	0.009024312	35.73261409	3.07114E-72	0.304620715	0.340303814	0.304620715	0.340303814
β1	0.019485751	0.000398256	48.9276546	6.36471E-90	0.018698377	0.020273125	0.018698377	0.020273125
β2	-0.000140187	4.78518E-06	-29.29612329	1.3875E-61	-0.000149648	-0.000130727	-0.000149648	-0.000130727
β3	3.41143E-07	1.55903E-08	21.88177944	5.04366E-47	3.1032E-07	3.71966E-07	3.1032E-07	3.71966E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.99407047
R Square	0.988176099
Adjusted R Square	0.98792273
Standard Error	0.026915882
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.476544403	2.825514801	3900.141282	1.1696E-134
Residual	140	0.101425062	0.000724465		
Total	143	8.577969465			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.324216701	0.009045462	35.84302113	2.08007E-72	0.306333337	0.342100066	0.306333337	0.342100066
β1	0.019446254	0.00039919	48.71430741	1.1346E-89	0.018657034	0.020235473	0.018657034	0.020235473
β2	-0.000140099	4.7964E-06	-29.20929598	1.98384E-61	-0.000149582	-0.000130617	-0.000149582	-0.000130617
β3	3.41157E-07	1.56268E-08	21.8315363	6.47229E-47	3.10262E-07	3.72052E-07	3.10262E-07	3.72052E-07

West Coast, Applied to OLOGSS Regions 6:

Regression Statistics	
Multiple R	0.994533252
R Square	0.98909639
Adjusted R Square	0.988862741
Standard Error	0.026511278
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.92601569	2.975338563	4233.261276	4.0262E-137
Residual	140	0.098398698	0.000702848		
Total	143	9.024414388			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.314154129	0.008909489	35.26062149	1.64245E-71	0.296539591	0.331768668	0.296539591	0.331768668
β1	0.019671366	0.000393189	50.03029541	3.32321E-91	0.01889401	0.020448722	0.01889401	0.020448722
β2	-0.000140565	4.7243E-06	-29.75371308	2.13494E-62	-0.000149906	-0.000131225	-0.000149906	-0.000131225
β3	3.40966E-07	1.53919E-08	22.15229024	1.32417E-47	3.10535E-07	3.71397E-07	3.10535E-07	3.71397E-07

Primary Workover Costs

Primary workover costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Workover costs consist of the total of workover rig services, remedial services, equipment repair and other costs. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \qquad (2.B\text{-}6)$$

where Cost = WRK_W
β0 = WRKK
β1 = WRKA
β2 = WRKB
β3 = WRKC
from equation 2-22 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.9839
R Square	0.9681
Adjusted R Square	0.9363
Standard Error	1,034.20
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	32,508,694.98	32,508,694.98	30.39	0.11
Residual	1	1,069,571.02	1,069,571.02		
Total	2	33,578,265.99			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	1,736.081	1,266.632	1.371	0.401	-14,357.935	17,830.097	-14,357.935	17,830.097
β1	1.320	0.239	5.513	0.114	-1.722	4.361	-1.722	4.361

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.7558
R Square	0.5713
Adjusted R Square	0.4284
Standard Error	978.19
Observations	5

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3,824,956.55	3,824,956.55	4.00	0.14
Residual	3	2,870,570.06	956,856.69		
Total	4	6,695,526.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	1,949.479	1,043.913	1.867	0.159	-1,372.720	5,271.678	-1,372.720	5,271.678
β1	0.364	0.182	1.999	0.139	-0.216	0.945	-0.216	0.945

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.9762
R Square	0.9530
Adjusted R Square	0.9060
Standard Error	2,405.79
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	117,342,912.53	117,342,912.53	20.27	0.14
Residual	1	5,787,839.96	5,787,839.96		
Total	2	123,130,752.49			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-2,738.051	2,946.483	-0.929	0.523	-40,176.502	34,700.400	-40,176.502	34,700.400
β1	2.507	0.557	4.503	0.139	-4.568	9.582	-4.568	9.582

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.9898
R Square	0.9798
Adjusted R Square	0.9595
Standard Error	747.71
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	27,074,389.00	27,074,389.00	48.43	0.09
Residual	1	559,069.20	559,069.20		
Total	2	27,633,458.19			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	389.821	915.753	0.426	0.744	-11,245.876	12,025.518	-11,245.876	12,025.518
β1	1.204	0.173	6.959	0.091	-0.995	3.403	-0.995	3.403

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.9985
R Square	0.9969
Adjusted R Square	0.9939
Standard Error	273.2
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	24,387,852.65	24,387,852.65	326.67	0.04
Residual	1	74,656.68	74,656.68		
Total	2	24,462,509.32			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	1,326.648	334.642	3.964	0.157	-2,925.359	5,578.654	-2,925.359	5,578.654
β1	1.143	0.063	18.074	0.035	0.339	1.947	0.339	1.947

Primary Workover Costs - Cost Adjustment Factor

The cost adjustment factor for primary workover costs was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994400682
R Square	0.988832717
Adjusted R Square	0.988593418
Standard Error	0.02694729
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.001886791	3.00062893	4132.207262	2.1441E-136
Residual	140	0.101661902	0.000726156		
Total	143	9.103548693			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312539579	0.009056017	34.51181296	2.43715E-70	0.294635346	0.330443812	0.294635346	0.330443812
β1	0.019707131	0.000399656	49.31028624	2.26953E-90	0.018916991	0.020497272	0.018916991	0.020497272
β2	-0.000140623	4.802E-06	-29.28428914	1.45673E-61	-0.000150117	-0.000131129	-0.000150117	-0.000131129
β3	3.40873E-07	1.5645E-08	21.78791181	8.03921E-47	3.09942E-07	3.71804E-07	3.09942E-07	3.71804E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994469633
R Square	0.98896985
Adjusted R Square	0.98873349
Standard Error	0.026569939
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.861572267	2.953857422	4184.161269	9.0291E-137
Residual	140	0.098834632	0.000705962		
Total	143	8.960406899			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.315903453	0.008929203	35.37868321	1.07799E-71	0.298249938	0.333556967	0.298249938	0.333556967
β1	0.019629392	0.000394059	49.81332121	5.91373E-91	0.018850316	0.020408468	0.018850316	0.020408468
β2	-0.000140391	4.73475E-06	-29.65123432	3.24065E-62	-0.000149752	-0.00013103	-0.000149752	-0.00013103
β3	3.40702E-07	1.5426E-08	22.08625878	1.83379E-47	3.10204E-07	3.712E-07	3.10204E-07	3.712E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994481853
R Square	0.988994155
Adjusted R Square	0.988758316
Standard Error	0.026752366
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.003736634	3.001245545	4193.504662	7.7373E-137
Residual	140	0.100196473	0.000715689		
Total	143	9.103933107			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312750341	0.00899051	34.78671677	9.00562E-71	0.294975619	0.330525063	0.294975619	0.330525063
β1	0.019699787	0.000396765	49.6510621	9.11345E-91	0.018915362	0.020484212	0.018915362	0.020484212
β2	-0.000140541	4.76726E-06	-29.480463	6.51147E-62	-0.000149966	-0.000131116	-0.000149966	-0.000131116
β3	3.40661E-07	1.55319E-08	21.93302302	3.91217E-47	3.09954E-07	3.71368E-07	3.09954E-07	3.71368E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.949969362
R Square	0.902441789
Adjusted R Square	0.900351256
Standard Error	0.090634678
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.63829925	3.546099748	431.6802228	1.59892E-70
Residual	140	1.150050289	0.008214645		
Total	143	11.78834953			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.281549378	0.030459064	9.243533578	3.55063E-16	0.221330174	0.341768582	0.221330174	0.341768582
β1	0.020360006	0.001344204	15.14651492	2.70699E-31	0.017702443	0.02301757	0.017702443	0.02301757
β2	-0.000140998	1.61511E-05	-8.729925387	6.86299E-15	-0.000172929	-0.000109066	-0.000172929	-0.000109066
β3	3.36972E-07	5.26206E-08	6.403797584	2.14112E-09	2.32938E-07	4.41006E-07	2.32938E-07	4.41006E-07

West Coast, Applied to OLOGSS Regions 6:

Regression Statistics	
Multiple R	0.994382746
R Square	0.988797046
Adjusted R Square	0.988556983
Standard Error	0.026729324
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.828330392	2.942776797	4118.9013	2.6803E-136
Residual	140	0.100023944	0.000714457		
Total	143	8.928354335			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.316566704	0.008982767	35.24155917	1.75819E-71	0.298807292	0.334326116	0.298807292	0.334326116
β1	0.019613748	0.000396423	49.47682536	1.45204E-90	0.018829998	0.020397497	0.018829998	0.020397497
β2	-0.000140368	4.76315E-06	-29.46957335	6.80842E-62	-0.000149785	-0.000130951	-0.000149785	-0.000130951
β3	3.40752E-07	1.55185E-08	21.95777375	3.46083E-47	3.10071E-07	3.71433E-07	3.10071E-07	3.71433E-07

Cost to Convert a Primary to Secondary Well

The cost to convert a primary to secondary well was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Conversion costs for a primary to a secondary well consist of pumping equipment, rods and pumps, and supply wells. The data was analyzed on a regional level. The secondary operations costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta 0 + \beta 1 * Depth + \beta 2 * Depth^2 + \beta 3 * Depth^3 \tag{2.B-7}$$

where Cost = PSW_W

β0 = PSWK

β1 = PSWA

β2 = PSWB

β3 = PSWC

from equation 2-35 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.999208
R Square	0.998416
Adjusted R Square	0.996832
Standard Error	9968.98
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	62,643,414,406.49	62,643,414,406.49	630.34	0.03
Residual	1	99,380,639.94	99,380,639.94		
Total	2	62,742,795,046.43			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-115.557	12,209.462	-0.009	0.994	-155,250.815	155,019.701	-155,250.815	155,019.701
β1	57.930	2.307	25.107	0.025	28.612	87.248	28.612	87.248

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.996760
R Square	0.993531
Adjusted R Square	0.991914
Standard Error	16909.05
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	175,651,490,230.16	175,651,490,230.16	614.35	0.00
Residual	4	1,143,664,392.16	285,916,098.04		
Total	5	176,795,154,622.33			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-10,733.7	14,643.670	-0.733	0.504	-51,391.169	29,923.692	-51,391.169	29,923.692
β1	68.593	2.767	24.786	0.000	60.909	76.276	60.909	76.276

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.999830
R Square	0.999660
Adjusted R Square	0.999320
Standard Error	4047.64
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	48,164,743,341	48,164,743,341	2,939.86	0.01
Residual	1	16,383,350	16,383,350		
Total	2	48,181,126,691			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-32,919.3	4,957.320	-6.641	0.095	-95,907.768	30,069.148	-95,907.768	30,069.148
β1	50.796	0.937	54.220	0.012	38.893	62.700	38.893	62.700

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	1.00000
R Square	0.99999
Adjusted R Square	0.99999
Standard Error	552.23
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	44,056,261,873.48	44,056,261,873.48	144,469.3	0.00
Residual	1	304,952.52	304,952.52		
Total	2	44,056,566,825.99			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	-25,175.8	676.335	-37.224	0.017	-33,769.389	-16,582.166	-33,769.389	-16,582.166
β1	48.581	0.128	380.091	0.002	46.957	50.205	46.957	50.205

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.999970
R Square	0.999941
Adjusted R Square	0.999882
Standard Error	2317.03
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	90,641,249,203.56	90,641,249,203.56	16,883.5	0.00
Residual	1	5,368,613.99	5,368,613.99		
Total	2	90,646,617,817.55			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	-47,775.5	2,837.767	-16.836	0.038	-83,832.597	-11,718.412	-83,832.597	-11,718.412
β1	69.683	0.536	129.937	0.005	62.869	76.498	62.869	76.498

Cost to Convert a Primary to Secondary Well - Cost Adjustment Factor

The cost adjustment factor for the cost to convert a primary to secondary well was calculated using data through 2008 from the Cost and Indices data base provided EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994210954
R Square	0.988455421
Adjusted R Square	0.988208037
Standard Error	0.032636269
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.7675639	4.255854635	3995.634681	2.1943E-135
Residual	140	0.149117649	0.001065126		
Total	143	12.91668155			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.386844292	0.010967879	35.27065592	1.58464E-71	0.365160206	0.408528378	0.365160206	0.408528378
β1	0.023681158	0.000484029	48.92509151	6.40898E-90	0.022724207	0.024638109	0.022724207	0.024638109
β2	-0.000169861	5.81577E-06	-29.207048	2.00231E-61	-0.00018136	-0.000158363	-0.00018136	-0.000158363
β3	4.12786E-07	1.89479E-08	21.78527316	8.14539E-47	3.75325E-07	4.50247E-07	3.75325E-07	4.50247E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.965088368
R Square	0.931395559
Adjusted R Square	0.929925464
Standard Error	0.077579302
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	11.43935934	3.813119781	633.5614039	3.21194E-81
Residual	140	0.842596733	0.006018548		
Total	143	12.28195608			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.403458143	0.02607162	15.4749932	4.09637E-32	0.351913151	0.455003136	0.351913151	0.455003136
β1	0.023030837	0.00115058	20.01672737	6.5441E-43	0.02075608	0.025305595	0.02075608	0.025305595
β2	-0.000167719	1.38246E-05	-12.13194348	1.34316E-23	-0.000195051	-0.000140387	-0.000195051	-0.000140387
β3	4.10451E-07	4.5041E-08	9.112847285	7.57277E-16	3.21403E-07	4.995E-07	3.21403E-07	4.995E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.930983781
R Square	0.866730801
Adjusted R Square	0.863875032
Standard Error	0.115716747
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.19199867	4.063999556	303.5017657	4.7623E-61
Residual	140	1.874651162	0.013390365		
Total	143	14.06664983			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.39376891	0.038888247	10.12565341	2.02535E-18	0.316884758	0.470653063	0.316884758	0.470653063
β1	0.023409924	0.001716196	13.6405849	1.759E-27	0.020016911	0.026802936	0.020016911	0.026802936
β2	-0.000169013	2.06207E-05	-8.196307608	1.41642E-13	-0.000209782	-0.000128245	-0.000209782	-0.000128245
β3	4.11972E-07	6.71828E-08	6.132113904	8.35519E-09	2.79148E-07	5.44796E-07	2.79148E-07	5.44796E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.930623851
R Square	0.866060752
Adjusted R Square	0.863190626
Standard Error	0.117705607
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	12.5418858	4.180628599	301.7500036	6.76263E-61
Residual	140	1.939645392	0.01385461		
Total	143	14.48153119			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.363067907	0.039556632	9.178433366	5.17966E-16	0.284862323	0.441273492	0.284862323	0.441273492
β1	0.024133277	0.001745693	13.82446554	5.96478E-28	0.020681947	0.027584606	0.020681947	0.027584606
β2	-0.000175479	2.09751E-05	-8.366057262	5.44112E-14	-0.000216948	-0.00013401	-0.000216948	-0.00013401
β3	4.28328E-07	6.83375E-08	6.267838182	4.24825E-09	2.93221E-07	5.63435E-07	2.93221E-07	5.63435E-07

West Coast, Applied to OLOGSS Regions 6:

Regression Statistics	
Multiple R	0.930187107
R Square	0.865248054
Adjusted R Square	0.862360512
Standard Error	0.116469162
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	12.19426209	4.06475403	299.6486777	1.03233E-60
Residual	140	1.899109212	0.013565066		
Total	143	14.0933713			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.393797507	0.039141107	10.06097011	2.96602E-18	0.316413437	0.471181577	0.316413437	0.471181577
β1	0.023409194	0.001727356	13.55204156	2.96327E-27	0.01999412	0.026824269	0.01999412	0.026824269
β2	-0.000168995	2.07548E-05	-8.142483197	1.91588E-13	-0.000210029	-0.000127962	-0.000210029	-0.000127962
β3	4.11911E-07	6.76196E-08	6.091589926	1.02095E-08	2.78223E-07	5.45599E-07	2.78223E-07	5.45599E-07

Cost to Convert a Producer to an Injector

The cost to convert a production well to an injection well was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Conversion costs for a production to an injection well consist of tubing replacement, distribution lines and header costs. The data was analyzed on a regional level. The secondary operation costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}8)$$

where Cost = PSI_W

β0 = PSIK

β1 = PSIA

β2 = PSIB

β3 = PSIC

from equation 2-36 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.994714
R Square	0.989456
Adjusted R Square	0.978913
Standard Error	3204.94
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	963,939,802.16	963,939,802.16	93.84	0.07
Residual	1	10,271,635.04	10,271,635.04		
Total	2	974,211,437.20			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	11,129.3	3,925.233	2.835	0.216	-38,745.259	61,003.937	-38,745.259	61,003.937
β1	7.186	0.742	9.687	0.065	-2.239	16.611	-2.239	16.611

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.988716
R Square	0.977560
Adjusted R Square	0.971950
Standard Error	4435.41
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3,428,080,322.21	3,428,080,322.21	174.25	0.00
Residual	4	78,691,571.93	19,672,892.98		
Total	5	3,506,771,894.14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	24,640.6	3,841.181	6.415	0.003	13,975.763	35,305.462	13,975.763	35,305.462
β1	9.582	0.726	13.201	0.000	7.567	11.598	7.567	11.598

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.993556
R Square	0.987154
Adjusted R Square	0.974307
Standard Error	3770.13
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,092,230,257.01	1,092,230,257.01	76.84	0.07
Residual	1	14,213,917.83	14,213,917.83		
Total	2	1,106,444,174.85			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	9,356.411	4,617.453	2.026	0.292	-49,313.648	68,026.469	-49,313.648	68,026.469
β1	7.649	0.873	8.766	0.072	-3.438	18.737	-3.438	18.737

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.995436
R Square	0.990893
Adjusted R Square	0.981785
Standard Error	3266.39
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	1,160,837,008.65	1,160,837,008.65	108.80	0.06
Residual	1	10,669,310.85	10,669,310.85		
Total	2	1,171,506,319.50			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	24,054.311	4,000.496	6.013	0.105	-26,776.589	74,885.211	-26,776.589	74,885.211
β1	7.886	0.756	10.431	0.061	-1.720	17.492	-1.720	17.492

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.998023
R Square	0.996050
Adjusted R Square	0.992100
Standard Error	2903.09
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	2,125,305,559.02	2,125,305,559.02	252.17	0.04
Residual	1	8,427,914.12	8,427,914.12		
Total	2	2,133,733,473.15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	11,125.846	3,555.541	3.129	0.197	-34,051.391	56,303.083	-34,051.391	56,303.083
β1	10.670	0.672	15.880	0.040	2.133	19.208	2.133	19.208

Cost to Convert a Producer to an Injector - Cost Adjustment Factor

The cost adjustment factor for the cost to convert a producer to an injector was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.99432304
R Square	0.988678308
Adjusted R Square	0.9884357
Standard Error	0.026700062
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.715578807	2.905192936	4075.214275	5.6063E-136
Residual	140	0.099805061	0.000712893		
Total	143	8.815383869			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.318906241	0.008972933	35.54091476	6.05506E-72	0.301166271	0.336646211	0.301166271	0.336646211
β1	0.019564167	0.000395989	49.40584281	1.75621E-90	0.018781276	0.020347059	0.018781276	0.020347059
β2	-0.000140323	4.75794E-06	-29.49235038	6.20216E-62	-0.00014973	-0.000130916	-0.00014973	-0.000130916
β3	3.40991E-07	1.55015E-08	21.9972576	2.84657E-47	3.10343E-07	3.71638E-07	3.10343E-07	3.71638E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994644466
R Square	0.989317613
Adjusted R Square	0.989088705
Standard Error	0.025871111
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.678119686	2.892706562	4321.895164	9.5896E-138
Residual	140	0.093704013	0.000669314		
Total	143	8.771823699			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.316208692	0.008694352	36.36943685	3.2883E-73	0.299019491	0.333397893	0.299019491	0.333397893
β1	0.01974618	0.000383695	51.46325116	7.80746E-93	0.018987594	0.020504765	0.018987594	0.020504765
β2	-0.000142963	4.61022E-06	-31.00997536	1.39298E-64	-0.000152077	-0.000133848	-0.000152077	-0.000133848
β3	3.4991E-07	1.50202E-08	23.29589312	5.12956E-50	3.20214E-07	3.79606E-07	3.20214E-07	3.79606E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994321224
R Square	0.988674696
Adjusted R Square	0.988432011
Standard Error	0.026701262
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.713550392	2.904516797	4073.899599	5.7329E-136
Residual	140	0.099814034	0.000712957		
Total	143	8.813364425			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.318954549	0.008973336	35.54470092	5.97425E-72	0.301213782	0.336695317	0.301213782	0.336695317
β1	0.019563077	0.000396007	49.40087012	1.77978E-90	0.018780151	0.020346004	0.018780151	0.020346004
β2	-0.000140319	4.75815E-06	-29.49027089	6.25518E-62	-0.000149726	-0.000130912	-0.000149726	-0.000130912
β3	3.40985E-07	1.55022E-08	21.99592439	2.8654E-47	3.10337E-07	3.71634E-07	3.10337E-07	3.71634E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.994322163
R Square	0.988676564
Adjusted R Square	0.988433919
Standard Error	0.026700311
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.714383869	2.904794623	4074.579587	5.667E-136
Residual	140	0.099806922	0.000712907		
Total	143	8.814190792			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.318944377	0.008973016	35.54483358	5.97144E-72	0.301204242	0.336684512	0.301204242	0.336684512
β1	0.019563226	0.000395993	49.40300666	1.76961E-90	0.018780328	0.020346125	0.018780328	0.020346125
β2	-0.000140317	4.75798E-06	-29.49085218	6.24031E-62	-0.000149724	-0.00013091	-0.000149724	-0.00013091
β3	3.40976E-07	1.55017E-08	21.99610109	2.8629E-47	3.10328E-07	3.71624E-07	3.10328E-07	3.71624E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.994041278
R Square	0.988118061
Adjusted R Square	0.987863448
Standard Error	0.027307293
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.681741816	2.893913939	3880.863048	1.6477E-134
Residual	140	0.104396354	0.000745688		
Total	143	8.78613817			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.31978359	0.009177001	34.84619603	7.26644E-71	0.301640166	0.337927015	0.301640166	0.337927015
β1	0.019531533	0.000404995	48.22662865	4.2897E-89	0.018730837	0.02033223	0.018730837	0.02033223
β2	-0.000140299	4.86615E-06	-28.83170535	9.47626E-61	-0.00014992	-0.000130679	-0.00014992	-0.000130679
β3	3.41616E-07	1.58541E-08	21.54755837	2.66581E-46	3.10272E-07	3.7296E-07	3.10272E-07	3.7296E-07

Facilities Upgrade Costs for Crude Oil Wells

The facilities upgrading cost for secondary oil wells was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Facilities costs for a secondary oil well consist of plant costs and electrical costs. The data was analyzed on a regional level. The secondary operation costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \qquad (2.B\text{-}9)$$

where Cost = FAC_W
β0 = FACUPK
β1 = FACUPA
β2 = FACUPB
β3 = FACUPC
from equation 2-23 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.947660
R Square	0.898060
Adjusted R Square	0.796120
Standard Error	6332.38
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	353,260,332.81	353,260,332.81	8.81	0.21
Residual	1	40,099,063.51	40,099,063.51		
Total	2	393,359,396.32			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	20,711.761	7,755.553	2.671	0.228	-77,831.455	119,254.977	-77,831.455	119,254.977
β1	4.350	1.466	2.968	0.207	-14.273	22.973	-14.273	22.973

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.942744
R Square	0.888767
Adjusted R Square	0.851689
Standard Error	6699.62
Observations	5

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,075,905,796.72	1,075,905,796.72	23.97	0.02
Residual	3	134,654,629.89	44,884,876.63		
Total	4	1,210,560,426.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	33,665.6	7,149.747	4.709	0.018	10,911.921	56,419.338	10,911.921	56,419.338
β1	6.112	1.248	4.896	0.016	2.139	10.085	2.139	10.085

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.950784
R Square	0.903990
Adjusted R Square	0.807980
Standard Error	6705.31
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	423,335,427.35	423,335,427.35	9.42	0.20
Residual	1	44,961,183.70	44,961,183.70		
Total	2	468,296,611.04			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	19,032.550	8,212.294	2.318	0.259	-85,314.094	123,379.194	-85,314.094	123,379.194
β1	4.762	1.552	3.068	0.201	-14.957	24.482	-14.957	24.482

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.90132
R Square	0.81238
Adjusted R Square	0.62476
Standard Error	8,531
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	315,132,483.91	315,132,483.91	4.33	0.29
Residual	1	72,780,134.04	72,780,134.04		
Total	2	387,912,617.95			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	37,322	10,448.454	3.572	0.174	-95,437.589	170,081.677	-95,437.589	170,081.677
β1	4.109	1.975	2.081	0.285	-20.980	29.198	-20.980	29.198

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.974616
R Square	0.949876
Adjusted R Square	0.899753
Standard Error	6,765.5
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	867,401,274.79	867,401,274.79	18.95	0.14
Residual	1	45,771,551.83	45,771,551.83		
Total	2	913,172,826.62			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	23,746.6	8,285.972	2.866	0.214	-81,536.251	129,029.354	-81,536.251	129,029.354
β1	6.817	1.566	4.353	0.144	-13.080	26.713	-13.080	26.713

Facilities Upgrade Costs for Oil Wells - Cost Adjustment Factor

The cost adjustment factor for facilities upgrade costs for oil wells was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994217662
R Square	0.988468759
Adjusted R Square	0.988221661
Standard Error	0.026793237
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.615198936	2.871732979	4000.310244	2.0238E-135
Residual	140	0.100502859	0.000717878		
Total	143	8.715701795			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.321111529	0.009004246	35.66223488	3.93903E-72	0.303309651	0.338913406	0.303309651	0.338913406
β1	0.019515262	0.000397371	49.11095778	3.88014E-90	0.018729638	0.020300885	0.018729638	0.020300885
β2	-0.00014023	4.77454E-06	-29.37035185	1.02272E-61	-0.00014967	-0.00013079	-0.00014967	-0.00013079
β3	3.4105E-07	1.55556E-08	21.92459665	4.07897E-47	3.10296E-07	3.71805E-07	3.10296E-07	3.71805E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994217643
R Square	0.988468723
Adjusted R Square	0.988221624
Standard Error	0.026793755
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.615504692	2.871834897	4000.297521	2.0242E-135
Residual	140	0.100506746	0.000717905		
Total	143	8.716011438			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.321091731	0.00900442	35.65934676	3.9795E-72	0.30328951	0.338893953	0.30328951	0.338893953
β1	0.019515756	0.000397379	49.11125155	3.87707E-90	0.018730117	0.020301395	0.018730117	0.020301395
β2	-0.000140234	4.77464E-06	-29.37065243	1.02145E-61	-0.000149674	-0.000130794	-0.000149674	-0.000130794
β3	3.41061E-07	1.55559E-08	21.92486379	4.07357E-47	3.10306E-07	3.71816E-07	3.10306E-07	3.71816E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994881087
R Square	0.989788377
Adjusted R Square	0.989569556
Standard Error	0.025598703
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.892246941	2.964082314	4523.289171	4.0903E-139
Residual	140	0.0917411	0.000655294		
Total	143	8.983988041			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.305413562	0.008602806	35.50162345	6.96151E-72	0.288405354	0.32242177	0.288405354	0.32242177
β1	0.019922983	0.000379655	52.47659224	5.82045E-94	0.019172385	0.020673581	0.019172385	0.020673581
β2	-0.000143398	4.56168E-06	-31.43544891	2.62249E-65	-0.000152417	-0.00013438	-0.000152417	-0.00013438
β3	3.48664E-07	1.48621E-08	23.45993713	2.3433E-50	3.1928E-07	3.78047E-07	3.1928E-07	3.78047E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994218671
R Square	0.988470767
Adjusted R Square	0.988223712
Standard Error	0.026793398
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.616820316	2.872273439	4001.015021	1.9993E-135
Residual	140	0.100504067	0.000717886		
Total	143	8.717324383			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.32105584	0.0090043	35.65583598	4.02926E-72	0.303253856	0.338857825	0.303253856	0.338857825
β1	0.019516684	0.000397373	49.11424236	3.84594E-90	0.018731056	0.020302312	0.018731056	0.020302312
β2	-0.00014024	4.77457E-06	-29.37236101	1.01431E-61	-0.00014968	-0.000130801	-0.00014968	-0.000130801
β3	3.4108E-07	1.55557E-08	21.92639924	4.0427E-47	3.10326E-07	3.71835E-07	3.10326E-07	3.71835E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.994682968
R Square	0.989394207
Adjusted R Square	0.98916694
Standard Error	0.025883453
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.749810675	2.916603558	4353.444193	5.7951E-138
Residual	140	0.093793438	0.000669953		
Total	143	8.843604113			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.320979436	0.0086985	36.90055074	5.22609E-74	0.303782034	0.338176837	0.303782034	0.338176837
β1	0.019117244	0.000383878	49.80033838	6.12166E-91	0.018358297	0.019876191	0.018358297	0.019876191
β2	-0.000134273	4.61242E-06	-29.11109331	2.97526E-61	-0.000143392	-0.000125154	-0.000143392	-0.000125154
β3	3.21003E-07	1.50274E-08	21.36117616	6.78747E-46	2.91293E-07	3.50713E-07	2.91293E-07	3.50713E-07

Natural Gas Well Facilities Costs

Natural gas well facilities costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Well facilities costs consist of flowlines and connections, production package costs, and storage tank costs. The data was analyzed on a regional level. The independent variables are depth and Q, which is the flow rate of natural gas in million cubic feet. The form of the equation is given below:

$$Cost = \beta 0 + \beta 1 * Depth + \beta 2 * Q + \beta 3 * Depth * Q \qquad (2.B\text{-}10)$$

where Cost = FWC_W
β0 = FACGK
β1 = FACGA
β2 = FACGB
β3 = FACGC
Q = PEAKDAILY_RATE
from equation 2-28 in Chapter 2.

Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9834
R Square	0.9672
Adjusted R Square	0.9562
Standard Error	5,820.26
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8,982,542,532.41	2,994,180,844.14	88.39	0.00
Residual	9	304,879,039.45	33,875,448.83		
Total	12	9,287,421,571.86			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,477.41	4,694.03	0.74	0.48	-7,141.24	14,096.05	-7,141.24	14,096.05
β1	5.04	0.40	12.51	0.00	4.13	5.95	4.13	5.95
β2	63.87	19.07	3.35	0.01	20.72	107.02	20.72	107.02
β3	0.00	0.00	-3.18	0.01	-0.01	0.00	-0.01	0.00

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.9621
R Square	0.9256
Adjusted R Square	0.9139
Standard Error	8,279.60
Observations	23

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	16,213,052,116.02	5,404,350,705.34	78.84	0.00
Residual	19	1,302,484,315.70	68,551,806.09		
Total	22	17,515,536,431.72			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	14,960.60	4,066.98	3.68	0.00	6,448.31	23,472.90	6,448.31	23,472.90
β1	4.87	0.47	10.34	0.00	3.88	5.85	3.88	5.85
β2	28.49	6.42	4.43	0.00	15.04	41.93	15.04	41.93
β3	0.00	0.00	-3.62	0.00	0.00	0.00	0.00	0.00

Mid-Continent, applied to OLOGSS regions 3 and 6:

Regression Statistics	
Multiple R	0.9917
R Square	0.9835
Adjusted R Square	0.9765
Standard Error	4,030.43
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6,796,663,629.62	2,265,554,543.21	139.47	0.00
Residual	7	113,710,456.60	16,244,350.94		
Total	10	6,910,374,086.22			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	10,185.92	3,441.41	2.96	0.02	2,048.29	18,323.54	2,048.29	18,323.54
β1	4.51	0.29	15.71	0.00	3.83	5.18	3.83	5.18
β2	55.38	14.05	3.94	0.01	22.16	88.60	22.16	88.60
β3	0.00	0.00	-3.78	0.01	-0.01	0.00	-0.01	0.00

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9594
R Square	0.9204
Adjusted R Square	0.8806
Standard Error	7,894.95
Observations	10

ANOVA

	df	SS	MS	F	Significance F
Regression	3	4,322,988,996.06	1,440,996,332.02	23.12	0.00
Residual	6	373,981,660.54	62,330,276.76		
Total	9	4,696,970,656.60			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	7,922.48	8,200.06	0.97	0.37	-12,142.36	27,987.31	-12,142.36	27,987.31
β1	6.51	1.14	5.71	0.00	3.72	9.30	3.72	9.30
β2	89.26	28.88	3.09	0.02	18.59	159.94	18.59	159.94
β3	-0.01	0.00	-2.77	0.03	-0.01	0.00	-0.01	0.00

Gas Well Facilities Costs - Cost Adjustment Factor

The cost adjustment factor for gas well facilities cost was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $1 to $20 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $5 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Gas Price} + \beta 2 * \text{Gas Price}^2 + \beta 3 * \text{Gas Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.995733794
R Square	0.991485789
Adjusted R Square	0.991303341
Standard Error	0.025214281
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.3648558	3.454951933	5434.365566	1.2179E-144
Residual	140	0.089006392	0.00063576		
Total	143	10.45386219			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.276309237	0.008473615	32.60818851	2.86747E-67	0.259556445	0.293062029	0.259556445	0.293062029
β1	0.20599743	0.003739533	55.08640551	8.89871E-97	0.198604173	0.213390688	0.198604173	0.213390688
β2	-0.014457925	0.000449317	-32.17753015	1.48375E-66	-0.015346249	-0.0135696	-0.015346249	-0.0135696
β3	0.000347281	1.46389E-05	23.72318475	6.71084E-51	0.000318339	0.000376223	0.000318339	0.000376223

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.99551629
R Square	0.991052684
Adjusted R Square	0.990860956
Standard Error	0.025683748
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.22936837	3.409789455	5169.05027	3.9254E-143
Residual	140	0.092351689	0.000659655		
Total	143	10.32172006			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.280854163	0.008631386	32.5387085	3.73403E-67	0.263789449	0.297918878	0.263789449	0.297918878
β1	0.204879431	0.00380916	53.78599024	2.17161E-95	0.197348518	0.212410345	0.197348518	0.212410345
β2	-0.014391989	0.000457683	-31.44530093	2.52353E-65	-0.015296854	-0.013487125	-0.015296854	-0.013487125
β3	0.000345909	1.49115E-05	23.19753012	8.21832E-50	0.000316428	0.00037539	0.000316428	0.00037539

Mid-Continent, Applied to OLOGSS Regions 3 and 6:

Regression Statistics	
Multiple R	0.995511275
R Square	0.991042698
Adjusted R Square	0.990850756
Standard Error	0.025690919
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.22356717	3.407855722	5163.235345	4.2442E-143
Residual	140	0.092403264	0.000660023		
Total	143	10.31597043			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.280965064	0.008633796	32.5424714	3.68097E-67	0.263895586	0.298034543	0.263895586	0.298034543
β1	0.204856879	0.003810223	53.7650588	2.28751E-95	0.197323863	0.212389895	0.197323863	0.212389895
β2	-0.014391983	0.000457811	-31.43650889	2.61165E-65	-0.0152971	-0.013486865	-0.0152971	-0.013486865
β3	0.000345929	1.49156E-05	23.19242282	8.42221E-50	0.00031644	0.000375418	0.00031644	0.000375418

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.995452965
R Square	0.990926606
Adjusted R Square	0.990732176
Standard Error	0.025768075
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.15228252	3.384094173	5096.576002	1.0453E-142
Residual	140	0.092959113	0.000663994		
Total	143	10.24524163			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.282511839	0.008659725	32.62364879	2.704E-67	0.265391097	0.299632581	0.265391097	0.299632581
β1	0.204502598	0.003821666	53.51137044	4.3021E-95	0.196946958	0.212058237	0.196946958	0.212058237
β2	-0.014382652	0.000459186	-31.32206064	4.08566E-65	-0.015290487	-0.013474816	-0.015290487	-0.013474816
β3	0.000345898	1.49604E-05	23.12086258	1.18766E-49	0.00031632	0.000375475	0.00031632	0.000375475

Fixed Annual Costs for Crude Oil Wells

The fixed annual cost for crude oil wells was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Fixed annual costs consist of supervision and overhead costs, auto usage costs, operative supplies, labor costs, supplies and services costs, equipment usage and other costs.

The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta 0 + \beta 1 * Depth + \beta 2 * Depth^2 + \beta 3 * Depth^3 \qquad (2.B\text{-}11)$$

where Cost = OMO_W
β0 = OMOK
β1 = OMOA
β2 = OMOB
β3 = OMOC
from equation 2-30 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9895
R Square	0.9792
Adjusted R Square	0.9584
Standard Error	165.6
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,290,021.8	1,290,021.8	47.0	0.1
Residual	1	27,419.5	27,419.5		
Total	2	1,317,441.3			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	6,026.949	202.804	29.718	0.021	3,450.097	8,603.802	3,450.097	8,603.802
β1	0.263	0.038	6.859	0.092	-0.224	0.750	-0.224	0.750

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.8631
R Square	0.7449
Adjusted R Square	0.6811
Standard Error	2,759.2
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	88,902,026.9	88,902,026.9	11.7	0.0
Residual	4	30,452,068.1	7,613,017.0		
Total	5	119,354,095.0			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	7,171.358	2,389.511	3.001	0.040	536.998	13,805.718	536.998	13,805.718
β1	1.543	0.452	3.417	0.027	0.289	2.797	0.289	2.797

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9888
R Square	0.9777
Adjusted R Square	0.9554
Standard Error	325.8
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4,654,650.4	4,654,650.4	43.9	0.1
Residual	1	106,147.3	106,147.3		
Total	2	4,760,797.7			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	5,572.283	399.025	13.965	0.046	502.211	10,642.355	502.211	10,642.355
β1	0.499	0.075	6.622	0.095	-0.459	1.458	-0.459	1.458

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9634
R Square	0.9282
Adjusted R Square	0.8923
Standard Error	455.6
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5,368,949.5	5,368,949.5	25.9	0.0
Residual	2	415,138.5	207,569.2		
Total	3	5,784,088.0			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	6,327.733	447.809	14.130	0.005	4,400.964	8,254.501	4,400.964	8,254.501
β1	0.302	0.059	5.086	0.037	0.046	0.557	0.046	0.557

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9908
R Square	0.9817
Adjusted R Square	0.9725
Standard Error	313.1
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	10,498,366.6	10,498,366.6	107.1	0.0
Residual	2	196,056.3	98,028.2		
Total	3	10,694,422.9			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	5,193.399	307.742	16.876	0.003	3,869.291	6,517.508	3,869.291	6,517.508
β1	0.422	0.041	10.349	0.009	0.246	0.597	0.246	0.597

Fixed Annual Costs for Oil Wells - Cost Adjustment Factor

The cost adjustment factor of the fixed annual cost for oil wells was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994014283
R Square	0.988064394
Adjusted R Square	0.987808631
Standard Error	0.026960479
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.424110153	2.808036718	3863.203308	2.2587E-134
Residual	140	0.101761442	0.000726867		
Total	143	8.525871595			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325522735	0.00906045	35.9278779	1.54278E-72	0.30760974	0.343435731	0.30760974	0.343435731
β1	0.019415379	0.000399851	48.55651174	1.74247E-89	0.018624852	0.020205906	0.018624852	0.020205906
β2	-0.000139999	4.80435E-06	-29.14014276	2.63883E-61	-0.000149498	-0.000130501	-0.000149498	-0.000130501
β3	3.41059E-07	1.56527E-08	21.78917295	7.98896E-47	3.10113E-07	3.72006E-07	3.10113E-07	3.72006E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.972995979
R Square	0.946721175
Adjusted R Square	0.945579485
Standard Error	0.052710031
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6.91165462	2.303884873	829.2285185	6.67464E-89
Residual	140	0.388968632	0.002778347		
Total	143	7.300623252			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.305890757	0.01771395	17.26835352	1.6689E-36	0.270869326	0.340912188	0.270869326	0.340912188
β1	0.019637228	0.000781743	25.11979642	1.01374E-53	0.01809168	0.021182776	0.01809168	0.021182776
β2	-0.000147609	9.39291E-06	-15.71490525	1.03843E-32	-0.000166179	-0.000129038	-0.000166179	-0.000129038
β3	3.60127E-07	3.06024E-08	11.76795581	1.17387E-22	2.99625E-07	4.2063E-07	2.99625E-07	4.2063E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.993998856
R Square	0.988033725
Adjusted R Square	0.987777305
Standard Error	0.02698784
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.419321124	2.806440375	3853.182417	2.7032E-134
Residual	140	0.10196809	0.000728344		
Total	143	8.521289214			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.32545185	0.009069645	35.88363815	1.80273E-72	0.307520675	0.343383025	0.307520675	0.343383025
β1	0.019419103	0.000400257	48.51658921	1.94263E-89	0.018627774	0.020210433	0.018627774	0.020210433
β2	-0.000140059	4.80922E-06	-29.12303298	2.83205E-61	-0.000149567	-0.000130551	-0.000149567	-0.000130551
β3	3.41232E-07	1.56686E-08	21.77807458	8.44228E-47	3.10254E-07	3.72209E-07	3.10254E-07	3.72209E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.977862049
R Square	0.956214186
Adjusted R Square	0.955275919
Standard Error	0.050111949
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	7.677722068	2.559240689	1019.127536	7.26235E-95
Residual	140	0.351569047	0.002511207		
Total	143	8.029291115			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.343679311	0.016840828	20.40750634	8.67459E-44	0.310384089	0.376974533	0.310384089	0.376974533
β1	0.020087054	0.000743211	27.02739293	2.04852E-57	0.018617686	0.021556422	0.018617686	0.021556422
β2	-0.000153877	8.92993E-06	-17.23164844	2.04504E-36	-0.000171532	-0.000136222	-0.000171532	-0.000136222
β3	3.91397E-07	2.9094E-08	13.45286338	5.31787E-27	3.33877E-07	4.48918E-07	3.33877E-07	4.48918E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.993729589
R Square	0.987498496
Adjusted R Square	0.987230606
Standard Error	0.027203598
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.183798235	2.727932745	3686.217436	5.7808E-133
Residual	140	0.103605007	0.000740036		
Total	143	8.287403242			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.330961672	0.009142153	36.20171926	5.90451E-73	0.312887144	0.3490362	0.312887144	0.3490362
β1	0.019295414	0.000403457	47.82521879	1.29343E-88	0.018497758	0.02009307	0.018497758	0.02009307
β2	-0.000139784	4.84767E-06	-28.83529781	9.33567E-61	-0.000149368	-0.0001302	-0.000149368	-0.0001302
β3	3.4128E-07	1.57939E-08	21.60840729	1.96666E-46	3.10055E-07	3.72505E-07	3.10055E-07	3.72505E-07

Fixed Annual Costs for Natural Gas Wells

Fixed annual costs for natural gas wells were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Fixed annual costs consist of the lease equipment costs for natural gas production for a given year. The data was analyzed on a regional level. The independent variables are depth and Q which is the flow rate of natural gas in million cubic feet. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Q + \beta3 * Depth * Q \quad (2.B\text{-}12)$$

where Cost = FOAMG_W
$\beta0$ = OMGK
$\beta1$ = OMGA
$\beta2$ = OMGB
$\beta3$ = OMGC
Q = PEAKDAILY_RATE
from equation 2-29 in Chapter 2.

Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.928
R Square	0.861
Adjusted R Square	0.815
Standard Error	6,471.68
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	2,344,632,468.49	781,544,156.16	18.66	0.00
Residual	9	376,944,241.62	41,882,693.51		
Total	12	2,721,576,710.11			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,450.28	5,219.40	0.85	0.42	-7,356.84	16,257.40	-7,356.84	16,257.40
β1	2.50	0.45	5.58	0.00	1.49	3.51	1.49	3.51
β2	27.65	21.21	1.30	0.22	-20.33	75.63	-20.33	75.63
β3	0.00	0.00	-1.21	0.26	0.00	0.00	0.00	0.00

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.913
R Square	0.834
Adjusted R Square	0.807
Standard Error	6,564.36
Observations	23

ANOVA

	df	SS	MS	F	Significance F
Regression	3	4,100,685,576.61	1,366,895,192.20	31.72	0.00
Residual	19	818,725,806.73	43,090,831.93		
Total	22	4,919,411,383.34			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	11,145.70	3,224.45	3.46	0.00	4,396.85	17,894.55	4,396.85	17,894.55
β1	2.68	0.37	7.17	0.00	1.90	3.46	1.90	3.46
β2	7.67	5.09	1.51	0.15	-2.99	18.33	-2.99	18.33
β3	0.00	0.00	-1.21	0.24	0.00	0.00	0.00	0.00

Mid-Continent, applied to OLOGSS region 3 and 6:

Regression Statistics	
Multiple R	0.934
R Square	0.873
Adjusted R Square	0.830
Standard Error	6,466.88
Observations	13

ANOVA

	df	SS	MS	F	Significance F
Regression	3	2,578,736,610.45	859,578,870.15	20.55	0.00
Residual	9	376,384,484.71	41,820,498.30		
Total	12	2,955,121,095.16			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	8,193.82	5,410.04	1.51	0.16	-4,044.54	20,432.18	-4,044.54	20,432.18
β1	2.75	0.45	6.14	0.00	1.74	3.77	1.74	3.77
β2	21.21	18.04	1.18	0.27	-19.59	62.01	-19.59	62.01
β3	0.00	0.00	-1.12	0.29	0.00	0.00	0.00	0.00

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	0.945
R Square	0.893
Adjusted R Square	0.840
Standard Error	6,104.84
Observations	10

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1,874,387,985.75	624,795,995.25	16.76	0.00
Residual	6	223,614,591.98	37,269,098.66		
Total	9	2,098,002,577.72			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	7,534.86	6,340.77	1.19	0.28	-7,980.45	23,050.17	-7,980.45	23,050.17
β1	3.81	0.88	4.33	0.00	1.66	5.97	1.66	5.97
β2	32.27	22.33	1.44	0.20	-22.38	86.92	-22.38	86.92
β3	0.00	0.00	-1.18	0.28	-0.01	0.00	-0.01	0.00

Fixed Annual Costs for Gas Wells - Cost Adjustment Factor

The cost adjustment factor of the fixed annual cost for gas wells was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $1 to $20 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $5 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Gas Price} + \beta 2 * \text{Gas Price}^2 + \beta 3 * \text{Gas Price}^3$$

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.994836789
R Square	0.989700237
Adjusted R Square	0.989479527
Standard Error	0.029019958
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	11.32916798	3.776389326	4484.181718	7.4647E-139
Residual	140	0.117902114	0.000842158		
Total	143	11.44707009			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.234219858	0.009752567	24.01622716	1.68475E-51	0.21493851	0.253501206	0.21493851	0.253501206
β1	0.216761767	0.004303953	50.36340872	1.37772E-91	0.20825262	0.225270914	0.20825262	0.225270914
β2	-0.015234638	0.000517134	-29.45972427	7.08872E-62	-0.01625704	-0.014212235	-0.01625704	-0.014212235
β3	0.000365319	1.68484E-05	21.68270506	1.3574E-46	0.000332009	0.000398629	0.000332009	0.000398629

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.995657421
R Square	0.991333701
Adjusted R Square	0.991147994
Standard Error	0.02551118
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.42258156	3.474193854	5338.176859	4.2055E-144
Residual	140	0.091114842	0.00065082		
Total	143	10.5136964			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.276966489	0.008573392	32.30535588	9.09319E-67	0.260016432	0.293916546	0.260016432	0.293916546
β1	0.205740933	0.003783566	54.37751691	5.03408E-96	0.198260619	0.213221246	0.198260619	0.213221246
β2	-0.014407802	0.000454608	-31.6927929	9.63037E-66	-0.015306587	-0.013509017	-0.015306587	-0.013509017
β3	0.00034576	1.48113E-05	23.34441529	4.06714E-50	0.000316478	0.000375043	0.000316478	0.000375043

Mid-Continent, Applied to OLOGSS Region 3 and 6:

Regression Statistics	
Multiple R	0.995590124
R Square	0.991199695
Adjusted R Square	0.991011117
Standard Error	0.025596313
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.33109303	3.443697678	5256.179662	1.231E-143
Residual	140	0.091723972	0.000655171		
Total	143	10.42281701			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.278704883	0.008602002	32.40000063	6.33409E-67	0.261698262	0.295711504	0.261698262	0.295711504
β1	0.205373482	0.003796192	54.09986358	9.97995E-96	0.197868206	0.212878758	0.197868206	0.212878758
β2	-0.014404563	0.000456125	-31.58028284	1.49116E-65	-0.015306347	-0.013502779	-0.015306347	-0.013502779
β3	0.000345945	1.48607E-05	23.27919988	5.55628E-50	0.000316565	0.000375325	0.000316565	0.000375325

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.995548929
R Square	0.99111767
Adjusted R Square	0.990927334
Standard Error	0.02564864
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.27673171	3.425577238	5207.209824	2.3566E-143
Residual	140	0.092099383	0.000657853		
Total	143	10.3688311			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.279731342	0.008619588	32.45298388	5.17523E-67	0.262689954	0.296772729	0.262689954	0.296772729
β1	0.205151971	0.003803953	53.93125949	1.51455E-95	0.197631352	0.21267259	0.197631352	0.21267259
β2	-0.014402579	0.000457058	-31.51151347	1.94912E-65	-0.015306207	-0.013498952	-0.015306207	-0.013498952
β3	0.00034606	1.48911E-05	23.23943141	6.72233E-50	0.00031662	0.000375501	0.00031662	0.000375501

Fixed Annual Costs for Secondary Production

The fixed annual cost for secondary oil production was calculated an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). The data was analyzed on a regional level. The secondary operations costs for each region were determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}13)$$

where Cost = OPSEC_W
β0 = OPSECK
β1 = OPSECA
β2 = OPSECB
β3 = OPSECC
from equation 2-31 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9972
R Square	0.9945
Adjusted R Square	0.9890
Standard Error	1,969.67
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	698,746,493.71	698,746,493.71	180.11	0.05
Residual	1	3,879,582.16	3,879,582.16		
Total	2	702,626,075.87			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	30,509.3	2,412.338	12.647	0.050	-142.224	61,160.827	-142.224	61,160.827
β1	6.118	0.456	13.420	0.047	0.326	11.911	0.326	11.911

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.935260
R Square	0.874710
Adjusted R Square	0.843388
Standard Error	8414.07
Observations	6

ANOVA

	df	SS	MS	F	Significance F
Regression	1	1,977,068,663.41	1,977,068,663.41	27.93	0.01
Residual	4	283,186,316.21	70,796,579.05		
Total	5	2,260,254,979.61			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	55,732.7	7,286.799	7.648	0.002	35,501.310	75,964.186	35,501.310	75,964.186
β1	7.277	1.377	5.285	0.006	3.454	11.101	3.454	11.101

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.998942
R Square	0.997884
Adjusted R Square	0.995768
Standard Error	1329.04
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	833,049,989.02	833,049,989.02	471.62	0.03
Residual	1	1,766,354.45	1,766,354.45		
Total	2	834,816,343.47			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	28,208.7	1,627.738	17.330	0.037	7,526.417	48,890.989	7,526.417	48,890.989
β1	6.680	0.308	21.717	0.029	2.772	10.589	2.772	10.589

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.989924
R Square	0.979949
Adjusted R Square	0.959899
Standard Error	3639.10
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	647,242,187.96	647,242,187.96	48.87	0.09
Residual	1	13,243,073.43	13,243,073.43		
Total	2	660,485,261.39			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	53,857.06	4,456.973	12.084	0.053	-2,773.909	110,488.034	-2,773.909	110,488.034
β1	5.888	0.842	6.991	0.090	-4.814	16.591	-4.814	16.591

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.992089
R Square	0.984240
Adjusted R Square	0.968480
Standard Error	5193.40
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,684,438,248.88	1,684,438,248.88	62.45	0.08
Residual	1	26,971,430.96	26,971,430.96		
Total	2	1,711,409,679.84			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	35,893.465	6,360.593	5.643	0.112	-44,925.189	116,712.119	-44,925.189	116,712.119
β1	9.499	1.202	7.903	0.080	-5.774	24.773	-5.774	24.773

Fixed Annual Costs for Secondary Production - Cost Adjustment Factor

The cost adjustment factor of the fixed annual costs for secondary production was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994022382
R Square	0.988080495
Adjusted R Square	0.987825078
Standard Error	0.026956819
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.433336986	2.811112329	3868.484883	2.0551E-134
Residual	140	0.101733815	0.00072667		
Total	143	8.535070802			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325311813	0.00905922	35.90947329	1.646E-72	0.307401249	0.343222377	0.307401249	0.343222377
β1	0.019419982	0.000399797	48.57461816	1.65866E-89	0.018629562	0.020210402	0.018629562	0.020210402
β2	-0.000140009	4.80369E-06	-29.14604996	2.57525E-61	-0.000149506	-0.000130512	-0.000149506	-0.000130512
β3	3.41057E-07	1.56506E-08	21.79195958	7.87903E-47	3.10115E-07	3.71999E-07	3.10115E-07	3.71999E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.993830992
R Square	0.987700041
Adjusted R Square	0.987436471
Standard Error	0.027165964
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.296590955	2.765530318	3747.383987	1.8532E-133
Residual	140	0.103318541	0.00073799		
Total	143	8.399909496			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.321750317	0.009129506	35.24290662	1.74974E-71	0.303700794	0.33979984	0.303700794	0.33979984
β1	0.019369439	0.000402899	48.0752057	6.49862E-89	0.018572887	0.020165992	0.018572887	0.020165992
β2	-0.000140208	4.84096E-06	-28.96291516	5.49447E-61	-0.000149779	-0.000130638	-0.000149779	-0.000130638
β3	3.42483E-07	1.5772E-08	21.71459435	1.15795E-46	3.11301E-07	3.73665E-07	3.11301E-07	3.73665E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994021683
R Square	0.988079106
Adjusted R Square	0.987823658
Standard Error	0.026959706
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.43414809	2.811382697	3868.028528	2.0719E-134
Residual	140	0.101755604	0.000726826		
Total	143	8.535903693			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325281756	0.00906019	35.90231108	1.68802E-72	0.307369274	0.343194238	0.307369274	0.343194238
β1	0.019420568	0.00039984	48.57088177	1.67561E-89	0.018630063	0.020211072	0.018630063	0.020211072
β2	-0.000140009	4.80421E-06	-29.14305099	2.60734E-61	-0.000149507	-0.000130511	-0.000149507	-0.000130511
β3	3.41049E-07	1.56523E-08	21.7891193	7.99109E-47	3.10103E-07	3.71994E-07	3.10103E-07	3.71994E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994023418
R Square	0.988082555
Adjusted R Square	0.987827181
Standard Error	0.026956158
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.434398087	2.811466029	3869.161392	2.0304E-134
Residual	140	0.101728825	0.000726634		
Total	143	8.536126912			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325293493	0.009058998	35.90833165	1.65262E-72	0.307383368	0.343203618	0.307383368	0.343203618
β1	0.019420405	0.000399787	48.57686713	1.64854E-89	0.018630005	0.020210806	0.018630005	0.020210806
β2	-0.000140009	4.80358E-06	-29.14672886	2.56804E-61	-0.000149505	-0.000130512	-0.000149505	-0.000130512
β3	3.41053E-07	1.56502E-08	21.792237	7.86817E-47	3.10111E-07	3.71994E-07	3.10111E-07	3.71994E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.993899019
R Square	0.98783526
Adjusted R Square	0.987574587
Standard Error	0.027222624
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.42499532	2.808331773	3789.557133	8.5487E-134
Residual	140	0.103749972	0.000741071		
Total	143	8.528745292			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.327122709	0.009148547	35.75679345	2.81971E-72	0.30903554	0.345209878	0.30903554	0.345209878
β1	0.019283711	0.000403739	47.76280844	1.53668E-88	0.018485497	0.020081925	0.018485497	0.020081925
β2	-0.000138419	4.85106E-06	-28.53379985	3.28809E-60	-0.00014801	-0.000128828	-0.00014801	-0.000128828
β3	3.36276E-07	1.58049E-08	21.27670912	1.03818E-45	3.05029E-07	3.67523E-07	3.05029E-07	3.67523E-07

Lifting Costs

Lifting costs for crude oil wells were calculated using average an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Lifting costs consist of labor costs for the pumper, chemicals, fuel, power and water costs. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}14)$$

where Cost = OML_W

β0 = OMLK

β1 = OMLA

β2 = OMLB

β3 = OMLC

from equation 2-32 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9994
R Square	0.9988
Adjusted R Square	0.9976
Standard Error	136.7
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	15,852,301	15,852,301	849	0
Residual	1	18,681	18,681		
Total	2	15,870,982			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	7,534.515	167.395	45.010	0.014	5,407.565	9,661.465	5,407.565	9,661.465
β1	0.922	0.032	29.131	0.022	0.520	1.323	0.520	1.323

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.8546
R Square	0.7304
Adjusted R Square	0.6764
Standard Error	2263.5
Observations	7

ANOVA

	df	SS	MS	F	Significance F
Regression	1	69,387,339	69,387,339	14	0
Residual	5	25,617,128	5,123,426		
Total	6	95,004,467			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	11,585.191	1,654.440	7.002	0.001	7,332.324	15,838.058	7,332.324	15,838.058
β1	0.912	0.248	3.680	0.014	0.275	1.549	0.275	1.549

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9997
R Square	0.9995
Adjusted R Square	0.9990
Standard Error	82.0
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	13,261,874	13,261,874	1,972	0
Residual	1	6,726	6,726		
Total	2	13,268,601			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	8,298.339	100.447	82.614	0.008	7,022.045	9,574.634	7,022.045	9,574.634
β1	0.843	0.019	44.403	0.014	0.602	1.084	0.602	1.084

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	1.0000
R Square	1.0000
Adjusted R Square	0.9999
Standard Error	11.5
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	3,979,238	3,979,238	30,138	0
Residual	1	132	132		
Total	2	3,979,370			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	10,137.398	14.073	720.342	0.001	9,958.584	10,316.212	9,958.584	10,316.212
β1	0.462	0.003	173.603	0.004	0.428	0.495	0.428	0.495

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9969
R Square	0.9937
Adjusted R Square	0.9874
Standard Error	1134.3
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	203,349,853	203,349,853	158	0
Residual	1	1,286,583	1,286,583		
Total	2	204,636,436			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	5,147.313	1,389.199	3.705	0.168	-12,504.063	22,798.689	-12,504.063	22,798.689
β1	3.301	0.263	12.572	0.051	-0.035	6.636	-0.035	6.636

Lifting Costs - Cost Adjustment Factor

The cost adjustment factor for lifting costs for was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.994419415
R Square	0.988869972
Adjusted R Square	0.988631472
Standard Error	0.026749137
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.900010642	2.966670214	4146.195026	1.6969E-136
Residual	140	0.100172285	0.000715516		
Total	143	9.000182927			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.314447949	0.008989425	34.97976138	4.49274E-71	0.296675373	0.332220525	0.296675373	0.332220525
β1	0.019667961	0.000396717	49.57683267	1.11119E-90	0.018883631	0.020452291	0.018883631	0.020452291
β2	-0.000140635	4.76668E-06	-29.50377541	5.91881E-62	-0.000150059	-0.000131211	-0.000150059	-0.000131211
β3	3.41221E-07	1.553E-08	21.97170644	3.23018E-47	3.10517E-07	3.71924E-07	3.10517E-07	3.71924E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994725637
R Square	0.989479094
Adjusted R Square	0.989253646
Standard Error	0.026400955
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.177423888	3.059141296	4388.946164	3.302E-138
Residual	140	0.097581462	0.00069701		
Total	143	9.275005349			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.307250046	0.008872414	34.62981435	1.58839E-70	0.289708807	0.324791284	0.289708807	0.324791284
β1	0.019843369	0.000391553	50.6786443	6.01683E-92	0.019069248	0.020617491	0.019069248	0.020617491
β2	-0.000141338	4.70464E-06	-30.04217841	6.6318E-63	-0.000150639	-0.000132036	-0.000150639	-0.000132036
β3	3.42235E-07	1.53279E-08	22.32765206	5.59173E-48	3.11931E-07	3.72539E-07	3.11931E-07	3.72539E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994625665
R Square	0.989280214
Adjusted R Square	0.989050504
Standard Error	0.026521235
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.087590035	3.029196678	4306.653909	1.2247E-137
Residual	140	0.09847263	0.000703376		
Total	143	9.186062664			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309274775	0.008912836	34.69993005	1.23231E-70	0.291653621	0.32689593	0.291653621	0.32689593
β1	0.019797213	0.000393337	50.33145871	1.49879E-91	0.019019565	0.020574861	0.019019565	0.020574861
β2	-0.000141221	4.72607E-06	-29.88132995	1.27149E-62	-0.000150565	-0.000131878	-0.000150565	-0.000131878
β3	3.42202E-07	1.53977E-08	22.22423366	9.29272E-48	3.1176E-07	3.72644E-07	3.1176E-07	3.72644E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994686146
R Square	0.98940053
Adjusted R Square	0.989173398
Standard Error	0.026467032
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.154328871	3.051442957	4356.069182	5.5581E-138
Residual	140	0.09807053	0.000700504		
Total	143	9.252399401			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.307664081	0.00889462	34.58990756	1.8356E-70	0.29007894	0.325249222	0.29007894	0.325249222
β1	0.019836272	0.000392533	50.53404116	8.79346E-92	0.019060214	0.020612331	0.019060214	0.020612331
β2	-0.000141357	4.71641E-06	-29.97123684	8.83426E-63	-0.000150681	-0.000132032	-0.000150681	-0.000132032
β3	3.42352E-07	1.53662E-08	22.27954719	7.08083E-48	3.11973E-07	3.72732E-07	3.11973E-07	3.72732E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.993880162
R Square	0.987797777
Adjusted R Square	0.987536301
Standard Error	0.027114753
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.332367897	2.777455966	3777.77319	1.0603E-133
Residual	140	0.102929375	0.00073521		
Total	143	8.435297272			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.326854136	0.009112296	35.86957101	1.8943E-72	0.308838638	0.344869634	0.308838638	0.344869634
β1	0.019394839	0.000402139	48.22916512	4.26E-89	0.018599788	0.02018989	0.018599788	0.02018989
β2	-0.000140183	4.83184E-06	-29.01231258	4.47722E-61	-0.000149736	-0.00013063	-0.000149736	-0.00013063
β3	3.41846E-07	1.57423E-08	21.71513554	1.15483E-46	3.10722E-07	3.72969E-07	3.10722E-07	3.72969E-07

Secondary Workover Costs

Secondary workover costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Secondary workover costs consist of workover rig services, remedial services and equipment repair. The data was analyzed on a regional level. The secondary operations costs for each region were determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta 0 + \beta 1 * Depth + \beta 2 * Depth^2 + \beta 3 * Depth^3 \qquad (2.B\text{-}15)$$

where Cost = SWK_W
β0 = OMSWRK
β1 = OMSWRA
β2 = OMSWRB
β3 = OMSWRC
from equation 2-33 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9993
R Square	0.9986
Adjusted R Square	0.9972
Standard Error	439.4
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	136,348,936	136,348,936	706	0
Residual	1	193,106	193,106		
Total	2	136,542,042			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,951.059	538.200	9.199	0.069	-1,887.392	11,789.510	-1,887.392	11,789.510
β1	2.703	0.102	26.572	0.024	1.410	3.995	1.410	3.995

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.9924
R Square	0.9849
Adjusted R Square	0.9811
Standard Error	1356.3
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	480,269,759	480,269,759	261	0
Residual	4	7,358,144	1,839,536		
Total	5	487,627,903			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	10,560.069	1,174.586	8.990	0.001	7,298.889	13,821.249	7,298.889	13,821.249
β1	3.587	0.222	16.158	0.000	2.970	4.203	2.970	4.203

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9989
R Square	0.9979
Adjusted R Square	0.9958
Standard Error	544.6
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	140,143,261	140,143,261	473	0
Residual	1	296,583	296,583		
Total	2	140,439,844			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,732.510	666.989	5.596	0.113	-4,742.355	12,207.375	-4,742.355	12,207.375
β1	2.740	0.126	21.738	0.029	1.138	4.342	1.138	4.342

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	0.9996
R Square	0.9991
Adjusted R Square	0.9983
Standard Error	290.9
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	98,740,186	98,740,186	1,167	0
Residual	1	84,627	84,627		
Total	2	98,824,812			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	5,291.954	356.287	14.853	0.043	764.922	9,818.987	764.922	9,818.987
β1	2.300	0.067	34.158	0.019	1.444	3.155	1.444	3.155

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9991
R Square	0.9983
Adjusted R Square	0.9966
Standard Error	454.7
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	120,919,119	120,919,119	585	0
Residual	1	206,762	206,762		
Total	2	121,125,881			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	4,131.486	556.905	7.419	0.085	-2,944.638	11,207.610	-2,944.638	11,207.610
β1	2.545	0.105	24.183	0.026	1.208	3.882	1.208	3.882

Secondary Workover Costs - Cost Adjustment Factor

The cost adjustment factor for secondary workover costs was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.994646805
R Square	0.989322267
Adjusted R Square	0.989093459
Standard Error	0.026416612
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.051925882	3.017308627	4323.799147	9.3015E-138
Residual	140	0.097697232	0.000697837		
Total	143	9.149623114			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312179978	0.008877675	35.1646082	2.31513E-71	0.294628337	0.329731619	0.294628337	0.329731619
β1	0.019705242	0.000391785	50.29605017	1.64552E-91	0.018930662	0.020479822	0.018930662	0.020479822
β2	-0.000140397	4.70743E-06	-29.82464336	1.6003E-62	-0.000149704	-0.000131091	-0.000149704	-0.000131091
β3	3.4013E-07	1.53369E-08	22.17714344	1.1716E-47	3.09808E-07	3.70452E-07	3.09808E-07	3.70452E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994648271
R Square	0.989325182
Adjusted R Square	0.989096436
Standard Error	0.026409288
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.049404415	3.016468138	4324.992582	9.1255E-138
Residual	140	0.097643067	0.00069745		
Total	143	9.147047482			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.31224985	0.008875214	35.18223288	2.17363E-71	0.294703075	0.329796624	0.294703075	0.329796624
β1	0.019703773	0.000391676	50.30624812	1.60183E-91	0.018929408	0.020478139	0.018929408	0.020478139
β2	-0.000140393	4.70612E-06	-29.83187838	1.55398E-62	-0.000149697	-0.000131088	-0.000149697	-0.000131088
β3	3.40125E-07	1.53327E-08	22.18299399	1.13834E-47	3.09811E-07	3.70439E-07	3.09811E-07	3.70439E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994391906
R Square	0.988815263
Adjusted R Square	0.98857559
Standard Error	0.027366799
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.269694355	3.089898118	4125.685804	2.3918E-136
Residual	140	0.104851837	0.000748942		
Total	143	9.374546192			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.301399555	0.009196999	32.7715099	1.54408E-67	0.283216594	0.319582517	0.283216594	0.319582517
β1	0.020285999	0.000405877	49.980617	3.79125E-91	0.019483558	0.021088441	0.019483558	0.021088441
β2	-0.000145269	4.87675E-06	-29.78803686	1.85687E-62	-0.00015491	-0.000135627	-0.00015491	-0.000135627
β3	3.51144E-07	1.58886E-08	22.10035946	1.71054E-47	3.19731E-07	3.82556E-07	3.19731E-07	3.82556E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994645783
R Square	0.989320233
Adjusted R Square	0.989091381
Standard Error	0.026422924
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.054508298	3.018169433	4322.966602	9.4264E-138
Residual	140	0.097743924	0.000698171		
Total	143	9.152252223			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312146343	0.008879797	35.15242029	2.41837E-71	0.294590508	0.329702178	0.294590508	0.329702178
β1	0.019706241	0.000391879	50.28658391	1.68714E-91	0.018931476	0.020481006	0.018931476	0.020481006
β2	-0.000140397	4.70855E-06	-29.81743751	1.64782E-62	-0.000149706	-0.000131088	-0.000149706	-0.000131088
β3	3.4012E-07	1.53406E-08	22.17121727	1.20629E-47	3.09791E-07	3.70449E-07	3.09791E-07	3.70449E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.994644139
R Square	0.989316964
Adjusted R Square	0.989088042
Standard Error	0.026428705
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.05566979	3.018556597	4321.629647	9.6305E-138
Residual	140	0.097786705	0.000698476		
Total	143	9.153456495			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312123671	0.00888174	35.14217734	2.50872E-71	0.294563994	0.329683347	0.294563994	0.329683347
β1	0.019707015	0.000391964	50.27755672	1.72782E-91	0.01893208	0.020481949	0.01893208	0.020481949
β2	-0.0001404	4.70958E-06	-29.81159891	1.68736E-62	-0.000149711	-0.000131089	-0.000149711	-0.000131089
β3	3.40124E-07	1.5344E-08	22.16666321	1.23366E-47	3.09789E-07	3.7046E-07	3.09789E-07	3.7046E-07

Additional Cost Equations and Factors

The model uses several updated cost equations and factors originally developed for DOE/NETL's Comprehensive Oil and Gas Analysis Model (COGAM). These are:

- The crude oil and natural gas investment factors for tangible and intangible investments as well as the operating costs. These factors were originally developed based upon the 1984 Enhanced Oil Recovery Study completed by the National Petroleum Council.
- The G&A factors for capitalized and expensed costs.
- The limits on impurities, such as N2, CO2, and H2S used to calculate natural gas processing costs.
- Cost equations for stimulation, the produced water handling plant, the chemical handling plant, the polymer handling plant, CO_2 recycling plant, and the steam manifolds and pipelines.

Natural and Industrial CO2 Prices

The model uses regional CO_2 prices for both natural and industrial sources of CO_2. The cost equation for natural CO_2 is derived from the equation used in COGAM and updated to reflect current dollar values. According to University of Wyoming, this equation is applicable to the natural CO_2 in the Permian basin (Southwest). The cost of CO_2 in other regions and states is calculated using state calibration factors which represent the additional cost of transportation.

The industrial CO_2 costs contain two components: cost of capture and cost of transportation. The capture costs are derived using data obtained from Denbury Resources, Inc. and other sources. CO_2 capture costs range between \$20 and \$63/ton. The transportation costs were derived using an external economic model which calculates pipeline tariff based upon average distance, compression rate, and volume of CO_2 transported.

National Crude Oil Drilling Footage Equation

The equation for crude oil drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Oil Footage} = \beta 0 + \beta 1 * \text{Oil Price} \tag{2.B-16}$$

where $\beta 0$ = OILA0

$\beta 1$ = OILA1

from equation 2-99 in Chapter 2.

Oil footage is the footage of total developmental crude oil wells drilled in the United States in thousands of feet. The crude oil price is a rolling five year average of crude oil prices from 1995 – 2008. The parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Oil Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9623
R Square	0.9259
Adjusted R Square	0.9167
Standard Error	5,108.20
Observations	10

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2,609,812,096.02	2,609,812,096.02	100.02	0.00
Residual	8	208,749,712.88	26,093,714.11		
Total	9	2,818,561,808.90			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,984.11	4,377.97	0.91	0.39	-6,111.51	14,079.72	-6,111.51	14,079.72
β1	1,282.45	128.23	10.00	0.00	986.74	1,578.16	986.74	1,578.16

Regional Crude Oil Footage Distribution

The regional drilling distributions for crude oil were estimated using an updated EIA well count file. The percent allocations for each region are calculated using the average footage drilled from 2004 – 2008 for developed crude oil or natural gas fields.

Region Name	States Included	Oil
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	7.6%
Gulf Coast	AL,FL,LA,MS,TX	29.3%
Midcontinent	AR,KS,MO,NE,OK,TX	16.8%
Southwest	TX,NM	18.3%
Rocky Mountains	CO,NV,UT,WY,NM	10.7%
West Coast	CA,WA	9.6%
Northern Great Plains	MT,ND,SD	7.6%

National Natural Gas Drilling Footage Equation

The equation for natural gas drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Gas Footage} = \beta0 + \beta1 * \text{Gas Price} \qquad (2.B\text{-}17)$$

where $\beta0 = GASA0$

$\beta1 = GASA1$

from equation 2-100 in Chapter 2.

Gas footage is footage of total developmental natural gas wells drilled in the United States in thousands of feet. The gas price is a rolling five year average of natural gas prices from 1995 – 2008. The parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Gas Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9189
R Square	0.8444
Adjusted R Square	0.7666
Standard Error	9,554.63
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	990,785,019.79	990,785,019.79	10.85	0.08
Residual	2	182,581,726.21	91,290,863.10		
Total	3	1,173,366,746.00			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	2,793.29	53,884.13	0.05	0.96	-229,051.57	234,638.14	-229,051.57	234,638.14
β1	30,429.72	9,236.81	3.29	0.08	-9,313.08	70,172.52	-9,313.08	70,172.52

Regional Natural Gas Footage Distribution

The regional drilling distributions for natural gas were estimated using an updated EIA well count file. The percent allocations for each region are calculated using the average footage drilled from 2004 – 2008 for developed crude oil or natural gas fields.

Region Name	States Included	Gas
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	13.2%
Gulf Coast	AL,FL,LA,MS,TX	18.7%
Midcontinent	AR,KS,MO,NE,OK,TX	13.4%
Southwest	TX,NM	34.5%
Rocky Mountains	CO,NV,UT,WY,NM	19.5%
West Coast	CA,WA	0.4%
Northern Great Plains	MT,ND,SD	0.4%

National Exploration Drilling Footage Equation

The equation for exploration well drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Exploration Footage} = \beta 0 + \beta 1 * \text{Oil Price} \tag{2.B-18}$$

where $\beta 0 = \text{EXPA0}$
$\beta 1 = \text{EXPA1}$

Exploration footage is footage of total exploratory crude oil, natural gas and dry wells drilled in the United States in thousands of feet. The crude oil price is a rolling five year average of oil prices from 1995 – 2008. The parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Exploration Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9467
R Square	0.8963
Adjusted R Square	0.8834
Standard Error	2,825.10
Observations	10

ANOVA

	df	SS	MS	F	Significance F
Regression	1	552,044,623.08	552,044,623.08	69.17	0.00
Residual	8	63,849,573.82	7,981,196.73		
Total	9	615,894,196.90			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	4,733.91	2,421.24	1.96	0.09	-849.49	10,317.31	-849.49	10,317.31
β1	589.83	70.92	8.32	0.00	426.28	753.37	426.28	753.37

Regional Exploration Footage Distribution

The regional distribution for drilled exploration projects is also estimated using the updated EIA well count file. The percent allocations for each corresponding region are calculated using a 2004 – 2008 average of footage drilled for exploratory fields for both crude oil and natural gas.

Region Name	States Included	Exploration
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	22.3%
Gulf Coast	AL,FL,LA,MS,TX	9.0%
Midcontinent	AR,KS,MO,NE,OK,TX	28.8%
Southwest	TX,NM	14.3%
Rocky Mountains	CO,NV,UT,WY,NM	11.5%
West Coast	CA,WA	0.3%
Northern Great Plains	MT,ND,SD	13.8%

Regional Dryhole Rate for Discovered Projects

The percent allocation for existing regional dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each corresponding region. Existing dryhole rates calculate the projects which have already been discovered. The formula for the percentage is given below:

Existing Dryhole Rate = Developed Dryhole / Total Drilling (2.B-19)

Region Name	States Included	Existing
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	5.8%
Gulf Coast	AL,FL,LA,MS,TX	9.4%
Midcontinent	AR,KS,MO,NE,OK,TX	13.2%
Southwest	TX,NM	9.7%
Rocky Mountains	CO,NV,UT,WY,NM	4.3%
West Coast	CA,WA	1.5%
Northern Great Plains	MT,ND,SD	5.2%

Regional Dryhole Rate for First Exploration Well Drilled

The percent allocation for undiscovered regional exploration dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each region. Undiscovered regional exploration dryhole rates calculate the rate for the first well drilled in an exploration project. The formula for the percentage is given below:

Undiscovered Exploration = Exploration Dryhole / (Exploration Gas + Exploration Oil)

Region Name	States Included	Undisc. Exp
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	30.8%
Gulf Coast	AL,FL,LA,MS,TX	167.8%
Midcontinent	AR,KS,MO,NE,OK,TX	76.4%
Southwest	TX,NM	86.2%
Rocky Mountains	CO,NV,UT,WY,NM	74.0%
West Coast	CA,WA	466.0%
Northern Great Plains	MT,ND,SD	46.9%

Regional Dryhole Rate for Subsequent Exploration Wells Drilled

The percent allocation for undiscovered regional developed dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each corresponding region. Undiscovered regional developed dryhole rates calculate the rate for subsequent wells drilled in an exploration project. The formula for the percentage is given below:

Undiscovered Developed = (Developed Dryhole + Explored Dryhole) / Total Drilling (2.B-20)

Region Name	States Included	Undisc. Dev
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	7.3%
Gulf Coast	AL,FL,LA,MS,TX	11.6%
Midcontinent	AR,KS,MO,NE,OK,TX	16.8%
Southwest	TX,NM	10.8%
Rocky Mountains	CO,NV,UT,WY,NM	6.5%
West Coast	CA,WA	1.8%
Northern Great Plains	MT,ND,SD	10.5%

National Rig Depth Rating

The national rig depth rating schedule was calculated using a three year average based on the Smith Rig Count as reported by *Oil and Gas Journal*. Percentages are applied to determine the cumulative available rigs for drilling.

Appendix 2.C: Play-level Resource Assumptions for Tight Gas, Shale Gas, and Coalbed Methane

The detailed resource assumptions underlying the estimates of remaining unproved technically recoverable resources for tight gas, shale gas, and coalbed methane are presented in the following tables.

Table 2.C-1. Remaining Technically Recoverable Resources (TRR) – Tight Gas

REGION	BASIN	PLAY	AREA (mi^2)	WELL SPACING	DEPTH (ft)	EUR (bcf/well)	OFFICIAL NO ACCESS	TRR (bcf)
1	Appalachian	Berea Sandstone	51863	8	4000	0.18	0%	11401
1	Appalachian	Clinton/Medina High	14773	8	5900	0.25	0%	6786
1	Appalachian	Clinton/Medina Moderate/Low	27281	15	5200	0.08	0%	16136
1	Appalachian	Tuscarora Sandstone	42495	8	8000	0.69	0%	1485
1	Appalachian	Upper Devonian High	12775	10	4600	0.21	0%	10493
1	Appalachian	Upper Devonian Moderate/Low	29808	10	5400	0.06	0%	5492
2	East Texas	Cotton Valley/Bossier	2730	12	12500	1.39	0%	36447
2	Texas-Gulf	Olmos	2500	4	5000	0.44	0%	3624
2	Texas-Gulf	Vicksburg	600	8	11000	2.36	0%	4875
2	Texas-Gulf	Wilcox/Lobo	1500	8	9500	1.60	0%	8532
3	Anadarko	Cherokee/Redfork	1500	4	8500	0.90	0%	1168
3	Anadarko	Cleveland	1500	4	6500	0.91	0%	3690
3	Anadarko	Granite Wash/Atoka	1500	4	13000	1.72	0%	6871
3	Arkoma	Arkoma Basin	1000	8	8000	1.30	0%	2281
4	Permian	Abo	1500	8	3800	1.00	0%	9158
4	Permian	Canyon	6000	8	4500	0.22	0%	11535
5	Denver	Denver/Jules	3500	16	4999	0.24	1%	12953
5	Greater Green River	Deep Mesaverde	16416	4	15100	0.41	8%	2939
5	Greater Green River	Fort Union/Fox Hills	3858	8	5000	0.70	12%	1062
5	Greater Green River	Frontier (Deep)	15619	4	17000	2.58	9%	11303
5	Greater Green River	Frontier (Moxa Arch)	2334	8	9500	1.20	15%	3414
5	Greater Green River	Lance	5500	8	10000	6.60	11%	31541
5	Greater Green River	Lewis	5172	8	9500	1.32	6%	18893
5	Greater Green River	Shallow Mesaverde (1)	5239	4	9750	1.25	8%	12606
5	Greater Green River	Shallow Mesaverde (2)	6814	8	10500	0.67	8%	17874
5	Piceance	Iles/Mesaverde	972	8	8000	0.73	5%	1858
5	Piceance	North Williams Fork/Mesaverde	1008	8	8000	0.65	2%	4278
5	Piceance	South Williams Fork/Mesaverde	1008	32	7000	0.65	9%	22402
5	San Juan	Central Basin/Dakota	3918	6	6500	0.49	7%	15007
5	San Juan	Central Basin/Mesaverde	3689	8	4500	0.72	2%	8737
5	San Juan	Picture Cliffs	6558	4	3500	0.48	2%	4899
5	Uinta	Basin Flank Mesaverde	1708	8	8000	0.99	33%	5767
5	Uinta	Deep Synclinal Mesaverde	2893	8	18000	0.99	2%	3292
5	Uinta	Tertiary East	1600	16	6000	0.58	16%	5910
5	Uinta	Tertiary West	1603	8	6500	4.06	57%	10630
5	Williston	High Potential	2000	4	2300	0.61	4%	2960
5	Williston	Low Potential	3000	4	2500	0.21	1%	1886
5	Williston	Moderate Potential	2000	4	2300	0.33	4%	2071
5	Wind River	Fort Union/Lance Deep	2500	4	14500	0.54	9%	4261
5	Wind River	Fort Union/Lance Shallow	1500	8	11000	1.17	0%	13197
5	Wind River	Mesaverde/Frontier Deep	250	4	17000	1.99	9%	1221
5	Wind River	Mesaverde/Frontier Shallow	250	4	13500	1.25	0%	1037
6	Columbia	Basin Centered	1500	8	13100	1.26	0%	7508

Table 2.C-2. Remaining Technically Recoverable Resources (TRR) – Shale Gas

REGION	BASIN	PLAY	AREA (mi^2)	WELL SPACING	DEPTH (ft)	EUR (bcf/well)	OFFICIAL NO ACCESS	TRR (bcf)
1	Appalachian	Cincinatti Arch	6000	4	1800	0.12	0%	1435
1	Appalachian	Devonian Big Sandy - Active	8675	8	3800	0.32	0%	6490
1	Appalachian	Devonian Big Sandy - Undeveloped	1994	8	3800	0.32	0%	940
1	Appalachian	Devonian Greater Siltstone Area	22914	11	2911	0.20	0%	8463
1	Appalachian	Devonian Low Thermal Maturity	45844	7	3000	0.30	0%	13534
1	Appalachian	Marcellus - Active	10622	8	6750	3.49	0%	177931
1	Appalachian	Marcellus - Undeveloped	84271	8	6750	1.15	0%	232443
1	Illinois	New Albany	1600	8	2750	1.09	0%	10947
1	Michigan	Antrim	12000	7	1400	0.28	0%	20512
2	Black Warrior	Floyd-Neal/Conasauga	2429	2	8000	0.92	0%	4465
2	TX-LA-MS Salt	Haynesville - Active	3574	8	12000	6.48	0%	60615
2	TX-LA-MS Salt	Haynesville - Undeveloped	5426	8	12000	1.50	0%	19408
2	West Gulf Coast	Eagle Ford - Dry	200	4	7000	5.50	0%	4378
2	West Gulf Coast	Eagle Ford - Wet	890	8	7000	2.31	0%	16429
3	Anadarko	Cana Woodford	688	4	13500	3.42	0%	5718
3	Anadarko	Woodford - Central Oklahoma	1800	4	5000	1.01	0%	2946
3	Arkoma	Fayetteville - Central	4000	8	4000	2.29	0%	29505
3	Arkoma	Fayetteville - West	5000	8	4000	1.17	0%	4639
3	Arkoma	Woodford - Western Arkoma	2900	4	9500	4.06	0%	19771
4	Fort Worth	Barnett - Fort Worth Active	2649	5	7500	1.60	0%	15834
4	Fort Worth	Barnett - Fort Worth Undeveloped	477	8	7500	1.20	0%	4094
4	Permian	Barnett - Permian Active	1426	5	7500	1.60	0%	19871
4	Permian	Barnett - Permian Undeveloped	1906	8	7500	1.20	0%	15823
4	Permian	Barnett-Woodford	2691	4	10200	2.99	0%	32152
5	Greater Green River	Hilliard-Baxter-Mancos	16416	8	14750	0.18	0%	3770
5	San Juan	Lewis	7506	3	4500	1.53	0%	11638
5	Uinta	Mancos	6589	8	15250	1.00	0%	21021
5	Williston	Shallow Niobrara	10000	2	1000	0.46	4%	6757

Table 2.C-3. Remaining Technically Recoverable Resources (TRR) – Coalbed Methane

REGION	BASIN	PLAY	AREA (mi^2)	WELL SPACING	DEPTH (ft)	EUR (bcf/well)	OFFICIAL NO ACCESS	TRR (bcf)
1	Appalachian	Central Basin	3870	8	1900	0.18	0%	1709
1	Appalachian	North Appalachia - High	3817	12	1400	0.12	0%	532
1	Appalachian	North Appalachia - Mod/Low	8906	12	1800	0.08	0%	469
1	Illinois	Central Basin	1214	8	1000	0.12	0%	1161
2	Black Warrior	Extention Area	700	8	1900	0.08	0%	931
2	Black Warrior	Main Area	1000	12	1950	0.21	0%	2190
2	Cahaba	Cahaba Coal Field	387	8	3000	0.18	0%	379
3	Midcontinent	Arkoma	2998	8	1500	0.22	0%	3032
3	Midcontinent	Cherokee & Forest City	2750	8	1000	0.06	0%	1308
4	Raton	Southern	386	8	2000	0.37	2%	962
5	Greater Green River	Deep	3600	4	7000	0.60	15%	3879
5	Greater Green River	Shallow	720	8	1500	0.20	20%	1053
5	Piceance	Deep	2000	4	7000	0.60	3%	3677
5	Piceance	Divide Creek	144	8	3800	0.18	13%	194
5	Piceance	Shallow	2000	4	3500	0.30	9%	2230
5	Piceance	White River Dome	216	8	7500	0.41	8%	657
5	Powder River	Big George/Lower Fort Union	2880	16	1100	0.26	1%	5943
5	Powder River	Wasatch	216	8	1100	0.06	1%	92
5	Powder River	Wyodak/Upper Fort Union	3600	20	600	0.14	1%	18859
5	Raton	Northern	470	8	2500	0.35	0%	957
5	Raton	Purgatoire River	360	8	2000	0.31	0%	430
5	San Juan	Fairway NM	670	4	3250	1.14	7%	774
5	San Juan	North Basin	2060	4	3000	0.28	7%	1511
5	San Juan	North Basin CO	780	4	2800	1.51	7%	10474
5	San Juan	South Basin	1190	4	2000	0.20	7%	820
5	San Juan	South Menefee NM	7454	5	2500	0.10	7%	177
5	Uinta	Blackhawk	586	8	3250	0.16	5%	1864
5	Uinta	Ferron	400	8	3000	0.78	11%	1409
5	Uinta	Sego	534	4	3250	0.31	10%	417

3. Offshore Oil and Gas Supply Submodule

Introduction

The Offshore Oil and Gas Supply Submodule (OOGSS) uses a field-based engineering approach to represent the exploration and development of U.S. offshore oil and natural gas resources. The OOGSS simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore petroleum resources are divided into 3 categories:

- **Undiscovered Fields.** The number, location, and size of the undiscovered fields is based on the Minerals Management Service's (MMS) 2006 hydrocarbon resource assessment.[1] MMS was renamed Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) in 2010.

- **Discovered, Undeveloped Fields.** Any discovery that has been announced but is not currently producing is evaluated in this component of the model. The first production year is an input and is based on announced plans and expectations.

- **Producing Fields.** The fields in this category have wells that have produced oil and/or gas by 2009. The production volumes are from the BOEMRE production database.

Resource and economic calculations are performed at an evaluation unit basis. An evaluation unit is defined as the area within a planning area that falls into a specific water depth category. Planning areas are the Western Gulf of Mexico (GOM), Central GOM, Eastern GOM, Pacific, and Atlantic. There are six water depth categories: 0-200 meters, 200-400 meters, 400-800 meters, 800-1600 meters, 1600-2400 meters, and greater than 2400 meters. The crosswalk between region and evaluation unit is shown in Table 3-1.

Supply curves for crude oil and natural gas are generated for three offshore regions: Pacific, Atlantic, and Gulf of Mexico. Crude oil production includes lease condensate. Natural gas production accounts for both nonassociated gas and associated-dissolved gas. The model is responsive to changes in oil and natural gas prices, royalty relief assumptions, oil and natural gas resource base, and technological improvements affecting exploration and development.

Undiscovered Fields Component

Significant undiscovered oil and gas resources are estimated to exist in the Outer Continental Shelf, particularly in the Gulf of Mexico. Exploration and development of these resources is projected in this component of the OOGSS.

Within each evaluation unit, a field size distribution is assumed based on BOEMRE's latest[1] resource assessment (Table 3-2). The volume of resource in barrels of oil equivalence by field size class as defined by the BOEMRE is shown in Table 3-3. In the OOGSS, the mean estimate represents the size of each field in the field size class. Water depth and field size class are used for specifying many of the technology assumptions in the OOGSS. Fields smaller than field size class 2 are assumed to be uneconomic to develop.

[1]U.S. Department of Interior, Minerals Management Service, *Report to Congress: Comprehensive Inventory of U.S.OCS Oil and Natural Gas Resources*, February 2006.

Table 3-1. Offshore Region and Evaluation Unit Crosswalk

No.	Region Name	Planning Area	Water Depth (meters)	Drilling Depth (feet)	Evaluation Unit Name	Region ID
1	Shallow GOM	Western GOM	0 - 200	< 15,000	WGOM0002	3
2	Shallow GOM	Western GOM	0 - 200	> 15,000	WGOMDG02	3
3	Deep GOM	Western GOM	201 - 400	All	WGOM0204	4
4	Deep GOM	Western GOM	401 - 800	All	WGOM0408	4
5	Deep GOM	Western GOM	801 - 1,600	All	WGOM0816	4
6	Deep GOM	Western GOM	1,601 - 2,400	All	WGOM1624	4
7	Deep GOM	Western GOM	> 2,400	All	WGOM2400	4
8	Shallow GOM	Central GOM	0 - 200	< 15,000	CGOM0002	3
9	Shallow GOM	Central GOM	0 - 200	> 15,000	CGOMDG02	3
10	Deep GOM	Central GOM	201 - 400	All	CGOM0204	4
11	Deep GOM	Central GOM	401 - 800	All	CGOM0408	4
12	Deep GOM	Central GOM	801 - 1,600	All	CGOM0816	4
13	Deep GOM	Central GOM	1,601 – 2,400	All	CGOM1624	4
14	Deep GOM	Central GOM	> 2,400	All	CGOM2400	4
15	Shallow GOM	Eastern GOM	0 - 200	All	EGOM0002	3
16	Deep GOM	Eastern GOM	201 - 400	All	EGOM0204	4
17	Deep GOM	Central GOM	401 - 800	All	EGOM0408	4
18	Deep GOM	Eastern GOM	801 - 1600	All	EGOM0816	4
19	Deep GOM	Eastern GOM	1601 - 2400	All	EGOM1624	4
20	Deep GOM	Eastern GOM	> 2400	All	EGOM2400	4
21	Deep GOM	Eastern GOM	> 200	All	EGOML181	4
22	Atlantic	North Atlantic	0 - 200	All	NATL0002	1
23	Atlantic	North Atlantic	201 - 800	All	NATL0208	1
24	Atlantic	North Atlantic	> 800	All	NATL0800	1
25	Atlantic	Mid Atlantic	0 - 200	All	MATL0002	1
26	Atlantic	Mid Atlantic	201 - 800	All	MATL0208	1
27	Atlantic	Mid Atlantic	> 800	All	MATL0800	1
28	Atlantic	South Atlantic	0 - 200	All	SATL0002	1
29	Atlantic	South Atlantic	201 - 800	All	SATL0208	1
30	Atlantic	South Atlantic	> 800	All	SATL0800	1
31	Atlantic	Florida Straits	0 – 200	All	FLST0002	1
32	Atlantic	Florida Straits	201 - 800	All	FLST0208	1
33	Atlantic	Florida Straits	> 800	All	FLST0800	1
34	Pacific	Pacific Northwest	0-200	All	PNW0002	2
35	Pacific	Pacific Northwest	201-800	All	PNW0208	2
36	Pacific	North California	0-200	All	NCA0002	2
37	Pacific	North California	201-800	All	NCA0208	2
38	Pacific	North California	801-1600	All	NCA0816	2
39	Pacific	North California	1600-2400	All	NCA1624	2
40	Pacific	Central California	0-200	All	CCA0002	2
41	Pacific	Central California	201-800	All	CCA0208	2
42	Pacific	Central California	801-1600	All	CCA0816	2
43	Pacific	South California	0-200	All	SCA0002	2
44	Pacific	South California	201-800	All	SCA0208	2
45	Pacific	South California	801-1600	All	SCA0816	2
46	Pacific	South California	1601-2400	All	SCA1624	2

Source: U.S. Energy Information Administration, Energy Analysis, Office of Petroleum, Gas, and Biofuels Analysis

Table 3-2. Number of Undiscovered Fields by Evaluation Unit and Field Size Class, as of January 1, 2003

Evaluation Unit	Field Size Class (FSC)																Number of Fields	Total Resource (BBOE)
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17		
WGOM0002	1	5	11	14	20	23	24	27	30	8	6	8	2	0	0	0	179	4.348
WGOMDG02	0	0	2	4	5	6	8	9	9	3	2	2	1	0	0	0	51	1.435
WGOM0204	0	0	0	0	0	0	2	3	3	4	2	1	1	0	0	0	16	1.027
WGOM0408	0	0	0	0	0	1	3	3	7	7	3	2	1	0	0	0	27	1.533
WGOM0816	0	0	0	0	0	0	4	7	16	16	15	9	3	2	1	0	73	8.082
WGOM1624	0	0	0	1	2	6	10	14	18	18	14	10	6	4	1	0	104	10.945
WGOM2400	0	0	0	0	2	3	3	6	7	6	5	3	3	2	0	0	40	4.017
CGOM0002	1	1	6	11	28	52	79	103	81	53	20	1	0	0	0	0	436	8.063
CGOMDG02	0	0	1	1	4	4	4	6	7	6	5	3	1	0	0	0	42	3.406
CGOM0204	0	0	0	0	0	0	1	2	3	2	2	2	1	0	0	0	13	1.102
CGOM0408	0	0	0	0	0	1	1	4	4	4	1	1	1	1	0	0	18	1.660
CGOM0816	0	0	0	0	2	4	8	11	20	22	19	14	7	3	1	0	111	11.973
CGOM1624	0	0	0	1	2	5	9	15	18	19	15	13	8	4	1	0	110	12.371
CGOM2400	0	0	0	0	2	2	3	5	5	5	5	4	3	2	0	0	36	4.094
EGOM0002	4	6	7	11	16	18	18	16	13	10	6	1	0	0	0	0	126	1.843
EGOM0204	0	1	1	2	3	4	4	3	1	1	1	0	0	0	0	0	21	0.233
EGOM0408	0	1	2	3	5	5	5	4	3	2	1	0	0	0	0	0	31	0.348
EGOM0816	0	1	1	3	4	4	4	3	3	2	1	0	0	0	0	0	26	0.326
EGOM1624	0	0	0	0	2	1	1	1	0	1	0	1	0	0	0	0	7	0.250
EGOM2400	0	0	0	1	1	3	5	7	8	9	7	6	3	2	0	0	52	4.922
EGOML181	0	0	0	0	1	3	3	5	8	5	4	2	2	1	1	0	35	1.836
NATL0002	5	7	10	14	16	17	15	11	10	8	3	2	1	0	0	0	119	1.896
NATL0208	1	1	1	2	2	3	3	3	2	1	1	0	0	0	0	0	20	0.246
NATL0800	1	2	3	5	7	10	13	12	7	6	4	1	0	0	0	0	71	1.229
MATL0002	4	6	8	12	13	14	13	11	8	7	5	2	0	0	0	0	103	1.585
MATL0208	1	1	2	3	3	3	3	4	2	2	2	2	0	0	0	0	28	0.377
MATL0800	2	4	5	8	9	10	10	8	5	5	3	2	0	0	0	0	71	1.173
SATL0002	1	2	2	3	5	6	5	5	4	4	1	1	0	0	0	0	39	0.658
SATL0208	4	5	7	10	12	13	12	10	8	7	3	2	0	0	0	0	93	1.382
SATL0800	2	2	4	5	9	15	20	17	11	7	2	1	1	0	0	0	96	1.854
FLST0002	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	0.012
FLST0208	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	2	0.009
FLST0800	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000
PNW0002	10	17	24	29	27	21	13	8	5	2	1	0	0	0	0	0	157	0.597
PNW0208	4	6	9	10	11	7	6	3	2	1	0	0	0	0	0	0	59	0.209
NCA0002	1	2	3	5	5	5	5	4	3	3	2	0	0	0	0	0	38	0.485
NCA0208	9	17	24	28	26	22	15	10	5	3	1	1	0	0	0	0	161	0.859
NCA0816	3	6	9	12	12	11	9	7	4	3	2	1	0	0	0	0	79	0.784
NCA1624	1	2	3	5	6	6	7	6	4	2	1	1	0	0	0	0	44	0.595
CCA0002	1	4	6	11	15	19	20	17	12	8	4	2	0	0	0	0	119	1.758
CCA0208	1	2	3	5	8	10	10	8	7	5	2	0	0	0	0	0	61	0.761
CCA0816	0	1	1	2	3	4	5	3	2	2	0	0	0	0	0	0	23	0.218
SCA0002	1	2	4	10	16	21	22	19	12	6	2	1	0	0	0	0	116	1.348
SCA0208	3	6	12	25	38	49	51	43	28	14	5	3	1	0	0	0	278	3.655
SCA0816	1	3	6	9	13	17	18	15	12	8	2	2	1	0	0	0	107	1.906
SCA1624	0	1	2	3	4	5	5	5	4	3	1	1	0	0	0	0	34	0.608

Source: U.S. Energy Information Administration, Energy Analysis, Office of Petroleum, Gas, and Biofuels Analysis

Table 3-3. BOEMRE Field Size Definition (MMBOE)

Field Size Class	Mean
2	0.083
3	0.188
4	0.356
5	0.743
6	1.412
7	2.892
8	5.919
9	11.624
10	22.922
11	44.768
12	89.314
13	182.144
14	371.727
15	690.571
16	1418.883
17	2954.129

Source: Bureau of Ocean Energy Management, Regulation, and Enforcement

Projection of Discoveries

The number and size of discoveries is projected based on a simple model developed by J. J. Arps and T. G. Roberts in 1958[2]. For a given evaluation unit in the OOGSS, the number of cumulative discoveries for each field size class is determined by

$$\text{DiscoveredFields}_{\text{EU,iFSC}} = \text{TotalFields}_{\text{EU,iFSC}} * (1 - e^{\gamma_{\text{EU,iFSC}} * \text{CumNFW}_{\text{EU}}}) \quad (3\text{-}1)$$

where,

TotalFields	=	Total number of fields by evaluation unit and field size class
CumNFW	=	Cumulative new field wildcats drilled in an evaluation unit
γ	=	search coefficient
EU	=	evaluation unit
iFSC	=	field size class.

The search coefficient (γ) was chosen to make the Equation 3-1 fit the data. In many cases, however, the sparse exploratory activity in an evaluation unit made fitting the discovery model problematic. To provide reasonable estimates of the search coefficient in every evaluation unit, the data in various field size classes within a region were grouped as needed to obtain enough data points to provide a reasonable fit to the discovery model. A polynomial was fit to all of the relative search coefficients in the region. The polynomial was fit to the resulting search coefficients as follows:

[2] Arps, J. J. and T. G. Roberts, *Economics of Drilling for Cretaceous Oil on the East Flank of the Denver-Julesburg Basin*, Bulletin of the American Association of Petroleum Geologists, November 1958.

$$\gamma_{EU,iFSC} = \beta 1 * iFSC^2 + \beta 2 * iFSC + \beta 3 * \gamma_{EU,10} \tag{3-2}$$

where

$\beta 1$	=	0.0243 for Western GOM and 0.0399 for Central and Eastern GOM
$\beta 2$	=	-0.3525 for Western GOM and -0.6222 for Central and Eastern GOM
$\beta 3$	=	1.5326 for Western GOM and 2.2477 for Central and 3.0477 for Eastern GOM
iFSC	=	field size class
γ	=	search coefficient for field size class 10.

Cumulative new field wildcat drilling is determined by

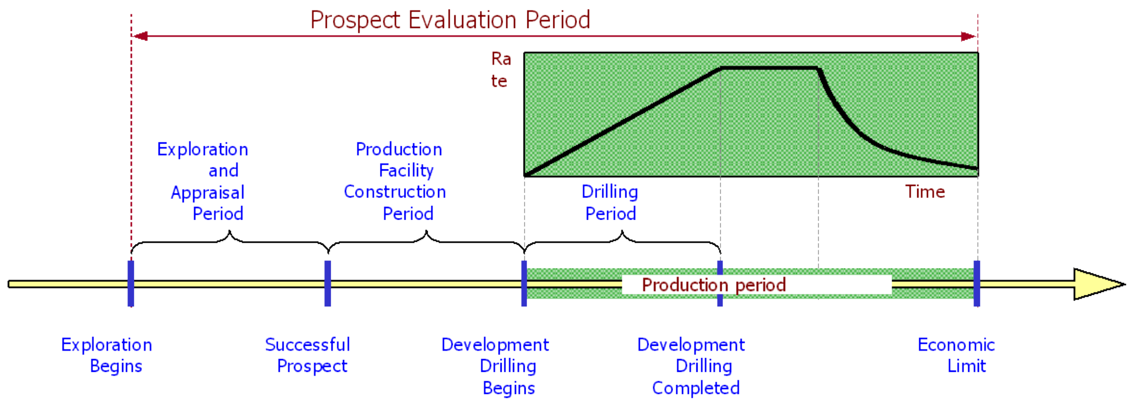
$$CumNFW_{EU,t} = CumNFW_{EU,t-1} + \alpha 1_{EU} + \beta_{EU} * (OILPRICE_{t-nlag1} * GASPRICE_{t-nlag2}) \tag{3-3}$$

where

OILPRICE	=	oil wellhead price
GASPRICE	=	natural gas wellhead price
$\alpha 1$, β	=	estimated parameter
nlag1	=	number of years lagged for oil price
nlag2	=	number of years lagged for gas price
EU	=	evaluation unit

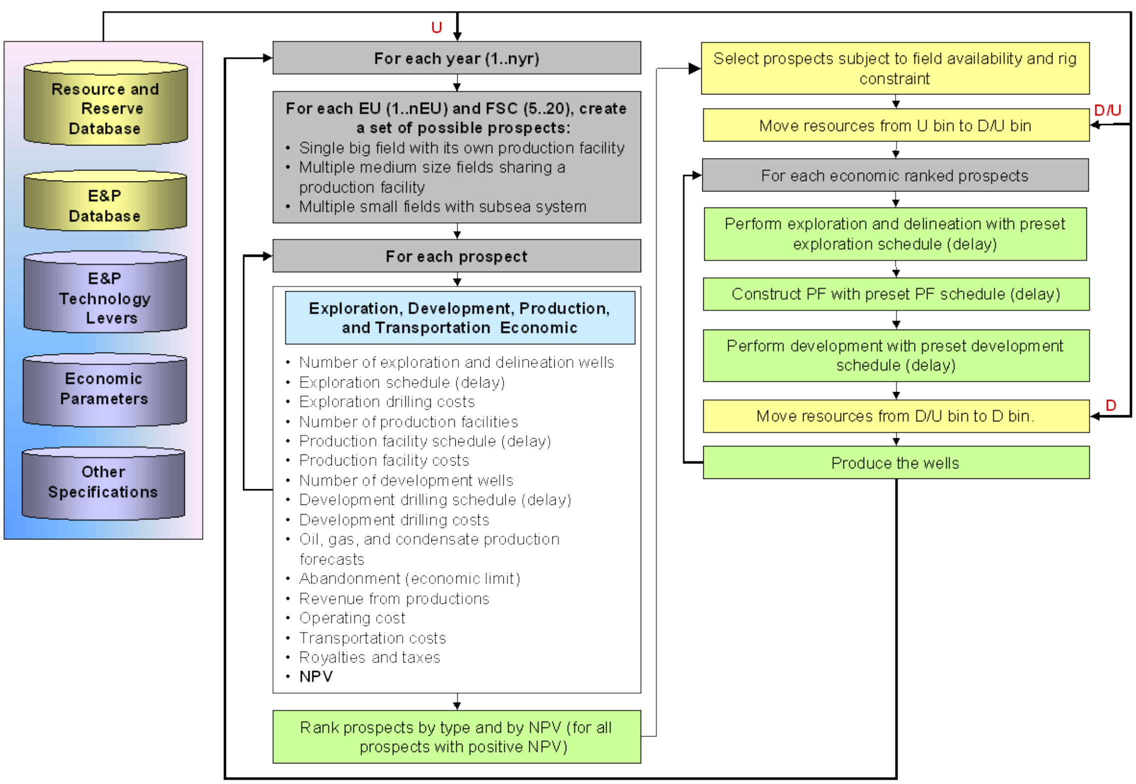
The decision for exploration and development of the discoveries determine from Equation 3-1 is performed at a prospect level that could involve more than one field. A prospect is defined as a potential project that covers exploration, appraisal, production facility construction, development, production, and transportation (Figure 3-1). There are three types of prospects: (1) a single field with its own production facility, (2) multiple medium size fields sharing a production facility, and (3) multiple small fields utilizing nearby production facility. The net present value (NPV) of each possible prospect is generated using the calculated exploration costs, production facility costs, development costs, completion costs, operating costs, flowline costs, transportation costs, royalties, taxes, and production revenues. Delays for exploration, production facility construction, and development are incorporated in this NPV calculation. The possible prospects are then ranked from best (highest NPV) to worst (lowest NPV). The best prospects are selected subject to field availability and rig constraint. The basic flowchart is presented in Figure 3-2.

Figure 3-1. Prospect Exploration, Development, and Production Schedule



Source: ICF Consulting

Figure 3-2. Flowchart for the Undiscovered Field Component of the OOGSS



Note: U = Undiscovered, D/U = Discovered/Undeveloped, D=Developed
Source: ICF Consulting

Calculation of Costs

The technology employed in the deepwater offshore areas to find and develop hydrocarbons can be significantly different than that used in shallower waters, and represents significant challenges for the companies and individuals involved in the deepwater development projects. In many situations in the deepwater OCS, the choice of technology used in a particular situation depends on the size of the prospect being developed. The following base costs are adjusted with the oil price to capture the variation in costs over time as activity level and demand for equipment and other supplies change. The adjustment factor is [1 + (oilprice/baseprice – 1)*0.4], where baseprice = $30/barrel.

Exploration Drilling

During the exploration phase of an offshore project, the type of drilling rig used depends on both economic and technical criteria. Offshore exploratory drilling usually is done using self-contained rigs that can be moved easily. Three types of drilling rigs are incorporated into the OOGSS. The exploration drilling costs per well for each rig type are a function of water depth (WD) and well drilling depth (DD), both in feet.

Jack-up rigs are limited to a water depth of about 600 feet or less. Jack-ups are towed to their location where heavy machinery is used to jack the legs down into the water until they rest on the ocean floor. When this is completed, the platform containing the work area rises above the water. After the platform has risen about 50 feet out of the water, the rig is ready to begin drilling.

$$\text{ExplorationDrillingCosts(\$/well)} = 2{,}000{,}000 + (5.0\text{E-}09)*WD*DD^3 \tag{3-4}$$

Semi-submersible rigs are floating structures that employ large engines to position the rig over the hole dynamically. This extends the maximum operating depth greatly, and some of these rigs can be used in water depths up to and beyond 3,000 feet. The shape of a semisubmersible rig tends to dampen wave motion greatly regardless of wave direction. This allows its use in areas where wave action is severe.

$$\text{ExplorationDrillingCosts(\$/well)} = 2{,}500{,}000 + 200*(WD+DD) + WD*(400+(2.0\text{E-}05)*DD^2) \tag{3-5}$$

Dynamically positioned drill ships are a second type of floating vessel used in offshore drilling. They are usually used in water depths exceeding 3,000 feet where the semi-submersible type of drilling rigs can not be deployed. Some of the drillships are designed with the rig equipment and anchoring system mounted on a central turret. The ship is rotated about the central turret using thrusters so that the ship always faces incoming waves. This helps to dampen wave motion.

$$\text{ExplorationDrillingCosts(\$/well)} = 7{,}000{,}000 + (1.0\text{E-}05)*WD*DD^2 \tag{3-6}$$

Water depth is the primary criterion for selecting a drilling rig. Drilling in shallow waters (up to 1,500 feet) can be done with jack-up rigs. Drilling in deeper water (greater than 1,500 feet) can be done with semi-submersible drilling rigs or drill ships. The number of rigs available for exploration is limited and varies by water depth levels. Drilling rigs are allowed to move one water depth level lower if needed.

Production and Development Structure

Six different options for development/production of offshore prospects are currently assumed in OOGSS, based on those currently considered and/or employed by operators in Gulf of Mexico OCS. These are the conventional fixed platforms, the compliant towers, tension leg platforms, Spar platforms, floating production systems and subsea satellite well systems. Choice of platform tends to be a function of the size of field and water depth, though in reality other operational, environmental, and/or economic decisions influence the choice. Production facility costs are a function of water depth (WD) and number of slots per structure (SLT).

Conventional Fixed Platform (FP). A fixed platform consists of a jacket with a deck placed on top, providing space for crew quarters, drilling rigs, and production facilities. The jacket is a tall vertical section made of tubular steel members supported by piles driven into the seabed. The fixed platform is economical for installation in water depths up to 1,200 feet. Although advances in engineering design and materials have been made, these structures are not economically feasible in deeper waters.

$$\text{StructureCost}(\$) = 2{,}000{,}000 + 9{,}000 * \text{SLT} + 1{,}500 * \text{WD} * \text{SLT} + 40 * \text{WD}^2 \qquad (3\text{-}7)$$

Compliant Towers (CT). The compliant tower is a narrow, flexible tower type of platform that is supported by a piled foundation. Its stability is maintained by a series of guy wires radiating from the ower and terminating on pile or gravity anchors on the sea floor. The compliant tower can withstand significant forces while sustaining lateral deflections, and is suitable for use in water depths of 1,200 to 3,000 feet. A single tower can accommodate up to 60 wells; however, the compliant tower is constrained by limited deck loading capacity and no oil storage capacity.

$$\text{StructureCost}(\$) = (\text{SLT} + 30) * (1{,}500{,}000 + 2{,}000 * (\text{WD} - 1{,}000)) \qquad (3\text{-}8)$$

Tension Leg Platform (TLP). The tension leg platform is a type of semi-submersible structure which is attached to the sea bed by tubular steel mooring lines. The natural buoyancy of the platform creates an upward force which keeps the mooring lines under tension and helps maintain vertical stability. This type of platform becomes a viable alternative at water depths of 1,500 feet and is considered to be the dominant system at water depths greater than 2,000 feet. Further, the costs of the TLP are relatively insensitive to water depth. The primary advantages of the TLP are its applicability in ultra-deepwaters, an adequate deck loading capacity, and some oil storage capacity. In addition, the field production time lag for this system is only about 3 years.

$$\text{StructureCost}(\$) = (\text{SLT} + 30) * (3{,}000{,}000 + 750 * (\text{WD} - 1{,}000)) \qquad (3\text{-}9)$$

Floating Production System (FPS). The floating production system, a buoyant structure, consists of a semi-submersible or converted tanker with drilling and production equipment anchored in place with wire rope and chain to allow for vertical motion. Because of the movement of this structure in severe environments, the weather-related production downtime is estimated to be about 10 percent. These structures can only accommodate a maximum of approximately 25 wells. The wells are completed subsea on the ocean floor and are connected to the production deck through a riser system designed to accommodate platform motion. This system is suitable for marginally economic fields in water depths up to 4,000 feet.

$$\text{StructureCost}(\$) = (\text{SLT} + 20) * (7{,}500{,}000 + 250 * (\text{WD} - 1{,}000)) \tag{3-10}$$

Spar Platform (SPAR). A Spar Platform consists of a large diameter single vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (production, drilling, and export), and a hull which is moored using a taut caternary system of 6 to 20 lines anchored into the seafloor. Spar platforms are presently used in water depths up to 3,000 feet, although existing technology is believed to be able to extend this to about 10,000 feet.

$$\text{StructureCost}(\$) = (\text{SLT} + 20) * (3{,}000{,}000 + 500 * (\text{WD} - 1{,}000)) \tag{3-11}$$

Subsea Wells System (SS). Subsea systems range from a single subsea well tied back to a nearby production platform (such as FPS or TLP) to a set of multiple wells producing through a common subsea manifold and pipeline system to a distant production facility. These systems can be used in water depths up to at least 7,000 feet. Since the cost to complete a well is included in the development well drilling and completion costs, no cost is assumed for the subsea well system. However, a subsea template is required for all development wells producing to any structure other than a fixed platform.

$$\text{SubseaTemplateCost}(\$ / \text{well}) = 2{,}500{,}000 \tag{3-12}$$

The type of production facility for development and production depends on water depth level as shown in Table 3-4.

Table 3-4. Production Facility by Water Depth Level

Water Depth Range (feet)		Production Facility Type					
Minimum	Maximum	FP	CT	TLP	FPS	SPAR	SS
0	656	X					X
656	2625		X				X
2625	5249			X			X
5249	7874				X	X	X
7874	10000				X	X	X

Source: ICF Consulting

Development Drilling

Pre-drilling of development wells during the platform construction phase is done using the drilling rig employed for exploration drilling. Development wells drilled after installation of the platform which also serves as the development structure is done using the platform itself. Hence, the choice of drilling rig for development drilling is tied to the choice of the production platform.

For water depths less than or equal to 900 meters,

$$\begin{aligned}\text{DevelopmentDrillingCost}(\$ / \text{well}) &= 1{,}500{,}000 + (1{,}500 + 0.04 * DD) * WD \\ &+ (0.035 * DD - 300) * DD\end{aligned} \tag{3-13}$$

For water depths greater tan 900 meters,

$$\begin{aligned}\text{DevelopmentDrillingCost}(\$ / \text{well}) &= 4{,}500{,}000 + (150 + 0.004 * DD) * WD \\ &+ (0.035 * DD - 250) * DD\end{aligned} \tag{3-14}$$

where

WD = water depth in feet
DD = drilling depth in feet.

Completion and Operating

Completion costs per well are a function of water depth range and drilling depth as shown in Table 3-5.

Table 3-5. Well Completion and Equipment Costs per Well

Water Depth (feet)	Development Drilling Depth (feet)		
	< 10,000	10,001 - 20,000	> 20,000
0 - 3,000	800,000	2,100,000	3,300,000
> 3,000	1,900,000	2,700,000	3,300,000

Platform operating costs for all types of structures are assumed to be a function of water depth (WD) and the number of slots (SLT). These costs include the following items:

- primary oil and gas production costs,
- labor,
- communications and safety equipment,
- supplies and catering services,
- routine process and structural maintenance,
- well service and workovers,
- insurance on facilities, and
- transportation of personnel and supplies.

Annual operating costs are estimated by

$$\text{OperatingCost}(\$/\text{structure}/\text{year}) = 1{,}265{,}000 + 135{,}000 * \text{SLT} + 0.0588 * \text{SLT} * \text{WD}^2 \qquad (3\text{-}15)$$

Transportation

It is assumed in the model that existing trunk pipelines will be used and that the prospect economics must support only the gathering system design and installation. However, in case of small fields tied back to some existing neighboring production platform, a pipeline is assumed to be required to transport the crude oil and natural gas to the neighboring platform.

Structure and Facility Abandonment

The costs to abandon the development structure and production facilities depend on the type of production technology used. The model projects abandonment costs for fixed platforms and compliant towers assuming that the structure is abandoned. It projects costs for tension leg platforms, converted semi-submersibles, and converted tankers assuming that the structures are removed for transport to another location for reinstallation. These costs are treated as intangible capital investments and are expensed in the year following cessation of production. Based on historical data, these costs are estimated as a fraction of the initial structure costs, as follows:

	Fraction of Initial Platform Cost
Fixed Platform	0.45
Compliant Tower	0.45
Tension Leg Platform	0.45
Floating Production Systems	0.15
Spar Platform	0.15

Exploration, Development, and Production Scheduling

The typical offshore project development consists of the following phases:[3]

- Exploration phase,
    - Exploration drilling program
    - Delineation drilling program
- Development phase,
- Fabrication and installation of the development/production platform,
    - Development drilling program
    - Pre-drilling during construction of platform
    - Drilling from platform
    - Construction of gathering system
- Production operations, and
- Field abandonment.

[3]The pre-development activities, including early field evaluation using conventional geological and geophysical methods and the acquisition of the right to explore the field, are assumed to be completed before initiation of the development of the prospect.

The timing of each activity, relative to the overall project life and to other activities, affects the potential economic viability of the undiscovered prospect. The modeling objective is to develop an exploration, development, and production plan which both realistically portrays existing and/or anticipated offshore practices and also allows for the most economical development of the field. A description of each of the phases is provided below.

Exploration Phase

An undiscovered field is assumed to be discovered by a successful exploration well (i.e., a new field wildcat). Delineation wells are then drilled to define the vertical and areal extent of the reservoir.

Exploration drilling. The exploration success rate (ratio of the number of field discovery wells to total wildcat wells) is used to establish the number of exploration wells required to discover a field as follows:

number of exploratory wells = 1/ [exploration success rate]

For example, a 25 percent exploration success rate will require four exploratory wells: one of the four wildcat wells drilled finds the field and the other three are dry holes.

Delineation drilling. Exploratory drilling is followed by delineation drilling for field appraisal (1 to 4 wells depending on the size of the field). The delineation wells define the field location vertically and horizontally so that the development structures and wells may be set in optimal positions. All delineation wells are converted to production wells at the end of the production facility construction.

Development Phase

During this phase of an offshore project, the development structures are designed, fabricated, and installed; the development wells (successful and dry) are drilled and completed; and the product transportation/gathering system is installed.

Development structures. The model assumes that the design and construction of any development structure begins in the year following completion of the exploration and delineation drilling program. However, the length of time required to complete the construction and installation of these structures depends on the type of system used. The required time for construction and installation of the various development structures used in the model is shown in Table 3-6. This time lag is important in all offshore developments, but it is especially critical for fields in deepwater and for marginally economic fields.

Development drilling schedule. The number of development wells varies by water depth and field size class as follows.

$$DevelopmentWells = \frac{5}{FSC} * FSIZE^{\beta_{DepthClass}} \qquad (3\text{-}16)$$

where

FSC = field size class
FSIZE = resource volume (MMBOE)

β = 0.8 for water depths < 200 meters; 0.7 for water depths 200-800 meters; 0.65 for water depths > 800 meters.

Table 3-6. Production Facility Design, Fabrication, and Installation Period (Years)

PLATFORMS	**Water Depth (Feet)**														
Number of Slots	**0**	**100**	**400**	**800**	**1000**	**1500**	**2000**	**3000**	**4000**	**5000**	**6000**	**7000**	**8000**	**9000**	**10000**
2	1	1	1	1	1	1	1	1	2	2	3	3	4	4	4
8	2	2	2	2	2	2	2	2	2	2	3	3	4	4	4
12	2	2	2	2	2	2	2	2	2	2	3	3	4	4	4
18	2	2	2	2	2	2	2	2	2	3	3	3	4	4	4
24	2	2	2	2	2	2	2	2	2	3	3	4	4	4	5
36	2	2	2	2	2	2	2	2	2	3	3	4	4	4	5
48	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
60	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
OTHERS															
SS	1	1	1	1	1	1	2	2	2	3	3	3	4	4	4
FPS								3	3	3	4	4	4	4	5

Source: ICF Consulting

The development drilling schedule is determined based on the assumed drilling capacity (maximum number of wells that could be drilled in a year). This drilling capacity varies by type of production facility and water depth. For a platform type production facility (FP, CT, or TLP), the development drilling capacity is also a function of the number of slots. The assumed drilling capacity by production facility type is shown in Table 3-7.

Production transportation/gathering system. It is assumed in the model that the installation of the gathering systems occurs during the first year of construction of the development structure and is completed within 1 year.

Production Operations

Production operations begin in the year after the construction of the structure is complete. The life of the production depends on the field size, water depth, and development strategy. First production is from delineation wells that were converted to production wells. Development drilling starts at the end of the production facility construction period.

Table 3-7. Development Drilling Capacity by Production Facility Type

Maximum Number of Wells Drilled (wells/platform/year, 1 rig)	
Drilling Depth (feet)	**Drilling Capacity (24 slots)**
0	24
6000	24
7000	24
8000	20
9000	20
10000	20
11000	20
12000	16
13000	16
14000	12
15000	8
16000	4
17000	2
18000	2
19000	2
20000	2
30000	2

Maximum Number of Wells Drilled (wells/field/year)			
Water Depth (feet)	**SS**	**FPS**	**FPSO**
0	4	[redacted]	4
1000	4	[redacted]	4
2000	4	[redacted]	4
3000	4	4	4
4000	4	4	4
5000	3	3	3
6000	2	2	2
7000	2	2	2
8000	1	1	1
9000	1	1	1
10000	1	1	1

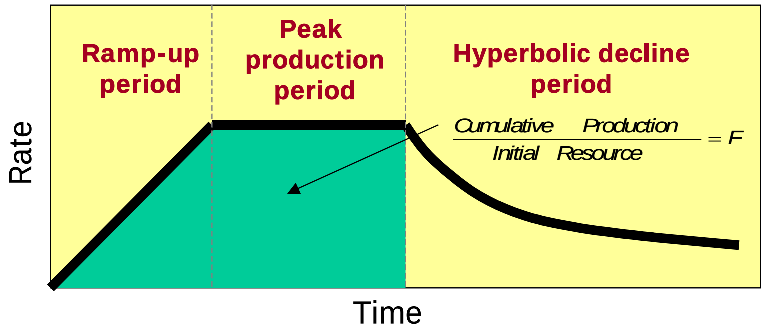
Source: ICF Consulting

Production profiles

The original hydrocarbon resource (in BOE) is divided between oil and natural gas using a user specified proportion. Due to the development drilling schedule, not all wells in the same field will produce at the same time. This yields a ramp-up profile in the early production period (Figure 3-3). The initial production rate is the same for all wells in the field and is constant for a period of time. Field production reaches its peak when all the wells have been drilled and start producing. The production will start to decline (at a user specified rate) when the ratio of cumulative production to initial resource equals a user specified fraction.

Gas (plus lease condensate) production is calculated based on gas resource, and oil (plus associated gas) production is calculated based on the oil resource. Lease condensate production is separated from the gas production using the user specified condensate yield. Likewise, associated-dissolved gas production is separated from the oil production using the user specified associated gas-to-oil ratio. Associated-dissolved gas production is then tracked separately from the nonassociated gas production throughout the projection. Lease condensate production is added to crude oil production and is not tracked separately.

Figure 3-3. Undiscovered Field Production Profile



Source: ICF Consulting

Field Abandonment

All wells in a field are assumed to be shut-in when the net revenue from the field is less than total State and Federal taxes. Net revenue is total revenue from production less royalties, operating costs, transportation costs, and severance taxes.

Discovered Undeveloped Fields Component

Announced discoveries that have not been brought into production by 2002 are included in this component of the OOGSS. The data required for these fields include location, field size class, gas percentage of BOE resource, condensate yield, gas to oil ratio, start year of production, initial production rate, fraction produced before decline, and hyperbolic decline parameters. The BOE resource for each field corresponds to the field size class as specified in Table 3-3.

The number of development wells is the same as that of an undiscovered field in the same water depth and of the same field size class (Equation 3-13). The production profile is also the same as that of an undiscovered field (Figure 3-3).

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2009 are shown in Table 3-8. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent is assumed to be gas.

Producing Fields Component

A separate database is used to track currently producing fields. The data required for each producing field include location, field size class, field type (oil or gas), total recoverable resources, historical production (1990-2002), and hyperbolic decline parameters.

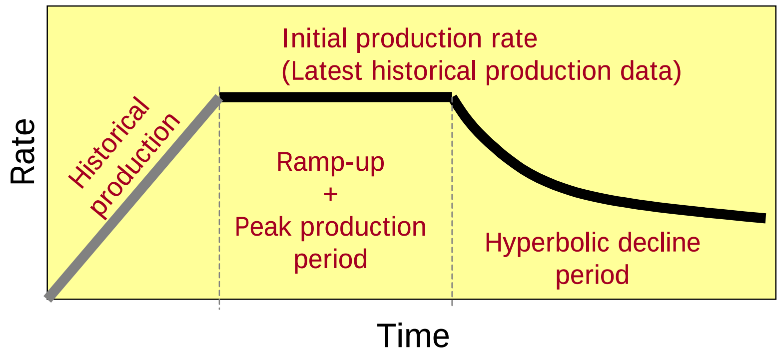
Projected production from the currently producing fields will continue to decline if, historically, production from the field is declining (Figure 3-4). Otherwise, production is held constant for a period of time equal to the sum of the specified number ramp-up years and number of years at peak production after which it will decline (Figure 3-5). The model assumes that production will decline according to a hyperbolic decline curve until the economic limit is achieved and the field is abandoned. Typical production profile data are shown in Table 3-9. Associated-dissolved gas and lease condensate production are determined the same way as in the undiscovered field component.

Table 3-8. Assumed Size and Initial Production Year of Major Announced Deepwater Discoveries

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBoe)	Start Year of Production
Great White	AC857	8717	2002	14	372	2010
Telemark	AT063	4457	2000	12	89	2010
Ozona	GB515	3000	2008	12	89	2011
West Tonga	GC726	4674	2007	12	89	2011
Gladden	MC800	3116	2008	12	89	2011
Pony	GC468	3497	2006	13	182	2013
Knotty Head	GC512	3557	2005	15	691	2013
Puma	GC823	4129	2003	14	372	2013
Big Foot	WR029	5235	2005	12	89	2013
Cascade	WR206	8143	2002	14	372	2013
Chinook	WR469	8831	2003	14	372	2013
Pyrenees	GB293	2100	2009	12	89	2014
Kaskida	KC292	5860	2006	15	691	2014
Appaloosa	MC503	2805	2008	14	372	2014
Jack	WR759	6963	2004	14	372	2014
Samurai	GC432	3400	2009	12	89	2015
Wide Berth	GC490	3700	2009	12	89	2015
Manny	MC199	2478	2010	13	182	2015
Kodiak	MC771	4986	2008	15	691	2015
St. Malo	WR678	7036	2003	14	372	2015
Mission Deep	GC955	7300	2006	13	182	2016
Tiber	KC102	4132	2009	16	1419	2016
Vito	MC984	4038	2009	13	182	2016
Stones	WR508	9556	2005	12	89	2016
Heidelberg	GB859	5000	2009	13	182	2017
Freedom	MC948	6095	2008	15	691	2017
Shenandoah	WR052	5750	2009	13	182	2017
Buckskin	KC872	6920	2009	13	182	2018
Julia	WR627	7087	2007	12	89	2018
Vicksburg	DC353	7457	2009	14	372	2019
Lucius	KC875	7168	2009	13	182	2019

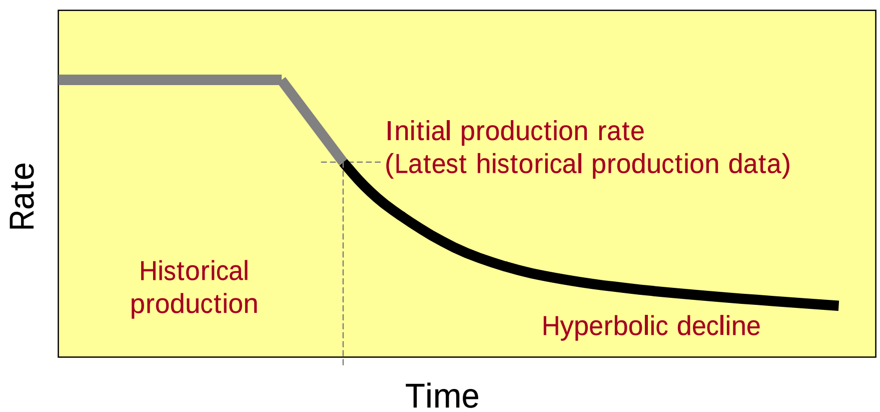
Source: U.S. Energy Information Administration, Energy Analysis, Office of Petroleum, Gas, and Biofuels Analysis

Figure 3-4. Production Profile for Producing Fields - Constant Production Case



Source: ICF Consulting

Figure 3-5. Production Profile for Producing Fields - Declining Production Case



Source: ICF Consulting

Table 3-9. Production Profile Data for Oil & Gas Producing Fields

Region	Crude Oil						Natural Gas					
	FSC 2 - 10			FSC 11 – 17			FSC 2 - 10			FSC 11 - 17		
	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate
Shallow GOM	2	2	0.15	3	3	0.10	2	1	0.20	3	2	0.10
Deep GOM	2	2	0.20	2	3	0.15	2	2	0.25	3	2	0.20
Atlantic	2	2	0.20	3	3	0.20	2	1	0.25	3	2	0.20
Pacific	2	2	0.10	3	2	0.10	2	1	0.20	3	2	0.20

FSC = Field Size Class
Source: ICF Consulting

Generation of Supply Curves

As mentioned earlier, the OOGSS does not determine the actual volume of crude oil and nonassociated natural gas produced in a given projection year but rather provides the parameters for the short-term supply functions used to determine regional supply and demand market equilibration. For each year, t, and offshore region, r, the OGSM calculates the stock of proved reserves at the beginning of year t+1 and the expected production-to-reserves (PR) ratio for year t+1 as follows.

The volume of proved reserves in any year is calculated as

$$RESOFF_{r,k,t+1} = RESOFF_{r,k,t} - PRDOFF_{r,k,t} + NRDOFF_{r,k,t} + REVOFF_{r,k,t} \tag{3-17}$$

where

RESOFF	=	beginning- of-year reserves
PRDOFF	=	production
NRDOFF	=	new reserve discoveries
REVOFF	=	reserve extensions, revisions, and adjustments
r	=	region (1=Atlantic, 2=Pacific, 3=GOM)
k	=	fuel type (1=oil; 2=nonassociated gas)
t	=	year.

Expected production, EXPRDOFF, is the sum of the field level production determined in the undiscovered fields component, the discovered, undeveloped fields component, and the producing field component. The volume of crude oil production (including lease condensate), PRDOFF, passed to the PMM is equal to EXPRDOFF. Nonassociated natural gas production in year t is the market equilibrated volume passed to the OGSM from the NGTDM.

Reserves are added through new field discoveries as well as delineation and developmental drilling. Each newly discovered field not only adds proved reserves but also a much larger amount of inferred reserves. The allocation between proved and inferred reserves is based on historical reserves growth statistics provided by the Minerals Management Service. Specifically,

$$NRDOFF_{r,k,t} = NFDISC_{r,k,t-1} * \left(\frac{1}{RSVGRO_k} \right) \tag{3-18}$$

$$NIRDOFF_{r,k,t} = NFDISC_{r,k,t-1} * \left(1 - \frac{1}{RSVGRO_k} \right) \tag{3-19}$$

where

NRDOFF	=	new reserve discovery
NIRDOFF	=	new inferred reserve additions
NFDISC	=	new field discoveries
RSVGRO	=	reserves growth factor (8.2738 for oil and 5.9612 for gas)
r	=	region (1=Atlantic, 2=Pacific, 3=GOM)
k	=	fuel type (1=oil; 2=gas)

t = year.

Reserves are converted from inferred to proved with the drilling of other exploratory (or delineation) wells and developmental wells. Since the expected offshore PR ratio is assumed to remain constant at the last historical value, the reserves needed to support the total expected production, EXPRDOFF, can be calculated by dividing EXPRDOFF by the PR ratio. Solving Equation 3-1 for $REVOFF_{r,k,t}$ and writing

gives

$$REVOFF_{r,k,t} = \frac{EXPRDOFF_{r,k,t+1}}{PR_{r,k}} + PRDOFF_{r,k,t} - RESOFF_{r,k,t} - NRDOFF_{r,k,t} \tag{3-20}$$

The remaining proved reserves, inferred reserves, and undiscovered resources are tracked throughout the projection period to ensure that production from offshore sources does not exceed the assumed resource base. Field level associated-dissolved gas is summed to the regional level and passed to the NGTDM.

Advanced Technology Impacts

Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a profound impact on the costs associated with these activities. The OOGSS has been designed to give due consideration to the effect of advances in technology that may occur in the future. The specific technology levers and values are presented in Table 3-10.

Table 3-10. Offshore Exploration and Production Technology Levers

Technology Lever	Total Improvement (percent)	Number of Years
Exploration success rates	30	30
Delay to commence first exploration and between exploration	15	30
Exploration & development drilling costs	30	30
Operating cost	30	30
Time to construct production facility	15	30
Production facility construction costs	30	30
Initial constant production rate	15	30
Decline rate	0	30

Source: ICF Consulting

Appendix 3.A. Offshore Data Inventory

VARIABLES				
Variable Name				
Code	Text	Description	Unit	Classification
ADVLTXOFF	PRODTAX	Offshore ad valorem tax rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CPRDOFF	COPRD	Offshore coproduct rate	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CUMDISC	DiscoveredFields	Cumulative number of dicovered offshore fields	NA	Offshore evaluation unit: Field size class
CUMNFW	CumNFW	Cumulative number of new fields wildcats drilled	NA	Offshore evaluation unit: Field size class
CURPRROFF	omega	Offshore initial P/R ratios	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CURRESOFF	R	Offshore initial reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
DECLOFF	--	Offshore decline rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
DEVLCOST	DevelopmentDrilling Cost	Development drilling cost	$ per well	Offshore evaluation unit
DRILLOFF	DRILL	Offshore drilling cost	1987$	4 Lower 48 offshore subregions
DRYOFF	DRY	Offshore dry hole cost	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions
DVWELLOFF	--	Offshore development project drilling schedules	wells per year	4 Lower 48 offshore subregions; Fuel (oil, gas)
ELASTOFF	--	Offshore production elasticity values	Fraction	4 Lower 48 offshore subregions
EXPLCOST	ExplorationDrillingC osts	Exploration well drilling cost	$ per wells	Offshore evaluation unit
EXWELLOFF	--	Offshore exploratory project drilling schedules	wells per year	4 Lower 48 offshore subregions
FLOWOFF	--	Offshore flow rates	bls, MCF per year	4 Lower 48 offshore subregions; Fuel (oil, gas)
FRMINOFF	FRMIN	Offshore minimum exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR1OFF	FR1	Offshore new field wildcat well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR2OFF	FR3	Offshore developmental well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR3OFF	FR2	Offshore other exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
HISTPRROFF	--	Offshore historical P/R ratios	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
HISTRESOFF	--	Offshore historical beginning-of-year reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
INFRSVOFF	I	Offshore inferred reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
KAPFRCOFF	EXKAP	Offshore drill costs that are tangible & must be depreciated	fraction	Class (exploratory, developmental)
KAPSPNDOFF	KAP	Offshore other capital expenditures	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions
LEASOFF	EQUIP	Offshore lease equipment cost	1987$ per project	Class (exploratory, developmental); 4 Lower 48 offshore subregions
NDEVWLS	DevelopmentWells	Number of development wells drilled	NA	Offshore evaluation unit
NFWCOSTOFF	COSTEXP	Offshore new field wildcat cost	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions

VARIABLES				
Variable Name				
Code	Text	Description	Unit	Classification
NFWELLOFF	--	Offshore exploratory and developmental project drilling schedules	wells per project per year	Class (exploratory, developmental); r=1
NIRDOFF	NIRDOFF	Offshore new inferred reserves	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
NRDOFF	NRDOFF	Offshore new reserve discoveries	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
OPEROFF	OPCOST	Offshore operating cost	1987$ per well per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions
OPRCOST	OperatingCost	Operating cost	$ per well	Offshore evaluation unit
PFCOST	StructureCost	Offshore production facility cost	$ per structure	Offshore evaluation unit
PRJOFF	N	Offshore project life	Years	Fuel (oil, gas)
RCPRDOFF	M	Offshore recovery period intangible & tangible drill cost	Years	Lower 48 Offshore
RESOFF	RESOFF	Offshore reserves	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
REVOFF	REVOFF	Offshore reserve revisions	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
SC	Γ	Search coefficient for discovery model	Fraction	Offshore evaluation unit: Field size class
SEVTXOFF	PRODTAX	Offshore severance tax rates	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
SROFF	SR	Offshore drilling success rates	fraction	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
STTXOFF	STRT	State tax rates	fraction	4 Lower 48 offshore subregions
TECHOFF	TECH	Offshore technology factors applied to costs	fraction	Lower 48 Offshore
TRANSOFF	TRANS	Offshore expected transportation costs	NA	4 Lower 48 offshore subregions; Fuel (oil, gas)
UNRESOFF	Q	Offshore undiscovered resources	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
WDCFOFFIRKLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
WDCFOFFIRLAG	--	1989 offshore regional exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions;
WDCFOFFLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental)
WELLAGOFF	WELLSOFF	1989 offshore wells drilled	Wells per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
XDCKAPOFF	XDCKAP	Offshore intangible drill costs that must be depreciated	fraction	NA

PARAMETERS		
Parameter	Description	Value
nREG	Region ID (1: CENTRAL & WESTERN GOM; 2: EASTERN GOM; 3: ATLANTIC; 4: PACIFIC)	4
nPA	Planning Area ID (1: WESTERN GOM; 2: CENTRAL GOM; 3: EASTERN GOM; 4: NORTH ATLANTIC; 5: MID ATLANTIC; 6: SOUTH ATLANTIC; 7: FLORIDA STRAITS; 8: PACIFIC; NORTHWEST; 9: CENTRAL CALIFORNIA; 10: SANTA BARBARA - VENTURA BASIN; 11: LOS ANGELES BASIN; 12: INNER BORDERLAND; 13: OUTER BORDERLAND)	13
ntEU	Total number of evaluation units (43)	43
nMaxEU	Maximum number of EU in a PA (6)	6
TOTFLD	Total number of evaluation units	3600
nANN	Total number of announce discoveries	127

PARAMETERS		
Parameter	**Description**	**Value**
nPRD	Total number of producing fields	1132
nRIGTYP	Rig Type (1: JACK-UP 0-1500; 2: JACK-UP 0-1500 (Deep Drilling); 3: SUBMERSIBLE 0-1500; 4: SEMI-SUBMERSIBLE 1500-5000; 5: SEMI-SUBMERSIBLE 5000-7500; 6: SEMI-SUBMERSIBLE 7500-10000; 7: DRILL SHIP 5000-7500; 8: DRILL SHIP 7500-10000)	8
nPFTYP	Production facility type (1: FIXED PLATFORM (FP); 2: COMPLIANT TOWER (CT); 3: TENSION LEG PLATFORM (TLP); 4: FLOATING PRODUCTION SYSTEM (FPS); 5: SPAR; 6: FLOATING PRODUCTION STORAGE & OFFLOADING (FPSO); 7: SUBSEA SYSTEM (SS))	7
nPFWDR	Production facility water depth range (1: 0 - 656 FEET; 2: 656 - 2625 FEET; 3: 2625 - 5249 FEET; 4: 5249 - 7874 FEET; 5: 7874 - 9000 FEET)	5
NSLTIdx	Number of platform slot data points	8
NPFWD	Number of production facility water depth data points	15
NPLTDD	Number of platform water depth data points	17
NOPFWD	Number of other production facitlity water depth data points	11
NCSTWD	Number of water depth data points for production facility costs	39
NDRLWD	Number of water depth data points for well costs	15
NWLDEP	Number of well depth data points	30
TRNPPLNCSTNDIAM	Number of pipeline diameter data points	19
MAXNFIELDS	Maximum number of fields for a project/prospect	10
nMAXPRJ	Maximum number of projects to evaluate per year	500
PRJLIFE	Maximum project life in years	10

INPUT DATA			
Variable	**Description**	**Unit**	**Source**
ann_EU	Announced discoveries - Evaluation unit name	-	PGBA
ann_FAC	Announced discoveries - Type of production facility	-	BOEMRE
ann_FN	Announced discoveries - Field name	-	PGBA
ann_FSC	Announced discoveries - Field size class	integer	BOEMRE
ann_OG	Announced discoveries - fuel type	-	BOEMRE
ann_PRDSTYR	Announced discoveries - Start year of production	integer	BOEMRE
ann_WD	Announced discoveries - Water depth	feet	BOEMRE
ann_WL	Announced discoveries - Number of wells	integer	BOEMRE
ann_YRDISC	Announced discoveries - Year of discovery	integer	BOEMRE
beg_rsva	AD gas reserves	bcf	calculated in model
BOEtoMcf	BOE to Mcf conversion	Mcf/BOE	ICF
chgDrlCstOil	Change of Drilling Costs as a Function of Oil Prices	fraction	ICF
chgOpCstOil	Change of Operating Costs as a Function of Oil Prices	fraction	ICF
chgPFCstOil	Change of Production facility Costs as a Function of Oil Prices	fraction	ICF
cndYld	Condensate yield by PA, EU	Bbl/mmcf	BOEMRE
cstCap	Cost of capital	percent	BOEMRE
dDpth	Drilling depth by PA, EU, FSC	feet	BOEMRE
deprSch	Depreciation schedule (8 year schedule)	fraction	BOEMRE
devCmplCst	Completion costs by region, completion type (1=Single, 2=Dual), water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index	million 2003 dollars	BOEMRE
devDrlCst	Mean development well drilling costs by region, water depth index, drilling depth index	million 2003 dollars	BOEMRE
devDrlDly24	Maximum number of development wells drilled from a 24-slot PF by drilling depth index	Wells/PF/year	ICF
devDrlDlyOth	Maximum number of development wells drilled for other PF by PF type, water depth index	Wells/field/year	ICF

INPUT DATA			
Variable	Description	Unit	Source
devOprCst	Operating costs by region, water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index	2003 $/well/year	BOEMRE
devTangFrc	Development Wells Tangible Fraction	fraction	ICF
dNRR	Number of discovered producing fields by PA, EU, FSC	integer	BOEMRE
Drillcap	Drilling Capacity	wells/year/rig	ICF
duNRR	Number of discovered/undeveloped fields by PA, EU, FSC	integer	ICF
EUID	Evaluation unit ID	integer	ICF
EUname	Names of evaluation units by PA	integer	ICF
EUPA	Evaluation unit to planning area x-walk by EU_Total	integer	ICF
exp1stDly	Delay before commencing first exploration by PA, EU	number of years	ICF
exp2ndDly	Total time (Years) to explore and appraise a field by PA, EU	number of years	ICF
expDrlCst	Mean Exploratory Well Costs by region, water depth index, drilling depth index	million 2003 dollars	BOEMRE
expDrlDays	Drilling days/well by rig type	number of days/well	ICF
expSucRate	Exploration success rate by PA, EU, FSC	fraction	ICF
ExpTangFrc	Exploration and Delineation Wells Tangible Fraction	fraction	ICF
fedTaxRate	Federal Tax Rate	percent	ICF
fldExpRate	Maximum Field Exploration Rate	percent	ICF
gasprice	Gas wellhead price by region	2003$/mcf	NGTDM
gasSevTaxPrd	Gas production severance tax	2003$/mcf	ICF
gasSevTaxRate	Gas severance tax rate	percent	ICF
GOprop	Gas proportion of hydrocarbon resource by PA, EU	fraction	ICF
GOR	Gas-to-Oil ratio (Scf/Bbl) by PA, EU	Scf/Bbl	ICF
GORCutOff	GOR cutoff for oil/gas field determination	-	ICF
gRGCGF	Gas Cumulative Growth Factor (CGF) for gas reserve growth calculation by year index	-	BOEMRE
levDelWls	Exploration drilling technology (reduces number of delineation wells to justify development	percent	PGBA
levDrlCst	Drilling costs R&D impact (reduces exploration and development drilling costs)	percent	PGBA
levExpDly	Pricing impact on drilling delays (reduces delays to commence first exploration and between exploration	percent	PGBA
levExpSucRate	Seismic technology (increase exploration success rate)	percent	PGBA
levOprCst	Operating costs R&D impact (reduces operating costs)	percent	PGBA
levPfCst	Production facility cost R&D impact (reduces production facility construction costs	percent	PGBA
levPfDly	Production facility design, fabrication and installation technology (reduces time to construct production facility)	percent	PGBA
levPrdPerf1	Completion technology 1 (increases initial constant production facility)	percent	PGBA
levPrdPerf2	Completion technology 2 (reduces decile rates)	percent	PGBA
nDelWls	Number of delineation wells to justify a production facility by PA, EU, FSC	integer	ICF
nDevWls	Maximum number of development wells by PA, EU, FSC	integer	ICF
nEU	Number of evaluation units in each PA	integer	ICF
nmEU	Names of evaluation units by PA	-	ICF
nmPA	Names of planning areas by PA	-	ICF
nmPF	Name of production facility and subsea-system by PF type index	-	ICF
nmReg	Names of regions by region	-	ICF
ndiroff	Additions to inferred reserves by region and fuel type	oil: MBbls; gas: Bcf	calculated in model
nrdoff	New reserve discoveries by region and fuel type	oil: Mbbls; gas: Bcf	calculated in model
nRigs	Number of rigs by rig type	integer	ICF

INPUT DATA			
Variable	Description	Unit	Source
nRigWlsCap	Number of well drilling capacity (Wells/Rig)	wells/rig	ICF
nRigWlsUtl	Number of wells drilled (Wells/Rig)	wells/rig	ICF
nSlt	Number of slots by # of slots index	integer	ICF
oilPrcCstTbl	Oil price for cost tables	2003$/Bbl	ICF
oilprice	Oil wellhead price by region	2003$/Bbl	PMM
oilSevTaxPrd	Oil production severance tax	2003$/Bbl	ICF
oilSevTaxRate	Oil severance tax rate	percent	ICF
oRGCGF	Oil Cumulative Growth Factor (CGF) for oil reserve growth calculation by year index	fraction	BOEMRE
paid	Planning area ID	integer	ICF
PAname	Names of planning areas by PA	-	ICF
pfBldDly1	Delay for production facility design, fabrication, and installation (by water depth index, PF type index, # of slots index (0 for non platform)	number of years	ICF
pfBldDly2	Delay between production facility construction by water depth index	number of years	ICF
pfCst	Mean Production Facility Costs in by region, PF type, water depth index, # of slots index (0 for non-platform)	million 2003 $	BOEMRE
pfCstFrc	Production facility cost fraction matrix by year index, year index	fraction	ICF
pfMaxNFld	Maximum number of fields in a project by project option	integer	ICF
pfMaxNWls	Maximum number of wells sharing a flowline by project option	integer	ICF
pfMinNFld	Minimum number of fields in a project by project option	integer	ICF
pfOptFlg	Production facility option flag by water depth range index, FSC	-	ICF
pfTangFrc	Production Facility Tangible Fraction	fraction	ICF
pfTypFlg	Production facility type flag by water depth range index, PF type index	-	ICF
platform	Flag for platform production facility	-	ICF
prd_DEPTH	Producing fields - Total drilling depth	feet	BOEMRE
prd_EU	Producing fields - Evaluation unit name	-	ICF
prd_FLAG	Producing fields - Production decline flag	-	ICF
prd_FN	Producing fields - Field name	-	BOEMRE
prd_ID	Producing fields - BOEMRE field ID	-	BOEMRE
prd_OG	Producing fields - Fuel type	-	BOEMRE
prd_YRDISC	Producing fields - Year of discovery	year	BOEMRE
prdDGasDecRatei	Initial gas decline rate by PA, EU, FSC range index	fraction/year	ICF
prdDGasHyp	Gas hyperbolic decline coefficient by PA, EU, FSC range index	fraction	ICF
prdDOilDecRatei	Initial oil decline rate by PA, EU,	fraction/year	ICF
prdDOilHyp	Oil hyperbolic decline coefficient by PA, EU, FSC range index	fraction	ICF
prdDYrPeakGas	Years at peak production for gas by PA, EU, FSC, range index	number of years	ICF
prdDYrPeakOil	Years at peak production for oil by PA, EU, FSC, range index	number of years	ICF
prdDYrRampUpGas	Years to ramp up for gas production by PA, EU, FSC range index	number of years	ICF
prdDYrRampUpOil	Years to ramp up for oil production by PA, EU, FSC range index	number of years	ICF
prdGasDecRatei	Initial gas decline rate by PA, EU	fraction/year	ICF
prdGasFrc	Fraction of gas produced before decline by PA, EU	fraction	ICF
prdGasHyp	Gas hyperbolic decline coefficient by PA, EU	fraction	ICF
prdGasRatei	Initial gas production (Mcf/Day/Well) by PA, EU	Mcf/day/well	ICF
PR	Expected production to reserves ratio by fuel typ	fraction	PGBA
prdoff	Expected production by fuel type	oil:MBbls; gas: Bcf	calculated in model
prdOilDecRatei	Initial oil decline rate by PA, EU	fraction/year	ICF
prdOilFrc	Fraction of oil produced before decline by PA, EU	fraction	ICF

INPUT DATA			
Variable	Description	Unit	Source
prdOilHyp	Oil hyperbolic decline coefficient by PA, EU	fraction	ICF
prdOilRatei	Initial oil production (Bbl/Day/Well) by PA, EU	Bbl/day/well	ICF
prod	Producing fields - annual production by fuel type	oil:MBbls; gas:Mmcf	BOEMRE
prod_asg	AD gas production	bcf	calculated in model
revoff	Extensions, revisions, and adjustments by fuel type	oil:MBbls; gas:Bcf	
rigBldRatMax	Maximum Rig Build Rate by rig type	percent	ICF
rigIncrMin	Minimum Rig Increment by rig type	integer	ICF
RigUtil	Number of wells drilled	wells/rig	ICF
rigUtilTarget	Target Rig Utilization by rig type	percent	ICF
royRateD	Royalty rate for discovered fields by PA, EU, FSC	fraction	BOEMRE
royRateU	Royalty rate for undiscovered fields by PA, EU, FSC	fraction	BOEMRE
stTaxRate	Federal Tax Rate by PA, EU	percent	ICF
trnFlowLineLen	Flowline length by PA, EU	Miles/prospect	ICF
trnPpDiam	Oil pipeline diameter by PA, EU	inches	ICF
trnPplnCst	Pipeline cost by region, pipe diameter index, water depth index	million 2003 $/mile	BOEMRE
trnTrfGas	Gas pipeline tariff ($/Mcf) by PA, EU	2003 $/Bbl	ICF
trnTrfOil	Oil pipeline tariff ($/Bbl) by PA, EU	2003 $/Bbl	ICF
uNRR	Number of undiscovered fields by PA, EU, FSC	integer	calculated in model
vMax	Maximum MMBOE of FSC	MMBOE	BOEMRE
vMean	Geometric mean MMBOE of FSC	MMBOE	BOEMRE
vMin	Minimum MMBOE of FSC	MMBOE	BOEMRE
wDpth	Water depth by PA, EU, FSC	feet	BOEMRE
yrAvl	Year lease available by PA, EU	year	ICF
yrCstTbl	Year of cost tables	year	ICF

Sources: BOEMRE = Bureau of Ocean Energy Management, Regulation, and Enforcement (formerly the Minerals Management Service); ICF = ICF Consulting; PGBA = EIA, Office of Petroleum, Gas, and Biofuels Analysis

4. Alaska Oil and Gas Supply Submodule

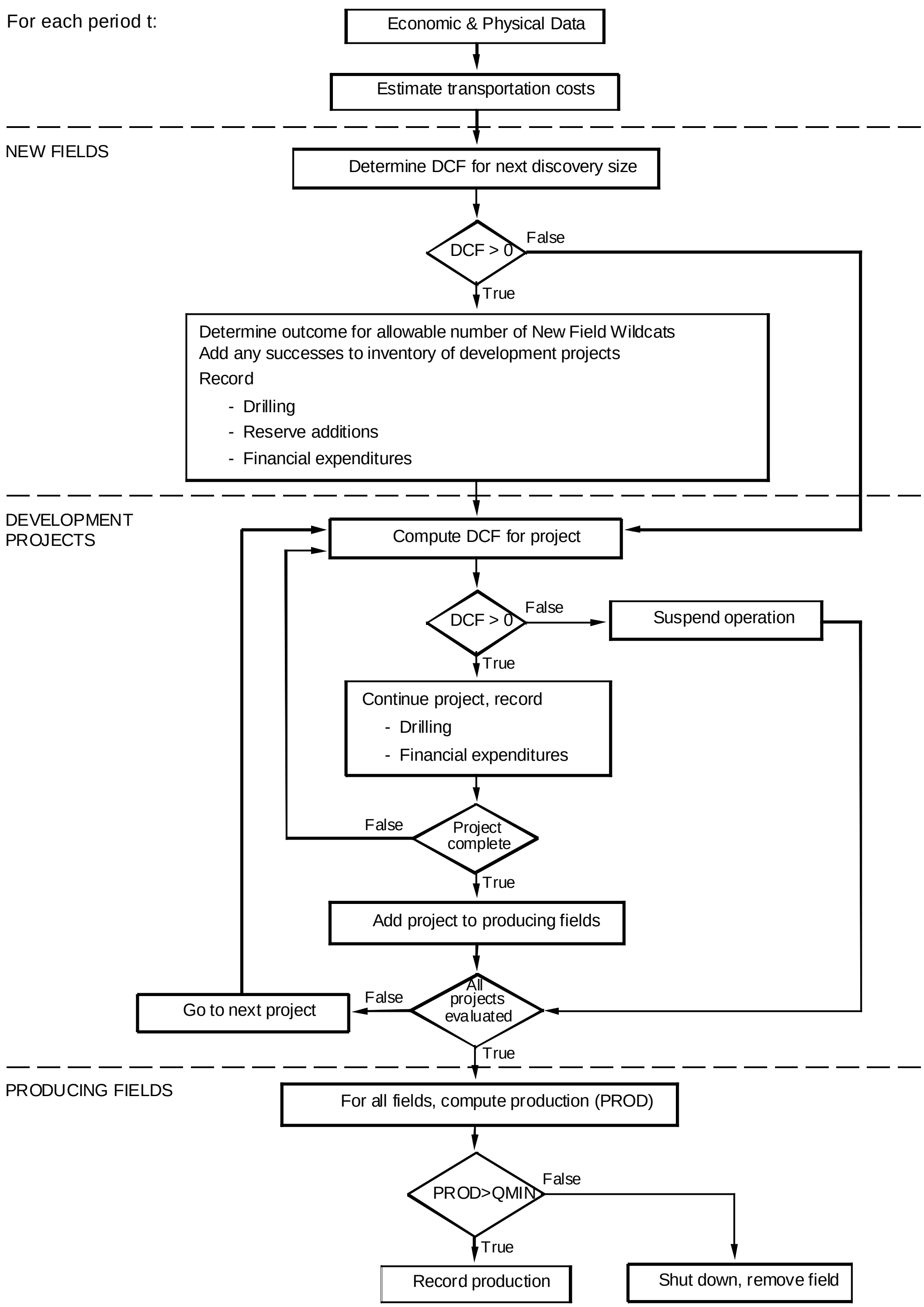
This section describes the structure for the Alaska Oil and Gas Supply Submodule (AOGSS). The AOGSS is designed to project field-specific oil production from the Onshore North Slope, Offshore North Slope, and Other Alaska areas (primarily the Cook Inlet area). The North Slope region encompasses the National Petroleum Reserve Alaska in the west, the State Lands in the middle, and the Arctic National Wildlife Refuge area in the east. This section provides an overview of the basic modeling approach, including a discussion of the discounted cash flow (DCF) method.

Alaska natural gas production is not projected by the AOGSS, but by Natural Gas Transmission and Distribution Module (NGTDM). The NGTDM projects Alaska gas consumption and whether an Alaska gas pipeline is projected to be built to carry Alaska North Slope gas into Canada and U.S. gas markets. As of January 1, 2009, Alaska was estimated to have 7.7 trillion cubic feet of proved reserves, 24.8 trillion cubic feet of inferred resources at existing fields (also known as field appreciation), and 257.5 trillion cubic feet of undiscovered resources, excluding the Arctic National Wildlife Refuge undiscovered gas resources. Over the long term, Alaska natural gas production is determined by and constrained by local consumption and by the capacity of a gas pipeline that might be built to serve Canada and U.S. lower-48 markets. The proven and inferred gas resources alone (i.e. 32.5 trillion cubic feet), plus known but undeveloped resources, are sufficient to satisfy at least 20 years of Alaska gas consumption and gas pipeline throughput. Moreover, large deposits of natural gas have been discovered (e.g., Point Thomson) but remain undeveloped due to a lack of access to gas consumption markets. Because Alaska natural gas production is best determined by projecting Alaska gas consumption and whether a gas pipeline is put into operation, the AOGSS does not attempt to project new gas field discoveries and their development or the declining production from existing fields.

AOGSS Overview

The AOGSS solely focuses on projecting the exploration and development of undiscovered oil resources, primarily with respect to the oil resources expected to be found onshore and offshore in North Alaska. The AOGSS is divided into three components: new field discoveries, development projects, and producing fields (Figure 4-1). Transportation costs are used in conjunction with the crude oil price to Southern California refineries to calculate an estimated wellhead (netback) oil price. A discounted cash flow (DCF) calculation is used to determine the economic viability of Alaskan drilling and production activities. Oil field investment decisions are modeled on the basis of discrete projects. The exploration, discovery, and development of new oil fields depend on the expected exploration success rate and new field profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, along with historical production patterns and announced plans for currently producing fields.

Figure 4-1. Flowchart of the Alaska Oil and Gas Supply Submodule



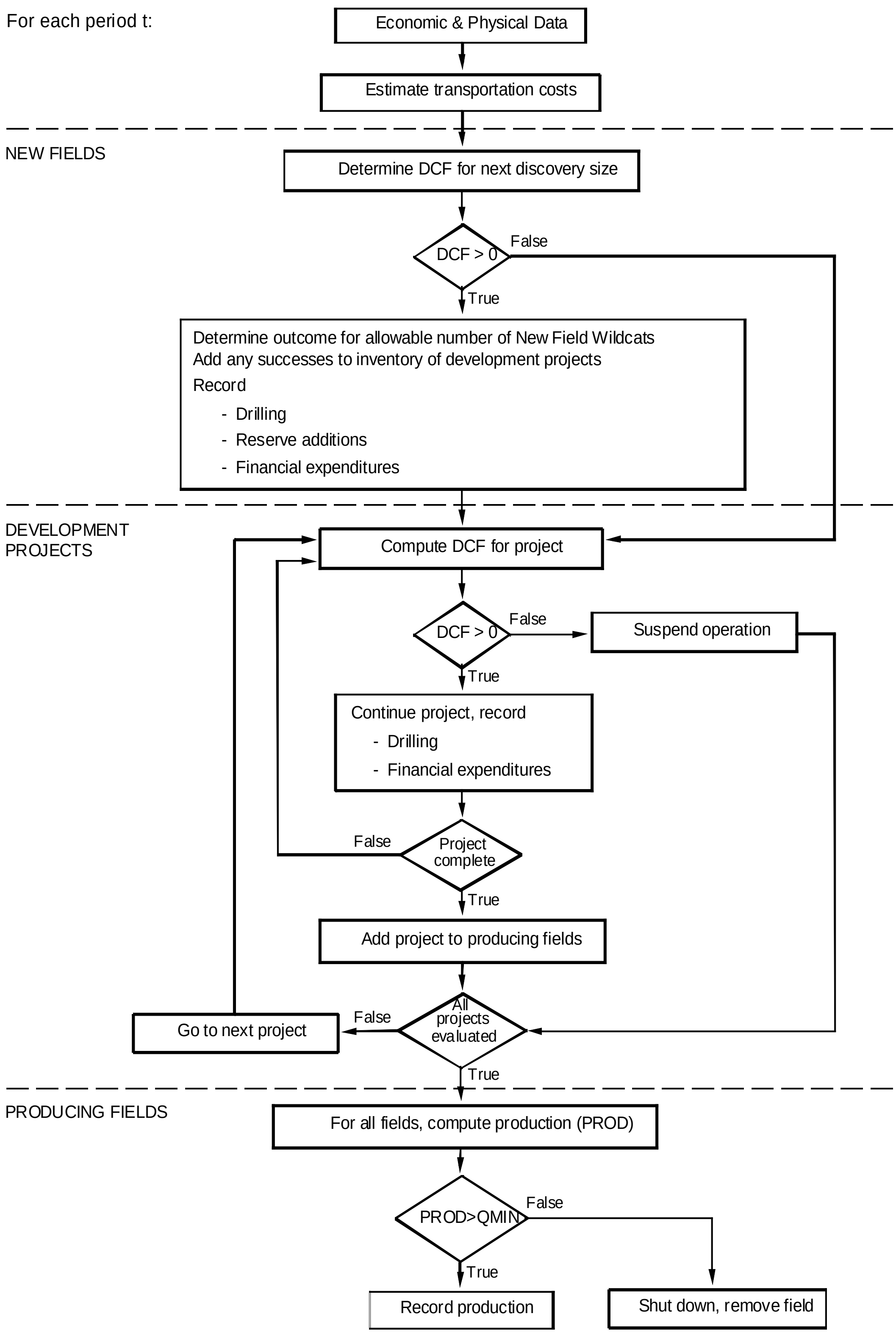
Calculation of Costs

Costs differ within the model for successful wells and dry holes. Costs are categorized functionally within the model as

- Drilling costs,
- Lease equipment costs, and
- Operating costs (including production facilities and general and administrative costs).

All costs in the model incorporate the estimated impact of environmental compliance. Environmental regulations that preclude a supply activity outright are reflected in other adjustments to the model. For example, environmental regulations that preclude drilling in certain locations within a region are modeled by reducing the recoverable resource estimates for that region.

Each cost function includes a variable that reflects the cost savings associated with technological improvements. As a result of technological improvements, average costs decline in real terms



relative to what they would otherwise be. The degree of technological improvement is a user specified option in the model. The equations used to estimate costs are similar to those used for the lower 48 but include cost elements that are specific to Alaska. For example, lease equipment includes gravel pads and ice roads.

Drilling Costs

Drilling costs are the expenditures incurred for drilling both successful wells and dry holes, and for equipping successful wells through the "Christmas tree," the valves and fittings assembled at the top of a well to control the fluid flow. Elements included in drilling costs are labor, material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. Drilling costs for exploratory wells include costs of support equipment such as ice pads. Lease equipment required for production is included as a separate cost calculation and covers equipment installed on the lease downstream from the Christmas tree.

The average cost of drilling a well in any field located within region r in year t is given by:

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1) ** (t - T_b) \tag{4-1}$$

where

i	=	well class (exploratory=1, developmental=2)
r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k	=	fuel type (oil=1, gas=2 - but not used)
t	=	forecast year
DRILLCOST	=	drilling costs
T_b	=	base year of the forecast
TECH1	=	annual decline in drilling costs due to improved technology.

The above function specifies that drilling costs decline at the annual rate specified by TECH1. Drilling costs are not modeled as a function of the drilling rig activity level as they are in the Onshore Lower 48 methodology. Drilling rigs and equipment are designed specifically for the harsh Arctic weather conditions. Once drilling rigs are moved up to Alaska and reconfigured for Arctic conditions, they typically remain in Alaska. Company drilling programs in Alaska are planned to operate at a relatively constant level of activity because of the limited number of drilling rigs and equipment available for use. Most Alaska oil rig activity pertains to drilling in-fill wells intended to slow the rate of production decline in the largest Alaska oil fields.

For the *Annual Energy Outlook 2011*, Alaska onshore and offshore drilling and completion costs were updated based on the American Petroleum Institute’s (API), *2007 Joint Association Survey on Drilling Costs*, dated December 2008. Based on these API drilling and completion costs and earlier work performed by Advanced Resources International, Inc. in 2002, the following oil well drilling and completion costs were incorporated into the AOGSS database (Table 4.1).

Table 4.1
AOGSS Oil Well Drilling and Completion Costs
By Location and Category
In millions of 2007 dollars

	New Field Wildcat Wells	New Exploration Wells	Developmental Wells
	In millions of 2007 dollars		
Offshore North Slope	206	103	98
Onshore North Slope	150	75	57
South Alaska	73	59	37
	In millions of 1990 dollars		
Offshore North Slope	140	70	67
Onshore North Slope	102	51	39
South Alaska	50	40	25

Table 1 provides both 1990 and 2007 well drilling and completion cost data because the former are used within the context of calculating AOGSS discounted cash flows, while the latter are comparable to the current price environment.

Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a developed lease. Costs include: producing equipment, the gathering system, processing equipment (e.g., oil/gas/water separation), and production related infrastructure such as gravel pads. Producing equipment costs include tubing, pumping equipment. Gathering system costs consist of flowlines and manifolds. The lease equipment cost estimate for a new oil well is given by:

$$\mathrm{EQUIP}_{r,k,t} = \mathrm{EQUIP}_{r,k,t} * (1 - \mathrm{TECH2})^{r - T_b} \qquad (4\text{-}2)$$

where

r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k	=	fuel type (oil=1, gas=2 – not used)
t	=	forecast year
EQUIP	=	lease equipment costs
T_b	=	base year of the forecast
TECH2	=	annual decline in lease equipment costs due to improved technology.

Operating Costs

EIA operating cost data, which are reported on a per well basis for each region, include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

The estimated operating cost curve is:

$$OPCOST_{r,k,t} = OPCOST_{r,k,t} * (1 - TECH2)^{r - T_b} \tag{4-3}$$

where

r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k	=	fuel type (oil=1, gas=2 – not used)
t	=	forecast year
OPCOST	=	operating cost
T_b	=	base year of the forecast
TECH3	=	annual decline in operating costs due to improved technology.

Drilling costs, lease equipment costs, and operating costs are integral components of the following discounted cash flow analysis. These costs are assumed to be uniform across all fields within each of the three Alaskan regions.

Treatment of Costs in the Model for Income Tax Purposes

All costs are treated for income tax purposes as either expensed or capitalized. The tax treatment in the DCF reflects the applicable provisions for oil producers. The DCF assumptions are consistent with standard accounting methods and with assumptions used in similar modeling efforts. The following assumptions, reflecting current tax law, are used in the calculation of costs.

- All dry-hole costs are expensed.
- A portion of drilling costs for successful wells is expensed. The specific split between expensing and amortization is based on the tax code.
- Operating costs are expensed.
- All remaining successful field development costs are capitalized.
- The depletion allowance for tax purposes is not included in the model, because the current regulatory limitations for invoking this tax advantage are so restrictive as to be insignificant in the aggregate for future drilling decisions.

- Successful versus dry-hole cost estimates are based on historical success rates of successful versus dry-hole footage.

- Lease equipment for existing wells is in place before the first forecast year of the model.

Discounted Cash Flow Analysis

A discounted cash flow (DCF) calculation is used to determine the profitability of oil projects.[1] A positive DCF is necessary to initiate the development of a discovered oil field. With all else being equal, large oil fields are more profitable to develop than small and mid-size fields. In Alaska, where developing new oil fields is quite expensive, particularly in the Arctic, the profitable development of small and mid-size oil fields is generally contingent on the pre-existence of infrastructure that was paid for by the development of a nearby large field. Consequently, AOGSS assumes that the largest oil fields will be developed first, followed by the development of ever smaller oil fields. Whether these oil fields are developed, regardless of their size, is projected on the basis of the profitability index, which is measured as the ratio of the expected discounted cash flow to expected capital costs for a potential project.

A key variable in the DCF calculation is the oil transportation cost to southern California refineries. Transportation costs for Alaskan oil include both pipeline and tanker shipment costs. The oil transportation cost directly affects the expected revenues from the production of a field as follows:[2]

$$REV_{f,t} = Q_{f,t} * (MP_t - TRANS_t) \tag{4-4}$$

where

f	=	field
t	=	year
REV	=	expected revenues
Q	=	expected production volumes
MP	=	market price in the lower 48 states
TRANS	=	transportation cost.

The expected discounted cash flow associated with a potential oil project in field f at time t is given by

$$\begin{aligned} DCF_{f,t} = {} & (PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP \\ & - PVOPCOST - PVPRODTAX - PVSIT - PVFIT)_{f,t} \end{aligned} \tag{4-5}$$

where,

PVREV	=	present value of expected revenues

[1]See Appendix 3.A at the end of this chapter for a detailed discussion of the DCF methodology.

[2]This formulation assumes oil production only. It can be easily expanded to incorporate the sale of natural gas.

PVROY	=	present value of expected royalty payments
PVDRILLCOST	=	present value of all exploratory and developmental drilling expenditures
PVEQUIP	=	present value of expected lease equipment costs
TRANSCAP	=	cost of incremental transportation capacity
PVOPCOST	=	present value of operating costs
PVPRODTAX	=	present value of expected production taxes (ad valorem and severance taxes)
PVSIT	=	present value of expected state corporate income taxes
PVFIT	=	present value of expected federal corporate income taxes

The expected capital costs for the proposed field f located in region r are:

$$COST_{f,t} = (PVEXPCOST + PVDEVCOST + PVEQUIP + TRANSCAP)_{f,t} \quad (4\text{-}6)$$

where

PVEXPCOST	=	present value exploratory drilling costs
PVDEVCOST	=	present value developmental drilling costs
PVEQUIP	=	present value lease equipment costs
TRANSCAP	=	cost of incremental transportation capacity

The profitability indicator from developing the proposed field is therefore

$$PROF_{f,t} = \frac{DCF_{f,t}}{COST_{f,t}} \quad (4\text{-}7)$$

The model assumes that field with the highest positive PROF in time t is eligible for exploratory drilling in the same year. The profitability indices for Alaska also are passed to the basic framework module of the OGSM.

New Field Discovery

Development of estimated recoverable resources, which are expected to be in currently undiscovered fields, depends on the schedule for the conversion of resources from unproved to reserve status. The conversion of resources into field reserves requires both a successful new field wildcat well and a positive discounted cash flow of the costs relative to the revenues. The discovery procedure can be determined endogenously, based on exogenously determined data. The procedure requires the following exogenously determined data:

- new field wildcat success rate,
- any restrictions on the timing of drilling,
- the distribution of technically recoverable field sizes within each region.

The endogenous procedure generates:

- the new field wildcat wells drilled in any year,
- the set of individual fields to be discovered, specified with respect to size and location (relative to the 3 Alaska regions, i.e., offshore North Slope, onshore North Slope, and South-Central Alaska),
- an order for the discovery sequence, and
- a schedule for the discovery sequence.

The new field discovery procedure relies on the U.S. Geological Survey (USGS) and Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) respective estimates of onshore and offshore technically recoverable oil resources as translated into the expected field size distribution of undiscovered fields. These onshore and offshore field size distributions are used to determine the field size and order of discovery in the AOGSS exploration and discovery process. Thus, the AOGSS oil field discovery process is consistent with the expected geology with respect to expected aggregate resource base and the relative frequency of field sizes.

AOGSS assumes that the largest fields in a region are found first, followed by successively smaller fields. This assumption is based on the following observations: 1) the largest volume fields typically encompass the greatest areal extent, thereby raising the probability of finding a large field relative to finding a smaller field, 2) seismic technology is sophisticated enough to be able to determine the location of the largest geologic structures that might possibly hold oil, 3) producers have a financial incentive to develop the largest fields first both because of their higher inherent rate of return and because the largest fields can pay for the development of expensive infrastructure that affords the opportunity to develop the smaller fields using that same infrastructure, and 4) historically, North Slope and Cook Inlet field development has generally progressed from largest field to smallest field.

Starting with the AEO2011, onshore and offshore North Slope new field wildcat drilling activity is a function of West Texas Intermediate crude oil prices from 1977 through 2008, expressed in 2008 dollars. The new field wildcat exploration function was statistically estimated based on West Texas Intermdiate crude oil prices from 1977 through 2008 and on exploration well drilling data obtained from the Alaska Oil and Gas Conservation Commission (AOGCC) data files for the same period.[3] The North Slope wildcat exploration drilling parameters were estimated using ordinary least squares methodology.

$$NAK\_NFW_t = (0.13856 * IT\_WOP_t) + 3.77 \qquad (4\text{-}8)$$

where

t	=	year
NAK_NFW_t	=	North Slope Alaska field wildcat exploration wells
IT_WOP_t	=	World oil price in 2008 dollars

[3] A number of alternative functional formulations were tested (e.g., using Alaska crude oil prices, lagged oil prices, etc.), yet none of the alternative formations resulted in statistically more significant relationships.

The summary statistics for the statistical estimation are as follows:

```
Dependent variable: NSEXPLORE
Current sample:  1 to 32
Number of observations:  32

       Mean of dep. var. = 9.81250      LM het. test = .064580 [.799]
  Std. dev. of dep. var. = 4.41725     Durbin-Watson = 2.04186 [<.594]
Sum of squared residuals = 347.747  Jarque-Bera test = .319848 [.852]
   Variance of residuals = 11.5916   Ramsey's RESET2 = .637229E-04 [.994]
Std. error of regression = 3.40464   F (zero slopes) = 22.1824 [.000]
               R-squared = .425094    Schwarz B.I.C. = 87.0436
      Adjusted R-squared = .405930    Log likelihood = -83.5778

           Estimated    Standard
Variable  Coefficient     Error       t-statistic   P-value
C         3.77029       1.41706       2.66065       [.012]
WTIPRICE  .138559       .029419       4.70982       [.000]
```

Because very few offshore North Slope wells have been drilled since 1977, within AOGSS, the total number of exploration wells drilled on the North Slope are shared between the onshore and offshore regions, with the wells being predominantly drilled onshore in the early years of the projections with progressively more wells drilled offshore, such that after 20 years 50 percent of the exploration wells are drilled onshore and 50 percent are drilled offshore.

Based on the AOGCC data for 1977 through 2008, the drilling of South-Central Alaska new field wildcat exploration wells was statistically unrelated to oil prices. On average, 3 exploration wells per year were drilled in South-Central Alaska over the 1977 through 2008 timeframe, regardless of prevailing oil prices. This result probably stems from the fact that most of the South-Central Alaska drilling activity is focused on natural gas rather than oil, and that natural gas prices are determined by the Regulatory Commission of Alaska rather than being “market driven.” Consequently, AOGSS specifies that 3 exploration wells are drilled each year.

The execution of the above procedure can be modified to reflect restrictions on the timing of discovery for particular fields. Restrictions may be warranted for enhancements such as delays necessary for technological development needed prior to the recovery of relatively small accumulations or heavy oil deposits. State and Federal lease sale schedules could also restrict the earliest possible date for beginning the development of certain fields. This refinement is implemented by declaring a start date for possible exploration. For example, AOGSS specifies that if Federal leasing in the Arctic National Wildlife Refuge were permitted in 2011, then the earliest possible date at which an ANWR field could begin oil production would be in 2021.[4] Another example is the wide-scale development of the West Sak field that is being delayed until a technology can be developed that will enable the heavy, viscous crude oil of that field to be economically extracted.

[4] The earliest ANWR field is assumed to go into production 10 years after the first projection year; so the first field comes on line in 2020 for the *Annual Energy Outlook 2010* projections. See also *Analysis of Crude Oil Production in the Arctic National Wildlife Refugee*, EIA, SR/OIAF/2008-03, (May 2008).

Development Projects

Development projects are those projects in which a successful new field wildcat has been drilled. As with the new field discovery process, the DCF calculation plays an important role in the timing of development and exploration of these multi-year projects.

Each model year, the DCF is calculated for each potential development project. Initially, the model assumes a drilling schedule determined by the user or by some set of specified rules. However, if the DCF for a given project is negative, then development of this project is suspended in the year in which the negative DCF occurs. The DCF for each project is evaluated in subsequent years for a positive value. The model assumes that development would resume when a positive DCF value is calculated.

Production from developing projects follows the generalized production profile developed for and described in previous work conducted by DOE staff.[5] The specific assumptions used in this work are as follows:

- a 2- to 4-year build-up period from initial production to the peak production rate,
- the peak production rate is sustained for 3 to 8 years, and
- after peak production, the production rate declines by 12 to 15 percent per year.

The production algorithm build-up and peak-rate period are based on the expected size of the undiscovered field, with larger fields having longer build-up and peak-rate periods than the smaller fields. The field production decline rates are also determined by the field size.

The pace of development and the ultimate number of wells drilled for a particular field is based on the historical field-level profile adjusted for field size and other characteristics of the field (e.g. API gravity.)

After all exploratory and developmental wells have been drilled for a given project, development of the project is complete. For this version of the AOGSS, no constraint is placed on the number of exploratory or developmental wells that can be drilled for any project. All completed projects are added to the inventory of producing fields.

Development fields include fields that have already been discovered but have not begun production. These fields include, for example, a series of expansion fields in both the Prudhoe Bay area, the National Petroleum Reserve - Alaska (NPRA), and for various offshore fields. For these fields, the starting date of production and their production rates were not determined by the discovery process outlined above, but are based on public announcements by the company(s) developing those fields.

[5] *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment*, EIA (May 2000) and *Alaska Oil and Gas - Energy Wealth of Vanishing Opportunity?*, DOE/ID/0570-H1 (January 1991).

Producing Fields

Oil production from fields producing as of the initial projection year (e.g., Prudhoe Bay, Kuparuk, Lisburne, Endicott, and Milne Point) are based on historical production patterns, remaining estimated recovery, and announced development plans. The production decline rates of these fields are periodically recalibrated based on recent field-specific production rates.

Natural gas production from the North Slope for sale to end-use markets depends on the construction of a pipeline to transport natural gas to lower 48 markets.[6] North Slope natural gas production is determined by the carrying capacity of a natural gas pipeline to the lower 48.[7] The Prudhoe Bay Field is the largest known deposit of North Slope gas (24.5 Tcf)[8] and currently all of the gas produced from this field is re-injected to maximize oil production. Total known North Slope gas resources equal 35.4 Tcf.[9] Furthermore, the undiscovered onshore central North Slope and NPRA technically recoverable natural gas resource base are respectively estimated to be 33.3 Tcf[10] and 52.8 Tcf.[11] Collectively, these North Slope natural gas reserves and resources equal 121.5 Tcf, which would satisfy the 1.64 Tcf per year gas requirements of an Alaska gas pipeline for almost 75 years, well after the end of the *Annual Energy Outlook* projections. Consequently, North Slope natural gas resources, both discovered and undiscovered, are more than ample to supply natural gas to an Alaska gas pipeline during the *Annual Energy Outlook* projection period.

[6]Initial natural gas production from the North Slope for Lower 48 markets is affected by a delay reflecting a reasonable period for construction. Details of how this decision is made in NEMS are included in the Natural Gas Transmission and Distribution Module documentation.

[7] The determination of whether an Alaska gas pipeline is economically feasible is calculated within the Natural Gas Transmission and Distribution Model.

[8] *Alaska Oil and Gas Report 2009*, Alaska Department of Natural Resources, Division of Oil and Gas, Table I.I, page 8.

[9] Ibid.

[10] U.S. Geological Survey, *Oil and Gas Assessment of Central North Slope, Alaska, 2005*, Fact Sheet 2005-3043, April 2005, page 2 table – mean estimate total.

[11] U.S. Geological Survey, *2010 Updated Assessment of Undiscovered Oil and Gas Resources of the National Petroleum Reserve in Alaska (NPRA)*, Fact Sheet 2010-3102, October 2010, Table 1 – mean estimate total, page 4.

Appendix 4.A. Alaskan Data Inventory

Variable Name		Description	Unit	Classification	Source
Code	Text				
ANGTSMAX	--	ANGTS maximum flow	BCF/D	Alaska	NPC
ANGTSPRC	--	Minimum economic price for ANGTS start up	1987$/MCF	Alaska	NPC
ANGTSRES	--	ANGTS reserves	BCF	Alaska	NPC
ANGTSYR	--	Earliest start year for ANGTS flow	Year	NA	NPC
DECLPRO	--	Alaska decline rates for currently producing fields	Fraction	Field	OPNGBA
DEV_AK	--	Alaska drilling schedule for developmental wells	Wells per year	3 Alaska regions; Fuel (oil, gas)	OPNGBA
DRILLAK	DRILL	Alaska drilling cost (not including new field wildcats)	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	OPNGBA
DRLNFWAK	--	Alaska drilling cost of a new field wildcat	1990$/well	3 Alaska regions; Fuel (oil, gas)	OPNGBA
DRYAK	DRY	Alaska dry hole cost	1990$/hole	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	OPNGBA
EQUIPAK	EQUIP	Alaska lease equipment cost	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	USGS
EXP_AK	--	Alaska drilling schedule for other exploratory wells	wells per year	3 Alaska regions	OPNGBA
FACILAK	--	Alaska facility cost (oil field)	1990$/bls	Field size class	USGS
FSZCOAK	--	Alaska oil field size distributions	MMB	3 Alaska regions	USGS
FSZNGAK	--	Alaska gas field size distributions	BCF	3 Alaska regions	USGS
HISTPRDCO	--	Alaska historical crude oil production	MB/D	Field	AOGCC
KAPFRCAK	EXKAP	Alaska drill costs that are tangible & must be depreciated	fraction	Alaska	U.S. Tax Code
MAXPRO	--	Alaska maximum crude oil production	MB/D	Field	Announced Plans
NAK_NFW	--	Number of new field wildcat wells drilling in Northern AK	wells per year	NA	OPNGBA
NFW_AK	--	Alaska drilling schedule for new field wildcats	wells	NA	OPNGBA
PRJAK	n	Alaska oil project life	Years	Fuel (oil, gas)	OPNGBA
PROYR	--	Start year for known fields in Alaska	Year	Field	Announced Plans

Variable Name		Description	Unit	Classification	Source
Code	Text				
RCPRDAK	m	Alaska recovery period of intangible & tangible drill cost	Years	Alaska	U.S. Tax Code
RECRES	--	Alaska crude oil resources for known fields	MMB	Field	OFE, *Alaska Oil and Gas - Energy Wealth or Vanishing Opportunity*
ROYRT	ROYRT	Alaska royalty rate	fraction	Alaska	USGS
SEVTXAK	PRODTAX	Alaska severance tax rates	fraction	Alaska	USGS
SRAK	SR	Alaska drilling success rates	fraction	Alaska	OPNGBA
STTXAK	STRT	Alaska state tax rate	fraction	Alaska	USGS
TECHAK	TECH	Alaska technology factors	fraction	Alaska	OPNGBA
TRANSAK	TRANS	Alaska transportation cost	1990$	3 Alaska regions; Fuel (oil, gas)	OPNGBA
XDCKAPAK	XDCKAP	Alaska intangible drill costs that must be depreciated	fraction	Alaska	U.S. Tax Code

Source: National Petroleum Council (NPC), EIA Office of Petroleum, Natural Gas, & Biofuels Analysis (OPNGBA), United States Geologic Survey (USGS), Alaska Oil and Gas Conservation Commission (AOGCC)

5. Oil Shale Supply Submodule

Oil shale rock contains a hydrocarbon known as kerogen,[12] which can be processed into a synthetic crude oil (syncrude) by heating the rock. During the 1970s and early 1980s, petroleum companies conducted extensive research, often with the assistance of public funding, into the mining of oil shale rock and the chemical conversion of the kerogen into syncrude. The technologies and processes developed during that period are well understood and well documented with extensive technical data on demonstration plant costs and operational parameters, which were published in the professional literature. The oil shale supply submodule in OGSM relies extensively on this published technical data for providing the cost and operating parameters employed to model the "typical" oil shale syncrude production facility.

In the 1970s and 1980s, two engineering approaches to creating the oil shale syncrude were envisioned. In one approach, which the majority of the oil companies pursued, the producer mines the oil shale rock in underground mines. A surface facility the retorts the rock to create bitumen, which is then further processed into syncrude. Occidental Petroleum Corp. pursued the other approach known as "modified in-situ," in which some of the oil shale rock is mined in underground mines, while the remaining underground rock is "rubblized" using explosives to create large caverns filled with oil shale rock. The rubblized oil shale rock is then set on fire to heat the kerogen and convert it into bitumen, with the bitumen being pumped to the surface for further processing into syncrude. The modified in-situ approach was not widely pursued because the conversion of kerogen into bitumen could not be controlled with any precision and because the leaching of underground bitumen and other petroleum compounds might contaminate underground aquifers.

When oil prices dropped below $15 per barrel in the mid-1990s, demonstrating an abundance of conventional oil supply, oil shale petroleum production became untenable and project sponsors canceled their oil shale research and commercialization programs. Consequently, no commercial-scale oil shale production facilities were ever built or operated. Thus, the technical and economic feasibility of oil shale petroleum production remains untested and unproven.

In 1997, Shell Oil Company started testing a completely in-situ oil shale process, in which the oil shale rock is directly heated underground using electrical resistance heater wells, while petroleum products[13] are produced from separate production wells. The fully in-situ process has significant environmental and cost benefits relative to the other two approaches. The environmental benefits are lower water usage, no waste rock disposal, and the absence of hydrocarbon leaching from surface waste piles. As an example of the potential environmental impact on surface retorting, an industry using 25 gallon per ton oil shale rock to produce 2 million barrels per day would generate about 1.2 billion tons of waste rock per year, which is about 11 percent more than the weight of all the coal mined in the United States in 2010. Other advantages of the in-situ process include: 1) access to deeper oil shale resources, 2) greater oil and gas generated per acre because the process uses multiple oil shale seams within the resource column rather than just a single seam, and 3) direct production of petroleum products rather than

[12] Kerogen is a solid organic compound, which is also found in coal.
[13] Approximately, 30 percent naphtha, 30 percent jet fuel, 30 percent diesel, and 10 percent residual fuel oil.

a synthetic crude oil that requires more refinery processing. Lower production costs are expected for the in-situ approach because massive volumes of rock would not be moved, and because the drilling of heater wells, production wells, and freeze-wall wells can be done in a modular fashion, which allows for a streamlined manufacturing-like process. Personnel safety would be greater and accident liability lower. Moreover, the in-situ process reduces the capital risk, because it involves building self-contained modular production units that can be multiplied to reach a desired total production level. Although the technical and economic feasibility of the in-situ approach has not been commercially demonstrated, there is already a substantial body of evidence from field tests conducted by Shell Oil Co. that the in-situ process is technologically feasible.[14] The current Shell field research program is expected to conclude around the 2014 through 2017 timeframe with the construction of a small scale demonstration plant expected to begin shortly thereafter. The Oil Shale Supply Submodule (OSSS) assumes that the first commercial size oil shale plant cannot be built prior to 2017.

Given the inherent cost and environmental benefits of the in-situ approach, a number of other companies, such as Chevron and ExxonMobil are testing alternative in-situ oil shale techniques. Although small-scale mining and surface retorting of oil shale is currently being developed, by companies such as Red Leaf Resources, the large scale production of oil shale will most likely use the in-situ process. However, because in-situ oil shale projects have never been built, and because companies developing the in-situ process have not publicly released detailed technical parameters and cost estimates, the cost and operational parameters of such in-situ facilities is unknown. Consequently, the Oil Shale Supply Submodule (OSSS) relies on the project parameters and costs associated with the underground mining and surface retorting approach that were designed during the 1970s and 1980s. In this context, the underground mining and surface retorting facility parameters and costs are meant to be a surrogate for the in-situ oil shale facility that is more likely to be built. Although the in-situ process is expected to result in a lower cost oil shale product, this lower cost is somewhat mitigated by the fact that the underground mining and surface retorting processes developed in the 1970s and 1980s did not envision the strict environmental regulations that prevail today, and therefore embody an environmental compliance cost structure that is lower than what would be incurred today by a large-scale underground mining and surface retorting facility. Also, the high expected cost structure of the underground mining/surface retorting facility constrains the initiation of oil shale project production, which should be viewed as a more conservative approach to simulating the market penetration of in-situ oil projects. On the other hand, OSSS oil shale facility costs are reduced by 1 percent per year to reflect technological progress, especially with respect to the improvement of an in-situ oil shale process. Finally, public opposition to building any type of oil shale facility is likely to be great, regardless of the fact that the in-situ process is expected to be more environmentally benign than the predecessor technologies; the cost of building an in-situ oil shale facility is therefore likely to be considerably greater than would be determined strictly by the engineering parameters of such a facility.[15]

The Oil Shale Supply Submodule (OSSS) only represents economic decision making. In the absence of any existing commercial oil shale projects, it was impossible to determine the

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[14] *See* "Shell's In-situ Conversion Process," a presentation by Harold Vinegar at the Colorado Energy Research Institute's 26th Oil Shale Symposium held on October 16 – 18, 2006 in Boulder, Colorado.

[15] Project delays due to public opposition can significantly increase project costs and reduce project rates of return.

potential environmental constraints and costs of producing oil on a large scale. Given the considerable technical and economic uncertainty of an oil shale industry based on an in-situ technology, and the infeasibility of the large-scale implementation of an underground mining/surface retorting technology, the oil shale syncrude production projected by the OSSS should be considered highly uncertain.

Given this uncertainty, the construction of commercial oil shale projects is constrained by a linear market penetration algorithm that restricts the oil production rate, which, at best, can reach a maximum of 2 million barrels per day by the end of a 40-year period after commercial oil shale facilities are deemed to be technologically feasible (starting in 2017). Whether domestic oil shale production actually reaches 2 million barrels per day at the end of the 40-year period depends on the relative profitability of oil shale facilities. If oil prices are too low to recover the weighted average cost of capital, no new facilities are built. However, if oil prices are sufficiently high to recover the cost of capital, then the rate of market penetration rises in direct proportion to facility profitability. So as oil prices rise and oil shale facility profitability increases, the model assumes that oil shale facilities are built in greater numbers, as dictated by the market penetration algorithm.

The 2 million barrel per day production limit is based on an assessment of what is feasible given both the oil shale resource base and potential environmental constraints.[16] The 40-year minimum market penetration timeframe is based on the observation that "…an oil shale production level of 1 million barrels per day is probably more than 20 years in the future…"[17] with a linear ramp-up to 2 million barrels per day equating to a 40-year minimum.

The actual rate of market penetration in the OSSS largely depends on projected oil prices, with low prices resulting in low rates of market penetration, and with the maximum penetration rate only occurring under high oil prices that result in high facility profitability. The development history of the Canadian oil sands industry is an analogous situation. The first commercial Canadian oil sands facility began operations in 1967; the second project started operation in 1978; and the third project initiated production in 2003.[18] So even though the Canadian oil sands resource base is vast, it took over 30 years before a significant number of new projects were announced. This slow penetration rate, however, was largely caused by both the low world oil prices that persisted from the mid-1980s through the 1990s and the lower cost of developing conventional crude oil supply.[19] The rise in oil prices that began in 2003 caused 17 new oil sands projects to be announced by year-end 2007.[20] Oil prices subsequently peaked in July 2008,

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[16] *See* U.S. Department of Energy, "Strategic Significance of America's Oil Shale Resource," March 2004, Volume I, page 23 – which speaks of an "aggressive goal" of 2 million barrels per day by 2020; and Volume II, page 7 – which concludes that the water resources in the Upper Colorado River Basin are "more than enough to support a 2 million barrel/day oil shale industry…"

[17] Source: RAND Corporation, "Oil Shale Development in the United States – Prospects and Policy Issues," MG-414, 2005, Summary page xi.

[18] The owner/operator for each of the 3 initial oil sands projects were respectively Suncor, Syncrude, and Shell Canada.

[19] The first Canadian commercial oil sands facility started operations in 1967. It took 30 years later until the mid to late 1990s for a building boom of Canadian oil sands facilities to materialize. Source: Suncor Energy, Inc. internet website at www.suncor.com, under "our business," under "oil sands."

[20] Source: Alberta Employment, Immigration, and Industry, "Alberta Oil Sands Industry Update," December 2007, Table 1, pages 17 – 21.

and declined significantly, such that a number of these new projects were put on hold at that time.

Extensive oil shale resources exist in the United States both in eastern Appalachian black shales and western Green River Formation shales. Almost all of the domestic high-grade oil shale deposits with 25 gallons or more of petroleum per ton of rock are located in the Green River Formation, which is situated in Northwest Colorado (Piceance Basin), Northeast Utah (Uinta Basin), and Southwest Wyoming. It has been estimated that over 400 billion barrels of syncrude potential exists in Green River Formation deposits that would yield at least 30 gallons of syncrude per ton of rock in zones at least 100 feet thick.[21] Consequently, the Oil Shale Supply Submodule assumes that future oil shale syncrude production occurs exclusively in the Rocky Mountains within the 2035 time frame of the projections. Moreover, the immense size of the western oil shale resource base precluded the need for the submodule to explicitly track oil shale resource depletion through 2035.

For each projection year, the oil shale submodule calculates the net present cash flow of operating a commercial oil shale syncrude production facility, based on that future year's projected crude oil price. If the calculated discounted net present value of the cash flow exceeds zero, the submodule assumes that an oil shale syncrude facility would begin construction, so long as the construction of that facility is not precluded by the construction constraints specified by the market penetration algorithm. So the submodule contains two major decision points for determining whether an oil shale syncrude production facility is built in any particular year: first, whether the discounted net present value of a facility's cash flow exceeds zero; second, by a determination of the number of oil shale projects that can be initiated in that year, based on the maximum total oil shale production level that is permitted by the market penetration algorithm.

In any one year, many oil shale projects can be initiated, raising the projected production rates in multiples of the rate for the standard oil shale facility, which is assumed to be 50,000 barrels per day, per project.

Oil Shale Facility Cost and Operating Parameter Assumptions

The oil shale supply submodule is based on underground mining and surface retorting technology and costs. During the late 1970s and early 1980s, when petroleum companies were building oil shale demonstration plants, almost all demonstration facilities employed this technology.[22] The facility parameter values and cost estimates in the OSSS are based on information reported for the Paraho Oil Shale Project, and which are inflated to constant 2004 dollars.[23] Oil shale rock mining costs are based on Western United States underground coal mining costs, which would be representative of the cost of mining oil shale rock, [24] because coal

[21] Source: Culbertson, W. J. and Pitman, J. K. "Oil Shale" in *United States Mineral Resources*, USGS Professional Paper 820, Probst and Pratt, eds. P 497-503, 1973.

[22] Out of the many demonstration projects in the 1970s only Occidental Petroleum tested a modified in-situ approach which used caved-in mining areas to perform underground retorting of the kerogen.

[23] Source: Noyes Data Corporation, *Oil Shale Technical Data Handbook*, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97.

[24] Based on the coal mining cost per ton data provided in coal company 2004 annual reports, particularly those of

mining techniques and technology would be employed to mine oil shale rock. However, the OSSS assumes that oil shale production costs fall at a rate of 1 percent per year, starting in 2005, to reflect the role of technological progress in reducing production costs. This cost reduction assumption results in oil shale production costs being 26 percent lower in 2035 relative to the initial 2004 cost structure.

Although the Paraho cost structure might seem unrealistic, given that the application of the in-situ process is more likely than the application of the underground mining/surface retorting process, the Paraho cost structure is well documented, while there is no detailed public information regarding the expected cost of the in-situ process. Even though the in-situ process might be cheaper per barrel of output than the Paraho process, this should be weighted against the following facts 1) oil and gas drilling costs have increased dramatically since 2005, somewhat narrowing that cost difference, and 2) the Paraho costs were determined at a time when environmental requirements were considerably less stringent. Consequently, the environmental costs that an energy production project would incur today are considerably more than what was envisioned in the late-1970s and early-1980s. It should also be noted that the Paraho process produces about the same volumes of oil and natural gas as the in-situ process does, and requires about the same electricity consumption as the in-situ process. Finally, to the degree that the Paraho process costs reported here are greater than the in-situ costs, the use of the Paraho cost structure provides a more conservative facility cost assessment, which is warranted for a completely new technology.

Another implicit assumption in the OSSS is that the natural gas produced by the facility is sold to other parties, transported offsite, and priced at prevailing regional wellhead natural gas prices. Similarly, the electricity consumed on site is purchased from the local power grid at prevailing industrial prices. Both the natural gas produced and the electricity consumed are valued in the Net Present Value calculations at their respective regional prices, which are determined elsewhere in the NEMS. Although the oil shale facility owner has the option to use the natural gas produced on-site to generate electricity for on-site consumption, building a separate on-site/offsite power generation decision process within OSSS would unduly complicate the OSSS logic structure and would not necessarily provide a more accurate portrayal of what might actually occur in the future.[25] Moreover, this treatment of natural gas and electricity prices automatically takes into consideration any embedded carbon dioxide emission costs associated with a particular NEMS scenario, because a carbon emissions allowance cost is embedded in the regional natural gas and electricity prices and costs.

OSSS Oil Shale Facility Configuration and Costs

The OSSS facility parameters and costs are based on those reported for the Paraho Oil Shale

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Arch Coal, Inc, CONSOL Energy Inc, and Massey Energy Company. Reported underground mining costs per ton range for $14.50 per ton to $27.50 per ton. The high cost figures largely reflect higher union wage rates, than the low cost figures reflect non-union wage rates. Because most of the Western underground mines are currently non-union, the cost used in OSSS was pegged to the lower end of the cost range. For example, the $14.50 per ton cost represents Arch Coal's average western underground mining cost.

[25] The Colorado/Utah/Wyoming region has relatively low electric power generation costs due to 1) the low cost of mining Powder River Basin subbituminous coal, and 2) the low cost of existing electricity generation equipment, which is inherently lower than new generation equipment due cost inflation and facility depreciation.

project. Because the Paraho Oil Shale Project costs were reported in 1976 dollars, the OSSS costs were inflated to constant 2004 dollar values. Similarly, the OSSS converts NEMS oil prices, natural gas prices, electricity costs, and carbon dioxide costs into constant 2004 dollars, so that all facility net present value calculations are done in constant 2004 dollars. Based on the Paraho Oil Shale Project configuration, OSSS oil shale facility parameters and costs are listed in Table 5-1, along the OSSS variable names. For the *Annual Energy Outlook 2009* and subsequent *Outlooks*, oil shale facility construction costs were increased by 50 percent to represent the world-wide increase in steel and other metal prices since the OSSS was initially designed. For the *Annual Energy Outlook 2011*, the oil shale facility plant size was reduced from 100,000 barrels per day to 50,000 barrels per day, based on discussions with industry representatives who believe that the smaller configuration was more likely for in-situ projects because this size captures most of the economies of scale, while also reducing project risk.

Table 5-1. OSSS Oil Shale Facility Configuration and Cost Parameters

Facility Parameters	OSSS Variable Name	Parameter Value
Facility project size	OS_PROJ_SIZE	50,000 barrels per day
Oil shale syncrude per ton of rock	OS_GAL_TON	30 gallons
Plant conversion efficiency	OS_CONV_EFF	90 percent
Average facility capacity factor	OS_CAP_FACTOR	90 percent per year
Facility lifetime	OS_PRJ_LIFE	20 years
Facility construction time	OS_PRJ_CONST	3 year
Surface facility capital costs	OS_PLANT_INVEST	$2.4 billion (2004 dollars)
Surface facility operating costs	OS_PLANT_OPER_CST	$200 million per year (2004 dollars)
Underground mining costs	OS_MINE_CST_TON	$17.50 per ton (2004 dollars)
Royalty rate	OS_ROYALTY_RATE	12.5 percent of syncrude value
Carbon Dioxide Emissions Rate	OS_CO2EMISS	150 metric tons per 50,000 bbl/day of production[26]

The construction lead time for oil shale facilities is assumed to be 3 years, which is less than the 5-year construction time estimates developed for the Paraho Project. The shorter construction period is based on the fact that the drilling of shallow in-situ heating and production wells can be accomplished much more quickly than the erection of a surface retorting facility.   Because it is not clear when during the year a new plant will begin operation and achieve full productive capacity, OSSS assumes that production in the first full year will be at half its rated output and that full capacity will be achieved in the second year of operation.

To mimic the fact that an industry's costs decline over time due to technological progress, better management techniques, and so on, the OSSS initializes the oil shale facility costs in the year 2005 at the values shown above (i.e., surface facility construction and operating costs, and underground mining costs). After 2005, these costs are reduced by 1 percent per year through 2035, which is consistent with the rate of technological progress witnessed in the petroleum industry over the last few decades.

[26] Based on the average of the Fischer Assays determined for four oil shale rock samples of varying kerogen content. Op. cit. Noyes Data Corporation, Table 3.8, page 20.

OSSS Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters

Based on the Paraho Oil Shale Project parameters, Table 5-2 provides the level of annual gas production and annual electricity consumption for a 50,000 barrel per day, operating at 100 percent capacity utilization for a full calendar year.[27]

Table 5-2. OSSS Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters and Their Prices and Costs

Facility Parameters	OSSS Variable Name	Parameter Value
Natural gas production	OS_GAS_PROD	16.1 billion cubic feet per year
Wellhead gas sales price	OS_GAS_PRICE	Dollars per Mcf (2004 dollars)
Electricity consumption	OS_ELEC_CONSUMP	0.83 billion kilowatt-hours per year
Electricity consumption price	OS_ELEC_PRICE	Dollars per kilowatt-hour (2004 dollars)

Project Yearly Cash Flow Calculations

The OSSS first calculates the annual revenues minus expenditures, including income taxes and depreciation expenses, which is then discounted to a net present value. In those future years in which the net present value exceeds zero, a new oil shale facility can begin construction, subject to the timing constraints outlined below.

The discounted cash flow algorithm is calculated for a 23 year period, composed of 3 years for construction and 20 years for a plant's operating life. During the first 3 years of the 23-year period, only plant construction costs are considered with the facility investment cost being evenly apportioned across the 3 years. In the fourth year, the plant goes into partial operation, and produces 50 percent of the rated output. In the fifth year, revenues and operating expenses are assumed to ramp up to the full-production values, based on a 90 percent capacity factor that allows for potential production outages. During years 4 through 23, total revenues equal oil production revenues plus natural gas production revenues.[28]

Discounted cash flow oil and natural gas revenues are calculated based on prevailing oil and natural gas prices projected for that future year. In other words, the OSSS assumes that the economic analysis undertaken by potential project sponsors is solely based on the prevailing price of oil and natural gas at that time in the future and is <u>not</u> based either on historical price trends or future expected prices. Similarly, industrial electricity consumption costs are also based on the prevailing price of electricity for industrial consumers in that region at that future time.

As noted earlier, during a plant's first year of operation (year 4), both revenues and costs are half the values calculated for year 5 through year 23.

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[27] Op. cit. Noyes Data Corporation, pages 89-97.

[28] Natural gas production revenues result from the fact that significant volumes of natural gas are produced when the kerogen is retorted in the surface facilities. See prior table regarding the volume of natural gas produced for a 50,000 barrel per day oil shale syncrude facility.

Oil revenues are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned} \text{OIL\_REVENUE}_t = & \text{OIT\_WOP}_t * (1.083 / 0.732) * \text{OS\_PRJ\_SIZE} \\ & * \text{OS\_ CAP\_FACTOR} * 365 \end{aligned} \tag{5-8}$$

where

OIT_WOP_t	=	World oil price at time t in 1987 dollars
(1.083 / 0.732)	=	GDP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_PROJ_PRJ_SIZE	=	Facility project size in barrels per day
OS_CAP_FACTOR	=	Facility capacity factor
365	=	Days per year.

Natural gas revenues are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned} \text{GAS\_REVENUE}_t = & \text{ OS\_GAS\_PROD * OGPRCL48}_t \text{ * 1.083/0.732)} \\ & \text{*OS\_CAP\_FACTOR,} \end{aligned} \tag{5-9}$$

where

OS_GAS_PROD	=	Annual natural gas production for 50,000 barrel per day facility
$OGPRCL48_t$	=	Natural gas price in Rocky Mtn. at time t in 1987 dollars
(1.083 / 0.732)	=	GDP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_CAP_FACTOR	=	Facility capacity factor.

Electricity consumption costs are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned} \text{ELECT\_COST}_t = & \text{OS\_ELEC\_CONSUMP} * \text{PELIN}_t * (1.083/.732) * 0.003412 \\ & * \text{OS\_ CAP\_FACTOR} \end{aligned} \tag{5-10}$$

where

OS_ELEC_CONSUMP	=	Annual electricity consumption for 50,000 barrel per day facility
$PELIN_t$	=	Electricity price Colorado/Utah/Wyoming at time t
(1.083 / .732)	=	GNP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_CAP_FACTOR	=	Facility capacity factor.

The carbon dioxide emission tax rate per metric ton is calculated as follows:

$$\text{OS\_EMETAX}_t = \text{EMETAX}_t(1) * 1000.0 * (12.0 / 44.0) * (1.083 / .732) \tag{5-11}$$

where,

$EMETAX_t(1)$ = Carbon emissions allowance price/tax per kilogram at time t
1,000 = Convert kilograms to metric tones
(12.0 / 44.0) = Atomic weight of carbon divided by atomic weight of carbon dioxide
(1.083 / .732) = GNP chain-type price deflators to convert 1987 dollars into 2004 dollars.

Annual carbon dioxide emission costs per plant are calculated as follows:

$$CO2\_COST_t = OS\_EMETAX_t * OS\_CO2EMISS * 365 * OS\_CAP\_FACTOR \quad (5\text{-}12)$$

where

OS_EMETAX_t = Carbon emissions allowance price/tax per metric tonne at time t in 2004 dollars
$OS\_CO2EMISS$ = Carbon dioxide emissions in metric tonnes per day
365 = Days per year
OS_CAP_FACTOR = Facility capacity factor

In any given year, pre-tax project cash flow is:

$$PRETAX\_CASH\_FLOW_t = TOT\_REVENUE_t - TOTAL\_COST_t \quad (5\text{-}13)$$

where

$TOT\_REVENUE_t$ = Total project revenues at time t
TOT_COST_t = Total project costs at time t.

Total project revenues are calculated as follows:

$$TOT\_REVENUE_t = OIL\_REVENUE_t + GAS\_REVENUE_t \quad (5\text{-}14)$$

Total project costs are calculated as follows:

$$\begin{aligned} TOT\_COST_t = {} & OS\_PLANT\_OPER\_CST + ROYALTY_t + PRJ\_MINE\_CST \\ & + ELEC\_COST_t + CO2\_COST_t + INVEST_t \end{aligned} \quad (5\text{-}15)$$

where

$OS\_PLANT\_OPER\_CST$ = Annual plant operating costs per year
$ROYALTY_t$ = Annual royalty costs at time t
PRJ_MINE_COST = Annual plant mining costs
$ELEC\_COST_t$ = Annual electricity costs at time t
$CO2\_COST_t$ = Annual carbon dioxide emissions costs at time t
$INVEST_t$ = Annual surface facility investment costs.

While the plant is under construction (years 1 through 3) only INVEST has a positive value, while the other four cost elements equal zero. When the plant goes into operation (years 4 through 23), the capital costs (INVEST) are zero, while the other five operating costs take on positive values. The annual investment cost for the three years of construction is calculated as follows, under the assumption that the construction costs are evenly spread over the 3-year construction period:

$$INVEST = OS\_PLANT\_INVEST / OS\_PRJ\_CONST \tag{5-16}$$

where the variables are defined as in Table 5-1. Because the plant output is composed of both oil and natural gas, the annual royalty cost (ROYALTY) is calculated by applying the royalty rate to total revenues, as follows:

$$ROYALTY_t = OS\_ROYALTY\_RATE * TOT\_REVENUE_t \tag{5-17}$$

Annual project mining costs are calculated as the mining cost per barrel of syncrude multiplied by the number of barrels produced, as follows:

$$PRJ\_MINE\_COST = OS\_MINE\_CST\_TON * \frac{42}{OS\_GALLON\_TON * OS\_CONV\_EFF} * OS\_PROJ\_SIZE * OS\_CAP\_FACTOR * 365 \tag{5-18}$$

where

42 = gallons per barrel
365 = days per year.

After the plant goes into operation and after a pre-tax cash flow is calculated, then a post-tax cash flow has to be calculated based on income taxes and depreciation tax credits. When the prevailing world oil price is sufficiently high and the pre-tax cash flow is positive, then the following post-tax cash flow is calculated as

$$\begin{aligned} CASH\_FLOW_t = &\left(PRETAX\_CASH\_FLOW_t * (1 - OS\_CORP\_TAX\_RATE)\right) + \\ &(OS\_CORP\_TAX\_RATE * OS\_PLANT\_INVEST / OS\_PRJ\_LIFE) \end{aligned} \tag{5-19}$$

The above depreciation tax credit calculation assumes straight-line depreciation over the operating life of the investment (OS_PRJ_LIFE).

Discount Rate Financial Parameters

The discounted cash flow algorithm uses the following financial parameters to determine the discount rate used in calculating the net present value of the discounted cash flow.

Table 5-3. Discount Rate Financial Parameters

Financial Parameters	OSSS Variable Name	Parameter Value
Corporate income tax rate	OS_CORP_TAX_RATE	38 percent
Equity share of total facility capital	OS_EQUITY_SHARE	60 percent
Facility equity beta	OS_EQUITY_VOL	1.8
Expected market risk premium	OS_EQUITY_PREMIUM	6.5 percent
Facility debt risk premium	OS_DEBT_PREMIUM	0.5 percent

The corporate equity beta (OS_EQUITY_VOL) is the project risk beta, not a firm's volatility of stock returns relative to the stock market's volatility. Because of the technology and construction uncertainties associated with oil shale plants, the project's equity holder's risk is expected to be somewhat greater than the average industry firm beta. The median beta for oil and gas field exploration service firms is about 1.65. Because a project's equity holders' investment risk level is higher, the facility equity beta assumed for oil shale projects is 1.8.

The expected market risk premium (OS_EQUITY_PREMIUM), which is 6.5 percent, is the expected return on market (S&P 500) over the rate of 10-year Treasury note (risk-free rate). A Monte Carlo simulation methodology was used to estimate the expected market return.

Oil shale project bond ratings are expected to be in the Ba-rating range. Since the NEMS macroeconomic module endogenously determines the industrial Baa bond rates for the forecasting period, the cost of debt rates are different in each year. The debt premium (OS_DEBT_PREMIUM) adjusts the bond rating for the project from the Baa to the Ba range, which is assumed to be constant at the average historical differential over the forecasting period.

Discount Rate Calculation

A seminal parameter used in the calculation of the net present value of the cash flow is the discount rate. The calculation of the discount rate used in the oil shale submodule is consistent with the way the discount rate is calculated through the National Energy Modeling System. The discount rate equals the post-tax weighted average cost of capital, which is calculated in the OSSS as follows:

$$OS\_DISCOUNT\_RATE_t = (((1 - OS\_EQUITY\_SHARE) * (MC\_RMCORPBAA_t / 100 + OS\_DEBT\_PREMIUM)) * (1 - OS\_CORP\_TAX\_RATE) + (OS\_EQUITY\_SHARE * ((OS\_EQUITY\_PREMIUM * OS\_EQUITY\_VOL) + MC\_RMGFCM\_10NS_t / 100)) \tag{5-20}$$

where

OS_EQUITY_SHARE	=	Equity share of total facility capital
$MC\_RMCORPBAA_t / 100$	=	BAA corporate bond rate
OS_DEBT_PREMIUM	=	Facility debt risk premium
OS_CORP_TAX_RATE	=	Corporate income tax rate
OS_EQUITY_PREMIUM	=	Expected market risk premium
OS_EQUITY_VOL	=	Facility equity volatility beta
$MC\_RMGFCM\_10NS_t / 100$	=	10-year Treasury note rate.

In calculating the facility's cost of equity, the equity risk premium (which is a product of the expected market premium and the facility equity beta, is added to a "risk-free" rate of return, which is considered to be the 10-year Treasury note rate.

The nominal discount rate is translated into a constant, real discount rate using the following formula:

$$OS\_DISCOUNT\_RATE_t = ((1.0 + OS\_DISCOUNT\_RATE_t) / (1.0 + INFL_t)) - 1.0 \tag{5-21}$$

where

$INFL_t$ = Inflation rate at time t.

Net Present Value Discounted Cash Flow Calculation

So far a potential project's yearly cash flows have been calculated along with the appropriate discount rate. Using these calculated quantities, the net present value of the yearly cash flow values is calculated as follows:

$$NET\_CASH\_FLOW_{t-1} = \sum_{t=1}^{OS\_PRJ\_LIFE + OS\_PRJ\_CONST} \left[CASH\_FLOW_t * \left[\frac{1}{1 + OS\_DISCOUNT\_RATE_t} \right]^t \right] \tag{5-22}$$

If the net present value of the projected cash flows exceeds zero, then the potential oil shale facility is considered to be economic and begins construction, so long as this facility construction does not violate the construction timing constraints detailed below.

Oil Shale Facility Market Penetration Algorithm

As noted in the introduction, there is no empirical basis for determining how rapidly new oil shale facilities would be built, once the OSSS determines that surface-retorting oil shale facilities are economically viable, because no full-scale commercial facilities have ever been constructed. However, there are three primary constraints to oil shale facility construction. First, the construction of an oil shale facility cannot be undertaken until the in-situ technology has been sufficiently developed and tested to be deemed ready for its application to commercial size projects (i.e., 50,000 barrels per day). Second, oil shale facility construction is constrained by the maximum oil shale production limit. Third, oil shale production volumes cannot reach the maximum oil shale production limit any earlier than 40 years after the in-situ technology has been deemed to be feasible and available for commercial size facilities. Table 5-4 summarizes the primary market penetration parameters in the OSSS.

Table 5-4. Market Penetration Parameters

Market Penetration Parameters	OSSS Variable Name	Parameter Value
Earliest Facility Construction Start Date	OS_START_YR	2017
Maximum Oil Shale Production	OS_MAX_PROD	2 million barrels per year
Minimum Years to Reach Full Market Penetration	OS_PENETRATE_YR	40

Shell's in-situ oil shale RD&D program is considered to be the most advanced, having begun in 1997. Shell is most likely to be the first party to build and operate a commercial scale oil shale production facility. Based on conversations between Shell personnel and EIA personnel, Shell is likely to conclude its field experiments, which test the various components of a commercial facility sometime during the 2014 through 2017 timeframe. Consequently, the earliest likely initiation of a full-scale commercial plant would be 2017.[29]

As discussed earlier, a 2 million barrel per day oil shale production level at the end of 40-year market penetration period is considered to be reasonable and feasible based on the size of the resource base and the volume and availability of water needed to develop those resources. The actual rate of market penetration in the OSSS, however, is ultimately determined by the projected profitability of oil shale projects. At a minimum, oil and natural gas prices must be sufficiently high to produce a facility revenue stream (i.e., discounted cash flow) that covers all capital and operating costs, including the weighted average cost of capital. When the discounted cash flow exceeds zero (0), then the market penetration algorithm allows oil shale facility construction to commence.

[29] Op. cit. EIA/OIAF/OGD memorandum entitled, "Oil Shale Project Size and Production Ramp-Up," and based on public information and private conversations subsequent to the development of that memorandum.

When project discounted cash flow is greater than zero, the relative project profitability is calculated as follows:

$$OS\_PROFIT_t = DCF_t \;/\; OS\_PLANT\_INVEST \tag{5-23}$$

where

DCF_t = Project discounted cash flow at time t

OS_PLANT_INVEST = Project capital investment

OS_PROFIT is an index of an oil project's expected profitability. The expectation is that, as OS_PROFIT increases, the relative financial attractiveness of producing oil shale also increases.

The level of oil shale facility construction that is permitted in any year depends on the maximum oil shale production that is permitted by the following market penetration algorithm:

$$\begin{aligned} MAX\_PROD_t &= OS\_MAX\_PROD * (OS\_PROFIT_t \;/\; (1 + OS\_PROFIT_t)) \\ &\quad * ((T - (OS\_START\_YR - 1989)) \;/\; OS\_PENETRATE\_YR\,) \end{aligned} \tag{5-24}$$

where,

OS_MAX_PROD	=	Maximum oil shale production limit
OS_PROFIT_t	=	Relative oil shale project profitability at time t
T	=	Time t
OS_START_YR	=	First year that an oil shale facility can be built
OS_PENTRATE_YR	=	Minimum number of years during which the maximum oil shale production can be achieved.

The OS_PROFIT portion of the market penetration algorithm (5-24) rapidly increases market penetration as the DCF numerator of OS_PROFIT increases. However, as OS_PROFIT continues to increase, the rate of increase in market penetration slows as (OS_PROFIT / (1 + OS_PROFIT) asymptotically approaches one (1.0). As this term approaches 1.0, the algorithm's ability to build more oil shale plants is ultimately constrained by OS_MAX_PROD term, regardless of how financially attractive the construction of new oil shale facilities might be. This formulation also prevents MAX_PROD from exceeding OS_MAX_PROD.

The second portion of the market penetration algorithm specifies that market penetration increases linearly over the number of years specified by OS_PENETRATE_YR. As noted earlier OS_PENETRATE_YR specifies the minimum number of years over which the oil shale industry can achieve maximum penetration. The maximum number of years required to achieve full penetration is dictated by the speed at which the OS_PROFIT portion of the equation approaches one (1.0). If OS_PROFIT remains low, then it is possible that MAX_PROD never comes close to reaching the OS_MAX_PROD value.

The number of new oil shale facilities that start construction in any particular year is specified by the following equation:

(5-25)

$$OS\_PLANTS\_NEW_t = INT((MAX\_PROD_t - (OS\_PLANTS_t * OS\_PRJ\_SIZE * OS\_CAP\_FACTOR)) / (OS\_PRJ\_SIZE * OS\_CAP\_FACTOR))$$

where

MAX_PROD_t	=	Maximum oil shale production at time t
OS_PLANT_t	=	Number of existing oil shale plants at time t
OS_PRJ_SIZE	=	Standard oil shale plant size in barrels per day
OS_CAP_FACTOR	=	Annual capacity factor of an oil shale plant in percent per year.

The first portion of the above formula specifies the incremental production capacity that can be built in any year, based on the number of plants already in existence. The latter portion of the equation determines the integer number of new plants that can be initiated in that year, based on the expected annual production rate of an oil shale plant.

Because oil shale production is highly uncertain, not only from a technological and economic perspective, but also from an environmental perspective, an upper limit to oil shale production is assumed within the OSSS. The upper limit on oil shale production is 2 million barrels per day, which is equivalent to 44 facilities of 50,000 barrels per day operating at a 90 percent capacity factor. So the algorithm allows enough plants to be built to fully reach the oil shale production limit, based on the expected plant capacity factor. As noted earlier, the oil shale market penetration algorithm is also limited by the earliest commercial plant construction date, which is assumed to be no earlier than 2017.

While the OSSS costs and performance profiles are based on technologies evaluated in the 1970’s and early 1980’s, the complete absence of any current commercial-scale oil shale production makes its future economic development highly uncertain. If the technological, environmental, and economic hurdles are as high or higher than those experienced during the 1970’s, then the prospects for oil shale development would remain weak throughout the projections. However, technological progress can alter the economic and environmental landscape in unanticipated ways. For example, if an in-situ oil shale process were to be demonstrated to be both technically feasible and commercially profitable, then the prospects for an oil shale industry would improve significantly, and add vast economically recoverable oil resources in the United States and possibly elsewhere in the world.

Appendix A. Discounted Cash Flow Algorithm

Introduction

The basic DCF methodology used in the Oil and Gas Supply Module (OGSM) is applied for a broad range of oil or natural gas projects, including single well projects or multiple well projects within a field. It is designed to capture the effects of multi-year capital investments (e.g., offshore platforms). The expected discounted cash flow value associated with exploration and/or development of a project with oil or gas as the primary fuel in a given region evaluated in year T may be presented in a stylized form (Equation A-1).

$$DCF_T = (PVTREV - PVROY - PVPRODTAX - PVDRILLCOST - PVEQUIP \\ - PVKAP - PVOPCOST - PVABANDON - PVSIT - PVFIT)_T \qquad \text{(A-1)}$$

where

T	=	year of evaluation
PVTREV	=	present value of expected total revenues
PVROY	=	present value of expected royalty payments
PVPRODTAX	=	present value of expected production taxes (ad valorem and severance taxes)
PVDRILLCOST	=	present value of expected exploratory and developmental drilling expenditures
PVEQUIP	=	present value of expected lease equipment costs
PVKAP	=	present value of other expected capital costs (i.e., gravel pads and offshore platforms)
PVOPCOST	=	present value of expected operating costs
PVABANDON	=	present value of expected abandonment costs
PVSIT	=	present value of expected state corporate income taxes
PVFIT	=	present value of expected federal corporate income taxes.

Costs are assumed constant over the investment life but vary across both region and primary fuel type. This assumption can be changed readily if required by the user. Relevant tax provisions also are assumed unchanged over the life of the investment. Operating losses incurred in the initial investment period are carried forward and used against revenues generated by the project in later years.

The following sections describe each component of the DCF calculation. Each variable of Equation A.1 is discussed starting with the expected revenue and royalty payments, followed by the expected costs, and lastly the expected tax payments.

Present Value of Expected Revenues, Royalty Payments, and Production Taxes

Revenues from an oil or gas project are generated from the production and sale of both the primary fuel as well as any co-products. The present value of expected revenues measured at the wellhead from the production of a representative project is defined as the summation of yearly expected net wellhead price[1]

[1]The DCF methodology accommodates price expectations that are myopic, adaptive, or perfect. The default is myopic expectations, so prices are assumed to be constant throughout the economic evaluation period.

times expected production[2] discounted at an assumed rate. The discount rate used to evaluate private investment projects typically represents a weighted average cost of capital (WACC), i.e., a weighted average of both the cost of debt and the cost of equity.

Fundamentally, the formula for the WACC is straightforward.

$$WACC = \frac{D}{D+E} * R_D * (1-t) + \frac{E}{D+E} * R_E \tag{A-2}$$

where D = market value of debt, E = market value of equity, t = corporate tax rate, R_D = cost of debt, and R_E = cost of equity. Because the drilling projects being evaluated are long term in nature, the values for all variables in the WACC formula are long run averages.

The WACC calculated using the formula given above is a nominal one. The real value can be calculated by

$$disc = \frac{(1+WACC)}{(1+\pi_e)} - 1 \tag{A-3}$$

where π_e = expected inflation rate. The expected rate of inflation over the forecasting period is measured as the average annual rate of change in the U.S. GDP deflator over the forecasting period using the forecasts of the GDP deflator from the Macro Module (MC_JPGDP).

The present value of expected revenue for either the primary fuel or its co-product is calculated as follows:

$$PVREV_{T,k} = \sum_{t=T}^{T+n} \left[Q_{t,k} * \lambda * P_{t,k} * \left[\frac{1}{1+disc} \right]^{t-T} \right], \lambda = \begin{cases} 1 \text{ if primary fuel} \\ COPRD \text{ if secondary fuel} \end{cases} \tag{A-4}$$

where,

k	=	fuel type (oil or natural gas)
T	=	time period
n	=	number of years in the evaluation period
disc	=	discount rate
Q	=	expected production volumes
P	=	expected net wellhead price
COPRD	=	co-product factor.[3]

Net wellhead price is equal to the market price minus any transportation costs. Market prices for oil and gas are defined as follows: the price at the receiving refinery for oil, the first purchase price for onshore natural gas, the price at the coastline for offshore natural gas, and the price at the Canadian border for Alaskan gas.

[2]Expected production is determined outside the DCF subroutine. The determination of expected production is described in Chapter 3.

[3]The OGSM determines coproduct production as proportional to the primary product production. COPRD is the ratio of units of coproduct per unit of primary product.

The present value of the total expected revenue generated from the representative project is

$$PVTREV_T = PVREV_{T,1} + PVREV_{T,2} \tag{A-5}$$

where

$PVREV_{T,1}$ = present value of expected revenues generated from the primary fuel
$PVREV_{T,2}$ = present value of expected revenues generated from the secondary fuel.

Present Value of Expected Royalty Payments

The present value of expected royalty payments (PVROY) is simply a percentage of expected revenue and is equal to

$$PVROY_T = ROYRT_1 * PVREV_{T,1} + ROYRT_2 * PVREV_{T,2} \tag{A-6}$$

where

ROYRT = royalty rate, expressed as a fraction of gross revenues.

Present Value of Expected Production Taxes

Production taxes consist of ad valorem and severance taxes. The present value of expected production tax is given by

$$\begin{aligned} PVPRODTAX_T = {} & PRREV_{T,1} * (1 - ROYRT_1) * PRDTAX_1 + PVREV_{T,2} \\ & *(1 - ROYRT_2) * PRODTAX_2 \end{aligned} \tag{A-7}$$

where

PRODTAX = production tax rate.

PVPRODTAX is computed as net of royalty payments because the investment analysis is conducted from the point of view of the operating firm in the field. Net production tax payments represent the burden on the firm because the owner of the mineral rights generally is liable for his/her share of these taxes.

Present Value of Expected Costs

Costs are classified within the OGSM as drilling costs, lease equipment costs, other capital costs, operating costs (including production facilities and general/administrative costs), and abandonment costs. These costs differ among successful exploratory wells, successful developmental wells, and dry holes. The present value calculations of the expected costs are computed in a similar manner as PVREV (i.e., costs are discounted at an assumed rate and then summed across the evaluation period).

Present Value of Expected Drilling Costs

Drilling costs represent the expenditures for drilling successful wells or dry holes and for equipping successful wells through the Christmas tree installation.[4] Elements included in drilling costs are labor,

[4]The Christmas tree refers to the valves and fittings assembled at the top of a well to control the fluid flow.

material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. The present value of expected drilling costs is given by

$$
\begin{aligned}
PVDRILLCOST_T = \sum_{t=T}^{T+n} \Bigg[\bigg[& COSTEXP_T * SR_1 * NUMEXP_t + COSTDEV_T * SR_2 * NUMDEV_t \\
& + COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t \\
& + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \bigg] * \left(\frac{1}{1 + disc} \right)^{t-T} \Bigg]
\end{aligned} \tag{A-8}
$$

where

COSTEXP	=	drilling cost for a successful exploratory well
SR	=	success rate (1=exploratory, 2=developmental)
COSTDEV	=	drilling cost for a successful developmental well
COSTDRY	=	drilling cost for a dry hole (1=exploratory, 2=developmental).
NUMEXP	=	number of exploratory wells drilled in a given period
NUMDEV	=	number of developmental wells drilled in a given period.

The number and schedule of wells drilled for an oil or gas project are supplied as part of the assumed production profile. This is based on historical drilling activities.

Present Value of Expected Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a drilled lease. Three categories of costs are included: producing equipment, the gathering system, and processing equipment. Producing equipment costs include tubing, rods, and pumping equipment. Gathering system costs consist of flowlines and manifolds. Processing equipment costs account for the facilities utilized by successful wells.

The present value of expected lease equipment cost is

$$
PVEQUIP_T = \sum_{t=T}^{T+n} \left[EQUIP_t * (SR_1 * NUMEXP_t + SR_2 * NUMDEV_t) * \left[\frac{1}{1 + disc} \right]^{t-T} \right] \tag{A-9}
$$

where

EQUIP	=	lease equipment costs per well.

Present Value of Other Expected Capital Costs

Other major capital expenditures include the cost of gravel pads in Alaska, and offshore platforms. These costs are exclusive of lease equipment costs. The present value of other expected capital costs is calculated as

$$
PVKAP_T = \sum_{t=T}^{T+n} \left[KAP_t * \left[\frac{1}{1 + disc} \right]^{t-T} \right] \tag{A-10}
$$

where

KAP = other major capital expenditures, exclusive of lease equipment.

Present Value of Expected Operating Costs

Operating costs include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

Total operating cost in time t is calculated by multiplying the cost of operating a well by the number of producing wells in time t. Therefore, the present value of expected operating costs is as follows:

$$PVOPCOST_T = \sum_{t=T}^{T+n} \left[OPCOST_t * \sum_{k=1}^{t} \left[SR_1 * NUMEXP_k + SR_2 * NUMDEV_k \right] * \left(\frac{1}{1+disc} \right)^{t-T} \right] \quad \text{(A-11)}$$

where

OPCOST = operating costs per well.

Present Value of Expected Abandonment Costs

Producing facilities are eventually abandoned and the cost associated with equipment removal and site restoration is defined as

$$PVABANDON_T = \sum_{t=T}^{T+n} \left[COSTABN_t * \left[\frac{1}{1+disc} \right]^{t-T} \right] \quad \text{(A-12)}$$

where

COSTABN = abandonment costs.

Drilling costs, lease equipment costs, operating costs, abandonment costs, and other capital costs incurred in each individual year of the evaluation period are integral components of the following determination of State and Federal corporate income tax liability.

Present Value of Expected Income Taxes

An important aspect of the DCF calculation concerns the tax treatment. All expenditures are divided into depletable,[5] depreciable, or expensed costs according to current tax laws. All dry hole and operating costs are expensed. Lease costs (i.e., lease acquisition and geological and geophysical costs) are capitalized and then amortized at the same rate at which the reserves are extracted (cost depletion). Drilling costs are split between tangible costs (depreciable) and intangible drilling costs (IDC's) (expensed). IDC's include

[5]The DCF methodology does not include lease acquisition or geological & geophysical expenditures because they are not relevant to the incremental drilling decision.

wages, fuel, transportation, supplies, site preparation, development, and repairs. Depreciable costs are amortized in accord with schedules established under the Modified Accelerated Cost Recovery System (MACRS).

Key changes in the tax provisions under the tax legislation of 1988 include the following:

- Windfall Profits Tax on oil was repealed,
- Investment Tax Credits were eliminated, and
- Depreciation schedules shifted to a Modified Accelerated Cost Recovery System.

Tax provisions vary with type of producer (major, large independent, or small independent) as shown in Table A-1. A major oil company is one that has integrated operations from exploration and development through refining or distribution to end users. An independent is any oil and gas producer or owner of an interest in oil and gas property not involved in integrated operations. Small independent producers are those with less than 1,000 barrels per day of production (oil and gas equivalent). The present DCF methodology reflects the tax treatment provided by current tax laws for large independent producers.

The resulting present value of expected taxable income (PVTAXBASE) is given by:

$$\mathrm{PVTAXBASE}_T = \sum_{t=T}^{T+n} \Big[\big(\mathrm{TREV}_t - \mathrm{ROY}_t - \mathrm{PRODTAX}_t - \mathrm{OPCOST}_t - \mathrm{ABANDON}_t - \mathrm{XIDC}_t - \mathrm{AIDC}_t - \mathrm{DEPREC}_t - \mathrm{DHC}_t\big) * \left(\frac{1}{1+\mathrm{disc}}\right)^{t-T} \Big] \tag{A-13}$$

where

T	=	year of evaluation
t	=	time period
n	=	number of years in the evaluation period
TREV	=	expected revenues
ROY	=	expected royalty payments
PRODTAX	=	expected production tax payments
OPCOST	=	expected operating costs
ABANDON	=	expected abandonment costs
XIDC	=	expected expensed intangible drilling costs
AIDC	=	expected amortized intangible drilling costs[6]
DEPREC	=	expected depreciable tangible drilling, lease equipment costs, and other capital expenditures
DHC	=	expected dry hole costs
disc	=	expected discount rate.

TREV_t, ROY_t, $\mathrm{PRODTAX}_t$, OPCOST_t, and $\mathrm{ABANDON}_t$ are the undiscounted individual year values. The following sections describe the treatment of expensed and amortized costs for the purpose of determining corporate income tax liability at the State and Federal level.

[6]This variable is included only for completeness. For large independent producers, all intangible drilling costs are expensed.

Expected Expensed Costs

Expensed costs are intangible drilling costs, dry hole costs, operating costs, and abandonment costs. Expensed costs and taxes (including royalties) are deductible from taxable income.

Expected Intangible Drilling Costs

For large independent producers, all intangible drilling costs are expensed. However, this is not true across the producer category (as shown in Table A-1). In order to maintain analytic flexibility with respect to changes in tax provisions, the variable XDCKAP (representing the portion of intangible drilling costs that must be depreciated) is included.

Table A-1. Tax Treatment in Oil and Gas Production by Category of Company Under Current Tax Legislation

Costs by Tax Treatment	Majors	Large Independents	Small Independents
Depletable Costs	**Cost Depletion** G&G[a] Lease Acquisition	**Cost Depletion**[b] G&G Lease Acquisition	**Maximum of Percentage or Cost Depletion** G&G Lease Acquisition
Depreciable Costs	**MACRS**[c] Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s **5-year SLM**[d] 20 percent of IDC=s	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s
Expensed Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs

[a]Geological and geophysical.
[b]Applicable to marginal project evaluation; first 1,000 barrels per day depletable under percentage depletion.
[c]Modified Accelerated Cost Recovery System; the period of recovery for depreciable costs will vary depending on the type of depreciable asset.
[d]Straight Line Method.

Expected expensed IDC's are defined as follows:

$$\begin{aligned} XIDC_t = {} & COSTEXP_T * (1 - EXKAP) * (1 - XDCKAP) * SR_1 * NUMEXP_t \\ & + COSTDEV_T * (1 - DVKAP) * (1 - XDCKAP) * SR_2 * NUMDEV_t \end{aligned} \tag{A-14}$$

where

COSTEXP	=	drilling cost for a successful exploratory well
EXKAP	=	fraction of exploratory drilling costs that are tangible and must be depreciated
XDCKAP	=	fraction of intangible drilling costs that must be depreciated[7]
SR	=	success rate (1=exploratory, 2=developmental)
NUMEXP	=	number of exploratory wells
COSTDEV	=	drilling cost for a successful developmental well
DVKAP	=	fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV	=	number of developmental wells.

If only a portion of IDC's are expensed (as is the case for major producers), the remaining IDC's must be depreciated. The model assumes that these costs are recovered at a rate of 10 percent in the first year, 20 percent annually for four years, and 10 percent in the sixth year; this method of estimating the costs is referred to as the 5-year Straight Line Method (SLM) with half-year convention. If depreciable costs accrue when fewer than 6 years remain in the life of the project, the recovered costs are estimated using a simple straight line method over the remaining period.

Thus, the value of expected depreciable IDC's is represented by

$$\begin{aligned}AIDC_t = \sum_{j=\beta}^{t} \Big[& \big(COSTEXP_T * (1 - EXKAP) * XDCKAP * SR_1 * NUMEXP_j \\ & + COSTDEV_T * (1 - DVKAP) * XDCKAP * SR_2 * NUMDEV_j\big) \\ & * DEPIDC_t * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j}\Big],\end{aligned} \tag{A-15}$$

$$\beta = \begin{cases} T \text{ for } t \le T + m - 1 \\ t - m + 1 \text{ for } t > T + m - 1 \end{cases}$$

where,

j	=	year of recovery
β	=	index for write-off schedule
DEPIDC	=	for t # n+T-m, 5-year SLM recovery schedule with half year convention; otherwise, 1/(n+T-t) in each period
infl	=	expected inflation rate[8]
disc	=	expected discount rate
m	=	number of years in standard recovery period.

AIDC will equal zero by default since the DCF methodology reflects the tax treatment pertaining to large independent producers.

[7]The fraction of intangible drilling costs that must be depreciated is set to zero as a default to conform with the tax perspective of a large independent firm.

[8]The write-off schedule for the 5-year SLM give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

Expected Dry Hole Costs

All dry hole costs are expensed. Expected dry hole costs are defined as

$$DHC_t = COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \qquad \text{(A-16)}$$

where

COSTDRY = drilling cost for a dry hole (1=exploratory, 2=developmental).

Total expensed costs in any year equals the sum of $XIDC_t$, $OPCOST_t$, $ABANDON_t$, and DHC_t.

Expected Depreciable Tangible Drilling Costs, Lease Equipment Costs and Other Capital Expenditures

Amortization of depreciable costs, excluding capitalized IDC's, conforms to the Modified Accelerated

Table A-2. MACRS Schedules
(Percent)

Year	3-year Recovery Period	5-year Recovery Period	7-year Recovery Period	10-year Recovery Period	15-year Recovery Period	20-year Recovery Period
1	33.33	20.00	14.29	10.00	5.00	3.750
2	44.45	32.00	24.49	18.00	9.50	7.219
3	14.81	19.20	17.49	14.40	8.55	6.677
4	7.41	11.52	12.49	11.52	7.70	6.177
5		11.52	8.93	9.22	6.93	5.713
6		5.76	8.92	7.37	6.23	5.285
7			8.93	6.55	5.90	4.888
8			4.46	6.55	5.90	4.522
9				6.56	5.91	4.462
10				6.55	5.90	4.461
11				3.28	5.91	4.462
12					5.90	4.461
13					5.91	4.462
14					5.90	4.461
15					5.91	4.462
16					2.95	4.461
17						4.462
18						4.461
19						4.462
20						4.461
21						2.231

Source: U.S. Master Tax Guide.

Cost Recovery System (MACRS) schedules. The schedules under differing recovery periods appear in Table A-2. The particular period of recovery for depreciable costs will conform to the specifications of the tax code. These recovery schedules are based on the declining balance method with half year convention. If depreciable costs accrue when fewer years remain in the life of the project than would allow for cost recovery over the standard period, then costs are recovered using a straight line method over the remaining period.

The expected tangible drilling costs, lease equipment costs, and other capital expenditures is defined as

$$\begin{aligned} DEPREC_t = \sum_{j=\beta}^{t} \Big[\big[& (COSTEXP_T * EXKAP + EQUIP_T) * SR_1 * NUMEXP_j \\ & + (COSTDEV_T * DVKAP + EQUIP_T) * SR_2 * NUMDEV_j + KAP_j \big] \\ & * DEP_{t-j+1} * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j} \Big], \end{aligned} \quad \text{(A-17)}$$

$$\beta = \begin{cases} T \ \text{ for } t \leq T+m-1 \\ t-m+1 \ \text{ for } \ t > T+m-1 \end{cases}$$

where

j	=	year of recovery
β	=	index for write-off schedule
m	=	number of years in standard recovery period
COSTEXP	=	drilling cost for a successful exploratory well
EXKAP	=	fraction of exploratory drilling costs that are tangible and must be depreciated
EQUIP	=	lease equipment costs per well
SR	=	success rate (1=exploratory, 2=developmental)
NUMEXP	=	number of exploratory wells
COSTDEV	=	drilling cost for a successful developmental well
DVKAP	=	fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV	=	number of developmental wells drilled in a given period
KAP	=	major capital expenditures such as gravel pads in Alaska or offshore platforms, exclusive of lease equipment
DEP	=	for t # n+T-m, MACRS with half year convention; otherwise, 1/(n+T-t) in each period
infl	=	expected inflation rate[9]
disc	=	expected discount rate.

Present Value of Expected State and Federal Income Taxes

The present value of expected state corporate income tax is determined by

$$PVSIT_T = PVTAXBASE_T * STRT \quad \text{(A-18)}$$

where

PVTAXBASE	=	present value of expected taxable income (Equation A.14)
STRT	=	state income tax rate.

[9]Each of the write-off schedules give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

The present value of expected federal corporate income tax is calculated using the following equation:

$$PVFIT_T = PVTAXBASE_T * (1 - STRT) * FDRT \qquad \text{(A-19)}$$

where

FDRT = federal corporate income tax rate.

Summary

The discounted cash flow calculation is a useful tool for evaluating the expected profit or loss from an oil or gas project. The calculation reflects the time value of money and provides a good basis for assessing and comparing projects with different degrees of profitability. The timing of a project's cash inflows and outflows has a direct affect on the profitability of the project. As a result, close attention has been given to the tax provisions as they apply to costs.

The discounted cash flow is used in each submodule of the OGSM to determine the economic viability of oil and gas projects. Various types of oil and gas projects are evaluated using the proposed DCF calculation, including single well projects and multi-year investment projects. Revenues generated from the production and sale of co-products also are taken into account.

The DCF routine requires important assumptions, such as assumed costs and tax provisions. Drilling costs, lease equipment costs, operating costs, and other capital costs are integral components of the discounted cash flow analysis. The default tax provisions applied to the costs follow those used by independent producers. Also, the decision to invest does not reflect a firm's comprehensive tax plan that achieves aggregate tax benefits that would not accrue to the particular project under consideration.

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Appendix C. Model Abstract

1. Model Name
   Oil and Gas Supply Module

2. Acronym
   OGSM

3. Description
   OGSM projects the following aspects of the crude oil and natural gas supply industry:
   - production
   - reserves
   - drilling activity
   - natural gas imports and exports

4. Purpose
   OGSM is used by the Oil and Gas Division in the Office of Integrated Analysis and Forecasting as an analytic aid to support preparation of projections of reserves and production of crude oil and natural gas at the regional and national level. The annual projections and associated analyses appear in the *Annual Energy Outlook* (DOE/EIA-0383) of the U.S. Energy Information Administration. The projections also are provided as a service to other branches of the U.S. Department of Energy, the Federal Government, and non-Federal public and private institutions concerned with the crude oil and natural gas industry.

5. Date of Last Update
   2010

6. Part of Another Model
   National Energy Modeling System (NEMS)

7. Model Interface References
   Coal Module
   Electricity Module
   Industrial Module
   International Module
   Natural Gas Transportation and Distribution Model (NGTDM)
   Macroeconomic Module
   Petroleum Market Module (PMM)

8. Official Model Representative
   Office: Integrating Analysis and Forecasting
   Division: Oil and Gas Analysis
   Model Contact: Dana Van Wagener
   Telephone: (202) 586-4725

9. Documentation Reference
   U.S. Department of Energy. 2009. *Documentation of the Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063, U.S. Energy Information Administration, Washington, DC.

10. Archive Media and Installation Manual
    NEMS2010

11. Energy Systems Described
    The OGSM projects oil and natural gas production activities for six onshore and three offshore regions as well as three Alaskan regions. Exploratory and developmental drilling activities are treated separately, with exploratory drilling further differentiated as new field wildcats or other exploratory wells. New field wildcats are those wells drilled for a new field on a structure or in an environment never before productive. Other exploratory wells are those drilled in already productive locations. Development wells are primarily within or near proven areas and can result in extensions or revisions. Exploration yields new additions to the stock of reserves, and development determines the rate of production from the stock of known reserves.

12. Coverage
    Geographic: Six Lower 48 onshore supply regions, three Lower 48 offshore regions, and three Alaskan regions.
    Time Units/Frequency: Annually 1990 through 2035
    Product(s): Crude oil and natural gas
    Economic Sector(s): Oil and gas field production activities

13. Model Features
    Model Structure: Modular, containing four major components
    - Onshore Lower 48 Oil and Gas Supply Submodule
    - Offshore Oil and Gas Supply Submodule
    - Alaska Oil and Gas Supply Submodule
    - Oil Shale Supply Submodule

    Modeling Technique: The OGSM is a hybrid econometric/discovery process model. Drilling activities in the United States are projected using the estimated discounted cash flow that measures the expected present value profits for the proposed effort and other key economic variables.
    Special Features: Can run stand-alone or within the NEMS. Integrated NEMS runs employ short-term natural gas supply functions for efficient market equilibration.

14. Non-DOE Input Data
    - Alaskan Oil and Gas Field Size Distributions - U.S. Geological Survey
    - Alaska Facility Cost By Oil Field Size - U.S. Geological Survey
    - Alaska Operating cost - U.S. Geological Survey
    - Basin Differential Prices - Natural Gas Week, Washington, DC
    - State Corporate Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
    - State Severance Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
    - Federal Corporate Tax Rate, Royalty Rate - U.S. Tax Code
    - Onshore Drilling Costs - (1.) American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-2008)*, Washington, D.C.; (2.) Additional unconventional gas recovery drilling and operating cost data from operating companies
    - Offshore Technically Recoverable Oil and Gas Undiscovered Resources - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
    - Offshore Exploration, Drilling, Platform, and Production Costs - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
    - Canadian Wells drilled - Canadian Association of Petroleum Producers. *Statistical Handbook*.

- Canadian Recoverable Resource Base - National Energy Board. *Canada's Conventional Natural Gas Resources: A Status Report*, Canada, April 2004.
- Canadian Reserves - Canadian Association of Petroleum Producers. *Statistical Handbook*.
- Unconventional Gas Resource Data - (1) USGS *1995 National Assessment of United States Oil and Natural Gas Resources*; (2) Additional unconventional gas data from operating companies
- Unconventional Gas Technology Parameters - (1) Advanced Resources International Internal studies; (2) Data gathered from operating companies

15. DOE Input Data
    - Onshore Lease Equipment Cost – U.S. Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2008)*, DOE/EIA-0815(80-08)
    - Onshore Operating Cost – U.S. Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2008)*, DOE/EIA-0815(80-08)
    - Emissions Factors – U.S. Energy Information Administration
    - Oil and Gas Well Initial Flow Rates – U.S. Energy Information Administration, Office of Oil and Gas
    - Wells Drilled – U.S. Energy Information Administration, Office of Oil and Gas
    - Expected Recovery of Oil and Gas Per Well – U.S. Energy Information Administration, Office of Oil and Gas
    - Oil and Gas Reserves – U.S. Energy Information Administration. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, (1977-2009), DOE/EIA-0216(77-09)

16. Computing Environment
    - Hardware Used: PC
    - Operating System: Windows 95/Windows NT/Windows XP
    - Language/Software Used: FORTRAN
    - Memory Requirement: Unknown
    - Storage Requirement: Unknown
    - Estimated Run Time: 287 seconds

17. Reviews conducted
    - Independent Expert Review of the Offshore Oil and Gas Supply Submodule - Turkay Ertekin from Pennsylvania State University; Bob Speir of Innovation and Information Consultants, Inc.; and Harry Vidas of Energy and Environmental Analysis , Inc., June 2004
    - Independent Expert Review of the Annual Energy Outlook 2003 - Cutler J. Cleveland and Robert K. Kaufmann of the Center for Energy and Environmental Studies, Boston University; and Harry Vidas of Energy and Environmental Analysis, Inc., June-July 2003
    - Independent Expert Reviews, Model Quality Audit; Unconventional Gas Recovery Supply Submodule - Presentations to Mara Dean (DOE/FE - Pittsburgh) and Ray Boswell (DOE/FE - Morgantown), April 1998 and DOE/FE (Washington, DC)

18. Status of Evaluation Efforts

    Not applicable

19. Bibliography

    See Appendix B of this document.

Appendix D. Output Inventory

Variable Name	Description	Unit	Classification	Passed To Module
OGANGTSMX	Maximum natural gas flow through ANGTS	BCF	NA	NGTDM
OGCCAPPRD	Coalbed Methane production from CCAP		17 OGSM/NGTDM regions	NGTDM
OGCOPRD	Crude production by oil category	MMbbl/day	10 OGSM reporting regions	Industrial
OGCOPRDGOM	Gulf of Mexico crude oil production	MMbbl/day	Shallow and deep water regions	Industrial
OGCOWHP	Crude wellhead price by oil category	87$/bbl	10 OGSM reporting regions	Industrial
OGCNQPRD	Canadian production of oil and gas	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGCNPPRD	Canadian price of oil and gas	oil:87$/ bbl gas:87$/ BCF	Fuel (oil, gas)	NGTDM
OGCORSV	Crude reserves by oil category	Bbbl	5 crude production categories	Industrial
OGCRDSHR	Crude oil shares by OGSM region and crude type	percent	7 OLOGSS regions	PMM
OGDNGPRD	Dry gas production	BCF	57 Lower 48 onshore & 6 Lower 48 offshore districts	PMM
OGELSCO	Oil production elasticity	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGELSHALE	Electricity consumed	Trillion Btu	NA	Industrial
OGELSNGOF	Offshore nonassociated dry gas production elasticity	fraction	3 Lower 48 offshore regions	NGTDM
OGELSNGON	Onshore nonassociated dry gas production elasticity	fraction	17 OGSM/NGTDM regions	NGTDM
OGEORFTDRL	Total footage drilled from CO2 projects	feet	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORINJWLS	Number of injector wells from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORNEWWLS	Number of new wells drilled from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORPRD	EOR production from CO2 projects	Mbbl	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORPRDWLS	Number of producing wells from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEOYAD	Unproved Associated-Dissolved gas resources	TCF	6 Lower 48 onshore regions	Industrial
OGEOYRSVON	Lower 48 Onshore proved reserves by gas category	TCF	6 Lower 48 onshore regions 5 gas categories	Industrial
OGEOYINF	Inferred oil and conventional NA gas reserves	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial

Variable Name	Description	Unit	Classification	Passed To Module
OGEOYRSV	Proved Crude oil and natural gas reserves	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGEOYUGR	Technically recoverable unconventional gas resources	TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGEOYURR	Undiscovered technically recoverable oil and conventional NA gas resources	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGGROWFAC	Factor to reflect expected future cons growth		NA	NGTDM
OGJOBS			NA	Macro
OGNGLAK	Natural Gas Liquids from Alaska	Mbbl/day	NA	PMM
OGNGPRD	Natural Gas production by gas category	TCF	10 OGSM reporting regions	Industrial
OGNGPRDGOM	Gulf of Mexico Natural Gas production	TCF	Shallow and deep water regions	Industrial
OGNGRSV	Natural gas reserves by gas category	TCF	12 oil and gas categories	Industrial
OGNGWHP	Natural gas wellhead price by gas category	87$/MCF	10 OGSM reporting regions	Industrial
OGNOWELL	Wells completed	wells	NA	Industrial
OGPCRWHP	Crude average wellhead price	87$/bbl	NA	Industrial
OGPNGEXP	NG export price by border	87$/MCF	26 Natural Gas border crossings	NGTDM
OGPNGWHP	Natural gas average wellhead price	87$/MCF	NA	Industrial
OGPPNGIMP	NG import price by border	87$/MCF	26 Natural Gas border crossings	NGTDM
OGPRCEXP	Adjusted price to reflect different expectation		NA	NGTDM
OGPRCOAK	Alaskan crude oil production	Mbbl	3 Alaska regions	NGTDM
OGPRDADOF	Offshore AD gas production	BCF	3 Lower 48 offshore regions	NGTDM
OGPRDADON	Onshore AD gas production	BCF	17 OGSM/NGTDM regions	NGTDM
OGPRDUGR	Lower 48 unconventional natural gas production	BCF	6 Lower 48 regions and 3 unconventional gas types	NGTDM
OGPRRCAN	Canadian P/R ratio	fraction	Fuels (oil, gas)	NGTDM
OGPRRCO	Oil P/R ratio	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGPRRNGOF	Offshore nonassociated dry gas P/R ratio	fraction	3 Lower 48 offshore regions	NGTDM
OGPRRNGON	Onshore nonassociated dry gas P/R ratio	fraction	17 OGSM/NGTDM regions	NGTDM
OGQANGTS	Gas flow at U.S. border from ANGTS	BCF	NA	NGTDM
OGQCRREP	Crude production by oil category	MMbbl	5 crude production categories	PMM
OGQCRRSV	Crude reserves	Bbbl	NA	Industrial
OGQNGEXP	Natural gas exports	BCF	6 US/Canada & 3 US/Mexico border crossings	NGTDM

Variable Name	Description	Unit	Classification	Passed To Module
OGQNGIMP	Natural gas imports	BCF	3 US/Mexico border crossings; 4 LNG terminals	NGTDM
OGQNGREP	Natural gas production by gas category	TCF	12 oil and gas categories	NGTDM
OGQNGRSV	Natural gas reserves	TCF	NA	Industrial
OGRADNGOF	Non Associated dry gas reserve additions, offshore	BCF	3 Lower 48 offshore regions	NGTDM
OGRADNGON	Non Associated dry gas reserve additions, onshore	BCF	17 OGSM/NGTDM regions	NGTDM
OGRESCAN	Canadian end-of-year reserves	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGRESCO	Oil reserves	MMB	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGRESNGOF	Offshore nonassociated dry gas reserves	BCF	3 Lower 48 offshore regions	NGTDM
OGRESNGON	Onshore nonassociated dry gas reserves	BCF	17 OGSM/NGTDM regions	NGTDM
OGSHALENG	Gas produced	BCF	NA	NGTDM
OGTAXPREM	Canadian tax premium	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGTECHON	Technology factors	BCF	3 cost categories, 6 fuel types	Industrial
OGWPTDM	Natural Gas wellhead price	87$/MCF	17 OGSM/NGTDM regions	NGTDM

Secretary of Energy Advisory Board

Shale Gas Production Subcommittee Second Ninety Day Report

November 18, 2011

U.S. DEPARTMENT OF ENERGY

The SEAB Shale Gas Production Subcommittee Second Ninety Day Report – November 18, 2011

Executive Summary

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board is charged with identifying measures that can be taken to reduce the environmental impact and to help assure the safety of shale gas production. Shale gas has become an important part of the nation's energy mix. It has grown rapidly from almost nothing at the beginning of the century to near 30 percent of natural gas production. Americans deserve assurance that the full economic, environmental and energy security benefits of shale gas development will be realized without sacrificing public health, environmental protection and safety. On August 18, 2011 the Subcommittee presented its initial Ninety-Day Report[1] including twenty recommendations that the Subcommittee believes, if implemented, would assure that the nation's considerable shale gas resources are being developed responsibly, in a way that protects human health and the environment and is most beneficial to the nation. The Secretary of Energy's charge to the Subcommittee is included in Annex A and members of the Subcommittee are given in Annex B.

In this report the Subcommittee focuses on implementation of the twenty recommendations presented in its Ninety-day report. The Executive Summary of these recommendations is presented in Annex C.

The Second Ninety-Day Report

The Subcommittee recommendations in its initial report were presented without indicating priority or how each recommendation might be implemented. Progress in achieving the Subcommittee's objective of continuous improvement in reducing the environmental impact of shale gas production depends upon implementation of the Subcommittee recommendation; hence this final report focuses on implementation. On October 31, 2011, the Subcommittee held a public meeting at DOE headquarters in Washington, D.C., to learn the views of the Department of Interior, the Environmental Protection Agency, and the Department of Energy about progress and barriers to implementation of the Subcommittee recommendations.

The Subcommittee is mindful that state and federal regulators and companies are already deeply involved in environmental management. Implementing the twenty Subcommittee recommendations will require a great deal of effort, and regulators, public officials, and companies need to decide how to allocate scarce human and financial resources to each recommendation, potentially shifting effort from other valuable existing activities. All of the Subcommittee recommendations in its Ninety-Day report involve actions by one or more parties: federal officials, state officials, and public and private sector entities.

Two criteria are important in deciding on the allocation: the importance and ease of implementation. Early success in implementing some recommendations may stimulate greater effort on other recommendations, which require greater time and effort for progress. Decisions about when, how and whether to proceed with our recommendations are the responsibility of the public and private participants in the process – not the Subcommittee. But, the Subcommittee can be helpful at identifying those recommendations that seem particularly important and particularly amendable to early action. Accordingly this report classifies the twenty recommendations into three categories:

(1) Recommendations ready for implementation, primarily by federal agencies;

(2) Recommendations ready for implementation, primarily by states;

(3) Recommendations that require new partnerships and mechanisms for success.

<u>The Subcommittee recognizes that successful implementation of each of its recommendations will require cooperation among and leadership by federal, state and local entities. In its initial report, the Subcommittee called for a process of continuous improvement and said: "This process should involve discussions and other collaborative efforts among companies involved in shale gas production (including service companies), state and federal regulators, and affected communities and public interest groups."</u>

The Subcommittee also believes it has a responsibility to assess and report progress in implementing the recommendations in its initial report. Too often advisory committee recommendations are ignored, not because of disagreement with substance, but because the implementation path is unclear or because of the press of more immediate matters on dedicated individuals who are over extended. The Subcommittee does not wish to see this happen to its recommendation, because it believes citizens expect prompt action. Absent action there will be little credible progress in toward reducing in the environmental impact of shale gas production, placing at risk the future of the enormous potential benefits of this domestic energy resource. At this early stage, it is reasonable to assess if initial, constructive, steps are underway; there is no expectation that any of the recommendations could be completely implemented in the three months since the Subcommittee issued its initial report.

(1) Recommendations for implementation, primarily by federal agencies.

The Subcommittee has identified nine recommendations where federal agencies have primary responsibility and that are ready for implementation; these are presented in Table I.

Recommendation #2 Two existing non-profit organizations – the State Review of Oil and Natural Gas Environmental Regulations (STONGER) and the Ground Water Protection Council (GWPC) are two existing organizations that work to share information to improve the quality of regulatory policy and practice in the states. The budgets for these organizations are small, and merit public support. Previously, federal agencies (DOE and EPA) provided funding for STRONGER and GWPC, but federal funding is currently not provided. To maintain credibility to have an ability to set their own agenda these organizations cannot rely exclusively on funding provided by companies of the regulated industry. The Subcommittee has recommended that $5 million per year would provide the resources to STRONGER and the GWCPC needed to strengthen and broaden its activities as discussed in the Subcommittees previous report, for example, updating hydraulic fracturing guidelines and well construction guidelines, and developing guidelines for water supply, air emissions and cumulative impacts. Additionally, DOE and/or EPA should consider making grants to those states that volunteer to have their regulations and practices peer-reviewed by STRONGER, as an incentive for states to undergo updated reviews and to implement recommended actions.

Table 1. Recommendations ready for immediate implementation		
Rec.#	**Recommendation**	**Comment & Status**
1.	Improve public information about shale gas operations	Federal responsibility to begin planning for public website. Some discussion between DOE and White House offices about possible hosting sites but no firm plan. States should also consider establishing sites.
2.	Improve communication among federal and state regulators and provide federal funding for STRONGER and the Ground Water Protection Council	Federal funding at $5m/y will allow state regulators/NGOs/industry to plan activities. Possible minor DOE FY2012 funding; no multi-year commitment. See discussion below.
3	Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable.	We encourage EPA to complete its current rule making as it applies to shale gas production quickly, and explicitly include methane, a greenhouse gas, and controls from existing shale gas production sources. Additionally, some states have taken action in this area, and others could do so as well. See discussion below.
4	Enlisting a subset of producers in different basins to design and field a system to collect air emissions data.	Industry initiative in advance of regulation. Several companies have shown interest. Possible start in Marcellus and Eagle Ford. See discussion below.
5	Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of natural gas use.	OSTP has not committed to leading an interagency effort, but the Administration is taking steps to collect additional data, including through the EPA air emissions rulemaking.
6	Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.	A general statement of the importance the Subcommittee places on reducing air emissions. Federal funding at $5m/y for state regulators/NGOs/industry will encourage planning. Some states have taken action in this area, and others could do so as well.
11	Launch addition field studies on possible methane migration from shale gas wells to water reservoirs.	No new studies launched; funding required from fed agencies or from states.[2]
14	Disclosure of Fracturing fluid composition	DOI has announced its intent to propose requirement. Industry appears ready to agree to mandatory stricter disclosure. See discussion below.
15	Elimination of diesel use in fracturing fluids	EPA is developing permitting guidance under the UIC program. The Subcommittee reiterates its recommendation that diesel fuel should be eliminated in hydraulic fracturing fluids.
20	R&D needs	OMB/OSTP must define proper limits for unconventional gas R&D and budget levels for DOE, EPA, and USGS. See discussion below.

Funding for the GWPC would allow the association to extend and expand its *Risk Based Data Management System,* which helps states collected and publicly share data associated with their oil and gas regulatory programs – for example, sampling and monitoring programs for surface waters, water wells, sediments and isotopic activity in and around areas of shale gas operations. Likewise, funding could go toward integrating the RBDMS into the national data portal discussed in Recommendation #1. Funding would also allow GWPC to upgrade its fracturing fluid chemical disclosure registry, *Frac Focus*, so that information can be searched, sorted and aggregated by chemical, by well, by company and by geography – as recommended by the Subcommittee in its 90-Day report.

Recommendation #3 On July 28th the U.S. EPA proposed New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants (NSPS/NESHAPs) for the oil and natural gas sector. The proposed rules, which are currently under comment and review, are scheduled to be finalized by April 3, 2012, represent a critical step forward in reducing emissions of smog-forming pollutants and air toxics. The Subcommittee commends EPA for taking this important step and encourages timely implementation. However, the proposed rules fall short of the recommendations made in the Subcommittee's Ninety-Day Report because the rules do not directly control methane emissions and the NSPS rules as proposed do not cover existing shale gas sources except for fractured or re-fractured existing gas wells.

Additionally, in its Ninety-Day report the Subcommittee recommended that companies be required to measure and disclose air emissions from shale gas sources. Recently, in response to a challenge, the EPA took two final actions that compromise the ability to get accurate emissions data from the oil and gas sector under the Greenhouse Gas Reporting Rule.[3] The Subcommittee reiterates its recommendation that the federal government or state agencies require companies to measure and disclose air emissions from shale gas sources.

Recommendation #4 The Subcommittee is aware that operating companies are considering projects to collect and disclose air emissions data from shale gas production sites. Discussions are underway to define the data to be collected, appropriate instrumentation, and subsequent analysis and disclosure of the data. The Subcommittee welcomes this development and underscores its earlier recommendation for disclosure, including independent technical review of the methodology.

Recommendation #14 The Subcommittee welcomes the announcement of the DOI of its intent to require disclosure of fracturing fluid composition on federal lands. The Subcommittee was pleased to learn from the DOI at its October 31, 2011 public hearing that the agency intends to follow the disclosure recommendations in its Ninety-Day Report that disclosure should include all chemicals, not just those that appear on

Material Safety Data Sheets, and that chemicals should be reported on a well-by-well basis and posted on a publicly available website that includes tools for searching and aggregating data by chemical, by well, by company and by geography. The Subcommittee recognized the need for protection of legitimate trade secrets but believes that the bar for trade secret protection should be high. The Subcommittee believes the DOI disclosure policy should meet the Subcommittee's criteria and that it can serve as a model for the states. The Ground Water Protection Council and the Interstate Oil and Gas Compact Commission have taken an important step in announcing their intent to require disclosure of all chemicals by operators who utilize their voluntary chemical disclosure registry, FracFocus. The Subcommittee welcomes this progress and encourages those organizations to continue their work toward upgrading FracFocus to meet the Subcommittee's recommended disclosure criteria.

Recommendation #20 As set out in its Ninety-day report, the Subcommittee believes there is a legitimate role for the federal government in supporting R&D on shale gas, arguably the country's most important domestic energy resource. To be effective such an R&D program must be pursued for several years, at a relatively modest level. The Subcommittee is aware that discussions have taken place between OMB and the involved agencies, DOI/USGS, DOE, and EPA about funding for unconventional gas R&D. The Subcommittee understands that agreement has been reached that the administration will seek funding for "priority items" for FY2012 in its discussions with Congress, but the "priority items" and the level of this funding is not decided. The Subcommittee welcomes the agencies effort to coordinate their planned out-year research effort for FY2013 and beyond, as described by DOI, DOE, and EPA at its public meeting on October 31, 2011. But, as yet, there has been no agreement with OMB on the scale and composition of a continuing unconventional gas R&D program. Failure to provide adequate funding for R&D would be deleterious and undermine achieving the policy objectives articulated by the President.

Note: after the Subcommittee completed its deliberations the Office of Management and Budget sent a letter setting forth the efforts underway to find funding for the Subcommittee recommendations; **see Annex D**. While the letter does not settle the matter, it is an important and welcome, positive step.

(2) Recommendations ready for implementation, primarily by states.

The Subcommittee has identified four recommendations in this category; all address water quality related issues.

Table 2. Recommendations requiring cooperation between regulators and industry

<table>
<tr><th>Rec.#</th><th>Recommendation</th><th>Comment & Status</th></tr>
<tr><td>8</td><td>Measure and publicly report the composition of water stocks and flow throughout the fracturing and cleanup process.</td><td rowspan="2">Awaits EPA’s study underway on the Impacts of hydraulic fracturing on drinking water resources. See discussion below. States should also determine a way forward to measure and record data from flow back operations as many issues will be local issues.</td></tr>
<tr><td>9</td><td>Manifest all transfers of water among different locations</td></tr>
<tr><td>10</td><td>Adopt best practices in well development and construction, especially casing, cementing, and pressure management</td><td>Widely recognized as a key practice by companies and regulators but no indication of a special initiative on field measurement and reporting.</td></tr>
<tr><td>12</td><td>Adopt requirements for background water quality measurements</td><td>The value of background measurements is recognized. Jurisdiction for access to private wells differs widely</td></tr>
</table>

Recommendation #8 and 9 EPA has a number of regulatory actions in process. On October 20, 2011 EPA announced a schedule setting waste water discharge standards that will affect some shale gas production activities.[4] Further water quality regulatory developments will benefit from the results of EPA’s study on the impact of hydraulic fracturing on drinking water that will not be complete until 2014 and will likely initiate significant negotiation between EPA and state regulators on the scope and responsibility for water regulations. The Subcommittee observes that there will be a tremendous amount of activity in the field before EPA completes its study (and any potential regulatory actions that flow from it) and urges the EPA to take action as appropriate during the course of its process.

Recommendation #12 In its initial report, the Subcommittee called for background water measurements at wells surrounding planned production sites to establish an objective benchmark to assess potential damage to water resources. All stakeholders agree that such measurements can be helpful in establishing facts and verifying disputed contamination claims. The lack of a clear pattern of state, local, and federal authority for access to private water wells to make such measurements is an impediment to policy development.

(3) Recommendations that require new partnerships or mechanisms for success

The following recommendations require development of new partnerships or mechanisms and hence the implementation challenge can be quite significant. These recommendations do, however, signal significant concerns shared by members of the Subcommittee that are noted in Table 3. The challenge is to devise new mechanisms for addressing these significant environmental problems.

Table 3. Recommendations that require new mechanisms for success

Rec.#	Recommendation	Comment & Status
7	Protection of water quality through a systems approach.	At present neither EPA or the states are engaged in developing a systems/lifecycle approach to water management.
13	Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.	Reflects Subcommittee unease that the present arrangement of shared federal and state responsibility for cradle-to-grave water quality is not working smoothly or as well as it should.
16	Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies.	No new studies launched; funding required from federal agencies or from states. See discussion below.
17	Organizing for best practice.	Industry intends to establish ‘centers of excellence’ regionally, that involve public interest groups, state and local regulatory and local colleges and universities.
18	Air	
19	Water	

Recommendation #16 Shale gas production brings both benefits and cost of economic development to a community, often rapidly and in a region that it is unfamiliar with oil and gas operations. Short and long term community impact range from traffic, noise, land use, disruption of wildlife and habitat, with little or no allowance for planning or effective mechanisms to bring companies, regulators, and citizens to deliberate about how best to deal with near term and cumulative impacts. The Subcommittee does not believe that these issues will solve themselves or be solved by prescriptive regulation or in the courts. State and local governments should take the lead in experimenting with different mechanisms for engaging these issues in a constructive way, seeking to be beyond discussion to practical mitigation. Successful models should be disseminated.

The U.S. Department of Interior, however, is somewhat unique in having tools at its disposal that could be used to address cumulative and community impacts. For example, Master Leasing and Development Plans, a relatively new tool, might help improve planning for production on federal lands through requirements for phased leasing and development, multi-well pad drilling, limitations on surface disturbance, centralization of infrastructure, land and roadway reclamation, etc.

Recommendation 17, 18 & 19 Industry has always been interested in best practices. The Subcommittee has called for industry to increase their best practices process for field engineering and environmental control activities by adopting the objective of continuous improvement, validated by measurement and disclosure of key operating metrics.[5] Leadership for this initiative lies with industry but also involves regulators and public interest groups. Best practices involves the entire range of shale gas operations including: (a) well design and siting, (b) drilling and well completion, including importantly casing and cementing, (c) hydraulic fracturing, (d) surface operations, (e) collection and distribution of gas and land liquids, (f) well abandonment and sealing, and (g) emergency response. Developing reliable metrics for best practices is a major task and must take into account regional differences of geology and regulatory practice. A properly trained work force is an important element in achieving best practice. Thus, organizing for best practice should include better mechanisms for training of oil field workers. Such training should utilize local community college and vocational education resources.

Industry is taking a regional approach to best practice, building on local organizations, such as the Marcellus Shale Coalition. Shale companies understand the importance of involving non-industry stakeholders in their efforts and are beginning to take initiatives that engage the public in a meaningful way. Industry is showing increased interest in engineering practice as indicated by the recent workshop on hydraulic fracturing sponsored by the American Petroleum Institute on October 4 and 5, 2011 in Pittsburgh PA.[6] The Subcommittee urges leading companies to adopt a more visible commitment to using quantitative measures as a means of achieving best practice and demonstrating to the public that there is continuous improvement in reducing the environmental impact of shale gas production.

Concluding remarks

The Subcommittee was gratified with the generally favorable, but not universally favorable, response to its initial report. In particular there was overwhelming agreement on two points: (1) If the country is to enjoy the economic and other benefits of shale gas production over the coming years disciplined attention must be devoted to reducing the environmental impact that accompanies this development, and (2) a prudent balance between development and environmental protection is best struck by establishing a strong foundation of regulation and enforcement, and adopting a policy and practice that measures, discloses, and continuously improves shale gas operations.

The Subcommittee believes that if action is not taken to reduce the environmental impact accompanying the very considerable expansion of shale gas production expected across the country – perhaps as many as 100,000 wells over the next several decades – there is a real risk of serious environmental consequences causing a loss of public confidence that could delay or stop this activity. Thus, the Subcommittee has an interest in assessing and reporting on, the progress that is being made on implementing its recommendations or some sensible variations of these recommendations.

The Subcommittee has the impression that its initial report stimulated interest in taking action to reduce the environmental impact of shale gas production by the administration, state governments, industry, and public interest groups. However, the progress to date is less than the Subcommittee hoped and it is not clear how to catalyze action at a time when everyone's attention is focused on economic issues, the press of daily business, and an upcoming election.   The Subcommittee cautions that whether its approach is followed or not, some concerted and sustained action is needed to avoid excessive environmental impacts of shale gas production and the consequent risk of public opposition to its continuation and expansion.

ANNEX A – CHARGE TO THE SUBCOMMITTEE

From: Secretary Chu

To: William J. Perry, Chairman, Secretary's Energy Advisory Board (SEAB)

On March 30, 2011, President Obama announced a plan for U.S. energy security, in which he instructed me to work with other agencies, the natural gas industry, states, and environmental experts to improve the safety of shale gas development. The President also issued the Blueprint for a Secure Energy Future ("Energy Blueprint"), which included the following charge:

> **"Setting the Bar for Safety and Responsibility:** To provide recommendations from a range of independent experts, the Secretary of Energy, in consultation with the EPA Administrator and Secretary of Interior, should task the Secretary of Energy Advisory Board (SEAB) with establishing a subcommittee to examine fracking issues. The subcommittee will be supported by DOE, EPA and DOI, and its membership will extend beyond SEAB members to include leaders from industry, the environmental community, and states. The subcommittee will work to identify, within 90 days, any immediate steps that can be taken to improve the safety and environmental performance of fracking and to develop, within six months, consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment." *Energy Blueprint (page 13).*

The President has charged us with a complex and urgent responsibility. I have asked SEAB and the Natural Gas Subcommittee, specifically, to begin work on this assignment immediately and to give it the highest priority.

This memorandum defines the task before the Subcommittee and the process to be used.

Membership:

In January of 2011, the SEAB created a Natural Gas Subcommittee to evaluate what role natural gas might play in the clean energy economy of the future. Members of the Subcommittee include John Deutch (chair), Susan Tierney, and Dan Yergin. Following consultation with the Environmental Protection Agency and the Department of the Interior, I have appointed the following additional members to the Subcommittee: Stephen Holditch, Fred Krupp, Kathleen McGinty, and Mark Zoback.

The varied backgrounds of these members satisfies the President's charge to include individuals with industry, environmental community, and state expertise. To facilitate an expeditious start, the Subcommittee will consist of this small group, but additional members may be added as appropriate.

Consultation with other Agencies:

The President has instructed DOE to work in consultation with EPA and DOI, and has instructed all three agencies to provide support and expertise to the Subcommittee. Both agencies have independent regulatory authority over certain aspects of natural gas production, and considerable expertise that can inform the Subcommittee's work.

- The Secretary and Department staff will manage an interagency working group to be available to consult and provide information upon request of the Subcommittee.
- The Subcommittee will ensure that opportunities are available for EPA and DOI to present information to the Subcommittee.
- The Subcommittee should identify and request any resources or expertise that lies within the agencies that is needed to support its work.
- The Subcommittee's work should at all times remain independent and based on sound science and other expertise held from members of the Subcommittee.
- The Subcommittee's deliberations will involve only the members of the Subcommittee.
- The Subcommittee will present its final report/recommendations to the full SEAB Committee.

Public input:

In arriving at its recommendations, the Subcommittee will seek timely expert and other advice from industry, state and federal regulators, environmental groups, and other stakeholders.

- To assist the Subcommittee, DOE's Office of Fossil Energy will create a website to describe the initiative and to solicit public input on the subject.
- The Subcommittee will meet with representatives from state and federal regulatory agencies to receive expert information on subjects as the Subcommittee deems necessary.
- The Subcommittee or the DOE (in conjunction with the other agencies) may hold one or more public meetings when appropriate to gather input on the subject.

Scope of work of the Subcommittee:

The Subcommittee will provide the SEAB with recommendations as to actions that can be taken to improve the safety and environmental performance of shale gas extraction processes, and other steps to ensure protection of public health and safety, on topics such as:

- well design, siting, construction and completion;
- controls for field scale development;
- operational approaches related to drilling and hydraulic fracturing;
- risk management approaches;
- well sealing and closure;
- surface operations;
- waste water reuse and disposal, water quality impacts, and storm water runoff;
- protocols for transparent public disclosure of hydraulic fracturing chemicals and other information of interest to local communities;
- optimum environmentally sound composition of hydraulic fracturing chemicals, reduced water consumption, reduced waste generation, and lower greenhouse gas emissions;

- emergency management and response systems;
- metrics for performance assessment; and
- mechanisms to assess performance relating to safety, public health and the environment.

The Subcommittee should identify, at a high level, the best practices and additional steps that could enhance companies' safety and environmental performance with respect to a variety of aspects of natural gas extraction. Such steps may include, but not be limited to principles to assure best practices by the industry, including companies' adherence to these best practices. Additionally, the Subcommittee may identify high-priority research and technological issues to support prudent shale gas development.

Delivery of Recommendations and Advice:

- Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracking."
- Within 180 days of its first meeting, the Subcommittee will report to SEAB "consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment."
- At each stage, the Subcommittee will report its findings to the full Committee and the SEAB will review the findings.
- The Secretary will consult with the Administrator of EPA and the Secretary of the Interior, regarding the recommendations from SEAB.

Other:

- The Department will provide staff support to the Subcommittee for the purposes of meeting the requirements of the Subcommittee charge. The Department will also engage the services of other agency Federal employees or contractors to provide staff services to the Subcommittee, as it may request.
- DOE has identified $700k from the Office of Fossil Energy to fund this effort, which will support relevant studies or assessments, report writing, and other costs related to the Subcommittee's process.
- The Subcommittee will avoid activity that creates or gives the impression of giving undue influence or financial advantage or disadvantage for particular companies involved in shale gas exploration and development.
- The President's request specifically recognizes the unique technical expertise and scientific role of the Department and the SEAB. As an agency not engaged in regulating this activity, DOE is expected to provide a sound, highly credible evaluation of the best practices and best ideas for employing these practices safely that can be made available to companies and relevant regulators for appropriate action. Our task does not include making decisions about regulatory policy.

ANNEX B – MEMBERS OF THE SUBCOMMITTEE

John Deutch, Institute Professor at MIT (Chair) **-** John Deutch served as Director of Energy Research, Acting Assistant Secretary for Energy Technology and Under Secretary of Energy for the U.S. Department of Energy in the Carter Administration and Undersecretary of Acquisition & Technology, Deputy Secretary of Defense and Director of Central Intelligence during the first Clinton Administration. Dr. Deutch also currently serves on the Board of Directors of Raytheon and Cheniere Energy and is a past director of Citigroup, Cummins Engine Company and Schlumberger. A chemist who has published more than 140 technical papers in physical chemistry, he has been a member of the MIT faculty since 1970, and has served as Chairman of the Department of Chemistry, Dean of Science and Provost. He is a member of the Secretary of Energy Advisory Board.

Stephen Holditch, Head of the Department of Petroleum Engineering at Texas A&M University and has been on the faculty since 1976 - Stephen Holditch, who is a member of the National Academy of Engineering, serves on the Boards of Directors of Triangle Petroleum Corporation and Matador Resources Corporation. In 1977, Dr. Holditch founded S.A. Holditch & Associates, a petroleum engineering consulting firm that specialized in the analysis of unconventional gas reservoirs. Dr. Holditch was the 2002 President of the Society of Petroleum Engineers. He was the Editor of an SPE Monograph on hydraulic fracturing treatments, and he has taught short courses for 30 years on the design of hydraulic fracturing treatments and the analyses of unconventional gas reservoirs. Dr. Holditch worked for Shell Oil Company prior to joining the faculty at Texas A&M University.

Fred Krupp, President, Environmental Defense Fund **-** Fred Krupp has overseen the growth of EDF into a recognized worldwide leader in the environmental movement. Krupp is widely acknowledged as the foremost champion of harnessing market forces for environmental ends. He also helped launch a corporate coalition, the U.S. Climate Action Partnership, whose Fortune 500 members - Alcoa, GE, DuPont and dozens more - have called for strict limits on global warming pollution. Mr. Krupp is coauthor, with Miriam Horn, of New York Times Best Seller, *Earth: The Sequel*. Educated at Yale and the University of Michigan Law School, Krupp was among 16 people named as America's Best Leaders by U.S. News and World Report in 2007.

Kathleen McGinty, Kathleen McGinty is a respected environmental leader, having served as President Clinton's Chair of the White House Council on Environmental Quality and Legislative Assistant and Environment Advisor to then-Senator Al Gore. More recently, she served as Secretary of the Pennsylvania Department of Environmental Protection. Ms. McGinty also has a strong background in energy. She is Senior Vice President of Weston Solutions where she leads the company's clean energy development business. She also is an Operating Partner at Element Partners, an investor in efficiency and renewables. Previously, Ms. McGinty was Chair of the Pennsylvania Energy Development Authority, and currently she is a Director at NRG Energy and Iberdrola USA.

Susan Tierney, Managing Principal, Analysis Group **-** Susan Tierney is a consultant on energy and environmental issues to public agencies, energy companies, environmental organizations, energy consumers, and tribes. She chairs the Board of the Energy Foundation, and serves on the Boards of Directors of the World Resources Institute, the Clean Air Task Force, among others. She recently, co-chaired the National Commission on Energy Policy, and chairs the Policy Subgroup of the National Petroleum Council's study of North American natural gas and oil resources. Dr. Tierney served as Assistant Secretary for Policy at the U.S. Department of Energy during the Clinton Administration. In Massachusetts, she served as Secretary of Environmental Affairs, Chair of the Board of the Massachusetts Water Resources Agency, Commissioner of the Massachusetts Department of Public Utilities and executive director of the Massachusetts Energy Facilities Siting Council.

Daniel Yergin, Chairman, IHS Cambridge Energy Research Associates **-** Daniel Yergin is the co-founder and chairman of IHS Cambridge Energy Research Associates. He is a member of the U.S. Secretary of Energy Advisory Board, a board member of the Board of the United States Energy Association and a member of the U.S. National Petroleum Council. He was vice chair of the 2007 National Petroleum Council study, *Hard Truths* and is vice chair of the new National Petroleum Council study of North American natural gas and oil resources. He chaired the U.S. Department of Energy's Task Force on Strategic Energy Research and Development. Dr. Yergin currently chairs the Energy Security Roundtable at the Brookings Institution, where he is a trustee, and is member of the advisory board of the MIT Energy Initiative. Dr. Yergin is also CNBC's Global Energy Expert. He is the author of the Pulitzer Prize-winning book, *The Prize: The Epic Quest for Oil, Money and Power.* His new book – *The Quest: Energy, Security, and the Remaking of the Modern World* – will be published in September 2011..

Mark Zoback, Professor of Geophysics, Stanford University - Mark Zoback is the Benjamin M. Page Professor of Geophysics at Stanford University. He is the author of a textbook, *Reservoir Geomechanics*, and author or co-author of over 300 technical research papers. He was co-principal investigator of the San Andreas Fault Observatory at Depth project (SAFOD) and has been serving on a National Academy of Engineering committee investigating the Deepwater Horizon accident. He was the chairman and co-founder of GeoMechanics International and serves as a senior adviser to Baker Hughes, Inc. Prior to joining Stanford University, he served as chief of the Tectonophysics Branch of the U.S. Geological Survey Earthquake Hazards Reduction Program.

Annex C – Subcommittee Recommendations

A list of the Subcommittee's findings and recommendations follows.

1. Improve public information about shale gas operations: Create a portal for access to a wide range of public information on shale gas development, to include current data available from state and federal regulatory agencies. The portal should be open to the public for use to study and analyze shale gas operations and results.

2. Improve communication among state and federal regulators: Provide continuing annual support to STRONGER (the State Review of Oil and Natural Gas Environmental Regulation) and to the Ground Water Protection Council for expansion of the *Risk Based Data Management System* and similar projects that can be extended to all phases of shale gas development.

3. Improve air quality: Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable. The Subcommittee supports adoption of rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations. The Subcommittee recommends:

    4. Enlisting a subset of producers in different basins to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data from shale gas operations and make these data publically available;

    5. Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of shale gas operations throughout the lifecycle of natural gas use in comparison to other fuels; and

    6. Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.

7. Protection of water quality: The Subcommittee urges adoption of a systems approach to water management based on consistent measurement and public disclosure of the flow and composition of water at every stage of the shale gas production process. The Subcommittee recommends the following actions by shale gas companies and regulators – to the extent that such actions have not already been undertaken by particular companies and regulatory agencies:

    8. Measure and publicly report the composition of water stocks and flow throughout the fracturing and clean-up process.

    9. Manifest all transfers of water among different locations.

    10. Adopt best practices in well development and construction, especially casing, cementing, and pressure management. Pressure testing of cemented casing and state-of-the-art cement bond logs should be used to confirm formation isolation. Microseismic surveys should be carried out to assure that

hydraulic fracture growth is limited to the gas producing formations. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing jobs. The regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing.

11. Additional field studies on possible methane leakage from shale gas wells to water reservoirs.

12. Adopt requirements for background water quality measurements (e.g., existing methane levels in nearby water wells prior to drilling for gas) and report in advance of shale gas production activity.

13. Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.

14. Disclosure of fracturing fluid composition: The Subcommittee shares the prevailing view that the risk of fracturing fluid leakage into drinking water sources through fractures made in deep shale reservoirs is remote.[7] Nevertheless the Subcommittee believes there is no economic or technical reason to prevent public disclosure of all chemicals in fracturing fluids, with an exception for genuinely proprietary information. While companies and regulators are moving in this direction, progress needs to be accelerated in light of public concern.

15. Reduction in the use of diesel fuel: The Subcommittee believes there is no technical or economic reason to use diesel in shale gas production and recommends reducing the use of diesel engines for surface power in favor of natural gas engines or electricity where available.

16. Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies. Each relevant jurisdiction should pay greater attention to the combination of impacts from multiple drilling, production and delivery activities (e.g., impacts on air quality, traffic on roads, noise, visual pollution), and make efforts to plan for shale development impacts on a regional scale. Possible mechanisms include:

(1) Use of multi-well drilling pads to minimize transport traffic and need for new road construction.

(2) Evaluation of water use at the scale of affected watersheds.

(3) Formal notification by regulated entities of anticipated environmental and community impacts.

(4) Preservation of unique and/or sensitive areas as off-limits to drilling and support infrastructure as determined through an appropriate science-based process.

(5) Undertaking science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.

(6) Establishment of effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of surface and mineral rights owners.

17. Organizing for best practice: The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice, defined as improvements in techniques and methods that rely on measurement and field experience, is needed to improve operational and environmental outcomes. The Subcommittee favors a national approach including regional mechanisms that recognize differences in geology, land use, water resources, and regulation. The Subcommittee is aware that several different models for such efforts are under discussion and the Subcommittee will monitor progress during its next ninety days. The Subcommittee has identified several activities that deserve priority attention for developing best practices:

    18. Air: (a) Reduction of pollutants and methane emissions from all shale gas production/delivery activity. (b) Establishment of an emission measurement and reporting system at various points in the production chain.

    19. Water: (a) Well completion – casing and cementing including use of cement bond and other completion logging tools. (b) Minimizing water use and limiting vertical fracture growth.

20. Research and Development needs. The public should expect significant technical advances associated with shale gas production that will significantly improve the efficiency of shale gas production and that will reduce environmental impact. The move from single well to multiple-well pad drilling is one clear example. Given the economic incentive for technical advances, much of the R&D will be performed by the oil and gas industry. Nevertheless the federal government has a role especially in basic R&D, environment protection, and safety. The current level of federal support for unconventional gas R&D is small, and the Subcommittee recommends that the Administration and the Congress set an appropriate mission for R&D and level funding.

Annex D Letter from the Office of Management and Budget

EXECUTIVE OFFICE OF THE PRESIDENT
OFFICE OF MANAGEMENT AND BUDGET
WASHINGTON, D.C. 20503

THE DIRECTOR

November 8, 2011

Dr. John Deutch
Chairman
Secretary of Energy Advisory Board on Natural Gas
Washington, DC 20585

Dear John:

Thank you for your letter on Tuesday, November 1 about the Subcommittee of the Secretary of Energy Advisory Board on Natural Gas (SEAB). I am sorry that I could not attend the SEAB meeting earlier this week. Your work on this issue has been very helpful and it is a high priority of the Administration.

As you are aware, the Office of Management and Budget (OMB) is running an interagency working group to coordinate the research budget proposals on hydraulic fracturing and has received some preliminary suggestions from the agencies for FY 2013 activities. Over the course of the next few weeks, the interagency budget working group will review agencies' research proposals taking into consideration core competencies, which I understand was discussed with you on Monday, October 31. We will be looking carefully at the research and development (R&D) recommendations of the SEAB report as we put together the President's FY 2013 Budget.

As you know, all discretionary funding is capped in FY 2012 and FY 2013. Hydraulic fracturing R&D is a priority that we are seeking to fund as we make tough choices within these constraints. As your report acknowledges, the industry has a strong incentive to fund and carry out production-related R&D. To the degree that environmental constraints could impede continued growth, industry also has an interest in R&D to improve environmental performance and safety. Thus, finding the correct balance between public and private investment, within the broader Federal budget constraints is challenging, but important. As part of the R&D budget review, we are identifying existing programs across the government to avoid redundancies and to optimize budgetary resources. As a general matter, OMB does not announce budget decisions prior to the full presentation to the Congress in February of each year.

I am concerned there has been some confusion around OMB's position on funding this research. The Administration has opposed subsidies for conventional fossil energy exploration and production, just as the Bush Administration did. But hydraulic fracturing R&D that adheres to the framework set forth in the SEAB 90-day interim report – for air, water, induced seismicity or other public information needed to set appropriate regulatory boundaries – we strongly support, and we agree that the Environmental Protection Agency, Department of the Interior, and Department of Energy all have roles to play. However, we need to carefully articulate those roles and structure the President's Budget to most efficiently deliver the R&D funding needed to address environmental and safety concerns.

The SEAB 90-day interim report supports the existing Ultradeepwater and Unconventional Natural Gas and Other Petroleum Research Program (Sec. 999) which is funded through mandatory appropriations authorized by the Energy Policy Act of 2005. On this point, we disagree. Mandatory R&D funding from Sec. 999 is too inflexible a mechanism to adequately address environmental and safety concerns in the dynamic and rapidly evolving hydraulic fracturing space, and the President's Budgets have proposed eliminating this mandatory R&D program. Absent Congressional action to repeal Sec. 999, the Administration has sought to refocus this funding to support R&D with significant potential public benefits, including activities consistent with the SEAB recommendations.

Thank you again for reaching out to me on this important issue. Please do not assume that because we are busy, that this issue is not important to the Administration, and feel free to be in touch moving forward.

Hope all is well with you and would look forward to catching up.

Best regards,

Jack

Jacob J. Lew

Massachusetts Institute of Technology
77 Massachusetts Avenue
Building 6-215
Cambridge, Massachusetts 02139

John Deutch Institute Professor
Department of Chemistry
Tel: 617 253 1479
Fax: 617 258 6700
Email: jmd@mit.edu

To: Jack Lew, Director Office of Management and Budget

Dear Jack, November 1, 2011

In March, President Obama directed Steve Chu to establish a Subcommittee of the Secretary of Energy Advisory Board on Hydraulic Fracturing tasked to identify steps that should be taken to reduce the environmental impact of shale gas production. I am the chair of this Subcommittee, which released its initial report on August 18, 2011.

One of the Subcommittee's twenty recommendations called on the administration to adopt a unconventional gas R&D program to perform R&D that merits public funding such as environmental studies on methane leakage, assessing the relative greenhouse gas foot print of natural gas production, seismicity, inventing new techniques for real time monitoring and control of hydraulic fluid injection, and development of environmentally friendly stimulation fluids. The Subcommittee did not ask for "new" money, or suggest a particular level of funding, or how responsibilities should be distributed between the DOE, EPA, and the USGS.

On October 5, 2011, I wrote to you requesting that you or a designated representative come and speak with the Subcommittee (in open or closed session) about this matter. You designated Sally Ericsson, Associate Director for Natural Resources, who I understand participated in an interagency meeting on this subject and agreed to attend the Subcommittee's October 31 meeting. Unfortunately, Ms Ericsson had to cancel her attendance, inevitably leaving the Subcommittee, as it prepares its second and final report, with the impression that the administration has not yet been able to formulate a position on the level of distribution of federal support for unconventional gas R&D, arguably the most important near term domestic energy supply option for the country. The Subcommittee did learn that the administration will seek funds for "priority" items for FY2012 in its discussions with Congress and that EPA, DOE, and DOI are coordinating their research plans, but evidently an effective R&D program requires consistent multi-year funding.

I know that you are totally consumed by the budget deficit and countless other matters. Nevertheless, I urge you to devote a few minutes to resolving the issue of federal support for R&D on unconventional gas. President Obama in his *Blue Print for Secure Energy Future* recognized that realizing the enormous economic benefits of shale case requires improving the environmental performance of shale gas production and the *Blue Print* explicitly identified a role for federally sponsored research. It will be a shame if the administration does not take the initial steps necessary to establish a modest, but steady R&D effort by the participating agencies.

Sincerely

John Deutch

John Deutch

Cc: Steven Chu,
Heather Zichal,
Michael Froman

ENDNOTES

[1] The Subcommittee report is available at: http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf

[2] Duke University has launched a follow-on study effort to its initial methane migration study. NETL, in cooperation with other federal agencies and with PA state agencies, Penn State, and major producers is launching a study limited to two wells. More needs to be done by federal agencies.

[3] First, EPA has finalized a deferral that will prevent the agency from collecting inputs to emissions equations data until 2015 for Subpart W sources. These inputs are critical to verify emissions information calculated using emission equations. Second, EPA has finalized a rule allowing more widespread use of Best Available Monitoring Methods ("BAMM") in 2011 and beyond. This action allows reporters to use more relaxed, non-standard methods when monitoring under Subpart W.
See: Change to the Reporting Date for Certain Data Elements Required Under the Mandatory Reporting of Greenhouse Gases Rule, 76 Fed. Reg. 53,057 (Aug. 25, 2011); and Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems: Revisions to Best Available Monitoring Method Provisions, 76 Fed. Reg. 59,533 (Sept. 27, 2011).

[4] The EPA announcement of the schedule to Develop Natural Gas Wastewater Standards can be found on the EPA home web site: http://www.epa.gov/newsroom/. It states:

> **Shale Gas Standards:**Currently, wastewater associated with shale gas extraction is prohibited from being directly discharged to waterways and other waters of the U.S. While some of the wastewater from shale gas extraction is reused or re-injected, a significant amount still requires disposal. As a result, some shale gas wastewater is transported to treatment plants, many of which are not properly equipped to treat this type of wastewater. EPA will consider standards based on demonstrated, economically achievable technologies, for shale gas wastewater that must be met before going to a treatment facility.

[5] Since the release of the Subcommittee's Ninety-Day Report, the National Petroleum Council issued its "Prudent Development" report on September 15, 2011, with its recommendation that:

> "Natural gas and oil companies should establish regionally focused council(s) of excellence in effective environmental, health, and safety practices. These councils should be forums in which companies could identify and disseminate effective environmental, health, and safety practices and technologies that are appropriate to the particular region. These may include operational risk management approaches, better environmental management techniques, and methods for measuring environmental performance. The governance structures, participation processes, and transparency should be designed to: promote engagement of industry and other interested parties; and enhance the credibility of a council's products and the likelihood they can be relied upon by regulators at the state and federal level."

NPC, "Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," Executive Summary Section II.A.1.

[6] See: http://www.energyfromshale.org/commitment-excellence-hydraulic-fracturing-workshop

[7] An interesting Society of Petroleum Engineers paper sheds light on this point: *Hydraulic Fracture-Height Growth: Real Data,* Kevin Fisher and Norm Warpinski, SPE 145949 available at:
http://www.spe.org/atce/2011/pages/schedule/tech_program/documents/spe145949%201.pdf .

Secretary of Energy Advisory Board

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Shale Gas Production Subcommittee 90-Day Report

August 18, 2011

U.S. DEPARTMENT OF ENERGY

The SEAB Shale Gas Production Subcommittee
Ninety-Day Report – August 18, 2011

Executive Summary

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board is charged with identifying measures that can be taken to reduce the environmental impact and improve the safety of shale gas production.

Natural gas is a cornerstone of the U.S. economy, providing a quarter of the country's total energy. Owing to breakthroughs in technology, production from shale formations has gone from a negligible amount just a few years ago to being almost 30 percent of total U.S. natural gas production. This has brought lower prices, domestic jobs, and the prospect of enhanced national security due to the potential of substantial production growth. But the growth has also brought questions about whether both current and future production can be done in an environmentally sound fashion that meets the needs of public trust.

This 90-day report presents recommendations that if implemented will reduce the environmental impacts from shale gas production. The Subcommittee stresses the importance of a process of continuous improvement in the various aspects of shale gas production that relies on best practices and is tied to measurement and disclosure. While many companies are following such a process, much-broader and more extensive adoption is warranted. The approach benefits all parties in shale gas production: regulators will have more complete and accurate information; industry will achieve more efficient operations; and the public will see continuous, measurable improvement in shale gas activities.

A list of the Subcommittee's findings and recommendations follows.

- <u>Improve public information about shale gas operations</u>: Create a portal for access to a wide range of public information on shale gas development, to include current data available from state and federal regulatory agencies. The portal should be open to the public for use to study and analyze shale gas operations and results.

- Improve communication among state and federal regulators: Provide continuing annual support to STRONGER (the State Review of Oil and Natural Gas Environmental Regulation) and to the Ground Water Protection Council for expansion of the *Risk Based Data Management System* and similar projects that can be extended to all phases of shale gas development.

- Improve air quality: Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable. The Subcommittee supports adoption of rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations. The Subcommittee recommends:

  (1) Enlisting a subset of producers in different basins to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data from shale gas operations and make these data publically available;

  (2) Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of shale gas operations through out the lifecycle of natural gas use in comparison to other fuels; and

  (3) Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.

- Protection of water quality: The Subcommittee urges adoption of a systems approach to water management based on consistent measurement and public disclosure of the flow and composition of water at every stage of the shale gas production process. The Subcommittee recommends the following actions by shale gas companies and regulators – to the extent that such actions have not already been undertaken by particular companies and regulatory agencies:

  (1) Measure and publicly report the composition of water stocks and flow throughout the fracturing and clean-up process.

  (2) Manifest all transfers of water among different locations.

  (3) Adopt best practices in well development and construction, especially casing, cementing, and pressure management. Pressure testing of cemented casing and state-of-the-art cement bond logs should be used to confirm formation isolation. Microseismic surveys should be carried out to assure that hydraulic fracture growth is limited to the gas producing formations. Regulations and inspections are needed to confirm that operators

have taken prompt action to repair defective cementing jobs. The regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing.

(4) Additional field studies on possible methane leakage from shale gas wells to water reservoirs.

(5) Adopt requirements for background water quality measurements (e.g., existing methane levels in nearby water wells prior to drilling for gas) and report in advance of shale gas production activity.

(6) Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.

- Disclosure of fracturing fluid composition: The Subcommittee shares the prevailing view that the risk of fracturing fluid leakage into drinking water sources through fractures made in deep shale reservoirs is remote. Nevertheless the Subcommittee believes there is no economic or technical reason to prevent public disclosure of all chemicals in fracturing fluids, with an exception for genuinely proprietary information. While companies and regulators are moving in this direction, progress needs to be accelerated in light of public concern.

- Reduction in the use of diesel fuel: The Subcommittee believes there is no technical or economic reason to use diesel in shale gas production and recommends reducing the use of diesel engines for surface power in favor of natural gas engines or electricity where available.

- Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies. Each relevant jurisdiction should pay greater attention to the combination of impacts from multiple drilling, production and delivery activities (e.g., impacts on air quality, traffic on roads, noise, visual pollution), and make efforts to plan for shale development impacts on a regional scale. Possible mechanisms include:

  (1) Use of multi-well drilling pads to minimize transport traffic and need for new road construction.

  (2) Evaluation of water use at the scale of affected watersheds.

  (3) Formal notification by regulated entities of anticipated environmental and community impacts.

(4) Preservation of unique and/or sensitive areas as off-limits to drilling and support infrastructure as determined through an appropriate science-based process.

(5) Undertaking science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.

(6) Establishment of effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of surface and mineral rights owners.

- <u>Organizing for best practice:</u> The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice, defined as improvements in techniques and methods that rely on measurement and field experience, is needed to improve operational and environmental outcomes. The Subcommittee favors a national approach including regional mechanisms that recognize differences in geology, land use, water resources, and regulation. The Subcommittee is aware that several different models for such efforts are under discussion and the Subcommittee will monitor progress during its next ninety days. The Subcommittee has identified several activities that deserve priority attention for developing best practices:

  <u>Air</u>: (a) Reduction of pollutants and methane emissions from all shale gas production/delivery activity. (b) Establishment of an emission measurement and reporting system at various points in the production chain.

  <u>Water</u>: (a) Well completion – casing and cementing including use of cement bond and other completion logging tools. (b) Minimizing water use and limiting vertical fracture growth.

- <u>Research and Development needs</u>. The public should expect significant technical advances associated with shale gas production that will significantly improve the efficiency of shale gas production and that will reduce environmental impact. The move from single well to multiple-well pad drilling is one clear example. Given the economic incentive for technical advances, much of the R&D will be performed by the oil and gas industry. Nevertheless the federal government has a role especially in basic R&D, environment protection, and safety. The current level of federal support for unconventional gas R&D is small, and the Subcommittee recommends that the Administration and the Congress set an appropriate mission for R&D and level funding.

The Subcommittee believes that these recommendations, combined with a continuing focus on and clear commitment to measurable progress in implementation of best practices based on technical innovation and field experience, represent important steps toward meeting public concerns and ensuring that the nation's resources are responsibly being responsibly developed.

Introduction

On March 31, 2011, President Barack Obama declared that "recent innovations have given us the opportunity to tap large reserves – perhaps a century's worth" of shale gas. In order to facilitate this development, ensure environmental protection, and meet public concerns, he instructed Secretary of Energy Steven Chu to form a subcommittee of the Secretary of Energy Advisory Board (SEAB) to make recommendations to address the safety and environmental performance of shale gas production.[1] The Secretary's charge to the Subcommittee, included in Annex A, requested that:

> Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracturing.

This is the 90-day report submitted by the Subcommittee to SEAB in fulfillment of its charge. There will be a second report of the Subcommittee after 180 days. Members of the Subcommittee are given in Annex B.

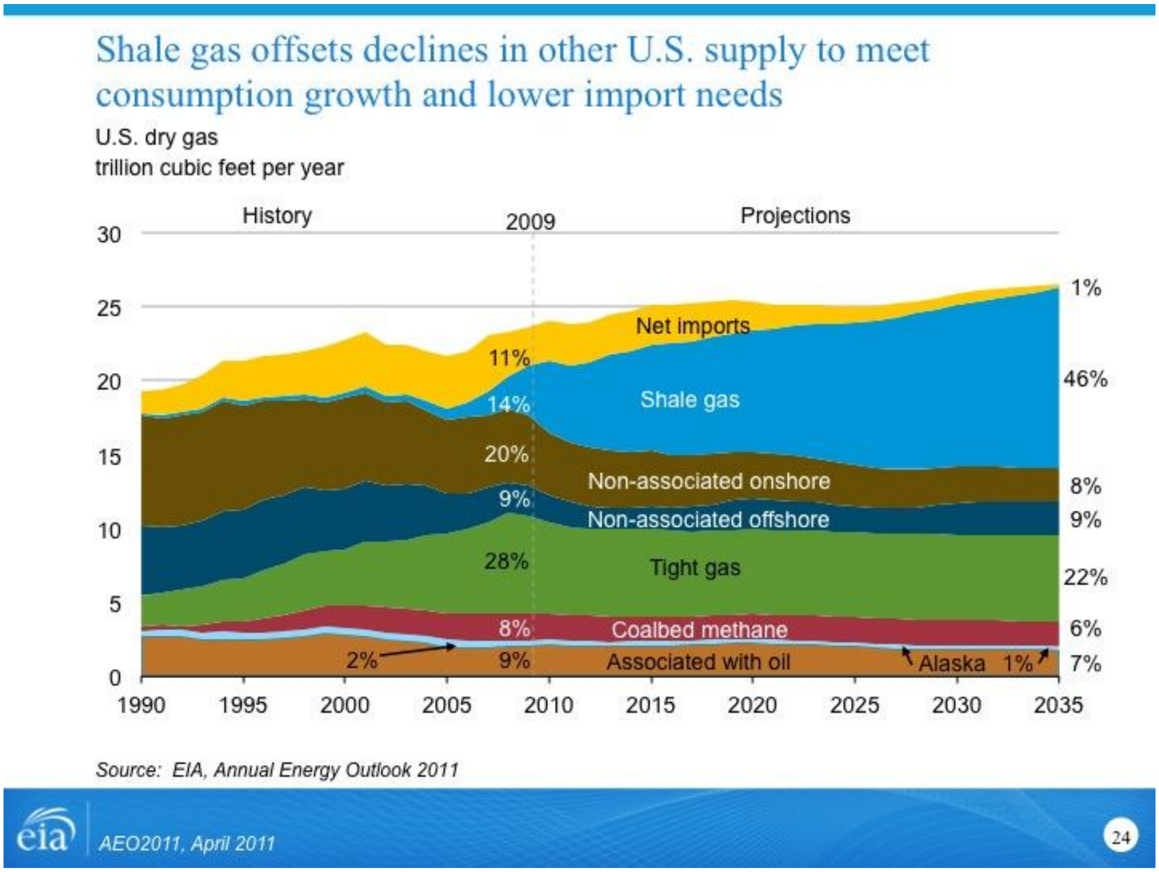
Context for the Subcommittee's deliberations

The Subcommittee believes that the U.S. shale gas resource has enormous potential to provide economic and environmental benefits for the county. Shale gas is a widely distributed resource in North America that can be relatively cheaply produced, creating jobs across the country. Natural gas – if properly produced and transported – also offers climate change advantages because of its low carbon content compared to coal.

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Domestic production of shale gas also has the potential over time to reduce dependence on imported oil for the United States. International shale gas production will increase the diversity of supply for other nations. Both these developments offer important national security benefits.[2]

The development of shale gas in the United States has been very rapid. Natural gas from all sources is one of America's major fuels, providing about 25 percent of total U.S. energy. Shale gas, in turn, was less than two percent of total U.S. natural gas production in 2001. Today, it is approaching 30 percent.[3] But it was only around 2008 that the significance of shale gas began to be widely recognized. Since then, output has increased four-fold. It has brought new regions into the supply mix. Output from the Haynesville shale, mostly in Louisiana, for example, was negligible in 2008; today, the Haynesville shale alone produces eight percent of total U.S. natural gas output. According to the U.S. Energy Information Administration (EIA), the rapid expansion of shale gas production is expected to continue in the future. The EIA projects shale gas to be 46 percent of domestic production by 2035. The following figure shows the stunning change.



The economic significance is potentially very large. While estimates vary, well over 200,000 of jobs (direct, indirect, and induced) have been created over the last several years by the development of domestic production of shale gas, and tens of thousands more will be created in the future.[4] As late as 2007, before the impact of the shale gas revolution, it was assumed that the United States would be importing large amounts of liquefied natural gas from the Middle East and other areas. Today, the United States is essentially self-sufficient in natural gas, with the only notable imports being from Canada, and expected to remain so for many decades. The price of natural gas has fallen by more than a factor of two since 2008, benefiting consumers in the lower cost of home heating and electricity.

The rapid expansion of production is rooted in change in applications of technology and field practice. It had long been recognized that substantial supplies of natural gas were embedded in shale rock. But it was only in 2002 and 2003 that the combination of two technologies working together – hydraulic fracturing and horizontal drilling – made shale gas commercial.

These factors have brought new regions into the supply mix. Parts of the country, such as regions of the Appalachian mountain states where the Marcellus Shale is located, which have not experienced significant oil and gas development for decades, are now undergoing significant development pressure. Pennsylvania, for example, which produced only one percent of total dry gas production in 2009, is one of the most active new areas of development. Even states with a history of oil and gas development, such as Wyoming and Colorado, have experienced significant development pressures in new areas of the state where unconventional gas is now technically and economically accessible due to changes in drilling and development technologies.

The urgency of addressing environmental consequences

As with all energy use, shale gas must be produced in a manner that prevents, minimizes and mitigates environmental damage and the risk of accidents and protects public health and safety. Public concern and debate about the production of shale gas has grown as shale gas output has expanded.

The Subcommittee identifies four major areas of concern: (1) Possible pollution of drinking water from methane and chemicals used in fracturing fluids; (2) Air pollution; (3) Community disruption during shale gas production; and (4) Cumulative adverse impacts that intensive shale production can have on communities and ecosystems.

There are serious environmental impacts underlying these concerns and these adverse environmental impacts need to be prevented, reduced and, where possible, eliminated as soon as possible. Absent effective control, public opposition will grow, thus putting continued production at risk. Moreover, with anticipated increase in U.S. hydraulically fractured wells, if effective environmental action is not taken today, the potential environmental consequences will grow to a point that the country will be faced a more serious problem. Effective action requires both strong regulation and a shale gas industry in which all participating companies are committed to continuous improvement.

The rapid expansion of production and rapid change in technology and field practice, requires federal and state agencies to adapt and evolve their regulations. Industry's pursuit of more efficient operations often has environmental as well as economic benefits, including waste minimization, greater gas recovery, less water usage, and a reduced operating footprint. So there are many reasons to be optimistic that continuous improvement of shale gas production in reducing existing and potential undesirable impacts can be a cooperative effort among the public, companies in the industry, and regulators.

Subcommittee scope, procedure and outline of this report

Scope: The Subcommittee has focused exclusively on production of natural gas (and some liquid hydrocarbons) from shale formations with hydraulic fracturing stimulation in either vertical or horizontal wells. The Subcommittee is aware that some of the observations and recommendations in this report could lead to extension of its findings to other oil and gas operations, but our intention is to focus singularly on issues related to shale gas development. We caution against applying our findings to other areas, because the Subcommittee has not considered the different development practices and other types of geology, technology, regulation and industry practice.

These shale plays in different basins have different geological characteristics and occur in areas with very different water resources. In the Eagle Ford, in Texas, there is almost no flow-back water from an operating well following hydraulic fracturing, while in the Marcellus, primarily in Ohio, New York, Pennsylvania and West Virginia, the flow-back water is between 20 and 40 percent of the injected volume. This geological diversity means that engineering practice and regulatory oversight will differ widely among regions of the country.

The Subcommittee describes in this report a comprehensive and collaborative approach to managing risk in shale gas production. The Subcommittee believes that a more systematic commitment to a process of *continuous improvement* to identify and implement best practices is needed, and should be embraced by all companies in the shale gas industry. Many companies already demonstrate their commitment to the kind of process we describe here, but the public should be confident that this is the practice across the industry.

This process should involve discussions and other collaborative efforts among companies involved in shale gas production (including service companies), state and federal regulators, and affected communities and public interests groups. The process should identify best practices that evolve as operational experience increases, knowledge of environmental effects and effective mitigation grows, and know-how and technology changes. It should also be supported by technology peer reviews that report on individual companies' performance and should be seen as a compliment to, not a substitute for, strong regulation and effective enforcement. There will be three benefits:

- For industry: As all firms move to adopt identified best practices, continuous improvement has the potential to both enhance production efficiency and reduce environmental impacts over time.

- For regulators: Sharing data and best practices will better inform regulators and help them craft policies and regulations that will lead to sounder and more efficient environmental practices than are now in place.

- For the public: Continuous improvement coupled with rigorous regulatory oversight can provide confidence that processes are in place that will result in improved safety and less environmental and community impact.

The realities of regional diversity of shale gas resources and rapid change in production practices and technology mean that a single best engineering practice cannot set for all locations and for all time. Rather, the appropriate starting point is to understand what are regarded as "best practices" today, how the current regulatory system works in the context of those operating in different parts of the country, and establishing a culture of continuous improvement.

The Subcommittee has considered the safety and environmental impact of all steps in shale gas production, not just hydraulic fracturing.[5] Shale gas production consists of several steps, from well design and surface preparation, to drilling and cementing steel casing at multiple stages of well construction, to well completion. The various steps include perforation, water and fracturing fluid preparation, multistage hydraulic fracturing, collection and handling of flow-back and produced water, gas collection, processing and pipeline transmission, and site remediation.[6] Each of these activities has safety and environmental risks that are addressed by operators and by regulators in different ways according to location. In light of these processes, the Subcommittee interprets its charge to assess this entire system, rather than just hydraulic fracturing.

<u>The Subcommittee's charge is not to assess the balance of the benefits of shale gas use against these environmental costs</u>. Rather, the Subcommittee's charge is to identify steps that can be taken to reduce the environmental and safety risks associated with shale gas development and, importantly, give the public concrete reason to believe that environmental impacts will be reduced and well managed on an ongoing basis, and that problems will be mitigated and rapidly corrected, if and when they occur.

<u>It is not within the scope of the Subcommittee's 90-day report to make recommendations about the proper regulatory roles for state and federal governments</u>. However, the Subcommittee emphasizes that effective and capable regulation is essential to protect the public interest. The challenges of protecting human health and the environment in light of the anticipated rapid expansion of shale gas production require the joint efforts of state and federal regulators. This means that resources dedicated to oversight of the industry must be sufficient to do the job and that there is adequate regulatory staff at the state and federal level with the technical expertise to issue, inspect, and enforce regulations. Fees, royalty payments and severance taxes are appropriate sources of funds to finance these needed regulatory activities.

The nation has important work to do in strengthening the design of a regulatory system that sets the policy and technical foundation to provide for continuous improvement in the protection of human health and the environment. While many states and several federal agencies regulate aspects of these operations, the efficacy of the regulations is far from clear. Raw statistics about enforcement actions and compliance are not sufficient to draw conclusions about regulatory effectiveness. Informed conclusions about the state of shale gas operations require analysis of the vast amount of data that is publically available, but there are surprisingly few published studies of this publically available data. Benchmarking is needed for the efficacy of existing regulations and consideration of additional mechanisms for assuring compliance such as disclosure of company performance and enforcement history, and operator certification of performance subject to stringent fines, if violated.

Subcommittee Procedure: In the ninety days since its first meeting, the Subcommittee met with representatives of industry, the environmental community, state regulators, officials of the Environmental Protection Agency, the Department of Energy, the Department of the Interior, both the United States Geologic Survey (USGS) and the Bureau of Land Management (BLM), which has responsibility for public land regulation,[7] and a number of individuals from industry and not-for-profit groups with relevant expertise and interest. The Subcommittee held a public meeting attended by over four hundred citizens in Washington Country, PA, and visited several Marcellus shale gas sites. The Subcommittee strove to hold all of its meeting in public although the Subcommittee held several private working sessions to review what it had learned and to deliberate on its course of action. A website is available that contains the Subcommittee meeting agendas, material presented to the Subcommittee, and numerous public comments.[8]

Outline of this report: The Subcommittee findings and recommendations are organized in four sections:

- Making information about shale gas production operations more accessible to the public – an immediate action.
- Immediate and longer term actions to reduce environmental and safety risks of shale gas operations
- Creation of a Shale Gas Industry Operation organization, on national and/or regional basis, committed to continuous improvement of best operating practices.
- R&D needs to improve safety and environmental performance – immediate and long term opportunities for government and industry.

The common thread in all these recommendations is that measurement and disclosure are fundamental elements of good practice and policy for all parties. Data enables companies to identify changes that improve efficiency and environmental performance and to benchmark against the performance of different companies. Disclosure of data permits regulators to identify cost/effective regulatory measures that better protect the environment and public safety, and disclosure gives the public a way to measure progress on reducing risks.

Making shale gas information available to the public

The Subcommittee has been struck by the enormous difference in perception about the consequences of shale gas activities. Advocates state that fracturing has been performed safety without significant incident for over 60 years, although modern shale gas fracturing of two mile long laterals has only been done for something less than a decade. Opponents point to failures and accidents and other environmental impacts, but these incidents are typically unrelated to hydraulic fracturing *per se* and sometimes lack supporting data about the relationship of shale gas development to incidence and consequences.[9] An industry response that hydraulic fracturing has been performed safely for decades rather than engaging the range of issues concerning the public will not succeed.

Some of this difference in perception can be attributed to communication issues. Many in the concerned public use the word “fracking” to describe all activities associated with shale gas development, rather than just the hydraulic fracturing process itself. Public concerns extend to accidents and failures associated with poor well construction and operation, surface spills, leaks at pits and impoundments, truck traffic, and the cumulative impacts of air pollution, land disturbance and community disruption.

The Subcommittee believes there is great merit to creating a national database to link as many sources of public information as possible with respect to shale gas development and production. Much information has been generated over the past ten years by state and federal regulatory agencies. Providing ways to link various databases and, where possible, assemble data in a comparable format, which are now in perhaps a hundred different locations, would permit easier access to data sets by interested parties.

Members of the public would be able to assess the current state of environmental protection and safety and inform the public of these trends. Regulatory bodies would be better able to assess and monitor the trends in enforcement activities. Industry would be able to analyze data on production trends and comparative performance in order to identify effective practices.

The Subcommittee recommends creation of this national database. A rough estimate for the initial cost is $20 million to structure and construct the linkages necessary for assembling this virtual database, and about $5 million annual cost to maintain it. This recommendation is not aimed at establishing new reporting requirements. Rather, it focuses on creating linkages among information and data that is currently collected and technically and legally capable of being made available to the public. What analysis of the data should be done is left entirely for users to decide.[10]

There are other important mechanisms for improving the availability and usefulness of shale gas information among various constituencies. The Subcommittee believes two such mechanisms to be exceptionally meritorious (and would be relatively inexpensive to expand).

The first is an existing organization known as STRONGER – the State Review of Oil and Natural Gas Environmental Regulation. STRONGER is a not-for-profit organization whose purpose is to accomplish genuine peer review of state regulatory activities. The peer reviews (conducted by a panel of state regulators, industry representatives, and environmental organization representatives with respect to the processes and policies of the state under review) are published publicly, and provide a means to share information about environmental protection strategies, techniques, regulations, and measures for program improvement. Too few states participate in STRONGER's voluntary review of state regulatory programs. The reviews allow for learning to be shared by states and the expansion of the STRONGER process should be encouraged. The Department of Energy, the Environmental Protection Agency, and the American Petroleum Institute have supported STRONGER over time.[11]

The second is the Ground Water Protection Council's project to extend and expand the *Risk Based Data Management System, which* allows states to exchange information about defined parameters of importance to hydraulic fracturing operations.[12]

The Subcommittee recommends that these two activities be funded at the level of $5 million per year beginning in FY2012. Encouraging these multi-stakeholder mechanisms will help provide greater information to the public, enhancing regulation and improving the efficiency of shale gas production. It will also provide support for STRONGER to expand its activities into other areas such as air quality, something that the Subcommittee encourages the states to do as part of the scope of STRONGER peer reviews.

Recommendations for immediate and longer term actions to reduce environmental and safety risks of shale gas operations

1. Improvement in air quality by reducing emissions of regulated pollutants and methane.

Shale gas production, including exploration, drilling, venting/flaring, equipment operation, gathering, accompanying vehicular traffic, results in the emission of ozone precursors (volatile organic compounds (VOCs), and nitrogen oxides), particulates from diesel exhaust, toxic air pollutants and greenhouse gases (GHG), such as methane.

As shale gas operations expand across the nation these air emissions have become an increasing matter of concern at the local, regional and national level. Significant air quality impacts from oil and gas operations in Wyoming, Colorado, Utah and Texas are well documented, and air quality issues are of increasing concern in the Marcellus region (in parts of Ohio, Pennsylvania, West Virginia and New York).[13]

The Environmental Protection Agency has the responsibility to regulate air emissions and in many cases delegate its authority to states. On July 28, 2011, EPA proposed amendments to its regulations for air emissions for oil and gas operations. If finalized and fully implemented, its proposal will reduce emissions of VOCs, air toxics and, collaterally, methane. EPA's proposal does not address many existing types of sources in the natural gas production sector, with the notable exception of hydraulically fractured well re-completions, at which "green" completions must be used. ("Green" completions use equipment that will capture methane and other air contaminants, avoiding its release.) EPA is under court order to take final action on these clean air measures in 2012. In addition, a number of states – notably, Wyoming and Colorado – have taken proactive steps to address air emissions from oil and gas activities.

The Subcommittee supports adoption of emission standards for both new and existing sources for methane, air toxics, ozone-forming pollutants, and other major airborne contaminants resulting from natural gas exploration, production, transportation and distribution activities. The Subcommittee also believes that companies should be required, as soon as practicable, to measure and disclose air pollution emissions, including greenhouse gases, air toxics, ozone precursors and other pollutants. Such disclosure should include direct measurements wherever feasible; include characterization of chemical composition of the natural gas measured; and be reported on a publically accessible website that allows for searching and aggregating by pollutant, company, production activity and geography.

Methane emissions from shale gas drilling, production, gas processing, transmission and storage are of particular concern because methane is a potent greenhouse gas: 25 to 72 times greater warming potential than carbon dioxide on 100-year and 20-year time scales respectively.[14] Currently, there is great uncertainty about the scale of methane emissions.

The Subcommittee recommends three actions to address the air emissions issue.

First, inadequate data are available about how much methane and other air pollutants are emitted by the consolidated production activities of a shale gas operator in a given area, with such activities encompassing drilling, fracturing, production, gathering, processing of gas and liquids, flaring, storage, and dispatch into the pipeline transmission and distribution network. Industry reporting of greenhouse gas emissions in 2012 pursuant to EPA's reporting rule will provide new insights, but will not eliminate key uncertainties about the actual amount and variability in emissions.

The Subcommittee recommends enlisting a subset of producers in different basins, on a voluntary basis, to immediately launch projects to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data.

These pioneering data sets will be useful to regulators and industry in setting benchmarks for air emissions from this category of oil and gas production, identifying cost-effective procedures and equipment changes that will reduce emissions; and guiding practical regulation and potentially avoid burdensome and contentious regulatory procedures. Each project should be conducted in a transparent manner and the results should be publicly disclosed.

There needs to be common definitions of the emissions and other parameters that should be measured and measurement techniques, so that comparison is possible between the data collected from the various projects. Provision should be made for an independent technical review of the methodology and results to establish their credibility. The Subcommittee will report progress on this proposal during its next phase.

The second recommendation regarding air emissions concerns the need for a thorough assessment of the greenhouse gas footprint for cradle-to-grave use of natural gas. This effort is important in light of the expectation that natural gas use will expand and substitute for other fuels. There have been relatively few analyses done of the question of the greenhouse gas footprint over the entire fuel-cycle of natural gas production, delivery and use, and little data are available that bear on the question. A recent peer-reviewed article reaches a pessimistic conclusion about the greenhouse gas footprint of shale gas production and use – a conclusion not widely accepted.[15] DOE's National Energy Technology Laboratory has given an alternative analysis.[16] Work has also been done for electric power, where natural gas is anticipated increasingly to substitute for coal generation, reaching a more favorable conclusion that natural gas results in about one-half the equivalent carbon dioxide emissions.[17]

The Subcommittee believes that additional work is needed to establish the extent of the footprint of the natural gas fuel cycle in comparison to other fuels used for electric power and transportation because it is an important factor that will be considered when formulating policies and regulations affecting shale gas development. These data will help answer key policy questions such as the time scale on which natural gas fuel switching strategies would produce real climate benefits through the full fuel cycle and the level of methane emission reductions that may be necessary to ensure such climate benefits are meaningful.

The greenhouse footprint of the natural gas fuel cycle can be either estimated indirectly by using surrogate measures or preferably by collecting actual data where it is practicable to do so. In the selection of methods to determine actual emissions, preference should be given to direct measurement wherever feasible, augmented by emissions factors that have been empirically validated. Designing and executing a comprehensive greenhouse gas footprint study based on actual data – the Subcommittee's recommended approach -- is a major project. It requires agreement on measurement equipment, measurement protocols, tools for integrating and analyzing data from different regions, over a multiyear period. Since producer, transmission and distribution pipelines, end-use storage and natural gas many different companies will necessarily be involved. A project of this scale will be expensive. Much of the cost will be borne by firms in the natural gas enterprise that are or will be required to collect and report air emissions. These measurements should be made as rapidly as practicable. Aggregating, assuring quality control and analyzing these data is a substantial task involving significant costs that should be underwritten by the federal government.

It is not clear which government agency would be best equipped to manage such a project. <u>The Subcommittee recommends that planning for this project should begin immediately</u> and that the Office of Science and Technology Policy, should be asked to coordinate an interagency effort to identify sources of funding and lead agency responsibility. This is a pressing question so a clear blueprint and project timetable should be produced within a year.

<u>Third, the Subcommittee recommends that industry and regulators immediately expand efforts to reduce air emissions using proven technologies and practices</u>. Both methane and ozone precursors are of concern. Methane leakage and uncontrolled venting of methane and other air contaminants in the shale gas production should be eliminated except in cases where operators demonstrate capture is technically infeasible, or where venting is necessary for safety reasons and where there is no alternative for capturing emissions. When methane emissions cannot be captured, they should be flared whenever volumes are sufficient to do so.

Ozone precursors should be reduced by using cleaner engine fuel, deploying vapor recovery and other control technologies effective on relevant equipment." Wyoming's emissions rules represent a good starting point for establishing regulatory frameworks and for encouraging industry best practices.

2. Protecting water supply and water quality.

The public understandably wants implementation of standards to ensure shale gas production does not risk polluting drinking water or lakes and streams. The challenge to proper understanding and regulation of the water impacts of shale production is the great diversity of water use in different regional shale gas plays and the different pattern of state and federal regulation of water resources across the country. The U.S. EPA has certain authorities to regulate water resources and it is currently undertaking a two-year study under congressional direction to investigate the potential impacts of hydraulic fracturing on drinking water resources.[18]

Water use in shale gas production passes through the following stages: (1) water acquisition, (2) drilling and hydraulic fracturing (surface formulation of water, fracturing chemicals and sand followed by injection into the shale producing formation at various locations), (3) collection of return water, (4) water storage and processing, and (5) water treatment and disposal.

The Subcommittee offers the following observations with regard to these water issues:

(1) Hydraulic fracturing stimulation of a shale gas well requires between 1 and 5 million gallons of water. While water availability varies across the country, in most regions water used in hydraulic fracturing represents a small fraction of total water consumption. Nonetheless, in some regions and localities there are significant concerns about consumptive water use for shale gas development.[19] There is considerable debate about the water intensity of natural gas compared to other fuels for particular applications such as electric power production.[20]

    One of the commonly perceived risks from hydraulic fracturing is the possibility of leakage of fracturing fluid through fractures into drinking water. Regulators and geophysical experts agree that the likelihood of properly injected fracturing fluid reaching drinking water through fractures is remote where there is a large depth separation between drinking water sources and the producing zone. In the great majority of regions where shale gas is being produced, such separation exists and there are few, if any, documented examples of such migration. An improperly executed fracturing fluid injection can, of course, lead to surface spills and leakage into surrounding shallow drinking water formations. Similarly, a well with poorly cemented casing could potentially leak, regardless of whether the well has been hydraulically fractured.

With respect to stopping surface spills and leakage of contaminated water, the Subcommittee observes that extra measures are now being taken by some operators and regulators to address the public's concern that water be protected. The use of mats, catchments and groundwater monitors as well as the establishment of buffers around surface water resources help ensure against water pollution and should be adopted.

Methane leakage from producing wells into surrounding drinking water wells, exploratory wells, production wells, abandoned wells, underground mines, and natural migration is a greater source of concern. The presence of methane in wells surrounding a shale gas production site is not *ipso facto* evidence of methane leakage from the fractured producing well since methane may be present in surrounding shallow methane deposits or the result of past conventional drilling activity.

However, a recent, credible, peer-reviewed study documented the higher concentration of methane originating in shale gas deposits (through isotopic abundance of C-13 and the presence of trace amounts of higher hydrocarbons) into wells surrounding a producing shale production site in northern Pennsylvania.[21] <u>The Subcommittee recommends several studies be commissioned to confirm the validity of this study and the extent of methane migration that may take place in this and other regions</u>.

(2) Industry experts believe that methane migration from shale gas production, when it occurs, is due to one or another factors: drilling a well in a geological unstable location; <u>loss of well integrity as a result of poor well completion (cementing or casing) or poor production pressure management</u>. Best practice can reduce the risk of this failure mechanism (as discussed in the following section). Pressure tests of the casing and state-of-the-art cement bond logs should be performed to confirm that the methods being used achieve the desired degree of

formation isolation. Similarly, frequent microseismic surveys should be carried out to assure operators and service companies that hydraulic fracture growth is limited to the gas-producing formations. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing (squeeze jobs).

(3) A producing shale gas well yields flow-back and other produced water. The flow-back water is returned fracturing water that occurs in the early life of the well (up to a few months) and includes residual fracturing fluid as well as some solid material from the formation. Produced water is the water displaced from the formation and therefore contains substances that are found in the formation, and may include brine, gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium) and organic compounds. Both the amount and the composition of the flow-back and produced water vary substantially among shale gas plays – for example, in the Eagle Ford area, there is very little returned water after hydraulic fracturing whereas, in the Marcellus, 20 to 40 percent of the fracturing fluid is produced as flow-back water. In the Barnett, there can significant amounts of saline water produced with shale gas if hydraulic fractures propagate downward into the Ellenburger formation.

(4) The return water (flow-back + produced) is collected (frequently from more than a single well), processed to remove commercially viable gas and stored in tanks or an impoundment pond (lined or unlined). For pond storage evaporation will change the composition. Full evaporation would ultimately leave precipitated solids that must be disposed in a landfill. <u>Measurement of the composition of the stored return water should be a routine industry practice</u>.

(5) There are four possibilities for disposal of return water: <u>reuse</u> as fracturing fluid in a new well (several companies, operating in the Marcellus are recycling over 90 percent of the return water); <u>underground injection into disposal wells</u> (this mode of disposal is regulated by the EPA); <u>waste water treatment</u> to produce clean water (though at present, most waste water treatment plants are not equipped with the capability to treat many of the contaminants associated with shale gas waste water); and <u>surface runoff</u> which is forbidden.

Currently, the approach to water management by regulators and industry is not on a "systems basis" where all aspect of activities involving water use is planned, analyzed, and managed on an integrated basis. The difference in water use and regulation in different shale plays means that there will not be a single water management integrated system applicable in all locations. Nevertheless, the Subcommittee believes certain common principles should guide the development of integrated water management and identifies three that are especially important:

- Adoption of a life cycle approach to water management from the beginning of the production process (acquisition) to the end (disposal): all water flows should be tracked and reported quantitatively throughout the process.

- Measurement and public reporting of the composition of water stocks and flow throughout the process (for example, flow-back and produced water, in water ponds and collection tanks).

- Manifesting of all transfers of water among locations.

Early case studies of integrated water management are desirable so as to provide better bases for understanding water use and disposition and opportunities for reduction of risks related to water use. The Subcommittee supports EPA's retrospective and prospective case studies that will be part of the EPA study of hydraulic fracturing impacts on drinking water resources, but these case studies focus on identification of possible consequences rather than the definition of an integrated water management system, including the measurement needs to support it. The Subcommittee believes that development and use of an integrated water management system has the potential for greatly reducing the environmental footprint and risk of water use in shale gas production and recommends that regulators begin working with industry and other stakeholders to develop and implement such systems in their jurisdictions and regionally.

Additionally, agencies should review field experience and modernize rules and enforcement practices – especially regarding well construction/operation, management of flow back and produced water, and prevention of blowouts and surface spills – to ensure robust protection of drinking and surface waters. Specific best practice matters that should receive priority attention from regulators and industry are described below.

3. Background water quality measurements.

At present there are widely different practices for measuring the water quality of wells in the vicinity of a shale gas production site. Availability of measurements in advance of drilling would provide an objective baseline for determining if the drilling and hydraulic fracturing activity introduced any contaminants in surrounding drinking water wells.

The Subcommittee is aware there is great variation among states with respect to their statutory authority to require measurement of water quality of private wells, and that the process of adopting practical regulations that would be broadly acceptable to the public would be difficult. Nevertheless, the value of these measurements for reassuring communities about the impact of drilling on their community water supplies leads the Subcommittee to recommend that states and localities adopt systems for measurement and reporting of background water quality in advance of shale gas production activity. These baseline measurements should be publicly disclosed, while protecting landowner's privacy.

4. Disclosure of the composition of fracturing fluids.

There has been considerable debate about requirements for reporting all chemicals (both composition and concentrations) used in fracturing fluids. Fracturing fluid refers to the slurry prepared from water, sand, and some added chemicals for high pressure injection into a formation in order to create fractures that open a pathway for release of the oil and gases in the shale. Some states (such as Wyoming, Arkansas and Texas) have adopted disclosure regulations for the chemicals that are added to fracturing fluid, and the U.S. Department of Interior has recently indicated an interest in requiring disclosure for fracturing fluids used on federal lands.

The DOE has supported the establishment and maintenance of a relatively new website, FracFocus.org (operated jointly by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission) to serve as a voluntary chemical registry for individual companies to report all chemicals that would appear on Material Safety Data Sheets (MSDS) subject to certain provisions to protect "trade secrets." While FracFocus is off to a good start with voluntary reporting growing rapidly, the restriction to MSDS data means that a large universe of chemicals frequently used in hydraulic fracturing treatments goes unreported. MSDS only report chemicals that have been deemed to be hazardous in an occupational setting under standards adopted by OSHA (the Occupational Safety and Health Administration); MSDA reporting does not include other chemicals that might be hazardous if human exposure occurs through environmental pathways. Another limitation of FracFocus is that the information is not maintained as a database. As a result, the ability to search for data is limited and there are no tools for aggregating data.

The Subcommittee believes that the high level of public concern about the nature of fracturing chemicals suggests that the benefit of immediate and complete disclosure of all chemical components and composition of fracturing fluid completely outweighs the restriction on company action, the cost of reporting, and any intellectual property value of proprietary chemicals. The Subcommittee believes that public confidence in the safety of fracturing would be significantly improved by complete disclosure and that the barrier to shield chemicals based on trade secret should be set very high. Therefore the Subcommittee recommends that regulatory entities immediately develop rules to require disclosure of all chemicals used in hydraulic fracturing fluids on both public and private lands. Disclosure should include all chemicals, not just those that appear on MSDS. It should be reported on a well-by-well basis and posted on a publicly available website that includes tools for searching and aggregating data by chemical, well, by company, and by geography.

5. Reducing the use of diesel in shale gas development

Replacing diesel with natural gas or electric power for oil field equipment will decrease harmful air emissions and improve air quality. Although fuel substitution will likely happen over time because of the lower cost of natural gas compared diesel and because of likely future emission restrictions, the Subcommittee recommends conversion from diesel to natural gas for equipment fuel or to electric power where available, as soon as practicable. The process of conversion may be slowed because manufacturers of compression ignition or spark ignition engines may not have certified the engine operating with natural gas fuel for off-road use as required by EPA air emission regulations.[22]

Eliminating the use of diesel as an additive to hydraulic fracturing fluid**.** The Subcommittee believes there is no technical or economic reason to use diesel as a stimulating fluid. Diesel is a refinery product that consists of several components possibly including some toxic impurities such as benzene and other aromatics. (EPA is currently considering permitting restrictions of the use of diesel fuels in hydraulic fracturing under Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) Class II.) Diesel is convenient to use in the oil field because it is present for use fuel for generators and compressors.

Diesel has two uses in hydraulic fracturing and stimulation. In modest quantities diesel is used to solubilize other fracturing chemical such as guar. Mineral oil (a synthetic mixture of C-10 to C-40 hydrocarbons) is as effective at comparable cost. Infrequently, diesel is use as a fracturing fluid in water sensitive clay and shale reservoirs. In these cases, light crude oil that is free of aromatic impurities picked up in the refining process, can be used as a substitute of equal effectiveness and lower cost compared to diesel, as a non-aqueous fracturing fluid.

6. Managing short-term and cumulative impacts on communities, land use, wildlife and ecologies.

Intensive shale gas development can potentially have serious impacts on public health, the environment and quality of life – even when individual operators conduct their activities in ways that meet and exceed regulatory requirements. The combination of impacts from multiple drilling and production operations, support infrastructure (pipelines, road networks, etc.) and related activities can overwhelm ecosystems and communities.

The Subcommittee believes that federal, regional, state and local jurisdictions need to place greater effort on examining these cumulative impacts in a more holistic manner; discrete permitting activity that focuses narrowly on individual activities does not reach to these issues. Rather than suggesting a simple prescription that every jurisdiction should follow to assure adequate consideration of these impacts, the Subcommittee believes that each relevant jurisdiction should develop and implement processes for community engagement and for preventing, mitigating and remediating surface impacts and community impacts from production activities. <u>There are a number of threshold mechanisms that should be considered:</u>

- Optimize use of multi-well drilling pads to minimize transport traffic and needs for new road construction.
- Evaluate water use at the scale of affected watersheds.
- Provide formal notification by regulated entities of anticipated environmental and community impacts.
- Declare unique and/or sensitive areas off-limits to drilling and support infrastructure as determined through an appropriate science-based process.
- Undertake science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.
- Establish effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.
- Mitigate noise, air and visual pollution.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of mineral rights owners.

Organizing for continuous improvement of "best practice"

In this report, the term "Best Practice" refers to industry <u>techniques or methods</u> that have proven over time to accomplish given tasks and objectives in a manner that most acceptably balances desired outcomes and avoids undesirable consequences. Continuous best practice in an industry refers to the evolution of best practice by adopting process improvements as they are identified, thus progressively improving the level and narrowing the distribution of performance of firms in the industry. Best practice is a particularly helpful management approach in a field that is growing rapidly, where technology is changing rapidly, and involves many firms of different size and technical capacity.

Best practice does not necessarily imply a single process or procedure; it allows for a range of practice that is believed to be equally effective at achieving desired out comes. This flexibility is important because it acknowledges the possibility that different operators in different regions will select different solutions.

The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice through development of standards, diffusion of these standards, and assessing compliance among its members can be an important mechanism for improving shale gas companies' commitment to safety and environmental protection as it carries out its business. The Subcommittee envisions that the industry organization would be governed by a board of directors composed of member companies, on a rotating basis, along with external members, for example from non-governmental organizations and academic institutions, as determined by the board.

Strong regulations and robust enforcement resources and practices are a prerequisite to protecting health, safety and the environment, but the job is easier where companies are motivated and committed to adopting best engineering and environmental practice. Companies have economic incentives to adopt best practice, because it improves operational efficiency and, if done properly, improves safety and environmental protection.

Achievement of best practice requires management commitment, adoption and dissemination of standards that are widely disseminated and periodically updated on the basis of field experience and measurements. A trained work force, motivated to adopt best practice, is also necessary. Creation of an industry organization dedicated to excellence in shale gas operations intended to advance knowledge about best practice and improve the interactions among companies, regulators and the public would be a major step forward.

The Subcommittee is aware that shale gas producers and other groups recognize the value of a best practice management approach and that industry is considering creating a mechanism for encouraging best practice. The design of such a mechanism involves many considerations including the differences in the shale production and regulations in different basins, making most effective use of mechanisms that are currently in place, and respecting the different capabilities of large and smaller operators. The Subcommittee will monitor progress on this important matter and continue to make its views known about the characteristics that such a mechanism and supporting organization should possess to maximize its effectiveness.

It should be stressed that any industry best practice mechanism would need to comply with anti-trust laws and would not replace any existing state or federal regulatory authority.

Priority best practice topics

Air

- Measurement and disclosure of air emissions including VOCs, methane, air toxics, and other pollutants.
- Reduction of methane emission from all shale gas operations

Water

- Integrated water management systems
- Well completion – casing and cementing
- Characterization and disclosure of flow back and other produced water

The Subcommittee has identified a number of promising best practice opportunities. Five examples are given in the call-out box. Two examples are discussed below to give a sense of the opportunities that presented by best practice focus.

Well integrity: an example. Well integrity is an example of the potential power of best practice for shale gas production. Well integrity encompasses the planning, design and execution of a well completion (cementing, casing and well head placement). It is fundamental to good outcomes in drilling oil and gas wells.

Methane leakage to water reservoirs is widely believed to be due to poor well completion, especially poor casing and cementing. Casing and cementing programs should be designed to provide optimal isolation of the gas-producing zone from overlaying formations. The number of cemented casings and the depth ranges covered will depend on local geologic and hydrologic conditions. However, there need to be multiple engineered barriers to prevent communication between hydrocarbons and potable aquifers. In addition, the casing program needs to be designed to optimize the potential success of cementing operations. Poorly cemented cased wells offer pathways for leakage; properly cemented and cased wells do not.

Well integrity is an ideal example of where a best practice approach, adopted by the industry, can stress best practice and collect data to validate continuous improvement. The American Petroleum Institute, for example, has focused on well completion in its standards activity for shale gas production.[23]

At present, however, there is a wide range in procedures followed in the field with regard to casing placement and cementing for shale gas drilling. There are different practices with regard to completion testing and different regulations for monitoring possible gas leakage from the annulus at the wellhead. In some jurisdictions, regulators insist that gas leakage can be vented; others insist on containment with periodic pressure testing. There are no common leakage criteria for intervention in a well that exhibits damage or on the nature of the intervention. It is very likely that over time a focus on best practice in well completion will result in safer operations and greater environmental protection. The best practice will also avoid costly interruptions to normal operations. The regulation of shale gas development should also include inspections at safety-critical stages of well construction and hydraulic fracturing.

<u>Limiting water use by controlling vertical fracture growth</u>: – a second example. While the vertical growth of hydraulic fractures does not appear to have been a causative factor in reported cases where methane from shale gas formations has migrated to the near surface, it is in the best interest of operators and the public to limit the vertical extent of hydraulic fractures to the gas bearing shale formation being exploited. By improving the efficiency of hydraulic fractures, more gas will be produced using less water for fracturing – which has economic value to operators and environmental value for the public.

The vertical propagation of hydraulic fractures results from the variation of earth stress with depth and the pumping pressure during fracturing. The variation of earth stress with depth is difficult to predict, but easy to measure in advance of hydraulic fracturing operations. Operators and service companies should assure that through periodic direct measurement of earth stresses and microseismic monitoring of hydraulic fracturing operations, everything possible is being done to limit the amount of water and additives used in hydraulic fracturing operations.

<u>Evolving best practices must be accompanied by metrics that permit tracking of the progress in improving shale gas operations performance and environmental impacts</u>. The Subcommittee has the impression that the current standard- setting processes do not utilize metrics. Without such metrics and the collection of relevant measured data,

operators lack the ability to track objectively the progress of the extensive process of setting and updating standards.

Research and development needs

The profitability, rapid expansion, and the growing recognition of the scale of the resource mean that oil and gas companies will mount significant R&D efforts to improve performance and lower cost of shale gas exploration and production. In general the oil and gas industry is a technology-focused and technology-driven industry, and it is safe to assume that there will be a steady advance of technology over the coming years.

In these circumstances the federal government has a limited role in supporting R&D. The proper focus should be on sponsoring R&D and analytic studies that address topics that benefit the public or the industry but which do not permit individual firms to attain a proprietary position. Examples are environmental and safety studies, risk assessments, resource assessments, and longer-term R&D (such as research on methane hydrates). Across many administrations, the Office of Management and Budget (OMB) has been skeptical of any federal support for oil and gas R&D, and many Presidents' budget have not included any request for R&D for oil and gas. Nonetheless Congress has typically put money into the budget for oil & gas R&D.

The following table summarizes the R&D outlays of the DOE, EPA, and USGS for unconventional gas:

Unconventional Gas R&D Outlays for Various Federal Agencies ($ millions)					
	FY2008	**FY2009**	**FY2010**	**FY2011**	**FY2012 request**
DOE Unconventional Gas					
EPAct Section 999 Program Funds					
RPSEA Administered	$14	$14	$14	$14	0
NETL Complementary	$9	$9	$9	$4	0
Annual Appropriated Program Funds					
Environmental	$2	$4	$2	0	0
Unconventional Fossil Energy	0	0	$6	0	0
Methane Hydrate projects	$15	$15	$15	$5	$10
Total Department of Energy	$40	$42	$46	$23	$10
Environmental Protection Agency	$0	$0	$1.9	$4.3	$6.1
USGS	$4.5	$4.6	$5.9	$7.4	$7.6
Total Federal R&D	**$44.5**	**$46.6**	**$53.8**	**$34.7**	**$23.7**

Near Term Actions:

The Subcommittee believes that given the scale and rapid growth of the shale gas resource in the nation's energy mix, the federal government should sponsor some R&D for unconventional gas, focusing on areas that have public and industry wide benefit and addresses public concern. The Subcommittee, at this point, is only in a position to offer some initial recommendations, not funding levels or to assignment of responsibility to particular government agencies. The DOE, EPA, the USGS, and DOI Bureau of Land Management all have mission responsibility that justify a continuing, tailored, federal R&D effort.

RPSEA is the Research Partnership to Secure Energy for America, a public/private research partnership authorized by the 2005 Energy Policy Act at a level of $50 million from offshore royalties. Since 2007, the RPSEA program has focused on unconventional gas. The Subcommittee strongly supports the RPSEA program at its authorized level.[24]

The Subcommittee recommends that the relevant agencies, the Office of Science and Technology Policy (OSTP), and OMB discuss and agree on an appropriate mission and level of funding for unconventional natural gas R&D. If requested, the Subcommittee, in the second phase of its work, could consider this matter in greater detail and make recommendations for the Administration's consideration.

In addition to the studies mentioned in the body of the report, the Subcommittee mentions several additional R&D projects where results could reduce safety risk and environmental damage for shale gas operations:

1. Basic research on the relationship of fracturing and micro-seismic signaling.
2. Determination of the chemical interactions between fracturing fluids and different shale rocks – both experimental and predictive.
3. Understanding induced seismicity triggered by hydraulic fracturing and injection well disposal.[25]
4. Development of "green" drilling and fracturing fluids.
5. Development of improved cement evaluation and pressure testing wireline tools assuring casing and cementing integrity.

Longer term prospects for technical advance

The public should expect significant technical advance on shale gas production that will substantially improve the efficiency of shale gas production and that will in turn reduce environmental impact. The expectation of significant production expansion in the future offers a tremendous incentive for companies to undertake R&D to improve efficiency and profitability. The history of the oil and gas industry supports such innovation, in particular greater extraction of the oil and gas in place and reduction in the unit cost of drilling and production.

The original innovations of directional drilling and formation fracturing plausibly will be extended by much more accurate placement of fracturing fluid guided by improved interpretation of micro-seismic signals and improved techniques of reservoir testing. As an example, oil services firms are already offering services that provide near-real-time monitoring to avoid excessive vertical fracturing growth, thus affording better control of fracturing fluid placement. Members of the Subcommittee estimate that an improvement in in efficiency of water use could be between a factor of two and four. There will be countless other innovations as well.

There has already been a major technical innovation – the switch from single well to pad-based drilling and production of multiple wells (up to twenty wells per pad have been drilled). The multi-well pad system allows for enhanced efficiency because of repeating operations at the same site and a much smaller footprint (e.g. concentrated gas gathering systems; many fewer truck trips associated with drilling and completion, especially related to equipment transport; decreased needs for road and pipeline constructions, etc.). It is worth noting that these efficiencies may require pooling acreage into large blocks.

Conclusion

The public deserves assurance that the full economic, environmental and energy security benefits of shale gas development will be realized without sacrificing public health, environmental protection and safety. Nonetheless, accidents and incidents have occurred with shale gas development, and uncertainties about impacts need to be quantified and clarified. Therefore the Subcommittee has highlighted important steps for more thorough information, implementation of best practices that make use of technical innovation and field experience, regulatory enhancement, and focused R&D, to ensure that shale operations proceed in the safest way possible, with enhanced efficiency and minimized adverse impact. If implemented these measures will give the public reason to believe that the nation's considerable shale gas resources are being developed in a way that is most beneficial to the nation.

ANNEX A – CHARGE TO THE SUBCOMMITTEE

From: Secretary Chu

To: William J. Perry, Chairman, Secretary's Energy Advisory Board (SEAB)

On March 30, 2011, President Obama announced a plan for U.S. energy security, in which he instructed me to work with other agencies, the natural gas industry, states, and environmental experts to improve the safety of shale gas development. The President also issued the Blueprint for a Secure Energy Future ("Energy Blueprint"), which included the following charge:

> **"Setting the Bar for Safety and Responsibility:** To provide recommendations from a range of independent experts, the Secretary of Energy, in consultation with the EPA Administrator and Secretary of Interior, should task the Secretary of Energy Advisory Board (SEAB) with establishing a subcommittee to examine fracking issues. The subcommittee will be supported by DOE, EPA and DOI, and its membership will extend beyond SEAB members to include leaders from industry, the environmental community, and states. The subcommittee will work to identify, within 90 days, any immediate steps that can be taken to improve the safety and environmental performance of fracking and to develop, within six months, consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment." *Energy Blueprint (page 13).*

The President has charged us with a complex and urgent responsibility. I have asked SEAB and the Natural Gas Subcommittee, specifically, to begin work on this assignment immediately and to give it the highest priority.

This memorandum defines the task before the Subcommittee and the process to be used.

Membership:

In January of 2011, the SEAB created a Natural Gas Subcommittee to evaluate what role natural gas might play in the clean energy economy of the future. Members of the Subcommittee include John Deutch (chair), Susan Tierney, and Dan Yergin. Following consultation with the Environmental Protection Agency and the Department of the Interior, I have appointed the following additional members to the Subcommittee: Stephen Holditch, Fred Krupp, Kathleen McGinty, and Mark Zoback.

The varied backgrounds of these members satisfies the President's charge to include individuals with industry, environmental community, and state expertise. To facilitate an expeditious start, the Subcommittee will consist of this small group, but additional members may be added as appropriate.

Consultation with other Agencies:

The President has instructed DOE to work in consultation with EPA and DOI, and has instructed all three agencies to provide support and expertise to the Subcommittee. Both agencies have independent regulatory authority over certain aspects of natural gas production, and considerable expertise that can inform the Subcommittee's work.

- The Secretary and Department staff will manage an interagency working group to be available to consult and provide information upon request of the Subcommittee.
- The Subcommittee will ensure that opportunities are available for EPA and DOI to present information to the Subcommittee.
- The Subcommittee should identify and request any resources or expertise that lies within the agencies that is needed to support its work.
- The Subcommittee's work should at all times remain independent and based on sound science and other expertise held from members of the Subcommittee.
- The Subcommittee's deliberations will involve only the members of the Subcommittee.
- The Subcommittee will present its final report/recommendations to the full SEAB Committee.

Public input:

In arriving at its recommendations, the Subcommittee will seek timely expert and other advice from industry, state and federal regulators, environmental groups, and other stakeholders.

- To assist the Subcommittee, DOE's Office of Fossil Energy will create a website to describe the initiative and to solicit public input on the subject.
- The Subcommittee will meet with representatives from state and federal regulatory agencies to receive expert information on subjects as the Subcommittee deems necessary.
- The Subcommittee or the DOE (in conjunction with the other agencies) may hold one or more public meetings when appropriate to gather input on the subject.

Scope of work of the Subcommittee:

The Subcommittee will provide the SEAB with recommendations as to actions that can be taken to improve the safety and environmental performance of shale gas extraction processes, and other steps to ensure protection of public health and safety, on topics such as:

- well design, siting, construction and completion;
- controls for field scale development;
- operational approaches related to drilling and hydraulic fracturing;
- risk management approaches;
- well sealing and closure;
- surface operations;
- waste water reuse and disposal, water quality impacts, and storm water runoff;

- protocols for transparent public disclosure of hydraulic fracturing chemicals and other information of interest to local communities;
- optimum environmentally sound composition of hydraulic fracturing chemicals, reduced water consumption, reduced waste generation, and lower greenhouse gas emissions;
- emergency management and response systems;
- metrics for performance assessment; and
- mechanisms to assess performance relating to safety, public health and the environment.

The Subcommittee should identify, at a high level, the best practices and additional steps that could enhance companies' safety and environmental performance with respect to a variety of aspects of natural gas extraction. Such steps may include, but not be limited to principles to assure best practices by the industry, including companies' adherence to these best practices. Additionally, the Subcommittee may identify high-priority research and technological issues to support prudent shale gas development.

Delivery of Recommendations and Advice:

- Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracking."
- Within 180 days of its first meeting, the Subcommittee will report to SEAB "consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment."
- At each stage, the Subcommittee will report its findings to the full Committee and the SEAB will review the findings.
- The Secretary will consult with the Administrator of EPA and the Secretary of the Interior, regarding the recommendations from SEAB.

Other:

- The Department will provide staff support to the Subcommittee for the purposes of meeting the requirements of the Subcommittee charge. The Department will also engage the services of other agency Federal employees or contractors to provide staff services to the Subcommittee, as it may request.
- DOE has identified $700k from the Office of Fossil Energy to fund this effort, which will support relevant studies or assessments, report writing, and other costs related to the Subcommittee's process.
- The Subcommittee will avoid activity that creates or gives the impression of giving undue influence or financial advantage or disadvantage for particular companies involved in shale gas exploration and development.
- The President's request specifically recognizes the unique technical expertise and scientific role of the Department and the SEAB. As an agency not engaged in regulating this activity, DOE is expected to provide a sound, highly credible evaluation of the best practices and best ideas for employing these practices safely that can be made available to companies and relevant regulators for appropriate action. Our task does not include making decisions about regulatory policy.

ANNEX B – MEMBERS OF THE SUBCOMMITTEE

John Deutch, Institute Professor at MIT (Chair) **-** John Deutch served as Director of Energy Research, Acting Assistant Secretary for Energy Technology and Under Secretary of Energy for the U.S. Department of Energy in the Carter Administration and Undersecretary of Acquisition & Technology, Deputy Secretary of Defense and Director of Central Intelligence during the first Clinton Administration. Dr. Deutch also currently serves on the Board of Directors of Raytheon and Cheniere Energy and is a past director of Citigroup, Cummins Engine Company and Schlumberger. A chemist who has published more than 140 technical papers in physical chemistry, he has been a member of the MIT faculty since 1970, and has served as Chairman of the Department of Chemistry, Dean of Science and Provost. He is a member of the Secretary of Energy Advisory Board.

Stephen Holditch, Head of the Department of Petroleum Engineering at Texas A&M University and has been on the faculty since 1976 - Stephen Holditch, who is a member of the National Academy of Engineering, serves on the Boards of Directors of Triangle Petroleum Corporation and Matador Resources Corporation. In 1977, Dr. Holditch founded S.A. Holditch & Associates, a petroleum engineering consulting firm that specialized in the analysis of unconventional gas reservoirs. Dr. Holditch was the 2002 President of the Society of Petroleum Engineers. He was the Editor of an SPE Monograph on hydraulic fracturing treatments, and he has taught short courses for 30 years on the design of hydraulic fracturing treatments and the analyses of unconventional gas reservoirs. Dr. Holditch worked for Shell Oil Company prior to joining the faculty at Texas A&M University.

Fred Krupp, President, Environmental Defense Fund **-** Fred Krupp has overseen the growth of EDF into a recognized worldwide leader in the environmental movement. Krupp is widely acknowledged as the foremost champion of harnessing market forces for environmental ends. He also helped launch a corporate coalition, the U.S. Climate Action Partnership, whose Fortune 500 members - Alcoa, GE, DuPont and dozens more - have called for strict limits on global warming pollution. Mr. Krupp is coauthor, with Miriam Horn, of New York Times Best Seller, *Earth: The Sequel*. Educated at Yale and the University of Michigan Law School, Krupp was among 16 people named as America's Best Leaders by U.S. News and World Report in 2007.

Kathleen McGinty, Kathleen McGinty is a respected environmental leader, having served as President Clinton's Chair of the White House Council on Environmental Quality and Legislative Assistant and Environment Advisor to then-Senator Al Gore.

More recently, she served as Secretary of the Pennsylvania Department of Environmental Protection. Ms. McGinty also has a strong background in energy. She is Senior Vice President of Weston Solutions where she leads the company's clean energy development business. She also is an Operating Partner at Element Partners, an investor in efficiency and renewables. Previously, Ms. McGinty was Chair of the Pennsylvania Energy Development Authority, and currently she is a Director at NRG Energy and Iberdrola USA.

Susan Tierney, Managing Principal, Analysis Group **-** Susan Tierney is a consultant on energy and environmental issues to public agencies, energy companies, environmental organizations, energy consumers, and tribes. She chairs the Board of the Energy Foundation, and serves on the Boards of Directors of the World Resources Institute, the Clean Air Task Force, among others. She recently, co-chaired the National Commission on Energy Policy, and chairs the Policy Subgroup of the National Petroleum Council's study of North American natural gas and oil resources. Dr. Tierney served as Assistant Secretary for Policy at the U.S. Department of Energy during the Clinton Administration. In Massachusetts, she served as Secretary of Environmental Affairs, Chair of the Board of the Massachusetts Water Resources Agency, Commissioner of the Massachusetts Department of Public Utilities and executive director of the Massachusetts Energy Facilities Siting Council.

Daniel Yergin, Chairman, IHS Cambridge Energy Research Associates **-** Daniel Yergin is the co-founder and chairman of IHS Cambridge Energy Research Associates. He is a member of the U.S. Secretary of Energy Advisory Board, a board member of the Board of the United States Energy Association and a member of the U.S. National Petroleum Council. He was vice chair of the 2007 National Petroleum Council study, *Hard Truths* and is vice chair of the new National Petroleum Council study of North American natural gas and oil resources. He chaired the U.S. Department of Energy's Task Force on Strategic Energy Research and Development. Dr. Yergin currently chairs the Energy Security Roundtable at the Brookings Institution, where he is a trustee, and is member of the advisory board of the MIT Energy Initiative. Dr. Yergin is also CNBC's Global Energy Expert. He is the author of the Pulitzer Prize-winning book, *The Prize: The Epic Quest for Oil, Money and Power.* His new book – *The Quest: Energy, Security, and the Remaking of the Modern World* – will be published in September 2011..

Mark Zoback, Professor of Geophysics, Stanford University - Mark Zoback is the Benjamin M. Page Professor of Geophysics at Stanford University. He is the author of a textbook, *Reservoir Geomechanics*, and author or co-author of over 300 technical research papers. He was co-principal investigator of the San Andreas Fault Observatory at Depth project (SAFOD) and has been serving on a National Academy of Engineering committee investigating the Deepwater Horizon accident. He was the chairman and co-founder of GeoMechanics International and serves as a senior adviser to Baker Hughes, Inc. Prior to joining Stanford University, he served as chief of the Tectonophysics Branch of the U.S. Geological Survey Earthquake Hazards Reduction Program.

ENDNOTES

[1] http://www.whitehouse.gov/sites/default/files/blueprint_secure_energy_future.pdf

[2] The James Baker III Institute for Public Policy at Rice University has recently released a report on *Shale Gas and U.S. National Security,* Available at: http://bakerinstitute.org/publications/EF-pub-DOEShaleGas-07192011.pdf.

[3] As a shale of total dry gas production in the “lower ’48”, shale gas was 6 percent in 2006, 8 percent in 2007, at which time its share began to grow rapidly – reaching 12 percent in 2008, 16 percent in 2009, and 24 percent in 2010. In June 2011, it reached 29 percent. Source: Energy Information Adminstration and Lippman Consulting.

[4] Timothy Considine, Robert W. Watson, and Nicholas B. Considine, “The Economy Opportunities of Shale Energy Development,” Manhattan Institute, May 2011, Table 2, page 6.

[5] Essentially all fracturing currently uses water at the working fluid. The possibility exists of using other fluids, such as nitrogen, carbon dioxide or foams as the working fluid.

[6] The Department of Energy has a shale gas technology primer available on the web at: http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/Shale_Gas_March_2011.pdf

[7] See the Bureau of Land Management *Gold Book* for a summary description of the DOI’s approach:
http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/oil_and_gas.Par.18714.File.dat/OILgas.pdf

[8] http://www.shalegas.energy.gov/

[9] The 2011 *MIT Study on the Future of Natural Gas,* gives an estimate of about 50 widely reported incidents between 2005 and 2009 involving groundwater contamination, surface spills, off-site disposal issues, water issues, air quality and blow outs, Table 2.3 and Appendix 2E. http://web.mit.edu/mitei/research/studies/naturalgas.html

[10] The Ground Water Protection Council and the Interstate Oil and Gas Compact Commission are considering a project to create a *National Oil and Gas Data Portal* with similar a objective, but broader scope to encompass all oil and gas activities.

[11] Information about STRONGER can be found at: http://www.strongerinc.org/

[12] The RBMS project is supported by the DOE Office of Fossil Energy, DOE grant #DE-FE0000880 at a cost of $1.029 million. The project is described at:
http://www.netl.doe.gov/technologies/oil-gas/publications/ENVreports/FE0000880_GWPC_Kickoff.pdf

[13] See, for example: John Corra, “Emissions from Hydrofracking Operations and General Oversight Information for Wyoming,” presented to the U.S. Department of Energy Natural Gas Subcommittee of the Secretary of Energy Advisory Board, July 13, 2011; Al Armendariz, “Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements,” Southern Methodist University, January 2009; Colorado Air Quality Control Commission, “Denver Metro Area & North Front Range Ozone Action Plan,” December 12, 2008; Utah Department of Environmental Quality, “2005 Uintah Basin Oil and Gas Emissions Inventory,” 2005.

[14] IPCC 2007 –The Physical Science Basis, Section 2.10.2).

[15] Robert W. Howarth, Renee Santoro, and Anthony Ingraffea, *Methane and the greenhouse-gas*

footprint of natural gas from shale formations, Climate Change, The online version of this article (doi:10.1007/s10584-011-0061-5) contains supplementary material.

[16] Timothy J. Skone, *Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States,* DOE, NETL, May 2011, available at: http://www.netl.doe.gov/energy-analyses/pubs/NG_LC_GHG_PRES_12MAY11.pdf

[17] Paulina Jaramillo, W. Michael Griffin, and H. Scott Mathews, *Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, Environmental Science & Technology, 41, 6290-6296 (2007).

[18] The EPA draft hydraulic fracturing study plan is available along with other information about EPA hydraulic fracturing activity at: http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm

[19] See, for example, "South Texas worries over gas industry's water use during drought," Platts, July 5, 2011, found at: http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/3555776; "Railroad Commission, Halliburton officials say amount of water used for fracking is problematic," Abeline Reporter News, July 15, 2011, found at: http://www.reporternews.com/news/2011/jul/15/railroad-commission-halliburton-officials-say-of/?print=1; "Water Use in the Barnett Shale," Texas Railroad Commission Website, updated January 24, 2011, found at: http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php.

[20] See, for example, *Energy Demands on Water Resources, DOE Report to Congress,* Dec 2006, http://www.sandia.gov/energy-water/docs/121-RptToCongress-EWwEIAcomments-FINAL.pdf

[21] Stephen G. Osborna, Avner Vengoshb, Nathaniel R. Warnerb, and Robert B. Jackson, *Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing*, Proceedings of the National Academy of Science, 108, 8172-8176, (2011).

[22] See EPA Certification Guidance for Engines Regulated Under: 40 CFR Part 86 (On-Highway Heavy-Duty Engines) and 40 CFR Part 89 (Nonroad CI Engines); available at: http://www.epa.gov/oms/regs/nonroad/equip-hd/420b98002.pdf

[23] API standards documents addressing hydraulic fracturing are: API HF1, Hydraulic Fracturing Operations-Well Construction and Integrity Guidelines, First Edition/October 2009, API HF2, Water Management Associated with Hydraulic Fracturing, First Edition/June 2010, API HF3, Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing, First Edition/January 2011, available at: http://www.api.org/policy/exploration/hydraulicfracturing/index.cfm

[24] Professor Steven Holditch, one of the Subcommittee members, is chair of the RPSEA governing committee.

[25] Extremely small microearthquakes are triggered as an integral part of shale gas development. While essentially all of these earthquakes are so small as to pose no hazard to the public or facilities (they release energy roughly equivalent to a gallon of milk falling of a kitchen counter), earthquakes of larger (but still small) magnitude have been triggered during hydraulic fracturing operations and by the injection of flow-back water after hydraulic fracturing. It is important to develop a hazard assessment and remediation protocol for triggered earthquakes to allow operators and regulators to know what steps need to be taken to assess risk and modify, as required, planned field operations.

United States Environmental Protection Agency

Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

Background Technical Support Document for Proposed Standards

EPA-453/R-11-002
July 2011

Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

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Office of Air and Radiation
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This report has been reviewed by EPA’s Office of Air Quality Planning and Standards and has been approved for publication. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use.

FOREWORD

This background technical support document (TSD) provides information relevant to the proposal of New Source Performance Standards (NSPS) for limiting VOC emissions from the Oil and Natural Gas Sector. The proposed standards were developed according to section 111(b)(1)(B) under the Clean Air Act, which requires EPA to review and revise, is appropriate, NSPS standards. The NSPS review allows EPA to identify processes in the oil and natural sector that are not regulated under the existing NSPS but may be appropriate to regulate under NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and SO_2, as well as any additional pollutants that are identified. This document is the result of that review process. Chapter 1 provides introduction on NSPS regulatory authority. Chapter 2 presents an overview of the oil and natural gas sector. Chapter 3 discusses the entire NSPS review process undertaken for this review. Finally, Chapters 4-8 provide information on previously unregulated emissions sources. Each chapter describes the emission source, the estimated emissions (on average) from these sources, potential control options identified to reduce these emissions and the cost of each control option identified. In addition, secondary impacts are estimated and the rationale for the proposed NSPS for each emission source is provided.

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1.0 NEW SOURCE PERFORMANCE STANDARD BACKGROUND

Standards of performance for new stationary sources are established under section 111 of the Clean Air Act (42 U.S.C. 7411), as amended in 1977. Section 111 directs the Administrator to establish standards of performance for any category of new stationary sources of air pollution which "…causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare." This technical support document (TSD) supports the proposed standards, which would control volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from the oil and natural gas sector.

1.1 Statutory Authority

Section 111 of the Clean Air Act (CAA) requires the Environmental Protection Agency Administrator to list categories of stationary sources, if such sources cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for such source categories. A performance standard reflects the degree of emission limitation achievable through the application of the "best system of emission reduction" (BSER) which the EPA determines has been adequately demonstrated. The EPA may consider certain costs and nonair quality health and environmental impact and energy requirements when establishing performance standards. Whereas CAA section 112 standards are issued for existing and new stationary sources, standards of performance are issued for new and modified stationary sources. These standards are referred to as new source performance standards (NSPS). The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to "at least every 8 years review and, if appropriate, revise" performance standards unless the "Administrator determines that such review is not appropriate in light of readily available information on the efficacy" of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to "reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.” This level of control is referred to as the best system of emission reduction (BSER). In determining BSER, a technology review is conducted that identifies what emission reduction systems exist and how much the identified systems reduce air pollution in practice. For each control system identified, the costs and secondary air benefits (or disbenefits) resulting from energy requirements and non-air quality impacts such as solid waste generation are also evaluated. This analysis determines BSER. The resultant standard is usually a numerical emissions limit, expressed as a performance level (i.e., a rate-based standard or percent control), that reflects the BSER. Although such standards are based on the BSER, the EPA may not prescribe a particular technology that must be used to comply with a performance standard, except in instances where the Administrator determines it is not feasible to prescribe or enforce a standard of performance. Typically, sources remain free to elect whatever control measures that they choose to meet the emission limits. Upon promulgation, a NSPS becomes a national standard to which all new, modified or reconstructed sources must comply.

1.2 History of Oil and Natural Gas Source Category

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). On June 24, 1985 (50 FR 26122), the EPA promulgated a NSPS for the source category that addressed volatile organic compound (VOC) emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates sulfur dioxide (SO_2) emissions from natural gas processing plants (40 CFR part 60, subpart LLL). Other than natural gas processing plants, EPA has not previously set NSPS for a variety of oil and natural gas operations. These NSPS are relatively narrow in scope as they address emissions only at natural gas processing plants. Specifically, subpart KKK addresses VOC emissions from leaking equipment at onshore natural gas processing plants, and subpart LLL addresses SO_2 emissions from natural gas processing plants.

1.3 NSPS Review Process Overview

CAA section 111(b)(1)(B) requires EPA to review and revise, if appropriate, NSPS standards. First, the existing NSPS were evaluated to determine whether it reflects BSER for the emission affected sources. This review was conducted by examining control technologies currently in use and assessing whether these technologies represent advances in emission reduction techniques compared to the technologies upon which the existing NSPS are based. For each new control technology identified, the potential emission reductions, costs, secondary air benefits (or disbenefits) resulting from energy requirements and non-air quality impacts such as solid waste generation are evaluated. The second step is evaluating whether there are additional pollutants emitted by facilities in the oil and natural gas sector that contribute significantly to air pollution and may reasonably be anticipated to endanger public health or welfare. The final review step is to identify additional processes in the oil and natural gas sector that are not covered under the existing NSPS but may be appropriate to develop NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and SO_2, as well as any additional pollutants that are identified. The entire review process is described in Chapter 3.

2.0 OIL AND NATURAL GAS SECTOR OVERVIEW

The oil and natural gas sector includes operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas. Specifically for oil, the sector includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the sector includes all operations from the well to the customer. The oil and natural gas operations can generally be separated into four segments: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and (4) natural gas distribution. Each of these segments is briefly discussed below.

Oil and natural gas production includes both onshore and offshore operations. Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and "Christmas tree" piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include well drilling, completion and recompletion processes; which includes all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the "pads" where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production sector also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants. None of the operations upstream of the natural gas processing plant (i.e. from the well to the natural gas processing plant) are covered by the existing NSPS. Offshore oil and natural gas production occurs on platform structures that house equipment to extract oil and gas from the ocean or lake floor and that process and/or transfer the oil and gas to storage, transport vessels or onshore. Offshore production can also include secondary platform structures connected to the platform structure, storage tanks associated with the platform structure and floating production and offloading equipment.

There are three basic types of wells: Oil wells, gas wells and associated gas wells. Oil wells can have "associated" natural gas that is separated and processed or the crude oil can be the only product processed. Once the crude oil is separated from the water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar or pipeline. The oil refinery sector is considered separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced "pipeline quality" dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover natural gas liquids or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of natural gas liquids, sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility. Natural gas processing plants are the only operations covered by the existing NSPS.

The pipeline quality natural gas leaves the processing segment and enters the transmission segment. Pipelines in the natural gas transmission segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission segment includes underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration and flow measurement.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. The delivery point where the natural gas leaves the transmission segment and enters the distribution segment is often called the “citygate.” Typically, utilities take ownership of the gas at the citygate. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas sector. Primarily, these emissions are organic compounds such as methane, ethane, VOC and organic hazardous air pollutants (HAP). The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide and SO_2 are emitted from production and processing operations that handle and treat sour gas[i]

In addition, there are significant emissions associated with the reciprocating internal combustion engines and combustion turbines that power compressors throughout the oil and natural gas sector. However, emissions from internal combustion engines and combustion turbines are covered by regulations specific to engines and turbines and, thus, are not addressed in this action.

[i] Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2

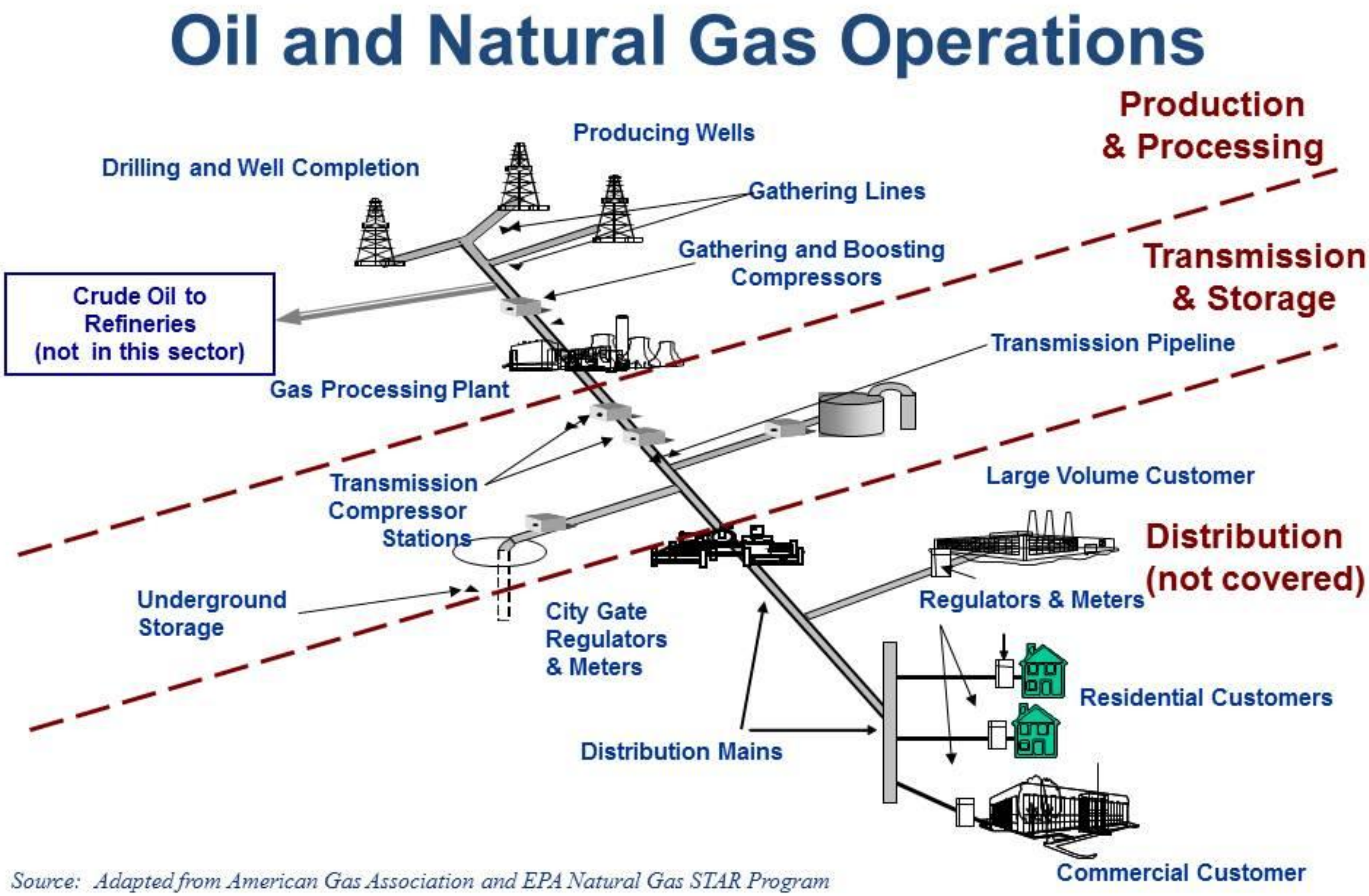

Figure 2-1. Oil and Natural Gas Operations

3.0 NEW SOURCE PERFORMANCE STANDARD REVIEW

As discussed in section 1.2, there are two NSPS that impact the oil and natural gas sector: (1) the NSPS for equipment leaks of VOC at natural gas processing plants (subpart KKK) and (2) the NSPS for SO_2 emissions from sweetening units located at natural gas processing plants (subpart LLL). Because they only address emissions from natural gas processing plants, these NSPS are relatively narrow in scope.

Section 111(b)(1) of the CAA requires the EPA to review and revise, if appropriate, NSPS standards. This review process consisted of the following steps:

1. Evaluation of the existing NSPS to determine whether they continue to reflect the BSER for the emission sources that they address;
2. Evaluation of whether there were additional pollutants emitted by facilities in the oil and natural gas sector that warrant regulation and for which there is adequate information to promulgate standards of performance; and
3. Identification of additional processes in the oil and natural gas sector for which it would be appropriate to develop performance standards, including processes that emit the currently regulated pollutants as well as any additional pollutants identified in step two.

The following sections detail each of these steps.

3.1 Evaluation of BSER for Existing NSPS

Consistent with the obligations under CAA section 111(b), control options reflected in the current NSPS for the Oil and Natural Gas source category were evaluated in order to distinguish if these options still represent BSER. To evaluate the BSER options for equipment leaks the following was reviewed: EPA's current leak detection and repair (LDAR) programs, the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database, and emerging technologies that have been identified by partners in the Natural Gas STAR program.[1]

3.1.1 BSER for VOC Emissions from Equipment Leaks at Natural Gas Processing Plants

The current NSPS for equipment leaks of VOC at natural gas processing plants (40 CFR part 60, subpart KKK) requires compliance with specific provisions of 40 CFR part 60, subpart VV, which is a LDAR program, based on the use of EPA Method 21 to identify equipment leaks. In addition to the subpart VV requirements, the LDAR requirements in 40 CFR part 60, subpart VVa were also reviewed. This LDAR program is considered to be more stringent than the subpart VV requirements, because it has lower component leak threshold definitions and more frequent monitoring, in comparison to the subpart VV program. Furthermore, subpart VVa requires monitoring of connectors, while subpart VV does not. Options based on optical gas imaging were also reviewed.

The currently required LDAR program for natural gas processing plants (40 CFR part 60, subpart KKK) is based on EPA Method 21, which requires the use of an organic vapor analyzer to monitor components and to measure the concentration of the emissions in identifying leaks. Although there have been advancements in the use of optical gas imaging to detect leaks from these same types of components, these instruments do not yet provide a direct measure of leak concentrations. The instruments instead provide a measure of a leak relative to an instrument specific calibration point. Since the promulgation of 40 CFR part 60, subpart KKK (which requires Method 21 leak measurement monthly), the EPA has updated the 40 CFR part 60 General Provisions to allow the use of advanced leak detection tools, such as optical gas imaging and ultrasound equipment as an alternative to the LDAR protocol based on Method 21 leak measurements (see 40 CFR 60.18(g)). The alternative work practice allowing use of these advanced technologies includes a provision for conducting a Method 21-based LDAR check of the regulated equipment annually to verify good performance.

In considering BSER for VOC equipment leaks at natural gas processing plants, four options were evaluated. One option evaluated consists of changing from a 40 CFR part 60, subpart VV-level program, which is what 40 CFR part 60, subpart KKK currently requires, to a 40 CFR part 60, subpart VVa program, which applies to new synthetic organic chemical plants after 2006. Subpart VVa lowers the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm, and requires the monitoring of connectors. In our analysis of these impacts, it was estimated that, for a typical natural gas processing plant, the incremental cost effectiveness of changing from the current subpart VV-level program to a subpart VVa-level program using Method 21 is $3,352 per ton of VOC reduction.

In evaluating 40 CFR part 60, subpart VVa-level LDAR at processing plants, the individual types of components (valves, connectors, pressure relief devices and open-ended lines) were also analyzed separately to determine cost effectiveness for individual components. Detailed discussions of these component-by-component analyses are provided in Chapter 8. Cost effectiveness ranged from $144 per ton of VOC (for valves) to $4,360 per ton of VOC (for connectors), with no change in requirements for pressure relief devices and open-ended lines.

Another option evaluated for gas processing plants was the use of optical gas imaging combined with an annual EPA Method 21 check (i.e., the alternative work practice for monitoring equipment for leaks at 40 CFR 60.18(g)). It was previously determined that the VOC reduction achieved by this combination of optical gas imaging and Method 21 would be equivalent to reductions achieved by the 40 CFR part 60, subpart VVa-level program. Based on the emission reduction level, the cost effectiveness of this option was estimated to be $6,462 per ton of VOC reduction. This analysis was based on the facility purchasing an optical gas imaging system costing $85,000. However, at least one manufacturer was identified that rents the optical gas imaging systems. That manufacturer rents the optical gas imaging system for $3,950 per week. Using this rental cost in place of the purchase cost, the VOC cost effectiveness of the monthly optical gas imaging combined with annual Method 21 inspection visits is $4,638 per ton of VOC reduction.[i]

A third option evaluated consisted of monthly optical gas imaging without an annual Method 21 check. The annual cost of the monthly optical gas imaging LDAR program was estimated to be $76,581 based on camera purchase, or $51,999 based on camera rental. However, it is not possible to quantify the VOC emission reductions achieved by an optical imaging program alone, therefore the cost effectiveness of this option could not be determined. Finally, a fourth option was evaluated that was similar to the third option, except that the optical gas imaging would be performed annually rather than monthly. For this option, the annual cost was estimated to be $43,851, based on camera purchase, or $18,479, based on camera rental.

Because the cost effectiveness of options 3 and 4 could not be estimated, these options could not be identified as BSER for reducing VOC leaks at gas processing plants. Because options 1 and 2 achieve equivalent VOC reduction and are both cost effective, both options 1 and 2 reflect BSER for LDAR for natural gas processing plants. As mentioned above, option 1 is the LDAR in 40 CFR part 60, subpart VVa and option 2 is the alternative work practice at 40 CFR 60.18(g) and is already available to use as an alternative to subpart VVa LDAR.

3.1.2 BSER for SO_2 Emissions from Sweetening Units at Natural Gas Processing Plants

For 40 CFR part 60, subpart LLL, control systems for SO_2 emissions from sweetening units located at natural gas processing plants were evaluated, including those followed by a sulfur recovery unit. Subpart

[i] Because optical gas imaging is used to view multiple pieces of equipment at a facility during one leak survey, options involving imaging are not amenable to a component by component analysis.

LLL provides specific standards for SO_2 emission reduction efficiency, on the basis of sulfur feed rate and the sulfur content of the natural gas.

According to available literature, the most widely used process for converting H_2S in acid gases (i.e., H_2S and CO_2) separated from natural gas by a sweetening process (such as amine treating) into elemental sulfur is the Claus process. Sulfur recovery efficiencies are higher with higher concentrations of H_2S in the feed stream due to the thermodynamic equilibrium limitation of the Claus process. The Claus sulfur recovery unit produces elemental sulfur from H_2S in a series of catalytic stages, recovering up to 97-percent recovery of the sulfur from the acid gas from the sweetening process. Further, sulfur recovery is accomplished by making process modifications or by employing a tail gas treatment process to convert the unconverted sulfur compounds from the Claus unit.

In addition, process modifications and tail gas treatment options were also evaluated at the time 40 CFR part 60, subpart LLL was proposed.[ii] As explained in the preamble to the proposed subpart LLL, control through sulfur recovery with tail gas treatment may not always be cost effective, depending on sulfur feed rate and inlet H_2S concentrations. Therefore, other methods of increasing sulfur recovery via process modifications were evaluated.

As shown in the original evaluation for the proposed subpart LLL, the performance capabilities and costs of each of these technologies are highly dependent on the ratio of H_2S and CO_2 in the gas stream and the total quantity of sulfur in the gas stream being treated. The most effective means of control was selected as BSER for the different stream characteristics. As a result, separate emissions limitations were developed in the form of equations that calculate the required initial and continuous emission reduction efficiency for each plant. The equations were based on the design performance capabilities of the technologies selected as BSER relative to the gas stream characteristics.[iii] The emission limit for sulfur feed rates at or below 5 long tons per day, regardless of H_2S content, was 79 percent. For facilities with sulfur feed rates above 5 long tons per day, the emission limits ranged from 79 percent at an H_2S content below 10 percent to 99.8 percent for H_2S contents at or above 50 percent.

To review these emission limitations, a search was performed of the RBLC database[1] and state regulations. No State regulations were identified that included emission limitations more stringent than 40 CFR part 60, subpart LLL. However, two entries in the RBLC database were identified having SO_2

[ii] 49 FR 2656, 2659-2660 (1984).
[iii] 49 FR 2656, 2663-2664 (1984).

emission reductions of 99.9 percent. One entry is for a facility in Bakersfield, California, with a 90 long ton per day sulfur recovery unit followed by an amine-based tailgas treating unit. The second entry is for a facility in Coden, Alabama, with a sulfur recovery unit with a feed rate of 280 long tons of sulfur per day, followed by selective catalytic reduction and a tail gas incinerator. However, neither of these entries contained information regarding the H_2S contents of the feed stream. Because the sulfur recovery efficiency of these large sized plants was greater than 99.8 percent, the original data was reevaluated. Based on the available cost information, a 99.9 percent efficiency is cost effective for facilities with a sulfur feed rate greater than 5 long tons per day and H_2S content equal to or greater than 50 percent. Based on this review, the maximum initial and continuous efficiency for facilities with a sulfur feed rate greater than 5 long tons per day and a H_2S content equal to or greater than 50 percent is raised to 99.9 percent.

The search of the RBLC database did not uncover information regarding costs and achievable emission reductions to suggest that the emission limitations for facilities with a sulfur feed rate less than 5 long tons per day or H_2S content less than 50 percent should be modified. Therefore, there were not any identifiable changes to the emissions limitations for facilities with sulfur feed rate and H_2S content less than 5 long tons per day and 50 percent, respectively.[1]

3.2 Additional Pollutants

The two current NSPS for the Oil and Natural Gas source category address emissions of VOC and SO_2. In addition to these pollutants, sources in this source category also emit a variety of other pollutants, most notably, air toxics. However, there are NESHAP that address air toxics from the oil and natural gas sector, specifically 40 CFR subpart HH and 40 CFR subpart HHH.

In addition, processes in the Oil and Natural Gas source category emit significant amounts of methane. The 1990 - 2009 U.S. GHG Inventory estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries) to be 251.55 MMtCO2e (million metric tons of CO2-equivalents (CO2e)).[iv] The emissions estimated from well completions and recompletions exclude a significant number of wells completed in tight sand plays, such as the Marcellus, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays (being considered as a planned improvement in development of the 2010 Inventory).

[iv] U.S. EPA. Inventory of U.S. Greenhouse Gas Inventory and Sinks. 1990 - 2009. http://www.epa.gov/climatechange/emissions/downloads10/US-GHGInventory2010_ExecutiveSummary.pdf

This adjustment would increase the 2009 Inventory estimate by 76.74 MMtCO2e. The total methane emissions from Petroleum and Natural Gas Systems, based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus, is 328.29 MMtCO2e.

Although this proposed rule does not include standards for regulating the GHG emissions discussed above, EPA continues to assess these significant emissions and evaluate appropriate actions for addressing these concerns. Because many of the proposed requirements for control of VOC emissions also control methane emissions as a co-benefit, the proposed VOC standards would also achieve significant reduction of methane emissions.

Significant emissions of oxides of nitrogen (NO_x) also occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors that move natural gas through the system, and from combustion of natural gas in heaters and boilers. While these engines, turbines, heaters and boilers are co-located with processes in the oil and natural gas sector, they are not in the Oil and Natural Gas source category and are not being addressed in this action. The NO_x emissions from engines and turbines are covered by the Standards of Performance for Stationary Spark Internal Combustion Engines (40 CFR part 60, subpart JJJJ) and Standards of Performance for Stationary Combustion Turbines (40 CFR part 60, subpart KKKK), respectively.

An additional source of NO_x emissions would be pit flaring of VOC emissions from well completions. As discussed in Chapter 4 Well completions, pit flaring is one option identified for controlling VOC emissions. Because there is no way of directly measuring the NO_x produced, nor is there any way of applying controls other than minimizing flaring, flaring would only be required for limited conditions.

3.3 Additional Processes

The current NSPS only cover emissions of VOC and SO_2 from one type of facility in the oil and natural gas sector, which is the natural gas processing plant. This is the only type of facility in the Oil and Natural Gas source category where SO_2 is expected to be emitted directly; although H_2S contained in sour gas[v] forms SO_2 as a product of oxidation when oxidized in the atmosphere or combusted in boilers and heaters in the field. These field boilers and heaters are not part of the Oil and Natural Gas source category and are generally too small to be regulated by the NSPS covering boilers (i.e., they have a heat

[v] Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2.

input of less than 10 million British Thermal Units per hour). They may, however, be included in future rulemakings.

In addition to VOC emissions from gas processing plants, there are numerous sources of VOC throughout the oil and natural gas sector that are not addressed by the current NSPS. Pursuant to CAA section 111(b), a modification of the listed category will now include all segments of the oil and natural gas industry for regulation. In addition, VOC standards will now cover additional processes at oil and natural gas operations. These include NSPS for VOC from gas well completions and recompletions, pneumatic controllers, compressors and storage vessels. In addition, produced water ponds may also be a potentially significant source of emissions, but there is very limited information available regarding these emissions. Therefore, no options could be evaluated at this time. The remainder of this document presents the evaluation for each of the new processes to be included in the NSPS.

3.4 References

1 Memorandum to Bruce Moore from Brad Nelson and Phil Norwood. Crude Oil and Natural Gas Production NSPS Technology Reviews. EC/R Incorporated. July 28, 2011.

4.0 WELL COMPLETIONS AND RECOMPLETIONS

In the oil and natural gas sector, well completions and recompletions contain multi-phase processes with various sources of emissions. One specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during recompletion activities that involve re-drilling or re-fracturing an existing well. This chapter describes completions and recompletions, and provides estimates for representative wells in addition to nationwide emissions. Control techniques employed to reduce emissions from flowback gas venting during completions and recompletions are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for reducing flowback emissions during completions and recompletions.

4.1 Process Description

4.1.1 Oil and Gas Well Completions

All oil and natural gas wells must be "completed" after initial drilling in preparation for production. Oil and natural gas completion activities not only will vary across formations, but can vary between wells in the same formation. Over time, completion and recompletion activities may change due to the evolution of well characteristics and technology advancement. Conventional gas reservoirs have well defined formations with high resource allocation in permeable and porous formations, and wells in conventional gas reservoirs have generally not required stimulation during production. Unconventional gas reservoirs are more dispersed and found in lower concentrations and may require stimulation (such as hydraulic fracturing) to extract gas.[1]

Well completion activities include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Surface components, including wellheads, pumps, dehydrators, separators, tanks, and gathering lines are installed as necessary for production to begin. The flowback stage of a well completion is highly variable but typically lasts between 3 and 10 days for the average well.[2]

Developmental wells are drilled within known boundaries of a proven oil or gas field, and are located near existing well sites where well parameters are already recorded and necessary surface equipment is in place. When drilling occurs in areas of new or unknown potential, well parameters such as gas composition, flow rate, and temperature from the formation need to be ascertained before surface facilities required for production can be adequately sized and brought on site. In this instance, exploratory (also referred to as "wildcat") wells and field boundary delineation wells typically either vent or combust the flowback gas.

One completion step for improving gas production is to fracture the reservoir rock with very high pressure fluid, typically a water emulsion with a proppant (generally sand) that "props open" the fractures after fluid pressure is reduced. Natural gas emissions are a result of the backflow of the fracture fluids and reservoir gas at high pressure and velocity necessary to clean and lift excess proppant to the surface. Natural gas from the completion backflow escapes to the atmosphere during the reclamation of water, sand, and hydrocarbon liquids during the collection of the multi-phase mixture directed to a surface impoundment. As the fracture fluids are depleted, the backflow eventually contains a higher volume of natural gas from the formation. Due to the additional equipment and resources involved and the nature of the backflow of the fracture fluids, completions involving hydraulic fracturing have higher costs and vent substantially more natural gas than completions not involving hydraulic fracturing.

Hydraulic fracturing can and does occur in some conventional reservoirs, but it is much more common in "tight" formations. Therefore, this analysis assumes hydraulic fracturing is performed in tight sand, shale, and coalbed methane formations. This analysis defines tight sand as sandstones or carbonates with an in situ permeability (flow rate capability) to gas of less than 0.1 millidarcy.[i]

"Energized fractures" are a relatively new type of completion method that injects an inert gas, such as carbon dioxide or nitrogen, before the fracture fluid and proppant. Thus, during initial flowback, the gas stream will first contain a high proportion of the injected gas, which will gradually decrease overtime.

4.1.2 Oil and Gas Well Recompletions

Many times wells will need supplementary maintenance, referred to as recompletions (these are also referred to as workovers). Recompletions are remedial operations required to maintain production or minimize the decline in production. Examples of the variety of recompletion activities include

[i] A darcy (or darcy unit) and millidarcies (mD) are units of permeability Converted to SI units, 1 darcy is equivalent to 9.869233×10^{-13} m² or 0.9869233 (µm)². This conversion is usually approximated as 1 (µm)².

completion of a new producing zone, re-fracture of a previously fractured zone, removal of paraffin buildup, replacing rod breaks or tubing tears in the wellbore, and addressing a malfunctioning downhole pump. During a recompletion, portable equipment is conveyed back to the well site temporarily and some recompletions require the use of a service rig. As with well completions, recompletions are highly specialized activities, requiring special equipment, and are usually performed by well service contractors specializing in well maintenance. Any flowback event during a recompletion, such as after a hydraulic fracture, will result in emissions to the atmosphere unless the flowback gas is captured.

When hydraulic re-fracturing is performed, the emissions are essentially the same as new well completions involving hydraulic fracture, except that surface gas collection equipment will already be present at the wellhead after the initial fracture. The backflow velocity during re-fracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

Backflow emissions are not a direct result of produced water. Backflow emissions are a result of free gas being produced by the well during well cleanup event, when the well also happens to be producing liquids (mostly water) and sand. The high rate backflow, with intermittent slugs of water and sand along with free gas, is typically directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels. Therefore, nearly all of the backflow emissions originate from the recompletion process but are vented as the backflow enters the impoundment or vessels. Minimal amounts of emissions are caused by the fluid (mostly water) held in the impoundment or vessels since very little gas is dissolved in the fluid when it enters the impoundment or vessels.

4.2. Emission Data and Emissions Factors

4.2.1 Summary of Major Studies and Emission Factors

Given the potential for significant emissions from completions and recompletions, there have been numerous recent studies conducted to estimate these emissions. In the evaluation of the emissions and emission reduction options for completions and recompletions, many of these studies were consulted. Table 4-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Documents [3]	EPA	2010	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 [4,5]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry [6, 7, 8, 9]	Gas Research Institute /US Environmental Protection Agency	1996	Nationwide	X	X
Methane Emissions from the US Petroleum Industry (Draft) [10]	EPA	1996	Nationwide	X	
Methane Emissions from the US Petroleum Industry [11]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [12]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories [13]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[14]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements [15]	Environmental Defense Fund	2009	Regional	X	X
Emissions from Oil and Natural Gas Production Facilities [16]	Texas Commission for Environmental Quality	2007	Regional	X	X
Availability, Economics and Production of North American Unconventional Natural Gas Supplies 1	Interstate Natural Gas Association of America	2008	Nationwide		

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Petroleum and Natural Gas Statistical Data[17]	U.S. Energy Information Administration	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations [18]	EPA	1999		X	
Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program [19]	New York State Department of Environmental Conservation	2009	Regional	X	X
Natural Gas STAR Program [20, 21, 22, 23, 24, 25]	EPA	2000-2010	Nationwide/ Regional	X	X

4.2.2 Representative Completion and Recompletion Emissions

As previously mentioned, one specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during the completion of a new well or during recompletion activities that involve re-drilling or re-fracturing of an existing well. For this analysis, well completion and recompletion emissions are estimated as the venting of emissions from the well during the initial phases of well preparation or during recompletion maintenance and/or re-fracturing of an existing well.

As previously stated, this analysis assumes wells completed/recompleted with hydraulic fracturing are found in tight sand, shale, or coal bed methane formations. A majority of the available emissions data for recompletions is for vertically drilled wells. It is projected that in the future, a majority of completions and recompletions will predominantly be performed on horizontal wells. However, there is not enough history of horizontally drilled wells to make a reasonable estimation of the difference in emissions from recompletions of horizontal versus vertical wells. Therefore, for this analysis, no distinction was made between vertical and horizontal wells.

As shown in Table 4-1, methane emissions from oil and natural gas operations have been measured, analyzed and reported in studies spanning the past few decades. The basic approach for this analysis was to approximate methane emissions from representative oil and gas completions and recompletions and then estimate volatile organic compounds (VOC) and hazardous air pollutants (HAP) using a representative gas composition.[26] The specific gas composition ratios used for gas wells were 0.1459 pounds (lb) VOC per lb methane (lb VOC/lb methane) and 0.0106 lb HAP/lb methane. The specific gas composition ratios used for oil wells were 0.8374 pounds lb VOC/lb methane and 0.0001 lb HAP/lb methane.

The EPA's analysis to estimate methane emissions conducted in support of the Greenhouse Gas Mandatory Reporting Rule (Subpart W), which was published in the *Federal Register* on November 30, 2010 (75 FR 74458), was the foundation for methane emission estimates from natural gas completions with hydraulic fracturing and recompletions with hydraulic fracturing. Methane emissions from oil well completions, oil well recompletions, natural gas completions without hydraulic fracturing, and natural gas recompletions without hydraulic fracturing were derived directly from the EPA's Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 (Inventory).[4] A summary of emissions for a representative model well completion or recompletion is found in Table 4-2.

Table 4-2. Uncontrolled Emissions Estimates from Oil and Natural Gas Well Completions and Recompletions

Well Completion Category	Emissions (Mcf/event)	Emissions (tons/event)		
	Methane	Methane[a]	VOC[b]	HAP[c]
Natural Gas Well Completion without Hydraulic Fracturing	38.6	0.8038	0.12	0.009
Natural Gas Well Completion with Hydraulic Fracturing	7,623	158.55	23.13	1.68
Oil Well Completions	0.34	0.0076	0.00071	0.0000006
Natural Gas Well Recompletion without Hydraulic Fracturing	2.59	0.0538	0.0079	0.0006
Natural Gas Well Recompletion with Hydraulic Fracturing	7,623	158.55	23.13	1.68
Oil Well Recompletions	0.057	0.00126	0.001	0.0000001

Minor discrepancies may exist due to rounding.

a. Reference 4, Appendix B., pgs 84-89. The conversion used to convert methane from volume to weight is 0.0208 tons methane is equal to 1 Mcf of methane. It is assumed methane comprises 83.081 percent by volume of natural gas from gas wells and 46.732 percent by volume of methane from oil wells.
b. Assumes 0.1459 lb VOC /lb methane for natural gas wells and 0.8374 lb VOC/lb methane for oil wells.
c. Assumes 0.0106 lb HAP/lb methane for natural gas wells and 0.0001 lb HAP/lb methane for oil wells.

4.3 Nationwide Emissions from New Sources

4.3.1 Overview of Approach

The first step in this analysis is to estimate nationwide emissions in absence of the proposed rulemaking, referred to as the baseline emissions estimate. In order to develop the baseline emissions estimate, the number of completions and recompletions performed in a typical year was estimated and then multiplied by the expected uncontrolled emissions per well completion listed in Table 4-2. In addition, to ensure no emission reduction credit was attributed to sources already controlled under State regulations, it was necessary to account for the number of completions/recompletions already subject to State regulations as detailed below. In order to estimate the number of wells that are already controlled under State regulations, existing well data was analyzed to estimate the percentage of currently controlled wells. This percentage was assumed to also represent the wells that would have been controlled in absence of a federal regulation and applied to the number of well completions estimated for future years.

4.3.2 Number of Completions and Recompletions

The number of new well completions was estimated using the National Energy Modeling System (NEMS). NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration (EIA). NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy economy from the current year to 2035. EIA is legally required to make the NEMS source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of NEMS, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues. NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions.

New well completion estimates are based on predictions from the NEMS Oil and Gas Supply Model, drawing upon the same assumptions and model used in the Annual Energy Outlook 2011 Reference Case. New well completions estimates were based on total successful wells drilled in 2015 (the year of analysis for regulatory impacts) for the following well categories: natural gas completions without hydraulic fracturing, natural gas completions with hydraulic fracturing, and oil well completions.

Successful wells are assumed to be equivalent to completed wells. Meanwhile, it was assumed that new dry wells would be abandoned and shut in and would not be completed. Therefore estimates of the number of dry wells were not included in the activity projections or impacts discussion for exploratory and developmental wells. Completion estimates are based on successful developmental and exploratory wells for each category defined in NEMS that includes oil completions, conventional gas completions and unconventional gas completions. The NEMS database defines unconventional reservoirs as those in shale, tight sand, and coalbed methane formations and distinguishes those from wells drilled in conventional reservoirs. Since hydraulic fracturing is most common in unconventional formations, this analysis assumes new successful natural gas wells in shale, tight sand, and coalbed methane formations are completed with hydraulic fracturing. New successful natural gas wells in conventional formations are assumed to be completed without hydraulic fracturing.

The number of natural gas recompletions with hydraulic fracturing (also referred to as a re-fracture), natural gas recompletions without hydraulic fracturing and oil well recompletions was based on well count data found in the HPDI® database.[ii, iii] The HPDI database consists of oil and natural gas well information maintained by a private organization that provides parameters describing the location, operator, and production characteristics. HPDI® collects information on a well basis such as the operator, state, basin, field, annual gas production, annual oil production, well depth, and shut-in pressure, all of which is aggregated from operator reports to state governments. HPDI was used to estimate the number of recompleted wells because the historical well data from HPDI is a comprehensive resource describing existing wells. Well data from 2008 was used as a base year since it was the most recent available data at the time of this analysis and is assumed to represent the number of recompletions that would occur in a representative year. The number of hydraulically fractured natural gas recompletions was estimated by estimating each operator and field combination found in the HPDI database and multiplying by 0.1 to represent 10 percent of the wells being re-fractured annually (as assumed in Subpart W's Technical Supporting Document3). This results in 14,177 total natural gas recompletions with hydraulic fracturing in the U.S. for the year 2008; which is assumed to depict a representative year. Non-fractured

[ii] HPDI, LLC is a private organization specializing in oil and gas data and statistical analysis. The HPDI database is focused on historical oil and gas production data and drilling permit data.

[iii] For the State of Pennsylvania, the most recent drilling information available from HPDI was for 2003. Due to the growth of oil and gas operations occurring in the Marcellus region in Pennsylvania, this information would not accurately represent the size of the industry in Pennsylvania for 2006 through 2008. Therefore, information from the Pennsylvania's Department of Environmental Protection was used to estimate well completion activities for this region. Well data from remaining states were based on available information from HPDI. From
<http://www.marcellusreporting.state.pa.us/OGREReports/Modules/DataExports/DataExports.aspx

recompletions were based on well data for 2008 in HPDI. The number of estimated well completions and recompletions for each well source category is listed in Table 4-3.

4.3.3 Level of Controlled Sources in Absence of Federal Regulation

As stated previously, to determine the impact of a regulation, it is first necessary to determine the current level of emissions from the sources being evaluated, or baseline emissions. To more accurately estimate baseline emissions for this analysis, and to ensure no emission reduction credit was attributed for sources already being controlled, it was necessary to evaluate the number of completions and recompletions already subject to regulation. Therefore, the number of completions and recompletions already being controlled in the absence of federal regulation was estimated based on the existing State regulations that require control measures for completions and recompletions. Although there may be regulations issued by other local ordinances for cities and counties throughout the U.S., wells impacted by these regulations were not included in this analysis because well count data are not available on a county or local ordinance level. Therefore, the percentage calculated based on the identified State regulations should be considered a conservative estimate.

In order to determine the number of completions and recompletions that are already controlled under State regulations, EIA historical well count data was analyzed to determine the percentage of new wells currently undergoing completion and recompletion in the States identified as having existing controls.[iv] Colorado (CO) and Wyoming (WY) were the only States identified as requiring controls on completions prior to NSPS review. The State of Wyoming's Air Quality Division (WAQD) requires operators to complete wells without flaring or venting where the following criteria are met: (1) the flowback gas meets sales line specifications and (2) the pressure of the reservoir is high enough to enable REC. If the above criteria are not met, then the produced gas is to be flared. [27] The WAQD requires that, "emissions of VOC and HAP associated with the flaring and venting of hydrocarbon fluids (liquids and gas) associated with well completion and recompletion activities shall be eliminated to the extent practicable by routing the recovered liquids into storage tanks and routing the recovered gas into a gas sales line or collection system." Similar to WY, the Colorado Oil and Gas Conservation Commission (COOGCC) requires REC for both oil and natural gas wells.[28] It was assumed for this analysis that the ratio of natural wells in CO and WY to the total number of wells in the U.S. represents the percentage of controlled wells for well completions. The ratio of wells in WY to the number of total nationwide wells

[iv] See EIA's The Number of Producing Wells, http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm

Table 4-3: Estimated Number of Total Oil and Natural Gas Completions and Recompletions for a Typical Year

Well Completion Category	Estimated Number of Total Completions and Recompletions[a]	Estimated Number of Controlled Completions and Recompletions	Estimated Number of Uncontrolled Completions and Recompletions[b]
Natural Gas Well Completions without Hydraulic Fracturing*	7,694		7,694
Exploratory Natural Gas Well Completions with Hydraulic Fracturing**	446		446
Developmental Natural Gas Well Completions with Hydraulic Fracturing[c]	10,957	1,644	9,313
Oil Well Completions[d]	12,193		12,193
Natural Gas Well Recompletions without Hydraulic Fracturing	42,342		42,342
Natural Gas Well Recompletions with Hydraulic Fracturing‡‡	14,177	2,127	12,050
Oil Well Recompletions‡	39,375		39,375

a. Natural gas completions and recompletions without hydraulic fracturing are assumed to be uncontrolled at baseline.
b. Fifteen percent of natural gas well completions with hydraulic fracturing are assumed as controlled at baseline.
c. Oil well completions and recompletions are assumed to be uncontrolled at baseline.
d. Fifteen percent of natural gas well recompletions with hydraulic fracturing are assumed to be controlled at baseline.

was assumed to represent the percentage of controlled well recompletions as it was the only State identified as having regulations directly regulated to recompletions.

From this review it was estimated that 15 percent of completions and 15 percent of recompletions are controlled in absence of federal regulation. It is also assumed for this analysis that only natural gas wells undergoing completion or recompletion with hydraulic fracturing are controlled in these States. Completions and recompletions that are performed without hydraulic fracturing, in addition to oil well completions and recompletions were assumed to not be subject to State regulations and therefore, were assumed to not be regulated at baseline. Baseline emissions for the controlled completions and recompletions covered by regulations are assumed to be reduced by 95 percent from the use of both REC and combustion devices that may be used separately or in tandem, depending on the individual State regulation.[v] The final activity factors for uncontrolled completions and uncontrolled recompletions are also listed in Table 4-3.

4.3.4 Emission Estimates

Using the estimated emissions, number of uncontrolled and controlled wells at baseline, described above, nationwide emission estimates for oil and gas well completions and recompletions in a typical year were calculated and are summarized in Table 4-4. All values have been independently rounded to the nearest ton for estimation purposes. As the table indicates, hydraulic fracturing significantly increases the magnitude of emissions. Completions and recompletions without hydraulic fracturing have lower emissions, while oil completions and recompletions have even lower emissions in comparison.

4.4 Control Techniques

4.4.1 Potential Control Techniques

Two techniques were considered that have been proven to reduce emissions from well completions and recompletions: REC and completion combustion. One of these techniques, REC, is an approach that not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented. The second technique, completion combustion, destroys the organic compounds. Both of these techniques are discussed in the following sections, along with estimates of the impacts of their application for a representative well. Nationwide impacts of chosen regulatory options are discussed in

[v] Percentage of controls by flares versus REC were not determined, so therefore, the count of controlled wells with REC versus controlled wells with flares was not determined and no secondary baseline emission impacts were calculated.

Table 4-4. Nationwide Baseline Emissions from Uncontrolled Oil and Gas Well Completions and Recompletions

Well Completion Category	Uncontrolled Methane Emissions per event (tpy)	Number of Uncontrolled Wells[a]	Baseline Nationwide Emissions (tons/year)[a]		
			Methane[b]	VOC[c]	HAP[d]
Natural Gas Well Completions without Hydraulic Fracturing	0.8038	7,694	6,185	902	66
Exploratory Natural Gas Well Completions with Hydraulic Fracturing	158.55	446	70,714	10,317	750
Developmental Natural Gas Well Completions with Hydraulic Fracturing	158.55	9,313	1,476,664	215,445	15,653
Oil Well Completions	0.0076	12,193	93	87	.008
Natural Gas Well Recompletions without Hydraulic Fracturing	0.0538	42,342	2,279	332	24
Natural Gas Well Recompletions with Hydraulic Fracturing	158.55	12,050	1,910,549	278,749	20,252
Oil Well Recompletions	0.00126	39,375	50	47	.004

Minor discrepancies may be due to rounding.

a. Baseline emissions include emissions from uncontrolled wells plus five percent of emissions from controlled sources. The Baseline emission reductions listed in the Regulatory Impacts (Table 4-9) represents only emission reductions from uncontrolled sources.
b. The number of controlled and uncontrolled wells estimated based on State regulations.
c. Based on the assumption that VOC content is 0.1459 pounds VOC per pound methane for natural gas wells and 0.8374 pounds VOC per pound methane for oil wells This estimate accounts for 5 percent of emissions assumed as vented even when controlled. Does not account for secondary emissions from portion of gas that is directed to a combustion device.
d. Based on the assumption that HAP content is 0.0106 pounds HAP per pound methane for natural gas wells and 0.0001 pounds HAP per pound methane for oil wells. This estimate accounts for 5 percent of emissions assumed as vented even when controlled. Does not account for secondary emissions from portion of gas that is directed to a combustion device.

section 4.5.

4.4.2 Reduced Emission Completions and Recompletions

4.4.2.1 Description

Reduced emission completions, also referred to as "green" or "flareless" completions, use specially designed equipment at the well site to capture and treat gas so it can be directed to the sales line. This process prevents some natural gas from venting and results in additional economic benefit from the sale of captured gas and, if present, gas condensate. Additional equipment required to conduct a REC may include additional tankage, special gas-liquid-sand separator traps, and a gas dehydrator.[29] In many cases, portable equipment used for RECs operate in tandem with the permanent equipment that will remain after well drilling is completed. In other instances, permanent equipment is designed (e.g. oversized) to specifically accommodate initial flowback. Some limitations exist for performing RECs since technical barriers fluctuate from well to well. Three main limitations include the following for RECs:

- Proximity of pipelines. For exploratory wells, no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields. The State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area that has never had oil and gas well production prior to that drilling instance (i.e., a wildcat well).[30] In instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that existing surface REC equipment may be located near an exploratory well, which would allow for a REC.

- Pressure of produced gas. During each stage of the completion/recompletion process, the pressure of flowback fluids may not be sufficient to overcome the sales line backpressure. This pressure is dependent on the specific sales line pressure and can be highly variable. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line. Another control option is compressor applications. One application is gas lift which is accomplished by withdrawing gas from the sales line, boosting its pressure, and routing it down the well casing to push the fracture fluids up the tubing. The increased pressure facilitates flow into the separator and then the sales line where the lift gas becomes part of the normal flowback that can be recovered during a REC. Another potential compressor application is to boost pressure of the flowback gas after it exits the separator. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate.

- Inert gas concentration. If the concentration of inert gas, such as nitrogen or carbon dioxide, in the flowback gas exceeds sales line concentration limits, venting or combustion of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

4.4.2.2. Effectiveness

RECs are an effective emissions reduction method for only natural gas completions and recompletions performed with hydraulic fracturing based on the estimated flowback emissions described in Section 4.2. The emissions reductions vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on several experiences presented at Natural Gas STAR technology transfer workshops, this analysis assumes 90 percent of flowback gas can be recovered during a REC.[31] Any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95 percent reduction in emissions.

4.4.2.3 Cost Impacts

All completions incur some costs to a company. Performing a REC will add to these costs. Equipment costs associated with RECs vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment, such as a glycol dehydrator, is already installed or is planned to be in place at the well site as normal operations, costs may be reduced as this equipment can be used or resized rather than installing a portable dehydrator for temporary use during the completion. Some operators normally install equipment used in RECs, such as sand traps and three-phase separators, further reducing incremental REC costs.

Costs of performing a REC are projected to be between $700 and $6,500 per day, with representative well completion flowback lasting 3 to 10 days.2 This cost range is the incremental cost of performing a REC over a traditional completion, where typically the gas is vented or combusted because there is an absence of REC equipment. Since RECs involve techniques and technologies that are new and continually evolving, and these cost estimates are based on the state of the industry in 2006 (adjusted to 2008 US dollars). [vi] Cost data used in this analysis are qualified below:

- $700 per day (equivalent to $806 per day in 2008 dollars) represents completion and recompletion costs where key pieces of equipment, such as a dehydrator or three phase separator, are already found on site and are of suitable design and capacity for use during flowback.

- $6,500 per day (equivalent to $7,486 in 2008 dollars) represents situations where key pieces of equipment, such as a dehydrator or three-phase separator, are temporarily brought on site and then relocated after the completion.

Costs were assessed based on an average of the above data (for costs and number of days per completion), resulting in an average incremental cost for a REC of $4,146 per day (2008 dollars) for an average of 7 days per completion. This results in an overall incremental cost of $29,022 for a REC versus an uncontrolled completion. An additional $691 (2008 dollars) was included to account for transportation and placement of equipment, bringing total incremental costs estimated at $29,713. Reduced emission completions are considered one-time events per well; therefore annual costs were conservatively assumed to be the same as capital costs. Dividing by the expected emission reductions, cost-effectiveness for VOC is $1,429 per ton, with a methane co-benefit of $208 per ton. Table 4-5 provides a summary of REC cost-effectiveness.

Monetary savings associated with additional gas captured to the sales line was also estimated based on a natural gas price of $4.00[vii] per thousand cubic feet (Mcf).[32] It was assumed that all gas captured would be included as sales gas. Therefore, assuming that 90 percent of the gas is captured and sold, this equates

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[vi] The Chemical Engineering Cost Index was used to convert dollar years. For REC, the 2008 value equals 575.4 and the 2006 value equals 499.6.

[vii] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the price, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings. The value of natural gas condensate recovered during the REC would also be significant depending on the gas composition. This value was not incorporated into the monetary savings in order to not overstate savings.

Table 4-5. Reduced Emission Completion and Recompletion Emission Reductions and Cost Impacts Summary

Well Completion Category	Emission Reduction Per Completion/Recompletion (tons/year)[a]			Total Cost Per Completion/ Recompletion[b] ($/event)	VOC Cost Effectiveness ($/ton)[c]		Methane Cost Effectiveness ($/ton)	
	VOC	Methane	HAP		without savings	with savings	without savings	with savings
Natural Gas Completions and Recompletions with Hydraulic Fracturing	20.8	142.7	1.5	29,713	1,429	net savings	208	net savings

Minor discrepancies may be due to rounding.

a. This represents a ninety percent reduction from baseline for the average well.
b. Total cost for reduced emission completion is expressed in terms of incremental cost versus a completion that vents emissions. This is based on an average incremental cost of $4,146 per day for an average length of completion flowback lasting 7 days and an additional $691 for transportation and set up.
c. Cost effectiveness has been rounded to the nearest dollar.

to a total recovery of 8,258 Mcf of natural gas per completion or recompletion with hydraulic fracturing. The estimated value of the recovered natural gas for a representative natural gas well with hydraulic fracturing is approximately $33,030. In addition we estimate an average of 34 barrels of condensate is recovered per completion or recompletion. Assuming a condensate value of $70 per barrel (bbl), this result is an income due to condensate sales around $2,380.[33] When considering these savings from REC, for a completion or recompletion with hydraulic fracturing, there is a net savings on the order of $5,697 per completion.

4.4.2.4 Secondary Impacts

A REC is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., nitrogen oxides, particulate matter, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to REC.

4.4.3 Completion Combustion Devices

4.4.3.1 Description

Completion combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.[34] Completion combustion devices are used to control VOC in many industrial settings, since the completion combustion device can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[35] Completion combustion devices commonly found on drilling sites are rather crude and portable, often installed horizontally due to the liquids that accompany the flowback gas. These flares can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead. However, the flow directed to a completion combustion device may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. Sometimes referred to as pit flares, these types of combustion devices do not employ an actual control device, and are not capable of being tested or monitored for efficiency. They do provide a means of minimizing vented gas and is preferable to venting. For the purpose of this analysis, the term completion combustion device represents all types of combustion devices including pit flares.

4.4.3.2 Effectiveness

The efficiency of completion combustion devices, or exploration and production flares, can be expected to achieve 95 percent, on average, over the duration of the completion or recompletion. If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it is more reliable to install an igniter fueled by a consistent and continuous ignition source. This scenario would be especially true for energized fractures where the initial flowback concentration will be extremely high in inert gases. This analysis assumes use of a continuous ignition source with an independent external fuel supply is assumed to achieve an average of 95 percent control over the entire flowback period. Additionally, because of the nature of the flowback (i.e., with periods of water, condensate, and gas in slug flow), conveying the entire portion of this stream to a flare or other control device is not always feasible. Because of the exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (e.g., dry, windy conditions, proximity to residences, etc.). As a result, we are aware that owners and operators may not be able to flare unrecoverable gas safely in every case.

Federal regulations require industrial flares meet a combustion efficiency of 98 percent or higher as outlined in 40 CFR 60.18. This statute does not apply to completion combustion devices. Concerns have been raised on applicability of 40 CFR 60.18 within the oil and gas industry including for the production segment.[30, 36, 37] The design and nature of completion combustion devices must handle multiphase flow and stream compositions that vary during the flowback period. Thus, the applicability criterion that specifies conditions for flares used in highly industrial settings may not be appropriate for flares typically used to control emissions from well completions and recompletions.

4.4.3.3 Cost Impacts

An analysis depicting the cost for wells including completion combustion devices was conducted for the Petroleum Services Association of Canada (PSAC) [38] in 2009 by N.L. Fisher Supervision and Engineering, Ltd.[viii] The data corresponds to 34 gas wells for various types of formations, including coal bed methane and shale. Multiple completion methods were also examined in the study including hydraulic and energized fracturing. Using the cost data points from these natural gas well completions,

[viii] It is important to note that outliers were excluded from the average cost calculation. Some outliers estimated the cost of production flares to be as low as $0 and as high as $56,000. It is expected that these values are not representative of typical flare costs and were removed from the data set. All cost data found in the PSAC study were aggregated values of the cost of production flares and other equipment such as tanks. It is possible the inclusion of the other equipment is not only responsible for the outliers, but also provides a conservatively high estimate for completion flares.

an average completion combustion device cost is approximately $3,523 (2008 dollars).[ix] As with the REC, because completion combustion devices are purchased for these one-time events, annual costs were conservatively assumed to be equal to the capital costs.

It is assumed that the cost of a continuous ignition source is included in the combustion completion device cost estimations. It is understood that multiple completions and recompletions can be controlled with the same completion combustion device, not only for the lifetime of the combustion device but within the same yearly time period. However, to be conservative, costs were estimated as the total cost of the completion combustion device itself, which corresponds to the assumption that only one device will control one completion per year. The cost impacts of using a completion combustion device to reduce emissions from representative completions/recompletions are provided in Table 4-6. Completion combustion devices have a cost-effectiveness of $161 per ton VOC and a co-benefit of $23 per ton methane for completions and recompletions with hydraulic fracturing.

4.4.3.4 Secondary Impacts

Noise and heat are the two primary undesirable outcomes of completion combustion device operation. In addition, combustion and partial combustion of many pollutants also create secondary pollutants including nitrogen oxides (NO_x), carbon monoxide (CO), sulfur oxides (SO_x, carbon dioxide (CO_2), and smoke/particulates (PM). The degree of combustion depends on the rate and extent of fuel mixing with air and the temperature maintained by the flame. Most hydrocarbons with carbon-to-hydrogen ratios greater than 0.33 are likely to smoke.[34] Due to the high methane content of the gas stream routed to the completion combustion device, it suggests that there should not be smoke except in specific circumstances (e.g., energized fractures). The stream to be combusted may also contain liquids and solids that will also affect the potential for smoke. Soot can typically be eliminated by adding steam. Based on current industry trends in the design of completion combustion devices and in the decentralized nature of completions, virtually no completion combustion devices include steam assistance.[34]

Reliable data for emission factors from flare operations during natural gas well completions are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing

[ix] The Chemical Engineering Cost Index was used to convert dollar years. For the combustion device the 2009 value equals 521.9. The 2009 average value for the combustion device is $3,195.

Table 4-6. Emission Reduction and Cost-effectiveness Summary for Completion Combustion Devices

Well Completion Category	Emission Reduction Per Completion/Workover (tons/year)[a]			Total Capital Cost Per Completion Event ($)*	VOC Cost Effectiveness	Methane Cost Effectiveness
	VOC	Methane	HAP		($/ton)[b]	($/ton)
Natural Gas Well Completions without Hydraulic Fracturing	0.11	0.76	0.0081	3,523	31,619	4,613
Natural Gas Well Completions with Hydraulic Fracturing	21.9	150.6	1.597		160	23
Oil Well Completions	0.01	0.007	0.0000007		520,580	488,557
Natural Gas Well Recompletions without Hydraulic Fracturing	0.007	0.051	0.0005		472,227	68,889
Natural Gas Well Recompletions with Hydraulic Fracturing	21.9	150.6	1.597		160	23
Oil Well Recompletions	0.00	0.001	0.0000001		3,134,431	2,941,615

Minor discrepancies may be due to rounding.

a. This assumes one combustion device will control one completion event per year. This should be considered a conservative estimate, since it is likely multiple completion events will be controlled with the same combustion unit in any given year. Costs are stated in 2008 dollars.

80 percent propylene and 20 percent propane.[34] These emissions factors, however, are the best indication for secondary pollutants from flare operations currently available. These secondary emission factors are provided are provided in Table 4-7.

Since this analysis assumed pit flares achieve 95 percent efficiency over the duration of flowback, it is likely the secondary emission estimations are lower than actuality (i.e. AP-42 assumes 98 percent efficiency). In addition due, to the potential for the incomplete combustion of natural gas across the pit flare plume, the likelihood of additional NO_x formulating is also likely. The degree of combustion is variable and depends on the on the rate and extent of fuel mixing with air and on the flame temperature. Moreover, the actual NO_x (and CO) emissions may be greatly affected when the raw gas contains hydrocarbon liquids and water. For these reasons, the nationwide impacts of combustion devices discussed in Section 4.5 should be considered minimum estimates of secondary emissions from combustion devices.

4.5 Regulatory Options

The REC pollution prevention approach would not result in emissions of CO, NO_x, and PM from the combustion of the completion gases in the flare, and would therefore be the preferred option. As discussed above, REC is only an option for reducing emissions from gas well completions/workovers with hydraulic fracturing. Taking this into consideration, the following regulatory alternatives were evaluated:

- Regulatory Option 1: Require completion combustion devices for conventional natural gas well completions and recompletions;
- Regulatory Option 2: Require completion combustion devices for oil well completions and recompletions;
- Regulatory Option 3: Require combustion devices for all completions and recompletions;
- Regulatory Option 4: Require REC for all completions and recompletions of hydraulically fractured wells;
- Regulatory Option 5: Require REC and combustion operational standards for natural gas well completions with hydraulic fracturing, with the exception of exploratory, and delineation wells;
- Regulatory Option 6: Require combustion operational standards for exploratory and delineation wells; and

Table 4-7. Emission Factors from Flare Operations from AP-42 Guidelines Table 13.4-1[a]

Pollutant	Emission Factor ($lb/10^6$ Btu)
Total Hydrocarbon[b]	0.14
Carbon Monoxide	0.37
Nitrogen Oxides	0.068
Particular Matter[c]	0-274
Carbon Dioxide[d]	60

a. Based on combustion efficiency of 98 percent.
b. Measured as methane equivalent.
c. Soot in concentration values: nonsmoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.
d. Carbon dioxide is measured in kg CO2/MMBtu and is derived from the carbon dioxide emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

- Regulatory Option 7: Require REC and combustion operational standards for all natural gas well recompletions with hydraulic fracturing.

The following sections discuss these regulatory options.

4.5.1 Evaluation of Regulatory Options

The first two regulatory options (completion combustion devices for conventional natural gas well completions and recompletions and completion combustion devices for oil well completions and recompletions) were evaluated first. As shown in Table 4-6, the cost effectiveness associated with controlling conventional natural gas and oil well completions and recompletions ranges from $31,600 per ton VOC to over $3.7 million per ton VOC. Therefore, Regulatory Options 1 and 2 were rejected due to the high cost effectiveness.

The next regulatory option, to require completion combustion devices for all completions and recompletions, was considered. Under Regulatory Option 3, all of the natural gas emitted from the well during flowback would be destroyed by sending flowback gas through a combustion unit. Not only would this regulatory option result in the destruction of a natural resource with no recovery of salable gas, it also would result in an increase in emissions of secondary pollutants (e.g., nitrogen oxides, carbon monoxide, etc.). Therefore, Regulatory Option 3 was also rejected.

The fourth regulatory option would require RECs for all completions and recompletions of hydraulically fractured wells. As stated previously, RECs are not feasible for all well completions, such as exploratory wells, due to their distance from sales lines, etc. Further, RECs are also not technically feasible for each well at all times during completion and recompletion activities due to the variability of the pressure of produced gas and/or inert gas concentrations. Therefore, Regulatory Option 4 was rejected.

The fifth regulatory option was to require an operational standard consisting of a combination of REC and combustion for natural gas well completions with hydraulic fracturing. As discussed for Regulatory Option 4, RECs are not feasible for every well at all times during completion or recompletion activities due to variability of produced gas pressure and/or inert gas concentrations. In order to allow for wellhead owners and operators to continue to reduce emissions when RECs are not feasible due to well characteristics (e.g, wellhead pressure or inert gas concentrations), Regulatory Option 5 also allows for the use of a completion combustion device in combination with RECs.

Under Regulatory Option 5, a numerical limit was considered, but was rejected in favor of an operational standard. Under section 111(h)(2) of the CAA, EPA can set an operational standard which represents the best system of continuous emission reduction, provided the following criteria are met:

> "(A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or
>
> (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations."

As discussed in section 4.4.3, emissions from a completion combustion device cannot be measured or monitored to determine efficiency making an operational standard appropriate. Therefore, an operational standard under this regulatory option consists of a combination of REC and a completion combustion device to minimize the venting of natural gas and condensate vapors to the atmosphere, but allows venting in lieu of combustion for situations in which combustion would present safety hazards, other concerns, or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Sources would also be required, under this regulatory option, to maintain documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion. It was also evaluated whether Regulatory Option 5 should apply to all well completions, including exploratory and delineation wells.

As discussed previously, one of the technical limitations of RECs is that they are not feasible for use at some wells due to their proximity to pipelines. Section 111(b)(2) of the CAA allows EPA to "…distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing…." performance standards. Due to their distance from sales lines, and the relatively unknown characteristics of the formation, completion activities occurring at exploratory or delineation wells were considered to be a different "type" of activity than the types of completion activities occurring at all other gas wells. Therefore, two subcategories of completions were identified: *Subcategory 1* wells are all natural gas wells completed with hydraulic fracturing that do not fit the definition of exploratory or delineation wells. *Subcategory 2* wells are natural gas wells that meet the following definitions of exploratory or delineation wells:

- Exploratory wells are wells outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists or

- Delineation wells means a well drilled in order to determine the boundary of a field or producing reservoir.

Based on this subcategorization, Regulatory Option 5 would apply to the Subcategory 1 wells and a sixth regulatory option was developed for Subcategory 2 wells.

Regulatory Option 6 requires an operational standard for combustion for the Subcategory 2 wells. As described above, REC is not an option for exploratory and delineation wells due to their distance from sales lines. As with the Regulatory Option 5, a numerical limitation is not feasible. Therefore, this regulatory option requires an operational standard where emissions are minimized using a completion combustion device during completion activities at Subcategory 2 wells, with an allowance for venting in situations where combustion presents safety hazards or other concerns or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Consistent with Regulatory Option 5, records would be required to document the overall duration of the completion event, the duration of combustion, the duration of venting, and specific reasons for venting in lieu of combustion.

The final regulatory option was considered for recompletions. Regulatory Option 7 requires an operational standard for a combination of REC and a completion combustion device for all recompletions with hydraulic fracturing performed on new and existing natural gas wells. Regulatory Option 7 has the same requirements as Regulatory Option 5. Subcategorization similar to Regulatory Option 5 was not necessary for recompletions because it was assumed that RECs would be technically feasible for recompletions at all types of wells since they occur at wells that are producing and thus proximity to a sales line is not an issue. While evaluating this regulatory option, it was considered whether or not recompletions at existing wells should be considered modifications and subject to standards.

The affected facility under the New Source Performance Standards (NSPS) is considered to be the wellhead. Therefore, a new well drilled after the proposal date of the NSPS would be subject to emission control requirements. Likewise, wells drilled prior to the proposal date of the NSPS would not be subject to emission control requirements unless they underwent a modification after the proposal date. Under section 111(a) of the Clean Air Act, the term "modification" means:

> "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."

The wellhead is defined as the piping, casing, tubing, and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. In order to fracture an existing well during recompletion, the well would be re-perforated, causing physical change to the wellbore and casing and therefore a physical change to the wellhead, the affected facility. Additionally, much of the emissions data on which this analysis is based demonstrates that hydraulic fracturing results in an increase in emissions. Thus, recompletions using hydraulic fracturing result in an increase in emissions from the existing well producing operations. Based on this understanding of the work performed in order to recomplete the well, it was determined that a recompletion would be considered a modification under CAA section 111(a) and thus, would constitute a new wellhead affected facility subject to NSPS. Therefore, Regulatory Option 7 applies to recompletions using hydraulic fracturing at new and existing wells.

In summary, Regulatory Options 1, 2, 3, and 4 were determined to be unreasonable due to cost considerations, other impacts or technical feasibility and thereby rejected. Regulatory Options 5, 6, and 7 were determined to be applicable to natural gas wells and were evaluated further.

4.5.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Options 5, 6, and 7 which were selected as viable options for setting standards for completions and recompletions.

4.5.2.1 Primary Environmental Impacts of Regulatory Options

Regulatory Options 5, 6, and 7 were selected as options for setting standards for completions and regulatory options as follows:

- Regulatory Option 5: Operational standard for completions with hydraulic fracturing for Subcategory 1 wells (i.e., wells which do not meet the definition of exploratory or delineation wells), which requires a combination of REC with combustion, but allows for venting during specified situations.

- Regulatory Option 6: An operational standard for completions with hydraulic fracturing for exploratory and delineation wells (i.e., Subcategory 2 wells) which requires completion combustion devices with an allowance for venting during specified situations.

- Regulatory Option 7: An operational standard equivalent to Regulatory Option 5 which applies to recompletions with hydraulic fracturing at new and existing wells.

The number of completions and recompletions that would be subject to the regulatory options listed above was presented in Table 4-3. It was estimated that there would be 9,313 uncontrolled developmental natural gas well completions with hydraulic fracturing subject to Regulatory Option 5. Regulatory Option 6 would apply to 446 uncontrolled exploratory natural gas well completions with hydraulic fracturing, and 12,050 uncontrolled recompletions at existing wells would be subject to Regulatory Option 7.[x]

Table 4-8 presents the nationwide emission reduction estimates for each regulatory option. It was estimated that RECs in combination with the combustion of gas unsuitable for entering the gathering line, can achieve an overall 95 percent VOC reduction over the duration of the completion operation. The 95 percent recovery was estimated based on 90 percent of flowback being captured to the sales line and assuming an additional 5 percent of the remaining flowback would be sent to the combustion device. Nationwide emission reductions were estimated by applying this 95 percent VOC reduction to the uncontrolled baseline emissions presented in Table 4-4.

4.5.2.2 Cost Impacts

Cost impacts of the individual control techniques (RECs and completion combustion devices) were presented in section 4.4. For Regulatory Option 6, the costs for completion combustion devices presented in Table 4-6 for would apply to Subcategory 2 completions. The cost per completion event was estimated to be $3,523. Applied to the 446 estimated Subcategory 2 completions, the nationwide costs were estimated to be $1.57 million. Completion combustion devices are assumed to achieve an overall 95 percent combustion efficiency. Since the operational standards for Regulatory Options 5 and 7 include both REC and completion combustion devices, an additional cost impact analysis was

[x] The number of uncontrolled recompletions at new wells is not included in this analysis. Based on the assumption that wells are recompleted once every 10 years, any new wells that are drilled after the date of proposal of the standard would not likely be recompleted until after the year 2015, which is the date of this analysis. Therefore, impacts were not estimated for recompletion of new wells, which will be subject to the standards.

Table 4-8. Nationwide Emission and Cost Analysis of Regulatory Option

Well Completion Category	Number of Sources subject to NSPS[a]	Annual Cost Per Completion Event ($)[b]	Nationwide Emission Reductions (tpy)[c]			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
			VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 5 (operational standard for REC and combustion)												
Subcategory 1: Natural gas Completions with Hydraulic Fracturing	9,313	33,237	204,134	1,399,139	14,831	1,516	net savings	221	net savings	309.5	309.5	(20.24)
Regulatory Option 6 (operational standard for combustion)												
Subcategory 2: Natural gas Completions with Hydraulic Fracturing	446	3,523	9,801	67,178	712	160	160	23	23	1.57	1.57	1.57
Regulatory Option 7 (operational standard for REC and combustion)												
Natural Gas Well Recompletions with Hydraulic Fracturing	12,050	33,237	264,115	1,810,245	19,189	1,516	net savings	221	net savings	400.5	400.5	(26.18)

Minor discrepancies may be due to rounding.

a. Number of sources in each well completion category that are uncontrolled at baseline as presented in Table 4-3.
b. Costs per event for Regulatory Options 5 and 7 are calculated by adding the costs for REC and completion combustion device presented in Tables 4-5 and 4-6, respectively. Cost per event for Regulatory Option 6 is presented for completion combustion devices in Table 4-6.
c. Nationwide emission reductions calculated by applying the 95 percent emission reduction efficiency to the uncontrolled nationwide baseline emissions in Table 4-4.

performed to analyze the nationwide cost impacts of these regulatory options. The total incremental cost of the operational standard for Subcategory 1 completions and for recompletions is estimated at around $33,237, which includes the costs in Table 4-5 for the REC equipment and transportation in addition to the costs in Table 4-6 for the completion combustion device. Applying the cost for the combined REC and completion combustion device to the estimated 9,313 Subcategory 1 completions, the total nationwide cost was estimated to be $309.5 million, with a net annual savings estimated around $20 million when natural gas savings are considered. A cost of $400.5 million was estimated for recompletions, with an overall savings of around $26 million when natural gas savings are considered. The VOC cost effectiveness for Regulatory Options 5 and 7 was estimated at around $1,516 per ton, with a methane co-benefit of $221 per ton.

4.5.2.3 Secondary Impacts

Regulatory Options 5, 6 and 7 all require some amount of combustion; therefore the estimated nationwide secondary impacts are a direct result of combusting all or partial flowback emissions. Although, it is understood the volume of gas captured, combusted and vented may vary significantly depending on well characteristics and flowback composition, for the purpose of estimating secondary impacts for Regulatory Options 5 and 7, it was assumed that ninety percent of flowback is captured and an additional five percent of the remaining gas is combusted. For both Subcategory 1 natural gas well completions with hydraulic fracturing and for natural gas well recompletions with hydraulic fracturing, it is assumed around 459 Mcf of natural gas is combusted on a per well basis. For Regulatory Option 6, Subcategory 2 natural gas completions with hydraulic fracturing, it is assumed that 95 percent (8,716 Mcf) of flowback emissions are consumed by the combustion device. Tons of pollutant per completion event was estimated assuming 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas and applying the AP-42 emissions factors listed in Table 4-7.

From category 1 well completions and from recompletions, it is estimated 0.02 tons of NO_x are produced per event. This is based on assumptions that 5 percent of the flowback gas is combusted by the combustion device. From category 2 well completions, it is estimated 0.32 tons of NO_x are produced in secondary emissions per event. This is based on the assumption 95 percent of flowback gas is combusted by the combustion device. Based on the estimated number of completions and recompletions, the proposed regulatory options are estimated to produce around 507 tons of NO_x in secondary emissions nationwide from controlling all or partial flowback by combustion. Table 4-9 summarizes the estimated secondary emissions of the selected regulatory options.

Table 4-9 Nationwide Secondary Impacts of Selected Regulatory Options[a]

Pollutant	Regulatory Options 5[b] Subcategory 1 Natural Gas Well Completions with Hydraulic Fracturing		Regulatory Option 6[c] Subcategory 2 Natural Gas Well Completions with Hydraulic Fracturing		Regulatory Options 7[b] Natural Gas Well Recompletions with Hydraulic Fracturing	
	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)
Total Hydrocarbons	0.03	326	0.66	296	0.03	422
Carbon Monoxide	0.09	861	1.76	783	0.09	1,114
Nitrogen Oxides	0.02	158	0.32	144	0.02	205
Particulate Matter	0.00000002	0.0002	0.011	5	0.00000002	0.0003
Carbon Dioxide	33.06	307,863	628	280,128	33.06	398,341

a. Nationwide impacts are based on AP-42 Emission Guidelines for Industrial Flares as outlined in Table 4-7. As such, these emissions should be considered the minimum level of secondary emissions expected.

b. The operational standard (Regulatory Options 5 and 7) combines REC and combustion is assumed to capture 90 percent of flowback gas. Five percent of the remaining flowback is assumed to be consumed in the combustion device. Therefore, it is estimated 459 Mcf is sent to the combustion device per completion event. This analysis assumes there are 9,313 Subcategory 1 wells and 12,050 recompletions.

c. Assumes 8,716 Mcf of natural gas is sent to the combustion unit per completion. This analysis assumes 446 exploratory wells fall into this category.

d. Based on 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas.

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5.0 PNEUMATIC CONTROLLERS

The natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature, and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are used throughout the oil and natural gas sector as part of the instrumentation to control the position of valves. This chapter describes pneumatic devices including their function and associated emissions. Options available to reduce emissions from pneumatic devices are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for pneumatic devices.

5.1 Process Description

For the purpose of this document, a pneumatic controller is a device that uses natural gas to transmit a process signal or condition pneumatically and that may also adjust a valve position based on that signal, with the same bleed gas and/or a supplemental supply of power gas. In the vast majority of applications, the natural gas industry uses pneumatic controllers that make use of readily available high-pressure natural gas to provide the required energy and control signals. In the production segment, an estimated 400,000 pneumatic devices control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. There are around 13,000 gas pneumatic controllers located in the gathering, boosting and processing segment that control and monitor temperature, liquid, and pressure levels. In the transmission segment, an estimated 85,000 pneumatic controllers actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.[1]

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate control of a valve. In these “gas-driven” pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs: (1) continuous bleed devices are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) snap-acting devices release gas only when they open or close a valve or as they throttle the gas flow; and (3) self-contained devices release gas to a downstream pipeline instead of to the atmosphere. This analysis assumes self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. Furthermore, it is recognized "closed loop" systems are applicable only in instances with very low pressure[2] and may not be suitable to replace many applications of bleeding pneumatic devices. Therefore, these devices are not further discussed in this analysis.

Snap-acting controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from snap-acting devices is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the device's bleed stream. Since actuation emissions serve the device's functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 5.2.2) account for only the continuous flow of emissions (i.e. the bleed rate) and do not include emissions directly resulting from actuation. Snap-acting controllers are assumed to have zero bleed emissions. Most applications (but not all), snap-acting devices serve functionally different purposes than bleed devices. Therefore, snap-acting controllers are not further discussed in this analysis.

In addition, not all pneumatic controllers are gas driven. At sites without electrical service sufficient to power an instrument air compressor, mechanical or electrically powered pneumatic devices can be used. These "non-gas driven" pneumatic controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed "instrument air." Because these devices are not gas driven, they do not directly release natural gas or VOC emissions. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient to power an air compressor. This analysis assumes that natural gas processing plants are the only facilities in the oil and natural gas sector highly likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of gas driven devices.[9] The application of electrical controls is further elaborated in Section 5.3.

5.2 Emissions Data and Information

5.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic devices and the potential options available to reduce these emissions, numerous studies were consulted. Table 5-1 lists these references with an indication of the type of relevant information contained in each study.

5.2.2 Representative Pneumatic Device Emissions

Bleeding pneumatic controllers can be classified into two types based on their emissions rates: (1) high-bleed controllers and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 standard cubic feet per hour (scfh), while low-bleed devices bleed at a rate less than or equal to 6 scfh.[i]

For this analysis, EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, Subpart W of the Greenhouse Gas Reporting rule, as well as obtained updated data from major vendors of pneumatic devices. The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic device model (or model family). All pneumatic devices that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold.

Although by definition, a low-bleed device can emit up to 6 scfh, through this vendor research, it was determined that the typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have emissions from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.[3,ii] While the vendor data provides useful information on specific makes and models, it did not yield sufficient information about the

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[i] The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the Gas Research Institute (GRI) in 1990 titled "Unaccounted for Gas Project Summary Volume." This classification was adopted for the October 1993 Report to Congress titled "Opportunities to Reduce Anthropogenic Methane Emissions in the United States". As described on page 2-16 of the report, "devices with emissions or 'bleed' rates of 0.1 to 0.5 cubic feet per minute are considered to be 'high-bleed' types (PG&E 1990)." This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

[ii] All rates are listed at an assumed supply gas pressure of 20 psig.

Table 5-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Document [3]	EPA	2010	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2009 [4, 5]	EPA	2011	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry [6, 7, 8, 9]	Gas Research Institute / EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry (draft) [10]	EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry [11]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [12]	Western Regional Air Partnership	2005	Regional	X	
Natural Gas STAR Program[1]	EPA	2000-2010		X	X

prevalence of each model type in the population of devices; which is an important factor in developing a representative emission factor. Therefore, for this analysis, EPA determined that best available emissions estimates for pneumatic devices are presented in Table W-1A and W-1B of the Greenhouse Gas Mandatory Reporting Rule for the Oil and Natural Gas Industry (Subpart W). However, for the natural gas processing segment, a more conservative approach was assumed since it has been determined that natural gas processing plants would have sufficient electrical service to upgrade to non-gas driven controls. Therefore, to quantify representative emissions from a bleed-device in the natural gas processing segment, information from Volume 12 of the EPA/GRI report[iii] was used to estimate the methane emissions from a single pneumatic device by type.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic device type in each industry segment and then estimate VOC and hazardous air pollutants (HAP) using a representative gas composition.[13] The specific ratios from the gas composition were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment. Table 5-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment and device type.

5.3 Nationwide Emissions from New Sources

5.3.1 Approach

Nationwide emissions from newly installed natural gas pneumatic devices for a typical year were calculated by estimating the number of pneumatic devices installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 5-2. The number of new pneumatic devices installed for a typical year was determined for each segment of the industry including natural gas production, natural gas processing, natural gas transmission and storage, and oil production. The methodologies that determined the estimated number of new devices installed in a typical year is provided in section 5.3.2 of this chapter.

5.3.2 Population of Devices Installed Annually

In order to estimate the average number of pneumatic devices installed in a typical year, each industry

[iii] Table 4-11. page 56. epa.gov/gasstar/tools/related.html

Table 5-2. Average Bleed Emission Estimates per Pneumatic Device in the Oil and Natural Gas Sector (tons/year)[a]

Industry Segment	High-Bleed			Low-Bleed		
	Methane	VOC	HAP	Methane	VOC	HAP
Natural Gas Production[b]	6.91	1.92	0.073	0.26	0.072	0.003
Natural Gas Transmission and Storage[c]	3.20	0.089	0.003	0.24	0.007	0.0002
Oil Production[d]	6.91	1.92	0.073	0.26	0.072	0.003
Natural Gas Processing[e]	1.00	0.28	0.01	1.00	0.28	0.01

Minor discrepancies may be due to rounding.

a. The conversion factor used in this analysis is 1 thousand cubic feet of methane (Mcf) is equal to 0.0208 tons methane. Minor discrepancies may be due to rounding.
b. Natural Gas Production methane emissions are derived from Table W-1A and W-1B of Subpart W.
c. Natural gas transmission and storage methane emissions are derived from Table W-3 of Subpart W.
d. Oil production methane emissions are derived from Table W-1A and W-1B of Subpart W. It is assumed only continuous bleed devices are used in oil production.
e. Natural gas processing sector methane emissions are derived from Volume 12 of the 1996 GRI report.[9] Emissions from devices in the processing sector were determined based on data available for snap-acting and bleed devices, further distinction between high and low bleed could not be determined based on available data.

segment was analyzed separately using the best data available for each segment. The number of facilities estimated in absence of regulation was undeterminable due to the magnitude of new sources estimated and the lack of sufficient data that could indicate the number of controllers that would be installed in states that may have regulations requiring low bleed controllers, such as in Wyoming and Colorado.

For the natural gas production and oil production segments, the number of new pneumatics installed in a typical year was derived using a multiphase analysis. First, data from the US Greenhouse Gas Inventory: Emission and Sinks 1990-2009 was used to establish the ratio of pneumatic controllers installed per well site on a regional basis. These ratios were then applied to the number of well completions estimated in Chapter 4 for natural gas well completions with hydraulic fracturing, natural gas well completions without hydraulic fracturing and for oil well completions. On average, one pneumatic device was assumed to be installed per well completion for a total of 33,411 pneumatic devices. By applying the estimated 51 percent of bleed devices (versus snap acting controllers), it is estimated that an average of 17,040 bleed-devices would be installed in the production segment in a typical year.

The number of pneumatic controllers installed in the transmission segment was approximated using the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009. The number of new devices installed in a given year was estimated by subtracting the prior year (e.g. 2007) from the given year's total (e.g. 2008). This difference was assumed to be the number of new devices installed in the latter year (e.g. Number of new devices installed during 2008 = Pneumatics in 2008 – Pneumatics in 2007). A 3-year average was calculated based on the number of new devices installed in 2006 through 2008 in order to determine the average number of new devices installed in a typical year.

Once the population counts for the number of pneumatics in each segment were established, this population count was further refined to account for the number of snap-acting devices that would be installed versus a bleed device. This estimate of the percent of snap-acting and bleed devices was based on raw data found in the GRI study, where 51 percent of the pneumatic controllers are bleed devices in the production segment, and 32 percent of the pneumatic controllers are bleed devices in the transmission segment.9 The distinction between the number of high-bleed and low-bleed devices was not estimated because this analysis assumes it is not possible to predict or ensure where low bleeds will be used in the future. Table 5-3 summarizes the estimated number of new devices installed per year.

Table 5-3. Estimated Number of Pneumatic Devices Installed in an Typical Year

Industry Segment	Number of New Devices Estimated for a Typical Year[a]		
	Snap-Acting	Bleed-Devices	Total
Natural Gas and Oil Production[b]	16,371	17,040	33,411
Natural Gas Transmission and Storage[c]	178	84	262

a. National averages of population counts from the Inventory were refined to include the difference in snap-acting and bleed devices based on raw data found in the GRI/EPA study. This is based on the assumption that 51 percent of the pneumatic controllers are bleed devices in the production segment, while 32 percent are bleed devices in the transmission segment.

b. The number of pneumatics was derived from a multiphase analysis. Data from the US Greenhouse Gas Inventory: Emission and Sinks 1990-2009 was used to establish the number of pneumatics per well on a regional basis. These ratios were applied to the number of well completions estimated in Chapter 4 for natural gas wells with hydraulic fracturing, natural gas wells without hydraulic fracturing and for oil wells.

c. The number of pneumatics estimated for the transmission segment was approximated from comparing a 3 year average of new devices installed in 2006 through 2008 in order to establish an average number of pneumatics being installed in this industry segment in a typical year. This analysis was performed using the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009.

For the natural gas processing segment, this analysis assumes that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e. an instrument air system) and any high-bleed devices that remain are safety related. As a result, the number of new pneumatic bleed devices installed at existing natural gas processing plants was estimated as negligible. A new greenfield natural gas processing plant would require multiple control loops. In Chapter 8 of this document, it is estimated that 29 new and existing processing facilities would be subject to the NSPS for equipment leak detection. In order to quantify the impacts of the regulatory options represented in section 5.5 of this Chapter, it is assumed that half of these facilities are new sites that will install an instrument air system in place of multiple control valves. This indicates about 15 instrument air systems will be installed in a representative year.

5.3.3 Emission Estimates

Nationwide baseline emission estimates for pneumatic devices for new sources in a typical year are summarized in Table 5-4 by industry segment and device type. This analysis assumed for the nationwide emission estimate that all bleed-devices have the high-bleed emission rates estimated in Table 5-2 per industry segment since it cannot be predicted which sources would install a low bleed versus a high bleed controller.

5.4 Control Techniques

Although pneumatic devices have relatively small emissions individually, due to the large population of these devices installed on an annual basis, the cumulative VOC emissions for the industry are significant. As a result, several options to reduce emissions have been developed over the years. Table 5-5 provides a summary of these options for reducing emissions from pneumatic devices including: instrument air, non-gas driven controls, and enhanced maintenance.

Given the various control options and applicability issues, the replacement of a high-bleed with a low-bleed device is the most likely scenario for reducing emissions from pneumatic device emissions. This is also supported by States such as Colorado and Wyoming that require the use of low-bleed controllers in place of high-bleed controllers. Therefore, low-bleed devices are further described in the following section, along with estimates of the impacts of their application for a representative device and nationwide basis. Although snap-acting devices have zero bleed emissions, this analysis assumes the

Table 5-4. Nationwide Baseline Emissions from Representative Pneumatic Device Installed in a Typical Year for the Oil and Natural Gas Industry (tons/year)[a]

Industry Segment	Baseline Emissions from Representative New Unit (tpy)			Number of New Bleed Devices Expected Per Year	Nationwide Baseline Emissions from Bleeding Pneumatic (tpy)[b]		
	VOC	Methane	HAP		VOC	Methane	HAP
Oil and Gas Production	1.9213	6.9112	0.0725	17,040	32,739	117,766	1,237
Natural Gas Transmission and Storage	0.09523	3.423	0.003	84	8	288	0.2

Minor discrepancies may be due to rounding.

a. Emissions have been based on the bleed rates for a high-bleed device by industry segment. Minor discrepancies may be due to rounding.
b. To estimate VOC and HAP, weight ratios were developed based on methane emissions per device. The specific ratios used were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment.

Table 5-5. Alternative Control Options for Pneumatic Devices

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Install Low Bleed Device in Place of High Bleed Device	Low-bleed devices provide the same functional control as a high-bleed device, while emitting less continuous bleed emissions.	Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller.	Low-bleed devices are, on average, around $165 more than high bleed versions.
Convert to Instrument Air[14]	Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. For utility purposes such as small pneumatic pumps, gas compressor motor starters, pneumatic tools and sand blasting, air would not need to be dried. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel.	Replacing natural gas with instrument air in pneumatic controls eliminates VOC emissions from bleeding pneumatics. It is most effective at facilities where there are a high concentration of pneumatic control valves and an operator present. Since the systems are powered by electric compressors, they require a constant source of electrical power or a back-up natural gas pneumatic device. These systems can achieve 100 percent reduction in emissions.	A complete cost analysis is provided in Section 5.4.2. System costs are dependent on size of compressor, power supply needs, labor and other equipment.
Mechanical and Solar Powered Systems in place of Bleed device[15]	Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of back-up power or storage to ensure reliability.	Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric powered valves are only reliable with a constant supply of electricity. Overall, these options are applicable in niche areas but can achieve 100 percent reduction in emissions where applicable.	Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems.
Enhanced Maintenance[16]	Instrumentation in poor condition typically bleeds 5 to 10 scf per hour more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear, or loose control tube fittings. This may not impact the operations but does increase emissions.	Enhanced maintenance to repair and maintain pneumatic devices periodically can reduce emissions. Proper methods of maintaining a device are highly variable and could incur significant costs.	Variable based on labor, time, and fuel required to travel to many remote locations.

devices are not always used in the same functional application as bleed devices and are, therefore, not an appropriate form of control for all bleed devices. It is assumed snap-acting, or no-bleed, devices meet the definition of a low-bleed. This concept is further detailed in Section 5.5 of this chapter. Since this analysis has assumed areas with electrical power have already converted applicable pneumatic devices to instrument air systems, instrument air systems are also described for natural gas processing plants only. Given applicability, efficiency and the expected costs of the other options identified in Table 5-5 (i.e. mechanical controls and enhanced maintenance), were not further conducted for this analysis.

5.4.1 Low-Bleed Controllers

5.4.1.1 Emission Reduction Potential

As discussed in the above sections, low-bleed devices provide the same functional control as a high-bleed device, but have lower continuous bleed emissions. As summarized in Table 5-6, it is estimated on average that 6.6 tons of methane and 1.8 tons of VOC will be reduced annually in the production segment from installing a low-bleed device in place of a high-bleed device. In the transmission segment, the average achievable reductions per device are estimated around 3.7 tons and 0.08 tons for methane and VOC, respectively. As noted in section 5.2, a low-bleed controller can emit up to 6 scfh, which is higher than the expected emissions from the typical low-bleed device available on the current market.

5.4.1.1 Effectiveness

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, it is assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the production and transmission and storage industry segments.[1] This corresponds to 13,632 new high-bleed devices in the production segment (out of 17,040) and 67 new high-bleed devices in the transmission and storage segment (out of 84) that can be replaced with a new low-bleed alternative. For high-bleed devices in natural gas processing, this analysis assumed that the replaceable devices have already been replaced with instrument air and the remaining high-bleed devices are safety related for about half of the existing processing plants.

Table 5-6. Estimated Annual Bleed Emission Reductions from Replacing a Representative High-Bleed Pneumatic Device with a Representative Low-Bleed Pneumatic Device

Segment/Device Type	Emissions (tons/year)[a]		
	Methane	**VOC**	**HAP**
Oil and Natural Gas Production	6.65	1.85	0.07
Natural Gas Transmission and Storage	2.96	0.082	0.002

Minor discrepancies may be due to rounding.

a. Average emission reductions for each industry segment based on the typical emission flow rates from high-bleed and low-bleed devices as listed in Table 5-2 by industry segment.

Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller. High-bleed pneumatic devices may not be applicable for replacement with low-bleed devices because a process condition may require a fast or precise control response so that it does not stray too far from the desired set point. A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic devices may monitor the suction and discharge pressure and actuate a re-cycle when one or the other is out of the specified target range. Other scenarios for fast and precise control include transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can accommodate control from a low-bleed device, which is slower-acting and less precise.

Safety concerns may be a limitation issue, but only in specific situations because emergency valves are not bleeding controllers since safety is the pre-eminent consideration. Thus, the connection between the bleed rate of a pneumatic device and safety is not a direct one. Pneumatic devices are designed for process control during normal operations and to keep the process in a normal operating state. If an Emergency Shut Down (ESD) or Pressure Relief Valve (PRV) actuation occurs,[iv] the equipment in place for such an event is spring loaded, or otherwise not pneumatically powered. During a safety issue or emergency, it is possible that the pneumatic gas supply will be lost. For this reason, control valves are deliberately selected to either fail open or fail closed, depending on which option is the failsafe.

5.4.1.2 Cost Impacts

As described in Section 5.2.2, costs were based on the vendor research described in Section 5.2 as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices.[1] As Table 5-7 indicates, the average cost for a low bleed pneumatic is $2,553, while the average cost for a high bleed is $2,338.[v] Thus, the incremental cost of installing a low-bleed device instead of a high-bleed device is on the order of $165 per device. In order to analyze cost impacts, the incremental cost to install a low-bleed instead of a high-bleed was

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[iv] ESD valves either close or open in an emergency depending on the fail safe configuration. PRVs always open in an emergency.
[v] Costs are estimated in 2008 U.S. Dollars.

Table 5-7. Cost Projections for the Representative Pneumatic Devices[a]

Device	Minimum cost ($)	Maximum cost ($)	Average cost ($)	Low-Bleed Incremental Cost ($)
High-bleed controller	366	7,000	2,388	$165
Low-bleed controller	524	8,852	2,553	

a. Major pneumatic devices vendors were surveyed for costs, emission rates, and any other pertinent information that would give an accurate picture of the present industry.

annualized for a 10 year period using a 7 percent interest rate. This equated to an annualized cost of around $23 per device for both the production and transmission segments.

Monetary savings associated with additional gas captured to the sales line was estimated based on a natural gas value of $4.00 per Mcf.[vi,17] The representative low-bleed device is estimated to emit 6.65 tons, or 319 Mcf, (using the conversion factor of 0.0208 tons methane per 1 Mcf) of methane less than the average high-bleed device per year. Assuming production quality gas is 82.8 percent methane by volume, this equals 385.5 Mcf natural gas recovered per year. Therefore, the value of recovered natural gas from one pneumatic device in the production segment equates to approximately $1,500. Savings were not estimated for the transmission segment because it is assumed the owner of the pneumatic controller generally is not the owner of the natural gas. Table 5-8 provides a summary of low-bleed pneumatic cost effectiveness.

5.4.1.3 Secondary Impacts

Low-bleed pneumatic devices are a replacement option for high-bleed devices that simply bleed less natural gas that would otherwise be emitted in the actuation of pneumatic valves. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the use of low-bleed pneumatic devices.

5.4.2 Instrument Air Systems

5.4.2.1 Process Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following is a description of each component as described in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air:*

- Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank.

[vi] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the value, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings.

Table 5-8. Cost-effectiveness for Low-Bleed Pneumatic Devices versus High Bleed Pneumatics

Segment	Incremental Capital Cost Per Unit ($)[a]	Total Annual Cost Per Unit ($/yr)[b]		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		without savings	with savings	without savings	with savings	without savings	with savings
Oil and Natural Gas Production	165	23.50	-1,519	13	net savings	4	net savings
Natural Gas Transmission and Storage	165	23.50	23.50	286	286	8	8

a. Incremental cost of a low bleed device versus a high bleed device as summarized in Table 5-7.
b. Annualized cost assumes a 7 percent interest rate over a 10 year equipment lifetime.

For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.

- A critical component of the instrument air control system is the power source required to operate the compressor. Since high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of electric power can be difficult to assure. In some instances, solar-powered battery-operated air compressors can be cost effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.

- Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.

- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. The use of instrument air eliminates natural gas emissions from natural gas powered pneumatic controllers. All other parts of a gas pneumatic system will operate the same way with instrument air as they do with natural gas. The conversion of natural gas pneumatic controllers to instrument air systems is applicable to all natural gas facilities with electrical service available.[14]

5.4.2.2 Effectiveness

The use of instrument air eliminates natural gas emissions from the natural gas driven pneumatic devices; however, the system is only applicable in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is a high concentration of pneumatic control valves and the presence of an operator that can ensure the system is properly functioning.[14]

5.4.2.3 Cost Impacts

Instrument air conversion requires additional equipment to properly compress and control the pressured air. The size of the compressor will depend on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas used to run the existing instrumentation – adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is one cubic foot per minute (cfm) of instrument air for each control loop.[14] As the system is powered by electric compressors, the system requires a constant source of electrical power or a back-up pneumatic device. Table 5-9 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and related equipment and the operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator and a storage vessel. It is assumed that in either an instrument air solution or a natural gas pneumatic solution, gas supply piping, control instruments, and valve actuators of the gas pneumatic system are required. The total cost, including installation and labor, of three representative sizes of compressors were evaluated based on assumptions found in the Natural Gas STAR document, "Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air"[14] and summarized in Table 5-10.[vii]

For natural gas processing, the cost-effectiveness of the three representative instrument air system sizes was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because we assume new processing plants will need to provide instrumentation of multiple control loops and size the instrument air system accordingly. We also assume that existing processing plants have already upgraded to instrument air

[vii] Costs have been converted to 2008 US dollars using the Chemical Engineering Cost Index.

Table 5-9. Compressor Power Requirements and Costs for Various Sized Instrument Air Systems[a]

Compressor Power Requirements[b]			Flow Rate	Control Loops
Size of Unit	hp	kW	(cfm)	Loops/Compressor
small	10	13.3	30	15
medium	30	40	125	63
large	75	100	350	175

a. Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*[14]

b. Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50 percent of the year).

Table 5-10 Estimated Capital and Annual Costs of Various Sized Representative Instrument Air Systems

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital[a]	Annualized Capital[b]	Labor Cost	Total Annual Costs[c]	Annualized Cost of Instrument Air System
Small	$3,772	$754	$2,262	$16,972	$2,416	$1,334	$8,674	$11,090
Medium	$18,855	$2,262	$6,787	$73,531	$10,469	$4,333	$26,408	$36,877
Large	$33,183	$4,525	$15,083	$135,750	$19,328	$5,999	$61,187	$80,515

a. Total Capital includes the cost for two compressors, tank, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the Natural Gas Star Lessons Learned document and converted to 2008 dollars from 2006 dollars using the Chemical Engineering Cost Index.
b. The annualized cost was estimated using a 7 percent interest rate and 10 year equipment life.
c. Annual Costs include the cost of electrical power as listed in Table 5-9 and labor.

unless the function has a specific need for a bleeding device, which would most likely be safety related.[9] Table 5-11 summarizes the cost-effectiveness of the three sizes of representative instrument air systems.

5.4.2.4 Secondary Impacts

The secondary impacts from instrument air systems are indirect, variable and dependent on the electrical supply used to power the compressor. No other secondary impacts are expected.

5.5 Regulatory Options

The affected facility definition for pneumatic controllers is defined as a single natural gas pneumatic controller. Therefore, pneumatic controllers would be subject to a New Source Performance Standard (NSPS) at the time of installation. The following Regulatory alternatives were evaluated:

- Regulatory Option 1: Establish an emissions limit equal to 0 scfh.
- Regulatory Option 2: Establish an emissions limit equal to 6 scfh.

5.5.1 Evaluation of Regulatory Options

By establishing an emission limit of 0 scfh, facilities would most likely install instrument air systems to meet the threshold limit. This option is considered cost effective for natural gas processing plants as summarized in Table 5-11. A major assumption of this analysis, however, is that processing plants are constructed at a location with sufficient electrical service to power the instrument air compression system. It is assumed that facilities located outside of the processing plant would not have sufficient electrical service to install an instrument air system. This would significantly increase the cost of the system at these locations, making it not cost effective for these facilities to meet this regulatory option. Therefore, Regulatory Option 1 was accepted for natural gas processing plants and rejected for all other types of facilities.

Regulatory Option 2 would establish an emission limit equal to the maximum emissions allowed for a low-bleed device in the production and transmissions and storage industry segments. This would most likely be met by the use of low-bleed controllers in place of a high-bleed controller, but allows flexibility in the chosen method of meeting the requirement. In the key instances related to pressure control that would disallow the use of a low-bleed device, specific monitoring and recordkeeping criteria

Table 5-11 Cost-effectiveness of Representative Instrument Air Systems in the Natural Gas Processing Segment

System Size	Number of Control Loops	Annual Emissions Reduction[a] (tons/year)			Value of Product Recovered ($/year)[b]	Annualized Cost of System		VOC Cost-effectiveness ($/ton)		Methane Cost-effectiveness ($/ton)	
		VOC	CH_4	HAP		without savings	with savings	without savings	with savings	without savings	with savings
Small	15	4.18	15	0.16	3,484	11,090	7,606	2,656	1,822	738	506
Medium	63	17.5	63	0.66	14,632	36,877	22,245	2,103	1,269	585	353
Large	175	48.7	175	1.84	40,644	80,515	39,871	1,653	819	460	228

Minor discrepancies may be due to rounding.

a. Based on the emissions mitigated from the entire system, which includes multiple control loops.
b. Value of recovered product assumes natural gas processing is 82.8 percent methane by volume. A natural gas price of $4 per Mcf was assumed.

would be required to ensure the device function dictates the precision of a high bleed device. Therefore, Regulatory Option 2 was accepted for locations outside of natural gas processing plants.

5.5.2 Nationwide Impacts of Regulatory Options

Table 5-12 summarizes the costs impacts of the selected regulatory options by industry segment. Regulatory Option 1 for the natural gas processing segment is estimated to affect 15 new processing plants with nationwide annual costs discounting savings of $166,000. When savings are realized the net annual cost is reduced to around $114,000. Regulatory Option 2 has nationwide annual costs of $320,000 for the production segment and around $1,500 in the natural gas transmission and storage segment. When annual savings are realized in the production segment there is a net savings of $20.7 million in nationwide annual costs.

Table 5-12 Nationwide Cost and Emission Reduction Impacts for Selected Regulatory Options by Industry Segment

Industry Segment	Number of Sources subject to NSPS*	Capital Cost Per Device/IAS ($)**	Annual Costs ($/year)		Nationwide Emission Reductions (tpy)†			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs ($/year)		
			without savings	with savings	VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 1 (emission threshold equal to 0 scfh)														
Natural Gas Processing	15	16,972	11,090	7,606	63	225	2	2,656	1,822	738	506	254,576	166,351	114,094
Regulatory Option 2 (emission threshold equal to 6 scfh)														
Oil and Natural Gas Production	13,632	165	23	(1,519)	25,210	90,685	952	13	net savings	4	net savings	2,249,221	320,071	(20,699,918)
Natural Gas Transmission and Storage	67	165	23	23	6	212	0.2	262	262	7	7	11,039	1,539	1,539

Minor discrepancies may be due to rounding.

a. The number of sources subject to NSPS for the natural gas processing and the natural gas transmission and storage segments represent the number of new devices expected per year reduced by 20 percent. This is consistent with the assumption that 80 percent of high bleed devices can be replaced with a low bleed device. It is assumed all new sources would be installed as a high bleed for these segments. For the natural gas processing segment the number of new sources represents the number of Instrument Air Systems (IAS) that is expected to be installed, with each IAS expected to power 15 control loops (or replace 15 pneumatic devices).
b. The capital cost for regulatory option 2 is equal to the incremental cost of a low bleed device versus a new high bleed device. The capital cost of the IAS is based on the small IAS as summarized in Table 5-10.
c. Nationwide emission reductions vary based on average expected emission rates of bleed devices typically used in each segment industry segment as summarized in Tables 5-2.

5.6 References

1 U.S. Environmental Protection Agency. Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004

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6.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and gas industry as prime movers are reciprocating and centrifugal compressors. This chapter discusses the air pollutant emissions from these compressors and provides emission estimates for reducing emission from these types of compressors. In addition, nationwide emissions estimates from new sources are estimated. Options for controlling pollutant emissions from these compressors are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for both reciprocating and centrifugal compressors.

6.1 Process Description

6.1.1 Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time,during operation of the compressor, the rings become worn and the packing system will need to be replaced to prevent excessive leaking from the compression cylinder.

6.1.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and absorbs some compressed natural gas which is released to the atmosphere during the seal oil recirculation process. Alternatively, dry seals can be used to replace the wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic groves and springs. The opposing forcescreate a thin gap of high pressure gas between the rings through which little gas can leak. The rings do not wear or need lubrication because they are not in contact with each other. Therefore, operation and maintenance costs are lower for dry seals in comparison to wet seals.

6.2 Emissions Data and Emission Factors

6.2.1 Summary of Major Studies and Emissions Factors

There are a few studies that have been conducted that provide leak estimates from reciprocating and centrifugal compressors. These studies are provided in Table 6-1, along with the type of information contained in the study.

6.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The methodology for estimating emission from reciprocating compressor rod packing was to use the methane emission factors referenced in the EPA/GRI study[1] and use the methane to pollutant ratios developed in the gas composition memorandum.[2] The emission factors in the EPA/GRI document were expressed in thousand standard cubic feet per cylinder (Mscf/cyl), and were multiplied by the average number of cylinder per reciprocating compressor at each oil and gas industry segment. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the methane emission factors is presented in Table 6-2. Once the methane emissions were calculated, ratios were used to estimate volatile organic compounds (VOC) and hazardous air pollutants (HAP). The specific ratios that were used for this analysis were 0.278 pounds VOC per pound of methane and 0.105 pounds HAP per pound of methane for the production and processing segments, and 0.0277 pounds VOC per pound of methane and 0.0008 pounds HAP per pound of methane for the transmission and storage segments. A summary of the reciprocating compressor emissions are presented in Table 6-3.

The compressor emission factors for wet seals and dry seals are based on data used in the GHG inventory. The wet seals methane emission factor was calculated based on a sampling of 48 wet seal centrifugal compressors. The dry seal methane emission factor was based on data collected by the

Table 6-1. Major Studies Reviewed for Consideration Of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Information	Emissions Information	Control Information
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008[1]	EPA	2010	Nationwide	X	
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Document[2]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry[3]	Gas Research Institute/EPA	1996	Nationwide	X	
Natural Gas STAR Program[4,5]	EPA	1993-2010	Nationwide	X	X

Table 6-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors

Oil and Gas Industry Segment	Reciprocating Compressors			Centrifugal Compressors	
	Methane Emission Factor (scf/hr-cylinder)	Average Number of Cylinders	Pressurized Factor (% of hour/year Compressor Pressurized)	Wet Seal Methane Emission Factor (scf/minute)	Dry Seals Methane Emission Factor (scf/minute)
Production (Well Pads)	0.271[a]	4	100%	N/A[f]	N/A[f]
Gathering & Boosting	25.9[b]	3.3	79.1%	N/A[f]	N/A[f]
Processing	57[c]	2.5	89.7%	47.7[g]	6[g]
Transmission	57[d]	3.3	79.1%	47.7[g]	6[g]
Storage	51[e]	4.5	67.5%	47.7[g]	6[g]

a. EPA/GRI. (1996). “Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks.” Table 4-8.
b. Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites.* (Draft): 2006.
c. EPA/GRI. (1996). Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks. Table 4-14.
d. EPA/GRI. (1996). “Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks.” Table 4-17.
e. EPA/GRI. (1996). “Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks.” Table 4-24.
f. The 1996 EPA/GRI Study Volume 11[3], does not report any centrifugal compressors in the production or gathering/boosting sectors, therefore no emission factor data were published for those two sectors.
g. U.S Environmental Protection Agency. Methodology for Estimating CH4 and CO2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks1990-2009. Washington, DC. April 2011. Annex 3. Page A-153.

Table 6-3.Baseline Emission Estimates for Reciprocating and Centrifugal Compressors

Industry Segment/ Compressor Type	Baseline Emission Estimates (tons/year)		
	Methane	**VOC**	**HAP**
Reciprocating Compressors			
Production (Well Pads)	0.198	0.0549	0.00207
Gathering & Boosting	12.3	3.42	0.129
Processing	23.3	6.48	0.244
Transmission	27.1	0.751	0.0223
Storage	28.2	0.782	0.0232
Centrifugal Compressors (Wet seals)			
Processing	228	20.5	0.736
Transmission	126	3.50	0.104
Storage	126	3.50	0.104
Centrifugal Compressors (Dry seals)			
Processing	28.6	2.58	0.0926
Transmission	15.9	0.440	0.0131
Storage	15.9	0.440	0.0131

Natural Gas STAR Program. The methane emissions were converted to VOC and HAP emissions using the same gas composition ratios that were used for reciprocating engines.[4] A summary of the emission factors are presented in Table 6-2 and the individual compressor emission are shown in Table 6-3 for each of the oil and gas industry segments.

6.3 Nationwide Emissions from New Sources

6.3.1 Overview of Approach

The number of new affected facilities in each of the oil and gas sectors was estimated using data from the U.S. Greenhouse Gas Inventory,[5,6] with some exceptions. This basis was used whenever the total number of existing facilities was explicitly estimated as part of the Inventory, so that the difference between two years can be calculated to represent the number of new facilities. The Inventory was not used to estimate the new number of reciprocating compressor facilities in gas production, since more recent information is available in the comments received to subpart W of the mandatory reporting rule. Similarly, the Inventory was not used to estimate the new number of reciprocating compressor facilities in gas gathering, since more recent information is available in comments received as comments to subpart W of the mandatory reporting rule. For both gas production and gas gathering, information received as comments to subpart W of the mandatory reporting rule was combined with additional EPA estimates and assumptions to develop the estimates for the number of new affected facilities.

Nationwide emission estimates for new sources were then determined by multiplying the number of new sources for each oil and gas segment by the expected emissions per compressor using the emission data in Table 6-3. A summary of the number of new reciprocating and centrifugal compressors for each of the oil and gas segments is presented in Table 6-4.

6.3.2 Activity Data for Reciprocating Compressors

6.3.2.1 Wellhead Reciprocating Compressors

The number of wellhead reciprocating compressors was estimated using data from industry comments on Subpart W of the Greenhouse Gas Mandatory Reporting Rule.[7] The 2010 U.S. GHG Inventory reciprocating compressor activity data was not considered in the analysis because it does not distinguish between wellhead and gathering and boosting compressors. Therefore, using data submitted to EPA during the subpart W comment period from nine basins supplied by the El Paso Corporation,[8] the

Table 6-4.Approximate Number of New Sources in the Oil and Gas Industry in 2008

<table>
<tr><th>Industry Segment</th><th>Number of New Reciprocating Compressors</th><th>Number of New Centrifugal Compressors</th></tr>
<tr><td>Wellheads</td><td>6,000</td><td>0</td></tr>
<tr><td>Gathering and Boosting</td><td>210</td><td>0</td></tr>
<tr><td>Processing</td><td>209</td><td>16</td></tr>
<tr><td>Transmission</td><td>20</td><td rowspan="2">14</td></tr>
<tr><td>Storage</td><td>4</td></tr>
</table>

average number of new wellhead compressors per new well was calculated using the 315 well head compressors provided in the El Paso comments and 3,606 wells estimated in the Final Subpart W onshore production threshold analysis. This produced an average of 0.087 compressors per wellhead. The average wellhead compressors per well was multiplied by the total well completions (oil and gas) determined from the HPDI® database[9] between 2007 and 2008, which came to 68,000 new well completions. Using this methodology, the estimated number of new reciprocating compressors at production pads was calculated to be 6,000 for 2008. A summary of the number of new reciprocating compressors located at well pads is presented in Table 6-4.

6.3.2.2 Gathering and Boosting Reciprocating Compressors

The number of gathering & boosting reciprocating compressors was also estimated using data from industry comments on Subpart W. DCP Midstream stated on page 3 of its 2010 Subpart W comments that it operates 48 natural gas processing plants and treaters and 700 gathering system compressor stations. Using this data, there were an average of 14.583 gathering and boosting compressor stations per processing plant. The number of new gathering and boosting compressors was determined by taking the average difference between the number of processing plants for each year in the 2010 U.S Inventory, which references the total processing plants in the Oil and Gas Journal. This was done for each year up to 2008. An average was taken of only the years with an increase in processing plants, up to 2008. The resulting average was multiplied by the 14.583 ratio of gathering and boosting compressor stations to processing plants and the 1.5 gathering and boosting compressors per station yielding 210 new source gathering and boosting compressor stations and is shown in Table 6-4.

6.3.2.3 Processing Reciprocating Compressors

The number of new processing reciprocating compressors at processing facilities was estimated by averaging the increase of reciprocating compressors at processing plants in the greenhouse gas inventory data for 2007, 2008, and 2009.[10,11] The estimated number of existing reciprocating compressors in the processing segment was 4,458, 4,781, and 4,876 for the years 2007, 2008, and 2009 respectively. This calculated to be 323 new reciprocating compressors between 2007 and 2008, and 95 new reciprocating compressors between 2008 and 2009. The average difference was calculated to be 209 reciprocating compressors and was used to estimate the number of new sources in Table 6-4.

6.3.2.4 Transmission and Storage Reciprocating Compressors

The number of new transmission and storage reciprocating compressors was estimated using the differences in the greenhouse gas inventory[12,13] data for 2007, 2008, and 2009 and calculating an average of those differences. The estimated number of existing reciprocating compressors at transmission stations was 7,158, 7,028, and 7,197 for the years 2007, 2008, and 2009 respectively. This calculated to be -130 new reciprocating compressors between 2007 and 2008, and 169 new reciprocating compressors between 2008and 2009. The average difference was calculated to be 20 reciprocating compressors and was used to estimate the number of new sources at transmission stations. The number of existing reciprocating compressors at storage stations was 1,144, 1,178, and 1,152 for the years 2007, 2008, and 2009 respectively. This calculated to be 34 new reciprocating compressors between 2007 and 2008, and -26 new reciprocating compressors between 2008and 2009. The average difference was calculated to be 4 reciprocating compressors and was used to estimate the number of new sources at storage stations in Table 6-4.

6.3.3 Activity Data for Centrifugal Compressors

The number of new centrifugal compressors in 2008 for the processing and transmission/storage segments was determined by taking the average difference between the centrifugal compressor activity data for each year in the 2008 U.S. Inventory . For example, the number of compressors in 1992 was subtracted from the number of compressors in 1993 to determine the number of new centrifugal compressors in 1993. This was done for each year up to 2008. An average was taken of only the years with an increase in centrifugal compressors, up to 2008, to determine the number of new centrifugal compressors in 2008. The result was 16 and 14 new centrifugal compressors in the processing and transmission segments respectively. A summary of the estimates for new centrifugal compressor is presented in Table 6-4.

6.3.4 Emission Estimates

Nationwide baseline emission estimates for new reciprocating and centrifugal compressors are summarized in Table 6-5 by industry segment.

Table 6-5.Nationwide Baseline Emissions for New Reciprocating and Centrifugal Compressors

Industry Segment/ Compressor Type	Nationwide baseline Emissions (tons/year)		
	Methane	**VOC**	**HAP**
Reciprocating Compressors			
Production (Well Pads)	1,186	330	12.4
Gathering & Boosting	2,587	719	27.1
Processing	4,871	1,354	51.0
Transmission	529	14.6	0.435
Storage	113	3.13	0.0929
Centrifugal Compressors			
Processing	3,640	329	11.8
Transmission/Storage	1,768	48.9	1.45

6.4 Control Techniques

6.4.1 Potential Control Techniques

The potential control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. This includesreplacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod.

The replacement of the rod packing is a maintenance task performed on reciprocating compressors to reduce the leakage of natural gas past the piston rod. Over time the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings reduces methane and VOC emissions. Therefore, this control technique was determined to be an appropriate optionfor reciprocating compressors.

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.[14] Rods wear "out-of-round" or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. This analysis assumes operators will choose, at their discretion, when to replace the rod and hence, does not consider this control technique to be a practical control option for reciprocating compressors. A summary of these techniques are presented in the following sections.

Potential control options to reduce emissions from centrifugal compressors include control techniques that limit the leaking of natural gas across the rotating shaft, or capture and destruction of the emissions using a flare. A summary of these techniques are presented in the following sections.

A control technique for limiting or reducing the emission from the rotating shaft of a centrifugal compressor is a mechanical dry seal system. This control technique uses rings to prevent the escape of natural gas across the rotating shaft. This control technique was determined to be a viable option for reducing emission from centrifugal compressors.

For centrifugal compressors equipped with wet seals, a flare was considered to be a reasonable option for reducing emissions from centrifugal compressors. Centrifugal compressors require seals around the rotating shaft to prevent natural gas from escaping where the shaft exits the compressor casing. "Beam" type compressors have two seals, one on each end of the compressor, while "over-hung" compressors have a seal on only the "inboard" (motor end) side. These seals use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. The seal also includes "O-ring" rubber seals, which prevent leakage around the stationary rings. The oil barrier allows some gas to escape from the seal, but considerably more gas is entrained and absorbed in the oil under the high pressures at the "inboard" (compressor side) seal oil/gas interface, thus contaminating the seal oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated back to the seal. As a control measure, the recovered gas would then be sent to a flare or other combustion device.

6.4.2 Reciprocating Compressor Rod Packing Replacement

6.4.2.1 Description

Reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the "nose gasket" around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed gas will escape. Periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod.

6.4.2.2 Effectiveness

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The potential emission reductions were calculated by comparing the average rod packing emissionswith the average emissions from newly installed and worn-in rod packing. Since the estimate for newly installed rod packing was intended for larger processing and transmission compressors, this analysis uses the estimate to calculate reductions from only gathering and boosting compressors and not wellhead compressor which are known to be smaller. The calculation for gathering and boosting reductions is shown in Equation 1.

$$R_{WP}^{G\&B} = \frac{Comp_{New}^{G\&B}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6} \qquad \textbf{Equation 1}$$

where,

$R_{WP}^{G\&B}$ = Potential methane emission reductions from gathering and boosting compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{G\&B}$ = Number of new gathering and boosting compressors;
$E_{G\&B}$ = Methane emission factor for gathering and boosting compressors inTable 6-2, in cubic feet per hour per cylinder;
E_{New}=Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[15] for this analysis;
C = Average number of cylinders for gathering and boosting compressors in Table 6-2;
O = Percent of time during the calendar year the average gathering and boosting compressor is in the operating and standby pressurized modes, 79.1%;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

For wellhead reciprocating compressors, this analysis calculates a percentage reduction using the transmission emission factor from the 1996 EPA/GRI report and the minimum emissions rate from a newly installed rod packing to determine methane emission reductions. The calculation for wellhead compressor reductions is shown in Equation 2 below.

$$R_{Well} = \frac{Comp_{New}^{Well}\left(E_{Well}\right) \times C \times O \times 8760}{10^6}\left(\frac{E_{Trans} - E_{New}}{E_{Trans}}\right) \qquad \textbf{Equation 2}$$

where,

R_{Well} = Potential methane emission reductions from wellhead compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{Well}$ = Number of new wellhead compressors;
E_{Well} = Methane emission factor for wellhead compressors from Table 6-2, cubic feet per hour per cylinder;
C = Average number of cylinders for wellhead compressors in Table 6-2;
O = Percent of time during the calendar year the average gathering and boosting compressor is in the operating and standby pressurized modes, 100%;

E_{Trans} = Methane emissions factor for transmission compressors from Table 6-2 in cubic feet per hour per cylinder;
E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[16] for this analysis;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

The emission reductions for the processing, transmission, and storage segments were calculated by multiplying the number of new reciprocating compressors in each segment by the difference between the average rod packing emission factors in Table 6-2 by the average emission factor from newly installed rod packing. This calculation, shown in the Equation 3 below, was performed for each of the natural gas processing, transmission, and storage/LNG sectors.

$$R_{PTS} = \frac{Comp_{New}^{PTS}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6}$$ ***Equation 3***

where,

R_{PTS} = Potential methane emission reductions from processing, transmission, or storage compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{PTS}$ = Number of new processing, transmission, or storage compressors;
$E_{G\&B}$ = Methane emission factor for processing, transmission, or storage compressors in Table 6-2, in cubic feet per hour per cylinder;
E_{New}=Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[17] for this analysis;
C = Average number of cylinders for processing, transmission, or storage compressors in Table 6-2;
O = Percent of time during the calendar year the average processing, transmission, or storage compressor is in the operating and standby pressurized modes, 89.7%, 79.1%, 67.5% respectively;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

A summary of the potential emission reductions for reciprocating rod packing replacement for each of the oil and gas segments is shown in Table 6-6. The emissions of VOC and HAP were calculated using the methane emission reductions calculated above the gas composition[18] for each of the segments. Reciprocating compressors in the processing sector were assumed to be used to compress production gas.

Table 6-6.Estimated Annual Reciprocating Compressor Emission Reductions from Replacing Rod Packing

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)			Nationwide Emission Reductions (tons/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Production (Well Pads)	6,000	0.158	0.0439	0.00165	947	263	9.91
Gathering & Boosting	210	6.84	1.90	0.0717	1,437	400	15.1
Processing	375	18.6	5.18	0.195	3,892	1,082	40.8
Transmission	199	21.7	0.600	0.0178	423	11.7	0.348
Storage	9	21.8	0.604	0.0179	87.3	2.42	0.0718

6.4.2.3 Cost Impacts

Costs for the replacement of reciprocating compressor rod packing were obtained from a Natural Gas Star Lessons Learned document[19] which estimated the cost to replace the packing rings to be $1,620 per cylinder. It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring becausethe rod packingplacement is based on number of hours that the compressor operates. The replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program. [20] The cost impacts arebased on the replacement of the rod packing 26,000 hours that the reciprocating compressor operates in the pressurized mode. The number of hours used for the cost impacts was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized for all of the new sources. This weighted hours, on average, per year the reciprocating compressor is pressurized was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. This calculates to an average of 3 years for production compressors, 3.8 years for gathering and boosting compressors, 3.3 years for processing compressors, 3.8 years for transmission compressors, and 4.4 years for storage compressors using the operating factors in Table 6-2. The calculated years were assumed to be the equipment life of the compressor rod packing and were used to calculate the capital recovery factor for each of the segments. Assuming an interest rate of 7 percent, the capital recovery factors were calculated to be 0.3848, 0.3122, 0.3490, 0.3122, and 0.2720 for the production, gathering and boosting, processing, transmission, and storage sectors, respectively. The capital costs were calculated using the average rod packing cost of $1,620 and the average number of cylinders per segment in Table 6-2. The annual costs were calculated using the capital cost and the capital recovery factors. A summary of the capital and annual costs for each of the oil and gas segments is shown in Table 6-7.

Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement was estimated using a natural gas price of $4.00 per Mcf.[21] This cost was used to calculate theannual cost with gas savings using the methane emission reductions in Table 6-6. The annual cost with savings is shown in Table 6-7 for each of the oil and gas segments. The cost effectiveness for the reciprocating rod packing replacement option is presented in Table 6-7. There is no gas savings cost benefits for transmission and storage facilities, because they do not own the natural gas that is

Table 6-7. Cost Effectiveness for Reciprocating Compressor Rod Packing Replacement

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor ($/compressor-year)		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		Without savings	With savings	Without savings	With savings	Without savings	With savings
Production	$6,480	$2,493	$2,457	$56,847	$56,013	$15,802	$15,570
Gathering & Boosting	$5,346	$1,669	$83	$877	$43	$244	$12
Processing	$4,050	$1,413	-$2,903	$273	-$561	$76	-$156
Transmission	$5,346	$1,669	N/A	$2,782	N/A	$77	N/A
Storage	$7,290	$2,276	N/A	$3,766	N/A	$104	N/A

compressed at their compressor stations.

6.4.2.4 Secondary Impacts

The reciprocating compressor rod packing replacement is an option that prevents the escape of natural gas from the piston rod. No wastes should be created, no wastewater generated, and no electricity maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring becausethe rod packing

6.4.3 Centrifugal Compressor Dry Seals

6.4.3.1 Description

Centrifugal compressor dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This gas is pumped between the rings by grooves in the rotating ring. The opposing force of high-pressure gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little gas can leak. While the compressor is operating, the rings are not in contact with each other, and therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.

Dry seals substantially reduce methane emissions. At the same time, they significantly reduce operating costs and enhance compressor efficiency. Economic and environmental benefits of dry seals include:

- Gas Leak Rates. During normal operation, dry seals leak at a rate of 6scfmmethane per compressor.[22] While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is re-circulated is usually vented to the atmosphere, bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.[23,24]
- Mechanically Simpler. Dry seal systems do not require additional oil circulation components and treatment facilities.

- Reduced Power Consumption. Because dry seals have no accessory oil circulation pumps and systems, they avoid "parasitic" equipment power losses. Wet seal systems require 50 to 100 kW per hour, while dry seal systems need about 5 kW of power per hour.
- Improved Reliability. The highest percentage of downtime for a compressor using wet seals is due to seal system problems. Dry seals have fewer ancillary components, which translates into higher overall reliability and less compressor downtime.
- Lower Maintenance. Dry seal systems have lower maintenance costs than wet seals because they do not have moving parts associated with oil circulation (e.g., pumps, control valves, relief valves, and the seal oil cost itself).
- Elimination of Oil Leakage from Wet Seals. Substituting dry seals for wet seals eliminates seal oil leakage into the pipeline, thus avoiding contamination of the gas and degradation of the pipeline.

Centrifugal compressors were found in the processing and transmission sectors based on information in the greenhouse gas inventory.[25] Therefore, it was assumed that new compressors would be located in these sectors only.

6.4.3.2 Effectiveness

The control effectiveness of the dry seals was calculated by subtracting the dry seal emissions from a centrifugal compressor equipped with wet seals. The centrifugal compressor emission factors in Table 6-2 were used in combination with an operating factor of 43.6 percent for processing centrifugal compressors and 24.2 percent for transmission centrifugal compressors. The operating factors are used to account for the percent of time in a year that a compressor is in the operating mode. The operating factors for the processing and transmission sectors are based on data in the EPA/GRI study.[26] The wet seals emission factor is an average of 48 different wet seal centrifugal compressors. The dry seal emission factor is based on information from the Natural Gas STAR Program.[27] A summary of the emission reduction from the replacement of wet seals with dry seals is shown in Table 6-8.

6.4.3.3 Cost Impacts

The price difference between a brand new dry seal and brand new wet seal centrifugal compressor is insignificant relative to the cost for the entire compressor. General Electric (GE) stated that a natural gas transmission pipeline centrifugal compressor with dry seals cost between $50,000 and $100,000 more than the same centrifugal compressor with wet seals. However, this price difference is only about 1 to 3

Table 6-8. Estimated Annual Centrifugal Compressor Emission Reductions from Replacing Wet Seals with Dry Seals

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (ton/compressor-year)			Nationwide Emission Reductions (ton/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Transmission/Storage	16	199	18.0	0.643	3,183	287	10.3
Storage	14	110	3.06	0.0908	1,546	42.8	1.27

percent of the total cost of the compressor. The price of a brand new natural gas transmission pipeline centrifugal compressor between 3,000 and 5,000 horsepower runs between $2 million to $5 million depending on the number of stages, desired pressure ratio, and gas throughput. The larger the compressor, the less significant the price difference is between dry seals and wet seals. This analysis assumes the additional capital cost for a dry seal compressor is $75,000. The annual cost was calculatedas the capital recovery of this capital cost assuming a 10-year equipment life and 7 percent interest which came to $10,678 per compressor. The Natural Gas STAR Program estimated that the operation and maintenance savings from the installation of dry seals is $88,300 in comparison to wet seals. Monetary savings associated with the amount of gas saved with the replacement of wet seals with dry seals for centrifugal compressors was estimated using a natural gas price of $4.00 per Mcf.[28] This cost was used to calculate the annual cost with gas savings using the methane emission reductions in Table 6-8. A summary of the capital and annual costs for dry seals is presented in Table 6-9. The methane and VOC cost effectiveness for the dry seal option is also shown in Table 6-9. There is no gas savings cost benefits for transmission and storage facilities, because it is assumed the owners of the compressor station may not own the natural gas that is compressed at the station.

6.4.3.4 Secondary Impacts

Dry seals for centrifugal compressors are an option that prevents the escape of natural gas across the rotating compressor shaft. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the installation of dry seals on centrifugal compressors.

6.4.4 Centrifugal Compressor Wet Seals with a Flare

6.4.4.1 Description

Another control option used to reduce pollutant emissions from centrifugal compressors equipped withwet seals is to route the emissions to a combustion device or capture the emissions and route them to afuel system. A wet seal system uses oil that is circulated under high pressure between three rings aroundthe compressor shaft, forming a barrier against the compressed gas. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. Compressed gas becomes absorbed and entrained in the fluid barrier and is removed using a heater, flash tank, or other degassing technique so that the oil can be recirculated back to the wet seal. The removed gas is either

Table 6-9. Cost Effectiveness for Centrifugal Compressor Dry Seals

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor ($/compressor-yr)		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		without savings	with O&M and gas savings	without savings	with O&M and gas savings	without savings	with O&M and gas savings
Processing	$75,000	$10,678	-$123,730	$595	-$6,892	$54	-$622
Transmission/Storage	$75,000	$10,678	-$77,622	$3,495	-$25,405	$97	-$703

combusted or released to the atmosphere. The control technique investigated in this section is the use of wet seals with the removed gas sent to an enclosed flare.

6.4.4.2 Effectiveness

Flares have been used in the oil and gas industry to combust gas streams that have VOC and HAP. A flare typically achieves 95 percent reduction of these compounds when operated according to the manufacturer instructions. For this analysis, it was assumed that the entrained gas from the seal oil that is removed in the degassing process would be directed to a flare that achieves 95 percent reduction of methane, VOC, and HAP. The wet seal emissions in Table 6-5 were used along with the control efficiency to calculate the emissions reductions from this option. A summary of the emission reductions is presented in Table 6-10.

6.4.4.3 Cost Impacts

The capital and annual cost of the enclosed flare was calculated using the methodology in the EPA Control Cost Manual.[29] The heat content of the gas stream was calculated using information from the gas composition memorandum.[30] A summary of the capital and annual costs for wet seals routed to a flare is presented in Table 6-11. The methane and VOC cost effectiveness for the wet seals routed to a flare option is also shown in Table 6-12. There is no cost saving estimated for this option because the recovered gas is combusted.

6.4.4.4 Secondary Impacts

There are secondary impacts with the option to use wet seals with a flare. The combustion of the recovered gas creates secondary emissions of hydrocarbons, nitrogen oxide (NO_X), carbon dioxide (CO_2), and carbon monoxide (CO) emissions. A summary of the estimated secondary emission are presented in Table 6-11. No other wastes should be created or wastewater generated.

6.5 Regulatory Options

The affected facility definition for a reciprocating compressor is defined as a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of thedriveshaft. A centrifugal compressor is defined as a piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers. Therefore these types of compressor would be

Table 6-10. Estimated Annual Centrifugal Compressor Emission Reductions from Wet Seals Routed to a Flare

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)			Nationwide Emission Reductions (tons/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Processing	16	216	19.5	0.699	3,283	296	10.6
Transmission/Storage	14	120	3.32	0.0986	1,596	44.2	1.31

Table 6-11. Secondary Impacts from Wet Seals Equipped with a Flare

Industry Segment	Secondary Impacts from Wet Seals Equipped with a Flare (tons/year)				
	Total Hydrocarbons	**Carbon Monoxide**	**Carbon Dioxide**	**Nitrogen Oxides**	**Particulate Matter**
Processing	0.0289	0.0205	7.33	0.00377	Negligible
Transmission/Storage	0.00960	0.00889	3.18	0.00163	Negligible

Table 6-12. Cost Effectiveness for Centrifugal Compressor Wet Seals Routed to a Flare

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor ($/compressor-year)		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		without savings	with gas savings	without savings	with gas savings	without savings	with gas savings
Processing	$67,918	$103,371	N/A	$5,299	N/A	$478	N/A
Transmission/Storage	$67,918	$103,371	N/A	$31,133	N/A	$862	N/A

subject to a New Performance Standard (NSPS) at the time of installation. The following Regulatory options were evaluated:

- Regulatory Option 1: Require replacement of the reciprocating compressor rod packing based on26,000 hours of operation while the compressor is pressurized.
- Regulatory Option 2: Require all centrifugal compressors to be equipped with dry seals.
- Regulatory Option 3: Require centrifugal compressors equipped with a wet seal to route the recovered gas emissions to a combustion device.

6.5.1 Evaluation of Regulatory Options

The first regulatory option for replacement of the reciprocating compressor rod packing based on the number of hours that the compressor operates in the pressurized mode was described in Section 6.4.1. The VOC cost effectiveness from $56,847 for reciprocating compressors located at production pads to $273 for reciprocating compressors located at processing plants. The VOC cost effectiveness for the gathering and boosting, transmission, and storage segments were $877, $2,782, and 3,766 respectively. Based on these cost effectiveness values, Regulatory Option 1 was accepted for the processing, gathering and boosting, transmission, and storage segments and rejected for the production segment.

The second regulatory option would require all centrifugal compressors to be equipped with dry seals. As presented in Section 6.4.2, dry seals are effective at reducing emissions from the rotating shaft of a centrifugal compressor. Dry seals also reduce operation and maintenance costs in comparison to wet seals. In addition, a vendor reported in 2003 that 90 percent of new compressors that were sold by the company were equipped with dry seals. Another vendor confirmed in 2010 that the rate at which new compressor sales have dry seals is still 90 percent; thus, it was assumed that from 2003 onward, 90 percent of new compressors are equipped with dry seals. The VOC cost effectiveness of dry seals was calculated to be $595 for centrifugal compressors located at processing plants, and $3,495 for centrifugal compressors located at transmission or storage facilities. Therefore, Regulatory Option 2 was accepted as a regulatory option for centrifugal compressors located at processing, transmission, or storage facilities.

The third regulatory option would allow the use of wet seals if the recovered gas emissions were routed to a flare. Centrifugal compressors with wet seals are commonly used in high pressure applications over 3,000 pounds per square inch (psi). None of the applications in the oil and gas industry operate at these pressures. Therefore, it does not appear that any facilities would be required to operate a centrifugal compressor with wet seals. The VOC control effectiveness for the processing and transmission/storage segments were $5,299 and $31,133 respectively. Therefore, Regulatory Option 3 was rejected due to the high VOC cost effectiveness.

6.5.2 Nationwide Impacts of Regulatory Options

Tables 6-13 and 6-14 summarize the impacts of the selected regulatory options by industry segment. Regulatory Option 1 is estimated to affect 210 reciprocating compressors at gathering and boosting stations, 209 reciprocating compressors at processing plants, 20 reciprocating compressors at transmission facilities, and 4 reciprocating compressors at underground storage facilities. A summary of the capital and annual costs and emission reductions for this option is presented in Table 6-13.

Regulatory Option 2 is expected to affect 16 centrifugal compressors in the processing segment and 14 centrifugal compressors in the transmission and storage segments. A summary of the capital and annual costs and emission reductions for this option is presented in Table 6-14.

Table 6-13. Nationwide Cost Impacts for Regulatory Option 1

Oil & Gas Segment	Number of New Sources Per Year	Nationwide Emission Reductions (tons/year)			Total Nationwide Costs		
		VOC	Methane	HAP	Capital Cost ($)	Annual Cost without savings ($/yr)	Annual Cost with savings ($/yr)
Gathering & Boosting	210	400	1,437	15.1	$1,122,660	$350,503	$17,337
Processing	209	1,082	3,892	40.8	$846,450	$295,397	-$606,763
Transmission	20	11.7	423	0.348	$104,247	$32,547	$32,547
Storage	4	2.42	87.3	0.0718	$29,160	$9,104	$9,104

Table 6-14. Nationwide Cost Impacts for Regulatory Option 2

Oil & Gas Segment	Number of New Sources Per Year	Nationwide Emission Reductions[1] (tons/year)			Total Nationwide Costs[a]		
		VOC	Methane	HAP	Capital Cost ($)	Annual Cost w/o Savings ($/year)	Annual Cost w/ Savings ($/year)
Production (Well Pads)	0	0	0	0	0	0	0
Gathering & Boosting	0	0	0	0	0	0	0
Processing	16	118	422	4.42	$100,196	$14,266	-$120,144
Transmission/Storage	14	3.24	117	0.0962	$50,098	$7,133	-$37,017

a. The nationwide emission reduction and nationwide costs are based on the emission reductions and costs for 2 centrifugal compressors with wet seals located a processing facility and 1 centrifugal compressor equipped with wet seal located at a transmission or storage facility.

6.6 References

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7.0 STORAGE VESSELS

Storage vessels, or storage tanks, are sources of air emissions in the oil and natural gas sector. This chapter provides a description of the types of storage vessels present in the oil and gas sector, and provides emission estimates for a typical storage vessel as well as nationwide emission estimates. Control techniques employed to reduce emissions from storage vessels are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter provides a discussion of considerations used in developing regulatory alternatives for storage vessels.

7.1 Process Description

Storage vessels in the oil and natural gas sector are used to hold a variety of liquids, including crude oil, condensates, produced water, etc. Underground crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons (as well as water) are removed through as series of high-pressure and low-pressure separators. Crude oil under high pressure conditions is passed through either a two phase separator (where the associated gas is removed and any oil and water remain together) or a three phase separator (where the associated gas is removed and the oil and water are also separated). At the separator, low pressure gas is physically separated from the high pressure oil. The remaining low pressure oil is then directedto a storage vessel where it is stored for a period of time before being shipped off-site. The remaining hydrocarbons in the oil are released from the oil as vapors in the storage vessels. Storage vessels are typically installed with similar or identical vessels in a group, referred to in the industry as a tank battery.

Emissions of the remaining hydrocarbons from storage vessels are a function of working, breathing (or standing), and flash losses. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage vesselfrom a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage stage. Temperature of the liquid may also influence the amount of flash emissions.

The volume of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the overall throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vesselwill affect the volume of flashed gases coming out of the oil.

The composition of the vapors from storage vessels varies, and the largest component is methane, but also includes ethane, butane, propane, and hazardous air pollutants (HAP) such as benzene, toluene, ethylbenzene, xylene (collectively referred to as BTEX), and n-hexane.

7.2 Emissions Data

7.2.1 Summary of Major Studies and Emissions

Given the potentially significant emissions from storage vessels, there have been numerous studies conducted to estimate these emissions. Many of these studies were consulted to evaluate the emissions and emission reduction options for emissions from storage vessels. Table 7-1 presents a summary of these studies, along with an indication of the type of information available in each study.

7.2.2 Representative Storage Vessel Emissions

Due to the variability in the sizes and throughputs, model tank batteries were developed to represent the ranges of sizes and population distribution of storage vessels located attank batteries throughout the sector. Model tank batteries were not intended to represent any single facility, but rather a range of facilities with similar characteristics that may be impacted by standards. Model tank batteries were developed for condensate tank batteries and crude oil tank batteries. Average VOC emissions were then developed and applied to the model tank batteries.

7.2.2.1 Model Condensate Tank Batteries

During the development of the national emissions standards for HAP (NESHAP) for oil and natural gas production facilities (40 CFR part 63, subpart HH), model plants were developed to represent condensate tank batteries across the industry.[1]For this current analysis, the most recent inventory data available was the 2008 U.S. Greenhouse Gas Emissions Inventory.[2,3] Therefore, 2008 was chosen to represent the base year for this impacts analysis.To estimate the current condensate battery population and distribution across the model plants, the number of tanks represented by the model plants was scaled

Table 7-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emission Figures	Control Information
VOC Emissions from Oil and Condensate Storage Tanks[4]	Texas Environmental Research Consortium	2009	Regional	X	X
Lessons Learned from Natural Gas STAR Partners:Installing Vapor Recovery Units on Crude Oil Storage Tanks[5]	EPA	2003	National		X
Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation – Final Report[6]	Texas Commission on Environmental Quality	2009	Regional	X	
Initial Economics Impact Analysis for Proposed State Implementation Plan Revisions to the Air Quality Control Commission's Regulation Number [7]	Colorado	2008	n/a		X
E&P TANKS[8]	American Petroleum Institute		National	X	
Inventory of U.S. Greenhouse Gas Emissions and Sinks[2,3]	EPA	2008 and 2009	National	X	

from 1992 (the year for which that the model plants were developed under the NESHAP) to 2008 for this analysis. Based on this approach, it was estimated that there were a total of 59,286 existing condensate tanks in 2008. Condensate throughput data from the U.S. Greenhouse Gas Emissions Inventory was used to scale up from 1992 the condensate tank populations for each model condensate tank battery under the assumption that an increase in condensate production would be accompanied by a proportional increase in number of condensate tanks. The inventory data indicate that condensate production increased from a level of 106 million barrels per year (MMbbl/yr) in 1992to 124 MMbbl/yr in 2008.This increase in condensate production was then distributed across the model condensate tank batteriesin the same proportion as was done for the NESHAP. The model condensate tank batteries are presented in Table 7-2.

7.2.2.2 Model Crude Oil Tank Batteries

According to the Natural Gas STAR program,[5] there were 573,000 crude oil storage tanksin 2003. According to the U.S. Greenhouse Gas Emissions Inventory, crude oil production decreased from 1,464 MMbbl/yr in 2003 to 1,326 MMbbl/yr (a decrease of approximately 9.4 percent) in 2008. Therefore, it was assumed that the number of crude oil tanks in 2008 were approximately 90.6 percent of the number of tanks identified in 2003. Therefore, for this analysis it was assumed that there were 519,161 crude oil storage tanks in 2008. During the development of the NESHAP, model crude oil tank batteries were not developed and a crude oil tank population was not estimated. Therefore, it was assumed that the percentage distribution of crude oil storage tanks across the four model crude oil tank battery classifications was the same as for condensate tank batteries.Table 7-3 presents the model crude oil tank batteries.

7.2.2.3 VOC Emissions from Condensate and Crude Oil Storage Vessels

Once the modelcondensate and crude oil tank battery distributionswere developed, VOC emissions from a representative storage vessel were estimated. Emissions from storage vessels vary considerably depending on many factors, including, but not limited to, throughput, API gravity, Reid vapor pressure, separator pressure, etc. The American Petroleum Institute (API) has developed a software program called E&P TANKS which contains a dataset of more than 100 storage vessels from across the country.[8] A summary of the information contained in the dataset, as well as the output from the E&P TANKS program, is presented in Appendix A of this document. According to industry representatives, this

Table 7-2. Model Condensate Tank Batteries

	Model Condensate Tank Battery			
Parameter	**E**	**F**	**G**	**H**
Condensate throughput (bbl/day)[a]	15	100	1,000	5,000
Condensate throughput (bbl/yr) [a]	5,475	36,500	365,000	1,825,000
Number of fixed-roof product storage vessels [a]				
210 barrel capacity	4	2		
500 barrel capacity		2	2	
1,000 barrel capacity			2	4
Estimated tank battery population (1992)[a]	12,000	500	100	70
Estimated tank battery population (2008) [b]	14,038	585	117	82
Total number of storage vessels (2008) [b]	56,151	2,340	468	328
Percent of number of storage vessels in model condensate tank battery	94.7%	3.95%	0.789%	0.552%
Percent of throughput per model condensate tank battery[a]	26%	7%	15%	51%
Total tank battery condensate throughput (MMbbl/yr)[c]	32.8	9.11	18.2	63.8
Condensate throughput per model condensate battery (bbl/day)	6.41	42.7	427	2,135
Condensate throughput per storage vessel (bbl/day)	1.60	10.7	106.8	534

Minor discrepancies may be due to rounding.

a. Developed for NESHAP (Reference 1).
b. Population of tank batteries for 2008 determined based on condensate throughput increase from 106 MMbbl/yr in 1992 to 124 MMbbl/yr in 2008 (References2,3).
c. 2008 condensate production rate of 124 MMbbl/yr distributed across model tank batteries using same relative ratio as developed for NESHAP (Reference 1).

Table 7-3. Model Crude Oil Tank Batteries

	Model Crude Oil Tank Battery			
Parameter	**E**	**F**	**G**	**H**
Percent of number of condensate storage vessels in model size range[a]	94.7%	3.95%	0.789%	0.552%
Number of storage vessels[b]	491,707	20,488	4,098	2,868
Percent of throughput across condensate tank batteries	26%	7%	15%	51%
Crude oil throughput per model plant category (MMbbl/yr)	351	97.5	195	683
Crude oil throughput per storage vessel (bbl/day)	1.96	13.0	130	652

Minor discrepancies may be due to rounding.

a. Same relative percent of storage vessel population developed for model condensate tank batteries.Refer to Table 7-2.

b. Calculated by applying the percent of number of condensate storage vessels in model size range to total number of crude oil storage vessels (519,161 crude oil storage vessels estimated for 2008) (Reference 5).

c. Same relative percent of throughput developed for model condensate tank batteries.Refer to Table 7-2.

dataset in combination with the output of the E&P TANKS program is representative of the various VOC emissions from storage vessels across the country.[9]

The more than 100 storage vesselsprovided with the E&P TANKS program, which had varying characteristics, were modeled with a constant throughput (based on the assumption that emissions would increase in proportion with throughput) and the relationship of these different characteristics and emissionswas studied. While many of the characteristics impacted emissions, a correlation was found to exist between API gravity and emissions. The average API gravity for all storage vessels in the data set was approximately 40 degrees. Therefore, we selected an API gravity of 40 degrees as a parameter to distinguish between lower emitting storage vessels and higher emitting storage vessels.[i] While the liquid type was not specified for the storage vessels modeled in the study, it was assumed that condensate storage vessels would have higher emissions than crude oil storage vessels. Therefore, based on this study using the E&P TANKS program, it was assumed for this analysis that liquids with API gravity equal to or greater than 40 degrees should be classified as condensate and liquids with API gravity less than 40 degrees should be classified as crude oil.

The VOC emissions from all storage vessels in the analysis are presented in Appendix A.Table 7-4 presents a summary of the average VOC emissions from all storage vessels as well as the average VOC emissions from the storage vessels identified as being condensate storage vessels and those identified as being crude oil storage vessels. As shown in Table 7-4, the storage vessels were modeled at a constant throughput of 500 bpd.[ii]An average emission factor was developed for each type of liquid. The average of condensate storage vessel VOC emissions was modeled to be 1,046 tons/year or 11.5 lb VOC/bbl and the average of crude oil storage vessel VOC emissions was modeled to be 107 tons/year or 1.18 lb VOC/bbl. These emission factors were then applied to each of the two sets of model storage vessels in Tables 7-2 and 7-4 to develop the VOC emissions from the model tank batteries. These are presented in Table 7-5.

[i] The range of VOC emissions within the 95 percent confidence interval for storage vessels with an API gravity greater than 40 degrees was from 667 tons/year to 1425 tons/year. The range for API gravity less than 40 degrees was 76 tons/year to 138.
[ii] This throughput was originally chosen for this analysis to be equal to the 500 bbl/day throughput cutoff in subpart HH. While not part of the analysis described in this document, one of the original objectives of the E&P TANKS analysis was to assess the level of emissions associated with a storage vessel with a throughput below this cutoff. Due to the assumption that emissions increase and decrease in proportion with throughput, it was decided that using a constant throughput of 500 bbl/day would still provide the information necessary to determine VOC emissions from model condensate and crude oil storage vessels for this document.

Table 7-4. Summary of Data from E&P TANKS Modeling

Parameter[a]		Average of Dataset	Average of Storage Vessels with API Gravity > 40 degrees	Average of Storage Vessels with API Gravity ≤ 40 degrees
Throughput Rate (bbl)		500	500	500
API Gravity		40.6	52.8	30.6
VOC	Emissions (tons/year)	531	1046	107
	Emission factor (lb/bbl)	5.8	11.5	1.18

a. Information from analysis of E&P Tanks dataset, refer to Appendix A.

Table 7-5. Model Storage Vessel VOC Emissions

Parameter	Model Tank Battery			
	E	F	G	H
Model Condensate Tank Batteries				
Condensate throughput per storage vessel (bbl/day)	1.60	10.7	107	534
VOC Emissions (tons/year)[b]	3.35	22.3	223	1117
Model Crude Oil Tank Batteries				
Crude Oil throughput per storage vessel (bbl/day)[c]	2.0	13	130	652
VOC Emissions (tons/year)[d]	0.4	2.80	28	140

a. Condensate throughput per storage vessel from table 7-2.

b. Calculated using the VOC emission factor for condensate storage vessels of 11.5 lb VOC/bbl condensate.

c. Crude oil throughput per storage vessel from table 7-3.

d. Calculated using the VOC emission factor for crude oil storage vessels of 1.18 lb VOC/bbl crude oil.

7.3 Nationwide Baseline Emissions from New or Modified Sources

7.3.1 Overview of Approach

The first step in this analysis is to estimate nationwide emissions in absence of a federal rulemaking, referred to as the nationwide baseline emissions estimate. In order to develop the baseline emissions estimate, the number of new storage vessels expected in a typical year was calculated and then multiplied by the expected uncontrolled emissions per storage vessels presented in Table 7-5. In addition, to ensure no emission reduction credit was attributed to new sources that would already be required to be controlled under State regulations, it was necessary to account for the number of storage vessels already subject to State regulations as detailed below.

7.3.2 Number of New Storage Vessels Expected to be Constructed or Reconstructed

The number of new storage vessels expected to be constructed was determined for the year 2015 (the year of analysis for the regulatory impacts). To do this, it was assumed that the number of new or modified storage vessels would increase in proportion with increases in production. The Energy Information Administration (EIA), published crude oil production rates up to the year 2011.[10]Therefore, using the forecast function in Microsoft Excel® , crude oil production was predicted for the year 2015.[iii] From 2009 to 2015,[iv] the expected growth of crude oil production was projected to be 8.25 percent (from 5.36 bpd to 5.80 bpd). Applying this expected growth to the number of existing storage vessels results in an estimate of 4,890 new or modified condensate storage vessels and 42,811 new or modified crude oil storage vessels. The number of new or modified condensate and crude oil storage vessels expected to be constructed or reconstructed is presented in Table 7-6.

7.3.3 Level of Controlled Sources in Absence of Federal Regulation

As stated previously, to determine the impact of a regulation, it was first necessary to determine the current level of emissions from the sources being evaluated, or baseline emissions. To more accurately estimate baseline emissions for this analysis, and to ensure no emission reduction credit was attributed

[iii] The crude oil production values published by the EIA include leased condensate. Therefore, the increase in crude oil production was assumed to be valid for both crude oil and condensate tanks for the purpose of this analysis.
[iv] For the purposes of estimating growth, the crude oil production rate in the year 2008 was considered an outlier for production and therefore was not used in this analysis.

Table 7-6. Nationwide Baseline Emissions for Storage Vessels

	Model Tank Battery				
	E	**F**	**G**	**H**	**Total**
Model Condensate Tank Batteries					
Total number of storage vessels (2008)	56,151	2,340	468	328	59,286
Total projected number of new or modified storage vessels (2015) [a]	4,630	193	39	27	4,889
Number of uncontrolled storage vessels in absence of federal regulation[b]	1,688	70	14	10	1,782
Uncontrolled VOC Emissions from storage vessel at model tank battery[c]	3.35	22.3	223	1,117	1,366
Total Nationwide Uncontrolled VOC Emissions	5,657	1,572	3,143	11,001	21,373
Model Crude Oil Tank Batteries					
Total number of storage vessels (2008)	491,707	20,488	4,098	2,868	519,161
Total projected number of new or modified storage vessels (2015) [a]	40,548	1,689	338	237	42,812
Number of uncontrolled storage vessels in absence of federal regulation[b]	14,782	616	123	86	15,607
Uncontrolled VOC Emissions from storage vessel at model tank battery[c]	0.4	2.80	28	140	171
Total Nationwide Uncontrolled VOC Emissions	6,200	1,722	3,444	12,055	23,421

Minor discrepancies may be due to rounding

a. Calculated by applying the expected 8.25 percent industry growth to the number of storage vessels in 2008.
b. Calculated by applying the estimated 36 percent of storage vessels that are uncontrolled in the absence of a Federal Regulation to the total projected number of new or modified storage vessels in 2015.
c. VOC Emissions from individual storage vessel at model tank battery, see Table 7-5.

for sources already being controlled, it was necessary to determine which storage vessels were already being controlled. To do this, the 2005 National Emissions Inventory (NEI) was used.Storage vessels in the oil and natural gas sector were identified under the review of the maximum achievable control technology (MACT) standards.[11] There were 5,412 storage vessels identified in the NEI, and of these, 1,973 (or 36 percent) were identified as being uncontrolled. Therefore, this percent of storage vessels that would not require controls under State regulations was applied to the number of new or modified storage vessels results in an estimate of 1,782 new or modified condensate storage vessels and 15,607 new or modified crude oil storage vessels.These are also presented in Table 7-6.

7.3.4 Nationwide Emission Estimates for New or Modified Storage Vessels

Nationwide emissions estimates are presented in Table 7-6 for condensate storage vessels and crude oil storage vessels. Model storage vessel emissions were multiplied by the number of expected new or modified storage vessels that would be uncontrolled in the absence of a federal regulation.As shown in Table 7-6, the baseline nationwide emissions are estimated to be 21,373 tons/year for condensate storage vessels and 23,421 tons/year for crude oil storage vessels.

7.4 Control Techniques

7.4.1 Potential Control Techniques

In analyzing controls for storage vessels, we reviewed control techniques identified in the Natural Gas STAR program and state regulations. We identified two ways of controlling storage vessel emissions, both of which can reduce VOC emissions by 95 percent. One option would be to install a vapor recovery unit (VRU) and recover all the vapors from the storage vessels. The other option would be to route the emissions from the storage vessels to a combustor. These control technologies are described below along with their effectiveness as they apply to storage vessels in the oil and gas sector, cost impacts associated with the installation and operation of these control technologies, and any secondary impacts associated with their use.

7.4.2 Vapor Recovery Units

7.4.2.1 Description

Typically, with a VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator, or suction scrubber, to collect any condensed liquids, which are typically recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system. Vapors are then either sent to the pipeline for sale or used as on-site fuel.[5]

7.4.2.2 Effectiveness

Vapor recovery units have been shown to reduce VOC emissions from storage vessels by approximately 95 percent.***Error! Bookmark not defined.***A VRU recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold.If natural gas is recovered, it can be sold as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU also does not have secondary air impacts, as described below. However, a VRU cannot be used in all instances. Some conditions that affect the feasibility of VRU are: availability of electrical service sufficient to power the compressor; fluctuations in vapor loading caused by surges in throughput and flash emissions from the storage vessel; potential for drawing air into condensate storage vessels causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

7.4.2.3 Cost Impacts

Cost data for a VRU was obtained from an Initial Economic Impact Analysis (EIA) prepared for proposed state-only revisions to a Colorado regulation.Cost information contained in the EIA was assumed to be giving in 2007 dollars.[7]Therefore costs were escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4).[12] According to the EIA, the purchased equipment cost of a VRU was estimated to be $85,423 (escalated to 2008 dollars from $75,000 in 2007 dollars). Total capital investment, including freight and design and installation was estimated to be $98,186. These cost data are presented in Table 7-7. Total annual costs were estimated to be $18,983/year.

7.4.2.4 Secondary Impacts

A VRU is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., nitrogen oxides, particulate matter, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the use of a VRU.

Table 7-7. Total Capital Investment and Total Annual Cost of a Vapor Recovery Unit

Cost Item[a]	Capital Costs ($)	Non-Recurring, One-time Costs ($)	Total Capital Investment ($)[b]	O&M Costs ($)	Savings due to Fuel Sales ($/yr)	Annualized Total Cost ($/yr)[c]
VRU	$78,000					
Freight and Design		$1,500				
VRU Installation		$10,154				
Maintenance				$8,553		
Recovered natural gas					($1,063)	
Subtotal Costs (2007)	$78,000	$11,654		$8,553	($1,063)	
Subtotal Costs (2008)[d]	$85,423	$12,763	$98,186	$9,367	($1,164)	
Annualized costs (using 7% interest, 15 year equipment life)	$9,379	$1,401		n/a	n/a	$18,983

Minor discrepancies may be due to rounding

a. Assume cost data provided is for the year 2007. Reference 7.
b. Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.
c. Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.
d. Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 12.

7.4.3 Combustors

7.4.3.1 Description and Effectiveness

Combustors are also used to control emissions from condensate and crude oil storage vessels.The type of combustor used is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.[13] Combustors are used to control VOC in many industrial settings, since thecombustorcan normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[14] For this analysis, the types of combustors installed for the oil and gas sector are assumed to achieve 95 percent efficiency.[7] Combustors do not have the same operational issues as VRUs, however secondary impacts are associated with combustors as discussed below.

7.4.3.2 Cost Impacts

Cost data for a combustor was also obtained from the Initial EIA prepared for proposed state-only revisions to the Colorado regulation.[7] As performed for the VRU, costs were escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4).[12] According to the EIA, the purchased equipment cost of a combustor, including an auto igniter and surveillance system was estimated to be $23,699 (escalated to 2008 dollars from $21,640 in 2007 dollars). Total capital investment, including freight and design and installation was estimated to be $32,301. These cost data are presented in Table 7-8. Total annual costs were estimated to be $8,909/year.

7.4.3.3 Secondary Impacts

Combustion and partial combustion of many pollutants also create secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide, and smoke/particulates. Reliable data for emission factors from combustors on condensate and crude oil storage vessels are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing 80 percent propylene and 20 percent propane.[13] These emissions factors, however, are thebest indication for secondary pollutants from combustors currently available. The secondary emissionsper storage vessel are provided in Table 7-9.

Table 7-8. Total Capital Investment and Total Annual Cost of a Combustor

Cost Item[a]	Capital Costs ($)	Non-Recurring, One-time Costs ($)	Total Capital Investment ($)[b]	O&M Costs ($)	Annualized Total Cost ($/yr) [c]
Combustor	$16,540				
Freight and Design		$1,500			
Combustor Installation		$6,354			
Auto Igniter	$1,500				
Surveillance System[d]	$3,600				
Pilot Fuel				$1,897	
Maintenance				$2,000	
Data Management				$1,000	
Subtotal Costs (2007)	$21,640	$7,854		$4,897	
Subtotal Costs (2008) [e]	$23,699	$8,601	$32,301	$5,363	
Annualized costs (using 7% interest, 15 year equipment life)	$2,602	$944		n/a	$8,909

Minor discrepancies may be due to rounding

a. Assume cost data provided is for the year 2007. Reference 7.
b. Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.
c. Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.
d. Surveillance system identifies when pilot is not lit and attempt to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.
e. Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 12.

Table 7-9. Secondary Impacts for Combustors used to Control Condensate and Crude Oil Storage Vessels

Pollutant	Emission Factor	Units	Emissions per Storage Vessel (tons/year)[a]
THC	0.14	lb/MMBtu	0.0061
CO	0.37	lb/MMBtu	0.0160
CO_2	60	Kg/MMBtu[b]	5.62
NO_X	0.068	lb/MMBtu	2.95E-03
PM	40	µg/l (used lightly smoking flares due to criteria that flares should not have visible emissions i.e. should not smoke)	5.51E-05

a. Converted using average saturated gross heating value of the storage vessel vapor (1,968 Btu/scf) and an average vapor flow rate of 44.07 Mcf per storage vessel. See Appendix A.
b. CO_2 emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

7.5 Regulatory Options and Nationwide Impacts of Regulatory Options

7.5.1 Consideration of Regulatory Options for Condensate and Crude Oil Storage Vessels

The VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (i.e., its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility and temperature of the liquid.Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric pressure. Therefore, in order to determine the most cost effective means of controlling the storage vessels, a cutoff was evaluated to limit the applicability of the standards to these storage vessels. Rather than require a cutoff in terms of emissions that would require a facility to conduct an emissions test on their storage vessel, a throughput cutoff was evaluated. It was assumed that facilities would have storage vessel throughput data readily available. Therefore, we evaluated the costs of controlling storage vessels with varying throughputs to determine which throughput level would provide the most cost effective control option.

The standard would require an emission reduction of 95 percent, which, as discussed above, could be achieved with a VRU or a combustor. A combustoris an option for tank batteries because of the operational issues associated with a VRU as discussed above.However the use of a VRU is preferable to a combustorbecause a combustordestroys, rather than recycles, valuable resources and there are secondary impacts associated with the use of a combustor. Therefore, the cost impacts associated a VRU installed for the control of storage vessels were evaluated.

To conduct this evaluation, emission factor data from a study prepared for the Texas Environmental Research Consortium[15] was used to represent emissions from the different throughputs being evaluated. For condensate storage vessels, an emission factor of 33.3 lb VOC/bbl was used and for crude oil storage vessels, an emission factor of 1.6 lb VOC/bbl was used.Using the throughput for each control option, an equivalent emissions limit was determined.Table 7-10 presents the following regulatory options considered for condensate storage vessels:

- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 0.5 bbl/day (equivalent emissions of 3.0 tons/year);

Table 7-10. Options for Throughput Cutoffs for Condensate Storage Vessels

Regulatory Option	Throughput Cutoff (bbl/day)	Equivalent Emissions Cutoff (tons/year) [a]	Emission Reduction (tons/year) [b]	Annual Costs for VRU ($/yr) [c]	Cost Effectiveness ($/ton)	Number of impacted units[d]
1	0.5	3.0	2.89	$18,983	$6,576	1782
2	1	6.1	5.77	$18,983	$3,288	94
3	2	12.2	11.55	$18,983	$1,644	94
4	5	30.4	28.87	$18,983	$658	24

Minor discrepancies may be due to rounding

a. Emissions calculated using emission factor of 33.3 lb VOC/bbl condensate and the throughput associated with each option.
b. Calculated using 95 percent reduction
c. Refer to Table 7-7 for VRU Annual Costs.
d. Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-6) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its throughput and emissions were greater than the cutoffs for the option.

- Regulatory Option 2: Control condensate storage vessels with a throughput greater than 1 bbl/day (equivalent emissions of 6 tons/year);

- Regulatory Option 3: Control condensate storage vessels with a throughput greater than 2 bbl/day (equivalent emissions of 12 tons/year);

- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 5.0 bbl/day (equivalent emissions of 30 tons/year);

As shown in Table 7-10, Regulatory Option 1 is not cost effective for condensate storage vessels with a throughput of 0.5 bbl/day.Therefore Regulatory Option 1 is rejected.Since the cost effectiveness associated with Regulatory Option 2 is acceptable ($3,288/ton), this option was selected. As shown in Table 7-5, Model Condensate Storage Vessel Categories F, G, and H have throughputs greater than 1 bbl/day and emissions greater than 6 tons/year. Therefore, for the purposes of determining impacts, the populations of new and modified condensate storage vessels associated with categories F, G, and H are assumed to be required to reduce their emissions by 95 percent, a total of 94 new or modified condensate storage vessels.

A similar evaluation was performed for crude oil vessels and is presented in Table 7-11 for the following regulatory options:

- Regulatory Option 1: Control crude oil storage vessels with a throughput greater than 1 bbl/day (equivalent emissions of 0.3 tons/year);

- Regulatory Option 2: Control condensate storage vessels with a throughput greater than 5 bbl/day (equivalent emissions of 1.5 tons/year);

- Regulatory Option 3: Control condensate storage vessels with a throughput greater than 20 bbl/day (equivalent emissions of 6 tons/year);

- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 50 bbl/day (equivalent emissions of 15 tons/year);

As shown in Table 7-11, Regulatory Options 1 and 2 are not cost effective crude oil storage vessels with a throughput of 1 and 5 bbl/day, respectively. Therefore Regulatory Options 1 and 2 are rejected.Since the cost effectiveness associated with Regulatory Option 3 is acceptable ($3,422/ton), this option was selected. As shown in Table 7-5, Model Crude Oil Storage Vessel CategoriesG and H have throughputs greater than 20 bbl/day and emissions greater than 6 tons/year. Therefore, for the purposes of determining impacts, the populations of new and modified crude oil storage vessels associated with categories G

Table 7-11. Options for Throughput Cutoffs for Crude Oil Storage Vessels

Regulatory Option	Throughput Cutoff (bbl/day)	Equivalent Emissions Cutoff (tons/year) [a]	Emission Reduction (tons/year) [b]	Annual Costs for VRU ($/yr) [c]	Cost Effectiveness ($/ton)	Number of impacted units[d]
1	1	0.3	0.28	$18,983	$68,432	15607
2	5	1.5	1.4	$18,983	$13,686	825
3	20	5.8	5.55	$18,983	$3,422	209
4	50	14.6	13.87	$18,983	$1,369	209

Minor discrepancies may be due to rounding

a. Emissions calculated using emission factor of 1.6 lb VOC/bbl condensate and the throughput associated with each option.
b. Calculated using 95 percent reduction
c. Refer to Table 7-7 for VRU Annual Costs.
d. Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-6) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its throughput and emissions were greater than the cutoffs for the option.

and H are assumed to be required to reduce their emissions by 95 percent, a total of 209 new or modified condensate storage vessels.

7.5.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Option 2 for condensate storage vessels and Regulatory Option 3 for crude oil storage vessels which were selected as viable options for setting standards for storage vessels.In addition, combined impacts for a typical storage vessel are presented.

7.5.3 Primary Environmental Impacts of Regulatory Options

Regulatory Option2 (condensate storage vessels) and 3 (crude oil storage vessels) were selected as options for setting standards for storage vessels as follows:

- Regulatory Option 2 (Condensate Storage Vessels): Reduce emissions from condensate storage vessels with an average throughput greater than 1 bbl/day.

- Regulatory Option 3 (Crude Oil Storage Vessels): Reduce emissions from crude oil storage vessels with an average throughput greater than 20 bbl/day.

The number of storage vessels that would be subject to the regulatory options listed above are presented in Tables7-10 and 7-11. It was estimated that there would be 94 new or modified condensate storage vessels not otherwise subject to State regulationsand impacted by Regulatory Option 2 (condensate storage vessels).As shown in Table 7-11, 209 new or modified crude oil storage vessels not otherwise subject to State regulations would be impacted by Regulatory Option 3 (crude oil storage tanks).

Table 7-12 presents the nationwide emission reduction estimates for each regulatory option. Emissions reductions were estimated by applying 95 percent control efficiency to the VOC emissions presented in Table 7-6 for each storage vessel in the model condensate and crude oil tank batteries and multiplying by the number of impacted storage vessels. For Regulatory Option 2 (condensate storage vessels), the total nationwide VOC emission reduction was estimated to be 15,061 tons/year and 14,710 tons/year for Regulatory Option 3 (crude oil storage vessels).

Table 7-12. Nationwide Impacts of Regulatory Options

Model Tank Battery	Number of Sources subject to Regulatory Option[a]	VOC Emissions for a Typical Storage Vessel (tons/year)	Capital Cost forTypical Storage Vessel[b] ($)	Annual Cost for a Typical Storage Vessel[b] ($/yr)		Nationwide Emission Reductions (tons/year)[c]		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
				without savings	with savings	VOC	Methane[d]	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 2: Condensate Storage Vessels														
F	70	22.3	65,243	14,528	13,946	1,483	325	685	658	3129	3004	4.57	1.02	0.98
G	14	223	65,243	14,528	13,946	2,966	649	68	66	313	301	0.913	0.203	0.195
H	10	1117	65,243	14,528	13,946	10,612	2,322	14	13	62.6	60.1	0.652	0.145	0.139
Total for Regulatory Option 2						**15,061**	**3,296**					**6.14**	**1.37**	**1.31**
Regulatory Option 3: Crude Oil Storage Vessels														
G	123	28	65,243	14,528	13,946	3,272	716	546	524	2496	2396	8.02	1.79	1.71
H	86	140	65,243	14,528	13,946	11,438	2,503	109	104	499	479	5.61	1.25	1.20
Total for Regulatory Option 3						**14,710**	**3,219**					**13.6**	**3.04**	**2.91**
Combined Impacts[e]														
Typical Storage Vessel	**304**	**103**	**65,243**	**14,528**	**13,946**	**29,746**	**6,490**	**149**	**143**	**680**	**652**	**19.8**	**4.41**	**4.24**

Minor discrepancies may be due to rounding

a. Number of storage vessels in each model tank battery (refer to Table 7-6) determined to be subject to the regulatory option as outlined in Table 7-10.

b. It was assumed for the purposes of estimating nationwide impacts that 50 percent of facilities would install a combustor and 50 percent a VRU.This accounts for the operational difficulties of using a VRU. Capital and Annual Costs determined using the average of costs presented in Tables 7-7 and 7-8.

c. Nationwide emission reductions calculated by applying a 95 percent emissions reduction to the VOC emissions for a typical storage vessel multiplied by the number of sources subject to the regulatory option.

d. Methane Reductions calculated by applying the average Methane to VOC factor from the E&P Tanks Study (see Appendix A).Methane:VOC = 0.219

e. For purposes of evaluating NSPS impact, impacts were determined for an average storage vessel by calculating total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels to obtain the average VOC emissions per storage vessel.

7.5.4 Cost Impacts

Cost impacts of the individual control techniques (VRU and combustors) were presented in Section 7.4. For both regulatory options, it was assumed that 50 percent of facilities would install a combustor and 50 percent a VRU. This accounts for the operational difficulties of using a VRU. Therefore, the average capital cost of control for each storage vessel was estimated to be $65,243 (the average of the total capital investment for a VRU of $98,186 and $32,301 for a combustor from Tables 7-7 and 7-8, respectively). Similarly, the average annual cost for a typical storage vessel was estimated to be $14,528/yr (average of the total annual cost for a VRU of $20,147/yr and $8,909/yr for a combustor from Tables 7-7 and 7-8, respectively) without including any cost savings due to fuel sales and $13,946/yr (average of the total annual cost for a VRU of $18,983/yr and $8,909/yr for a combustorfrom Tables 7-7 and 7-8, respectively) including cost savings.

Nationwide capital and annual costs were calculated by applying the number of storage vessels subject to the regulatory option. As shown in Table 7-12, the nationwide capital cost of Regulatory Option 2 (condensate storage vessels) was estimated to be $6.14 million and for RegulatoryOption 3 (crude oil storage vessels) nationwide capital cost was estimated to be $13.6 million.Total annual costs without fuel savings were estimated to be $1.37 million/yr for Regulatory Option 2 (condensate storage vessels) and $3.04 million/yr for Regulatory Option 3 (crude oil storage vessels). Total annual costs with fuel savings were estimated to be $1.31 million/yr for Regulatory Option 2 (condensate storage vessels) and $2.91 million/yr for Regulatory Option 3 (crude oil storage vessels).

For purposes of evaluating the impact of a federal standard, impacts were determined for an average storage vessel by calculating the total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels (304) to obtain the average VOC emissions per storage vessel (103 tons/year).Therefore, the nationwide annual costs were estimated to be $4.41 million/yr. A total nationwide VOC emission reduction of 29,746 tons/year results in a cost effectiveness of $149/ton.

7.5.5 Nationwide Secondary Emission Impacts

Regulatory Options 2 (condensate storage vessels) and 3 (crude oil storage vessels) allow for the use of a combustor; therefore the estimated nationwide secondary impacts are a result of combusting 50 percent of all storage vessel emissions. The secondary impacts for controlling a single storage vessel using a combustor are presented in Table 7-9. Nationwide secondary impacts are calculated by

Table 7-13. Nationwide Secondary Combined Impacts for Storage Vessels

Pollutant	Emissions per Storage Vessel (tons/year) [a]	Nationwide Emissions (tons/year)[b]
THC	0.0061	0.927
CO	0.0160	2.43
CO_2	5.62	854
NO_X	2.95E-03	0.448
PM	5.51E-05	0.0084

a. Emissions per storage vessel presented in Table 7-9.
b. Nationwide emissions calculated by assuming that 50 percent of the 304 impacted storage vessels would install a combustor.

multiplying 50 percent of the estimated number of impacted storage vessels (152) by the secondary emissions and are presented in Table 7-13.

7.6 References

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8.0 EQUIPMENT LEAKS

Leaks from components in the oil and natural gas sector are a source of pollutant emissions. This chapter explains the causes for these leaks, and provides emission estimates for "model" facilities in the various segments of the oil and gas sector. In addition, nationwide equipment leak emission estimates from new sources are estimated. Programs that are designed to reduce equipment leak emissions are explained, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for equipment leaks.

8.1 Equipment Leak Description

There are several potential sources of equipment leak emissions throughout the oil and natural gas sector. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. The following sub-sections describe potential equipment leak sources and the magnitude of the volatile emissions from typical facilities in the oil and gas industry.

Due to the large number of valves, pumps, and other components within oil and natural gas production, processing, and/or transmission facilities, total equipment leak VOC emissions from these components can be significant. Tank batteries or production pads are generally small facilities as compared with other oil and gas operations, and are generally characterized by a small number of components. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components.

8.2. Equipment leak Emission Data and Emissions Factors

8.2.1 Summary of Major Studies and Emission Factors

Emissions data from equipment leaks have been collected from chemical manufacturing and petroleum production to develop control strategies for reducing HAP and VOC emissions from these sources.[1,2,3] In the evaluation of the emissions and emission reduction options for equipment leaks, many of these studies were consulted. Table 8-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

8.2.2 Model Plants

Facilities in the oil and gas sector can consist of a variety of combinations of process equipment and components. This is particularly true in the production segment of the industry, where “surface sites” can vary from sites where only a wellhead and associated piping is located to sites where a substantial amount of separation, treatment, and compression occurs. In order to conduct analyses to be used in evaluating potential options to reduce emissions from leaking equipment, a model plant approach was used. The following sections discuss the creation of these model plants.

Information related to equipment counts was obtained from a natural gas industry report. This document provided average equipment counts for gas production, gas processing, natural gas transmission and distribution. These average counts were used to develop model plants for wellheads, well pads, and gathering line and boosting stations in the production segment of the industry, for a natural gas processing plant, and for a compression/transmission station in the natural gas transmission segment. These equipment counts are consistent with those contained in EPA’s analysis to estimate methane emissions conducted in support of the Greenhouse Gas Mandatory Reporting Rule (subpart W), which was published in the *Federal Register* on November 30, 2010 (75 FR 74458), These model plants are discussed in the following sections.

8.2.2.1 Oil and Natural Gas Production

Oil and natural gas production varies from site-to site. Many production sites may include only a wellhead that is extracting oil or natural gas from the ground. Other production sites consist of wellheads attached to a well pad. A well pad is a site where the production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) associated with these operations. A well pad can serve one well on a pad or several wells on a pad. A wellhead site consisting of only the wellhead and affiliated piping is not considered to be a well pad. The number of wells feeding into a well pad can vary from one to as many as 7 wells. Therefore, the number of components with potential for equipment leaks can vary depending on the number of wells feeding into the production pad and the amount of processing equipment located at the site.

Table 8-1. Major Studies Reviewed for Consideration or Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor (s)	Emissions Data	Control Options
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Documents	EPA	2010	Nationwide	X	X
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008[4]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry[567]	Gas Research Institute / EPA	1996	Nationwide	X	X
Methane Emissions from the US Petroleum Industry (Draft) [8]	EPA	1996	Nationwide	X	
Methane Emissions from the US Petroleum Industry [9]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [10]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories [11]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[12]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements [13]	Environmental Defense Fund	2009	Regional	X	X
Emissions from oil and Natural Gas Production Facilities [14]	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data[15]	U.S. Energy Information Administration	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations [16]	EPA	1999		X	X
Protocol for Equipment Leak Emission Estimates[17]	EPA	1995	Nationwide	X	X

In addition to wellheads and well pads, model plants were developed for gathering lines and boosting stations. The gathering lines and boosting stations are sites that collect oil and gas from well pads and direct them to the gas processing plants. These stations have similar equipment to well pads; however they are not directly connected to the wellheads.

The EPA/GRI report provided the average number of equipment located at a well pad and the average number of components for each of these pieces of equipment.[4]The type of production equipment located at a well pad include: gas wellheads, separators, meters/piping, gathering compressors, heaters, and dehydrators. The types of components that are associated with this equipment include: valves, connectors, open-ended lines, and pressure relief valves. Four model plants were developed for well pads and are presented in Table 8-2. These model plants were developed starting with one, three, five and seven wellheads, and adding the average numberof other pieces of equipment per wellhead. Gathering compressors are not included at well pads and were included in the equipment for gathering lines and boosting stations.

Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S and the Western U.S. for the EPA/GRI document. A summary of the component counts for oil and gas production well pads is presented in Table 8-3.

Gathering line and boosting station model plants were developed using the average equipment counts for oil and gas production. The average equipment count was assigned Model Plant 2 and Model Plants 1 and 3 were assumed to be equally distributed on either side of the average equipment count. Therefore, Model Plant 1 can be assumed to be a small gathering and boosting station, and Model Plant 3 can be assumed to be a large gathering and boosting station. A summary of the model plant production equipment counts for gathering lines and boosting stations is provided in Table 8-4.

Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S and the Western U.S. from the EPA/GRIdocument. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressors seals are addressed in a Chapter 6 of this document. A summary of the component counts for oil and gas gathering line and boosting stations are presented in Table 8-5.

Table 8-2.Average Equipment Count for Oil and Gas Production Well Pad Model Plants

Equipment	Model Plant 1	Model Plant 2	Model Plant 3
Gas Wellheads	1	5	48
Separators	---	4	40
Meter/Piping	---	2	24
In-Line Heaters	---	2	26
Dehydrators	---	2	19

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and Table 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-3.Average Component Count for Oil and Gas Production Well Pad Model Plants

Component	Model Plant 1	Model Plant 2	Model Plant 3	Model Plant 4
Valve	9	122	235	348
Connectors	37	450	863	1,276
Open-Ended Line	1	15	29	43
Pressure Relief Valve	0	5	10	15

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-4.Average Equipment Count for Oil and Gas Production Gathering Line and Boosting Station Model Plants

Equipment	Model Plant 1	Model Plant 2	Model Plant 3
Separators	7	11	15
Meter/Piping	4	7	10
Gathering Compressors	3	5	7
In-Line Heaters	4	7	10
Dehydrators	3	5	7

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and Table 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-5. Average Component Count for Oil and Gas Production Gathering Line and Boosting Station Model Plants

Component	Model Plant 1	Model Plant 2	Model Plant 3
Valve	547	906	1,265
Connectors	1,723	2,864	4,005
Open-Ended Line	51	83	115
Pressure Relief Valve	29	48	67

DataSource: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8:Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

8.2.2.2 Oil and Natural Gas Processing

Natural gas processing involves the removal of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The types of process equipment used to separate the liquids are separators, glycol dehydrators, and amine treaters. In addition, centrifugal and/or reciprocating compressors are used to pressurize and move the gas from the processing facility to the transmission stations.

New Source Performance Standards (NSPS) have already been promulgated for equipment leaks at new natural gas processing plants (40 CFR Part 60, subpart KKK), and were assumed to be the baseline emissions for this analysis. Only one model plant was developed for the processing sector. A summary of the model plant production components counts for an oil and gas processing facility is provided in Table 8-6.

8.2.2.3 Natural Gas Transmission/Storage

Natural gas transmission/storage stations are facilities that use compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. This source category also does not include emissions from gathering lines and boosting stations. Component counts were obtained from the EPA/GRI report and are presented in Table 8-7.

8.3 Nationwide Emissions from New Sources

8.3.1 Overview of Approach

Nationwide emissions were calculated by using the model plant approach for estimating emissions. Baseline model plant emissions for the natural gas production, processing, and transmission sectors were calculated using the component counts and the component gas service emission factors.[5] Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors for the production and processing sectors that were used to estimate the new source emissions are presented in Table 8-8. Emission factors for the transmission sector are presented in

Table 8-6.Average Component Count for Oil and Gas Processing Model Plant

Component	Gas Plant (non-compressor components)
Valve	1,392
Connectors	4,392
Open-Ended Line	134
Pressure Relief Valve	29

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-13, June 1996. (EPA-600/R-96-080h)

Table 8-7.Average Component Count for a Gas TransmissionFacility

Component	Processing Plant Component Count
Valve	704
Connection	3,068
Open-Ended Line	55
Pressure Relief Valve	14

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-16, June 1996. (EPA-600/R-96-080h)

Table 8-8 Oil and Gas Production and Processing Operations Average Emissions Factors

Component Type	Component Service	Emission Factor (kg/hr/source)
Valves	Gas	4.5E-03
Connectors	Gas	2.0E-04
Open-Ended Line	Gas	2.0E-03
Pressure Relief Valve	Gas	8.8E-03

Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

Table 8-9. Emissions for VOC, hazardous air pollutants (HAP), and methane were calculated using TOC weight fractions.[6] A summary of the baseline emissions for each of the sectors are presented in Table 8-10.

8.3.2 Activity Data

Data from oil and gas technical documents and inventories were used to estimate the number of new sources for each of the oil and gas sectors. Information from the Energy Information Administration (EIA) was used to estimate the number of new wells, well pads, and gathering and boosting stations. The number of processing plants and transmission/storage facilities was estimated using data from the Oil and Gas Journal, and the EPA Greenhouse Gas Inventory. A summary of the steps used to estimate the new sources for each of the oil and gas sectors is presented in the following sections.

8.3.2.1 Well Pads

The EIA provided a forecast of the number of new conventional and unconventional gas wells for the Year 2015 for both exploratory and developmental wells. The EIA projected 19,097 conventional and unconventional gas wells in 2015. The number of wells was converted to number of well pads by dividing the total number of wells by the average number of wells serving a well pad which is estimated to be 5. Therefore, the number of new well pads was estimated to be 3,820. The facilities were divided into the model plants assuming a normal distribution of facilities around the average model plant (Model Plant 2).

8.3.2.2 Gathering and Boosting

The number of new gathering and boosting stations was estimated using the current inventory of gathering compressors listed in the EPA Greenhouse Gas Inventory. The total number of gathering compressors was listed as 32,233 in the inventory. The GRI/EPA document does not include a separate list of compressor counts for gathering and boosting stations, but it does list the average number of compressors in the gas production section. It was assumed that this average of 4.5 compressors for gas production facilities is applicable to gathering and boosting stations. Therefore, using the inventory of 32,233 compressors and the average number of 4.5 compressors per facility, we estimated the number of gathering and boosting stations to be 7,163. To estimate the number of new gathering and boosting stations, we used the same increase of 3.84 percent used to estimate well pads to estimate the number of new gathering and boosting stations. This provided an estimate of 275 new gathering and boosting

Table 8-9 Oil and Gas Transmission/Storage Average Emissions Factors

Component Type	Component Service	Emission Factor (kg/hr/source)
Valves	Gas	5.5E-03
Connectors	Gas	9.3E-04
Open-Ended Line	Gas	7.1E-02
Pressure Relief Valve	Gas	3.98E-02

Data Source:EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-17, June 1996. (EPA-600/R-96-080h)

Table 8-10. Baseline Emissions for the Oil and Gas Production, Processing, and Transmission/Storage Model Plants

Oil and Gas Sector	Model Plant	TOC Emissions (Tons/yr)	Methane Emissions (Tons/yr)	VOC Emissions (Tons/yr)	HAP Emissions (Tons/yr)
Well Pads	1	0.482	0.335	0.0930	0.00351
	2	13.3	9.24	2.56	0.0967
	3	139	96.5	26.8	1.01
Gathering & Boosting	1	30.5	21.2	5.90	0.222
	2	50.6	35.2	9.76	0.368
	3	70.6	49.1	13.6	0.514
Processing	1	74.0	51.4	14.3	0.539
Transmission/Storage	1	108.1	98.1	2.71	0.0806

stations that would be affected sources under the proposed NSPS. The new gathering and boosting stations were assumed to be normally distributed around the average model plant (Model Plant 2).

8.3.2.3 Processing Facilities

The number of new processing facilities was estimated using gas processing data from the Oil and Gas Journal. The Oil and Gas Journal Construction Survey currently shows 6,303 million cubic feet of gas per day (MMcf/day) additional gas processing capacity in various stages of development. The OGJ Gas Processing Survey shows that there is 26.9 trillion cubic feet per year (tcf/year) in existing capacity, with a current throughput of 16.6 tcf/year or 62 percent utilization rate. If the utilization rate remains constant, the new construction would add approximately 1.4 tcf/year to the processing system. This would be an increase of 8.5 percent to the processing sector. The recent energy outlook published by the EIApredicts a 1.03 tcf/year increase in natural gas processing from 21.07 to22.104 tcf/year. This would be an annual increase of 5 percent over the next five years.

The EPA Greenhouse Gas Inventory estimates the number of existing processing facilities to be 577 plants operating in the U.S. Based on the projections provided in Oil and Gas Journal and EIA, it was assumed that the processing sector would increase by 5 percent annually. Therefore the number of new sources was estimated to be 29 new processing facilities in the U.S.

8.3.2.4 Transmission/Storage Facilities

The number of new transmission and storage facilities was estimated using the annual growth rate of 5 percent used for the processing sector and the estimated number of existing transmission and storage facilities in the EPA Greenhouse Inventory. The inventory estimates 1,748 transmission stations and 400 storage facilities for a total of 2,148. Therefore, the number of new transmission/storage facilities was estimated to be 107.

8.3.3 Emission Estimates

Nationwide emission estimates for the new sources for well pads, gathering and boosting, processing, and transmission/storage are summarized in Table 8-11. For well pads and gathering and boosting stations, the numbers of new facilities were assumed to be normally distributed across the range of model plants.

Table 8-11. Nationwide Baseline Emissions for New Sources

Oil and Gas Sector	Model Plant	Number of New Facilities	TOC Emissions (tons/yr)	Methane Emissions (tons/yr)	VOC Emissions (tons/yr)	HAP Emissions (tons/yr)
Well Pads	1	605	292	203	56.3	2.12
	2	2,610	34,687	24,116	6,682	252
	3	605	84,035	58,389	16,214	612
	Total	3,820	119,014	82,708	22,952	866
Gathering & Boosting	1	44	1,312	912	254	9.55
	2	187	9,513	6,618	1,835	69.2
	3	44	3,106	2,160	598	22.6
	Total	275	13,931	9,690	2,687	101
Processing	1	29	2,146	1,490	415	15.6
Transmission/Storage	1	107	11,567	10,497	290	8.62

8.4 Control Techniques

8.4.1 Potential Control Techniques

EPA has determined that leaking equipment, such as valves, pumps, and connectors, are a significant source of VOC and HAP emissions from oil and gas facilities. The following section describes the techniques used to reduce emissions from these sources.

The most effective control technique for equipment leaks is the implementation of a leak detection and repair program (LDAR). Emissions reductions from implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators, decrease exposure of hazardous chemicals to the surrounding community, reduce emissions fees, and help facilities avoid enforcement actions. The elements of an effective LDAR program include:

- Identifying Components;
- Leak Definition;
- Monitoring Components;
- Repairing Components; and
- Recordkeeping.

The primary source of equipment leak emissions from oil and gas facilities are from valves and connectors, because these are the most prevalent components and can number in the thousands. The major cause of emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., leak definition) for the applicable regulation. Leak definitions vary by regulation, component type, service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring interval. Most NSPS regulations have a leak definition of 10,000 ppm, while many NESHAP regulations use a 500-ppm or 1,000-ppm leak definition. In addition, some regulations define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting or clouding from or around components), sound (such as hissing), and smell.

For many NSPS and NESHAP regulations with leak detection provisions, the primary method for monitoring to detect leaking components is EPA Reference Method 21 (40 CFR Part 60, Appendix A). Method 21 is a procedure used to detect VOC leaks from process equipment using toxic vapor analyzer (TVA) or organic vapor analyzer (OVA). In addition, other monitoring tools such as; infrared camera, soap solution, acoustic leak detection, and electronic screening device, can be used to monitor process components.

In optical gas imaging, a live video image is produced by illuminating the view area with laser light in the infrared frequency range. In this range, hydrocarbons absorb the infrared light and are revealed as a dark image or cloud on the camera. The passive infrared cameras scan an area to produce images of equipment leaks from a number of sources. Active infrared cameras point or aim an infrared beam at a potential source to indicate the presence of equipment leaks. The optical imaging camera is easy to use and very efficient in monitoring many components in a short amount of time. However, the optical imaging camera cannot quantify the amount or concentration of equipment leak. To quantify the leak, the user would need to measure the concentration of the leak using a TVA or OVA. In addition, the optical imaging camera has a high upfront capital cost of purchasing the camera.

Acoustic leak detectors measure the decibel readings of high frequency vibrations from the noise of leaking fluids from equipment leaks using a stethoscope-type device. The decibel reading, along with the type of fluid, density, system pressure, and component type can be correlated into leak rate by using algorithms developed by the instrument manufacturer. The acoustic detector does not decrease the monitoring time because components are measured separately, like the OVA or TVA monitoring. The accuracy of the measurements using the acoustic detector can also be questioned due to the number of variables used to determine the equipment leak emissions.

Monitoring intervals vary according to the applicable regulation, but are typically weekly, monthly, quarterly, and yearly. For connectors, the monitoring interval can be every 1, 2, 4, or 8 years. The monitoring interval depends on the component type and periodic leak rate for the component type. Also, many LDAR requirements specify weekly visual inspections of pumps, agitators, and compressors for indications of liquids leaking from the seals. For each component that is found to be leaking, the first attempt at repair is to be made no later than five calendar days after each leak is detected. First attempts at repair include, but are not limited to, the following best practices, where practicable and appropriate:

- Tightening of bonnet bolts;

- Replacement of bonnet bolts;
- Tightening of packing gland nuts; and
- Injection of lubricant into lubricated packing.

Once the component is repaired; it should be monitored daily over the next several days to ensure the leak has been successfully repaired. Another method that can be used to repair component is to replace the leaking component with "leakless" or other technologies.

The LDAR recordkeeping requirement for each regulated process requires that a list of all ID numbers be maintained for all equipment subject to an equipment leak regulation. A list of components that are designated as "unsafe to monitor" should also be maintained with an explanation/review of conditions for the designation. Detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams should also be maintained with the results of performance testing and leak detection monitoring, which may include leak monitoring results per the leak frequency, monitoring leakless equipment, and non-periodic event monitoring.

Other factors that can improve the efficiency of an LDAR program that are not addressed by the standards include training programs for equipment monitoring personnel and tracking systems that address the cost efficiency of alternative equipment (e.g., competing brands of valves in a specific application).

The first LDAR option is the implementation of a subpart VVa LDAR program. This program is similar to the VV monitoring, but finds more leaks due to the lower leak definition, thereby achieving better emission reductions. The VVa LDAR program requires the annual monitoring of connectors using an OVA or TVA (10,000 ppm leak definition), monthly monitoring of valves (500 ppm leak definition) and requires open-ended lines and pressure relief devices to operate with no detectable emissions (500 ppm leak definition). The monitoring of each of the equipment types were also analyzed as a possible option for reducing equipment leak emissions. The second option involves using the monitoring requirements in subpart VVa for each type of equipment which include: valves; connectors; pressure relief devices; and open-ended lines for each of the oil and gas sectors.

The thirdoption that was investigated was the implementation of a LDAR program using an optical gas imaging system. This option is currently available as an alternative work practice (40 CFR Part 60, subpart A) for monitoring emissions from equipment leaks in subpart VVa. The alternative work practice requires monthly monitoring of all components using the optical gas imaging system and an annual monitoring of all components using a Method 21 monitoring device. The Method 21 monitoring allows the facility to quantify emissions from equipment leaks, since the optical gas imaging system can only provide the magnitude of the equipment leaks.

A fourth option that was investigated is a modification of the 40 CFR Part 60, subpart Aalternative work practice. The alternative work practice was modified by removing the required annual monitoring using a Method 21 instrument. This option only requires the monthly monitoring of components using the optical gas imaging system.

8.4.2 Subpart VVa LDAR Program

8.4.2.1 Description

The subpart VVa LDAR requires the monitoring of pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors. These components are monitored with an OVA or TVA to determine if a component is leaking and measure the concentration of the organics if the component is leaking. Connectors, valves, and pressure relief devices have a leak definition of 500 parts per million by volume (ppmv). Valves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves have no monitoring requirements, but are required to operate without any detectable emissions. Compressors are not included in this LDAR option and are regulated separately.

8.4.2.2 Effectiveness

The control effectiveness of the LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks. A summary of the chemical manufacturing and petroleum refinery control effectiveness for each of the components is shown in Table 8-12. As shown in the table the control effectiveness for all of the components varies from 45 to 96 percent and is dependent on the frequency of monitoring and the leak definition. Descriptions of the frequency of monitoring and leak definition are described further below.

> <u>Monitoring Frequency:</u> The monitoring frequency is the number of times each component is checked for leaks. For an example, quarterly monitoring requires that each component be checked for leaks 4 times per year, and annual monitoring requires that each component be checked for leaks once per year. As shown in Table 8-12, monthly monitoring provides higher control effectiveness than quarterly

Table 8-12. Control Effectiveness for an LDAR program at a Chemical Process Unit and a Petroleum Refinery

Equipment Type and Service	Control Effectiveness (% Reduction)		
	Monthly Monitoring 10,000 ppmv Leak Definition	Quarterly Monitoring 10,000 ppmv Leak Definition	500 ppm Leak Definition[a]
Chemical Process Unit			
Valves – Gas Service[b]	87	67	92
Valves – Light Liquid Service[c]	84	61	88
Pumps – Light Liquid Service[c]	69	45	75
Connectors – All Services	---	---	93
Petroleum Refinery			
Valves – Gas Service[b]	88	70	96
Valves – Light Liquid Service[c]	76	61	95
Pumps – Light Liquid Service[c]	68	45	88
Connectors – All Services	---	---	81

Source: Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Nov 1995.

a. Control effectiveness attributable to the HON-negotiated equipment leak regulation (40 CFR 63, Subpart H) is estimated based on equipment-specific leak definitions and performance levels. However, pumps subject to the HON at existing process units have a 1,000 to 5,000 ppm leak definition, depending on the type of process.
b. Gas (vapor) service means the material in contact with the equipment component is in a gaseous state at the process operating conditions.
c. Light liquid service means the material in contact with the equipment component is in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure above 0.3 kilopascals (kPa) at 20°C is greater than or equal to 20% by weight.

monitoring. This is because leaking components are found and repaired more quickly, which lowers the amount of emissions that are leaked to the atmosphere.

> Leak Definition: The leak definition describes the local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound. Decreasing the leak definition concentration generally increases the number of leaks found during a monitoring period, which generally increases the number of leaks that are repaired.

The control effectiveness for the well pad, gathering and boosting stations, processing facilities, and transmissions and storage facilities were calculated using the LDAR control effectiveness and leak fraction equations for oil and gas production operation units in the EPA equipment leaks protocol document. The leak fraction equation uses the average leak rate (e.g., the component emission factor) and leak definition to calculate the leak fraction.[7] This leak fraction is used in a steady state set of equations to determine the final leak rate after implementing a LDAR program.[8] The initial leak rate and the final leak rate after implementing a LDAR program were then used to calculate the control effectiveness of the program. The control effectiveness for implementing a subpart VVa LDAR program was calculated to be 93.6 perccent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.2.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Subpart VVa monitoring frequency and leak definition were used for processing plants since they are already required to do subpart VV requirements. Connectors were assumed to be monitored over a 4-year period after initial annual compliance monitoring.
- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Subsequent monitoring costs are $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

It was assumed that a single Method 21 monitoring device could be used at multiple locations for production pads, gathering and boosting stations, and transmission and storage facilities. To calculate the shared cost of the Method 21 device, the time required to monitor a single facility was estimated. For production pads and gathering and boosting stations, it was assumed that it takes approximately 1 minute to monitor a single component, and approximately 451 components would have to be monitored at an average facility in a month. This calculates to be 451 minutes or 7.5 hours per day. Assuming 20 working days in a typical month, a single Method 21 device could monitor 20 facilities. Therefore, the capital cost of the Method 21 device ($6,500) was divided by 20 to get a shared capital cost of $325 per facility. It was assumed for processing facilities that the full cost of the Method 21 monitoring device would apply to each individual plant. The transmission and storage segment Method 21 device cost was estimated using assuming the same 1 minute per component monitoring time. The average number of components that would need to be monitored in a month was estimated to be 1,440, which calculates to be 24 hours of monitoring time or 3 days. Assuming the same 20 day work month, the total number of facilities that could be monitored by a single Method 21 device is 7. Therefore, the shared cost of the Method 21 monitoring device was calculated to be $929 per site.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectors are provided in Table 8-13. In addition to the full subpart VVa LDAR monitoring, a component by component LDAR analysis was performed for each of the oil and gas sectors using the component count for an average size facility. This Model Plant 2 for well pads, Model Plant 2 for gathering and boosting stations, and Model Plant 1 for processing plants and transmission and storage facilities.

Table 8-13. Summary of the Model Plant Cost Effectiveness for the Subpart VVa Option

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	0.0876	0.00330	0.315	$15,418	$23,423	$23,350	$267,386	$7,088,667	$74,253
2	2.43	0.0915	8.73	$69,179	$37,711	$35,687	$15,549	$412,226	$4,318
3	25.3	0.956	91.3	$584,763	$175,753	$154,595	$6,934	$183,835	$1,926
Gathering and Boosting Stations									
1	5.58	0.210	20.1	$148,885	$57,575	$52,921	$10,327	$273,769	$2,868
2	9.23	0.348	33.2	$255,344	$84,966	$77,259	$9,203	$243,987	$2,556
3	12.9	0.486	46.4	$321,203	$105,350	$94,591	$8,174	$216,692	$2,270
Processing Plants									
1	13.5	0.508	48.5	$7,522	$45,160	$33,915	$3,352	$88,870	$931
Transmission/Storage Facilities									
1	2.62	0.0780	94.9	$94,482	$51,875	N/A	$19,769	$665,155	$546

Note: Transmission and storage facilities do not own the natural gas; therefore they do not receive any cost benefits from reducing the amount of natural gas as the result of equipment leaks.

The component costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Subsequent monitoring costs are $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.
- Administrative costs and initial planning and training costs are were included for the component option and are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost for purchasing a TVA or OVA monitoring system was estimated to be $6,500.

The component control effectiveness for the subpart VVa component option were 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices. These were the same control effectiveness's that were used for the subpart VVa facility option. The control effectiveness for the modified subpart VVa option with less frequent monitoring was estimated assuming the control effectiveness follows a hyperbolic curve or a 1/x relationship with the monitoring frequency. Using this assumption the component cost effectiveness's were determined to be 87.2 percent for valves, 81.0 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices. The assumption is believed to provide a conservative estimate of the control efficiency based on less frequent monitoring. A summary of the capital and annual costs and the cost effectiveness for each of the components for each of the oil and gas sectors are provided in Tables 8-14, 8-15, 8-16, and 8-17.

8.4.2.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

Table 8-14. Summary of Component Cost Effectiveness for Well Pads for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	235	12	1.84	0.0696	6.64	$11,175	$27,786	$15,063	$399,331	$4,183
Connectors	863	1/0.25[a]	0.308	0.0116	1.11	$7,830	$22,915	$74,283	$1,969,328	$20,628
PRD	10	0	0.164	0.00619	0.591	$48,800	$29,609	$180,537	$4,786,215	$50,135
OEL	29	0	0.108	0.00408	0.389	$9,458	$22,915	$211,992	$5,620,108	$58,870
Modified Subpart VVa– Less Frequent Monitoring										
Valves	235	1	1.31	0.0496	4.73	$11,175	$23,436	$17,828	$472,640	$4,951
Connectors	863	1/0.125[b]	0.261	0.00983	0.938	$7,830	$22,740	$87,277	$2,313,795	$24,237
PRD	5	0	0.164	0.00619	0.591	$48,800	$29,609	$180,537	$4,786,215	$50,135
OEL	29	0	0.108	0.00408	0.389	$9,458	$22,915	$211,992	$5,620,108	$58,870

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

Table 8-15. Summary of Component Cost Effectiveness for Gathering and Boosting Stations for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	906	12	7.11	0.268	25.6	$24,524	$43,234	$6,079	$161,162	$1,688
Connectors	2,864	1/0.25[a]	1.02	0.0386	3.69	$10,914	$24,164	$23,603	$625,752	$6,555
PRD	48	0	0.787	0.0297	2.83	$195,140	$57,091	$72,523	$1,922,648	$20,139
OEL	83	0	0.309	0.0117	1.11	$14,966	$23,917	$77,310	$2,049,557	$21,469
Modified Subpart VVa – Less Frequent Monitoring										
Valves	906	1	5.07	0.191	18.2	$24,524	$24,461	$5,221	$138,417	$1,450
Connectors	2,864	1/0.125[b]	0.865	0.0326	3.11	$10,914	$23,584	$27,274	$723,067	$7,574
PRD	48	0	0.787	0.0297	2.83	$195,140	$57,091	$72,523	$1,922,648	$20,139
OEL	83	0	0.309	0.0117	1.11	$14,966	$23,917	$77,310	$2,049,557	$21,469

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

Table 8-16. Summary of Incremental Component Cost Effectiveness for Processing Plants for the Subpart VVa Option

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Incremental Component Cost for Subpart VV to Subpart VVa Option										
Valves	1,392	12	10.9	0.412	39.3	$6,680	$1,576	$144	$3,824	$40
Connectors	4,392	1/0.25[a]	1.57	0.0592	5.65	$2,559	$6,845	$4,360	$115,585	$1,211
PRD	29	0	0.499	0.0188	1.80	$0	$0	$0	$0	$0
OEL	134	0	0.476	0.0179	1.71	$0	$0	$0	$0	$0

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.

Table 8-17. Summary of Component Cost Effectiveness for Transmission and Storage Facilities for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	673	12	0.878	0.0261	31.8	$19,888	$37,870	$43,111	$1,450,510	$1,192
Connectors	3,068	1/0.25[a]	0.665	0.0198	24.1	$11,229	$24,291	$36,527	$1,229,005	$1,010
PRD	14	0	0.133	0.00397	4.83	$61,520	$32,501	$243,525	$8,193,684	$6,732
OEL	58	0	0.947	0.0282	34.3	$12,416	$23,453	$24,762	$833,137	$684
Modified Subpart VVa – Less Frequent Monitoring										
Valves	673	1	0.626	0.0186	22.6	$19,888	$25,410	$40,593	$1,365,801	$1,122
Connectors	3,068	1/0.125[b]	0.562	0.0167	20.3	$11,229	$23,669	$42,140	$1,417,844	$1,165
PRD	14	0	0.133	0.00397	4.83	$61,520	$32,501	$243,525	$8,193,684	$6,732
OEL	58	0	0.947	0.0282	34.3	$12,416	$23,453	$24,762	$833,137	$684

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

8.4.3 LDAR with Optical Gas Imaging

8.4.3.1 Description

The alternative work practice for equipment leaks in §60.18 of 40 CFR Part 60, subpart A allows the use of an optical gas imaging system to monitor leaks from components. This LDAR requires monthly monitoring and repair of components using an optical gas imaging system, and annual monitoring of components using a Method 21 instrument. This requirement does not have a leak definition because the optical gas imaging system can only measure the magnitude of a leak and not the concentration. However, this alternative work practice does not require the repair of leaks below 500 ppm. Compressors are not included in this LDAR option and arediscussed in Chapter 6 of this document.

8.4.3.2 Effectiveness

No data was found on the control effectiveness of the alternative work practice. It is believed that this option would provide the same control effectiveness as the subpart VVa monitoring program. Therefore, the control effectiveness's for implementing an alternative work practice was assumed to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.3.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are \$17.70 for valves, \$1.13 per connector, \$78.00 for pressure relief valve disks, \$3,852 for pressure relief valve disk holder and valves, and \$102 for open-ended lines.
- Monthly optical gas imaging monitoring costs are estimated to be \$0.50 for valves, connectors, pressure relief valve devices, and open-ended lines.
- Annual monitoring costs using a Method 21 device are estimated to be \$1.50 for valves and connectors, \$2.00 for pressure relief valve disks, and \$5.00 for pressure relief devices and open-ended lines.
- A wage rate of \$30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

It was assumed that a single optical gas imaging and a Method 21 monitoring device could be used at multiple locations for production pads, gathering and boosting stations, and transmission and storage facilities. To calculate the shared cost of the optical gas imaging system and the Method 21 device, the time required to monitor a single facility was estimated. For production pads and gathering and boosting stations, it was assumed that 8 production pads could be monitored per day. This means that 160 production facilities could be monitored in a month. In addition, it was assumed 13 gathering and boosting station would service these wells and could be monitored during the same month for a total of 173 facilities. Therefore, the capital cost of the optical gas imaging system (Flir Model GF320, $85,000) and the Method 21 device ($6,500) was divided by 173 to get a shared capital cost of $529 per facility. It was assumed for processing facilities that the full cost of the optical gas imaging system and the Method 21 monitoring device would apply to each individual plant. The transmission and storage segment Method 21 device cost was estimated assuming that one facility could be monitored in one hour, and the travel time between facilities was one hour. Therefore, in a typical day 4 transmission stations could be monitored in one day. Assuming the same 20 day work month, the total number of facilities that could be monitored by a single optical gas imaging system and Method 21 device is 80. Therefore, the shared cost of the Method 21 monitoring device was calculated to be $1,144 per site.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectorusing the alternative work practice monitoring is provided in Table 8-18. A component cost effectiveness analysis for the alternative work practice was not performed, because the optical gas imaging system is not conducive to component monitoring, but is intended for facility-wide monitoring.

8.4.3.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of

Table 8-18. Summary of the Model Plant Cost Effectiveness for the Optical Gas Imaging and Method 21 Monitoring Option

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	0.0876	0.00330	0.315	$15,428	$21,464	$21,391	$245,024	$6,495,835	$68,043
2	2.43	0.0915	8.73	$64,858	$39,112	$37,088	$16,127	$427,540	$4,478
3	25.3	0.956	91.3	$132,891	$135,964	$114,807	$5,364	$142,216	$1,490
Gathering and Boosting Stations									
1	5.58	0.210	20.1	$149,089	$63,949	$59,295	$11,470	$304,078	$3,185
2	9.23	0.348	33.2	$240,529	$93,210	$85,503	$10,096	$267,659	$2,804
3	12.9	0.486	46.4	$329,725	$121,820	$111,060	$9,451	$250,567	$2,625
Processing Plants									
1	13.5	0.508	48.5	$92,522	$87,059	$75,813	$6,462	$171,321	$1,795
Transmission/Storage Facilities									
1	2.62	0.0780	94.9	$20,898	$51,753	N/A	$19,723	$663,591	$545

Minor discrepancies may be due to rounding.

Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission segment..

equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

8.4.4 Modified Alternative Work Practice with Optical Gas Imaging

8.4.4.1 Description

The modified alternative work practice for equipment leaks in §60.18 of 40 CFR Part 60, subpart A allows the use of an optical gas imaging system to monitor leaks from components, but removes the requirement of the annual Method 21 device monitoring. Therefore, the modified work practice would require only monthly monitoring and repair of components using an optical gas imaging system. This requirement does not have a leak definition because the optical gas imaging system can only measure the magnitude of a leak and not the concentration. However, this alternative work practice does not require the repair of leaks below 500 ppm. Compressors are not included in this LDAR option and are regulated separately.

8.4.4.2 Effectiveness

No data was found on the control effectiveness of this modified alternative work practice. However, it is believed that this option would provide the similar control effectiveness and emission reductions as the subpart VVa monitoring program. Therefore, the control effectiveness's for implementing an alternative work practice was assumed to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.4.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Monthly optical gas imaging monitoring costs are estimated to be $0.50 for valves, connectors, pressure relief valve devices, and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The shared capital cost for optical gas imaging system is $491 for production and gathering and boosting, $85,000 for processing, and $1,063 for transmission for a FLIR Model GF320 optical gas imaging system.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectors using the alternative work practice monitoring is provided in Table 8-19. A component cost effectiveness analysis for the alternative work practice was not performed, because the optical gas imaging system is not conducive to component monitoring, but is intended for facility-wide monitoring.

8.4.4.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

8.5 Regulatory Options

The LDAR pollution prevention approach is believed to be the best method for reducing pollutant emissions from equipment leaks. Therefore, the following regulatory options were considered for reducing equipment leaks from well pads, gathering and boosting stations, processing facilities, and transmission and storage facilities:

- Regulatory Option 1: Require the implementation of a subpart VVa LDAR program;
- Regulatory Option 2: Require the implementation of a component subpart VVa LDAR program;
- Regulatory Option 3: Require the implementation of the alternative work practice in §60.18 of 40 CFR Part 60;

Table 8-19. Summary of the Model Plant Cost Effectiveness for Monthly Gas Imaging Monitoring

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	N/A	N/A	N/A	$15,390	$21,373	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	$64,820	$37,049	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	$537,313	$189,174	N/A	N/A	N/A	N/A
Gathering and Boosting Stations									
1	N/A	N/A	N/A	$149,051	$59,790	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	$240,491	$86,135	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	$329,687	$11,940	N/A	N/A	N/A	N/A
Processing Plants									
1	N/A	N/A	N/A	$92,522	$76,581	N/A	N/A	N/A	N/A
Transmission/Storage Facilities									
1	N/A	N/A	N/A	$20,817	$45,080	N/A	N/A	N/A	N/A

Note: This option only provides the number and magnitude of the leaks. Therefore, the emission reduction from this program cannot be quantified and the cost effectiveness values calculated.

- Regulatory Option 4: Require the implementation of a modified alternative work practice in §60.18 of 40 CFR Part 60 that removes the requirement for annual monitoring using a Method 21 device.

The following sections discuss these regulatory options.

8.5.1 Evaluation of Regulatory Options for Equipment Leaks

8.5.1.1 Well pads

The first regulatory option of a subpart VVa LDAR program was evaluated for well pads, which include the wells, processing equipment (separators, dehydrators, acid gas removal), as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. For well pads the VOC cost effectiveness for the model plants ranged from $267,386 per ton of VOC for a single well head facility to $6,934 ton of VOC for a well pad servicing 48 wells. Because of the high VOC cost effectiveness, Regulatory Option 1 was rejected for well pads.

The second regulatory option that was evaluated for well pads was Regulatory Option 2, which would require the implementation of a component subpart VVa LDAR program. The VOC cost effectiveness of this option ranged from $15,063 for valves to $211,992 for open-ended lines. These costs were determined to be unreasonable and therefore this regulatory option was rejected.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option ranged from $5,364 per ton of VOC for Model Plant 3to $245,024 per ton of VOC for Model Plant 1. This regulatory option was determined to be not cost effective and was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.2 Gathering and Boosting Stations

The first regulatory option was evaluated for gathering and boosting stations which include the processing equipment (separators, dehydrators, acid gas removal), as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. The VOC cost effectiveness for the gathering and boosting model plants ranged from $10,327 per ton of VOC for

Model Plant 1 to $8,174per ton of VOC for Model Plant 3. Regulatory Option 1 was rejected due to the high VOC cost effectiveness.

The second regulatory option that was evaluated for gathering and boosting stations was Regulatory Option 2. The VOC cost effectiveness of this option ranged from $6,079 for valves to $77,310 per ton of VOC for open-ended lines. These costs were determined to be unreasonable and therefore this regulatory option was also rejected.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option was calculated to be $10,724 per ton of VOC for Model Plant 1 and $8,685 per ton of VOC for Model Plant 3. This regulatory option was determined to be not cost effective and was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.3 Processing Plants

The VOC cost effectiveness of the first regulatory option was calculated to be $3,352 per ton of VOC. This cost effectiveness was determined to be reasonable and therefore this regulatory option was accepted.

The second option was evaluated for processing plants and the VOC cost effectiveness ranged from $0 for open-ended lined and pressure relief devices to $4,360 for connectors. Because the emission benefits and the cost effectiveness of Regulatory Option 1 were accepted, this option was not accepted.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option was calculated to be $6,462 per ton of VOC and was determined to be not cost effective. Therefore, this regulatory option was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.4 Transmission and Storage Facilities

The first regulatory option was evaluated for transmission and storage facilities which include separators and dehydrators, as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. This sector moves processed gas from the processing facilities to the city gates. The VOC cost effectiveness for Regulatory Option 1 was $19,769per ton of VOC. The high VOC cost effectiveness is due to the inherent low VOC concentration in the processed natural gas, therefore the VOC reductions from this sector are low in comparison to the other sectors. Regulatory Option 1 was rejected due to the high VOC cost effectiveness.

The second option was evaluated for transmission facilities and the VOC cost effectiveness ranged from $24,762 for open-ended lined to $243,525 for connectors. This option was not accepted because of the high cost effectiveness.

The third regulatory option that was evaluated for transmission and storage facilities was Regulatory Option 3. The VOC cost effectiveness of this option was calculated to be $19,723 per ton of VOC. Again, because of the low VOC content of the processed gas, the regulatory option has a low VOC reduction. This cost was determined to be unreasonable and therefore this regulatory option was also rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.2 Nationwide Impacts of Regulatory Options

Regulatory Option 1 was selected as an option for setting standards for equipment leaks at processing plants. This option would require the implementation of an LDAR program using the subpart VVa requirements. For production facilities, 29 facilities per year are expected to be affected sources by the NSPS regulation annually. Table 8-20 provides a summary of the expected emission reductions from the implementation of this option.

Table 8-20. Nationwide Emission and Cost Analysis of Regulatory Options

Category	Estimated Number of Sources subject to NSPS	Facility Capital Cost ($)	Nationwide Emission Reductions (tpy)			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
			VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 2 (Subpart VVa LDAR Program)												
Processing Plants	29	$7,522	392	1,407	14.7	$3,352	$2,517	$931	$699	0.218	1.31	0.984

8.6 References

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APPENDIX A

E&P TANKS ANALYSIS FOR STORAGE VESSELS

Tank ID	**Sample Tank No. 1**	**Sample Tank No. 2**	**Sample Tank No. 3**	**Sample Tank No. 4**	**Sample Tank No. 5**	**Sample Tank No. 6**	**Sample Tank No. 7**	**Sample Tank No. 8**
E&P Tank Number	**Tank No. 58**	**Tank No. 59**	**Tank No. 60**	**Tank No. 61**	**Tank No. 62**	**Tank No. 63**	**Tank No. 64**	**Tank No. 65**
Total Emissions (tpy)	289.778	230.196	129.419	129.853	201.547	738.511	294.500	142.371
VOC Emissions (tpy)	43.734	111.414	101.853	63.343	154.313	578.379	205.794	89.728
Methane Emissions (tpy)	0.197	56.006	10.064	50.910	8.343	47.831	26.305	24.276
HAP Emissions (tpy)	**4.236**	**13.100**	**5.050**	**2.730**	**3.500**	**37.840**	**4.480**	**2.680**
Benzene	*0.828*	*6.343*	*0.501*	*0.285*	*0.051*	*7.568*	*0.116*	*0.219*
Toluene	*1.194*	*3.539*	*0.648*	*0.243*	*0.067*	*5.950*	*0.085*	*0.301*
E-Benzene	*0.041*	*0.083*	*0.040*	*0.008*	*0.002*	*0.086*	*0.006*	*0.020*
Xylenes	*0.165*	*0.327*	*0.233*	*0.066*	*0.046*	*0.679*	*0.018*	*0.152*
n-C6	*2.008*	*2.809*	*3.623*	*2.132*	*3.333*	*23.553*	*4.252*	*1.989*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	66	66	13	64	28	95	29	44
Separator Temperature (F)	83	90	110	74	78	118	60	71
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	83	90	110	74	78	118	60	71
C10+ SG	0.848	0.865	0.879	0.866	0.864	0.862	0.841	0.849
C10+ MW	234	237	294	301	281	312	224	349
API Gravity	**40.0**	**40.0**	**40.0**	**40.0**	**42.0**	**42.0**	**44.0**	**44.0**
Production Rate (bbl/day)	500	500	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.00	4.10	4.80	3.90	4.20	8.10	5.70	7.00
GOR (scf/bbl)	25.96	30.32	12.30	19.58	19.68	68.74	32.46	16.92
Heating Value of Vapor (Btu/s	398.80	1689.70	2486.42	1567.19	2261.27	2529.29	2162.56	2003.83
LP Oil Component	mol %							
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	5.0200	0.2700	0.0000	0.0800	0.0400	0.0000	0.0100	0.0200
N2	0.0000	0.0100	0.0000	0.0200	0.3100	0.0200	0.0200	0.0100
C1	0.0100	2.2600	0.4700	2.6500	0.4000	2.2500	1.1300	1.2900
C2	0.0400	1.2000	0.4800	0.3900	0.6500	3.1100	1.4100	1.0300
C3	0.2000	1.3200	1.5800	0.9200	1.7500	4.1100	3.2900	2.3000
i-C4	0.2800	0.7100	0.6200	0.9800	0.9200	1.3300	0.4500	1.1200
n-C4	0.4800	1.0800	2.6100	1.4700	2.4500	3.8100	4.0200	3.2200
i-C5	0.7600	1.2000	1.8100	2.0500	2.3900	2.5400	0.7000	2.3600
n-C5	0.7400	1.1300	2.9300	2.1600	2.9500	3.5100	4.0700	2.9600
C6	1.5100	2.0000	3.8800	3.4500	2.7600	3.0900	0.9600	3.0600
C7	4.6600	6.7600	10.7300	7.9400	10.8800	8.0100	5.5900	9.5000
C8	6.6100	9.4200	12.5300	9.6900	11.6400	7.6800	5.5200	11.5900
C9	4.8700	6.5600	6.9400	6.5600	6.1800	4.4400	4.2700	6.3200
C10+	70.1100	49.2600	47.3100	56.3900	52.0200	47.6400	63.0500	47.7200
Benzene	0.5700	4.9100	0.5800	0.4300	0.0700	1.3400	0.1600	0.3600
Toluene	2.1400	7.7900	1.9900	1.1000	0.2700	2.6800	0.3700	1.4900
E-Benzene	0.1700	0.4600	0.2900	0.1000	0.0200	0.0900	0.0700	0.2600
Xylenes	0.7600	2.0500	1.9000	0.9000	0.5500	0.8000	0.2500	2.2900
n-C6	1.0700	1.6100	3.3500	2.7200	3.7500	3.5500	4.6600	3.1000
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 9**	**Sample Tank No. 10**	**Sample Tank No. 11**	**Sample Tank No. 12**	**Sample Tank No. 13**	**Sample Tank No. 14**	**Sample Tank No. 15**
E&P Tank Number	**Tank No. 66**	**Tank No. 67**	**Tank No. 68**	**Tank No. 69**	**Tank No. 70**	**Tank No. 71**	**Tank No. 72**
Total Emissions (tpy)	357.688	134.789	314.446	505.131	306.443	256.029	1061.274
VOC Emissions (tpy)	243.348	79.118	224.158	437.555	252.987	204.571	987.647
Methane Emissions (tpy)	56.846	37.876	18.892	21.472	15.159	21.237	32.940
HAP Emissions (tpy)	**5.590**	**5.680**	**7.030**	**13.450**	**15.330**	**6.500**	**56.780**
Benzene	*0.244*	*1.308*	*0.242*	*0.119*	*1.048*	*0.464*	*5.791*
Toluene	*0.440*	*1.184*	*0.385*	*0.146*	*1.488*	*0.927*	*6.793*
E-Benzene	*0.039*	*0.029*	*0.043*	*0.019*	*0.062*	*0.051*	*0.303*
Xylenes	*0.208*	*0.488*	*0.167*	*0.162*	*0.734*	*0.590*	*4.255*
n-C6	*4.661*	*2.671*	*6.191*	*13.008*	*12.001*	*4.468*	*39.634*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	60	41	20	23	24	52	45
Separator Temperature (F)	60	72	68	85	114	108	140
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	72	68	85	114	108	140
C10+ SG	0.878	0.854	0.926	0.848	0.87	0.886	0.893
C10+ MW	270	270	290	275	274	269	277
API Gravity	**44.0**	**45.0**	**45.0**	**46.0**	**46.0**	**47.0**	**47.0**
Production Rate (bbl/day)	500	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.10	5.20	8.10	4.70	5.00	5.30	6.00
GOR (scf/bbl)	41.30	17.66	30.80	43.26	26.30	24.28	78.80
Heating Value of Vapor (Btu/s	2060.54	1812.87	2234.66	2651.81	2611.90	2491.55	3120.85
LP Oil Component							
H2S	0.0000	0.0000	0.0000	0.0500	0.0700	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0500	0.0400	0.3100	0.2400	0.1700	0.0000	0.0400
N2	0.0000	0.0100	0.0200	0.0100	0.0000	0.0000	0.0000
C1	2.3400	1.8400	0.6900	0.9400	0.6200	0.9700	1.2100
C2	1.5600	0.6100	0.9400	0.6600	0.5200	0.7700	0.7600
C3	3.8500	1.2700	2.7300	2.1500	1.6800	2.0200	2.9200
i-C4	1.3600	0.8900	1.7300	1.1100	0.9900	1.5500	4.1500
n-C4	3.9600	1.5600	3.9300	4.5400	3.1200	2.1400	3.0600
i-C5	3.1300	1.8000	3.8800	3.0600	2.4500	3.3400	3.9300
n-C5	4.0300	1.8800	4.1000	4.9800	3.4200	2.8800	3.0900
C6	3.6100	3.4300	5.1500	4.1100	4.4300	3.2600	4.9100
C7	7.7900	10.7400	12.0700	10.2100	8.8900	9.0800	13.0800
C8	13.7700	12.6900	18.2000	10.6800	18.5800	11.7900	14.6200
C9	4.8300	7.8700	8.8800	5.4300	8.7200	5.8500	7.6300
C10+	42.2300	43.0100	27.3600	45.2800	36.2600	49.3100	31.1400
Benzene	0.2400	1.5600	0.3000	0.0600	0.5300	0.3000	0.6900
Toluene	1.3400	3.8100	1.4700	0.2100	1.9700	1.6000	1.9400
E-Benzene	0.3200	0.2200	0.4400	0.0700	0.1900	0.2100	0.1900
Xylenes	1.9700	4.1900	1.9600	0.6700	2.5500	2.7300	2.9800
n-C6	3.6200	2.5800	5.8400	5.5400	4.8400	2.2000	3.6600
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 16	Sample Tank No. 17	Sample Tank No. 18	Sample Tank No. 19	Sample Tank No. 20	Sample Tank No. 21
E&P Tank Number	**Tank No. 73**	**Tank No. 74**	**Tank No. 75**	**Tank No. 76**	**Tank No. 77**	**Tank No. 78**
Total Emissions (tpy)	464.597	214.658	1331.488	3972.618	540.533	1228.897
VOC Emissions (tpy)	383.349	135.482	1146.617	2331.105	399.555	940.078
Methane Emissions (tpy)	18.132	32.283	31.967	755.826	38.624	105.184
HAP Emissions (tpy)	**10.980**	**7.530**	**77.780**	**82.380**	**7.580**	**13.230**
Benzene	*0.222*	*1.269*	*7.661*	*12.470*	*2.447*	*0.543*
Toluene	*0.208*	*0.708*	*3.775*	*23.584*	*1.643*	*0.466*
E-Benzene	*0.058*	*0.019*	*0.113*	*0.056*	*0.051*	*0.006*
Xylenes	*0.193*	*0.411*	*0.929*	*0.635*	*0.256*	*0.052*
n-C6	*10.296*	*5.124*	*65.304*	*45.632*	*3.186*	*12.160*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	40	31	50	700	20	98
Separator Temperature (F)	76	76	125	100	48	40
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	76	76	125	100	48	40
C10+ SG	0.885	0.839	0.842	0.878	0.877	0.929
C10+ MW	318	296	287	178	179	324
API Gravity	**47.0**	**49.0**	**49.0**	**50.0**	**50.0**	**51.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.60	5.00	8.90	7.40	9.40	11.20
GOR (scf/bbl)	41.32	24.48	106.60	491.90	56.44	128.16
Heating Value of Vapor (Btu/s	2421.27	2045.68	2822.40	1916.15	2275.04	2279.83
LP Oil Component						
H2S	0.0000	0.0000	1.2800	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0400	0.0800	0.0300	0.4200	0.0100	0.0100
N2	0.8400	0.0100	0.0000	0.0700	0.0100	0.0400
C1	0.7800	1.4000	1.2700	15.3300	1.1400	3.2200
C2	0.7500	0.9700	2.0800	8.9600	1.6000	2.9500
C3	3.5300	1.3500	4.5700	8.2100	4.0100	6.4800
i-C4	2.0700	1.0500	1.8900	2.3100	2.3400	2.2000
n-C4	6.8800	2.4200	6.4800	4.1900	4.7300	8.5300
i-C5	5.0000	2.7100	3.8800	2.4300	4.1700	4.6800
n-C5	7.4800	3.2900	7.0400	2.3500	2.9700	7.4700
C6	4.1000	4.6900	3.0500	3.1100	4.3800	5.7300
C7	11.3200	11.3500	6.8200	8.4700	8.8100	15.8300
C8	11.7900	12.4100	7.7800	8.8400	12.3800	12.6400
C9	6.1100	9.3100	7.2300	3.7100	5.4900	4.0800
C10+	32.0700	36.0900	37.9300	23.5600	32.1400	18.1600
Benzene	0.1400	1.4000	0.8300	0.8200	2.8900	0.3400
Toluene	0.3800	2.3200	1.0200	4.6700	6.4200	1.0200
E-Benzene	0.2700	0.1600	0.0700	0.0300	0.5700	0.0400
Xylenes	1.0300	4.0200	0.6500	0.3900	3.3000	0.4000
n-C6	5.4200	4.9700	6.1000	2.1300	2.6400	6.1800
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 22**	**Sample Tank No. 23**	**Sample Tank No. 24**	**Sample Tank No. 25**	**Sample Tank No. 26**	**Sample Tank No. 27**
E&P Tank Number	**Tank No. 79**	**Tank No. 80**	**Tank No. 81**	**Tank No. 82**	**Tank No. 83**	**Tank No. 84**
Total Emissions (tpy)	362.298	790.092	557.188	5007.636	175.911	714.052
VOC Emissions (tpy)	175.304	665.349	483.599	3386.300	77.584	639.895
Methane Emissions (tpy)	109.676	24.115	10.288	842.206	54.660	18.553
HAP Emissions (tpy)	**7.150**	**28.770**	**14.580**	**101.610**	**4.770**	**30.190**
Benzene	*0.353*	*3.892*	*1.930*	*9.782*	*0.929*	*4.165*
Toluene	*0.102*	*6.465*	*1.651*	*12.547*	*0.909*	*2.542*
E-Benzene	*0.120*	*0.119*	*0.055*	*0.040*	*0.050*	*0.192*
Xylenes	*0.437*	*2.017*	*0.631*	*0.716*	*0.221*	*1.424*
n-C6	*6.133*	*16.273*	*10.317*	*78.528*	*2.665*	*21.871*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	115	30	15	770	39	38
Separator Temperature (F)	73	100	86	100	66	95
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	73	100	86	100	66	95
C10+ SG	0.873	0.901	0.878	0.858	0.854	0.823
C10+ MW	200	220	254	195	175	375
API Gravity	**54.0**	**54.0**	**54.0**	**55.0**	**57.0**	**57.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	5.30	9.40	10.30	7.80	5.70	9.60
GOR (scf/bbl)	51.34	68.32	47.12	578.20	25.46	57.38
Heating Value of Vapor (Btu/s	1678.80	2676.21	2764.90	2043.18	1632.00	2897.16
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0900	0.1100	0.0200	0.5500	0.0700	0.0400
N2	0.0300	0.0200	0.0100	0.0300	0.0000	0.0000
C1	3.5600	0.7100	0.3300	16.1500	1.7200	0.7000
C2	1.4300	1.5400	1.0900	7.1400	0.9000	1.0900
C3	1.8700	4.5900	3.8300	9.6600	1.3800	3.5600
i-C4	0.6800	2.3400	3.7000	3.8100	1.0000	2.9000
n-C4	2.0000	4.4400	4.8700	5.9600	1.4900	6.2100
i-C5	1.6600	3.9000	4.4800	3.5300	1.4600	6.0400
n-C5	2.0600	3.8000	3.9800	3.7200	1.5300	5.8400
C6	2.4100	5.0900	6.0500	3.8400	4.0600	7.3200
C7	15.0800	12.9700	15.6400	8.7600	14.5700	13.0000
C8	25.1900	19.0700	17.5800	8.9200	23.7200	12.2200
C9	12.4900	6.9500	6.1000	3.1000	13.7700	7.9600
C10+	24.3900	18.9200	21.1300	17.9300	20.9800	20.0200
Benzene	0.2400	1.2000	1.0500	0.5800	1.4900	1.2200
Toluene	0.2100	5.5400	2.6000	2.3000	4.5300	2.0500
E-Benzene	0.6600	0.2500	0.2200	0.0200	0.6700	0.3800
Xylenes	2.7600	4.8300	2.8900	0.4200	3.4200	3.2200
n-C6	3.1900	3.7300	4.4300	3.5800	3.2400	6.2300
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 28	Sample Tank No. 29	Sample Tank No. 30	Sample Tank No. 31	Sample Tank No. 32	Sample Tank No. 33
E&P Tank Number	**Tank No. 85**	**Tank No. 86**	**Tank No. 87**	**Tank No. 88**	**Tank No. 89**	**Tank No. 90**
Total Emissions (tpy)	801.228	983.881	4326.573	3074.670	2951.879	616.490
VOC Emissions (tpy)	757.176	750.313	2406.579	1892.668	1439.584	332.126
Methane Emissions (tpy)	5.307	49.123	1088.727	746.499	999.175	120.918
HAP Emissions (tpy)	**29.510**	**14.080**	**58.180**	**47.230**	**44.040**	**9.140**
Benzene	*3.415*	*1.119*	*4.653*	*5.891*	*1.409*	*0.576*
Toluene	*5.329*	*1.453*	*5.785*	*6.575*	*2.934*	*1.658*
E-Benzene	*0.192*	*0.049*	*0.186*	*0.022*	*0.159*	*0.079*
Xylenes	*1.786*	*0.263*	*0.989*	*0.316*	*1.136*	*0.806*
n-C6	*18.788*	*11.194*	*46.561*	*34.427*	*38.406*	*6.016*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	65	54	870	600	780	60
Separator Temperature (F)	80	60	78	70	70	56
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	80	60	78	70	70	60
C10+ SG	0.899	0.868	0.868	0.847	0.905	0.905
C10+ MW	166	268	268	176	174	174
API Gravity	**57.0**	**57.0**	**57.0**	**57.0**	**58.0**	**58.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.80	13.10	13.10	7.50	8.00	8.00
GOR (scf/bbl)	61.26	97.00	578.20	396.24	436.98	79.54
Heating Value of Vapor (Btu/s	3046.83	2390.47	1789.23	1831.51	1633.60	1851.14
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	0.0800	0.4200	0.5800	0.2700	0.0800
N2	0.0000	0.0000	0.0800	0.0200	0.0200	0.0100
C1	0.1500	1.4800	21.2000	16.0200	20.3000	3.3900
C2	0.5700	2.9100	8.2900	4.1200	5.1800	2.4300
C3	2.4100	6.9600	8.5400	6.9000	5.6800	3.8400
i-C4	1.7300	2.6300	2.3000	2.7500	1.4200	1.3000
n-C4	3.5500	7.2100	5.8400	4.9100	4.1400	3.2000
i-C5	4.1400	4.6400	3.3500	3.6000	2.5400	2.4100
n-C5	3.8600	5.7100	4.0400	3.9000	3.1000	2.5600
C6	6.5100	5.0100	3.4200	3.9500	3.7700	3.7700
C7	18.7100	13.5500	9.1200	10.3800	11.2200	13.2600
C8	19.4300	15.0600	10.0900	11.3000	14.7500	22.4400
C9	6.8400	6.2300	4.1700	4.2100	7.0600	11.1300
C10+	15.5200	18.8400	12.5900	19.2800	13.5400	16.0600
Benzene	1.1800	0.5900	0.4000	0.8200	0.1800	0.4100
Toluene	5.2100	2.5000	1.6800	3.0600	1.2600	3.8600
E-Benzene	0.4600	0.2400	0.1600	0.0300	0.2000	0.5200
Xylenes	4.8600	1.4900	1.0000	0.5000	1.6700	6.1500
n-C6	4.8600	4.8700	3.3100	3.6700	3.7000	3.1800
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 34	Sample Tank No. 35	Sample Tank No. 36	Sample Tank No. 37	Sample Tank No. 38	Sample Tank No. 39
E&P Tank Number	**Tank No. 91**	**Tank No. 92**	**Tank No. 93**	**Tank No. 94**	**Tank No. 95**	**Tank No. 96**
Total Emissions (tpy)	2575.122	2774.089	653.459	3495.242	363.650	4744.399
VOC Emissions (tpy)	1494.749	2092.925	394.781	2876.860	223.772	3658.384
Methane Emissions (tpy)	581.208	346.071	121.446	169.818	84.912	381.967
HAP Emissions (tpy)	**65.980**	**48.710**	**14.210**	**93.030**	**10.760**	**89.970**
Benzene	*9.303*	*2.750*	*0.871*	*10.232*	*0.500*	*11.564*
Toluene	*14.114*	*2.311*	*2.688*	*11.558*	*0.279*	*11.735*
E-Benzene	*0.019*	*0.128*	*0.136*	*0.034*	*0.060*	*0.033*
Xylenes	*0.409*	*0.872*	*1.400*	*0.580*	*0.256*	*0.472*
n-C6	*42.130*	*42.650*	*9.111*	*70.629*	*9.661*	*66.162*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	500	300	110	750	85	730
Separator Temperature (F)	84	80	72	90	85	84
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	84	80	72	90	85	84
C10+ SG	0.909	0.882	0.901	0.898	0.9	0.898
C10+ MW	204	296	162	215	202	225
API Gravity	**58.0**	**58.0**	**59.0**	**60.0**	**61.0**	**61.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	9.10	10.60	10.00	9.40	7.00	9.80
GOR (scf/bbl)	323.88	287.10	79.90	320.48	45.04	475.20
Heating Value of Vapor (Btu/s	1892.64	2289.04	1946.32	2541.49	1921.87	2340.56
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.2300	0.0300	0.0800	0.3400	0.0400	0.4100
N2	0.0600	0.0900	0.0100	0.0200	0.0200	0.0300
C1	12.9800	8.4300	3.3900	3.7500	2.6100	7.3900
C2	5.7800	4.2300	2.4300	4.7700	1.1600	6.6400
C3	4.6400	5.9100	3.8400	9.2600	2.2100	10.9400
i-C4	2.0900	5.1700	1.3000	4.8100	0.9300	4.5800
n-C4	4.1800	6.2200	3.2000	7.0200	2.4900	8.3400
i-C5	4.9600	8.9100	2.4100	5.5900	2.1300	5.5000
n-C5	4.0700	4.9700	2.5600	6.1200	2.9200	5.8200
C6	6.0700	9.1100	3.7700	6.1300	3.5400	5.3200
C7	13.1100	11.3400	13.2600	12.8200	19.5300	11.2900
C8	11.9500	10.3900	22.4400	12.5200	27.1600	11.1800
C9	4.8600	5.9600	11.1300	4.0100	14.7000	3.1900
C10+	14.1100	11.7500	16.0600	11.4200	13.8800	8.8000
Benzene	1.1400	0.3700	0.4100	1.1000	0.2900	1.1400
Toluene	5.4100	0.9800	3.8600	3.7900	0.4700	3.7600
E-Benzene	0.0200	0.1500	0.5200	0.0300	0.2600	0.0300
Xylenes	0.5000	1.1900	6.1500	0.5900	1.2600	0.5000
n-C6	3.8400	4.8000	3.1800	5.9100	4.4000	5.1400
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 40	Sample Tank No. 41	Sample Tank No. 42	Sample Tank No. 43	Sample Tank No. 44	Sample Tank No. 45
E&P Tank Number	**Tank No. 97**	**Tank No. 98**	**Tank No. 99**	**Tank No. 100**	**Tank No. 101**	**Tank No. 102**
Total Emissions (tpy)	907.495	277.197	3410.034	2122.607	8152.118	6780.555
VOC Emissions (tpy)	734.651	158.333	2732.261	1066.705	5678.554	4276.160
Methane Emissions (tpy)	49.578	75.426	159.904	736.341	1206.981	1045.765
HAP Emissions (tpy)	**24.160**	**8.820**	**67.500**	**64.680**	**81.710**	**48.890**
Benzene	*1.573*	*0.204*	*9.290*	*9.500*	*10.844*	*5.934*
Toluene	*3.102*	*0.854*	*9.192*	*15.007*	*8.516*	*1.416*
E-Benzene	*0.094*	*0.042*	*0.016*	*0.161*	*0.012*	*0.222*
Xylenes	*1.079*	*0.375*	*0.371*	*1.585*	*0.288*	*1.359*
n-C6	*18.314*	*7.344*	*48.628*	*38.425*	*62.050*	*39.961*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	57	72	730	580	730	807
Separator Temperature (F)	82	80	80	77	80	96
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	82	80	80	77	80	96
C10+ SG	0.884	0.869	0.883	0.85	0.895	0.811
C10+ MW	240	190	226	190	197	173
API Gravity	**62.0**	**63.0**	**63.0**	**64.0**	**64.0**	**66.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.40	7.00	11.90	6.40	11.00	11.80
GOR (scf/bbl)	84.20	36.56	321.62	309.64	924.96	804.54
Heating Value of Vapor (Btu/s	2521.70	1805.12	2477.18	1622.20	2083.02	2013.21
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0800	0.0400	0.3200	0.0700	0.5600	0.2200
N2	0.0100	0.0300	0.0200	0.0700	0.0300	0.0800
C1	1.4000	2.3500	3.4800	16.3500	16.9100	16.2600
C2	1.7700	1.0000	5.5300	3.6400	8.6200	11.7100
C3	4.8200	2.0700	10.1700	3.5600	12.0400	11.6100
i-C4	2.8200	0.7100	4.9900	1.6900	5.2700	4.3900
n-C4	5.9700	2.2600	8.1400	2.9800	9.0700	7.5600
i-C5	4.3100	1.7000	5.8700	2.6800	5.6500	4.5200
n-C5	4.1900	2.7400	6.1600	2.7900	5.8200	3.9400
C6	6.5100	3.4900	5.7200	3.8200	5.1000	3.3600
C7	17.7500	17.7300	12.3800	18.1400	8.0600	5.9200
C8	18.6400	27.9100	12.3100	19.4700	7.5500	11.6900
C9	7.4400	16.1500	3.7900	4.5900	2.2200	5.9200
C10+	11.6100	12.2800	9.9100	6.7300	5.6700	8.9300
Benzene	0.5600	0.1600	1.2800	1.2200	0.8500	0.3700
Toluene	3.2800	1.9800	4.0500	6.0700	2.3800	0.3000
E-Benzene	0.2600	0.2500	0.0200	0.1800	0.0100	0.1400
Xylenes	3.4100	2.5800	0.5300	2.0600	0.2900	1.0100
n-C6	5.1700	4.5700	5.3300	3.8900	3.9000	2.0700
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 46**	**Sample Tank No. 47**	**Sample Tank No. 48**	**Sample Tank No. 49**	**Sample Tank No. 50**	**Sample Tank No. 51**
E&P Tank Number	**Tank No. 103**	**Tank No. 1**	**Tank No. 2**	**Tank No. 3**	**Tank No. 4**	**Tank No. 5**
Total Emissions (tpy)	927.902	95.816	112.738	74.503	155.244	93.073
VOC Emissions (tpy)	623.038	6.175	61.936	28.446	61.470	51.471
Methane Emissions (tpy)	167.129	0.115	1.927	0.309	46.064	0.440
HAP Emissions (tpy)	**20.320**	**0.460**	**2.960**	**0.990**	**1.760**	**3.190**
Benzene	*1.625*	*0.006*	*0.076*	*0.012*	*0.010*	*0.218*
Toluene	*1.876*	*0.013*	*0.060*	*0.031*	*0.037*	*0.074*
E-Benzene	*0.062*	*0.007*	*0.019*	*0.002*	*0.025*	*0.006*
Xylenes	*0.696*	*0.018*	*0.105*	*0.041*	*0.069*	*0.048*
n-C6	*16.059*	*0.421*	*2.704*	*0.904*	*1.616*	*2.845*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	170	45	22	20	53	15
Separator Temperature (F)	75	106	155	160	101	120
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	75	106	155	160	101	120
C10+ SG	0.801	0.972	0.972	0.952	0.961	0.984
C10+ MW	196	425	436	458	394	551
API Gravity	**68.0**	**15.0**	**17.0**	**18.0**	**19.0**	**19.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	12.50	0.80	2.00	0.60	2.30	4.80
GOR (scf/bbl)	106.60	8.88	9.60	6.44	17.78	7.52
Heating Value of Vapor (Btu/s	2081.33	181.43	1738.61	1076.97	1365.68	1718.17
LP Oil Component						
H2S	0.0000	0.1100	0.0000	0.0400	0.5100	0.1400
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	2.8500	1.3000	1.5400	1.1900	1.5000
N2	0.0100	0.0000	0.0000	0.0300	0.0100	0.0000
C1	4.9300	0.0100	0.1500	0.0300	1.5300	0.0400
C2	2.5800	0.0100	0.4000	0.0400	0.5300	0.2400
C3	3.4200	0.0200	0.7800	0.2200	0.8100	0.8500
i-C4	3.4300	0.0500	0.5600	0.1600	0.5000	0.6500
n-C4	3.7300	0.1800	1.2600	0.4700	1.2000	1.6500
i-C5	5.5500	0.3200	0.8700	0.4300	1.1500	2.1900
n-C5	3.6500	0.4500	1.2400	0.6500	1.3400	3.1500
C6	8.0700	0.6000	1.9800	0.6100	1.7500	4.7300
C7	14.6500	1.7200	3.4500	1.5800	3.6200	6.2500
C8	13.2600	2.1800	4.2600	2.0700	3.5300	10.2800
C9	7.8000	1.8400	3.6600	2.2800	3.5300	5.9300
C10+	19.6300	88.7100	78.1500	88.9700	76.8100	57.9100
Benzene	0.5400	0.0100	0.0500	0.0100	0.0100	0.3000
Toluene	1.9200	0.0600	0.0900	0.0600	0.1000	0.2600
E-Benzene	0.1700	0.0800	0.0600	0.0100	0.1600	0.0500
Xylenes	2.2200	0.2300	0.3700	0.1800	0.5100	0.4300
n-C6	4.4300	0.5700	1.3700	0.6200	1.2100	3.4500
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 52	Sample Tank No. 53	Sample Tank No. 54	Sample Tank No. 55	Sample Tank No. 56	Sample Tank No. 57
E&P Tank Number	**Tank No. 6**	**Tank No. 7**	**Tank No. 8**	**Tank No. 9**	**Tank No. 10**	**Tank No. 11**
Total Emissions (tpy)	24.484	26.091	29.739	114.630	42.075	
VOC Emissions (tpy)	3.087	17.629	11.288	74.707	8.263	
Methane Emissions (tpy)	15.587	2.836	5.908	25.400	27.176	
HAP Emissions (tpy)	**0.190**	**0.510**	**0.330**	**2.120**	**0.090**	
Benzene	*0.003*	*0.007*	*0.013*	*0.039*	*0.028*	
Toluene	*0.006*	*0.014*	*0.008*	*0.071*	*0.010*	
E-Benzene	*0.000*	*0.001*	*0.003*	*0.007*	*0.000*	
Xylenes	*0.005*	*0.012*	*0.007*	*0.090*	*0.001*	
n-C6	*0.175*	*0.474*	*0.298*	*1.919*	*0.052*	
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	
Separator Pressure (psig)	23	17	18	54	35	
Separator Temperature (F)	79	106	75	125	76	
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	
Ambient Temperature (F)	79	106	75	125	76	
C10+ SG	0.947	0.967	0.963	0.943	0.923	
C10+ MW	368	383	401	363	278	
API Gravity	**20.0**	**20.0**	**20.0**	**21.0**	**23.0**	
Production Rate (bbl/day)	500	500	500	500	500	
Reid Vapor Pressure (psia)	1.20	3.30	3.80	1.10	1.80	
GOR (scf/bbl)	4.98	2.82	3.94	13.90	8.52	
Heating Value of Vapor (Btu/s	1067.32	2208.23	1236.41	1980.20	1192.63	
LP Oil Component						
H2S	0.0100	0.0000	0.0000	0.0000	0.0000	
O2	0.0000	0.0000	0.0000	0.0000	0.0000	
CO2	0.0700	0.0000	0.2500	0.0000	0.0600	
N2	0.0900	0.0000	0.2100	0.0100	0.0100	
C1	1.2500	0.1900	0.5300	1.8000	1.7700	
C2	0.2000	0.2300	0.3300	0.5400	0.2900	
C3	0.0800	0.7500	0.7500	0.5200	0.3700	
i-C4	0.0900	0.4900	0.4900	0.2800	0.2300	
n-C4	0.1800	1.5700	1.5000	0.9200	0.3100	
i-C5	0.4000	1.5300	1.3500	0.9800	0.4900	
n-C5	0.4500	1.9100	1.7700	0.9700	0.2400	
C6	1.0500	2.7500	2.3700	1.6800	0.2500	
C7	2.3300	3.9000	4.3000	3.0100	0.5900	
C8	2.9800	6.8100	5.5200	3.7300	0.5000	
C9	2.6000	4.0100	3.5700	3.5400	0.2500	
C10+	87.0300	73.0300	74.2800	80.2500	94.2100	
Benzene	0.0200	0.0400	0.1000	0.0300	0.1100	
Toluene	0.1100	0.2200	0.1900	0.1400	0.1200	
E-Benzene	0.0200	0.0500	0.1900	0.0300	0.0100	
Xylenes	0.2700	0.5100	0.4700	0.4500	0.0500	
n-C6	0.7700	2.0100	1.8300	1.1200	0.1400	
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	
	100.0000	100.0000	100.0000	100.0000	100.0000	0.0000

Tank ID	Sample Tank No. 58	Sample Tank No. 59	Sample Tank No. 60	Sample Tank No. 61	Sample Tank No. 62	Sample Tank No. 63
E&P Tank Number	**Tank No. 12**	**Tank No. 13**	**Tank No. 14**	**Tank No. 15**	**Tank No. 16**	**Tank No. 17**
Total Emissions (tpy)	134.719	26.214	195.573	142.068	191.224	35.095
VOC Emissions (tpy)	63.729	5.207	109.615	69.135	105.838	25.578
Methane Emissions (tpy)	16.689	12.924	7.759	5.438	4.313	3.029
HAP Emissions (tpy)	**1.170**	**0.430**	**2.810**	**1.760**	**2.110**	**0.750**
Benzene	*0.020*	*0.008*	*0.033*	*0.024*	*0.041*	*0.011*
Toluene	*0.014*	*0.032*	*0.032*	*0.053*	*0.079*	*0.022*
E-Benzene	*0.007*	*0.002*	*0.023*	*0.003*	*0.003*	*0.003*
Xylenes	*0.027*	*0.019*	*0.064*	*0.041*	*0.016*	*0.011*
n-C6	*1.104*	*0.371*	*2.659*	*1.640*	*1.969*	*0.701*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	30	20	20	22	20	19
Separator Temperature (F)	66	122	88	86	68	133
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	66	122	88	86	68	133
C10+ SG	0.946	0.926	0.945	0.944	0.964	0.928
C10+ MW	382	336	381	404	444	327
API Gravity	**23.0**	**24.0**	**24.0**	**24.0**	**24.0**	**25.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.00	0.60	3.90	4.60	4.80	4.10
GOR (scf/bbl)	15.42	4.60	19.12	13.74	17.84	3.48
Heating Value of Vapor (Btu/s	1553.86	1059.39	1747.39	1543.44	1703.42	2314.31
LP Oil Component						
H2S	0.4400	0.0000	0.5200	0.4500	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.6400	0.1200	0.9600	1.1500	1.4200	0.0500
N2	0.0100	0.1000	0.1200	0.0200	0.0200	0.0000
C1	1.0700	0.9400	0.4900	0.3600	0.2700	0.2500
C2	0.5400	0.0500	0.6500	0.5000	0.6200	0.4900
C3	1.4100	0.0700	1.7300	1.5900	1.9400	1.1600
i-C4	0.7000	0.0600	0.7400	0.7600	1.1000	0.6000
n-C4	1.9400	0.1000	2.4600	2.4000	3.0100	1.5900
i-C5	1.8900	0.2400	1.7900	1.7300	2.1900	1.4300
n-C5	2.3600	0.2300	2.3100	2.1400	3.2100	1.4400
C6	2.7100	0.9100	2.6100	2.6400	3.9300	1.9900
C7	5.1800	2.8000	5.3300	5.5200	5.6800	3.5100
C8	5.3700	4.2200	5.5400	6.0700	11.3000	4.4100
C9	3.9800	4.3400	4.2100	4.6000	6.7600	4.4400
C10+	68.6500	84.5400	67.0700	66.9000	54.5000	76.8100
Benzene	0.0500	0.0200	0.0400	0.0400	0.0800	0.0300
Toluene	0.1100	0.2100	0.1100	0.2600	0.4700	0.1500
E-Benzene	0.1500	0.0300	0.2000	0.0400	0.0400	0.0400
Xylenes	0.6500	0.3100	0.6300	0.5800	0.2900	0.1800
n-C6	2.1500	0.7100	2.4900	2.2500	3.1700	1.4300
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 64**	**Sample Tank No. 65**	**Sample Tank No. 66**	**Sample Tank No. 67**	**Sample Tank No. 68**	**Sample Tank No. 69**
E&P Tank Number	**Tank No. 18**	**Tank No. 19**	**Tank No. 20**	**Tank No. 21**	**Tank No. 22**	**Tank No. 23**
Total Emissions (tpy)	139.887	70.761	171.538	38.394	215.631	148.757
VOC Emissions (tpy)	89.426	46.290	110.120	12.834	164.956	138.780
Methane Emissions (tpy)	21.590	4.142	15.382	16.424	8.875	1.515
HAP Emissions (tpy)	**1.190**	**2.570**	**1.670**	**0.720**	**4.240**	**5.310**
Benzene	*0.011*	*0.371*	*0.013*	*0.224*	*0.985*	*1.086*
Toluene	*0.035*	*0.697*	*0.017*	*0.209*	*0.787*	*0.854*
E-Benzene	*0.010*	*0.039*	*0.004*	*0.007*	*0.020*	*0.025*
Xylenes	*0.025*	*0.176*	*0.025*	*0.066*	*0.118*	*0.122*
n-C6	*1.109*	*1.292*	*1.613*	*0.216*	*2.331*	*3.227*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	30	25	31	23	17	20
Separator Temperature (F)	60	136	64	79	86	120
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	136	64	79	86	120
C10+ SG	0.94	0.916	0.938	0.908	0.946	0.932
C10+ MW	380	431	340	324	323	326
API Gravity	**25.0**	**27.0**	**27.0**	**29.0**	**29.0**	**29.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.90	3.30	5.20	3.10	4.80	4.90
GOR (scf/bbl)	16.66	6.76	18.46	6.36	20.11	11.50
Heating Value of Vapor (Btu/s	1966.88	2041.97	1887.18	1405.21	2354.30	2985.81
LP Oil Component						
H2S	0.0000	0.3800	0.2400	0.0000	0.2700	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0600	0.2200	0.2100	0.0900	0.0800	0.0300
N2	0.0400	0.1000	0.3000	0.0000	0.0000	0.0000
C1	1.3500	0.3200	0.8600	1.1200	0.4400	0.0800
C2	0.8500	0.4100	0.5400	0.5300	0.7000	0.2000
C3	2.0900	1.0700	1.7500	0.7000	2.0600	1.3000
i-C4	1.1400	0.5700	1.1600	0.4500	0.9700	1.0400
n-C4	2.7100	1.4500	3.1500	0.6300	2.7500	3.8800
i-C5	2.1900	1.5700	2.9100	0.6400	2.7000	2.2100
n-C5	2.4600	1.5100	2.5900	0.4600	2.3200	3.2000
C6	2.2400	2.5400	3.7200	0.8400	3.5000	2.5500
C7	5.7900	3.5300	5.8600	4.7900	8.3100	7.2000
C8	4.7900	4.9600	5.6200	8.9000	7.2900	7.2300
C9	4.4800	4.1700	3.7300	5.8000	7.0500	4.7500
C10+	66.3000	72.0600	63.8500	67.7100	53.9500	59.2600
Benzene	0.0300	0.4300	0.0300	1.0000	1.2400	1.1600
Toluene	0.2900	1.9600	0.1200	2.7600	2.8500	2.3500
E-Benzene	0.2200	0.2400	0.0800	0.2400	0.1800	0.1600
Xylenes	0.6500	1.2100	0.5400	2.5900	1.2300	0.8600
n-C6	2.3200	1.3000	2.7400	0.7500	2.1100	2.5400
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 70	Sample Tank No. 71	Sample Tank No. 72	Sample Tank No. 73	Sample Tank No. 74	Sample Tank No. 75
E&P Tank Number	**Tank No. 24**	**Tank No. 25**	**Tank No. 26**	**Tank No. 27**	**Tank No. 28**	**Tank No. 29**
Total Emissions (tpy)	243.873	502.831	13.397	154.387	119.805	263.134
VOC Emissions (tpy)	151.292	330.274	4.231	125.001	48.333	168.558
Methane Emissions (tpy)	7.881	124.465	6.395	4.603	45.716	54.016
HAP Emissions (tpy)	**2.480**	**13.120**	**0.070**	**10.900**	**1.090**	**3.440**
Benzene	*0.188*	*0.954*	*0.008*	*0.053*	*0.189*	*0.435*
Toluene	*0.276*	*1.256*	*0.003*	*0.110*	*0.076*	*0.413*
E-Benzene	*0.007*	*0.086*	*0.000*	*0.031*	*0.004*	*0.046*
Xylenes	*0.114*	*0.732*	*0.008*	*0.305*	*0.033*	*0.285*
n-C6	*1.896*	*10.096*	*0.055*	*10.401*	*0.785*	*2.257*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	22	280	4	25	64	80
Separator Temperature (F)	98	106	80	180	70	77
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	98	106	80	180	70	77
C10+ SG	0.917	0.921	0.893	0.916	0.898	0.896
C10+ MW	311	450	313	304	368	309
API Gravity	**29.0**	**30.0**	**30.0**	**30.0**	**30.0**	**33.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	6.20	4.80	2.60	2.70	2.80	2.20
GOR (scf/bbl)	24.26	61.80	2.34	11.76	18.78	32.78
Heating Value of Vapor (Btu/s	2141.84	1933.26	1394.74	2814.20	1478.45	1920.70
LP Oil Component						
H2S	1.0100	0.0000	0.0000	0.0300	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.1100	0.1200	0.0200	0.2700	0.1700	0.0300
N2	0.0000	0.0500	0.0000	0.0000	0.0200	0.0200
C1	0.4000	7.9800	0.5900	0.2600	3.1300	2.9000
C2	1.6600	1.5600	0.4000	0.4800	0.7000	1.1000
C3	2.2300	2.8200	0.5500	0.8100	1.0700	1.7100
i-C4	1.1500	1.4300	0.4500	0.3600	0.8800	1.0700
n-C4	1.9500	2.4400	0.6300	1.1800	1.1100	1.1500
i-C5	2.8400	2.1200	0.4800	1.2900	1.0500	1.5000
n-C5	1.3600	2.0900	0.4500	2.0600	1.0000	1.2300
C6	3.0700	2.5400	1.0000	2.6800	1.5300	2.3300
C7	6.9000	6.3500	4.3100	6.5200	4.4300	6.0000
C8	7.6500	8.0300	4.9000	7.3900	5.8900	8.7700
C9	5.8200	3.5600	4.1700	4.8600	4.2200	6.3100
C10+	61.2100	54.9600	80.5100	68.2000	72.4400	60.3600
Benzene	0.1500	0.2000	0.0900	0.0200	0.3100	0.3800
Toluene	0.6100	0.6800	0.1100	0.0900	0.3800	1.0700
E-Benzene	0.0400	0.1100	0.0200	0.0500	0.0500	0.3100
Xylenes	0.7000	1.0600	0.8100	0.5400	0.5000	2.2000
n-C6	1.1400	1.9000	0.5100	2.9100	1.1200	1.5600
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 76	Sample Tank No. 77	Sample Tank No. 78	Sample Tank No. 79	Sample Tank No. 80	Sample Tank No. 81
E&P Tank Number	**Tank No. 30**	**Tank No. 31**	**Tank No. 32**	**Tank No. 33**	**Tank No. 34**	**Tank No. 35**
Total Emissions (tpy)	75.697	67.111	33.481	98.139	246.837	206.565
VOC Emissions (tpy)	48.997	21.176	9.640	41.538	186.576	136.694
Methane Emissions (tpy)	15.026	39.198	18.906	45.393	13.777	5.258
HAP Emissions (tpy)	**1.330**	**0.460**	**0.290**	**1.230**	**7.150**	**4.120**
Benzene	*0.115*	*0.055*	*0.025*	*0.118*	*1.477*	*0.060*
Toluene	*0.088*	*0.025*	*0.040*	*0.085*	*1.336*	*0.122*
E-Benzene	*0.010*	*0.002*	*0.004*	*0.008*	*0.030*	*0.010*
Xylenes	*0.038*	*0.011*	*0.023*	*0.165*	*0.263*	*0.100*
n-C6	*1.075*	*0.362*	*0.196*	*0.852*	*4.047*	*3.833*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	20	60	18	40	18	15
Separator Temperature (F)	115	78	70	110	80	108
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	115	78	70	110	80	108
C10+ SG	0.885	0.866	0.875	0.87	0.923	0.887
C10+ MW	280	324	277	297	346	272
API Gravity	**33.0**	**34.0**	**34.0**	**34.0**	**35.0**	**35.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.10	2.00	2.20	3.20	4.70	4.50
GOR (scf/bbl)	8.96	12.60	6.20	16.18	24.36	18.78
Heating Value of Vapor (Btu/s	1989.27	1308.40	1280.62	1473.81	2361.43	2135.62
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0100	0.0500
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0300	0.0500	0.0700	0.0400	0.0600	0.6100
N2	0.0000	0.0000	0.0000	0.0100	0.0100	0.0500
C1	0.8400	2.8100	1.1600	2.9100	0.6400	0.2600
C2	0.3700	0.3100	0.2400	0.4400	1.0500	0.7800
C3	0.9200	0.6200	0.4900	0.6800	2.2200	1.7400
i-C4	1.0000	0.4700	0.4300	0.5800	0.8300	0.8400
n-C4	1.3200	0.7300	0.6500	0.6300	2.7600	2.3700
i-C5	1.3500	0.7100	0.8000	0.5300	2.1100	2.2400
n-C5	1.2200	0.6600	0.7000	0.4900	3.1100	2.2500
C6	1.8500	1.0800	1.2900	0.8900	3.5800	3.1500
C7	4.6800	2.3500	3.6200	4.6300	11.4200	6.1800
C8	5.5400	2.9600	5.5500	5.3100	11.2400	6.7100
C9	3.8000	1.9300	3.8000	4.5800	8.3200	5.0700
C10+	74.8700	84.1900	78.1200	76.3800	40.2000	64.3300
Benzene	0.1700	0.1100	0.1400	0.1000	1.6600	0.0500
Toluene	0.3400	0.1500	0.6900	0.1900	4.4100	0.2700
E-Benzene	0.0900	0.0300	0.1800	0.0400	0.2500	0.0500
Xylenes	0.3900	0.2000	1.2000	0.9800	2.5500	0.5900
n-C6	1.2200	0.6400	0.8700	0.5900	3.5700	2.4100
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 82	Sample Tank No. 83	Sample Tank No. 84	Sample Tank No. 85	Sample Tank No. 86	Sample Tank No. 87
E&P Tank Number	**Tank No. 36**	**Tank No. 37**	**Tank No. 38**	**Tank No. 39**	**Tank No. 40**	**Tank No. 41**
Total Emissions (tpy)	176.370	34.019	82.578	113.253	204.693	178.190
VOC Emissions (tpy)	121.493	16.601	32.683	56.649	107.904	100.629
Methane Emissions (tpy)	10.526	12.380	40.189	30.738	57.039	28.323
HAP Emissions (tpy)	**3.520**	**1.050**	**1.820**	**2.310**	**3.540**	**2.460**
Benzene	*0.068*	*0.262*	*0.364*	*0.285*	*0.530*	*0.307*
Toluene	*0.092*	*0.297*	*0.293*	*0.292*	*0.386*	*0.280*
E-Benzene	*0.019*	*0.011*	*0.016*	*0.018*	*0.030*	*0.012*
Xylenes	*0.072*	*0.048*	*0.125*	*0.138*	*0.208*	*0.068*
n-C6	*3.266*	*0.435*	*1.023*	*1.573*	*2.383*	*1.789*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	17	30	50	57	75	28
Separator Temperature (F)	100	125	68	80	81	60
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	100	125	68	80	81	60
C10+ SG	0.887	0.863	0.879	0.883	0.883	0.891
C10+ MW	283	276	356	294	288	277
API Gravity	**35.0**	**36.0**	**36.0**	**36.0**	**36.0**	**36.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.90	2.50	3.80	3.90	4.10	3.80
GOR (scf/bbl)	17.62	5.02	14.02	15.52	27.84	22.04
Heating Value of Vapor (Btu/s	2307.25	1616.36	1437.32	1721.01	1718.90	1846.39
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.2000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0900	0.0300	0.0300	0.0600	0.1400	0.0600
N2	0.0100	0.0000	0.0100	0.0100	0.0100	0.0100
C1	0.5300	0.9100	2.4200	1.5900	2.9000	1.3300
C2	1.1100	0.3200	0.4500	0.7200	0.9500	0.9300
C3	1.7600	0.5700	0.8100	1.1100	1.4500	1.7200
i-C4	0.8000	0.3900	0.5400	0.7700	1.0000	0.4400
n-C4	2.3800	0.5800	1.1700	1.6000	1.8400	1.9800
i-C5	2.1600	0.6500	1.3400	1.5200	1.6700	1.2300
n-C5	2.6700	0.5700	1.6000	1.6700	1.7900	2.2100
C6	3.3700	1.0700	2.4800	2.5900	2.1500	2.4300
C7	6.0700	3.3600	7.6400	7.1400	6.1000	9.4100
C8	6.8700	5.7300	10.3500	9.7000	7.9700	10.5500
C9	6.0400	4.2600	5.9100	5.1000	5.2600	6.0500
C10+	62.5300	77.9200	57.3100	59.8700	61.4100	54.5600
Benzene	0.0700	0.5500	0.8300	0.5000	0.5100	0.6300
Toluene	0.2600	1.5800	2.0500	1.5100	1.0900	1.8200
E-Benzene	0.1300	0.1300	0.2900	0.2400	0.2200	0.2100
Xylenes	0.5600	0.6500	2.6900	2.1000	1.7300	1.4100
n-C6	2.5900	0.7300	2.0800	2.2000	1.8100	2.8200
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 88	Sample Tank No. 89	Sample Tank No. 90	Sample Tank No. 91	Sample Tank No. 92	Sample Tank No. 93
E&P Tank Number	**Tank No. 42**	**Tank No. 43**	**Tank No. 44**	**Tank No. 45**	**Tank No. 46**	**Tank No. 47**
Total Emissions (tpy)	264.744	77.810	341.571	746.422	120.452	114.826
VOC Emissions (tpy)	197.667	45.796	126.289	598.797	71.033	53.659
Methane Emissions (tpy)	4.156	20.047	121.935	12.450	24.855	41.873
HAP Emissions (tpy)	**5.070**	**1.720**	**2.060**	**7.990**	**1.310**	**1.960**
Benzene	*0.536*	*0.269*	*0.294*	*3.587*	*0.126*	*0.496*
Toluene	*6.120*	*0.232*	*0.161*	*0.449*	*0.199*	*0.291*
E-Benzene	*0.040*	*0.014*	*0.036*	*0.061*	*0.009*	*0.009*
Xylenes	*0.205*	*0.121*	*0.106*	*0.072*	*0.077*	*0.052*
n-C6	*3.677*	*1.081*	*1.462*	*3.820*	*0.900*	*1.109*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	18	18	190	22	24	60
Separator Temperature (F)	95	98	70	50	68	72
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	95	98	70	50	68	72
C10+ SG	0.9	0.871	0.861	0.918	0.872	0.863
C10+ MW	288	270	270	372	239	318
API Gravity	**36.0**	**37.0**	**37.0**	**37.0**	**38.0**	**38.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	7.20	3.90	3.00	4.90	3.60	4.50
GOR (scf/bbl)	23.68	10.02	53.74	67.22	15.46	17.44
Heating Value of Vapor (Btu/s	2352.89	1820.80	1489.35	2491.03	1867.10	1590.85
LP Oil Component						
H2S	0.8700	0.0000	0.0000	0.1400	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.1200	0.0500	0.3100	0.5300	0.0200	0.0500
N2	0.0200	0.0000	0.0300	0.0000	0.0000	0.0000
C1	0.1900	1.0400	6.2500	0.5600	1.1400	2.5500
C2	0.6800	0.4200	2.2000	2.3100	0.5800	0.8600
C3	2.5400	0.9700	2.0200	4.1000	1.2600	1.3500
i-C4	1.1400	1.1500	0.5500	1.9100	0.9300	0.9700
n-C4	3.8100	1.3100	1.1800	5.0000	1.4400	1.3600
i-C5	2.9900	1.6600	0.8300	3.4000	1.6100	1.4200
n-C5	2.9100	1.2800	0.7100	3.5100	1.3900	1.3400
C6	3.7100	2.1200	1.3200	3.0200	2.3200	2.1100
C7	9.0500	5.2700	3.8300	13.2800	6.5000	5.5300
C8	7.1100	7.7200	6.7800	13.1300	8.7200	7.6500
C9	5.9500	4.7200	2.8000	5.9600	5.9100	5.6600
C10+	52.8400	67.1300	69.1900	36.1900	62.7500	64.2400
Benzene	0.4700	0.5000	0.1800	2.6100	0.3100	0.8400
Toluene	1.5000	1.1900	0.3000	1.0600	1.5000	1.4900
E-Benzene	0.2400	0.1800	0.1800	0.4000	0.1800	0.1200
Xylenes	1.4100	1.7200	0.6100	0.5500	1.7900	0.8100
n-C6	2.4500	1.5700	0.7300	2.3400	1.6500	1.6500
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 94	Sample Tank No. 95	Sample Tank No. 96	Sample Tank No. 97	Sample Tank No. 98	Sample Tank No. 99
E&P Tank Number	**Tank No. 48**	**Tank No. 49**	**Tank No. 50**	**Tank No. 51**	**Tank No. 52**	**Tank No. 53**
Total Emissions (tpy)	54.705	437.309	165.905	279.758	608.810	254.487
VOC Emissions (tpy)	37.588	181.269	149.208	103.605	571.582	161.927
Methane Emissions (tpy)	8.963	1.079	0.600	12.141	8.030	48.433
HAP Emissions (tpy)	**2.550**	**4.660**	**4.640**	**1.630**	**17.380**	**7.830**
Benzene	*0.263*	*0.041*	*0.202*	*0.453*	*0.424*	*2.228*
Toluene	*0.317*	*0.110*	*0.380*	*0.085*	*0.458*	*1.268*
E-Benzene	*0.024*	*0.053*	*0.035*	*0.015*	*0.025*	*0.039*
Xylenes	*0.218*	*0.149*	*0.168*	*0.017*	*0.441*	*0.399*
n-C6	*1.726*	*4.311*	*3.855*	*1.063*	*16.032*	*3.892*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	32	62	13	28	22	66
Separator Temperature (F)	149	80	113	45	114	89
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	149	80	113	45	114	89
C10+ SG	0.862	0.894	0.882	0.904	0.877	0.877
C10+ MW	251	310	294	294	337	282
API Gravity	**38.0**	**38.0**	**38.0**	**38.0**	**38.0**	**39.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.00	5.20	5.70	7.40	3.10	3.70
GOR (scf/bbl)	5.82	37.60	13.60	28.24	45.82	30.08
Heating Value of Vapor (Btu/s	2216.65	1206.29	2853.46	1313.43	3053.30	1945.58
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	4.1200	0.0100	2.0000	0.0400	0.1800
N2	0.0000	0.0200	0.0000	0.0000	0.2000	0.0000
C1	0.5100	0.0500	0.0300	0.5300	0.4200	2.2600
C2	0.4400	0.3200	0.4500	1.0400	0.5700	0.8400
C3	0.5900	1.4800	2.4200	1.9800	2.1600	1.4800
i-C4	0.5400	0.8700	1.1900	1.4200	1.1400	1.0300
n-C4	0.6500	3.3500	3.2300	3.7800	4.2600	1.6000
i-C5	1.3500	3.0800	2.0600	2.9700	2.9000	2.0600
n-C5	1.1500	2.8200	3.0500	2.9500	4.2900	1.8600
C6	2.5000	4.7100	2.3400	2.6800	3.5200	3.4100
C7	6.4600	10.0400	7.7900	11.8900	10.3400	8.6400
C8	8.5600	11.8100	8.3700	11.7900	9.9300	11.0300
C9	3.4500	6.4100	6.4400	6.6500	4.4300	5.1000
C10+	69.3200	46.8100	57.0400	45.6300	51.0200	51.2400
Benzene	0.3200	0.0300	0.2000	1.1100	0.1100	1.6600
Toluene	0.9100	0.2400	0.9900	0.7100	0.3100	2.6900
E-Benzene	0.1500	0.3000	0.2100	0.3600	0.0400	0.2100
Xylenes	1.4800	0.9700	1.1500	0.4800	0.7800	2.4200
n-C6	1.6100	2.5700	3.0300	2.0300	3.5400	2.2900
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 100	Sample Tank No. 101	Sample Tank No. 102	Sample Tank No. 103
E&P Tank Number	**Tank No. 54**	**Tank No. 55**	**Tank No. 56**	**Tank No. 57**
Total Emissions (tpy)	173.095	363.718	391.465	274.631
VOC Emissions (tpy)	97.629	237.995	191.567	204.825
Methane Emissions (tpy)	52.151	56.163	3.830	22.453
HAP Emissions (tpy)	**4.410**	**2.820**	**5.090**	**19.640**
Benzene	*0.242*	*0.369*	*0.970*	*5.674*
Toluene	*0.281*	*0.045*	*0.836*	*4.267*
E-Benzene	*0.031*	*0.026*	*0.019*	*0.070*
Xylenes	*0.164*	*0.129*	*0.135*	*0.436*
n-C6	*3.689*	*2.253*	*3.127*	*9.194*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	60	60	33	42
Separator Temperature (F)	80	58	60	110
Ambient Pressure (psia)	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	58	60	110
C10+ SG	0.891	0.877	0.907	0.879
C10+ MW	265	309	295	283
API Gravity	**39.0**	**39.0**	**39.0**	**39.0**
Production Rate (bbl/day)	500	500	500	500
Reid Vapor Pressure (psia)	5.60	6.80	6.40	5.40
GOR (scf/bbl)	23.36	43.14	36.04	26.60
Heating Value of Vapor (Btu/s	1766.66	2016.56	1509.76	2428.31
LP Oil Component				
H2S	0.0000	0.0000	0.1100	0.0000
O2	0.0000	0.0000	0.0000	0.0000
CO2	0.0500	0.0300	2.4000	0.0100
N2	0.0100	0.0100	0.0000	0.0000
C1	2.3200	2.6700	0.1600	1.0900
C2	0.7200	1.7300	0.7600	1.5000
C3	1.1900	3.6000	2.6400	2.1200
i-C4	0.8900	1.8800	0.9100	0.8400
n-C4	1.8300	3.2300	3.5800	2.2800
i-C5	2.3500	2.4900	2.6500	1.6400
n-C5	3.2400	2.1100	3.4400	2.5200
C6	3.9900	2.7200	3.7800	2.6100
C7	9.9400	8.1600	10.7700	9.7300
C8	11.5600	11.9800	11.8300	8.9300
C9	6.0600	4.9500	6.1900	5.8900
C10+	48.9900	50.3400	40.8600	47.7300
Benzene	0.3000	0.3800	1.2700	2.7500
Toluene	1.0300	0.1500	3.4900	5.3000
E-Benzene	0.2900	0.2400	0.2200	0.2000
Xylenes	1.7800	1.3700	1.8000	1.3900
n-C6	3.4600	1.9600	3.1400	3.4700
224Trimethylp	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000

Tank ID					**API > 40**		
E&P Tank Number		**Average**	**ratios to HAP**	**Ratio to VOC**	**Maximum**	**Minimum**	**Average**
Total Emissions (tpy)	Total	785.812			8152.118	129.419	1530.229
VOC Emissions (tpy)	VOC	530.750	**33.837**		5678.554	43.734	1046.343
Methane Emissions (tpy)	Methane	116.167	**7.406**	**0.219**	1206.981	0.197	230.569
HAP Emissions (tpy)	**HAP**	**15.685**		**0.030**	**101.610**	**2.680**	**30.684**
Benzene							
Toluene							
E-Benzene							
Xylenes							
n-C6							
224Trimethylp							
Separator Pressure (psig)	Separator Pressure	126.451			870.000	13.000	231.870
Separator Temperature (F)	Separator Temperature	88.657			140.000	40.000	82.500
Ambient Pressure (psia)							
Ambient Temperature (F)							
C10+ SG		0.893			0.929	0.801	0.873
C10+ MW		292.72			375.000	162.000	241.304
API Gravity	**API Gravity**	**40.6**			**68.0**	**40.0**	**52.8**
Production Rate (bbl/day)							
Reid Vapor Pressure (psia)	RVP	5.691			13.100	3.000	7.983
GOR (scf/bbl)	GOR	88.149			924.960	12.300	172.479
Heating Value of Vapor (Btu/s	Heating value	1968.085					
LP Oil Component		**Composition**					
H2S		0.0679					
O2		0.0000					
CO2		0.3661					
N2		0.0360					
C1		2.9248					
C2		1.6262					
C3		2.7564					
i-C4		1.3958					
n-C4		2.9738					
i-C5		2.4711					
n-C5		2.7194					
C6		3.2723					
C7		8.5230					
C8		10.3202					
C9		5.6686					
C10+		48.1339					
Benzene		0.6044					
Toluene		1.6882					
E-Benzene		0.1797					
Xylenes		1.4353					
n-C6		2.8369					
224Trimethylp		0.0000					
		100.0000					

Tank ID	API <40		
E&P Tank Number	**Maximum**	**Minimum**	**Average**
Total Emissions (tpy)	746.422	13.397	174.327
VOC Emissions (tpy)	598.797	3.087	107.227
Methane Emissions (tpy)	124.465	0.115	22.193
HAP Emissions (tpy)	**19.640**	**0.070**	**3.366**
Benzene	5.674	0.003	0.445
Toluene	6.120	0.003	0.431
E-Benzene	0.086	0.000	0.019
Xylenes	0.732	0.001	0.120
n-C6	16.032	0.052	2.449
224Trimethylp	0.000	0.000	0.000
Separator Pressure (psig)	280.000	4.000	39.857
Separator Temperature (F)			
Ambient Pressure (psia)			
Ambient Temperature (F)			
C10+ SG	0.984	0.861	0.910
C10+ MW	551.000	239.000	334.946
API Gravity	**39.0**	**15.0**	**30.6**
Production Rate (bbl/day)			
Reid Vapor Pressure (psia)	7.400	0.600	3.809
GOR (scf/bbl)	67.220	2.340	18.878
Heating Value of Vapor (Btu/s			
LP Oil Component			
H2S			
O2			
CO2			
N2			
C1			
C2			
C3			
i-C4			
n-C4			
i-C5			
n-C5			
C6			
C7			
C8			
C9			
C10+			
Benzene			
Toluene			
E-Benzene			
Xylenes			
n-C6			
224Trimethylp			

API Gravity >40		**API Gravity <40**	
VOC Emissions (tpy)		*VOC Emissions (tpy)*	
Mean	1046.343	Mean	107.2265
Standard Error	188.1410357	Standard Error	15.51304
Median	530.989	Median	72.87
Mode	#N/A	Mode	#N/A
Standard Deviation	1276.034588	Standard Deviation	116.0889
Sample Variance	1628264.269	Sample Variance	13476.64
Kurtosis	3.35522263	Kurtosis	9.02191
Skewness	1.864492873	Skewness	2.680349
Range	5634.82	Range	595.71
Minimum	43.734	Minimum	3.087
Maximum	5678.554	Maximum	598.797
Sum	48131.778	Sum	6004.685
Count	46	Count	56
Largest(1)	5678.554	Largest(1)	598.797
Confidence Level(95.0%)	378.9354921	Confidence Level(95.0%)	31.08882
	667.4075079		76.1377
VOC	1046.343	VOC	107.2265
	1425.278492		138.3153

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Hydrocarbon Emissions Characterization in the Colorado Front Range – A Pilot Study

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Abstract

The multi-species analysis of daily air samples collected at the NOAA Boulder Atmospheric Observatory (BAO) in Weld County in northeastern Colorado since 2007 shows highly correlated alkane enhancements caused by a regionally distributed mix of sources in the Denver-Julesburg Basin. To further characterize the emissions of methane and non-methane hydrocarbons (propane, n-butane, i-pentane, n-pentane and benzene) around BAO, a pilot study involving automobile-based surveys was carried out during the summer of 2008. A mix of venting emissions (leaks) of raw natural gas and flashing emissions from condensate storage tanks can explain the alkane ratios we observe in air masses impacted by oil and gas operations in northeastern Colorado. Using the WRAP Phase III inventory of total volatile organic compound (VOC) emissions from oil and gas exploration, production and processing, together with flashing and venting emission speciation profiles provided by State agencies or the oil and gas industry, we derive a range of bottom-up speciated emissions for Weld County in 2008. We use the observed ambient molar ratios and flashing and venting emissions data to calculate top-down scenarios for the amount of natural gas leaked to the atmosphere and the associated methane and non-methane emissions. Our analysis suggests that the emissions of the species we measured are most likely underestimated in current inventories and that the uncertainties attached to these estimates can be as high as a factor of two.

1) Introduction

Since 2004, the National Oceanic and Atmospheric Administration Earth System Research Laboratory (NOAA ESRL) has increased its measurement network density over North America, with continuous carbon dioxide (CO_2) and carbon monoxide (CO) measurements and daily collection of discrete air samples at a network of tall towers [Andrews et al., in preparation] and bi-weekly discrete air sampling along vertical aircraft profiles [Sweeney et al., in preparation]. Close to 60 chemical species or isotopes are measured in the discrete air samples, including long-lived greenhouse gases (GHGs) such as CO_2, methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6), tropospheric ozone precursors such as CO and several volatile organic compounds (VOCs), and stratospheric-ozone-depleting substances. The NOAA multi-species regional data set provides unique information on how important atmospheric trace gases vary in space and time over the continent, and it can be used to quantify how different processes contribute to GHG burdens and/or affect regional air quality.

In this study we focus our analysis on a very strong alkane atmospheric signature observed downwind of the Denver-Julesburg Fossil Fuel Basin (DJB) in the Colorado Northern Front Range (Figures 1 and 1S). In 2008, the DJB was home to over 20,000 active natural gas and condensate wells. Over 90% of the production in 2008 came from tight gas formations.

A few recent studies have looked at the impact of oil and gas operations on air composition at the local and regional scales in North America. Katzenstein et al. [2003] reported results of two intensive surface air discrete sampling efforts over the Anadarko

Fossil Fuel Basin in the southwestern United States in 2002. Their analysis revealed substantial regional atmospheric CH_4 and non-methane hydrocarbon (NMHC) pollution over parts of Texas, Oklahoma, and Kansas, which they attributed to emissions from the oil and gas industry operations. More recently, Schnell et al. [2009] observed very high wintertime ozone levels in the vicinity of the Jonah-Pinedale Anticline natural gas field in western Wyoming. Ryerson et al. [2003], Wert et al. [2003], de Gouw et al. [2009] and Mellqvist et al. [2009] reported elevated emissions of alkenes from petrochemical plants and refineries in the Houston area and studied their contribution to ozone formation. Simpson et al. [2010] present an extensive analysis of atmospheric mixing ratios for a long list of trace gases over oil sands mining operations in Alberta during one flight of the 2008 Arctic Research of the Composition of the Troposphere from Aircraft and Satellites campaign. Our study distinguishes itself from previous ones by the fact that it relies substantially on the analysis of daily air samples collected at a single tall-tower monitoring site between August 2007 and April 2010.

Colorado has a long history of fossil fuel extraction [Scamehorn, 2002]. Colorado natural gas production has been increasing since the 1980s, and its share of national production jumped from 3% in 2000 to 5.4% in 2008. 1.3% of the nationally produced oil in 2008 also came from Colorado, primarily from the DJB in northeastern Colorado and from the Piceance Basin in western Colorado. As of 2004, Colorado also contained 43 natural gas processing plants, representing 3.5% of the conterminous US processing capacity [EIA, 2006], and two oil refineries, located in Commerce City, in Adams County just north of Denver.

Emissions management requirements for both air quality and climate-relevant gases have led the state of Colorado to build detailed baseline emissions inventories for ozone precursors, including volatile organic compounds (VOCs), and for GHGs. Since 2004, a large fraction of the Colorado Northern Front Range, including Weld County and the Denver metropolitan area, has been in violation of the 8-hour ozone national ambient air quality standard [CDPHE, 2008a]. In December 2007, the Denver and Colorado Northern Front Range (DNFR) region was officially designated as a Federal Non-Attainment Area (NAA) for repeated violation in the summertime of the ozone National Ambient Air Quality Standard (see area encompassed by golden boundary in Figure 1). At the end of 2007, Colorado also adopted a Climate Action Plan, which sets greenhouse gas emissions reduction targets for the state [Ritter, 2007].

Methane, a strong greenhouse gas with a global warming potential (GWP) of 25 over a 100 yr time horizon [IPCC, 2007], accounts for a significant fraction of Colorado GHG emissions, estimated at 14% in 2005 ([Strait et al., 2007] and Table 1S; note that in this report, the oil and gas industry CH_4 emission estimates were calculated with the EPA State Greenhouse Gas Inventory Tool). The natural gas industry (including exploration, production, processing, transmission and distribution) is the single largest source of CH_4 in the state of Colorado (estimated at 238 Gg/yr or ktonnes/yr), followed closely by coal mining (233 Gg/yr); note that all operating surface and underground coal mines are now in western Colorado. Emission estimates for oil production operations in the state were much lower, at 9.5 Gg/yr, than those from gas production. In 2005, Weld County represented 16.5% of the state's natural gas production and 51% of the state crude oil/ natural gas condensate production (Table 2S). Scaling the state's total CH_4 emission estimates from Strait et al. [2007], rough estimates for the 2005 CH_4 source from natural gas production and processing operations and from natural gas condensate/oil production in Weld County are 19.6 Gg and 4.8 Gg, respectively. It is important to stress here that there are large uncertainties associated with these inventory-derived estimates.

Other important sources of CH_4 in the state include large open-air cattle feedlots, landfills, wastewater treatment facilities, forest fires, and agriculture waste burning, which are all difficult to quantify. 2005 state total CH_4 emissions from enteric fermentation and manure management were estimated at 143 and 48 Gg/yr, respectively [Strait et al., 2007]; this combined source is of comparable magnitude to the estimate from natural gas systems. On-road transportation is not a substantial source of methane [Nam et al., 2004].

In 2006, forty percent of the DNFR NAA's total anthropogenic VOC emissions were estimated to be due to oil and gas operations [CDPHE, 2008b]. Over the past few years, the State of Colorado has adopted more stringent VOC emission controls for oil and gas exploration and processing activities. In 2007, the Independent Petroleum Association of Mountain States (IPAMS, now Western Energy Alliance), in conjunction with the Western Regional Air Partnership (WRAP), funded a working group to build a state-of-the-knowledge process-based inventory of total VOC and NOx sources involved in oil and gas exploration, production and gathering activities for the western United State's fossil fuel basins, hereafter referred to as the WRAP Phase III effort (http://www.wrapair.org/forums/ogwg/index.html). Most of the oil and gas production in the DJB is concentrated in Weld County. Large and small condensate storage tanks in the County are estimated to be the largest VOC fossil fuel production source category (59%

and 9% respectively), followed by pneumatic devices (valve controllers) and unpermitted fugitives emissions (13% and 9% respectively). A detailed breakdown of the WRAP oil and gas source contributions is shown in Figure 2S for 2006 emissions and projected 2010 emissions [Bar-Ilan et al., 2008a,b]). The EPA NEI 2005 for Weld County, used until recently by most air quality modelers, did not include VOC sources from oil and natural gas operations (Table 3S).

Benzene (C_6H_6) is a known human carcinogen and it is one of the 188 hazardous air pollutants (HAPs) tracked by the EPA National Air Toxics Assessment (NATA). Benzene, like VOCs and CH_4, can be released at many different stages of oil and gas production and processing. Natural gas itself can contain varying amounts of aromatic hydrocarbons, including C_6H_6 [EPA, 1998]. Natural gas associated with oil production (such sources are located in several places around the DJB) usually has higher C_6H_6 levels [Burns et al., 1999] than non-associated natural gas. Glycol dehydrators used at wells and processing facilities to remove water from pumped natural gas can vent large amounts of C_6H_6 to the atmosphere when the glycol undergoes regeneration [EPA, 1998]. Condensate tanks, venting and flaring at the well-heads, compressors, processing plants, and engine exhaust are also known sources of C_6H_6 [EPA, 1998]. C_6H_6 can also be present in the liquids used for fracturing wells [EPA, 2004].

In this paper, we focus on describing and interpreting the measured variability in CH_4 and $C_{3\text{-}5}$ alkanes observed in the Colorado Northern Front Range. We use data from daily air samples collected at a NOAA tall tower located in Weld County as well as continuous CH_4 observations and discrete targeted samples from an intensive mobile sampling campaign in the Colorado Northern Front Range. These atmospheric measurements are then used together with other emissions data sets to provide an independent view of methane and non-methane hydrocarbon emissions inventory results.

The paper is organized as follows. Section 2 describes the study design and sampling methods. Section 3 presents results from the tall tower and the Mobile Lab surveys, in particular the strong correlation among the various alkanes measured. Based on the multi-species analysis in the discrete air samples, we were able to identify two major sources of C_6H_6 in Weld County. In section 4.1 we discuss the results and in section 4.2 we compare the observed ambient molar ratios with other relevant data sets, including raw natural gas composition data from 77 gas wells in the DJB. The last discussion section, 4.3, is an attempt to shed new light on methane and VOC emission estimates from oil and gas operations in Weld County. We first describe how we derived speciated bottom-up emission estimates based on the WRAP Phase III total VOC emission inventories for counties in the DJB. We then used 1) an average ambient propane-to-methane molar ratio, 2) a set of bottom-up estimates of propane and methane flashing emissions in Weld County and 3) three different estimates of the propane-to-methane molar ratio for the raw gas leaks to build top-down methane and propane emission scenarios for venting sources in the county. We also scaled the top-down propane (C_3H_8) estimates with the observed ambient alkane ratios to calculate top-down emission estimates for n-butane (n-C_4H_{10}), i- and n-pentane (i-C_5H_{12}, n-C_5H_{12}), and benzene. We summarize our main conclusions in section 5.

2) The Front Range Emissions Study: Sampling Strategy, Instrumentation, and Sample Analysis

2.1. Overall Experimental Design

The Colorado Northern Front Range study was a pilot project to design and test a new measurement strategy to characterize GHG emissions at the regional level. The anchor of the study was a 300-m tall tower located in Weld County, 25 km east-northeast of Boulder and 35 km north of Denver, called the Boulder Atmospheric Observatory (BAO) [40.05°N, 105.01°W; base of tower at 1584 m above sea level] (Figure 1). The BAO is situated on the southwestern edge of the DJB. A large landfill and a wastewater treatment plant are located a few kilometers southwest of BAO. Interstate 25, a major highway going through Denver, runs in a north-south direction 2 km east of the site. Both continuous and discrete air sampling have been conducted at BAO since 2007.

To put the BAO air samples into a larger regional context and to better understand the sources that impacted the discrete air samples, we made automobile-based on-road air sampling surveys around the Colorado Northern Front Range in June and July 2008 with an instrumented "Mobile Lab" and the same discrete sampling apparatus used at all the NOAA towers and aircraft sampling sites.

2.2. BAO and other NOAA cooperative Tall Towers

The BAO tall tower has been used as a research facility of boundary layer dynamics since the 1970s [Kaimal and Gaynor, 1983]. The BAO tower was instrumented by the NOAA ESRL Global Monitoring Division (GMD) in Boulder in April 2007, with sampling by a quasi-continuous CO_2 non-dispersive infrared sensor and a CO Gas Filter Correlation instrument, both oscillating between three intake levels (22, 100 and 300 m above ground level) [Andrews et al., in preparation]. Two continuous ozone UV-absorption instruments have also been deployed to monitor ozone at the surface and at the 300-m level.

The tower is equipped to collect discrete air samples from the 300-m level using a programmable compressor package (PCP) and a programmable flasks package (PFP) described later in section 2.4. Since August 2007 one or two air samples have been taken approximately daily in glass flasks using PFPs and a PCP. The air samples are brought back to GMD for analysis on three different systems to measure a series of compounds, including methane (CH_4 , also referred to as C_1), CO, propane (C_3H_8, also referred to as C_3), n-butane (n-C_4H_{10}, nC_4), isopentane (i-C_5H_{12}, iC_5), n-pentane (n-C_5H_{12}, nC_5), acetylene (C_2H_2), benzene, chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs) and hydrofluorocarbons (HFCs). Ethane and i-butane were not measured.

In this study, we use the results from the NOAA GMD multi-species analysis of air samples collected midday at the 300-m level together with 30- second wind speed and direction measured at 300-m. 30-minute averages of the wind speed and direction prior to the collection time of each flask are used to separate samples of air masses coming from three different geographic sectors: the North and East (NE sector), where the majority of the DJB oil and gas wells are located; the South (S sector), mostly influenced by the Denver metropolitan area; and the West (W sector), with relatively cleaner air.

In 2008, NOAA and its collaborators were operating a regional air sampling network of eight towers and 18 aircraft profiling sites located across the continental US employing in-situ measurements (most towers) and flask sampling protocols (towers and aircraft sites) that were similar to those used at BAO. Median mixing ratios for several alkanes, benzene, acetylene, and carbon monoxide from BAO and a subset of five other

NOAA towers and from one aircraft site are presented in the Results (Section 3). Table 1 provides the three letter codes used for each sampling site, their locations and sampling heights. STR is located in San Francisco. WGC is located 34 km south of downtown Sacramento in California's Central Valley where agriculture is the main economic sector. Irrigated crop fields and feedlots contribute to the higher CH_4 observed at WGC. The LEF tower in northern Wisconsin is in the middle of the Chequamegon National Forest which is a mix of temperate/boreal forest and lowlands/wetlands [Werner et al., 2003]. Air samples from NWF (surface elevation 3050m), in the Colorado Rocky Mountains, mostly reflect relatively unpolluted air from the free troposphere. The 457m tall Texas tower (WKT) is located between Dallas/Fort Worth and Austin. It often samples air masses from the surrounding metropolitan areas. In summer especially, it also detects air masses with cleaner background levels arriving from the Gulf of Mexico. The SGP NOAA aircraft sampling site [Sweeney et al., in preparation; http://www.esrl.noaa.gov/gmd/ccgg/aircraft/] in northern Oklahoma is also used in the comparison study. At each aircraft site, twelve discrete air samples are collected at specified altitudes on a weekly or biweekly basis. Oklahoma is the fourth largest state for natural gas production in the USA [EIA, 2008] and one would expect to observe signatures of oil and gas drilling operations at both SGP and BAO. Additional information on the tower and aircraft programs is available at http://www.esrl.noaa.gov/gmd/ccgg/. Median summer mixing ratios for several alkanes, C_2H_2, C_6H_6 and CO are presented in the Results section.

2.3. Mobile Sampling

Two mobile sampling strategies were employed during this study. The first, the Mobile Lab, consisted of a fast response CO_2 and CH_4 analyzer (Picarro, Inc.), a CO gas-filter correlation instrument from Thermo Environmental, Inc., an O_3 UV-absorption analyzer from 2B Technologies and a Global Positioning System (GPS) unit. All were installed onboard a vehicle. A set of 3 parallel inlets attached to a rack on top of the vehicle brought in outside air from a few meters above the ground to the instruments. Another simpler sampling strategy was to drive around and collect flask samples at predetermined locations in the Front Range region. A summary of the on-road surveys is given in Table 2.

The Mobile Lab's Picarro Envirosense $CO_2/CH_4/H_2O$ analyzer (model G1301, unit CFADS09) employs Wavelength-Scanned Cavity Ring-Down Spectroscopy (WS-CRDS), a time-based measurement utilizing a near-infrared laser to measure a spectral signature of the molecule. CO_2, CH_4, and water vapor were measured at a 5-second sampling rate (0.2 Hz), with a standard deviation of 0.09 ppm in CO_2 and 0.7 ppb for CH_4. The sample was not dried prior to analysis, and the CO_2 and CH_4 mole fractions were corrected for water vapor after the experiment based on laboratory tests. For water mole fractions between 1% and 2.5%, the relative magnitude of the CH_4 correction was quasi-linear, with values between 1 and 2.6%. CO_2 and CH_4 mole fractions were assigned against a reference gas tied to the relevant World Meteorological Organization (WMO) calibration scale. Total measurement uncertainties were 0.1 ppm for CO_2 and 2 ppb for CH_4 [Sweeney et al., in preparation]. The CO and ozone data from the Mobile Lab are not discussed here. GPS data were also collected in the Mobile Lab at 1 Hz, to allow data from the continuous analyzers to be merged with the location of the vehicle.

The excursions with the flask sampler (PFP) focused on characterizing the concentrations of trace gases in Boulder (June 4 and 11, 2008), the northeastern Front Range (June 19), Denver (July 1) and around oil and gas wells and feedlots in Weld County south of Greeley (July 14) (see Table 2). Up to 24 sampling locations away from direct vehicle emissions were chosen before each drive.

Each Mobile Lab drive lasted from four to six hours, after a ~30 min warm-up on the NOAA campus for the continuous analyzer before switching to battery mode. The first two Mobile Lab drives, which did not include discrete air sampling, were surveys around Denver (July 9) and between Boulder and Greeley (July 15). The last two drives with the Mobile Lab (July 25 and 31) combined in-situ measurements with discrete flask sampling to target emissions from specific sources: the quasi-real-time display of the data from the continuous CO_2/CH_4 analyzer was used to collect targeted flask samples at strong CH_4 point sources in the vicinity of BAO. Discrete air samples were always collected upwind of the surveying vehicle and when possible away from major road traffic.

2.4. Chemical Analyses of Flask Samples

Discrete air samples were collected at BAO and during the road surveys with a two-component collection apparatus. One (PCP) includes pumps and batteries, along with an onboard microprocessor to control air sampling. Air was drawn through Teflon tubing attached to an expandable 3-m long fishing pole. The second package (PFP) contained a sampling manifold and twelve cylindrical, 0.7L, glass flasks of flow-through design, fitted with Teflon O-ring on both stopcocks. Before deployment, manifold and flasks were leak-checked then flushed and pressurized to ~1.4 atm with synthetic dry zero-air containing approximately 330 ppm of CO_2 and no detectable CH_4. During sampling, the manifold and flasks were flushed sequentially, at ~5 L min^{-1} for about 1 min and 10 L min^{-1} for about 3 minutes respectively, before the flasks were pressurized to 2.7 atm. Upon returning to the NOAA lab, the PFP manifold was leak-checked and meta-data recorded by the PFP during the flushing and sampling procedures were read to verify the integrity of each air sample collected. In case of detected inadequate flushing or filling, the affected air sample is not analyzed.

Samples collected in flasks were analyzed for close to 60 compounds by NOAA GMD (http://www.esrl.noaa.gov/gmd/ccgg/aircraft/analysis.html). In this paper, we focus on eight species: 5 alkanes (CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12}) as well as CO, C_2H_2 and C_6H_6. CH_4 and CO in each flask were first quantified on one of two nearly identical automated analytical systems (MAGICC 1 & 2). These systems consist of a custom-made gas inlet system, gas-specific analyzers, and system-control software. Our gas inlet systems use a series of stream selection valves to select an air sample or standard gas, pass it through a trap for drying maintained at ~-80°C, and then to an analyzer.

CH_4 was measured by gas chromatography (GC) with flame ionization detection (±1.2 ppb = average repeatability determined as 1 s.d. of ~20 aliquots of natural air measured from a cylinder) [Dlugokencky et al., 1994]. We use the following abbreviations for measured mole fractions: ppm = μmol mol^{-1}, ppb = nmol mol^{-1}, and ppt = pmol mol^{-1}. CO was measured directly by resonance fluorescence at ~150 nm (±0.2 ppb) [Gerbig et al., 1999; Novelli et al., 1998]. All measurements are reported as dry air mole fractions relative to internally consistent calibration scales maintained at NOAA (http://www.esrl.noaa.gov/gmd/ccl/scales.html).

Gas chromatography/mass spectrometric (GC/MS) measurements were also performed on ~200 mL aliquots taken from the flask samples and pre-concentrated with a cryogenic trap at near liquid nitrogen temperatures [Montzka et al., 1993]. Analytes desorbed at ~110^{o}C were then separated by a temperature-programmed GC column (combination 25 m x 0.25 mm DB5 and 30 m x 0.25 mm Gaspro), followed by detection with mass spectrometry by monitoring compound-specific ion mass-to-charge ratios. Flask sample responses were calibrated versus whole air working reference gases which, in turn, are calibrated with respect to gravimetric primary standards (NOAA scales: benzene on NOAA-2006 and all other hydrocarbons (besides CH_4) on NOAA-2008). We used a provisional calibration for n-butane based on a diluted Scott Specialty Gas standard. Total uncertainties for analyses from the GC/MS reported here are <5% (accuracy) for all species except n-C_4H_{10} and C_2H_2, for which the total uncertainty at the time of this study was of the order of 15-20%. Measurement precision as repeatability is generally less than 2% for compounds present at mixing ratios above 10 ppt.

To access the storage stability of the compounds of interest in the PFPs, we conducted storage tests of typically 30 days duration, which is greater than the actual storage time of the samples used in this study. Results for C_2H_2 and C_3H_8 show no statistically significant enhancement or degradation with respect to our "control" (the original test gas tank results) within our analytical uncertainty. For the remaining species, enhancements or losses average less than 3% for the 30 day tests. More information on the quality control of the flask analysis data is available at http://www.esrl.noaa.gov/gmd/ccgg/aircraft/qc.html.

The flask samples were first sent to the GC/MS instrument for hydrocarbons, CFCs, and HFCs before being analyzed for major GHGs. This first step was meant to screen highly polluted samples that could potentially damage the greenhouse gas MAGICC analysis line with concentrations well above "background" levels. The time interval between flask collection and flask analysis spanned between 1 to 11 days for the GC/MS analysis and 3 to 12 days for MAGICC analysis.

3) Results

3.1 BAO tall tower: long-term sampling platform for regional emissions

3.1.1 Comparing BAO with other sampling sites in the US

Air samples collected at BAO tower have a distinct chemical signature (Figure 2), showing enhanced levels of most alkanes (C_3H_8, nC_4H_{10}, iC_5H_{12} and nC_5H_{12}) in comparison to results from other NOAA cooperative tall towers (see summary of site locations in Table 1 and data time series in Figure 1S). The midday summer time median mixing ratios for C_3H_8 and $n\text{-}C_4H_{10}$ at BAO were at least 6 times higher than those observed at most other tall tower sites. For $i\text{-}C_5H_{12}$ and $n\text{-}C_5H_{12}$, the summertime median mixing ratios at BAO were at least 3 times higher than at the other tall towers.

In Figure 2, we show nighttime measurements at the Niwot Ridge Forest tower (NWF) located at a high elevation site on the eastern slopes of the Rocky Mountains, 50 km west of BAO. During the summer nighttime, downslope flow brings clean air to the tower [Roberts et al., 1984]. The median summer mixing ratios at NWF for all the species shown in Figure 2 are much lower than at BAO, as would be expected given the site's remote location.

Similarly to BAO, the northern Oklahoma aircraft site, SGP, exhibits high alkane levels in the boundary layer and the highest methane summer median mixing ratio of all sites shown in Figure 2 (1889 ppb at SGP vs. 1867 ppb at BAO). As for BAO, SGP is located in an oil- and gas-producing region. Oklahoma, the fourth largest state in terms of natural gas production in the US, has a much denser network of interstate and intrastate natural gas pipelines compared to Colorado. Katzenstein et al. [2003] documented the spatial extent of alkane plumes around the gas fields of the Anadarko Basin in Texas, Oklahoma, and Kansas during two sampling intensives. The authors estimated that methane emissions from the oil and gas industry in that entire region could be as high as 4-6 Tg CH_4/yr, which is 13-20% of the US total methane emission estimate for year 2005 reported in the latest EPA US GHG Inventory [EPA, 2011a].

Enhancements of CH_4 at BAO are not as striking in comparison to other sites. CH_4 is a long-lived gas destroyed predominantly by its reaction with OH radicals. CH_4 has a background level that varies depending on the location and season [Dlugokencky et al., 1994], making it more difficult to interpret differences in median summer CH_4 mixing ratios at the suite of towers. Since we do not have continuous measurements of CH_4 at any of the towers except WGC, we cannot clearly separate CH_4 enhancements from background variability in samples with levels between 1800 and 1900 ppb if we only look at CH_4 mixing ratios by themselves (see more on this in the next section).

3.1.2 Influence of different sources at BAO

3.1.2.1. Median mixing ratios in the three wind sectors

To better separate the various sources influencing air sampled at BAO, Figure 3 shows the observed median mixing ratios of several species as a function of prevailing wind direction. For this calculation, we only used samples for which the associated 30-minute average wind speed (prior to collection time) was larger than 2.5 m/s. We separated the data into three wind sectors: NE, including winds from the north, northeast and east (wind directions between 345^o and 120^o); S, including south winds (120^o to 240^o); and W, including winds from the west (240^o to 345^o).

For the NE sector, we can further separate summer (June to August) and winter (November to April) data. For the other two wind sectors, only the winter months have enough data points. The species shown in Figure 3 have different photochemical lifetimes [Parrish et al., 1998], and all are shorter-lived in the summer season. This fact, combined with enhanced vertical mixing in the summer, leads to lower mixing ratios in summer than in winter.

Air masses from the NE sector pass over the oil and gas wells in the DJB and exhibit large alkane enhancements. In winter, median mole fractions of C_3-C_5 alkanes are 8 to 11 times higher in air samples from the NE compared to the samples from the W sector, while the median CH_4 value is 76 ppb higher. The NE wind sector also shows the highest median values of C_6H_6, but not CO and C_2H_2.

C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers in air samples from the NE wind sector are much higher than in air samples coming from the Denver metropolitan area in the South wind sector. Besides being influenced by Denver, southern air masses may pass over two operating landfills, the Commerce City oil refineries, and some oil and gas wells (Figure 1). The S sector BAO CO and C_2H_2 mixing ratios are higher than for the other wind sectors, consistent with the higher density of vehicular emission sources [Harley et al., 1992; Warneke et al., 2007; Baker et al., 2008] south of BAO. There are also occasional spikes in CFC-11 and CFC-12 mixing ratios in the S sector (not shown). These are most probably due to leaks from CFC-containing items in the landfills. Air parcels at BAO coming from the east pass over Interstate Highway 25, which could explain some of the high mole fractions observed for vehicle combustion tracers such as CO, C_2H_2, and C_6H_6 in the NE sector data (see more discussion on C_6H_6 and CO in section 4.4 & Figure 4).

The W wind sector has the lowest median mole fractions for all anthropogenic tracers, consistent with a lower density of emission sources west of BAO compared to the other wind sectors. However, the S and W wind sectors do have some data points with high alkane values, and these data will be discussed further below.

3.1.2.2. Strong alkane source signature

To detect if the air sampled at BAO has specific chemical signatures from various sources, we looked at correlation plots for the species shown in Figure 3. Table 3 summarizes the statistics for various tracer correlations for the three different wind sectors. Figure 4 (left column) shows correlation plots of some of these BAO species for summer data in the NE wind sector.

Even though BAO data from the NE winds show the largest alkane mixing ratios (Figure 3), all three sectors exhibit strong correlations between C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers (Table 3). The r^2 values for the correlations between C_3H_8 and n- C_4H_{10} or the C_5H_{12} isomers are over 0.9 for the NE and W sectors. CH_4 is also well correlated with C_3H_8 in the NE wind sector for both seasons. For the NE wind sector BAO summertime data, a min/max range for the C_3H_8/CH_4 slope is 0.099 to 0.109 ppb/ppb.

The tight correlations between the alkanes suggest a common source located in the vicinity of BAO. Since large alkane enhancements are more frequent in the NE wind sector, this common source probably has larger emissions north and east of the tower. This NE wind sector encompasses Interstate Highway 25 and most of the DJB oil and gas wells. The C_3-C_5 alkane mole fractions do not always correlate well with combustion tracers such as C_2H_2 and CO for the BAO NE wind sector ($C_{3\text{-}5}$/CO and $C_{3\text{-}5}/C_2H_2$: $r^2 < 0.3$ for 50 summer samples; $C_{3\text{-}5}$/CO: $r^2 < 0.4$ and $C_{3\text{-}5}/C_2H_2$: $r^2 \sim 0.6$ for 115 winter samples). These results indicate that the source responsible for the elevated alkanes at BAO is not the major source of CO or C_2H_2, which argues against vehicle combustion exhaust as being responsible. Northeastern Colorado is mostly rural with no big cities. The only operating oil refineries in Colorado are in the northern part of the Denver metropolitan area, south of BAO. The main industrial operations in the northeastern Front Range are oil and natural gas exploration and production and natural gas processing and transmission. We therefore hypothesize here that the oil and gas operations in the DJB, as noted earlier in Section 2, are a potentially substantial source of alkanes in the region.

3.1.2.3. At least two sources of benzene in BAO vicinity

The median winter C_6H_6 mixing ratio at BAO is higher for the NE wind sector compared to the South wind sector, which comprises the Denver metropolitan area. The C_6H_6-to-CO winter correlation is highest for the S and W wind sectors BAO samples (r^2=0.85 and 0.83 respectively) compared to the NE wind sector data (r^2=0.69). The C_6H_6-to-CO correlation slope is substantially higher for the NE wind sector data compared to the other two wind sectors, suggesting that there may be a source of benzene in the NE that is not a significant source of CO. The C_6H_6-to-C_2H_2 correlation slope is slightly higher for the NE wind sector data compared to the other two wind sectors. C_6H_6 in the BAO data from the NE wind sector correlates more strongly with C_3H_8 than with CO. The C_6H_6-to-C_3H_8 summer correlation slope for the NE wind sector is 10.1 ±1.2 ppt/ppb (r^2=0.67).

For the S and W wind sectors BAO data, the C_6H_6-to-C_2H_2 (0.27 - 0.32 ppt/ppt) and C_6H_6-to-CO (1.57 - 1.81 ppt/ppb) slopes are larger than observed emissions ratios for the Boston/New York City area in 2004: 0.171 ppt/ppt for C_6H_6-to-C_2H_2 ratio and 0.617 ppt/ppb for C_6H_6-to-CO ratio [Warneke et al., 2007]. Baker et al. [2008] report an atmospheric molar C_6H_6-to-CO ratio of 0.9 ppt/ppb for Denver in summer 2004, which is in between the Boston/NYC emissions ratio value reported by Warneke et al. [2007] and the BAO S and W wind sectors correlation slopes.

The analysis of the BAO C_6H_6 data suggests the existence of at least two distinct C_6H_6 sources in the vicinity of BAO: an urban source related mainly to mobile emissions, and a common source of alkanes and C_6H_6 concentrated in northeastern Colorado. We discuss C_6H_6 correlations and sources in more detail in section 4.4.

3.2. On-road surveys: tracking point and area source chemical signatures

Road surveys with flask sampling and the Mobile Lab with the fast-response CH_4 analyzer were carried out in June-July 2008 (Table 2). The extensive chemical analysis of air samples collected in the Front Range provides a snapshot of a broader chemical composition of the regional boundary layer during the time of the study. The Mobile Lab surveys around the Front Range using the in situ CH_4 analyzer allowed us to detect large-scale plumes with long-lasting enhancements of CH_4 mixing ratios as well as small-scale plumes associated with local CH_4 point sources. In the last two Mobile Lab surveys (surveys 8 and 9), we combined the monitoring of the continuous CH_4 analyzer with targeted flask sampling, using the CH_4 data to decide when to collect flask samples in and out of plumes.

The regional background CH_4 mixing ratio at the surface (interpreted here as the lowest methane level sustained for ~10 minutes or more) was between 1800 ppb and 1840 ppb for most surveys. Some of the highest "instantaneous" CH_4 mixing ratios measured during the Mobile Lab surveys were: 3166 ppb at a wastewater treatment plant, 2329 ppb at a landfill, 2825 ppb at a feedlot near Dacono, over 7000 ppb close to a feedlot waste pond near Greeley, and 4709 ppb at a large natural gas processing and propane plant in Fort Lupton (Figure 1).

The analysis of the summer 2008 intensive data suggests that regional scale mixing ratio enhancements of CH_4 and other alkanes are not rare events in the Colorado Northern Front Range airshed. Their occurrence and extent depends on both emissions and surface wind conditions, which are quite variable and difficult to predict in this area. During the Mobile Lab road surveys, the high-frequency measurements of CO_2 and CH_4 did not exhibit any correlation. Unlike CO_2, the CH_4 enhancements were not related to on-road emissions. Below we present two examples of regional enhancements of CH_4 observed during the Front Range Mobile Lab surveys.

3.2.1. Survey 9: $C_{3\text{-}5}$ alkane levels follow large-scale changes in methane

Figure 5 shows a time series of the continuous CH_4 mixing ratio data and alkane mixing ratios measured in twelve flask samples collected during the Front Range Mobile Lab survey on 31 July 2008 (flasks #1 to 12, sampled sequentially as shown in Figure 6). The wind direction on that day was from the ENE or E at the NCAR Foothills Lab and BAO tower. The Mobile Lab left the NOAA campus in Boulder around 11:40 am and measured increasing CH_4 levels going east towards the BAO tower (Figure 6). An air sample was collected close to the peak of the CH_4 broad enhancement centered around 11:55 am. The CH_4 mixing ratio then decreased over the next 25 minutes and reached a local minimum close to 1875 ppb. The CH_4 level stayed around 1875 ppb for over one hour and then decreased again, more slowly this time, to ~ 1830 ppb over the next two hours.

Flasks # 1 to 3 were collected before, at the peak, and immediately after the broad CH_4 feature between 11:40 and 12:15. Flasks # 4 & 5 were sampled close to a wastewater treatment plant and flasks # 7 to 8 were sampled in a landfill. The in situ measurements showed that CH_4 was still elevated above background as these samples were collected. After a 90-minute stop at BAO to recharge the Mobile Lab UPS batteries, flasks # 9 to 11 were collected in a corn field while the in situ measurements showed lower CH_4 levels. The last flask sample was collected on the NOAA campus just before 17:00 MDT, about 5.5 hours after the first flask sample was collected. The flask samples were always collected upwind of the Mobile Lab car exhaust.

Sharp spikes in the continuous CH_4 data reflect local point sources (wastewater treatment plant, landfill). The highly variable signals in both the continuous and discrete CH_4 close to these sources are driven by the spatial heterogeneity of the CH_4 emissions and variations in wind speed and direction. Broader enhancements in the continuous CH_4 data reflect larger (regional) plumes. The last flask (#12) sampled at NOAA has much higher levels of combustion tracers (CO, C_2H_2, C_6H_6) than the other samples.

Figure 7 shows correlation plots for C_3H_8 versus CH_4 and n-C_4H_{10} versus C_3H_8 in the 12 flasks taken on 31 July. Air samples not directly influenced by identified point sources (flasks #1-3, 6-7, 9-12) show a very strong correlation between the various measured alkanes. Using the data from the air samples not directly influenced by identified point sources (flasks #1-3, 6-7, 9-12), we derive a C_3H_8-to-CH_4 (C_3/C_1) mixing ratio slope of 0.097± 0.005 ppb/ppb (Figure 7A). This slope is very similar to the one observed for the summertime NE wind sector data at BAO (0.104± 0.005; Table 3). Three air samples collected downwind of the waste water treatment plant and the landfill (flasks # 4-5 and 8) are off the C_3H_8-to-CH_4 correlation line and have higher CH_4 than air samples collected nearby but not under the influence of these local CH_4 sources (flasks 3 and 6). Flask # 8 also has elevated CFC-11 (310 ppt) compared to the other samples collected that day (< 255 ppt), probably related to leaks from old appliances buried in the landfill.

The C_3-C_5 alkane mixing ratios in samples collected on 31 July are tightly correlated for flasks # 1 to 11 with $r^2 > 0.95$ (Figure 7B). As concluded for the BAO alkane mixing ratio enhancements earlier, this tight correlation suggests that the non-methane alkanes measured during the surveys are coming from the same source types. The nC_4/C_3 correlation slope on 31 July (0.47 ppb/ppb; flasks # 1-11) is similar to the summer slope in the BAO NE samples (0.45 ppb/ppb), while the 31 July iC_5/C_3 and nC_5/C_3 slopes are slightly higher (0.17 and 0.17 ppb/ppb, respectively) than for BAO (0.14 and 0.15 ppb/ppb, respectively).

3.2.2. Survey 6: Alkane enhancements in the Denver-Julesburg oil and gas production zone and cattle feedlot contributions to methane

The flask-sampling-only mobile survey on 14 July 2008 focused on the agricultural and oil and gas drilling region south of Greeley. Eleven of the twelve air samples collected on 14 July were taken over the Denver-Julesburg Basin (flasks# 2-12 in Figure 3S in Supplementary Material). Figure 8A shows a correlation plot of C_3H_8 versus CH_4 mixing ratios in these air samples. Flasks collected NE of BAO and not near feedlots (# 4, 6-8, and 10-12) fall on a line: y=0.114(x-1830) (r^2=0.99). This slope and the correlation slope calculated for the BAO NE wind sector data are indistinguishable (within the 1-σ uncertainties in the slopes). Four samples collected in the vicinity of four different cattle feedlots (flasks # 2, 3, 5, and 9) exhibit a lower C_3H_8-to-CH_4 correlation slope (0.083 ppb/ppb, r^2=0.93). The r^2 for the C_3H_8-to-CH_4 correlation using all the flasks is 0.91.

The n-C_4H_{10} versus C_3H_8 correlation plot and its slope, along with the n-C_4H_{10}–to-C_3H_8 and C_5H_{12}–to-C_3H_8 correlation slopes for air samples not collected downwind of feedlots are shown in Figure 8B. The r^2 for the n-C_4H_{10}-to-C_3H_8 correlation using all the flasks is 0.98, which is slightly higher than the r^2 for the C_3H_8-to-CH_4 correlation using all flasks (0.91). The r^2 for the i-C_5H_{12}-to-n-C_4H_{10} and n-C_5H_{12}-to-n-C_4H_{10} correlations using all the flasks are 0.96 ppb/ppb and 0.99 ppb/ppb, respectively. These results suggest that cattle feedlots have no substantial impact on n-C_4H_{10} and the C_5H_{12} levels.

The strong correlation observed between the various alkane mixing ratios for air samples not collected downwind of feedlots once again suggests that a common source contributes to most of the observed alkanes enhancements. It is possible that some of the C_3H_8 enhancements seen near the feedlots are due to leaks of propane fuel used for farm operations [Ronald Klusman, personal communication]. Two flask samples were collected downwind of a cattle feedlot near Dacono during Mobile Lab survey #8, on 25 July 2008. The analysis of these samples revealed large CH_4 enhancements (1946 and 2335 ppb), but no enhancement in C_3H_8 (~ 1ppb), n-C_4H_{10} (<300ppt), the C_5H_{12} (< 130ppt) or C_6H_6 (< 30ppt).

For survey #6, the n-C_4H_{10}-to-C_3H_8 correlation slope (0.56 ppb/ppb) is 16% higher than the summer slope observed at BAO for the NE wind sector data, while the 14 July i-C_5H_{12}-to-C_3H_8 and n-C_5H_{12}-to-C_3H_8 correlation slopes (0.24 and 0.23 ppb/ppb, respectively) are 76% and 53% higher, respectively, than the summer NE BAO data. These slopes are higher than for flasks from survey #9. The difference in the C_5/C_3 slopes between the various Mobile Lab surveys data and the BAO NE summer data may reflect the spatial variability in the alkane source molar composition.

3.2.3. Benzene source signatures

To look at the C_6H_6 correlations with other tracers, the 88 Mobile Lab flask samples have been divided into two subsets, none of which includes the three samples collected downwind of the natural gas and propane processing plant near Dacono, CO. In the summer, the lifetimes of C_6H_6 and C_3H_8 at 800 mbar and 40°N are close to 3 or 4 days and the lifetime of CO is about 10 days [Finlayson-Pitts and Pitts, 2000; Spivakovsky et al., 2000].

The first subset of 39 samples has C_3H_8 mixing ratios smaller than 3 ppb and it includes flasks collected mostly during surveys #2, 3 and 4. For this subset influenced mostly by urban and mobile emissions, C_6H_6 correlates well with CO (slope=1.82 ppt/ppb, r^2=0.89) and C_2H_2 (slope=0.37 ppt/ppt, r^2=0.75) but not with C_3H_8 (r^2<0.3). The C_6H_6-to-CO correlation slope for this subset is similar to the correlation slopes for the BAO S and W wind sector winter samples.

The second subset of 46 samples corresponds to flasks with a C_3H_8 mixing ratio larger than 3ppb. These flasks were collected mostly during surveys #1, 6, 8 and 9. For this second subset influenced mostly by emissions from the DJB, C_6H_6 correlates well with C_3H_8 (slope=17.9 ppt/ppb, r^2=0.95) but not with CO or C_2H_2 (r^2<0.3). The C_6H_6-to-

C_3H_8 slope for these samples is almost twice as big as the slope calculated for the BAO NE wind sector data (10.1 ppt/ppb) (Table 3).

4) Discussion

4.1. Comparing the alkane enhancements in the BAO and Mobile Lab data sets

In the previous section we showed two examples of enhanced alkanes in northeast Colorado using mobile sampling (surveys 6 and 9 on 14 and 31 July 2008, respectively). With lifetimes against OH removal on the order of 3.5, 1.7 and 1.0 days in the summer at 40^{o}N [Finlayson-Pitts and Pitts, 2000; Spivakovsky et al., 2000] respectively, C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers do not accumulate over the continent. Instead their atmospheric mixing ratios and the slopes of correlations between different alkanes reflect mostly local or regional sources within a few days of atmospheric transport.

The source responsible for the alkane enhancements observed at BAO and in multiple surveys during the Front Range Study appears to be located in the northeastern part of the Front Range region within the Denver-Julesburg Basin, so we call it the DJB source. The small differences in alkane correlation slopes for the BAO and Mobile Lab samples likely reflect differences in the emitted alkane molar ratios across this distributed source, as well as the mix of chemical ages for the air samples collected at a variety of locations and on different days.

In Table 3 and Figure 4, we compare the alkane correlation slopes in the Mobile Lab flask data set with the correlation slopes in the BAO data set. To calculate the DJB source C_3H_8-to-CH_4 correlation slope from the Mobile Lab data set, we have removed air samples collected downwind of feedlots, the wastewater treatment plant, and the natural gas and propane processing plant (Figure 1). The Mobile Lab flasks C_3H_8-to-CH_4 correlation slope is 0.095±0.007 ppb/ppb (R^2=0.76, 77 samples), similar to the slope calculated for the BAO NE wind sector data. Samples collected downwind of the natural gas processing plant exhibit variable chemical signatures, reflecting a complex mix of contributions from leaks of gas and combustion exhaust from flaring units and compressor engines.

To calculate the DJB source n-C_4H_{10}-to-C_3H_8, i-C_5H_{12}-to-C_3H_8 and n-C_5H_{12}-to-C_3H_8 correlation slopes from the Mobile Lab data set, we have removed the three air samples collected downwind of the natural gas and propane processing plant (Figure 1). The C_4/C_3, i-C_5/C_3 and n-C_5/C_3 correlation slopes in the Mobile Lab data are 0.49, 0.19 and 0.19 ppb/ppb, respectively (r^2> 0.8, 85 samples). The i-C_5/C_3 and n-C_5/C_3 correlation slopes are 40% and 30% higher, respectively, than the BAO NE sector summer slopes. If we remove the 11 data points from survey #6 samples collected in the middle of the DJB, the C_5H_{12}-to-C_3H_8 ratios are only 15% higher than calculated for the NE sector at BAO.

High correlations among various alkanes were reported in this region by Goldan et al. [1995]. In that study, hourly air samples were analyzed with an in-situ gas chromatograph deployed on a mesa at the western edge of Boulder for two weeks in

February 1991. CH_4 was not measured during that study. The correlation coefficient (r^2) between C_3H_8, n-C_4H_{10}, and the C_5H_{12} isomers was around 0.86, with a clear minimum slope for the abundance ratios (see Figure 4 in Goldan et al. [1995]). The authors proposed that the C_4-C_6 alkanes shared one common source with propane (called the "C_3 source" in the next section and in Figure 9), with additional emissions contributing to some C_4-C_6 alkane enhancements.

4.2. Comparing the Front Range observed alkane signatures with VOC emissions profiles for oil and gas operations in the Denver-Julesburg Basin

In this section we compare the alkane ratios calculated from the BAO NE wind sector and the Mobile Lab samples to emissions profiles from the DJB oil and gas exploration and production sector. Most of these profiles were provided by the WRAP Phase III inventory team, who developed total VOC and NOx emission inventories for oil and gas production and processing operation in the DJB for 2006 [Bar-Ilan et al., 2008a]. Emissions and activity data were extrapolated by the WRAP Phase III inventory team to derive emission estimates for 2010 based on projected production numbers and on state and federal emissions control regulations put in place in early 2008 for oil and gas permitted activities in the DNFR NAA [Bar-Ilan et al., 2008b]. The VOCs included in the inventories are: C_3H_8, i,n-C_4H_{10}, i,n-C_5H_{12} and higher alkanes, C_6H_6, toluene, ethyl-benzene, xylenes and 224-trimethylpentane. The WRAP Phase III inventories for 2006 and 2010 were only provided as total VOC and NOx emitted at the county level for all the counties in the Colorado part of the DJB. The emission estimates are based on various activity data (including the number of new wells (spuds), the total number of wells, estimates of oil, condensate and gas production, and equipment counts) and measured/reported or estimated VOC speciation profiles for the different source categories. Supplementary Figure 2S and Bar-Ilan et al. [2008a,b] present more details on how the inventory emission estimates are derived.

We focus primarily on flashing and venting sources here, since the WRAP Phase III inventory indicates that these two sources are responsible for 95% of the total VOC emissions from oil and gas exploration and production operations in Weld County and in the NAA [Bar-Ilan et al., 2008a,b] (see Figure 2S). In 2006, all the oil produced in the DJB was from condensate wells. Condensate tanks at well pads or processing plants store a mostly-liquid mix of hydrocarbons and aromatics separated from the lighter gases in the raw natural gas. Flash losses or emissions happen for example when the liquid condensate is exposed to decreasing atmospheric pressure: gases dissolved in the liquid are released and some of the heavier compounds may be entrained with these gases. Flashing emissions from condensate storage tanks are the largest source of VOCs from oil and gas operations in the DJB. In the DNFR NAA, operators of large condensate tanks have to control and report emission estimates to the Colorado Department of Public Health and the Environment (CDPHE). In 2006 and 2010 flashing emissions represented 69% and 65% respectively of the total VOC source from oil and gas exploration, production and processing operations, for the nine counties in the NAA (see supplementary Figure 2S and Bar-Ilan et al. [2008a] for more details on how the estimates are derived).

Venting emissions are related to loss of raw natural gas when a new oil or gas well is drilled or when an existing well is vented (blowdown), repaired or restimulated (recompletion). Equipment at active well sites (e.g. well head, glycol dehydrators and pumps) or in the midstream network of compressors and pipelines gathering the raw natural gas can also leak significant amounts of natural gas. In the WRAP Phase III inventory, venting emissions represented 27% and 21% respectively of the total VOC estimated source from the NAA oil and gas operations in 2006 and 2010 ([Bar-Ilan et al., 2008a,b], Figure 2S).

The molar compositions of venting and flashing emissions are quite different (see supplementary Figure 4S). Emissions from flash losses are enriched in C_{2+} alkanes compared to the raw natural gas emissions. To convert the total VOC bottom-up source into speciated emission ratio estimates, we use molar ratio profiles for both flashing and venting emissions reported in three data sets:

- Bar-Ilan et al. [2008a]: mean venting profile used for the 2006 DJB inventory, also called the "Venting-WRAP" profile;
- Colorado Oil and Gas Conservation Commission [COGCC, 2007]: composition of 77 samples of raw natural gas collected at different wells in the Greater Wattenberg Area in December 2006, also called "Venting-GWA" profiles. Note that C_6H_6 was not reported in this data set;
- Colorado Department of Public Health and the Environment (CDPHE, personal communication): flashing emissions profiles based on condensate composition data from 16 different storage tanks in the DJB and EPA TANK2.0 (flashing emissions model) runs.

Figure 9 shows a comparison of the alkane molar ratios for the raw natural gas and flash emissions data sets with the correlation slopes derived for the Mobile Lab 2008 samples and for air samples collected at BAO in the summer months only (between August 2007 and April 2010) for the NE wind sector (cf. Table 4S to get the plotted values). The alkane correlation slopes observed at BAO and across the Northern Front Range with the Mobile Lab are all within the range of ratios reported for flashing and/or venting emissions. The C_{3-5} alkane ratios for both flashing and venting emissions are too similar for their atmospheric ratios to be useful in distinguishing between the two source processes. The ambient C_3H_8-to-CH_4 and n-C_4H_{10}-to-CH_4 molar ratios are lower than what could be expected from condensate tank flashing emissions alone, indicating that most of the CH_4 observed came from the venting of raw natural gas. In the next section, we will describe how we derive bottom-up emission estimates for CH_4 and C_3H_8 as well as three top-down emissions scenarios consistent with the observed atmospheric slopes.

Figure 9 also shows the correlation slopes calculated by Goldan et al. [1995] for the 1991 Boulder study. These slopes compare very well with the BAO and Mobile Lab results and the oil and gas venting and flashing emissions ratios. Goldan et al. [1995] compared the measured C_4/C_3 and C_5/C_3 ratios for the Boulder C_3 source (see definition in Section 4.1) with the ratios reported in the locally distributed pipeline-quality natural gas for February 1991, and concluded that the common C_3H_8 and higher alkane source was not linked with the local distribution system of processed natural gas. However, the composition of the raw natural gas at the extraction well is quite different from the purified pipeline-quality natural gas distributed to end-users. Processed pipeline-quality natural gas delivered throughout the USA is almost pure CH_4 [Gas Research Institute, 1992]. Since Goldan et al. [1995] did not measure CH_4 in their 1991 study, they could not determine if the atmospheric C_{3+}/C_1 alkane ratios were higher than expected in processed natural gas.

4.3. Estimation of the alkane source in Weld County

Bottom-up speciated emission estimates

In this section, we derive bottom-up and top-down estimates of alkane emissions from the DJB source for Weld County. We have averaged the 2006 and 2010 WRAP Phase III total VOC emissions data [Bar-Ilan et al., 2008ab] to get bottom-up estimates for the year 2008, resulting in 41.3 Gg/yr for flashing emissions and 16.8 Gg/yr for venting emissions. There are no uncertainty estimates provided in the WRAP Phase III inventory. 2006 total VOC flashing emission estimates in Weld County are based on reported emissions for controlled large condensate tanks (34.8 Gg/yr) and calculated emissions for uncontrolled small condensate tanks (5.4 Gg/yr) (see [Bar-Ilan et al., 2008] for more details). Uncertainties attached to these estimates may be due to inaccurate emissions factors (number of pounds of VOC flashed per tons of condensate produced) and/or inaccurate estimate of the effectiveness of emission control systems.

The WRAP Phase III total VOC emission from venting sources for Weld County was calculated by averaging industry estimates of the volume of natural gas vented or leaked to the atmosphere by various processes shown in Figure 2S (well blowdown, well completion, pneumatic devices…). A basin-wide average of gas composition analyses provided by oil and gas producers was then used to compute a bottom-up estimate of the total mass of VOC vented to the atmosphere by oil and gas exploration, production and processing operations. Uncertainties attached to the venting source can be related to uncertainties in leak rates or intensity of out-gassing events, as well to the variability in the composition of raw natural gas, none of which were quantitatively taken into account in the WRAP Phase III inventory.

Next we describe the calculations, summarized in Figure 5S, to derive bottom-up estimates of venting and flashing emissions for the various trace gases we measured using information from the WRAP Phase III inventory and the COGCC GWA raw natural gas composition data set (Table 4 and supplementary Figure 6S). From the total annual vented VOC source and the average vented emission profile provided by Bar-Ilan et al. [2008a] (Table 2S), we derived an estimate of the volume of natural gas that we assumed is vented to the atmosphere by the oil and gas production and processing operations in Weld County. Following Bar-Ilan et al. inventory data and assumptions [2008a], we used the weight fraction of total VOC in the vented gas (18.74%), the molar mass of the vented gas (21.5g/mol) and standard pressure and temperature with the ideal gas law to assume that 1 mole of raw natural gas occupies a volume 22.4 L (as was done in the WRAP Phase III inventory). The total volume of vented gas we calculate for Weld County in 2008 is 3.36 billion cubic feet (Bcf), or the equivalent of 1.68% of the total natural gas produced in the county in 2008 (202.1 Bcf). We then use the estimate of the volume of vented gas and the molar composition profiles for the 77 raw natural gas samples reported in the COGCC GWA study to compute average, minimum, and maximum emissions for CH_4, each of the C_{3-5} alkanes we measured, and C_6H_6. Using this procedure, 2008 Weld County average venting CH_4 and C_3H_8 bottom-up source estimates are 53.1 Gg/yr and 7.8 Gg/yr, respectively (Table 4).

For flashing emissions, we distributed the WRAP 2008 total annual VOC source estimate (41.3 Gg/yr) using the modeled flash loss composition profiles for 16 different condensate tanks provided by the CDPHE. Average CH_4 and C_3H_8 emissions as well as the minimum and maximum estimates are reported in Table 4. The 2008 average flashing CH_4 and C_3H_8 bottom-up emission estimates are 11.2 Gg/yr and 18.3 Gg/yr, respectively (Table 4). The total flashing + venting CH_4 and C_3H_8 bottom-up estimates range from 46 to 86 Gg/yr and from 15 to 52 Gg/yr, respectively.

Top-Down emissions scenarios

Finally, we use our atmospheric measurements to bring new independent constraints for the estimation of venting and flashing emissions in Weld County in 2008. The exercise consists in calculating three top-down venting emission scenarios for CH_4 and C_3H_8 (x_m, x_p: mass of methane and propane vented respectively) consistent with a mean observed CH_4-to-C_3H_8 atmospheric molar ratio of 10 ppb/ppb (Table 4) in the DJB. We assume, as done earlier in the bottom-up calculations, that the observed C_3H_8-to-CH_4 ratio in the DJB results from a combination of flashing and venting emissions. The bottom-up information used here is (1) the set of speciated flashing emissions derived earlier for the 16 condensate tanks provided by CDPHE for CH_4 and C_3H_8 $(y_m, y_p)_{\text{tank}=1,16}$, and (2) three scenarios for the basin-average raw (vented) natural gas CH_4-to-C_3H_8 molar ratio, denoted $v_{m/p}$. The three values used for basin-average vented gas CH_4-to-C_3H_8 molar ratio are: 18.75, which is the WRAP Phase III inventory assumption (scenario 1);

15.43, which is the median of the molar ratios for the COGCC GWA 77 gas samples (scenario 2); and 24.83, which is the mean of the molar ratios for the COGCC GWA 77 gas samples (scenario 3). For each vented gas profile scenario, we use the set of 16 flash emission estimates to calculate an ensemble of venting emission estimates for CH_4 (x_m) and C_3H_8 (x_p) following the two equations below.

The first equation formalizes the assumption for CH_4-to-C_3H_8 molar ratio of the vented raw natural gas, with M_m (16g/mol) and M_p (44g/mol) being the molar masses of CH_4 and C_3H_8 respectively.:

$$v_{m/p} = \frac{M_p}{M_m} \times \frac{x_m}{x_p} \qquad (1)$$

In the second equation, the mean observed atmospheric CH_4-to-C_3H_8 molar ratio ($a_{m/p}$=10 ppb/ppb) constrains the overall ratio of methane versus propane emitted by both flashing and venting sources. Therefore, for each set of 16 bottom-up flashed emission estimates (y_m, y_p), we have:

$$\frac{M_p\left(x_m + y_m\right)}{M_m\left(x_p + y_p\right)} = a_{m/p} \qquad (2)$$

The analytical solutions to this set of equations are given by:

$$\begin{aligned} x_p &= \frac{1}{\left(v_{m/p} - a_{m/p}\right)} \times \left(a_{m/p} \times y_p - \frac{M_p}{M_m} y_m\right) \\ x_m &= v_{m/p} \times \frac{M_m}{M_p} \times x_p \end{aligned} \qquad (3)$$

The average, minimum and maximum venting emission estimates, x_m and x_p, are reported for the three vented gas profile scenarios in Table 4 and Figure 10.

The first goal of this top-down estimation exercise is to highlight the many assumptions required to build the bottom-up and top-down emission estimates. The choices made for the WRAP Phase III inventory or our top-down calculations are all reasonable, and the uncertainty attached to the values chosen (if available) should be propagated to calculate total uncertainty estimates for the final emission products. When the error propagation is done conservatively, the emission uncertainty is close to a factor of 2 for both CH_4 and C_3H_8. This number is much higher than the 30% uncertainty reported by the EPA for the 2009 national CH_4 source estimate from natural gas systems [EPA, 2011c].

The scenario 1 mean top-down vented CH_4 source (118.4 Gg/yr) is twice as large as the bottom-up estimate of 53.1 Gg/yr (Table 4). If we assume that 77% (by volume) of the raw gas is CH_4, an average estimate of 118.4 Gg/yr of CH_4 vented would mean that the equivalent of 4% of the 2008 natural gas gross production in Weld County was vented. It is important to note that the top-down scenarios cover a large range (67-229 Gg/yr), corresponding to between 2.3% and 7.7% of the annual production being lost to the atmosphere through venting (Table 4). The lowest estimate is, however, larger than what we derived from the WRAP Phase III bottom-up inventory (1.68%). If instead of using the EIA [EIA, 2004] convention for the molar volume of gas (23.6 L/mol), we used the standard molar volume used by WRAP (22.4 L/mol), our top-down calculations of the volume of gas vented would be 5% lower than reported in Table 4.

Emissions for the other alkanes measured are all derived from the C3H8 total sources scaled with the atmospheric molar ratios observed in the BAO NE summer samples and the Mobile Lab samples. Figure 10 shows a comparison of the bottom-up estimates and the top-down emission scenarios (mean of scenario 1 and overall minimum and maximum of the three scenarios).

The main result of this exercise is that for each of the three top-down total emissions scenarios, the mean estimates for CH_4, n-C_4H_{10} and the C_5H_{12} isomers are at least 60% higher than the bottom-up mean estimates. The minimum top-down emissions scenarios are lower than (in the case of C_3H_8) or higher than (for CH_4, nC_4H_{10}, i-C_5H_{12}, n-C_5H_{12}) the bottom-up mean estimates.

To put the top-down CH_4 source estimate from oil and gas exploration, production and processing operations in perspective, we compare it with an estimate of the passive "geological" CH_4 flux over the entire DJB. Klusman and Jakel [1998] reported an average flux of 0.57 mg CH_4/m^2/day in the DJB due to natural microseepage of light alkanes. Multiplied by a rough upper boundary estimate of the DJB surface area (Figure 1), the estimated annual natural flux is 0.66 Gg CH_4 /yr, or less than 1% of the top-down venting source estimated for active exploration and production of natural gas in Weld County.

4.4. Benzene sources in the Northern Front Range

On-road vehicles are estimated to be the largest source of C_6H_6 in the US [EPA, 2009a]. Emissions from on-road and off-road vehicles and from large point sources (including chemical plants and refineries) have been regulated by the EPA for over thirty years [Fortin et al., 2005; Harley et al., 2006]. When motor vehicle combustion dominates emissions, such as in the BAO S and W wind sectors, C_6H_6 correlates well with CO and C_2H_2.

Crude oil and natural gas production and processing emitted an estimated 8333 tonnes of benzene nationally in 2005, which represented 2% of the national total C_6H_6

source [EPA, 2009a]. C_6H_6 and C_3H_8 have similar photochemical lifetimes (~ 3-4 days in the summer), so the observed atmospheric ratios we report in Table 3 should be close to their emission ratio if they are emitted by a common source. The strong correlation between C_6H_6 and C_3H_8 (Figure 4, Table 3) for the BAO NE wind sector and in the DJB Mobile Lab air samples suggests that oil and gas operations could also be a non-negligible source of C_6H_6 in the Northern Colorado Front Range.

The C_6H_6-to-C_3H_8 molar ratios in the flash losses from 16 condensate tanks simulated with the EPA TANK model are between 0.4 to 5.6 ppt/ppb. The C_6H_6-to-C_3H_8 molar ratio reported for vented emissions in the WRAP Phase III inventory is 5.3 ppt/ppb, based on regionally averaged raw gas speciation profiles provided by local companies [Bar-Ilan et al., 2008a] (only an average profile was provided, other data is proprietary). These emission ratios are at least a factor of two lower than the atmospheric ratios measured in the Front Range air samples influenced by the DJB source (Table 3).

If we use the mean C_3H_8 emission estimate for scenario 1 described in Section 4.3 (35.7 Gg/yr), together with the C_6H_6-to-C_3H_8 correlation slope for the summer BAO NE wind sector data and that from the Mobile Lab samples (10.1 ppt/ppb and 17.9 ppt/ppb respectively), we derive a C_6H_6 emission estimate for the DJB source in Weld County in 2008 of 639 tonnes/yr (min/max range: 478/883 tonnes/yr) and 1145 tonnes/yr (min/max range: 847/1564 tonnes/yr), respectively. As expected, these numbers are much higher than what we derived for the bottom-up flashing and venting emissions (total of 139 tonnes/yr, min/max range of 49-229 tonnes/yr). For comparison, C_6H_6 emissions from facilities in Colorado reporting to the US EPA for the Toxics Release Inventory amounted to a total of 3.9 tonnes in 2008 [EPA, 2009b] and on–road emissions in Weld

County were estimated at 95.4 tonnes/yr in 2008 [CDPHE, personal communication]. Based on our analysis, oil and gas operations in the DJB could be the largest source of C_6H_6 in Weld County.

More measurements are needed to further evaluate the various potential sources associated with oil and gas operations (for example, glycol dehydrators and condensate tank flash emissions). The past two iterations of the C_6H_6 emissions inventory developed by the State of Colorado for the National Emissions Inventory and compiled by the EPA do not show much consistency from one year to another. The 2008 and 2005 NEI reported very different C_6H_6 emission estimates for condensate tanks in Weld County (21.5 Mg/yr versus 1120 Mg/yr, respectively; see also Table 3S). Estimates in the 2008 NEI are much closer to estimates provided by CDPHE (personal communication) for 2008 (21.3 Mg/yr), suggesting the 2005 NEI estimate may be flawed, even though it is in the range of our top-down estimation. We conclude that the current level of understanding of emissions of C_6H_6 from oil and gas operations cannot explain the top-down range of estimates we derive in our study, suggesting that, once again, more field measurements are needed to understand and quantify oil and gas operation sources.

5) Conclusion

This study provides a regional overview of the processes impacting ambient alkane and benzene levels in northeastern Colorado in the late 2000s. We report atmospheric observations collected by two sampling platforms: a 300-m tall tower located in the SW corner of Weld County (samples from 2007 to 2010), and road surveys by a Mobile Lab equipped with a continuous methane analyzer and discrete canister sampling (June-July 2008). The analysis of the tower data filtered by wind sector reveals a strong alkane and benzene signature in air masses coming from northeastern Colorado, where the main activity producing these compounds is related to oil and gas operations over the Denver–Julesburg Fossil Fuel Basin. Using the Mobile Lab platform, we sampled air directly downwind of different methane sources (oil and gas wells, a landfill, feedlots, and a waste water treatment plant) and collected targeted air samples in and out of plumes. The tall tower and Mobile Lab data both revealed a common source for air masses with enhanced alkanes. In the data from both platforms, the alkane mixing ratios were strongly correlated, with slight variations in the correlation slopes depending on the location and day of sampling. The alkanes did not correlate with combustion tracers such as carbon monoxide and acetylene. We hypothesize that the observed alkanes were emitted by the same source located over the Denver-Julesburg Basin, "the DJB source".

The second part of the study brings in information on VOC emissions from oil and gas activities in the DJB from the detailed bottom-up WRAP Phase III inventory [Bar Ilan et al., 2008a,b]. We have used the total VOC emission inventory and associated emissions data for DJB condensate and gas production and processing operations to calculate annual emission estimates for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The main findings are summarized below:

- The emissions profiles for flashing and venting losses are in good agreement with the atmospheric alkane enhancement ratios observed during this study and by Goldan et al. [1995] in Boulder in 1991. This is consistent with the hypothesis that the observed alkane atmospheric signature is due to oil and gas operations in the DJB.

- The three top-down emission scenarios for oil and gas operations in Weld County in 2008 give a rather large range of potential emissions for CH_4 (71.6-251.9 Gg/yr) and the higher alkanes. Except for propane, the lowest top-down alkanes emission estimates are always larger than the inventory-based mean estimate we derived based on the WRAP Phase III inventory data and the COGCC GWA raw gas composition data set.
- There are notable inconsistencies between our results and state and national regulatory inventories. In 2008 gas wells in Weld County represented 15% of the state's production. Based on our top-down analysis, Weld County methane emissions from oil and gas production and processing represent at least 30% of the state total methane source from natural gas systems derived by Strait et al. [2007] using the EPA State Inventory Tool. The methane source from natural gas systems in Colorado is most likely underestimated by at least a factor of two. Oil and gas operations are the largest source of alkanes in Weld County. They were included as a source of "total VOC" in the 2008 EPA NEI for Weld County but not in the 2005 NEI.
- There are at least two main sources of C_6H_6 in the region: one related to combustion processes, which also emit CO and C_2H_2 (engines and mobile vehicles), and one related to the DJB alkane source. The C_6H_6 source we derived based on flashing and venting VOC emissions in the WRAP inventory (143 Mg/yr) most likely underestimates the actual total source of C_6H_6 from oil and gas

operations. Our top-down source estimates for C_6H_6 from oil and gas operations in Weld County cover a large range: 385-2056 Mg/yr. Again, the lowest figure is much higher than reported in the 2008 CDPHE inventory for Weld County oil and gas total point sources (61.8 Mg/yr).

- Samples collected at the BAO tall tower or while driving around the Front Range reflect the emissions from a complex mix of sources distributed over a large area. Using a multi-species analysis including both climate and air quality relevant gases, we can start unraveling the contributions of different source types. Daily multi-species measurements from the NOAA collaborative network of tall towers in the US provide a unique opportunity to understand source chemical signatures in different airsheds and how these emissions may change over time.
- More targeted multi-species well-calibrated atmospheric measurements are needed to evaluate current and future bottom-up inventory emissions calculations for the fossil fuel energy sector and to reduce uncertainties on absolute flux estimates for climate and air quality relevant trace gases.

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List of Figures

Figure 1: Map of the study area centered on the Boulder Atmospheric Observatory (BAO), located 25 km east-northeast of Boulder. Overlaid on this map are the locations of active oil and gas wells (light purple dots) as of April 2008 (data courtesy of SkyTruth, http://blog.skytruth.org/2008/06/colorado-all-natural-gas-and-oil-wells.html, based on COGCC well data). Also shown are the locations of landmarks used in the study, including selected point sources (NGP Plant = natural gas processing plant, WWT Plant = Lafayette wastewater treatment plant).

Figure 2: Observed median mixing ratios for several species measured in air samples taken at various sites at midday during June-August (2007-2010). The sites are described in Table 1. Only nighttime samples are shown for NWF to capture background air with predominantly down-slope winds. Notice the different units with all columns and the different scaling applied to methane, propane and n-butane.

Figure 3: Summertime and wintertime median mixing ratios of several species measured in air samples from the 300-meter level at the BAO tower for three wind sectors: North and East (NE) where the density of gas drilling operations is highest, South (S) with Denver 35 km away, and West (W) with mostly clean air. The time span of the data is from August 2007 to April 2010. Summer includes data from June to August and winter includes data from November to April. Due to the small number of data points (<15), we do not show summer values for the S and W wind sectors. Data outside of the 11am-3pm local time window were not used. Notice the different scales used for methane, propane and n-butane. The minimum number of data points used for each wind sector is: NE summer 33, NE winter 89, S winter 65 and W winter 111.

Figure 4: Correlation plots for various species measured in the BAO summertime NE wind sector flask samples (left column) and summer 2008 Mobile Lab (right column) samples. Data at BAO were filtered to keep only midday air samples collected between June and August over the time period spanning August 2007 to August 2009. See also Table 3.

Figure 5: (Top panel) Time series of the continuous methane measurements from Mobile Lab Survey # 9 on July 31, 2008. Also shown are the mixing ratio data for the 12 flask samples collected during the road survey. The GC/MS had a faulty high energy dynode cable when these samples were analyzed, resulting in more noisy data for the alkanes and the CFCs ($\sigma < 10\%$ instead of 5%). However, the amplitudes of the $C_{3\text{-}5}$ alkane signals are much larger than the noise here. The methane mixing ratio scale is shown on the left hand vertical axis. For all other alkanes, refer to the right hand vertical axis.
(Bottom panel) Time series of wind directions at the NCAR Foothills and Mesa Laboratories in Boulder (see Figure 6 for locations) and from the 300-m level at the BAO on July 31, 2008.

Figure 6: Continuous methane observations (colored squares) and flask (circles) samples collected during the July 31, 2008 Mobile Lab Survey #9 in Boulder and Weld County. The size of the symbols (and the symbol color for the continuous methane data) represents the mixing ratio of continuous/flask methane (squares, green circles) and flask propane (blue circles). The labels indicate the flask sample number (also shown in the time series in Figure 5). NCAR = National Center for Atmospheric Research, FL = NCAR Foothills Laboratory, ML = NCAR Mesa Laboratory, WWT Plant = Lafayette wastewater treatment plant.

Figure 7: A) Propane versus methane mixing ratios for air samples collected during Survey #9 on July 31, 2008. B) n-butane versus propane mixing ratios in the same air samples. The black line in plot A shows the correlation line for samples not impacted by local sources of methane (all flasks except #4, 5, 8, and 12). The black line in plot B shows the correlation line for all samples except flask 12. The flask sample number is shown next to each data point. The twelve samples were filled sequentially (see Figure 6).

Figure 8: A) Propane versus methane mixing ratios for air samples collected during Survey #6 on July 14, 2008. B) n-butane versus propane mixing ratios in the same air samples. The black line in plot A shows the correlation line for samples not impacted by local sources of methane (all flasks except 1-3, 5, and 9). The black line in plot B shows the correlation line for samples not impacted by local sources of propane.

Figure 9: Alkane correlation slopes in air samples collected at BAO (NE wind sector, summer samples only, blue) and over the Denver-Julesburg Basin (red) during the Front Range Study (June-July 2008) are compared with VOC emissions molar ratios for flashing (green) and venting (grey) sources used by Bar-Ilan et al. [2008a] for the DJB WRAP Phase III emissions inventory. The error bars indicate the min and max values for the flashing emissions molar ratios. Also shown are the mean, min and max molar ratios derived from the composition analysis of gas samples collected in 2006 at 77 different gas wells in the Great Wattenberg Area (yellow, [Colorado Oil and Gas Conservation Commission, 2007]). Goldan et al. [1995] data are from a two week measurement campaign in the Foothills, west of Boulder, in February 1991 (light purple). Goldan et al. identified a "local" propane source (lower limit for correlation slope) with clear C_{4-5} alkane ratios to propane (dark propane, see also text). The error bars on the observed atmospheric molar ratios are the 2-sigma calculated for the ratios with linmix_err.pro (http://idlastro.gsfc.nasa.gov/ftp/pro/math/linmix_err.pro).

Figure 10: Bottom-up (inventory-derived) emission estimates and top-down emission scenarios for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The vertical bars show scenario 1 average values and the error bars indicate the minimum and maximum values for the three scenarios described in Table 4.

Tables

Table 1: Locations of a subset of the NOAA ESRL Towers and Aircraft Profile Sites used in this study. STR and WGC in Northern California are collaborations with Department of Energy Environmental Energy Technologies Division at Lawrence Berkeley National Laboratory (PI: Marc Fischer). The last column gives the altitudes of the quasi-daily flask air samples used in this study. We use midday data for all sites, but at Niwot Ridge Forest we used night time data to capture background air from summertime downslope flow. We also show the location information of SGP, a NOAA ESRL aircraft site in north central Oklahoma, for which we used samples taken below 650 meters altitude.

Site Code	City	State	Latitude ^{o}North	Longitude ^{o}East	Elevation (meters above sea level)	Sampling Height (meters above ground)
BAO	Erie	Colorado	40.05	105.01	1584	300
LEF	Park Falls	Wisconsin	45.93	90.27	472	396
NWF	Niwot Ridge	Colorado	40.03	105.55	3050	23
STR	San Francisco	California	37.7553	122.45	254	232
WGC	Walnut Grove	California	38.265	121.49	0	91
WKT	Moody	Texas	31.32	97.33	251	457
SGP*	Southern Great Plains	Oklahoma	36.80	97.50	314	< 650

* aircraft discrete air samples

Table 2: List of the Front Range Mobile Lab measurement and flasks sampling surveys. Some trips (#1, 2, 3, 4, 6) sampled air using the flask only. Surveys # 5 and 7 used only the continuous analyzers on the Mobile Lab with no discrete flask collection. The last two trips targeted flask sampling close to known point or area sources based on the continuous methane measurement display in the Mobile Lab.

Road Survey #	**Road Survey Date**	**Geographical Area / Target sources**	**Measurements/ Sampling Technique**
1	**June 4**	Boulder	12 flasks
2	**June 11**	Boulder + Foothills	12 flasks
3	**June 19**	NOAA-Longmont-Fort Collins-Greeley (Oil and Gas Drilling, Feedlots)	24 flasks
4	**July 1**	NOAA - Denver	12 flasks
5	**July 9**	Around Denver	Picarro
6	**July 14**	NOAA - Greeley	12 flasks
7	**July 15**	NOAA-Greeley	Picarro
8	**July 25**	BAO surroundings Dacono Natural Gas Compressor - Feedlot	Picarro + 8 flasks
9	**July 31**	"Regional" CH_4 enhancements, Landfill, Corn field	Picarro + 12 flasks

Table 3: Correlation slopes and r^2 for various species measured in the BAO tower midday air flask samples for summer (June to August, when more than 25 samples exist) and winter (November to April) over the time period spanning August 2007 to April 2010. The three wind sectors used in Figure 3 are also used here with a 30-min average wind speed threshold of 2.5 m/s. Also shown are the slopes derived from flask samples collected by the Mobile Lab in summer 2008. The slope is in bold when r^2 is higher than 0.7 and the slope is not shown when r^2 is less than 0.4. The number of data points (n) used for the slope and r^2 calculations are provided. All slope units are ppb/ppb, except for C_6H_6/C_3H_8, C_6H_6/CO and C_2H_2/CO, which are in ppt/ppb. We used the IDL routine linmix_err.pro for the calculations with the following random measurement errors: 2ppb for CH_4 and CO and 5% for C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12}, C_2H_2, and C_6H_6.

Sector		**BAO North and East**						**BAO South**			**BAO West**			**Mobile Lab**		
Season		**summer**			**winter**			**winter**			**winter**			**summer**		
Molar ratios y/x	**units**	**slope**	r^2	n	**slope**	r^2	n	**slope**	r^2	n	**slope**	r^2	n	**slope**	r^2	n
C_3H_8/ CH_4	ppb/ ppb	**0.104 ±0.005**	0.85	81	**0.105 ±0.004**	0.90	115	0.079 ±0.008	0.53	130	**0.085 ±0.005**	0.73	148	**0.095 ±0.007**	0.76	77
nC_4H_{10}/ C_3H_8	ppb/ ppb	**0.447 ±0.013**	1.00	81	**0.435 ±0.005**	1.0	120	**0.449 ±0.011**	0.98	131	**0.434 ±0.006**	1.00	151	**0.490 ±0.011**	1.00	85
iC_5H_{12}/ C_3H_8	ppb/ ppb	**0.14 1 ±0.004**	1.00	81	**0.134 ±0.004**	0.98	120	**0.142 ±0.009**	0.81	121	**0.130 ±0.004**	0.94	151	**0.185 ±0.011**	0.81	85
nC_5H_{12}/ C_3H_8	ppb/ ppb	**0.150 ±0.003**	1.00	81	**0.136 ±0.004**	0.98	120	**0.142 ±0.006**	0.90	131	**0.133 ±0.003**	0.91	151	**0.186 ±0.008**	0.92	85
C_6H_6/ C_3H_8	ppt/ ppb	10.1 ±1.2	0.67	49	**8.2 ±0.5**	0.79	117	-	0.33	130	-	0.39	150	**17.9 ±1.1**	0.95	46
C_6H_6/ CO	ppt/ ppb	2.89 ±0.40	0.58	53	3.18 ±0.24	0.69	112	**1.57 ±0.08**	0.85	123	**1.81 ±0.08**	0.83	148	**1.82 ±0.12**	0.89	39
C_2H_2/ CO	ppt/ ppb	**3.15 ±0.33**	0.85	81	**7.51 ±0.39**	0.85	100	**5.03 ±0.17**	0.92	110	**5.85 ±0.25**	0.86	131	**4.32 ±0.28**	0.89	39
C_6H_6/ C_2H_2	ppt/ ppt	0.51 ±0.09	0.55	50	**0.34 ±0.02**	0.90	103	**0.27 ±0.02**	0.90	111	**0.32 ±0.02**	0.96	132	**0.37 ±0.04**	0.75	39

Table 4: Bottom-up (inventory-derived) emission estimates and top-down emissions scenarios for CH_4 and C_3H_8 in Weld County.

	Bottom-Up Estimates				**Top-Down Scenarios[e]: Venting**			**Top-Down Scenarios[e]: TOTAL Bottom-Up Flashing + Top-Down Venting**			**Top-Down Scenarios[e]: % of production vented[f]**		
Gg/yr	**Flashing[b]**	**Venting[c]**	**Flashing + venting**	**% of production vented[d]**	**1**	**2**	**3**	**1**	**2**	**3**	**1**	**2**	**3**
methane	**11.2**	53.1	64.3	**1.68%**	118.4	92.5	157	**129.6**	103.7	168.2	**4.0%**	3.1%	5.3%
min[a]	**4**	42	46		86.5	67.6	114.7	90.5	**71.6**	118.7	2.9%	**2.3%**	3.8%
max[a]	**23**	63	86		172.6	134.9	228.9	195.6	157.9	**251.9**	5.8%	4.5%	**7.7%**
propane	**18.3**	7.8	26.1		17.4	10.2	28	**35.7**	28.5	46.3			
min[a]	**14**	1	15		12.7	7.5	20.5	26.7	**21.5**	34.5			
max[a]	**24**	28	52		25.3	14.9	40.8	49.3	38.9	**64.8**			

[a] The minimum and maximum values reported here come from the ensemble of 16 condensate tank emissions speciation profiles provided by CDPHE.

[b] The bottom-up flashing emissions for methane and propane were calculated using the 2008 estimate of total VOC flash emissions derived by averaging the WRAP estimate for 2006 and the projection for 2010 (Cf. section 4.3).

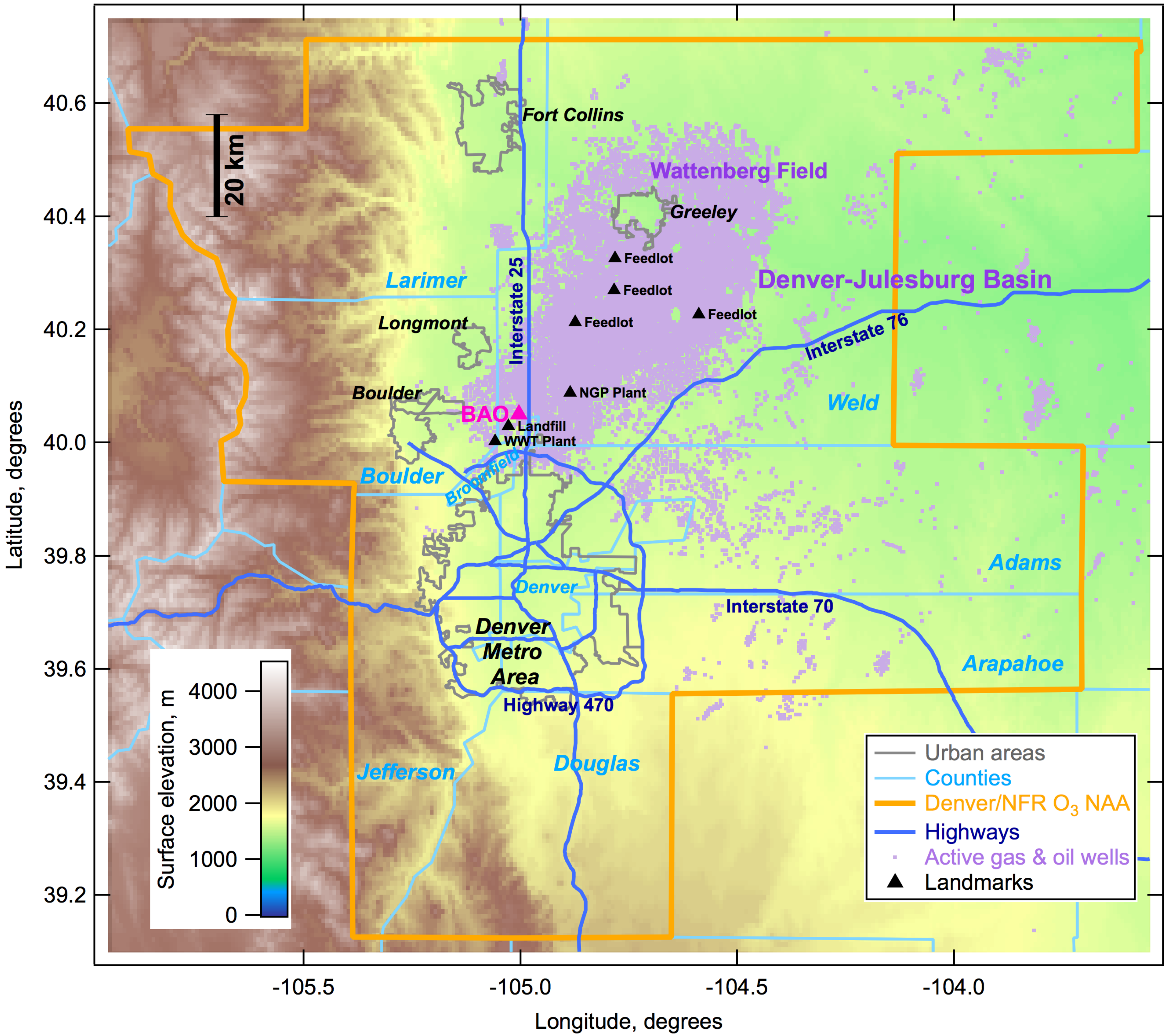
[c] The bottom-up venting emissions for methane and propane were calculated using the WRAP Phase III inventory estimate for the total volume of natural gas vented and the GWA 77 natural gas composition profiles.

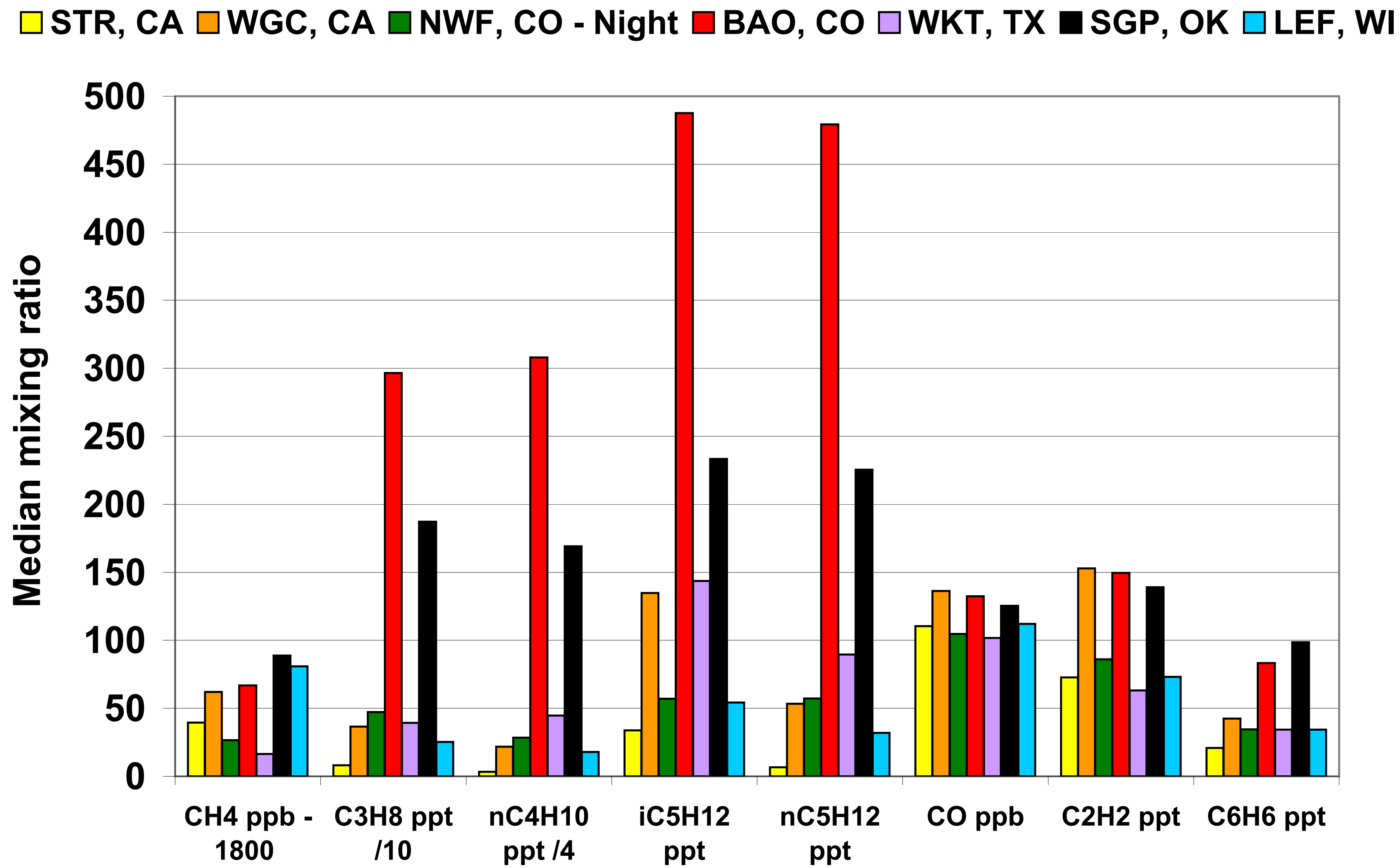
[d] Using the WRAP Phase III inventory data set and assumptions, including a CH_4 mean molar ratio of 77.44% for the vented natural gas and a molar volume for the gas of 22.4 L/mol.

[e] The CH_4-to-C_3H_8 molar ratio for vented natural gas is 18.75 (WRAP report estimate) for scenario 1, 15.43 for scenario 2 (median of molar ratios in GWA data set) and 24.83 for scenario 3 (mean of molar ratios in GWA data set).

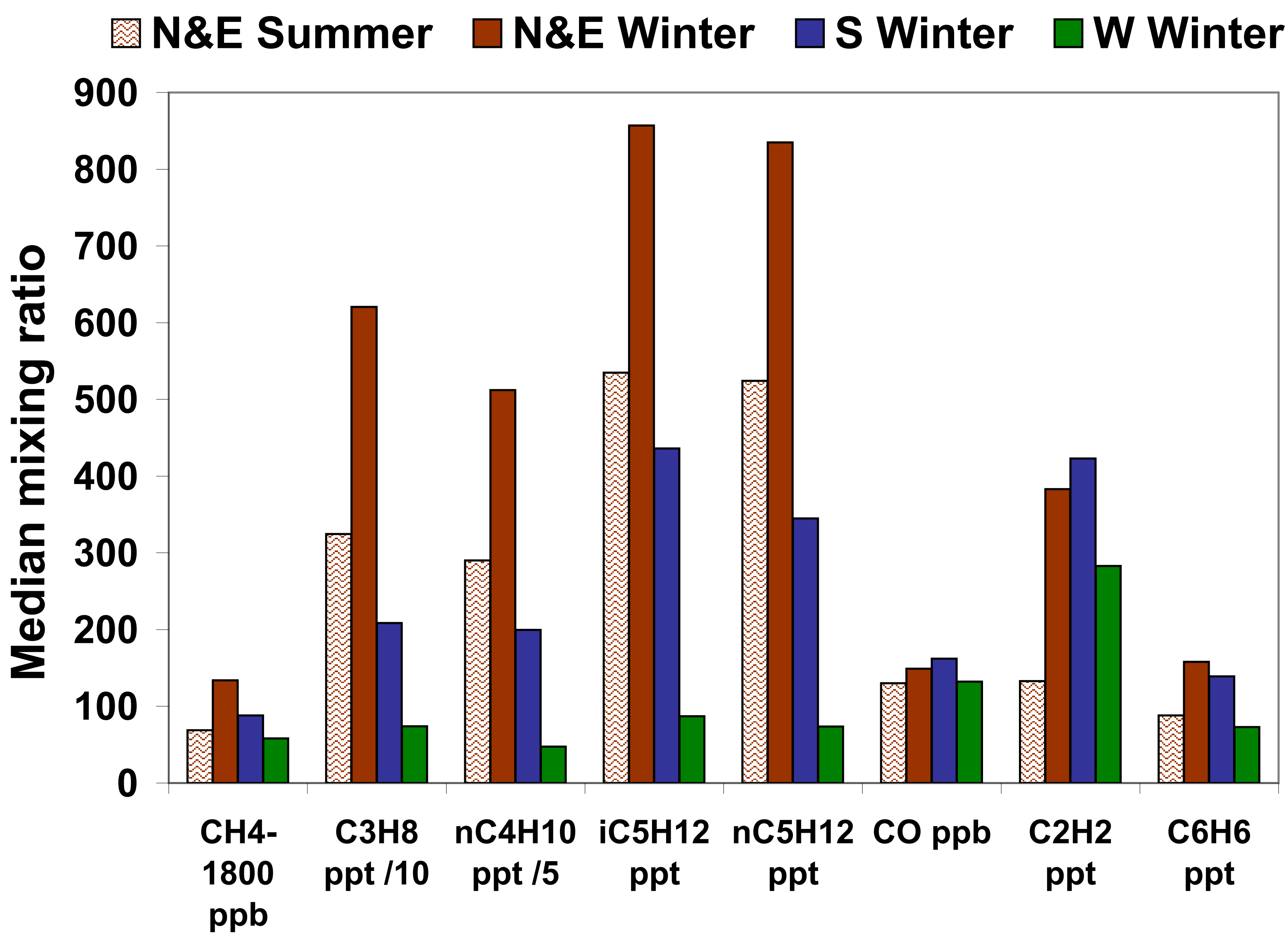
[f] Using the assumptions of a CH_4 molar ratio of 77% for the vented natural gas and a molar volume for the gas of 23.6 L/mol (Pressure= 14.73 pounds per square inch and Temperature= 60^{o}F) as used by the EIA [EIA, 2004].

1316

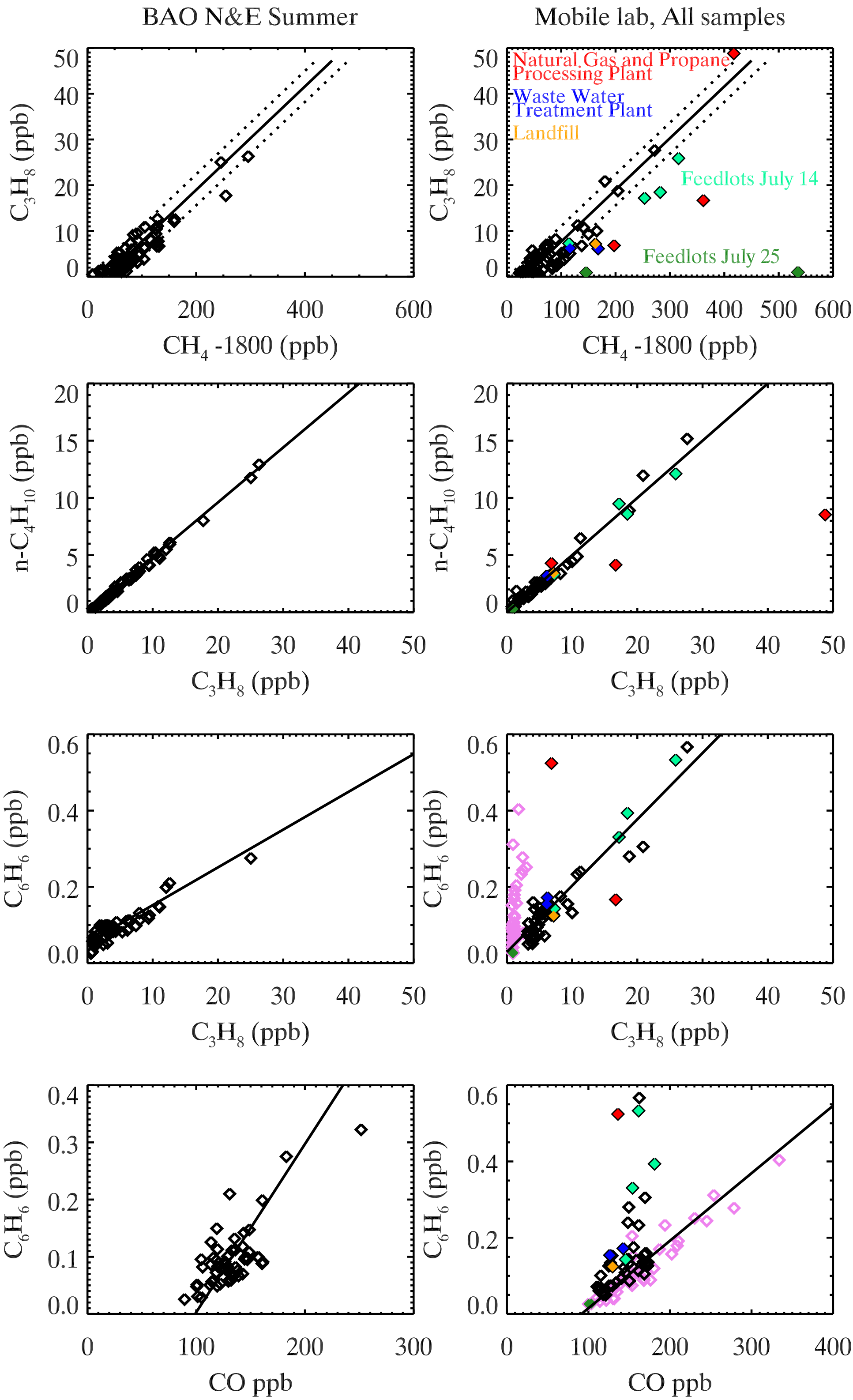

20 km
Fort Collins
Wattenberg Field
Greeley
Feedlot
Feedlot
Feedlot
Feedlot
Denver-Julesburg Basin
Larimer
Longmont
Interstate 25
Interstate 76
Boulder
NGP Plant
BAO
Landfill
WWT Plant
Weld
Boulder
Broomfield
Adams
Denver
Interstate 70
Denver
Metro
Area
Arapahoe
Highway 470
Jefferson
Douglas
Surface elevation, m
4000
3000
2000
1000
0
Urban areas
Counties
Denver/NFR O3 NAA
Highways
Active gas & oil wells
Landmarks
Latitude, degrees
40.6
40.4
40.2
40.0
39.8
39.6
39.4
39.2
-105.5
-105.0
-104.5
-104.0
Longitude, degrees



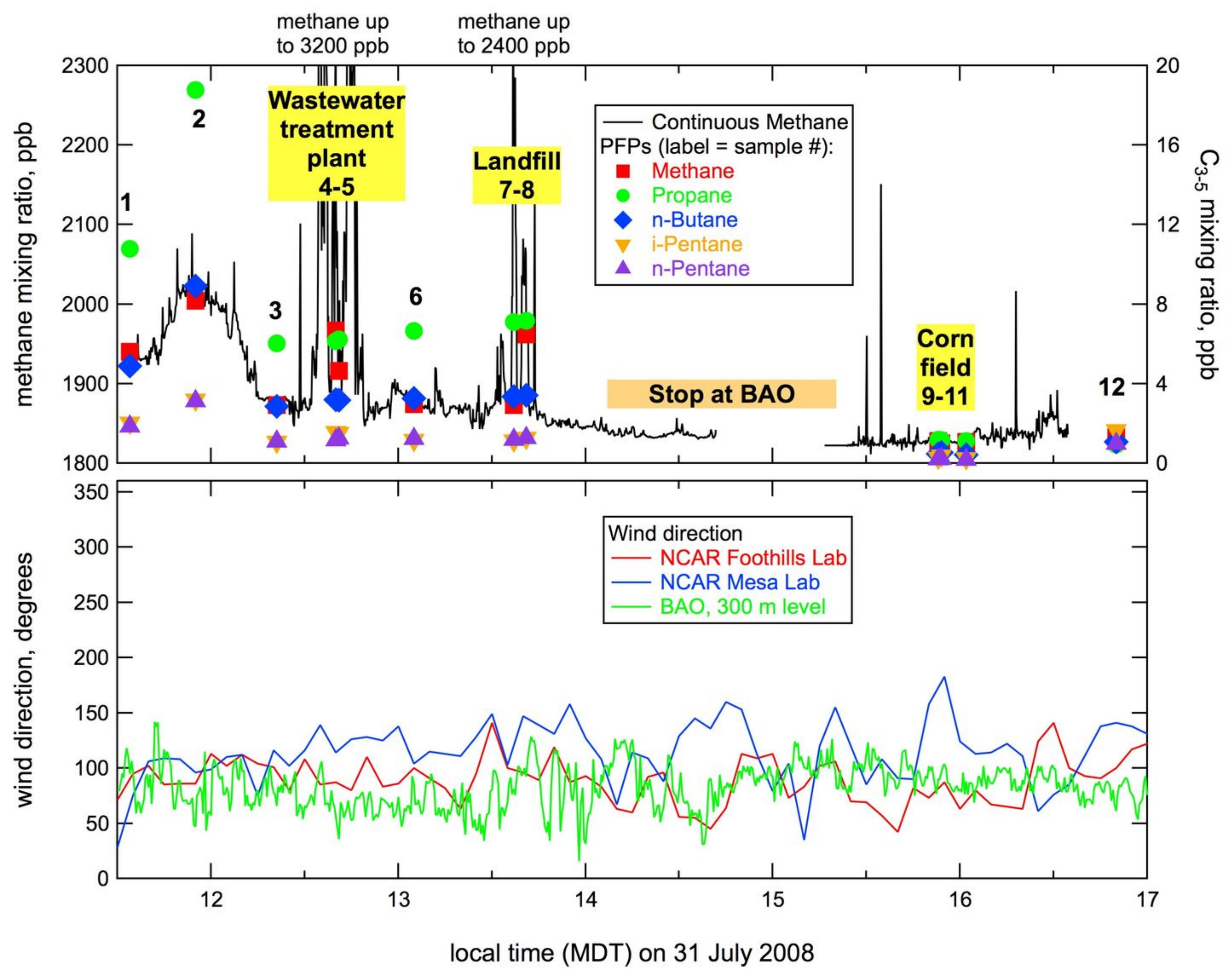
STR, CA
WGC, CA
NWF, CO - Night
BAO, CO
WKT, TX
SGP, OK
LEF, WI
Median mixing ratio
500
450
400
350
300
250
200
150
100
50
0
CH4 ppb - 1800
C3H8 ppt /10
nC4H10 ppt /4
iC5H12 ppt
nC5H12 ppt
CO ppb
C2H2 ppt
C6H6 ppt



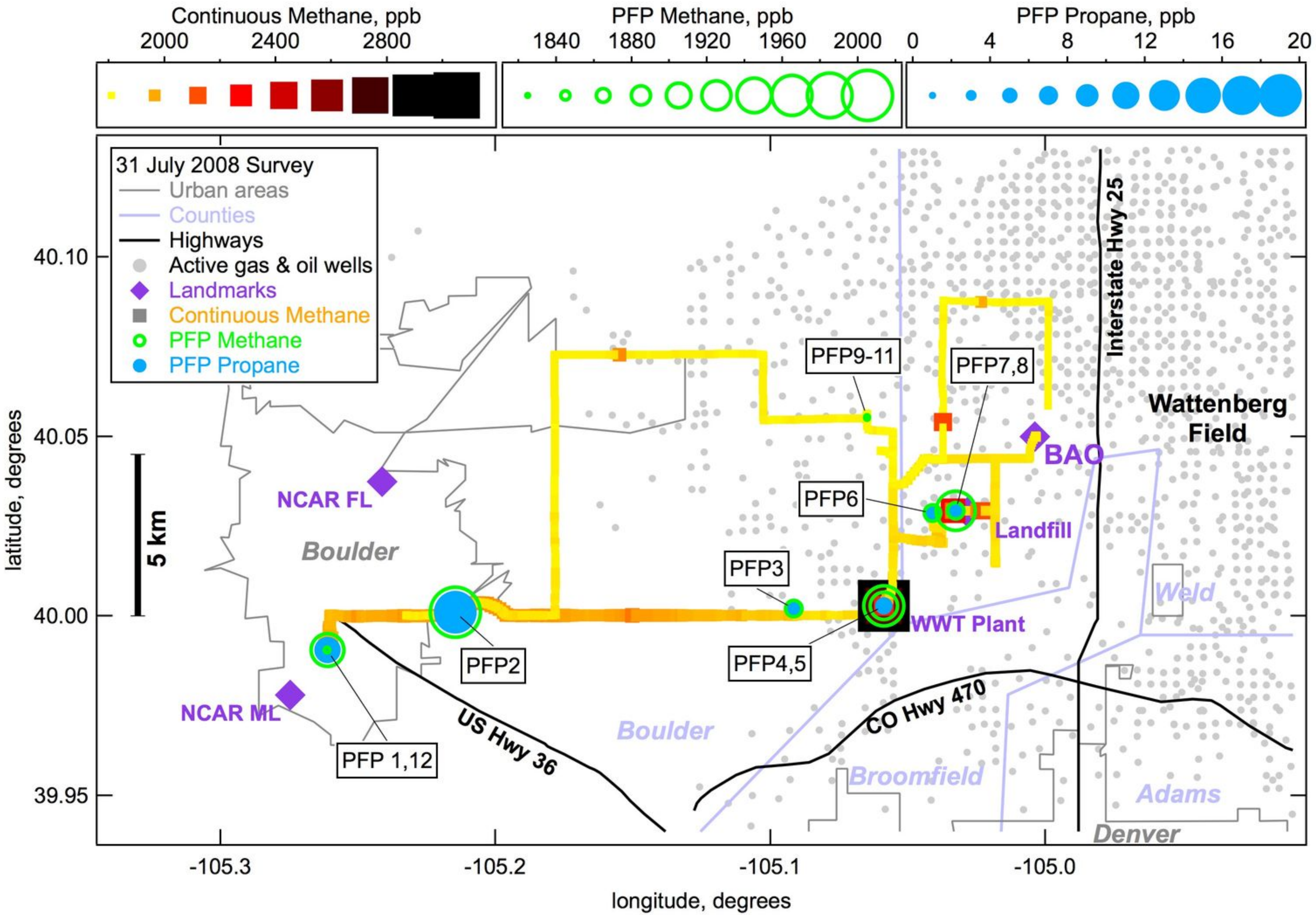
N&E Summer
N&E Winter
S Winter
W Winter
Median mixing ratio
900
800
700
600
500
400
300
200
100
0
CH4-1800 ppb
C3H8 ppt /10
nC4H10 ppt /5
iC5H12 ppt
nC5H12 ppt
CO ppb
C2H2 ppt
C6H6 ppt



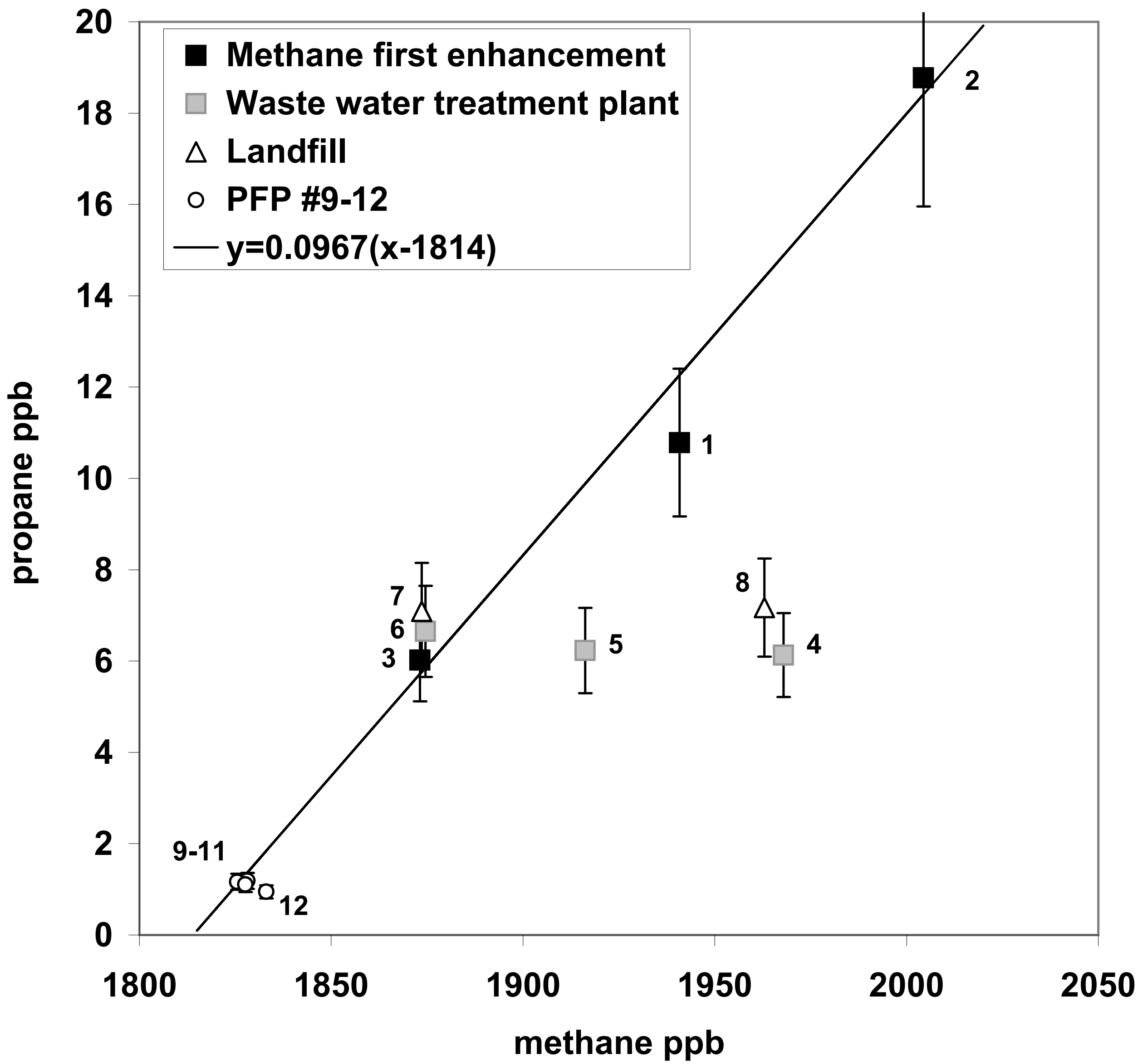
BAO N&E Summer
Mobile lab, All samples
Natural Gas and Propane Processing Plant
Waste Water Treatment Plant
Landfill
Feedlots July 14
Feedlots July 25
C_3H_8 (ppb)
CH_4 -1800 (ppb)
n-C_4H_{10} (ppb)
C_6H_6 (ppb)
CO ppb



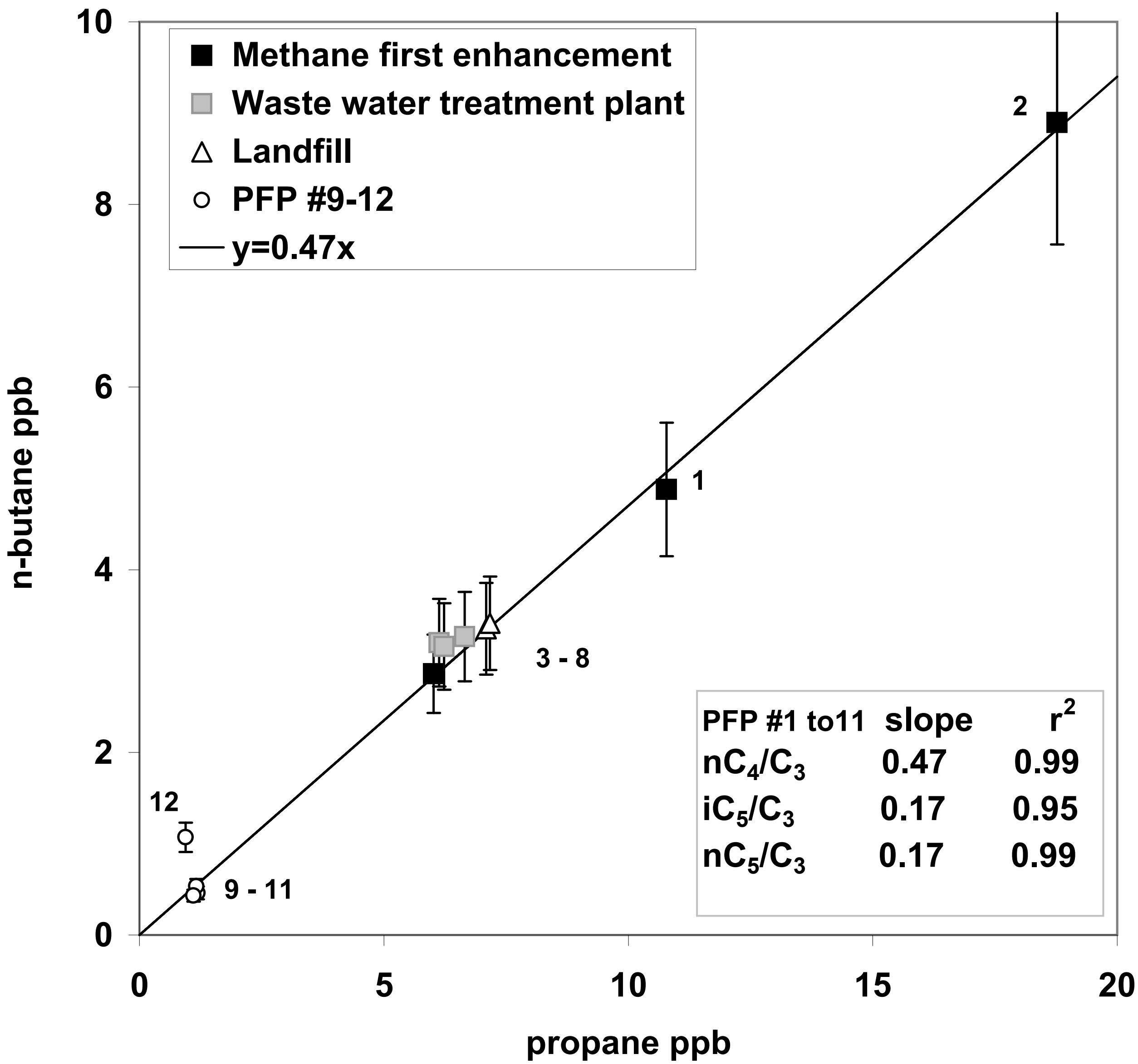
methane up to 3200 ppb
methane up to 2400 ppb
methane mixing ratio, ppb
$C_{3\text{-}5}$ mixing ratio, ppb
Wastewater treatment plant 4-5
Landfill 7-8
Stop at BAO
Corn field 9-11
1
2
3
6
12
Continuous Methane
PFPs (label = sample #):
Methane
Propane
n-Butane
i-Pentane
n-Pentane
wind direction, degrees
Wind direction
NCAR Foothills Lab
NCAR Mesa Lab
BAO, 300 m level
local time (MDT) on 31 July 2008



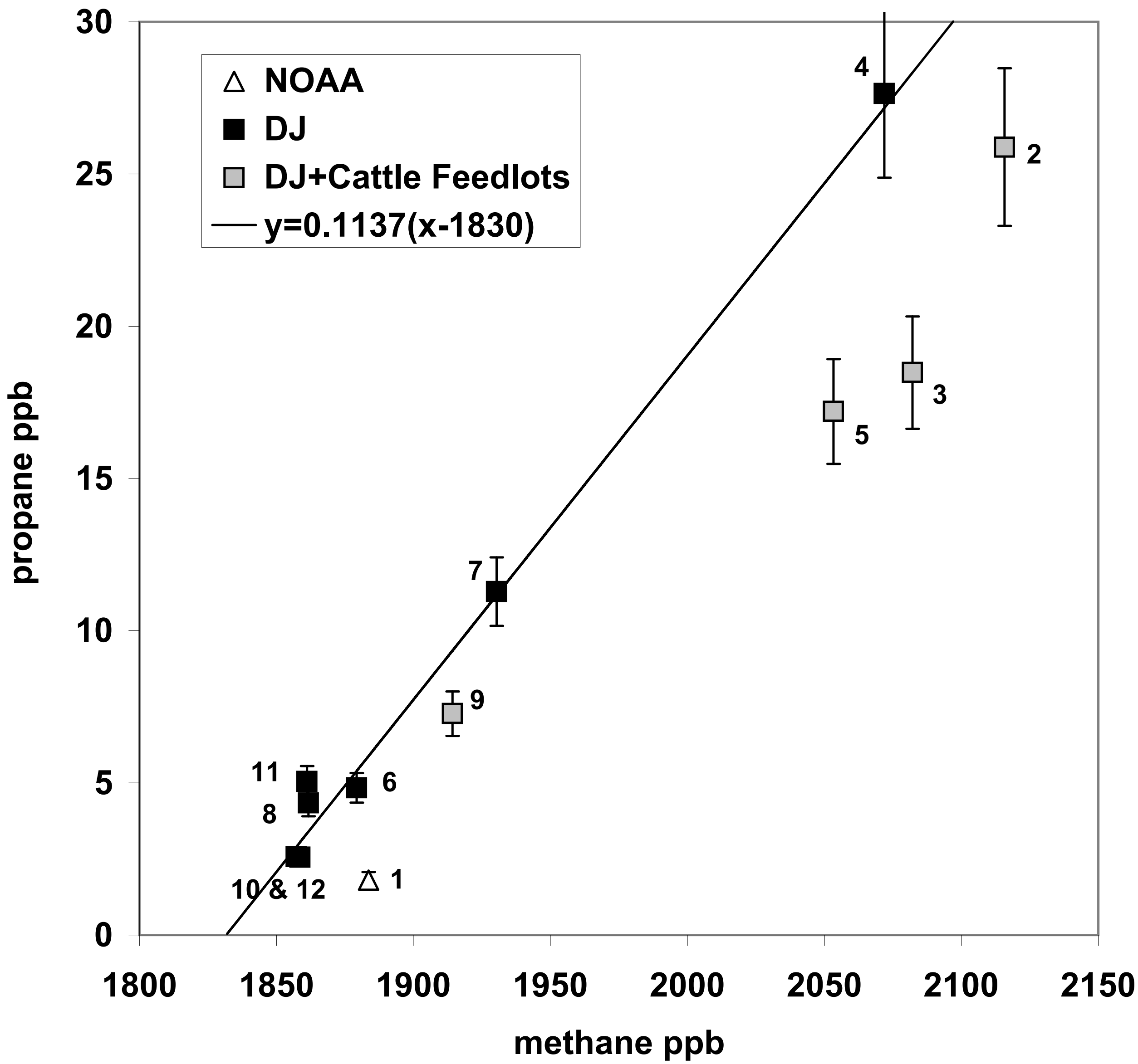
Continuous Methane, ppb
2000
2400
2800
PFP Methane, ppb
1840
1880
1920
1960
2000
PFP Propane, ppb
0
4
8
12
16
20
31 July 2008 Survey
Urban areas
Counties
Highways
Active gas & oil wells
Landmarks
Continuous Methane
PFP Methane
PFP Propane
40.10
40.05
40.00
39.95
latitude, degrees
5 km
-105.3
-105.2
-105.1
-105.0
longitude, degrees
Interstate Hwy 25
Wattenberg Field
PFP9-11
PFP7,8
BAO
NCAR FL
PFP6
Landfill
Boulder
PFP3
Weld
WWT Plant
PFP2
PFP4,5
NCAR ML
CO Hwy 470
PFP 1,12
US Hwy 36
Boulder
Broomfield
Adams
Denver



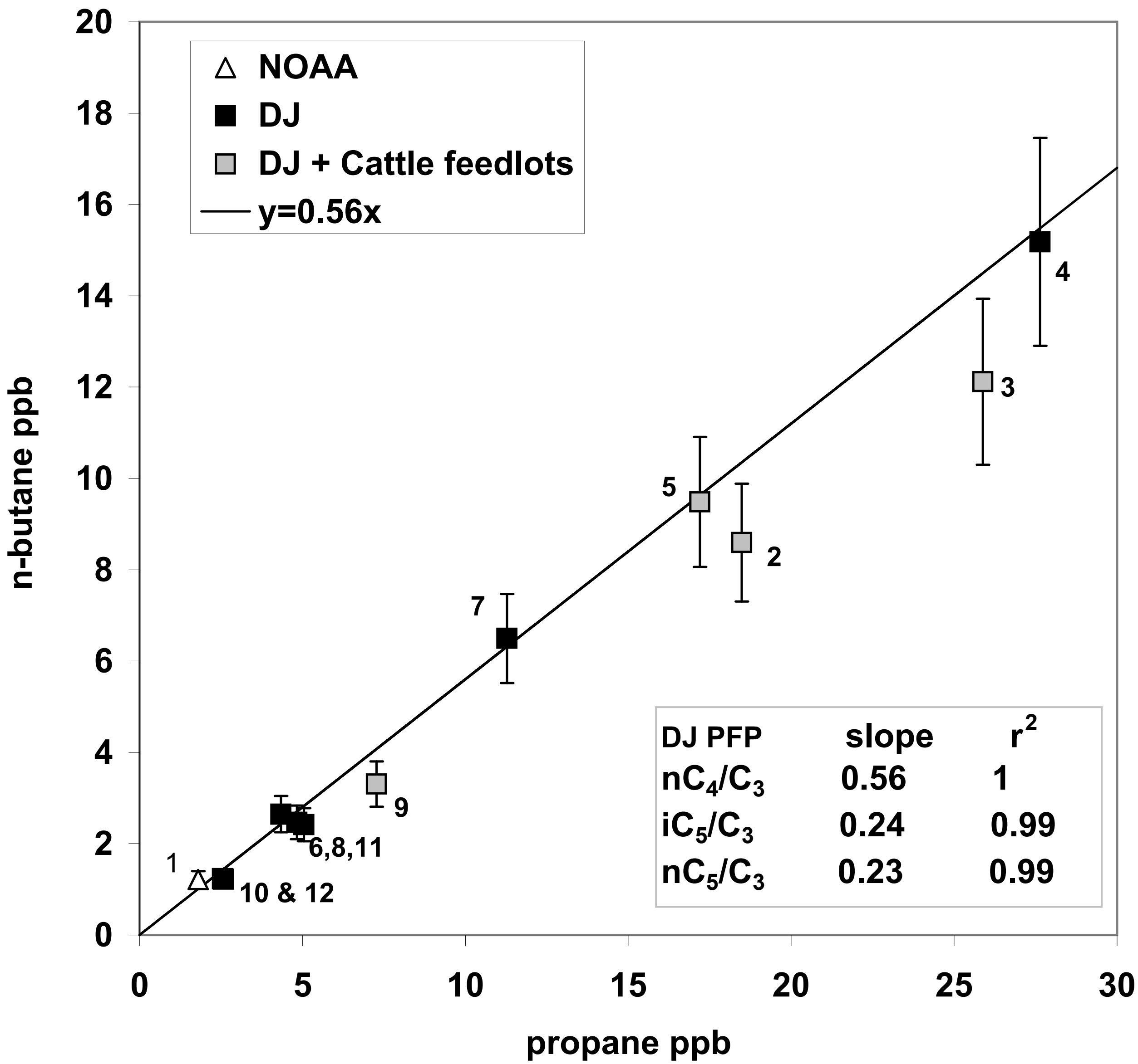
Methane first enhancement
Waste water treatment plant
Landfill
PFP #9-12
y=0.0967(x-1814)
propane ppb
methane ppb
0
2
4
6
8
10
12
14
16
18
20
1800
1850
1900
1950
2000
2050
1
2
3
4
5
6
7
8
9-11
12



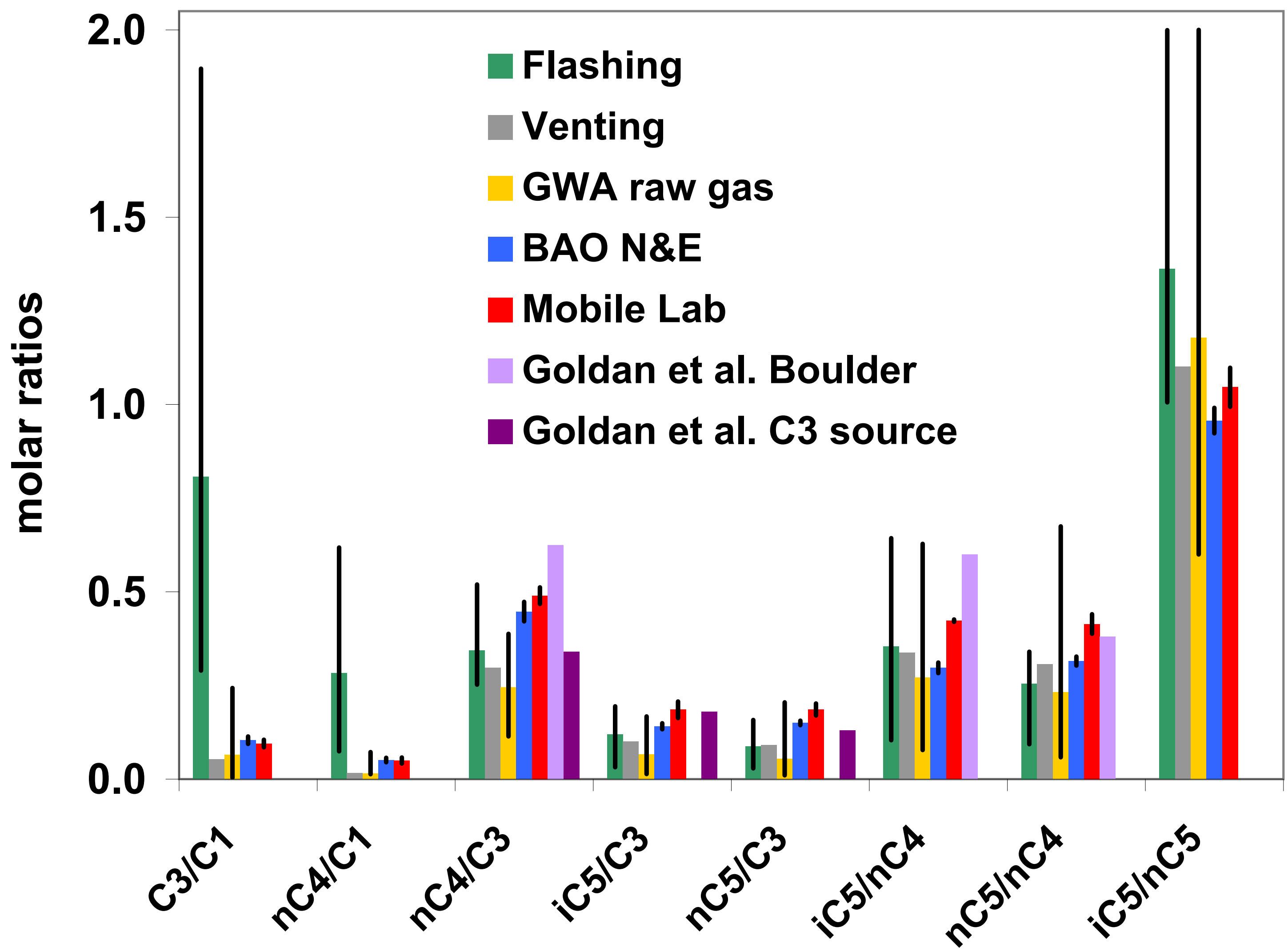
Methane first enhancement
Waste water treatment plant
Landfill
PFP #9-12
y=0.47x
2
1
3 - 8
12
9 - 11
PFP #1 to11 slope r2
nC4/C3 0.47 0.99
iC5/C3 0.17 0.95
nC5/C3 0.17 0.99
n-butane ppb
propane ppb
0
2
4
6
8
10
0
5
10
15
20



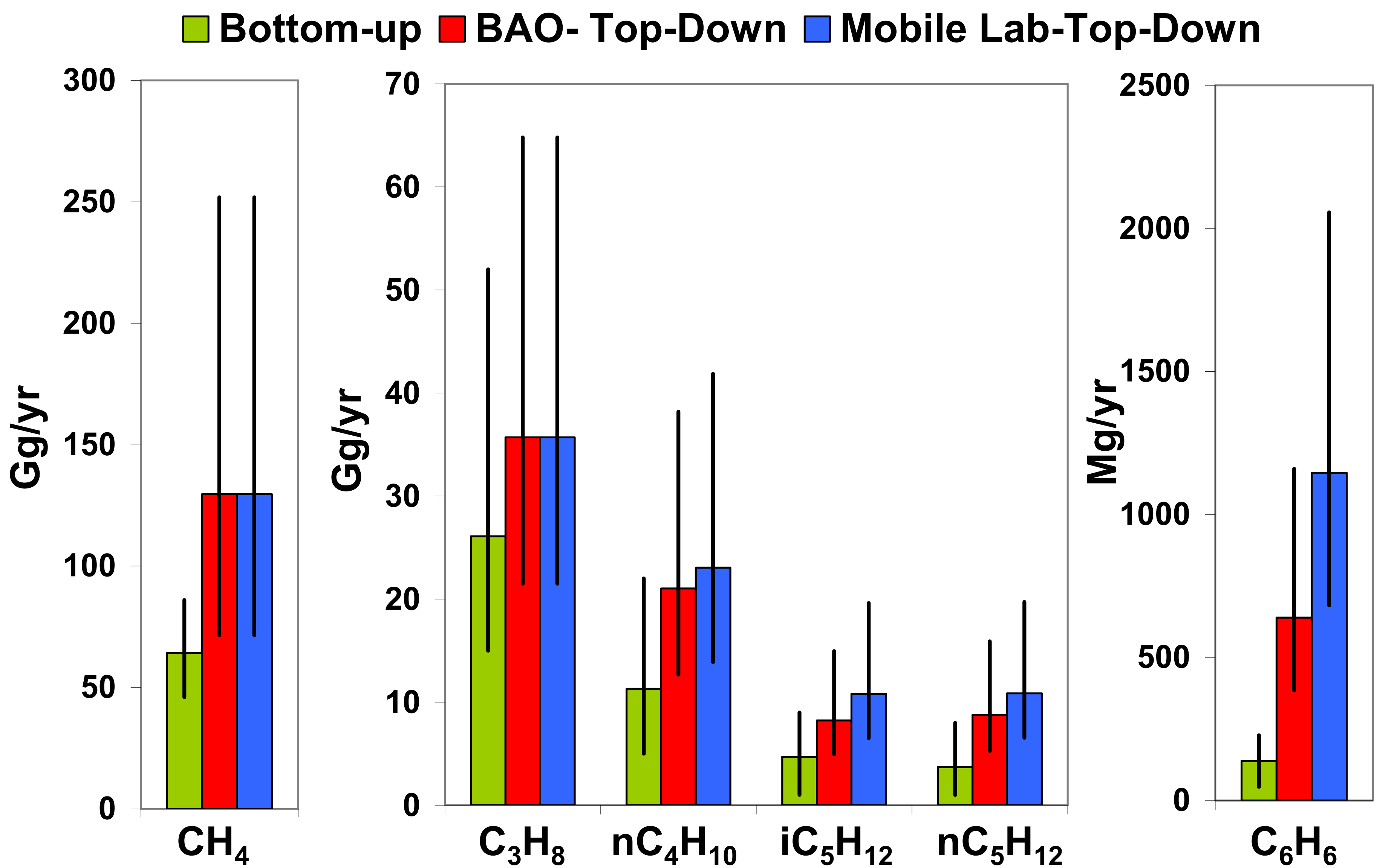
NOAA
DJ
DJ+Cattle Feedlots
y=0.1137(x-1830)
propane ppb
methane ppb
0
5
10
15
20
25
30
1800
1850
1900
1950
2000
2050
2100
2150
1
2
3
4
5
6
7
8
9
11
10 & 12



NOAA
DJ
DJ + Cattle feedlots
y=0.56x
n-butane ppb
propane ppb
1
10 & 12
6,8,11
9
7
5
2
3
4
DJ PFP slope r^2
nC_4/C_3 0.56 1
iC_5/C_3 0.24 0.99
nC_5/C_3 0.23 0.99



molar ratios
2.0
1.5
1.0
0.5
0.0
Flashing
Venting
GWA raw gas
BAO N&E
Mobile Lab
Goldan et al. Boulder
Goldan et al. C3 source
C3/C1
nC4/C1
nC4/C3
iC5/C3
nC5/C3
iC5/nC4
nC5/nC4
iC5/nC5



Bottom-up
BAO- Top-Down
Mobile Lab-Top-Down
Gg/yr
300
250
200
150
100
50
0
CH_4
70
60
40
30
20
10
C_3H_8
nC_4H_{10}
iC_5H_{12}
nC_5H_{12}
Mg/yr
2500
2000
1500
1000
500
C_6H_6

Supplementary Tables

Table 1S: Methane source estimates in Colorado (Gg CH4 /yr, for 2005)

Table 2S: Natural gas and crude oil production in Weld County, Colorado, and the US for 2005 and 2008 (Bcf=Billion cubic feet)

Table 3S: Total VOC and benzene source estimates for Weld County in different bottom-up inventories. Source categories may not sum to total due to rounding.
Sources: WRAP for year 2006 [Bar Ilan et al., 2008a], CDPHE for 2008 [CDPHE, personal communication], NEI 2005 [EPA, 2008], NEI 2008 [EPA, 2011b]

Table 4S: Inventory and measurement derived molar ratios for the various data sets plotted on Figure 9. Flashing emissions composition is based on EPA TANK model runs for 16 condensate tanks located in the DJB and sampled in 2002 [CDPHE, personal communication 2010]. Venting emissions composition is based on an average raw gas weight composition profile provided by Bar-Ilan et al. [2008a] and derived private data from several natural gas producing companies in the DJB. To get a range of distribution for vented emissions, we use the molar composition provided by COGCC for raw gas samples collected at 77 wells in the DJB in December 2006. The BAO NE summer data and Mobile Lab data are the same as in Table 3. The Goldan et al. data for samples collected west of Boulder in February 1991 are based on Goldan et al. [1995] Table 1 and Figure 5.

Supplementary Figures

Figure 1S: Time series of the Boulder Atmospheric Observatory flask data (collected between 17 and 21 UTC).

Figure 2S: Denver - Northern Front Range NAA VOC emissions inventories for oil and gas exploration, production and processing operations, developed by Bar-Ilan et al. [2008a,b]. The 2006 inventory is based on reported emissions for large condensate tanks and other permitted source categories identified with a (*) in the legend. Other source estimates are based on activity data and emissions factors. The 2010 ?projection? inventory was extrapolated based on oil and gas production trends, the 2006 emissions data, and federal and state regulations for emissions control of permitted sources that were ?on the book as of early 2008?. We distinguish three types of emissions based on distinct VOC speciation profiles used in the WRAP inventory: (1) flashing emissions from small and large condensate tanks; (2) venting emissions associated with leaks of raw natural gas at the well site or in the gathering network of pipelines; and (3) other emissions such as compressor engines (3% of total source), truck loading of condensate (1%), heaters, drill rigs, workover rigs, exempt engines, and spills which have different VOC emissions profiles.

Figure 3S: PFP samples collected during the mobile survey on July 14, 2008. The size of the symbols indicates the mixing ratio of PFP methane (red circles) and propane (green circles). The labels indicate the PFP sample number. NGP Plant = natural gas processing plant, WWT = Lafayette wastewater treatment plant.

Figure 4S: Molar composition of the venting (grey) and flashing (green) emissions data used to construct the bottom-up VOC emissions inventory for the DJB (average venting profile shared by Bar-Ilan et al. [2008a], flashing emissions profile based on EPA TANK runs for 16 condensate tanks in the DJB [CDPHE, personal communication]). For flashing emissions we show the average (green bar) and the minimum and maximum (error bars) molar fractions for all species. Also shown are the average (yellow bars) and the minimum and maximum molar fractions (error bars) of the various alkanes derived from the COGCC raw gas composition data for 77 wells in the Greater Wattenberg Area (GWA) (no aromatics data for this data set).

Figure 5S: Flow diagram of the calculation of speciated bottom-up emission estimates.

Figure 6S: Bottom-up flashing and venting emission estimates for Weld County in 2008. The colored bars indicate the mean emission estimates while the error bars indicate the minimum and maximum estimates. The WRAP inventory for the DJB used only one vented gas profile and therefore the corresponding Venting-WRAP emission estimates do not have error bars.

Table 1S: Methane source estimates in Colorado (Gg CH_4 /yr, for 2005)
Source: Strait et al., 2007

Natural gas systems	238
Coal mining	233
Enteric fermentation	143
Landfills	71
Manure management	48
Waste water treatment plants	24
Petroleum systems	10
Colorado total	767

Table 2S: Natural gas and crude oil production in Weld County, Colorado, and the US for 2005 and 2008 (Bcf=Billion cubic feet)

Source: COGCC (Weld County) and EIA (Colorado and US)

Year	**2005**			**2008**		
Gross withdrawal/ production	Natural gas *Bcf/yr*	Crude oil *Million barrels/yr*	Lease condensate *Million barrels/yr*	Natural gas *Bcf/yr*	Crude oil *Million barrels/yr*	Lease condensate *Million barrels/yr*
Weld County (% of Colorado)	188.5 (16.5%)	11.7 (51.3%)	na	202.1 (15.3%)	17.3 (71.8%)	na
DNFR NAA	201.1	12.6	na	214.1	18.5	na
Colorado	1144	22.8	5	1403	24.1	7
USA	23457	1890.1	174	25636	1811.8	173

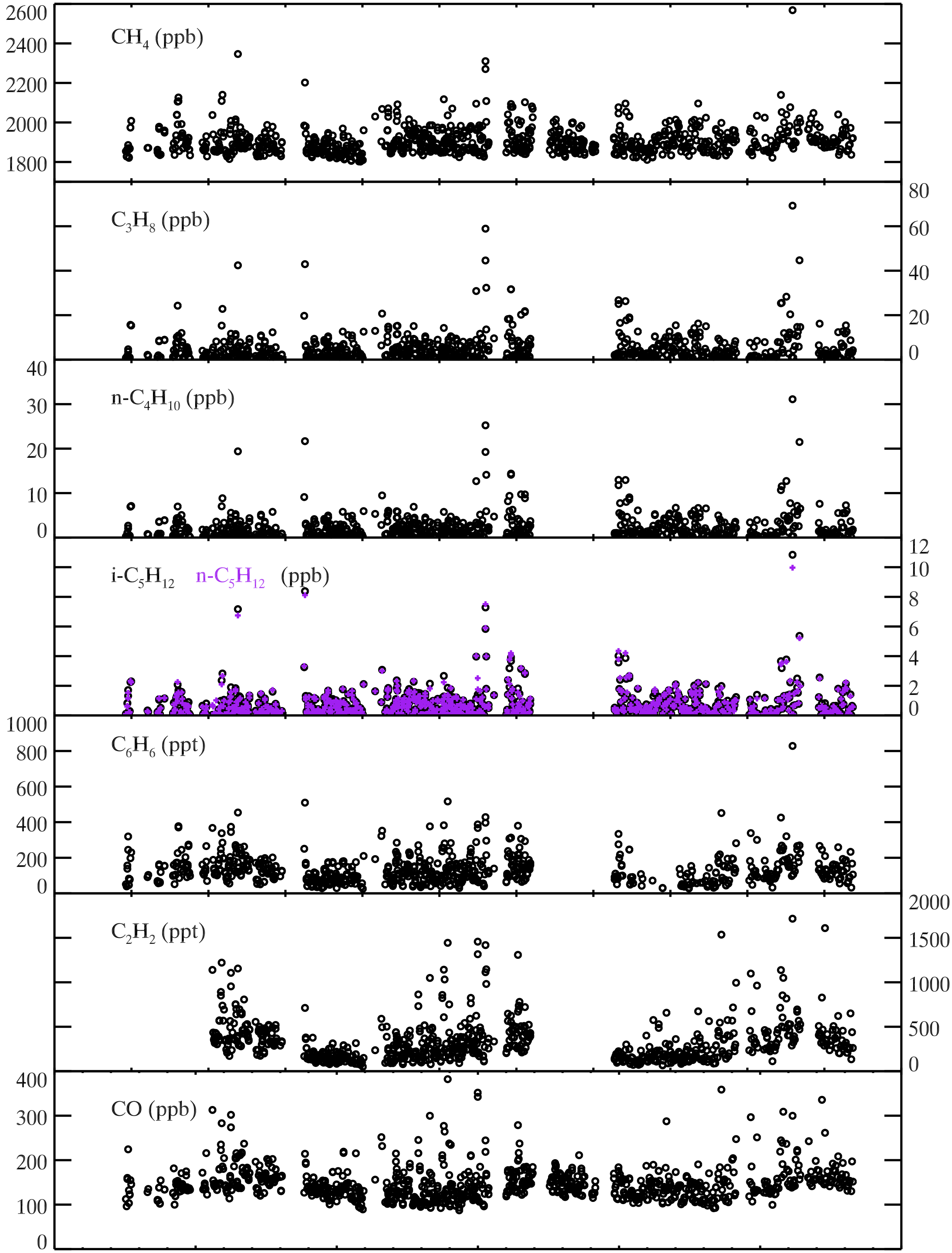
Table 3S: Total VOC and benzene source estimates for Weld County in different bottom-up inventories. Source categories may not sum to total *due to rounding.*
Sources: WRAP for year 2006 [Bar Ilan et al., 2008a], CDPHE for 2008 [CDPHE, personal communication], NEI 2005 [EPA, 2008], NEI 2008 [EPA, 2011b]

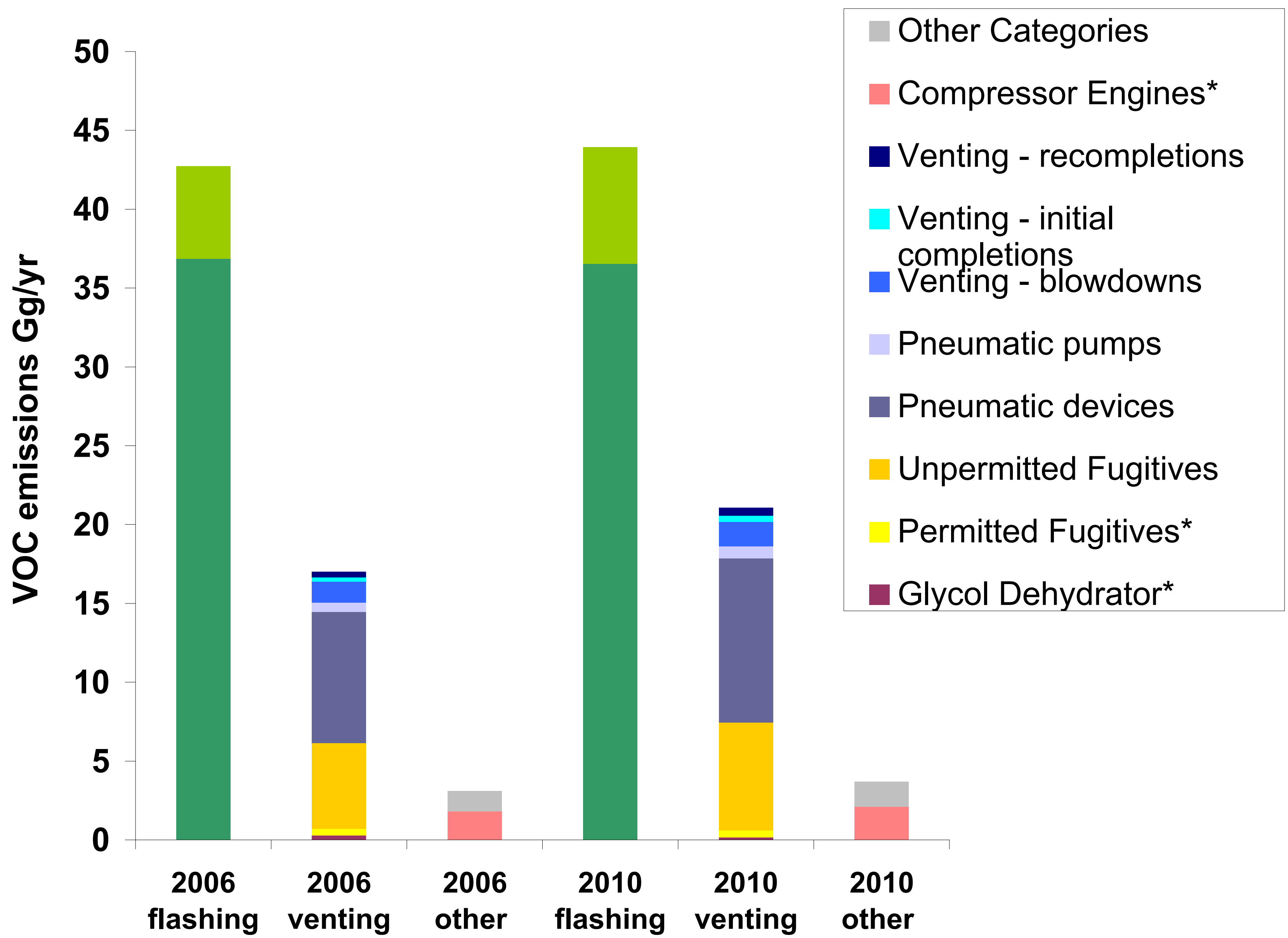
Species		**Total VOC**				**Benzene**		
Year		**2006**	**2008**	**2008**	**2005**	**2008**	**2008**	**2005**
Source		**WRAP**	**CDPHE**	**NEI**	**NEI**	**CDPHE**	**NEI**	**NEI**
unit		**Gg/yr**				**Mg/yr**		
On-Road			2533	2968	3532	95.4	121.4	160.1
Non-road + rail + aircraft			1596	1313	1626	44.2	36.0	45.9
Wood burning			232	-	187	8.8	-	5.7
Solvent utilization			201	1914	2819	-	-	31.6
Surface coating			1235	-	421	-	-	0.8
Oil and gas area		21145*	-	-	-	-	-	-
Oil and gas point	Large Condensate tanks	34790	17811	18163	-	21.3	21.5	1120.0
	Glycol dehydrators	218	220	-	-	15.1	-	47.6
	Gas sweetening	11	11	-	-	6.6	-	7.8
	Internal Combustion Engines	1996	1692	-	-	16.0	-	-
	Other	304	844	646	-	2.8	23.1	1.6
	Total	*37015*	*20628*	*18810*	*-*	*61.8*	*44.6*	*1177.0*
Gas stations/Gasoline bulk terminals			697	965	1270	8.0	11.1	11.8
Forest and prescribed fires			110		207	8.3	-	2.4
Fossil Fuel combustion Point (non O&G)			196	1880	651	0.5	16.5	3.9
Other point			547	680	335	1.0	15.6	12.3
Other area			1078		605	2.3		4.6
Total for available source categories		58160	29051	28530	11654	230.5	245.2	1454

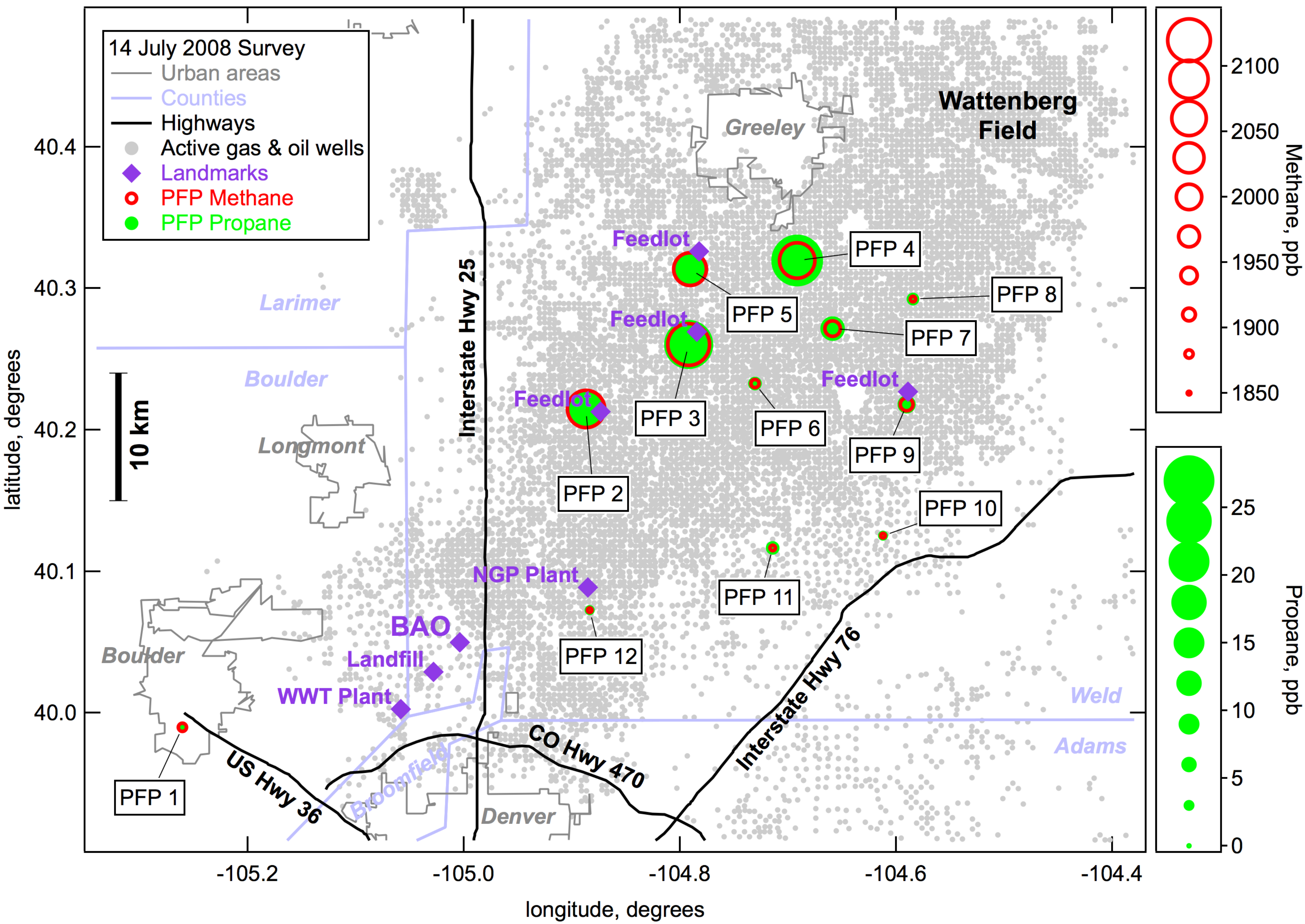
*Source categories included are: Pneumatic devices and pumps, small condensate tanks, fugitive emissions, heaters, process heaters, venting, truck loading, spills, NG production: flares, flanges and connections, and others.

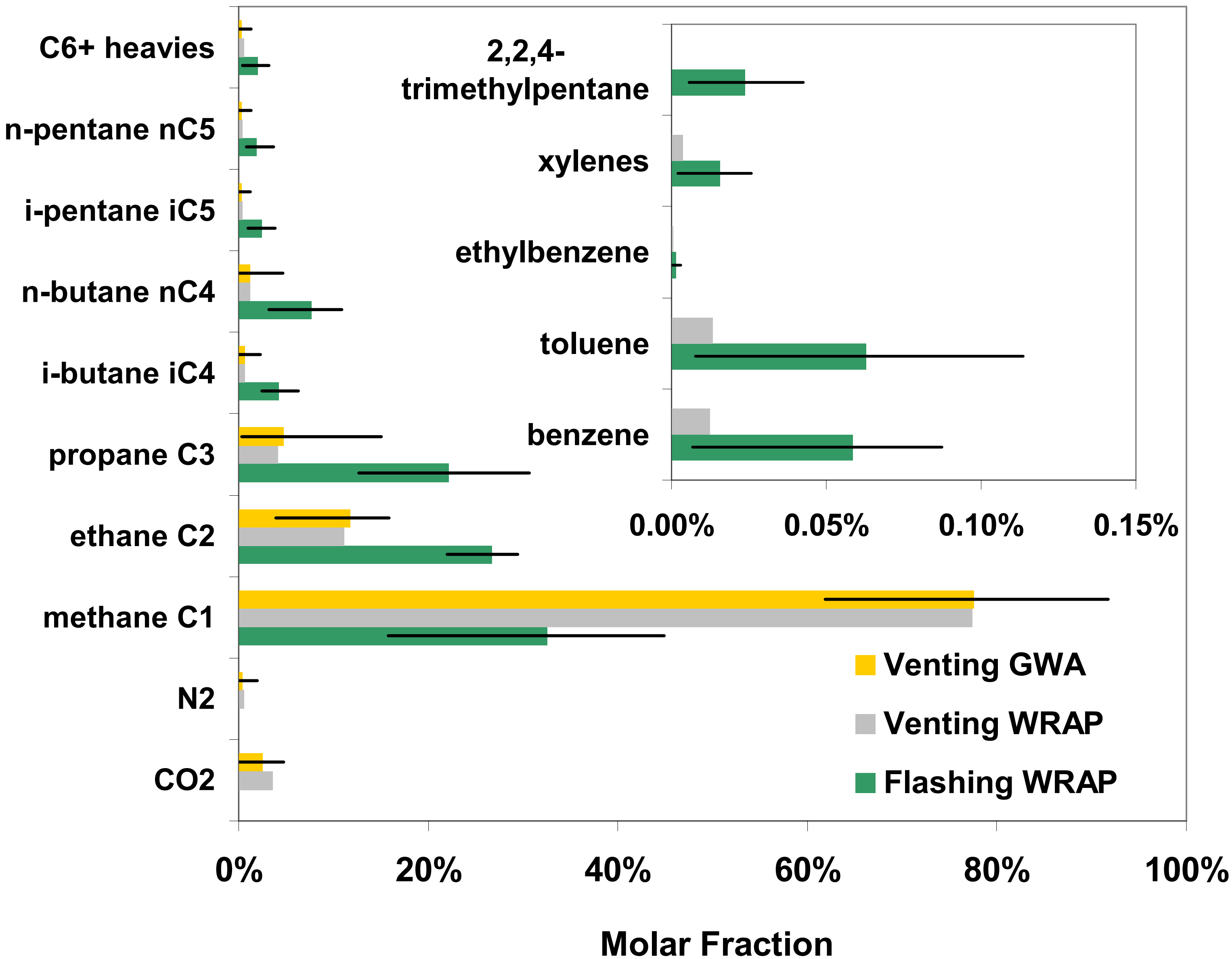
Table 4S: Inventory and measurement derived molar ratios for the various data sets plotted on Figure 9. Flashing emissions composition is based on EPA TANK model runs for 16 condensate tanks located in the DJB and sampled in 2002 [CDPHE, personal communication 2010]. Venting emissions composition is based on an average raw gas weight composition profile provided by Bar-Ilan et al. [2008a] and derived private data from several natural gas producing companies in the DJB. To get a range of distribution for vented emissions, we use the molar composition provided by COGCC for raw gas samples collected at 77 wells in the DJB in December 2006. The BAO NE summer data and Mobile Lab data are the same as in Table 3. The Goldan et al. data for samples collected west of Boulder in February 1991 are based on Goldan et al. [1995] Table 1 and Figure 5.

Data Set		**C_3/C_1**	**nC_4/C_1**	**nC_4/C_3**	**iC_5/C_3**	**nC_5/C_3**	**iC_5/nC_4**	**nC_5/nC_4**	**iC_5/nC_5**
WRAP Flashing emissions	Median	0.807	0.283	0.343	0.119	0.088	0.354	0.255	1.362
	Mean	0.654	0.271	0.339	0.123	0.088	0.354	0.262	1.271
	Min	0.290	0.074	0.252	0.032	0.029	0.104	0.093	1.006
	Max	1.896	0.618	0.519	0.194	0.158	0.643	0.340	1.999
WRAP Venting emissions		0.053	0.016	0.298	0.100	0.091	0.338	0.307	1.101
GWA raw gas	Median	0.065	0.015	0.245	0.066	0.054	0.270	0.231	1.179
	Mean	0.064	0.017	0.253	0.071	0.061	0.280	0.239	1.226
	Min	0.004	0.015	0.114	0.014	0.010	0.078	0.058	0.600
	Max	0.243	0.072	0.388	0.167	0.205	0.628	0.674	2.000
Bottom-up VOC inventory: WRAP Flashing + GWA Venting (mean profiles)		0.154	0.049	0.316	0.099	0.078	0.313	0.245	1.274
BAO NE -summer		0.104	0.051	0.447	0.141	0.150	0.297	0.315	0.957
Mobile Lab		0.095	0.050	0.510	0.185	0.186	0.423	0.414	1.046
Goldan et al.- all data		-	-	0.340	0.180	0.130	-	-	-
Goldan et al. C_3 source		-	-	0.625	-	-	0.600	0.380	-

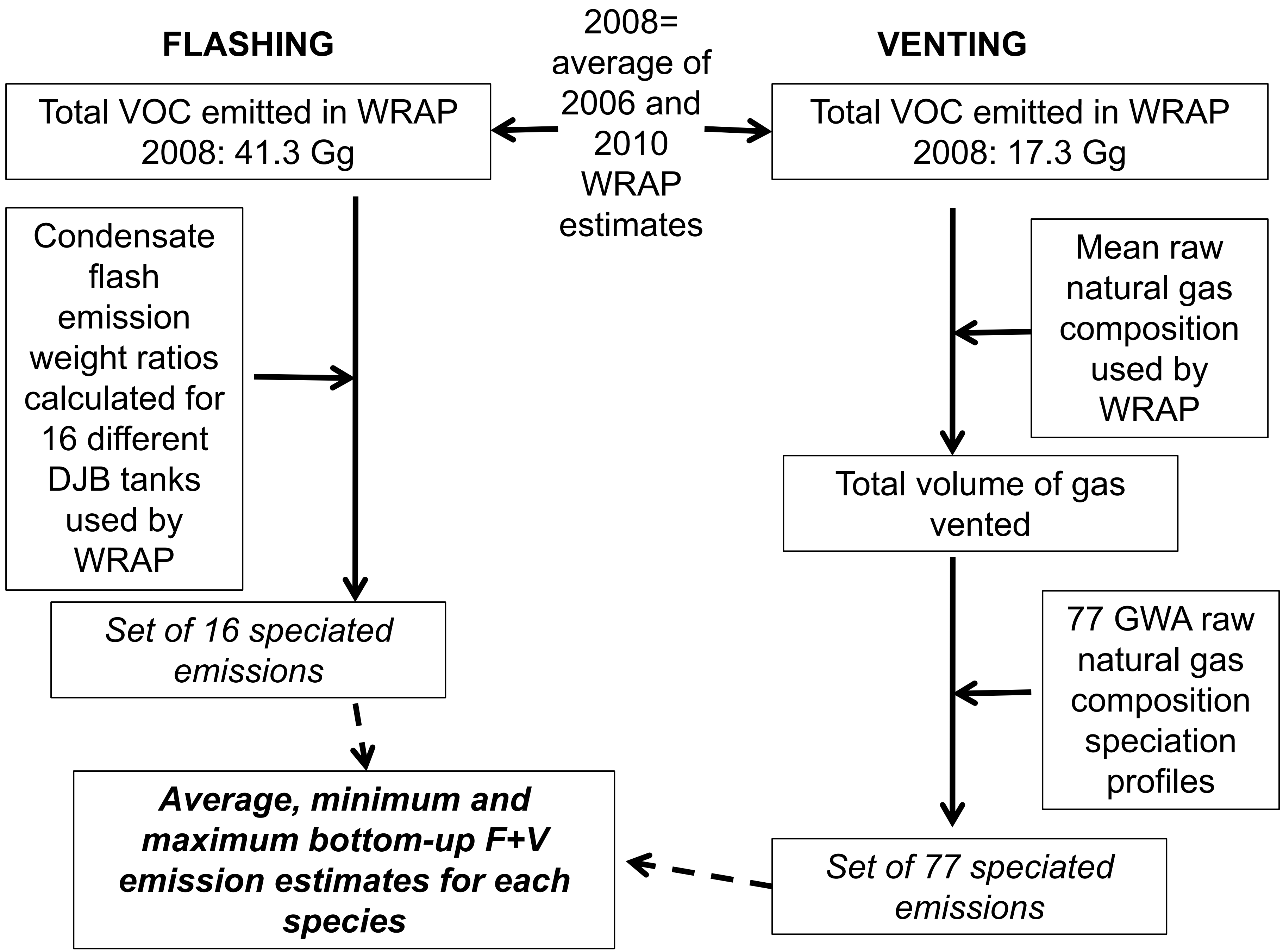

CH4 (ppb)
C3H8 (ppb)
n-C4H10 (ppb)
i-C5H12 n-C5H12 (ppb)
C6H6 (ppt)
C2H2 (ppt)
CO (ppb)
2600
2400
2200
2000
1800
80
60
40
20
0
40
30
20
10
0
12
10
8
6
4
2
0
1000
800
600
400
200
0
2000
1500
1000
500
0
400
300
200
100
0

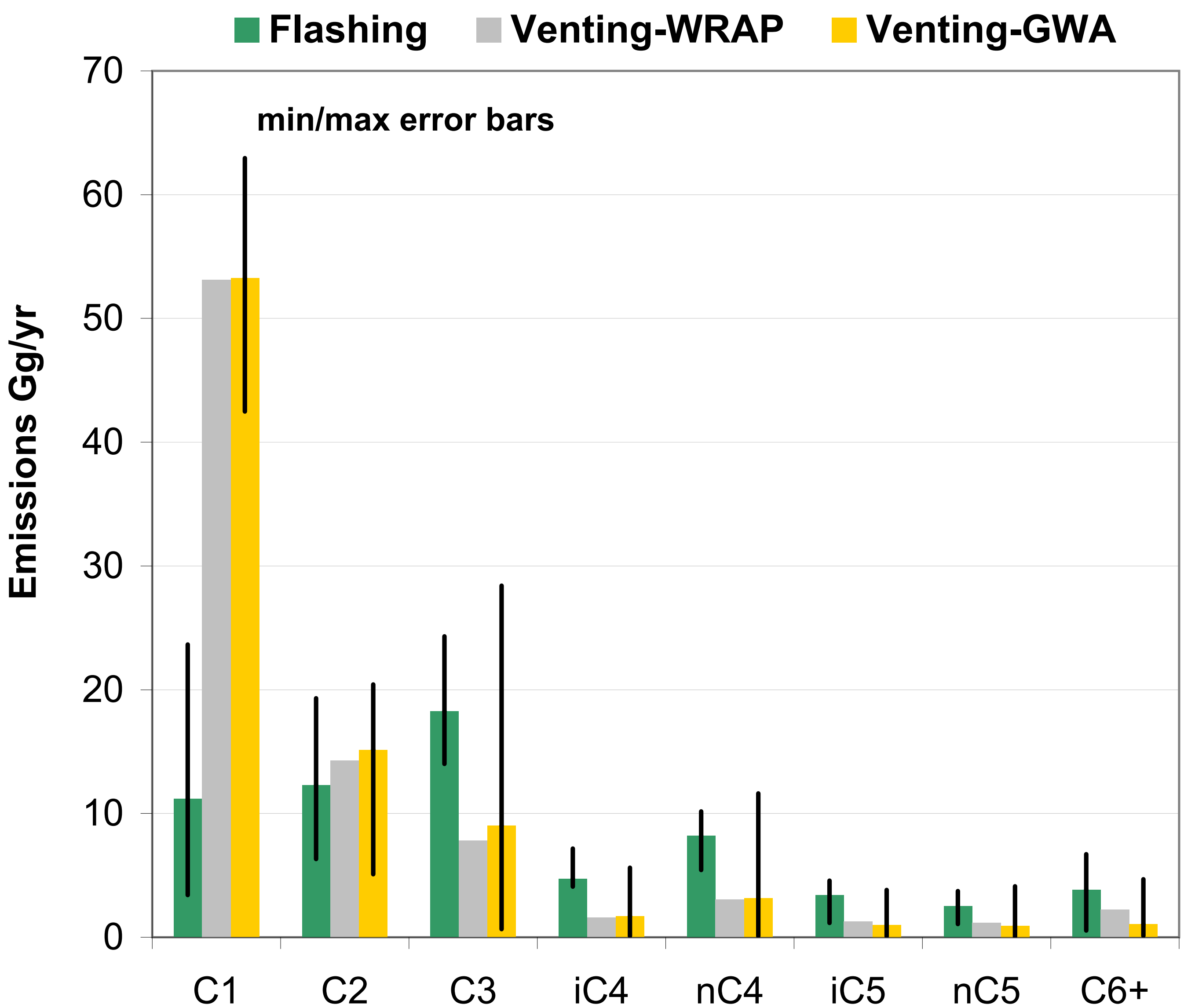

VOC emissions Gg/yr
50
45
40
35
30
25
20
15
10
5
0
2006 flashing
2006 venting
2006 other
2010 flashing
2010 venting
2010 other
Other Categories
Compressor Engines*
Venting - recompletions
Venting - initial completions
Venting - blowdowns
Pneumatic pumps
Pneumatic devices
Unpermitted Fugitives
Permitted Fugitives*
Glycol Dehydrator*


14 July 2008 Survey
Urban areas
Counties
Highways
Active gas & oil wells
Landmarks
PFP Methane
PFP Propane
Wattenberg Field
Greeley
Longmont
Boulder
Denver
Broomfield
Larimer
Boulder
Weld
Adams
Interstate Hwy 25
Interstate Hwy 76
CO Hwy 470
US Hwy 36
10 km
Feedlot
Feedlot
Feedlot
Feedlot
NGP Plant
BAO
Landfill
WWT Plant
PFP 1
PFP 2
PFP 3
PFP 4
PFP 5
PFP 6
PFP 7
PFP 8
PFP 9
PFP 10
PFP 11
PFP 12
latitude, degrees
40.0
40.1
40.2
40.3
40.4
longitude, degrees
-105.2
-105.0
-104.8
-104.6
-104.4
Methane, ppb
1850
1900
1950
2000
2050
2100
Propane, ppb
0
5
10
15
20
25



C6+ heavies
n-pentane nC5
i-pentane iC5
n-butane nC4
i-butane iC4
propane C3
ethane C2
methane C1
N2
CO2
2,2,4-trimethylpentane
xylenes
ethylbenzene
toluene
benzene
0.00%
0.05%
0.10%
0.15%
Venting GWA
Venting WRAP
Flashing WRAP
0%
20%
40%
60%
80%
100%
Molar Fraction


FLASHING
VENTING
2008= average of 2006 and 2010 WRAP estimates
Total VOC emitted in WRAP 2008: 41.3 Gg
Total VOC emitted in WRAP 2008: 17.3 Gg
Condensate flash emission weight ratios calculated for 16 different DJB tanks used by WRAP
Mean raw natural gas composition used by WRAP
Total volume of gas vented
77 GWA raw natural gas composition speciation profiles
Set of 16 speciated emissions
Set of 77 speciated emissions
Average, minimum and maximum bottom-up F+V emission estimates for each species


Flashing
Venting-WRAP
Venting-GWA
min/max error bars
Emissions Gg/yr
0
10
20
30
40
50
60
70
C1
C2
C3
iC4
nC4
iC5
nC5
C6+

NATURE | NEWS

Methane leaks erode green credentials of natural gas

Losses of up to 9% show need for broader data on US gas industry's environmental impact.

Jeff Tollefson

02 January 2013

Natural-gas wells such as this one in Colorado are increasingly important to the US energy supply.

DAVID ZALUBOWSKI/AP PHOTO

Scientists are once again reporting alarmingly high methane emissions from an oil and gas field, underscoring questions about the environmental benefits of the boom in natural-gas production that is transforming the US energy system.

The researchers, who hold joint appointments with the National Oceanic and Atmospheric Administration (NOAA) and the University of Colorado in Boulder, first sparked concern in February 2012 with a study[1] suggesting that up to 4% of the methane produced at a field near Denver was escaping into the atmosphere. If methane — a potent greenhouse gas — is leaking from fields across the country at similar rates, it could be offsetting much of the climate benefit of the ongoing shift from coal- to gas-fired plants for electricity generation.

Industry officials and some scientists contested the claim, but at an American Geophysical Union (AGU) meeting in San Francisco, California, last month, the research team reported new Colorado data that support the earlier work, as well as preliminary results from a field study in the Uinta Basin of Utah suggesting even higher rates of methane leakage — an eye-popping 9% of the total production. That figure is nearly double the cumulative loss rates estimated from industry data — which are already higher in Utah than in Colorado.

“We were expecting to see high methane levels, but I don’t think anybody really comprehended the true magnitude of what we would see,” says Colm Sweeney, who led the aerial component of the study as head of the aircraft programme at NOAA’s Earth System Research Laboratory in Boulder.

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Whether the high leakage rates claimed in Colorado and Utah are typical across the US natural-gas industry remains unclear. The NOAA data represent a “small snapshot” of a much larger picture that the broader scientific community is now assembling, says Steven Hamburg, chief scientist at the Environmental Defense Fund (EDF) in Boston, Massachusetts.

The NOAA researchers collected their data in February as part of a broader analysis of air pollution in the Uinta Basin, using ground-based equipment and an aircraft to make detailed measurements of various pollutants, including methane concentrations. The researchers used atmospheric modelling to calculate the level of methane emissions required to reach those concentrations, and then compared that with industry data on gas production to obtain the percentage escaping into the atmosphere through venting and leaks.

The results build on those of the earlier Colorado study[1] in the Denver–Julesburg Basin, led by NOAA scientist Gabrielle Pétron (see *Nature* **482,** 139–140; 2012). That study relied on pollution measurements taken in 2008 on the ground and from a nearby tower, and estimated a leakage rate that was about twice as high as official figures suggested. But the team’s methodology for calculating leakage — based on chemical analysis of the pollutants — remains in dispute. Michael Levi, an energy analyst at the Council on Foreign Relations in New York, published a peer-reviewed comment[2] questioning the findings and presenting an alternative interpretation of the data that would align overall leakage rates with previous estimates.

Pétron and her colleagues have a defence of the Colorado study in press[3], and at the AGU meeting she discussed a new study of the Denver–Julesburg Basin conducted with scientists at Picarro, a gas-analyser manufacturer based in Santa Clara, California. That study relies on carbon isotopes to differentiate between industrial emissions and methane from cows and feedlots, and the preliminary results line up with their earlier findings.

A great deal rides on getting the number right. A study[4] published in April by scientists at the EDF and Princeton University in New Jersey suggests that shifting to natural gas from coal-fired generators has immediate climatic benefits as long as the cumulative leakage rate from natural-gas production is below 3.2%; the benefits accumulate over time and are even larger if the gas plants replace older coal plants. By comparison, the authors note that the latest estimates from the US Environmental Protection Agency (EPA) suggest that 2.4% of total natural-gas production was lost to leakage in 2009.

To see if that number holds up, the NOAA scientists are also taking part in a comprehensive assessment of US natural-gas emissions, conducted by the University of Texas at Austin and the EDF, with various industry partners. The initiative will analyse emissions from the production, gathering, processing, long-distance transmission and local distribution of natural gas, and will gather data on the use of natural gas in the transportation sector. In addition to scouring through industry data, the scientists are collecting field measurements at facilities across the country. The researchers expect to submit the first of these studies for publication by February, and say that the others will be complete within a year.

In April, the EPA issued standards intended to reduce air pollution from hydraulic-fracturing operations — now standard within the oil and gas industry — and advocates say that more can be done, at the state and national levels, to reduce methane emissions. “There are clearly opportunities to reduce leakage,” says Hamburg.

Nature **493,** 12 (03 January 2013) doi:10.1038/493012a

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   Show context

4. Alvarez, R. A., Pacala, S. W. Winebrake, J. J., Chameides, W. L. & Hamburg, S. P. *Proc. Natl Acad. Sci. USA* **109**, 6435–6440 (2012).
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Comments

2013-01-02 07:43 AM

John Nethery said: One obvious question is: Did any of these studies carry out baseline measurements of methane in these areas prior to any drilling to check the amount of natural leakage via faults and fractures? If such studies were not done then basically the later measurements are irrelevant and conclusions are guesswork.

2013-01-03 06:18 AM

Ko van Huissteden said: The lack of baseline measurements on the environmental impact of unconventional gas is indeed a major problem in quantifying this impact. In general, the gas industry or US government should have taken the responsibility to do these baseline measurements, on groundwater quality, on air pollution and on greenhouse gas emissions. What is happening now with unconventional gas, is comparable to introducing medicines on the market without proper research on its side effects.
However, lack of baseline measurements does not justify dismissing any study on environmental or climate impact, because that would make practically all evaluation of environmental impact impossible and hinder any progress in environmental responsibility. Lack of baseline measurements often can be compensated for by good research design. In this case, any natural leakage of methane can also be accounted for in other ways.

2013-01-04 06:19 AM

Rinaldo Sorgenti said: Very interesting news.

The above subject is largely conditioned by the fact that, undoubtedly, coal at time of burning is releasing about double the CO_2 emissions in comparison to gas burning. What I call the "post-combustion" issue.

But, what about the "pre-combustion" issue, in a "Life Cycle Assessment", as it should logically be seen this matter, if really we have to bother about CO_2 emissions to the troposphere?

Strangely enough, none or only very few informed people are considering this issue and even the famous UN-IPCC is not considering, accounting and charging to anybody the usual and huge CO_2 emissions coming from the hydrocarbons wells extraction, where CO_2 (together with H_2S and N20) - naturally present underground, commingled with Methane and other gases – are coming out from ground during the fuels extraction.

These "nasty" ancillary gases (CO_2, H_2S, N20, etc.) are just regularly locally "captured" during wells extraction and then simply "vented" to the atmosphere!

In addition to the above mentioned "nasty" gases, there is also the "Methane fugitive emissions" issue to take into account and in relation to same I think useful to attract your and Mr. Dieter Helm's attention to the attached Study, published last year by the Cornell University – Ithaca/NY (USA): "Methane and GHG footprint of natural Gas from shale formation".

Considering the importance that many people (including the Ue) are placing to the above policy: "i.e.: switching from coal to natural gas for power production", I think that this matter need to be better understood and examined, to avoid that a wrong policy/action negatively influence so much the energy sector, worldwide at a very huge cost for the consumers.

The EPA should help to make this topic clear.

2013-01-04 04:14 AM

Larry Gilman said: Without seeing the work — here summarized secondhand — how do we actually know that lack of baseline is a problem? Pre-post comparison would be ideal, but could not a reasonable approximation of baseline be obtained by making measurements over geologically similar but undrilled areas?

2013-01-06 02:50 AM

Henk Daalder Wind farm wiki said: Natural gas does NOT have green credentials, it is just a fossil fuel, that contributes to the global warming problem.

The US has just been overtaken by China in building wind farms, they should work harder to reclaim this leadership, because wind power is better for the economy that natural gas.
And wind power is really green.
Since 2009 more wind power is build than any other war of generating electricity.

2013-01-09 11:29 AM

Robert Edwards said: Rinaldo Sorgenti is incorrect to assert that no-one considers "precombustion" emissions from fossil fuel extraction. Any life-cycle analysis worthy of the name of course take them into account. They are usually called "upstream emissions" or "production emissions".

2013-01-15 01:30 AM

Ronald Klusman said: Baseline measurements have been made for natural methane seepage in the Denver-Julesburg (DJ) basin. See Etiope and Klusman, 2010, Microseepage in drylands: Implications in the global atmospherice source/sink budget of methane. Global Planetary Change, v. 72, pp. 265-274. doi:10.1016/jgloplacha. 2010.0.02. See the first line in Table 1. These measurements were made in 1994-95. See also Klusman references therein. The estimated natural seepage rate for methane is about 14^6 kg/year over the entire DJ basin. There are strong seasonalities with higher rates in the winter due to slowing of methanotrophic oxidation in the soil column.

2013-01-24 09:28 AM

steve aaron said: I think you may add to that list, the fact that Jaguar Landrover seems to think 70% annual growth in car sales to China is something to be proud of (and not at all unsustainable).

The fact that the growthmaniacs have appropriated â€˜sustainabilityâ€™ drives me spare. Communication is hard enough as i t is without shifting the damn goalposts.

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Human health risk assessment of air emissions from development of unconventional natural gas resources ☆,☆☆

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ABSTRACT

Background: Technological advances (e.g. directional drilling, hydraulic fracturing), have led to increases in unconventional natural gas development (NGD), raising questions about health impacts.
Objectives: We estimated health risks for exposures to air emissions from a NGD project in Garfield County, Colorado with the objective of supporting risk prevention recommendations in a health impact assessment (HIA).
Methods: We used EPA guidance to estimate chronic and subchronic non-cancer hazard indices and cancer risks from exposure to hydrocarbons for two populations: (1) residents living >½ mile from wells and (2) residents living ≤½ mile from wells.
Results: Residents living ≤½ mile from wells are at greater risk for health effects from NGD than are residents living >½ mile from wells. Subchronic exposures to air pollutants during well completion activities present the greatest potential for health effects. The subchronic non-cancer hazard index (HI) of 5 for residents ≤½ mile from wells was driven primarily by exposure to trimethylbenzenes, xylenes, and aliphatic hydrocarbons. Chronic HIs were 1 and 0.4. for residents ≤½ mile from wells and >½ mile from wells, respectively. Cumulative cancer risks were 10 in a million and 6 in a million for residents living ≤½ mile and >½ mile from wells, respectively, with benzene as the major contributor to the risk.
Conclusions: Risk assessment can be used in HIAs to direct health risk prevention strategies. Risk management approaches should focus on reducing exposures to emissions during well completions. These preliminary results indicate that health effects resulting from air emissions during unconventional NGD warrant further study. Prospective studies should focus on health effects associated with air pollution.

1. Introduction

The United States (US) holds large reserves of unconventional natural gas resources in coalbeds, shale, and tight sands. Technological advances, such as directional drilling and hydraulic fracturing, have led to a rapid increase in the development of these resources. For example, shale gas production had an average annual growth rate of 48% over the 2006 to 2010 period and is projected to grow almost fourfold from 2009 to 2035 (US EIA, 2011). The number of unconventional natural gas wells in the US rose from 18,485 in 2004 to 25,145 in 2007 and is expected to continue increasing through at least 2020 (Vidas and Hugman, 2008). With this expansion, it is becoming increasingly common for unconventional natural gas development (NGD) to occur near where people live, work, and play. People living near these development sites are raising public health concerns, as rapid NGD exposes more people to various potential stressors (COGCC, 2009a).

The process of unconventional NGD is typically divided into two phases: well development and production (US EPA, 2010a; US DOE, 2009). Well development involves pad preparation, well drilling, and well completion. The well completion process has three primary stages: 1) completion transitions (concrete well plugs are installed in wells to separate fracturing stages and then drilled out to release gas for production); 2) hydraulic fracturing ("fracking": the high pressure injection of water, chemicals, and propants into the drilled well to release the natural gas); and 3) flowback, the return of fracking and geologic fluids, liquid hydrocarbons ("condensate") and natural gas to the surface (US EPA, 2010a; US DOE, 2009). Once development is

Abbreviations: BTEX, benzene, toluene, ethylbenzene, and xylenes; COGCC, Colorardo Oil and Gas Conservation Commission; HAP, hazardous air pollutant; HI, hazard index; HIA, health impact assessment; HQ, hazard quotient; NATA, National Air Toxics Assessment; NGD, natural gas development.

☆ This study was supported by the Garfield County Board of County Commissioners and the Colorado School of Public Health.
☆☆ The authors declare they have no competing financial interests.

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complete, the "salable" gas is collected, processed, and distributed. While methane is the primary constituent of natural gas, it contains many other chemicals, including alkanes, benzene, and other aromatic hydrocarbons (TERC, 2009).

As shown by ambient air studies in Colorado, Texas, and Wyoming, the NGD process results in direct and fugitive air emissions of a complex mixture of pollutants from the natural gas resource itself as well as diesel engines, tanks containing produced water, and on site materials used in production, such as drilling muds and fracking fluids (CDPHE, 2009; Frazier, 2009; Walther, 2011; Zielinska et al., 2011). The specific contribution of each of these potential NGD sources has yet to be ascertained and pollutants such as petroleum hydrocarbons are likely to be emitted from several of these NGD sources. This complex mixture of chemicals and resultant secondary air pollutants, such as ozone, can be transported to nearby residences and population centers (Walther, 2011; GCPH, 2010).

Multiple studies on inhalation exposure to petroleum hydrocarbons in occupational settings as well as residences near refineries, oil spills and petrol stations indicate an increased risk of eye irritation and headaches, asthma symptoms, acute childhood leukemia, acute myelogenous leukemia, and multiple myeloma (Glass et al., 2003; Kirkeleit et al., 2008; Brosselin et al., 2009; Kim et al., 2009; White et al., 2009). Many of the petroleum hydrocarbons observed in these studies are present in and around NGD sites (TERC, 2009). Some, such as benzene, ethylbenzene, toluene, and xylene (BTEX) have robust exposure and toxicity knowledge bases, while toxicity information for others, such as heptane, octane, and diethylbenzene, is more limited. Assessments in Colorado have concluded that ambient benzene levels demonstrate an increased potential risk of developing cancer as well as chronic and acute non-cancer health effects in areas of Garfield County Colorado where NGD is the only major industry other than agriculture (CDPHE, 2007; Coons and Walker, 2008; CDPHE, 2010). Health effects associated with benzene include acute and chronic nonlymphocytic leukemia, acute myeloid leukemia, chronic lymphocytic leukemia, anemia, and other blood disorders and immunological effects. (ATSDR, 2007a, IRIS, 2011). In addition, maternal exposure to ambient levels of benzene recently has been associated with an increase in birth prevalence of neural tube defects (Lupo et al., 2011). Health effects of xylene exposure include eye, nose, and throat irritation, difficulty in breathing, impaired lung function, and nervous system impairment (ATSDR, 2007b). In addition, inhalation of xylenes, benzene, and alkanes can adversely affect the nervous system (Carpenter et al., 1978; Nilsen et al., 1988; Galvin and Marashi, 1999; ATSDR, 2007a; ATSDR, 2007b).

Previous assessments are limited in that they were not able to distinguish between risks from ambient air pollution and specific NGD stages, such as well completions or risks between residents living near wells and residents living further from wells. We were able to isolate risks to residents living near wells during the flowback stage of well completions by using air quality data collected at the perimeter of the wells while flowback was occurring.

Battlement Mesa (population ~5000) located in rural Garfield County, Colorado is one community experiencing the rapid expansion of NGD in an unconventional tight sand resource. A NGD operator has proposed developing 200 gas wells on 9 well pads located as close as 500 ft from residences. Colorado Oil and Gas Commission (COGCC) rules allow natural gas wells to be placed as close as 150 ft from residences (COGCC, 2009b). Because of community concerns, as described elsewhere, we conducted a health impact assessment (HIA) to assess how the project may impact public health (Witter et al., 2011), working with a range of stakeholders to identify the potential public health risks and benefits.

In this article, we illustrate how a risk assessment was used to support elements of the HIA process and inform risk prevention recommendations by estimating chronic and subchronic non-cancer hazard indices (HIs) and lifetime excess cancer risks due to NGD air emissions.

2. Methods

We used standard United States Environmental Protection Agency (EPA) methodology to estimate non-cancer HIs and excess lifetime cancer risks for exposures to hydrocarbons (US EPA, 1989; US EPA, 2004) using residential exposure scenarios developed for the NGD project. We used air toxics data collected in Garfield County from January 2008 to November 2010 as part of a special study of short term exposures as well as on-going ambient air monitoring program data to estimate subchronic and chronic exposures and health risks (Frazier, 2009; GCPH, 2009; GCPH, 2010; GCPH, 2011; Antero, 2010).

2.1. Sample collection and analysis

All samples were collected and analyzed according to published EPA methods. Analyses were conducted by EPA certified laboratories. The Garfield County Department of Public Health (GCPH) and Olsson Associates, Inc. (Olsson) collected ambient air samples into evacuated SUMMA® passivated stainless-steel canisters over 24-hour intervals. The GCPH collected the samples from a fixed monitoring station and along the perimeters of four well pads and shipped samples to Eastern Research Group for analysis of 78 hydrocarbons using EPA's compendium method TO-12, Method for the Determination of Non-Methane Organic Compounds in Ambient Air Using Cyrogenic Preconcentration and Direct Flame Ionization Detection (US EPA, 1999). Olsson collected samples along the perimeter of one well pad and shipped samples to Atmospheric Analysis and Consulting, Inc. for analysis of 56 hydrocarbons (a subset of the 78 hydrocarbons determined by Eastern Research Group) using method TO-12. Per method TO-12, a fixed volume of sample was cryogenically concentrated and then desorbed onto a gas chromatography column equipped with a flame ionization detector. Chemicals were identified by retention time and reported in a concentration of parts per billion carbon (ppbC). The ppbC values were converted to micrograms per cubic meter ($\mu g/m^3$) at 01.325 kPa and 298.15 K.

Two different sets of samples were collected from rural (population < 50,000) areas in western Garfield County over varying time periods. The main economy, aside from the NGD industry, of western Garfield County is agricultural. There is no other major industry.

2.1.1. NGD area samples

The GCPH collected ambient air samples every six days between January 2008 and November 2010 (163 samples) from a fixed monitoring station located in the midst of rural home sites and ranches and NGD, during both well development and production. The site is located on top of a small hill and 4 miles upwind of other potential emission sources, such as a major highway (Interstate-70) and the town of Silt, CO (GCPH, 2009; GCPH, 2010; GCPH, 2011).

2.1.2. Well completion samples

The GCPH collected 16 ambient air samples at each cardinal direction along 4 well pad perimeters (130 to 500 ft from the well pad center) in rural Garfield County during well completion activities. The samples were collected on the perimeter of 4 well pads being developed by 4 different natural gas operators in summer 2008 (Frazier, 2009). The GCPH worked closely with the NGD operators to ensure these air samples were collected during the period while at least one well was on uncontrolled (emissions not controlled) flowback into collection tanks vented directly to the air. The number of wells on each pad and other activities occurring on the pad were not documented. Samples were collected over 24 to 27-hour intervals, and samples included emissions from both uncontrolled flowback and

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diesel engines (i.e., from. trucks and generators supporting completion activities). In addition, the GCPH collected a background sample 0.33 to 1 mile from each well pad (Frazier, 2009). The highest hydrocarbon levels corresponded to samples collected directly downwind of the tanks (Frazier, 2009; Antero, 2010). The lowest hydrocarbon levels corresponded either to background samples or samples collected upwind of the flowback tanks (Frazier, 2009; Antero, 2010).

Antero Resources Inc., a natural gas operator, contracted Olsson to collect eight 24-hour integrated ambient air samples at each cardinal direction at 350 and 500 ft from the well pad center during well completion activities conducted on one of their well pads in summer 2010 (Antero, 2010). Of the 12 wells on this pad, 8 were producing salable natural gas; 1 had been drilled but not completed; 2 were being hydraulically fractured during daytime hours, with ensuing uncontrolled flowback during nighttime hours; and 1 was on uncontrolled flowback during nighttime hours.

All five well pads are located in areas with active gas production, approximately 1 mile from Interstate-70.

2.2. Data assessment

We evaluated outliers and compared distributions of chemical concentrations from NGD area and well completion samples using Q–Q plots and the Mann–Whitney *U* test, respectively, in EPA's ProUCL version 4.00.05 software (US EPA, 2010b). The Mann–Whitney *U* test was used because the measurement data were not normally distributed. Distributions were considered as significantly different at an alpha of 0.05. Per EPA guidance, we assigned the exposure concentration as either the 95% upper confidence limit (UCL) of the mean concentration for compounds found in 10 or more samples or the maximum detected concentration for compounds found in more than 1 but fewer than 10 samples. This latter category included three compounds: 1,3-butadiene, 2,2,4-trimethylpentane, and styrene in the well completion samples. EPA's ProUCL software was used to select appropriate methods based on sample distributions and detection frequency for computing 95% UCLs of the mean concentration (US EPA, 2010b).

2.3. Exposure assessment

Risks were estimated for two populations: (1) residents >½ mile from wells; and (2) residents ≤½ mile from wells. We defined residents ≤½ mile from wells as living near wells, based on residents reporting odor complaints attributed to gas wells in the summer of 2010 (COGCC, 2011).

Exposure scenarios were developed for chronic non-cancer HIs and cancer risks. For both populations, we assumed a 30-year project duration based on an estimated 5-year well development period for all well pads, followed by 20 to 30 years of production. We assumed a resident lives, works, and otherwise remains within the town 24 h/day, 350 days/year and that lifetime of a resident is 70 years, based on standard EPA reasonable maximum exposure (RME) defaults (US EPA, 1989).

2.3.1. Residents >½ mile from well pads

As illustrated in Fig. 1, data from the NGD area samples were used to estimate chronic and subchronic risks for residents >½ mile from well development and production throughout the project. The exposure concentrations for this population were the 95% UCL on the mean concentration and median concentration from the 163 NGD samples.

2.3.2. Residents ≤½ mile from well pads

To evaluate subchronic non-cancer HIs from well completion emissions, we estimated that a resident lives ≤½ mile from two well pads resulting a 20-month exposure duration based on 2 weeks per well for completion and 20 wells per pad, assuming some overlap in between activities. The subchronic exposure concentrations for this population were the 95% UCL on the mean concentration and the median concentration from the 24 well completion samples. To evaluate chronic risks to residents ≤½ mile from wells throughout the NGD project, we calculated a time-weighted exposure concentration (C_{S+c}) to account for exposure to emissions from well completions for 20-months followed by 340 months of exposure to emissions from the NGD area using the following formula:

$$C_{S+c} = (C_c \times ED_c/ED) + (C_S \times ED_S/ED)$$

where:

C_c Chronic exposure point concentration ($\mu g/m^3$) based on the 95% UCL of the mean concentration or median concentration from the 163 NGD area samples

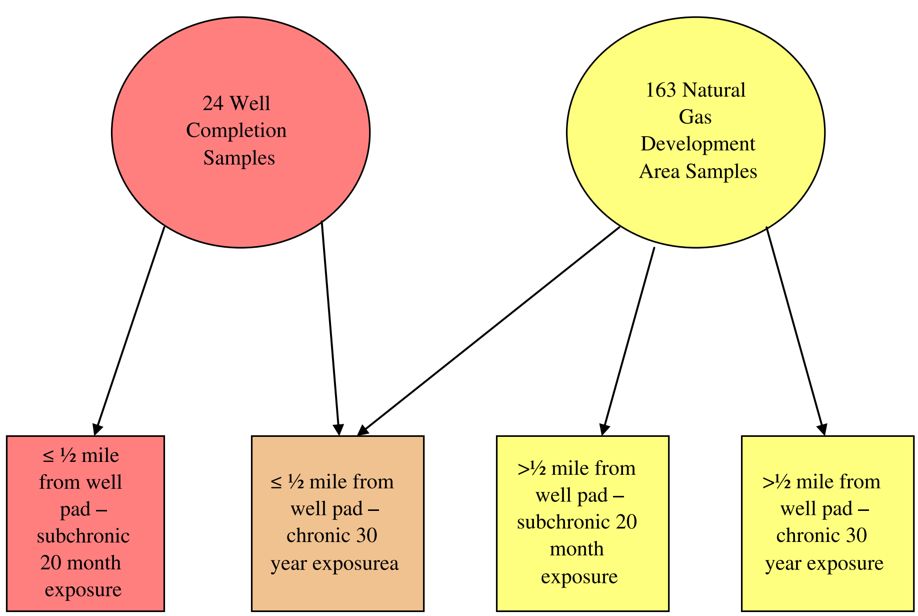

Fig. 1. Relationship between completion samples and natural gas development area samples and residents living ≤½ mile and >½ mile from wells. [a]Time weighted average based on 20-month contribution from well completion samples and 340-month contribution from natural gas development samples.

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ED_c Chronic exposure duration
C_S Subchronic exposure point concentration (μg/m^3) based on the 95% UCL of the mean concentration or median concentration from the 24 well completion samples
ED_S Subchronic exposure duration
ED Total exposure duration

2.4. Toxicity assessment and risk characterization

For non-carcinogens, we expressed inhalation toxicity measurements as a reference concentration (RfC in units of μg/m^3 air). We used chronic RfCs to evaluate long-term exposures of 30 years and subchronic RfCs to evaluate subchronic exposures of 20-months. If a subchronic RfC was not available, we used the chronic RfC. We obtained RfCs from (in order of preference) EPA's Integrated Risk Information System (IRIS) (US EPA, 2011), California Environmental Protection Agency (CalEPA) (CalEPA, 2003), EPA's Provisional Peer-Reviewed Toxicity Values (ORNL, 2009), and Health Effects Assessment Summary Tables (US EPA, 1997). We used surrogate RfCs according to EPA guidance for C_5 to C_{18} aliphatic and C_6 to C_{18} aromatic hydrocarbons which did not have a chemical-specific toxicity value (US EPA, 2009a). We derived semi-quantitative hazards, in terms of the hazard quotient (HQ), defined as the ratio between an estimated exposure concentration and RfC. We summed HQs for individual compounds to estimate the total cumulative HI. We then separated HQs specific to neurological, respiratory, hematological, and developmental effects and calculated a cumulative HI for each of these specific effects.

For carcinogens, we expressed inhalation toxicity measurements as inhalation unit risk (IUR) in units of risk per μg/m^3. We used IURs from EPA's IRIS (US EPA, 2011) when available or the CalEPA (CalEPA, 2003). The lifetime cancer risk for each compound was derived by multiplying estimated exposure concentration by the IUR. We summed cancer risks for individual compounds to estimate the cumulative cancer risk. Risks are expressed as excess cancers per 1 million population based on exposure over 30 years.

Toxicity values (i.e., RfCs or IURs) or a surrogate toxicity value were available for 45 out of 78 hydrocarbons measured. We performed a quantitative risk assessment for these hydrocarbons. The remaining 33 hydrocarbons were considered qualitatively in the risk assessment.

3. Results

3.1. Data assessment

Evaluation of potential outliers revealed no sampling, analytical, or other anomalies were associated with the outliers. In addition, removal of potential outliers from the NGD area samples did not change the final HIs and cancer risks. Potential outliers in the well completion samples were associated with samples collected downwind from flowback tanks and are representative of emissions during flowback. Therefore, no data was removed from either data set.

Descriptive statistics for concentrations of the hydrocarbons used in the quantitative risk assessment are presented in Table 1. A list of the hydrocarbons detected in the samples that were considered qualitatively in the risk assessment because toxicity values were not available is presented in Table 2. Descriptive statistics for all hydrocarbons are available in Supplemental Table 1. Two thirds more hydrocarbons were detected at a frequency of 100% in the well completion samples (38 hydrocarbons) than in the NGD area samples (23 hydrocarbons). Generally, the highest alkane and aromatic hydrocarbon median concentrations were observed in the well completion samples, while the highest median concentrations of several alkenes were observed in the NGD area samples. Median concentrations of benzene, ethylbenzene, toluene, and m-xylene/p-xlyene were 2.7, 4.5, 4.3, and 9 times higher in the well completion samples than in the NGD area samples, respectively. Wilcoxon–Mann–Whitney test results indicate that

Table 1
Descriptive statistics for hydrocarbon concentrations with toxicity values in 24-hour integrated samples collected in NGD area and samples collected during well completions.

Hydrocarbon (μg/m^3)	NGD area sample results[a]							Well completion sample results[b]						
	No.	% >MDL	Med	SD	95% UCL[c]	Min	Max	No.	% >MDL	Med	SD	95% UCL[c]	Min	Max
1,2,3-Trimethylbenzene	163	39	0.11	0.095	0.099	0.022	0.85	24	83	0.84	2.3	3.2	0.055	12
1,2,4-Trimethylbenzene	163	96	0.18	0.34	0.31	0.063	3.1	24	100	1.7	17	21	0.44	83
1,3,5-Trimethylbenzene	163	83	0.12	0.13	0.175	0.024	1.2	24	100	1.3	16	19.5	0.33	78
1,3-Butadiene	163	7	0.11	0.020	0.0465	0.025	0.15	16	56	0.11	0.021	NC	0.068	0.17
Benzene	163	100	0.95	1.3	1.7	0.096	14	24	100	2.6	14	20	0.94	69
Cyclohexane	163	100	2.1	8.3	6.2	0.11	105	24	100	5.3	43	58	2.21	200
Ethylbenzene	163	95	0.17	0.73	0.415	0.056	8.1	24	100	0.77	47	54	0.25	230
Isopropylbenzene	163	38	0.15	0.053	0.074	0.020	0.33	24	67	0.33	1.0	1.0	0.0	4.8
Methylcyclohexane	163	100	3.7	4.0	6.3	0.15	24	24	100	14	149	190	3.1	720
m-Xylene/p-Xylene	163	100	0.87	1.2	1.3	0.16	9.9	24	100	7.8	194	240	2.0	880
n-Hexane	163	100	4.0	4.2	6.7	0.13	25	24	100	7.7	57	80	1.7	255
n-Nonane	163	99	0.44	0.49	0.66	0.064	3.1	24	100	3.6	61	76	1.2	300
n-Pentane	163	100	9.1	9.8	14	0.23	62	24	100	11	156	210	3.9	550
n-Propylbenzene	163	66	0.10	0.068	0.10	0.032	0.71	24	88	0.64	2.4	3.3	0.098	12
o-Xylene	163	97	0.22	0.33	0.33	0.064	3.6	24	100	1.2	40	48.5	0.38	190
Propylene	163	100	0.34	0.23	0.40	0.11	2.5	24	100	0.41	0.34	0.60	0.16	1.9
Styrene	163	15	0.15	0.26	0.13	0.017	3.4	24	21	0.13	1.2	NC	0.23	5.9
Toluene	163	100	1.8	6.2	4.8	0.11	79	24	100	7.8	67	92	2.7	320
Aliphatic hydrocarbons C_5–C_8[d]	163	NC	29	NA	44	1.7	220	24	NC	56	NA	780	24	2700
Aliphatic hydrocarbons C_9–C_{18}[e]	163	NC	1.3	NA	14	0.18	400	24	NC	7.9	NA	100	1.4	390
Aromatic hydrocarbons C_9–C_{18}[f]	163	NC	0.57	NA	0.695	0.17	5.6	24	NC	3.7	NA	27	0.71	120

Abbreviations: Max, maximum detected concentration; Med, median; Min, minimum detected concentration; NGD, natural gas development; NC, not calculated; No., number of samples; SD, standard deviation; % >MDL, percent greater than method detection limit; μg/m^3 micrograms per cubic meter; 95% UCL 95% upper confidence limit on the mean.

[a] Samples collected at one site every 6 six days between 2008 and 2010.

[b] Samples collected at four separate sites in summer 2008 and one site in summer 2010.

[c] Calculated using EPA's ProUCL version 4.00.05 software (US EPA, 2010b).

[d] Sum of 2,2,2-trimethylpentane, 2,2,4-trimethylpentane, 2,2-dimethylbutane, 2,3,4-trimethylpentane, 2,3-dimethylbutane, 2,3-dimethylpentane, 2,4-dimethylpentane, 2-methylheptane, 2-methylhexane, 2-methylpentane, 3-methylheptane, 3-methylhexane, 3-methylpentane, cyclopentane, isopentane, methylcyclopentane, n-heptane, n-octane.

[e] Sum of n-decane, n-dodecane, n-tridecane, n-undecane.

[f] Sum of m-diethylbenzene, m-ethyltoluene, o-ethyltoluene, p-diethylbenzene, p-ethyltoluene.

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Table 2
Detection frequencies of hydrocarbons without toxicity values detected in NGD area or well completion samples.

Hydrocarbon	NGD area sample[a] detection frequency (%)	Well completion sample[b] detection frequency (%)
1-Dodecene	36	81
1-Heptene	94	100
1-Hexene	63	79
1-Nonene	52	94
1-Octene	29	75
1-Pentene	98	79
1-Tridecene	7	38
1-Undecene	28	81
2-Ethyl-1-butene	1	0
2-Methyl-1-butene	29	44
2-Methyl-1-pentene	1	6
2-Methyl-2-butene	36	69
3-Methyl-1-butene	6	6
4-Methyl-1-pentene	16	69
Acetylene	100	92
a-Pinene	63	100
b-Pinene	10	44
cis-2-Butene	58	75
cis-2-Hexene	13	81
cis-2-Pentene	38	54
Cyclopentene	44	94
Ethane	100	100
Ethylene	100	100
Isobutane	100	100
Isobutene/1-Butene	73	44
Isoprene	71	96
n-Butane	98	100
Propane	100	100
Propyne	1	0
trans-2-Butene	80	75
trans-2-Hexene	1	6
trans-2-Pentene	55	83

Abbreviations: NGD, natural gas development.
[a] Samples collected at one site every 6 six days between 2008 and 2010.
[b] Samples collected at four separate sites in summer 2008 and one site in summer 2010.

concentrations of hydrocarbons from well completion samples were significantly higher than concentrations from NGD area samples ($p<0.05$) with the exception of 1,2,3-trimethylbenzene, n-pentane, 1,3-butadiene, isopropylbenzene, n-propylbenzene, propylene, and styrene (Supplemental Table 2).

3.2. Non-cancer hazard indices

Table 3 presents chronic and subchronic RfCs used in calculating non-cancer HIs, as well critical effects and other effects. Chronic non-cancer HQ and HI estimates based on ambient air concentrations are presented in Table 4. The total chronic HIs based on the 95% UCL of the mean concentration were 0.4 for residents >½ mile from wells and 1 for residents ≤½ mile from wells. Most of the chronic non-cancer hazard is attributed to neurological effects with neurological HIs of 0.3 for residents >½ mile from wells and 0.9 for residents ≤½ mile from wells.

Total subchronic non-cancer HQs and HI estimates are presented in Table 5. The total subchronic HIs based on the 95% UCL of the mean concentration were 0.2 for residents >½ mile from wells and 5 for residents ≤½ mile from wells. The subchronic non-cancer hazard for residents >½ mile from wells is attributed mostly to respiratory effects (HI = 0.2), while the subchronic hazard for residents ≤½ mile from wells is attributed to neurological (HI = 4), respiratory (HI = 2), hematologic (HI = 3), and developmental (HI = 1) effects.

For residents >½ mile from wells, aliphatic hydrocarbons (51%), trimethylbenzenes (22%), and benzene (14%) are primary contributors to the chronic non-cancer HI. For residents ≤½ mile from wells, trimethylbenzenes (45%), aliphatic hydrocarbons (32%), and xylenes (17%) are primary contributors to the chronic non-cancer HI, and trimethylbenzenes (46%), aliphatic hydrocarbons (21%) and xylenes (15%) also are primary contributors to the subchronic HI.

3.3. Cancer risks

Cancer risk estimates calculated based on measured ambient air concentrations are presented in Table 6. The cumulative cancer risks based on the 95% UCL of the mean concentration were 6 in a million for residents >½ from wells and 10 in a million for residents ≤½ mile from wells. Benzene (84%) and 1,3-butadiene (9%) were the primary contributors to cumulative cancer risk for residents >½ mile from wells. Benzene (67%) and ethylbenzene (27%) were the primary contributors to cumulative cancer risk for residents ≤½ mile from wells.

4. Discussion

Our results show that the non-cancer HI from air emissions due to natural gas development is greater for residents living closer to wells. Our greatest HI corresponds to the relatively short-term (i.e., subchronic), but high emission, well completion period. This HI is driven principally by exposure to trimethylbenzenes, aliphatic hydrocarbons, and xylenes, all of which have neurological and/or respiratory effects. We also calculated higher cancer risks for residents living nearer to wells as compared to residents residing further from wells. Benzene is the major contributor to lifetime excess cancer risk for both scenarios. It also is notable that these increased risk metrics are seen in an air shed that has elevated ambient levels of several measured air toxics, such as benzene (CDPHE, 2009; GCPH, 2010).

4.1. Representation of exposures from NGD

It is likely that NGD is the major source of the hydrocarbons observed in the NGD area samples used in this risk assessment. The NGD area monitoring site is located in the midst of multi-acre rural home sites and ranches. Natural gas is the only industry in the area other than agriculture. Furthermore, the site is at least 4 miles upwind from any other major emission source, including Interstate 70 and the town of Silt, Colorado. Interestingly, levels of benzene, m,p-xylene, and 1,3,5-trimethylbenzene measured at this rural monitoring site in 2009 were higher than levels measured at 27 out of 37 EPA air toxics monitoring sites where SNMOCs were measured, including urban sites such as Elizabeth, NJ, Dearborn, MI, and Tulsa, OK (GCPH, 2010; US EPA, 2009b). In addition, the 2007 Garfield County emission inventory attributes the bulk of benzene, xylene, toluene, and ethylbenzene emissions in the county to NGD, with NGD point and non-point sources contributing five times more benzene than any other emission source, including on-road vehicles, wildfires, and wood burning. The emission inventory also indicates that NGD sources (e.g. condensate tanks, drill rigs, venting during completions, fugitive emissions from wells and pipes, and compressor engines) contributed ten times more VOC emissions than any source, other than biogenic sources (e.g. plants, animals, marshes, and the earth) (CDPHE, 2009).

Emissions from flowback operations, which may include emissions from various sources on the pads such as wells and diesel engines, are likely the major source of the hydrocarbons observed in the well completion samples. These samples were collected very near (130 to 500 ft from the center) well pads during uncontrolled flowback into tanks venting directly to the air. As for the NGD area samples, no sources other than those associated with NGD were in the vicinity of the sampling locations.

Subchronic health effects, such as headaches and throat and eye irritation reported by residents during well completion activities

Table 3
Chronic and subchronic reference concentrations, critical effects, and major effects for hydrocarbons in quantitative risk assessment.

Hydrocarbon	Chronic		Subchronic		Critical effect/ target organ	Other effects
	RfC (μg/m³)	Source	RfC (μg/m³)	Source		
1,2,3-Trimethylbenzene	5.00E+00	PPTRV	5.00E+01	PPTRV	Neurological	Respiratory, hematological
1,3,5-Trimethylbenzene	6.00E+00	PPTRV	1.00E+01	PPTRV	Neurological	Hematological
Isopropylbenzene	4.00E+02	IRIS	9.00E+01	HEAST	Renal	Neurological, respiratory
n-Hexane	7.00E+02	IRIS	2.00E+03	PPTRV	Neurological	–
n-Nonane	2.00E+02	PPTRV	2.00E+03	PPTRV	Neurological	Respiratory
n-Pentane	1.00E+03	PPTRV	1.00E+04	PPTRV	Neurological	–
Styrene	1.00E+03	IRIS	3.00E+03	HEAST	Neurological	–
Toluene	5.00E+03	IRIS	5.00E+03	PPTRV	Neurological	Developmental, respiratory
Xylenes, total	1.00E+02	IRIS	4.00E+02	PPTRV	Neurological	Developmental, respiratory
n-propylbenzene	1.00E+03	PPTRV	1.00E+03	Chronic RfC PPTRV	Developmental	Neurological
1,2,4-Trimethylbenzene	7.00E+00	PPTRV	7.00E+01	PPTRV	Decrease in blood clotting time	Neurological, respiratory
1,3-Butadiene	2.00E+00	IRIS	2.00E+00	Chronic RfC IRIS	Reproductive	Neurological, respiratory
Propylene	3.00E+03	CalEPA	1.00E+03	Chronic RfC CalEPA	Respiratory	–
Benzene	3.00E+01	ATSDR	8.00E+01	PPTRV	Decreased lymphocyte count	Neurological, developmental, reproductive
Ethylbenzene	1.00E+03	ATSDR	9.00E+03	PPTRV	Auditory	Neurological, respiratory, renal
Cyclohexane	6.00E+03	IRIS	1.80E+04	PPTRV	Developmental	Neurological
Methylcyclohexane	3.00E+03	HEAST	3.00E+03	HEAST	Renal	–
Aliphatic hydrocarbons C_5–C_8 [a]	6E+02	PPTRV	2.7E+04	PPTRV	Neurological	–
Aliphatic hydrocarbons C_9–C_{18}	1E+02	PPTRV	1E+02	PPTRV	Respiratory	–
Aromatic hydrocarbons C_9–C_{18} [b]	1E+02	PPTRV	1E+03	PPRTV	Decreased maternal body weight	Respiratory

Abbreviations: 95%UCL, 95% upper confidence limit; CalEPA, California Environmental Protection Agency; HEAST, EPA Health Effects Assessment Summary Tables 1997; HQ, hazard quotient; IRIS, Integrated Risk Information System; Max, maximum; PPTRV, EPA Provisional Peer-Reviewed Toxicity Value; RfC, reference concentration; μg/m³, micrograms per cubic meter. Data from CalEPA 2011; IRIS (US EPA, 2011); ORNL 2011.

[a] Based on PPTRV for commercial hexane.

[b] Based on PPTRV for high flash naphtha.

occurring in Garfield County, are consistent with known health effects of many of the hydrocarbons evaluated in this analysis (COGCC, 2011; Witter et al., 2011). Inhalation of trimethylbenzenes and xylenes can irritate the respiratory system and mucous membranes with effects ranging from eye, nose, and throat irritation to difficulty in breathing and impaired lung function (ATSDR, 2007a;

Table 4
Chronic hazard quotients and hazard indices for residents living >½ mile from wells and residents living ≤½ mile from wells.

Hydrocarbon	>½ mile		≤½ mile	
	Chronic HQ based on median concentration	Chronic HQ based on 95% UCL of mean concentration	Chronic HQ based on median concentration	Chronic HQ based on 95% UCL of mean concentration
1,2,3-Trimethylbenzene	2.09E−02	1.90E−02	2.87E−02	5.21E−02
1,2,4-Trimethylbenzene	2.51E−02	4.22E−02	3.64E−02	2.01E−01
1,3,5-Trimethylbenzene	1.96E−02	2.80E−02	3.00E−02	1.99E−01
1,3-Butadiene	5.05E−02	2.23E−02	5.05E−02	2.25E−02
Benzene	3.03E−02	5.40E−02	3.32E−02	8.70E−02
Cyclohexane	3.40E−04	9.98E−04	3.67E−04	1.46E−03
Ethylbenzene	1.63E−04	3.98E−04	1.95E−04	3.23E−03
Isopropylbenzene	3.68E−04	1.78E−04	3.90E−04	3.05E−04
Methylcyclohexane	1.18E−03	2.00E−03	1.36E−03	5.32E−03
n-Hexane	5.49E−03	9.23E−03	5.76E−03	1.47E−02
n-Nonane	2.11E−03	3.14E−03	2.95E−03	2.31E−02
n-Pentane	8.71E−03	1.32E−02	8.79E−03	2.39E−02
n-propylbenzene	9.95E−05	9.59E−05	1.28E−04	2.64E−04
Propylene	1.09E−04	1.27E−04	1.10E−04	1.30E−04
Styrene	1.43E−04	1.25E−04	1.42E−04	4.32E−04
Toluene	3.40E−04	9.28E−04	4.06E−04	1.86E−03
Xylenes, total	1.16E−02	1.57E−02	1.54E−02	1.71E−01
Aliphatic hydrocarbons C_5–C_8	4.63E−02	7.02E−02	4.87E−02	1.36E−01
Aliphatic hydrocarbons C_9–C_{18}	1.22E−02	1.35E−01	1.58E−02	1.83E−01
Aromatic hydrocarbons C_9–C_{18}	5.44E−03	6.67E−03	7.12E−03	2.04E−02
Total Hazard Index	2E−01	4E−01	3E−01	1E+00
Neuorological Effects Hazard Index[a]	2E−01	3E−01	3E−01	9E−01
Respiratory Effects Hazard Index[b]	1E−01	2E−02	2E−02	7E−01
Hematogical Effects Hazard Index[c]	1E−01	1E−01	1E−01	5E−01
Developmental Effects Hazard Index[d]	4E−02	7E−02	5E−02	3E−01

Abbreviations: 95%UCL, 95% upper confidence limit; HQ, hazard quotient.

[a] Sum of HQs for hydrocarbons with neurological effects: 1,2,3-Trimethylbenzene, 1,2,4-Trimethylbenzene, 1,3,5-Trimethylbenzene, 1,3-butadiene, benzene, cyclohexane, ethylbenzene, isopropylbenzene, n-hexane, n-nonane, n-pentane, n-propylbenzene, styrene, toluene, xylenes, aliphatic C_5–C_8 hydrocarbons.

[b] Sum of HQs for hydrocarbons with respiratory effects: 1,2,3-Trimethylbenzene, 1,2,4-Trimethylbenzene, 1,3-butadiene, ethylbenzene, isopropylbenzene, n-nonane, propylene, toluene, xylenes, aliphatic C_9–C_{18} hydrocarbons, aromatic C_9–C_{18} hydrocarbons.

[c] Sum of HQs for hydrocarbons with hematological effects: 1,2,3-trimethylbenzene, 1,2,4-trimethylbenzene, 1,3,5-trimethylbenzene, benzene.

[d] Sum of HQs for hydrocarbons with developmental effects: benzene, cyclohexane, toluene, and xylenes.

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Table 5
Subchronic hazard quotients and hazard indices residents living >½ mile from wells and residents living ≤½ mile from wells.

Hydrocarbon (μg/m^3)	>½ mile		≤½ mile	
	Subchronic HQ based on median concentration	Subchronic HQ based on 95% UCL of mean concentration	Subchronic HQ based on median concentration	Subchronic HQ based on 95% UCL of mean concentration
1,2,3-Trimethylbenzene	2.09E−03	1.90E−03	1.67E−02	6.40E−02
1,2,4-Trimethylbenzene	2.51E−03	4.22E−03	2.38E−02	3.02E−01
1,3,5-Trimethylbenzene	1.18E−02	1.68E−02	1.29E−01	1.95E+00
1,3-Butadiene	5.04E−02	2.23E−02	5.25E−02	8.30E−02
Benzene	1.14E−02	2.02E−02	3.25E−02	2.55E−01
Cyclohexane	1.13E−04	3.33E−04	2.93E−04	3.24E−03
Ethylbenzene	1.81E−05	4.42E−05	8.56E−05	5.96E−03
Isopropylbenzene	1.63E−03	7.92E−04	3.62E−03	1.14E−02
Methylcyclohexane	1.18E−03	2.01E−03	4.67E−03	6.47E−02
n-Hexane	1.92E−03	3.23E−03	3.86E−03	3.98E−02
n-Nonane	2.11E−04	3.14E−04	1.80E−03	3.78E−02
n-Pentane	8.71E−04	1.32E−03	1.05E−03	2.13E−02
n-propylbenzene	9.95E−05	9.57E−05	6.36E−04	3.26E−03
Propylene	1.43E−04	3.80E−04	4.12E−04	6.02E−04
Styrene	5.68E−04	4.16E−05	4.00E−06	1.97E−03
Toluene	4.18E−05	9.28E−04	2.46E−04	1.84E−02
Xylenes, total	2.91E−03	3.93E−03	2.05E−02	7.21E−01
Aliphatic hydrocarbons C_5–C_8	1.07E−03	1.63E−03	2.07E−03	2.89E−02
Aliphatic hydrocarbons C_9–C_{18}	1.3E−02	1.41E−01	7.9E−02	1.03E−00
Aromatic hydrocarbons C_9–C_{18}	6.00E−04	6.95E−04	3.7E−03	2.64E−02
Total Hazard Index	1E−01	2E−01	4E−01	5E+00
Neurological Effects Hazard Index[a]	9E−02	8E−02	3E−01	4E+00
Respiratory Effects Hazard Index[b]	7E−02	2E−01	2E−01	2E+00
Hematogical Effects Hazard Index[c]	3E−02	4E−02	2E−01	3E+00
Developmental Effects Hazard Index[d]	1E−02	3E−02	5E−02	1E+00

Abbreviations: 95%UCL, 95% upper confidence limit; HQ, hazard quotient.
[a] Sum of HQs for hydrocarbons with neurological effects: 1,2,3-Trimethylbenzene, 1,2,4-Trimethylbenzene, 1,3,5-Trimethylbenzene, 1,3-butadiene, benzene, cyclohexane, ethylbenzene, isopropylbenzene, n-hexane, n-nonane, n-pentane, n-propylbenzene, styrene, toluene, xylenes, aliphatic C_5–C_8 hydrocarbons.
[b] Sum of HQs for hydrocarbons with respiratory effects: 1,2,3-Trimethylbenzene, 1,2,4-Trimethylbenzene, 1,3-butadiene, ethylbenzene, isopropylbenzene, n-nonane, propylene, toluene, xylenes, aliphatic C_9–C_{18} hydrocarbons, aromatic C_9–C_{18} hydrocarbons.
[c] Sum of HQs for hydrocarbons with hematological effects: 1,2,3-trimethylbenzene, 1,2,4-trimethylbenzene, 1,3,5-trimethylbenzene, benzene.
[d] Sum of HQs for hydrocarbons with developmental effects: benzene, cyclohexane, toluene, and xylenes.

ATSDR, 2007b; US EPA, 1994). Inhalation of trimethylbenzenes, xylenes, benzene, and alkanes can adversely affect the nervous system with effects ranging from dizziness, headaches, fatigue at lower exposures to numbness in the limbs, incoordination, tremors, temporary limb paralysis, and unconsciousness at higher exposures (Carpenter et al., 1978; Nilsen et al., 1988; US EPA, 1994; Galvin and Marashi, 1999; ATSDR, 2007a; ATSDR, 2007b).

4.2. Risk assessment as a tool for health impact assessment

HIA is a policy tool used internationally that is being increasingly used in the United States to assess multiple complex hazards and exposures in communities. Comparison of risks between residents based on proximity to wells illustrates how the risk assessment process can be used to support the HIA process. An important component of the HIA process is to identify where and when public health is most likely to be impacted and to recommend mitigations to reduce or eliminate the potential impact (Collins and Koplan, 2009). This risk assessment indicates that public health most likely would be impacted by well completion activities, particularly for residents living nearest the wells. Based on this information, suggested risk prevention strategies in the HIA are directed at minimizing exposures for those living closet to the well pads, especially during well completion activities when emissions are the highest. The HIA includes recommendations to (1) control and monitor emissions during completion transitions and flowback; (2) capture and reduce emissions through use of low or no emission flowback tanks; and (3) establish and maintain communications regarding well pad activities with the community (Witter et al., 2011).

4.3. Comparisons to other risk estimates

This risk assessment is one of the first studies in the peer-reviewed literature to provide a scientific perspective to the potential health risks associated with development of unconventional natural

Table 6
Excess cancer risks for residents living >½ mile from wells and residents living ≤½ mile from wells.

Hydrocarbon	WOE		Unit Risk (μg/m^3)	Source	>½ mile		≤½ mile	
	IRIS	IARC			Cancer risk based on median concentration	Cancer risk based on 95% UCL of mean concentration	Cancer risk based on median concentration	Cancer risk based on 95% UCL of mean concentration
1,3-Butadiene	B2	1	3.00E−05	IRIS	1.30E−06	5.73E−07	1.30E−06	6.54E−07
Benzene	A	1	7.80E−06	IRIS	3.03E−06	5.40E−06	3.33E−06	8.74E−06
Ethylbenzene	NC	2B	2.50E−06	CalEPA	1.75E−07	4.26E−07	2.09E−07	3.48E−06
Styrene	NC	2B	5.00E−07	CEP	3.10E−08	2.70E−08	3.00E−08	9.30E−08
Cumulative cancer risk					5E−06	6E−06	5E−06	1E−05

Abbreviations: 95%UCL, 95% upper confidence limit; CalEPA, California Environmental Protection Agency; CEP, (Caldwell et al., 1998); IARC, International Agency for Research on Cancer; IRIS, Integrated Risk Information System; Max, maximum; NC, not calculated; WOE, weight of evidence; μg/m^3, micrograms per cubic meter. Data from CalEPA 2011; IRIS (US EPA, 2011).

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gas resources. Our results for chronic non-cancer HIs and cancer risks for residents > than ½ mile from wells are similar to those reported for NGD areas in the relatively few previous risk assessments in the non-peer reviewed literature that have addressed this issue (CDPHE, 2010; Coons and Walker, 2008; CDPHE, 2007; Walther, 2011). Our risk assessment differs from these previous risk assessments in that it is the first to separately examine residential populations nearer versus further from wells and to report health impact of emissions resulting from well completions. It also adds information on exposure to air emissions from development of these resources. These data show that it is important to include air pollution in the national dialogue on unconventional NGD that, to date, has largely focused on water exposures to hydraulic fracturing chemicals.

4.4. Limitations

As with all risk assessments, scientific limitations may lead to an over- or underestimation of the actual risks. Factors that may lead to overestimation of risk include use of: 1) 95% UCL on the mean exposure concentrations; 2) maximum detected values for 1,3-butadiene, 2,2,4-trimethylpentane, and styrene because of a low number of detectable measurements; 3) default RME exposure assumptions, such as an exposure time of 24 h per day and exposure frequency of 350 days per year; and 4) upper bound cancer risk and non-cancer toxicity values for some of our major risk drivers. The benzene IUR, for example, is based on the high end of a range of maximum likelihood values and includes uncertainty factors to account for limitations in the epidemiological studies for the dose–response and exposure data (US EPA, 2011). Similiarly, the xylene chronic RfC is adjusted by a factor of 300 to account for uncertainties in extrapolating from animal studies, variability of sensitivity in humans, and extrapolating from subchronic studies (US EPA, 2011). Our use of chronic RfCs values when subchronic RfCs were not available may also have overestimated 1,3-butadiene, n-propylbenzene, and propylene subchronic HQs. None of these three chemicals, however, were primary contributors to the subchronic HI, so their overall effect on the HI is relatively small.

Several factors may have lead to an underestimation of risk in our study results. We were not able to completely characterize exposures because several criteria or hazardous air pollutants directly associated with the NGD process via emissions from wells or equipment used to develop wells, including formaldehyde, acetaldehyde, crotonaldehyde, naphthalene, particulate matter, and polycyclic aromatic hydrocarbons, were not measured. No toxicity values appropriate for quantitative risk assessment were available for assessing the risk to several alkenes and low molecular weight alkanes (particularly $<C_5$ aliphatic hydrocarbons). While at low concentrations the toxicity of alkanes and alkenes is generally considered to be minimal (Sandmeyer, 1981), the maximum concentrations of several low molecular weight alkanes measured in the well completion samples exceeded the 200–1000 μg/m^3 range of the RfCs for the three alkanes with toxicity values: n-hexane, n-pentane, and n-nonane (US EPA, 2011; ORNL, 2009). We did not consider health effects from acute (i.e., less than 1 h) exposures to peak hydrocarbon emissions because there were no appropriate measurements. Previous risk assessments have estimated an acute HQ of 6 from benzene in grab samples collected when residents noticed odors they attributed to NGD (CDPHE, 2007). We did not include ozone or other potentially relevant exposure pathways such as ingestion of water and inhalation of dust in this risk assessment because of a lack of available data. Elevated concentrations of ozone precursors (specifically, VOCs and nitrogen oxides) have been observed in Garfield County's NGD area and the 8-h average ozone concentration has periodically approached the 75 ppb National Ambient Air Quality Standard (NAAQS) (CDPHE, 2009; GCPH, 2010).

This risk assessment also was limited by the spatial and temporal scope of available monitoring data. For the estimated chronic exposure, we used 3 years of monitoring data to estimate exposures over a 30 year exposure period and a relatively small database of 24 samples collected at varying distances up to 500 ft from a well head (which also were used to estimate shorter-term non-cancer hazard index). Our estimated 20-month subchronic exposure was limited to samples collected in the summer, which may have not have captured temporal variation in well completion emissions. Our ½ mile cut point for defining the two different exposed populations in our exposure scenarios was based on complaint reports from residents living within ½ mile of existing NGD, which were the only data available. The actual distance at which residents may experience greater exposures from air emissions may be less than or greater than a ½ mile, depending on dispersion and local topography and meteorology. This lack of spatially and temporally appropriate data increases the uncertainty associated with the results.

Lastly, this risk assessment was limited in that appropriate data were not available for apportionment to specific sources within NGD (e.g. diesel emissions, the natural gas resource itself, emissions from tanks, etc.). This increases the uncertainty in the potential effectiveness of risk mitigation options.

These limitations and uncertainties in our risk assessment highlight the preliminary nature of our results. However, there is more certainty in the comparison of the risks between the populations and in the comparison of subchronic to chronic exposures because the limitations and uncertainties similarly affected the risk estimates.

4.5. Next steps

Further studies are warranted, in order to reduce the uncertainties in the health effects of exposures to NGD air emissions, to better direct efforts to prevent exposures, and thus address the limitations of this risk assessment. Next steps should include the modeling of short- and longer-term exposures as well as collection of area, residential, and personal exposure data, particularly for peak short-term emissions. Furthermore, studies should examine the toxicity of hydrocarbons, such as alkanes, including health effects of mixtures of HAPs and other air pollutants associated with NGD. Emissions from specific emission sources should be characterized and include development of dispersion profiles of HAPs. This emissions data, when coupled with information on local meteorological conditions and topography, can help provide guidance on minimum distances needed to protect occupant health in nearby homes, schools, and businesses. Studies that incorporate all relevant pathways and exposure scenarios, including occupational exposures, are needed to better understand the impacts of NGD of unconventional resources, such as tight sands and shale, on public health. Prospective medical monitoring and surveillance for potential air pollution-related health effects is needed for populations living in areas near the development of unconventional natural gas resources.

5. Conclusions

Risk assessment can be used as a tool in HIAs to identify where and when public health is most likely to be impacted and to inform risk prevention strategies directed towards efficient reduction of negative health impacts. These preliminary results indicate that health effects resulting from air emissions during development of unconventional natural gas resources are most likely to occur in residents living nearest to the well pads and warrant further study. Risk prevention efforts should be directed towards reducing air emission exposures for persons living and working near wells during well completions.

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1

Historical Overview of Climate Change Science

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Executive Summary

Awareness and a partial understanding of most of the interactive processes in the Earth system that govern climate and climate change predate the IPCC, often by many decades. A deeper understanding and quantification of these processes and their incorporation in climate models have progressed rapidly since the IPCC First Assessment Report in 1990.

As climate science and the Earth's climate have continued to evolve over recent decades, increasing evidence of anthropogenic influences on climate change has been found. Correspondingly, the IPCC has made increasingly more definitive statements about human impacts on climate.

Debate has stimulated a wide variety of climate change research. The results of this research have refined but not significantly redirected the main scientific conclusions from the sequence of IPCC assessments.

1.1 Overview of the Chapter

To better understand the science assessed in this Fourth Assessment Report (AR4), it is helpful to review the long historical perspective that has led to the current state of climate change knowledge. This chapter starts by describing the fundamental nature of earth science. It then describes the history of climate change science using a wide-ranging subset of examples, and ends with a history of the IPCC.

The concept of this chapter is new. There is no counterpart in previous IPCC assessment reports for an introductory chapter providing historical context for the remainder of the report. Here, a restricted set of topics has been selected to illustrate key accomplishments and challenges in climate change science. The topics have been chosen for their significance to the IPCC task of assessing information relevant for understanding the risks of human-induced climate change, and also to illustrate the complex and uneven pace of scientific progress.

In this chapter, the time frame under consideration stops with the publication of the Third Assessment Report (TAR; IPCC, 2001a). Developments subsequent to the TAR are described in the other chapters of this report, and we refer to these chapters throughout this first chapter.

1.2 The Nature of Earth Science

Science may be stimulated by argument and debate, but it generally advances through formulating hypotheses clearly and testing them objectively. This testing is the key to science. In fact, one philosopher of science insisted that to be genuinely scientific, a statement must be susceptible to testing that could potentially show it to be false (Popper, 1934). In practice, contemporary scientists usually submit their research findings to the scrutiny of their peers, which includes disclosing the methods that they use, so their results can be checked through replication by other scientists. The insights and research results of individual scientists, even scientists of unquestioned genius, are thus confirmed or rejected in the peer-reviewed literature by the combined efforts of many other scientists. It is not the belief or opinion of the scientists that is important, but rather the results of this testing. Indeed, when Albert Einstein was informed of the publication of a book entitled *100 Authors Against Einstein*, he is said to have remarked, 'If I were wrong, then one would have been enough!' (Hawking, 1988); however, that one opposing scientist would have needed proof in the form of testable results.

Thus science is inherently self-correcting; incorrect or incomplete scientific concepts ultimately do not survive repeated testing against observations of nature. Scientific theories are ways of explaining phenomena and providing insights that can be evaluated by comparison with physical reality. Each successful prediction adds to the weight of evidence supporting the theory, and any unsuccessful prediction demonstrates that the underlying theory is imperfect and requires improvement or abandonment. Sometimes, only certain kinds of questions tend to be asked about a scientific phenomenon until contradictions build to a point where a sudden change of paradigm takes place (Kuhn, 1996). At that point, an entire field can be rapidly reconstructed under the new paradigm.

Despite occasional major paradigm shifts, the majority of scientific insights, even unexpected insights, tend to emerge incrementally as a result of repeated attempts to test hypotheses as thoroughly as possible. Therefore, because almost every new advance is based on the research and understanding that has gone before, science is cumulative, with useful features retained and non-useful features abandoned. Active research scientists, throughout their careers, typically spend large fractions of their working time studying in depth what other scientists have done. Superficial or amateurish acquaintance with the current state of a scientific research topic is an obstacle to a scientist's progress. Working scientists know that a day in the library can save a year in the laboratory. Even Sir Isaac Newton (1675) wrote that if he had 'seen further it is by standing on the shoulders of giants'. Intellectual honesty and professional ethics call for scientists to acknowledge the work of predecessors and colleagues.

The attributes of science briefly described here can be used in assessing competing assertions about climate change. Can the statement under consideration, in principle, be proven false? Has it been rigorously tested? Did it appear in the peer-reviewed literature? Did it build on the existing research record where appropriate? If the answer to any of these questions is no, then less credence should be given to the assertion until it is tested and independently verified. The IPCC assesses the scientific literature to create a report based on the best available science (Section 1.6). It must be acknowledged, however, that the IPCC also contributes to science by identifying the key uncertainties and by stimulating and coordinating targeted research to answer important climate change questions.

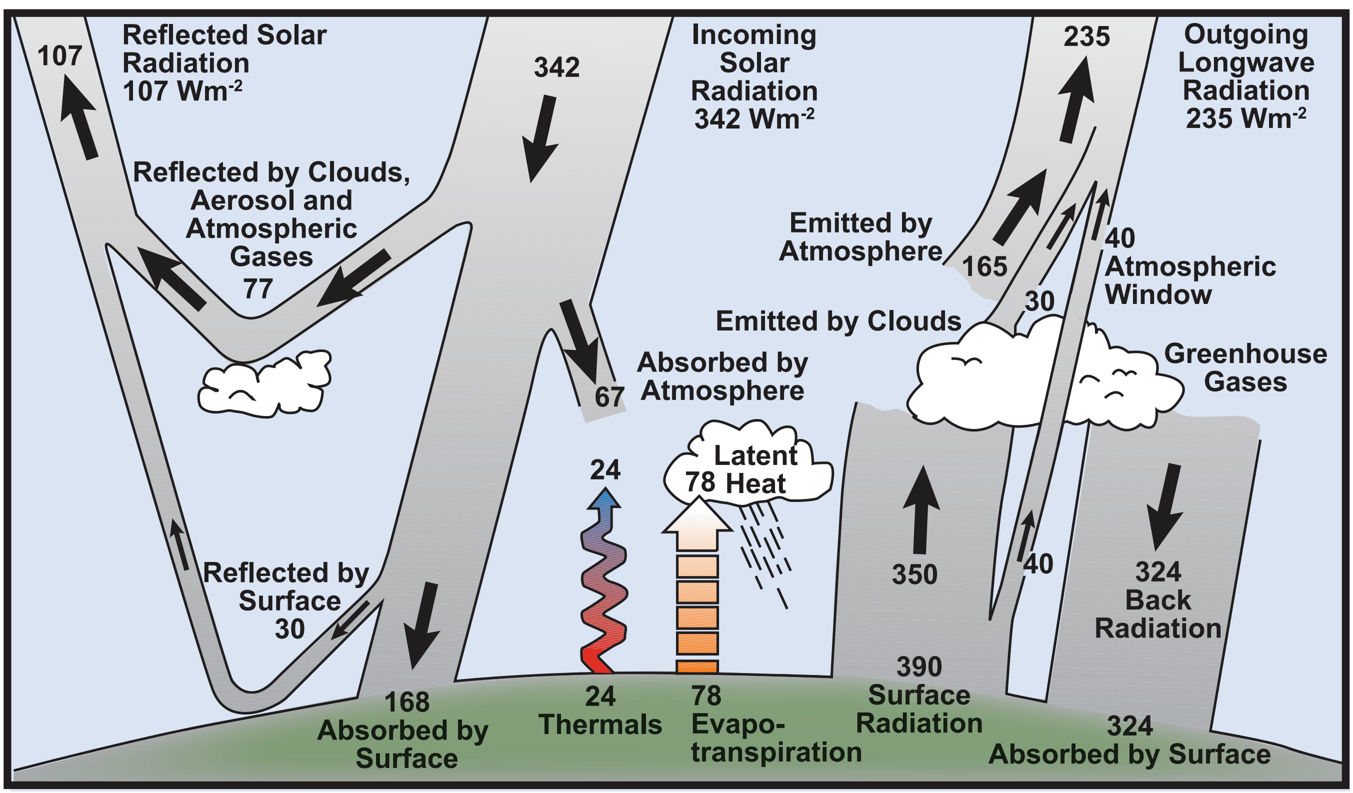
Frequently Asked Question 1.1

What Factors Determine Earth's Climate?

The climate system is a complex, interactive system consisting of the atmosphere, land surface, snow and ice, oceans and other bodies of water, and living things. The atmospheric component of the climate system most obviously characterises climate; climate is often defined as 'average weather'. Climate is usually described in terms of the mean and variability of temperature, precipitation and wind over a period of time, ranging from months to millions of years (the classical period is 30 years). The climate system evolves in time under the influence of its own internal dynamics and due to changes in external factors that affect climate (called 'forcings'). External forcings include natural phenomena such as volcanic eruptions and solar variations, as well as human-induced changes in atmospheric composition. Solar radiation powers the climate system. There are three fundamental ways to change the radiation balance of the Earth: 1) by changing the incoming solar radiation (e.g., by changes in Earth's orbit or in the Sun itself); 2) by changing the fraction of solar radiation that is reflected (called 'albedo'; e.g., by changes in cloud cover, atmospheric particles or vegetation); and 3) by altering the longwave radiation from Earth back towards space (e.g., by changing greenhouse gas concentrations). Climate, in turn, responds directly to such changes, as well as indirectly, through a variety of feedback mechanisms.

The amount of energy reaching the top of Earth's atmosphere each second on a surface area of one square metre facing the Sun during daytime is about 1,370 Watts, and the amount of energy per square metre per second averaged over the entire planet is one-quarter of this (see Figure 1). About 30% of the sunlight that reaches the top of the atmosphere is reflected back to space. Roughly two-thirds of this reflectivity is due to clouds and small particles in the atmosphere known as 'aerosols'. Light-coloured areas of Earth's surface – mainly snow, ice and deserts – reflect the remaining one-third of the sunlight. The most dramatic change in aerosol-produced reflectivity comes when major volcanic eruptions eject material very high into the atmosphere. Rain typically

(continued)



FAQ 1.1, Figure 1. *Estimate of the Earth's annual and global mean energy balance. Over the long term, the amount of incoming solar radiation absorbed by the Earth and atmosphere is balanced by the Earth and atmosphere releasing the same amount of outgoing longwave radiation. About half of the incoming solar radiation is absorbed by the Earth's surface. This energy is transferred to the atmosphere by warming the air in contact with the surface (thermals), by evapotranspiration and by longwave radiation that is absorbed by clouds and greenhouse gases. The atmosphere in turn radiates longwave energy back to Earth as well as out to space. Source: Kiehl and Trenberth (1997).*

clears aerosols out of the atmosphere in a week or two, but when material from a violent volcanic eruption is projected far above the highest cloud, these aerosols typically influence the climate for about a year or two before falling into the troposphere and being carried to the surface by precipitation. Major volcanic eruptions can thus cause a drop in mean global surface temperature of about half a degree celsius that can last for months or even years. Some man-made aerosols also significantly reflect sunlight.

The energy that is not reflected back to space is absorbed by the Earth's surface and atmosphere. This amount is approximately 240 Watts per square metre (W m^{-2}). To balance the incoming energy, the Earth itself must radiate, on average, the same amount of energy back to space. The Earth does this by emitting outgoing longwave radiation. Everything on Earth emits longwave radiation continuously. That is the heat energy one feels radiating out from a fire; the warmer an object, the more heat energy it radiates. To emit 240 W m^{-2}, a surface would have to have a temperature of around –19°C. This is much colder than the conditions that actually exist at the Earth's surface (the global mean surface temperature is about 14°C). Instead, the necessary –19°C is found at an altitude about 5 km above the surface.

The reason the Earth's surface is this warm is the presence of greenhouse gases, which act as a partial blanket for the longwave radiation coming from the surface. This blanketing is known as the natural greenhouse effect. The most important greenhouse gases are water vapour and carbon dioxide. The two most abundant constituents of the atmosphere – nitrogen and oxygen – have no such effect. Clouds, on the other hand, do exert a blanketing effect similar to that of the greenhouse gases; however, this effect is offset by their reflectivity, such that on average, clouds tend to have a cooling effect on climate (although locally one can feel the warming effect: cloudy nights tend to remain warmer than clear nights because the clouds radiate longwave energy back down to the surface). Human activities intensify the blanketing effect through the release of greenhouse gases. For instance, the amount of carbon dioxide in the atmosphere has increased by about 35% in the industrial era, and this increase is known to be due to human activities, primarily the combustion of fossil fuels and removal of forests. Thus, humankind has dramatically altered the chemical composition of the global atmosphere with substantial implications for climate.

Because the Earth is a sphere, more solar energy arrives for a given surface area in the tropics than at higher latitudes, where sunlight strikes the atmosphere at a lower angle. Energy is transported from the equatorial areas to higher latitudes via atmospheric and oceanic circulations, including storm systems. Energy is also required to evaporate water from the sea or land surface, and this energy, called latent heat, is released when water vapour condenses in clouds (see Figure 1). Atmospheric circulation is primarily driven by the release of this latent heat. Atmospheric circulation in turn drives much of the ocean circulation through the action of winds on the surface waters of the ocean, and through changes in the ocean's surface temperature and salinity through precipitation and evaporation.

Due to the rotation of the Earth, the atmospheric circulation patterns tend to be more east-west than north-south. Embedded in the mid-latitude westerly winds are large-scale weather systems that act to transport heat toward the poles. These weather systems are the familiar migrating low- and high-pressure systems and their associated cold and warm fronts. Because of land-ocean temperature contrasts and obstacles such as mountain ranges and ice sheets, the circulation system's planetary-scale atmospheric waves tend to be geographically anchored by continents and mountains although their amplitude can change with time. Because of the wave patterns, a particularly cold winter over North America may be associated with a particularly warm winter elsewhere in the hemisphere. Changes in various aspects of the climate system, such as the size of ice sheets, the type and distribution of vegetation or the temperature of the atmosphere or ocean will influence the large-scale circulation features of the atmosphere and oceans.

There are many feedback mechanisms in the climate system that can either amplify ('positive feedback') or diminish ('negative feedback') the effects of a change in climate forcing. For example, as rising concentrations of greenhouse gases warm Earth's climate, snow and ice begin to melt. This melting reveals darker land and water surfaces that were beneath the snow and ice, and these darker surfaces absorb more of the Sun's heat, causing more warming, which causes more melting, and so on, in a self-reinforcing cycle. This feedback loop, known as the 'ice-albedo feedback', amplifies the initial warming caused by rising levels of greenhouse gases. Detecting, understanding and accurately quantifying climate feedbacks have been the focus of a great deal of research by scientists unravelling the complexities of Earth's climate.

A characteristic of Earth sciences is that Earth scientists are unable to perform controlled experiments on the planet as a whole and then observe the results. In this sense, Earth science is similar to the disciplines of astronomy and cosmology that cannot conduct experiments on galaxies or the cosmos. This is an important consideration, because it is precisely such whole-Earth, system-scale experiments, incorporating the full complexity of interacting processes and feedbacks, that might ideally be required to fully verify or falsify climate change hypotheses (Schellnhuber et al., 2004). Nevertheless, countless empirical tests of numerous different hypotheses have built up a massive body of Earth science knowledge. This repeated testing has refined the understanding of numerous aspects of the climate system, from deep oceanic circulation to stratospheric chemistry. Sometimes a combination of observations and models can be used to test planetary-scale hypotheses. For example, the global cooling and drying of the atmosphere observed after the eruption of Mt. Pinatubo (Section 8.6) provided key tests of particular aspects of global climate models (Hansen et al., 1992).

Another example is provided by past IPCC projections of future climate change compared to current observations. Figure 1.1 reveals that the model projections of global average temperature from the First Assessment Report (FAR; IPCC, 1990) were higher than those from the Second Assessment Report (SAR; IPCC, 1996). Subsequent observations (Section 3.2) showed that the evolution of the actual climate system fell midway between the FAR and the SAR 'best estimate' projections and were within or near the upper range of projections from the TAR (IPCC, 2001a).

Not all theories or early results are verified by later analysis. In the mid-1970s, several articles about possible global cooling appeared in the popular press, primarily motivated by analyses indicating that Northern Hemisphere (NH) temperatures had decreased during the previous three decades (e.g., Gwynne, 1975). In the peer-reviewed literature, a paper by Bryson and Dittberner (1976) reported that increases in carbon dioxide (CO_2) should be associated with a decrease in global temperatures. When challenged by Woronko (1977), Bryson and Dittberner (1977) explained that the cooling projected by their model was due to aerosols (small particles in the atmosphere) produced by the same combustion that caused the increase in CO_2. However, because aerosols remain in the atmosphere only a short time compared to CO_2, the results were not applicable for long-term climate change projections. This example of a prediction of global cooling is a classic illustration of the self-correcting nature of Earth science. The scientists involved were reputable researchers who followed the accepted paradigm of publishing in scientific journals, submitting their methods and results to the scrutiny of their peers (although the peer-review did not catch this problem), and responding to legitimate criticism.

A recurring theme throughout this chapter is that climate science in recent decades has been characterised by the increasing rate of advancement of research in the field and by the notable evolution of scientific methodology and tools, including the models and observations that support and enable the research. During the last four decades, the rate at which scientists have added to the body of knowledge of atmospheric and oceanic processes has accelerated dramatically. As scientists incrementally increase the totality of knowledge, they publish their results in peer-reviewed journals. Between 1965 and 1995, the number of articles published per year in atmospheric science journals tripled (Geerts, 1999). Focusing more narrowly, Stanhill (2001) found that the climate change science literature grew approximately exponentially with a doubling time of 11 years for the period 1951 to 1997. Furthermore, 95% of all the climate change science literature since 1834 was published after 1951. Because science is cumulative, this represents considerable growth in the knowledge of climate processes and in the complexity of climate research. An important example of this is the additional physics incorporated in climate models over the last several decades, as illustrated in Figure 1.2. As a result of the cumulative nature of science, climate science today is an interdisciplinary synthesis of countless tested and proven physical processes and principles painstakingly compiled and verified over several centuries of detailed laboratory measurements, observational experiments and theoretical analyses; and is now far more wide-ranging and physically comprehensive than was the case only a few decades ago.

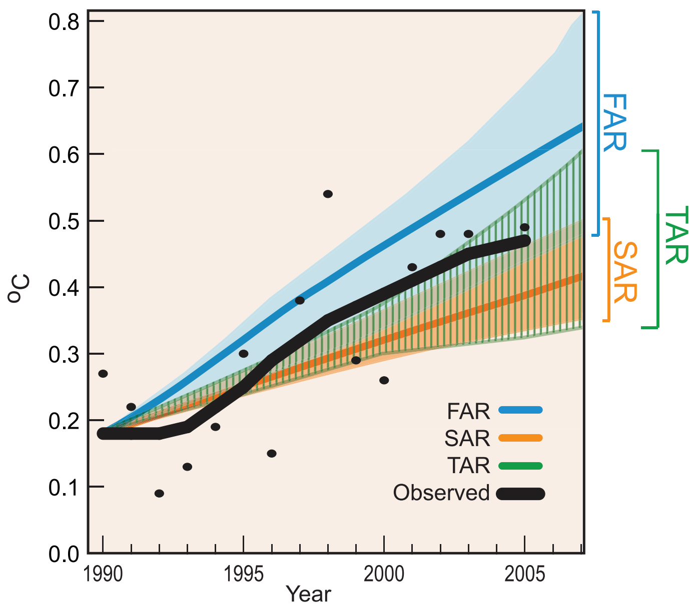


Figure 1.1. *Yearly global average surface temperature (Brohan et al., 2006), relative to the mean 1961 to 1990 values, and as projected in the FAR (IPCC, 1990), SAR (IPCC, 1996) and TAR (IPCC, 2001a). The 'best estimate' model projections from the FAR and SAR are in solid lines with their range of estimated projections shown by the shaded areas. The TAR did not have 'best estimate' model projections but rather a range of projections. Annual mean observations (Section 3.2) are depicted by black circles and the thick black line shows decadal variations obtained by smoothing the time series using a 13-point filter.*

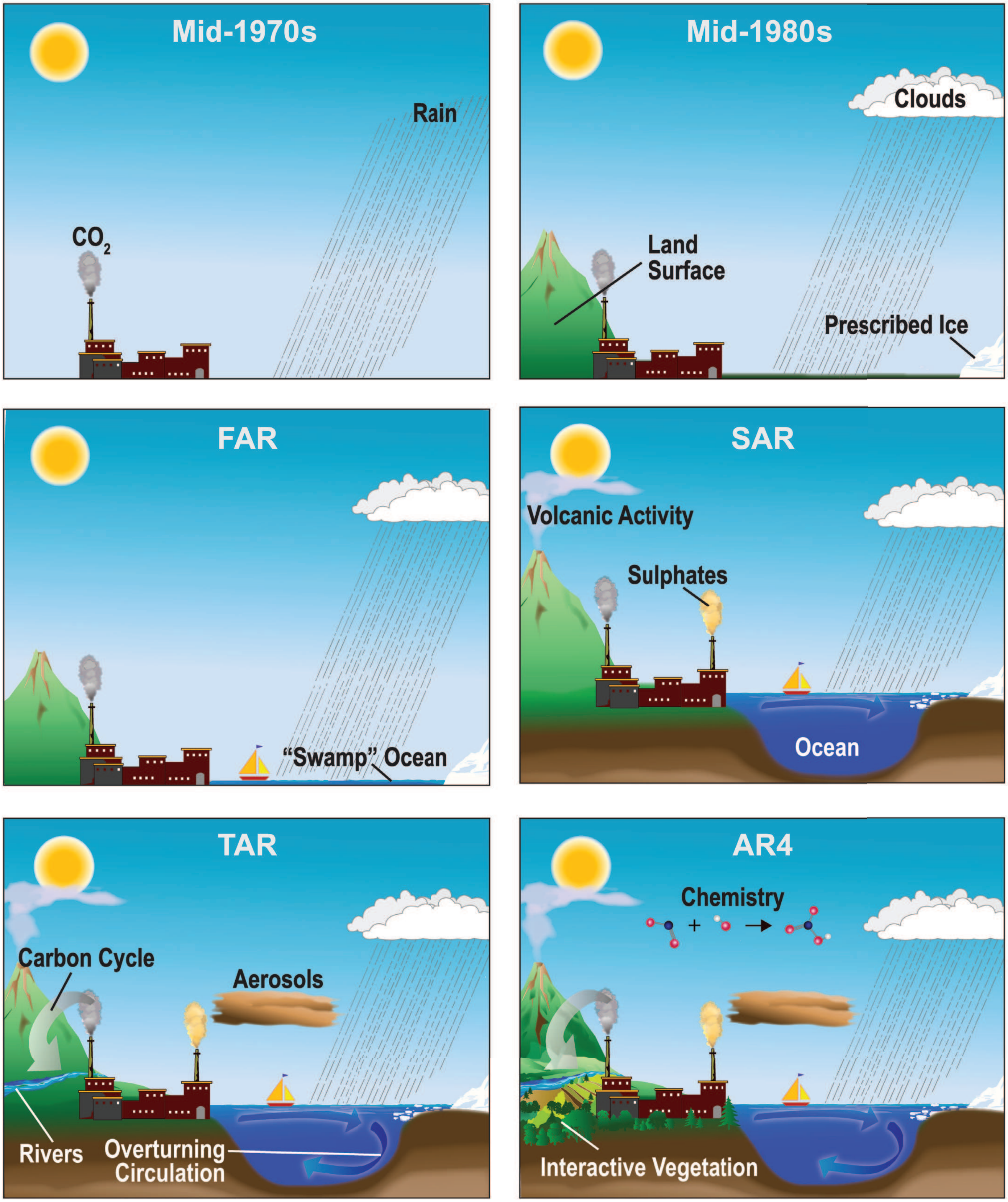


Figure 1.2. *The complexity of climate models has increased over the last few decades. The additional physics incorporated in the models are shown pictorially by the different features of the modelled world.*

1.3 Examples of Progress in Detecting and Attributing Recent Climate Change

1.3.1 The Human Fingerprint on Greenhouse Gases

The high-accuracy measurements of atmospheric CO_2 concentration, initiated by Charles David Keeling in 1958, constitute the master time series documenting the changing composition of the atmosphere (Keeling, 1961, 1998). These data have iconic status in climate change science as evidence of the effect of human activities on the chemical composition of the global atmosphere (see FAQ 7.1). Keeling's measurements on Mauna Loa in Hawaii provide a true measure of the global carbon cycle, an effectively continuous record of the burning of fossil fuel. They also maintain an accuracy and precision that allow scientists to separate fossil fuel emissions from those due to the natural annual cycle of the biosphere, demonstrating a long-term change in the seasonal exchange of CO_2 between the atmosphere, biosphere and ocean. Later observations of parallel trends in the atmospheric abundances of the $^{13}CO_2$ isotope (Francey and Farquhar, 1982) and molecular oxygen (O_2) (Keeling and Shertz, 1992; Bender et al., 1996) uniquely identified this rise in CO_2 with fossil fuel burning (Sections 2.3, 7.1 and 7.3).

To place the increase in CO_2 abundance since the late 1950s in perspective, and to compare the magnitude of the anthropogenic increase with natural cycles in the past, a longer-term record of CO_2 and other natural greenhouse gases is needed. These data came from analysis of the composition of air enclosed in bubbles in ice cores from Greenland and Antarctica. The initial measurements demonstrated that CO_2 abundances were significantly lower during the last ice age than over the last 10 kyr of the Holocene (Delmas et al., 1980; Berner et al., 1980; Neftel et al., 1982). From 10 kyr before present up to the year 1750, CO_2 abundances stayed within the range 280 ± 20 ppm (Indermühle et al., 1999). During the industrial era, CO_2 abundance rose roughly exponentially to 367 ppm in 1999 (Neftel et al., 1985; Etheridge et al., 1996; IPCC, 2001a) and to 379 ppm in 2005 (Section 2.3.1; see also Section 6.4).

Direct atmospheric measurements since 1970 (Steele et al., 1996) have also detected the increasing atmospheric abundances of two other major greenhouse gases, methane (CH_4) and nitrous oxide (N_2O). Methane abundances were initially increasing at a rate of about 1% yr^{-1} (Graedel and McRae, 1980; Fraser et al., 1981; Blake et al., 1982) but then slowed to an average increase of 0.4% yr^{-1} over the 1990s (Dlugokencky et al., 1998) with the possible stabilisation of CH_4 abundance (Section 2.3.2). The increase in N_2O abundance is smaller, about 0.25% yr^{-1}, and more difficult to detect (Weiss, 1981; Khalil and Rasmussen, 1988). To go back in time, measurements were made from firn air trapped in snowpack dating back over 200 years, and these data show an accelerating rise in both CH_4 and N_2O into the 20th century (Machida et al., 1995; Battle et al., 1996). When ice core measurements extended the CH_4 abundance back 1 kyr, they showed a stable, relatively constant abundance of 700 ppb until the 19th century when a steady increase brought CH_4 abundances to 1,745 ppb in 1998 (IPCC, 2001a) and 1,774 ppb in 2005 (Section 2.3.2). This peak abundance is much higher than the range of 400 to 700 ppb seen over the last half-million years of glacial-interglacial cycles, and the increase can be readily explained by anthropogenic emissions. For N_2O the results are similar: the relative increase over the industrial era is smaller (15%), yet the 1998 abundance of 314 ppb (IPCC, 2001a), rising to 319 ppb in 2005 (Section 2.3.3), is also well above the 180-to-260 ppb range of glacial-interglacial cycles (Flückiger et al., 1999; see Sections 2.3, 6.2, 6.3, 6.4, 7.1 and 7.4)

Several synthetic halocarbons (chlorofluorocarbons (CFCs), hydrofluorocarbons, perfluorocarbons, halons and sulphur hexafluoride) are greenhouse gases with large global warming potentials (GWPs; Section 2.10). The chemical industry has been producing these gases and they have been leaking into the atmosphere since about 1930. Lovelock (1971) first measured CFC-11 ($CFCl_3$) in the atmosphere, noting that it could serve as an artificial tracer, with its north-south gradient reflecting the latitudinal distribution of anthropogenic emissions. Atmospheric abundances of all the synthetic halocarbons were increasing until the 1990s, when the abundance of halocarbons phased out under the Montreal Protocol began to fall (Montzka et al., 1999; Prinn et al., 2000). In the case of synthetic halocarbons (except perfluoromethane), ice core research has shown that these compounds did not exist in ancient air (Langenfelds et al., 1996) and thus confirms their industrial human origin (see Sections 2.3 and 7.1).

At the time of the TAR scientists could say that the abundances of all the well-mixed greenhouse gases during the 1990s were greater than at any time during the last half-million years (Petit et al, 1999), and this record now extends back nearly one million years (Section 6.3). Given this daunting picture of increasing greenhouse gas abundances in the atmosphere, it is noteworthy that, for simpler challenges but still on a hemispheric or even global scale, humans have shown the ability to undo what they have done. Sulphate pollution in Greenland was reversed in the 1980s with the control of acid rain in North America and Europe (IPCC, 2001b), and CFC abundances are declining globally because of their phase-out undertaken to protect the ozone layer.

1.3.2 Global Surface Temperature

Shortly after the invention of the thermometer in the early 1600s, efforts began to quantify and record the weather. The first meteorological network was formed in northern Italy in 1653 (Kington, 1988) and reports of temperature observations were published in the earliest scientific journals (e.g., Wallis and Beale, 1669). By the latter part of the 19th century, systematic observations of the weather were being made in almost all inhabited areas of the world. Formal international coordination of meteorological observations from ships commenced in 1853 (Quetelet, 1854).

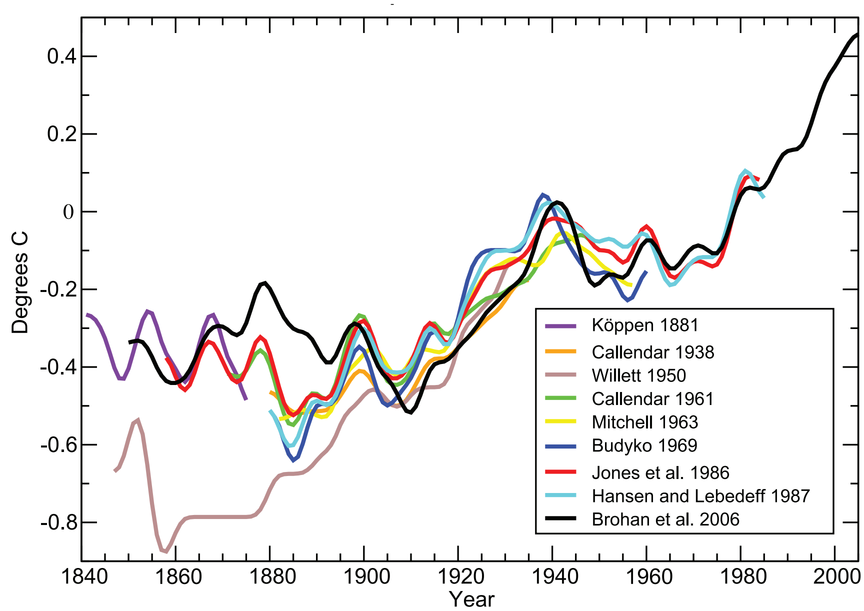


Figure 1.3. *Published records of surface temperature change over large regions. Köppen (1881) tropics and temperate latitudes using land air temperature. Callendar (1938) global using land stations. Willett (1950) global using land stations. Callendar (1961) 60°N to 60°S using land stations. Mitchell (1963) global using land stations. Budyko (1969) Northern Hemisphere using land stations and ship reports. Jones et al. (1986a,b) global using land stations. Hansen and Lebedeff (1987) global using land stations. Brohan et al. (2006) global using land air temperature and sea surface temperature data is the longest of the currently updated global temperature time series (Section 3.2). All time series were smoothed using a 13-point filter. The Brohan et al. (2006) time series are anomalies from the 1961 to 1990 mean (°C). Each of the other time series was originally presented as anomalies from the mean temperature of a specific and differing base period. To make them comparable, the other time series have been adjusted to have the mean of their last 30 years identical to that same period in the Brohan et al. (2006) anomaly time series.*

Inspired by the paper *Suggestions on a Uniform System of Meteorological Observations* (Buys-Ballot, 1872), the International Meteorological Organization (IMO) was formed in 1873. Its successor, the World Meteorological Organization (WMO), still works to promote and exchange standardised meteorological observations. Yet even with uniform observations, there are still four major obstacles to turning instrumental observations into accurate global time series: (1) access to the data in usable form; (2) quality control to remove or edit erroneous data points; (3) homogeneity assessments and adjustments where necessary to ensure the fidelity of the data; and (4) area-averaging in the presence of substantial gaps.

Köppen (1873, 1880, 1881) was the first scientist to overcome most of these obstacles in his quest to study the effect of changes in sunspots (Section 2.7). Much of his data came from Dove (1852), but wherever possible he used data directly from the original source, because Dove often lacked information about the observing methods. Köppen considered examination of the annual mean temperature to be an adequate technique for quality control of far distant stations. Using data from more than 100 stations, Köppen averaged annual observations into several major latitude belts and then area-averaged these into a near-global time series shown in Figure 1.3.

Callendar (1938) produced the next global temperature time series expressly to investigate the influence of CO_2 on temperature (Section 2.3). Callendar examined about 200 station records. Only a small portion of them were deemed defective, based on quality concerns determined by comparing differences with neighbouring stations or on homogeneity concerns based on station changes documented in the recorded metadata. After further removing two arctic stations because he had no compensating stations from the antarctic region, he created a global average using data from 147 stations.

Most of Callendar's data came from World Weather Records (WWR; Clayton, 1927). Initiated by a resolution at the 1923 IMO Conference, WWR was a monumental international undertaking producing a 1,196-page volume of monthly temperature, precipitation and pressure data from hundreds of stations around the world, some with data starting in the early 1800s. In the early 1960s, J. Wolbach had these data digitised (National Climatic Data Center, 2002). The WWR project continues today under the auspices of the WMO with the digital publication of decadal updates to the climate records for thousands of stations worldwide (National Climatic Data Center, 2005).

Willett (1950) also used WWR as the main source of data for 129 stations that he used to create a global temperature time series going back to 1845. While the resolution that initiated WWR called for the publication of long and homogeneous records, Willett took this mandate one step further by carefully selecting a subset of stations with as continuous and homogeneous a record as possible from the most recent update of WWR, which included data through 1940. To avoid over-weighting certain areas such as Europe, only one record, the best available, was included from each 10° latitude and longitude square. Station monthly data were averaged into five-year periods and then converted to anomalies with respect to the five-year period 1935 to 1939. Each station's anomaly was given equal weight to create the global time series.

Callendar in turn created a new near-global temperature time series in 1961 and cited Willett (1950) as a guide for some of his improvements. Callendar (1961) evaluated 600 stations with about three-quarters of them passing his quality checks. Unbeknownst to Callendar, a former student of Willett, Mitchell (1963), in work first presented in 1961, had created his own updated global temperature time series using slightly fewer than 200 stations and averaging the data into latitude bands. Landsberg and Mitchell (1961) compared Callendar's results with Mitchell's and stated that there was generally good agreement except in the data-sparse regions of the Southern Hemisphere.

Meanwhile, research in Russia was proceeding on a very different method to produce large-scale time series. Budyko (1969) used smoothed, hand-drawn maps of monthly temperature anomalies as a starting point. While restricted to analysis of the NH, this map-based approach not only allowed the inclusion of an increasing number of stations over time (e.g., 246 in 1881, 753 in 1913, 976 in 1940 and about 2,000 in 1960) but also the utilisation of data over the oceans (Robock, 1982).

Increasing the number of stations utilised has been a continuing theme over the last several decades with considerable effort being spent digitising historical station data as well as addressing the continuing problem of acquiring up-to-date data, as there can be a long lag between making an observation and the data getting into global data sets. During the 1970s and 1980s, several teams produced global temperature time series. Advances especially worth noting during this period include the extended spatial interpolation and station averaging technique of Hansen and Lebedeff (1987) and the Jones et al. (1986a,b) painstaking assessment of homogeneity and adjustments to account for discontinuities in the record of each of the thousands of stations in a global data set. Since then, global and national data sets have been rigorously adjusted for homogeneity using a variety of statistical and metadata-based approaches (Peterson et al., 1998).

One recurring homogeneity concern is potential urban heat island contamination in global temperature time series. This concern has been addressed in two ways. The first is by adjusting the temperature of urban stations to account for assessed urban heat island effects (e.g., Karl et al., 1988; Hansen et al., 2001). The second is by performing analyses that, like Callendar (1938), indicate that the bias induced by urban heat islands in the global temperature time series is either minor or non-existent (Jones et al., 1990; Peterson et al., 1999).

As the importance of ocean data became increasingly recognised, a major effort was initiated to seek out, digitise and quality-control historical archives of ocean data. This work has since grown into the International Comprehensive Ocean-Atmosphere Data Set (ICOADS; Worley et al., 2005), which has coordinated the acquisition, digitisation and synthesis of data ranging from transmissions by Japanese merchant ships to the logbooks of South African whaling boats. The amount of sea surface temperature (SST) and related data acquired continues to grow.

As fundamental as the basic data work of ICOADS was, there have been two other major advances in SST data. The first was adjusting the early observations to make them comparable to current observations (Section 3.2). Prior to 1940, the majority of SST observations were made from ships by hauling a bucket on deck filled with surface water and placing a thermometer in it. This ancient method eventually gave way to thermometers placed in engine cooling water inlets, which are typically located several metres below the ocean surface. Folland and Parker (1995) developed an adjustment model that accounted for heat loss from the buckets and that varied with bucket size and type, exposure to solar radiation, ambient wind speed and ship speed. They verified their results using time series of night marine air temperature. This adjusted the early bucket observations upwards by a few tenths of a degree celsius.

Most of the ship observations are taken in narrow shipping lanes, so the second advance has been increasing global coverage in a variety of ways. Direct improvement of coverage has been achieved by the internationally coordinated placement of drifting and moored buoys. The buoys began to be numerous enough to make significant contributions to SST analyses in the mid-1980s (McPhaden et al., 1998) and have subsequently increased to more than 1,000 buoys transmitting data at any one time. Since 1982, satellite data, anchored to *in situ* observations, have contributed to near-global coverage (Reynolds and Smith, 1994). In addition, several different approaches have been used to interpolate and combine land and ocean observations into the current global temperature time series (Section 3.2). To place the current instrumental observations into a longer historical context requires the use of proxy data (Section 6.2).

Figure 1.3 depicts several historical 'global' temperature time series, together with the longest of the current global temperature time series, that of Brohan et al. (2006; Section 3.2). While the data and the analysis techniques have changed over time, all the time series show a high degree of consistency since 1900. The differences caused by using alternate data sources and interpolation techniques increase when the data are sparser. This phenomenon is especially illustrated by the pre-1880 values of Willett's (1950) time series. Willett noted that his data coverage remained fairly constant after 1885 but dropped off dramatically before that time to only 11 stations before 1850. The high degree of agreement between the time series resulting from these many different analyses increases the confidence that the changes they are indicating are real.

Despite the fact that many recent observations are automatic, the vast majority of data that go into global surface temperature calculations – over 400 million individual readings of thermometers at land stations and over 140 million individual *in situ* SST observations – have depended on the dedication of tens of thousands of individuals for well over a century. Climate science owes a great debt to the work of these individual weather observers as well as to international organisations such as the IMO, WMO and the Global Climate Observing System, which encourage the taking and sharing of high-quality meteorological observations. While modern researchers and their institutions put a great deal of time and effort into acquiring and adjusting the data to account for all known problems and biases, century-scale global temperature time series would not have been possible without the conscientious work of individuals and organisations worldwide dedicated to quantifying and documenting their local environment (Section 3.2).

1.3.3 Detection and Attribution

Using knowledge of past climates to qualify the nature of ongoing changes has become a concern of growing importance during the last decades, as reflected in the successive IPCC reports. While linked together at a technical level, detection and attribution have separate objectives. Detection of climate change is the process of demonstrating that climate has changed in some defined statistical sense, without providing a reason for that change. Attribution of causes of climate change is the process of establishing the most likely causes for the detected change with some defined level of confidence. Using traditional approaches, unequivocal attribution would require controlled experimentation with our climate system. However, with no spare Earth with which to experiment, attribution of anthropogenic climate change must be pursued by: (a) detecting that the climate has changed (as defined above); (b) demonstrating that the detected change is consistent with computer model simulations of the climate change 'signal' that is calculated to occur in response to anthropogenic forcing; and (c) demonstrating that the detected change is not consistent with alternative, physically plausible explanations of recent climate change that exclude important anthropogenic forcings.

Both detection and attribution rely on observational data and model output. In spite of the efforts described in Section 1.3.2, estimates of century-scale natural climate fluctuations remain difficult to obtain directly from observations due to the relatively short length of most observational records and a lack of understanding of the full range and effects of the various and ongoing external influences. Model simulations with no changes in external forcing (e.g., no increases in atmospheric CO_2 concentration) provide valuable information on the natural internal variability of the climate system on time scales of years to centuries. Attribution, on the other hand, requires output from model runs that incorporate historical estimates of changes in key anthropogenic and natural forcings, such as well-mixed greenhouse gases, volcanic aerosols and solar irradiance. These simulations can be performed with changes in a single forcing only (which helps to isolate the climate effect of that forcing), or with simultaneous changes in a whole suite of forcings.

In the early years of detection and attribution research, the focus was on a single time series – the estimated global-mean changes in the Earth's surface temperature. While it was not possible to detect anthropogenic warming in 1980, Madden and Ramanathan (1980) and Hansen et al. (1981) predicted it would be evident at least within the next two decades. A decade later, Wigley and Raper (1990) used a simple energy-balance climate model to show that the observed change in global-mean surface temperature from 1867 to 1982 could not be explained by natural internal variability. This finding was later confirmed using variability estimates from more complex coupled ocean-atmosphere general circulation models (e.g., Stouffer et al., 1994).

As the science of climate change progressed, detection and attribution research ventured into more sophisticated statistical analyses that examined complex patterns of climate change. Climate change patterns or 'fingerprints' were no longer limited to a single variable (temperature) or to the Earth's surface. More recent detection and attribution work has made use of precipitation and global pressure patterns, and analysis of vertical profiles of temperature change in the ocean and atmosphere. Studies with multiple variables make it easier to address attribution issues. While two different climate forcings may yield similar changes in global mean temperature, it is highly unlikely that they will produce exactly the same 'fingerprint' (i.e., climate changes that are identical as a function of latitude, longitude, height, season and history over the 20th century).

Such model-predicted fingerprints of anthropogenic climate change are clearly statistically identifiable in observed data. The common conclusion of a wide range of fingerprint studies conducted over the past 15 years is that observed climate changes cannot be explained by natural factors alone (Santer et al., 1995, 1996a,b,c; Hegerl et al., 1996, 1997, 2000; Hasselmann, 1997; Barnett et al., 1999; Tett et al., 1999; Stott et al., 2000). A substantial anthropogenic influence is required in order to best explain the observed changes. The evidence from this body of work strengthens the scientific case for a discernible human influence on global climate.

1.4 Examples of Progress in Understanding Climate Processes

1.4.1 The Earth's Greenhouse Effect

The realisation that Earth's climate might be sensitive to the atmospheric concentrations of gases that create a greenhouse effect is more than a century old. Fleming (1998) and Weart (2003) provided an overview of the emerging science. In terms of the energy balance of the climate system, Edme Mariotte noted in 1681 that although the Sun's light and heat easily pass through glass and other transparent materials, heat from other sources (*chaleur de feu*) does not. The ability to generate an artificial warming of the Earth's surface was demonstrated in simple greenhouse experiments such as Horace Benedict de Saussure's experiments in the 1760s using a 'heliothermometer' (panes of glass covering a thermometer in a darkened box) to provide an early analogy to the greenhouse effect. It was a conceptual leap to recognise that the air itself could also trap thermal radiation. In 1824, Joseph Fourier, citing Saussure, argued 'the temperature [of the Earth] can be augmented by the interposition of the atmosphere, because heat in the state of light finds less resistance in penetrating the air, than in repassing into the air when converted into non-luminous heat'. In 1836, Pouillit followed up on Fourier's ideas and argued 'the atmospheric stratum…exercises a greater absorption upon the terrestrial than on the solar rays'. There was still no understanding of exactly what substance in the atmosphere was responsible for this absorption.

In 1859, John Tyndall (1861) identified through laboratory experiments the absorption of thermal radiation by complex molecules (as opposed to the primary bimolecular atmospheric constituents O_2 and molecular nitrogen). He noted that changes in the amount of any of the radiatively active constituents of the atmosphere such as water (H_2O) or CO_2 could have produced 'all the mutations of climate which the researches of geologists

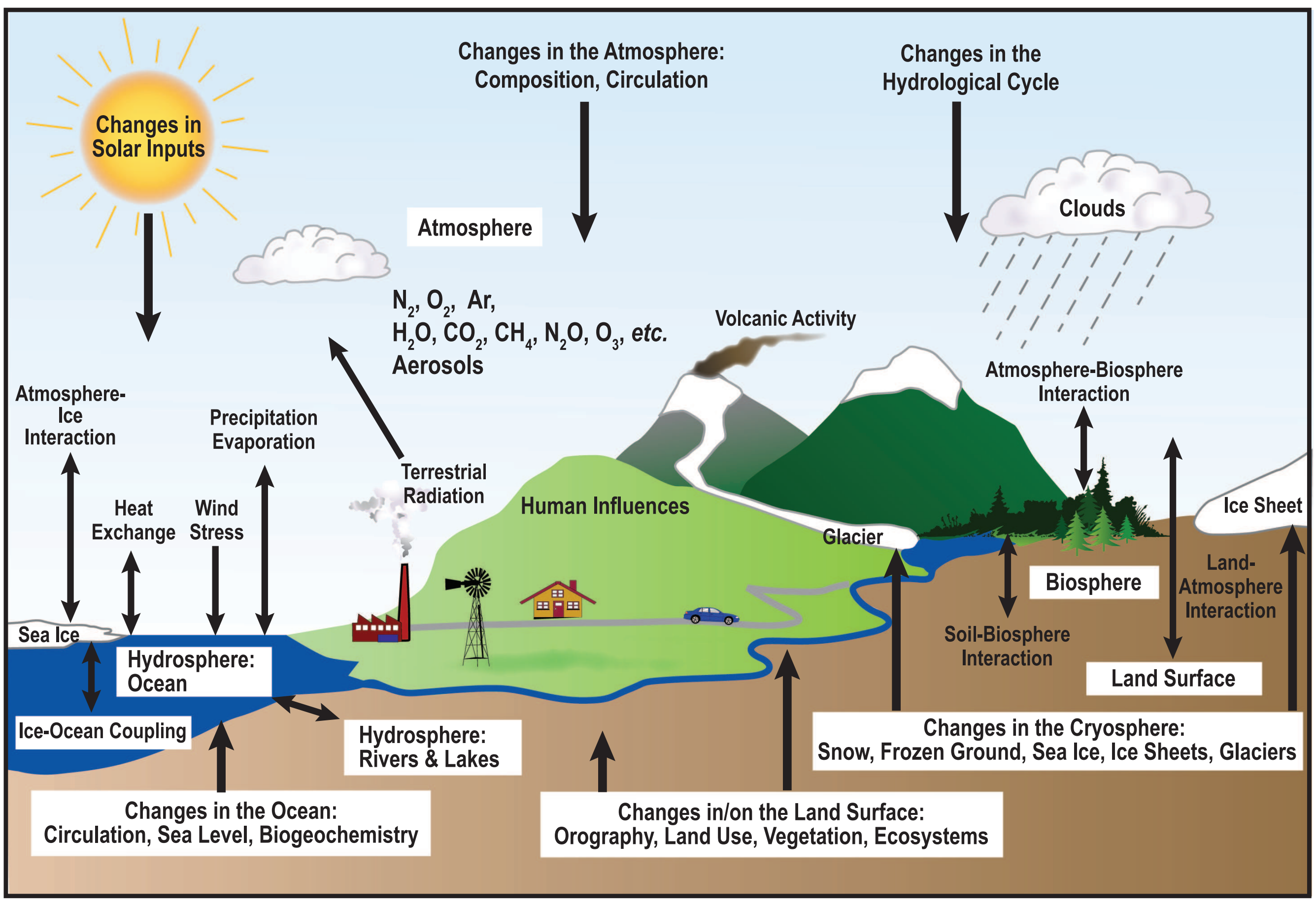
Frequently Asked Question 1.2

What is the Relationship between Climate Change and Weather?

Climate is generally defined as average weather, and as such, climate change and weather are intertwined. Observations can show that there have been changes in weather, and it is the statistics of changes in weather over time that identify climate change. While weather and climate are closely related, there are important differences. A common confusion between weather and climate arises when scientists are asked how they can predict climate 50 years from now when they cannot predict the weather a few weeks from now. The chaotic nature of weather makes it unpredictable beyond a few days. Projecting changes in climate (i.e., long-term average weather) due to changes in atmospheric composition or other factors is a very different and much more manageable issue. As an analogy, while it is impossible to predict the age at which any particular man will die, we can say with high confidence that the average age of death for men in industrialised countries is about 75. Another common confusion of these issues is thinking that a cold winter or a cooling spot on the globe is evidence against global warming. There are always extremes of hot and cold, although their frequency and intensity change as climate changes. But when weather is averaged over space and time, the fact that the globe is warming emerges clearly from the data.

Meteorologists put a great deal of effort into observing, understanding and predicting the day-to-day evolution of weather systems. Using physics-based concepts that govern how the atmosphere moves, warms, cools, rains, snows, and evaporates water, meteorologists are typically able to predict the weather successfully several days into the future. A major limiting factor to the predictability of weather beyond several days is a fundamental dynamical property of the atmosphere. In the 1960s, meteorologist Edward Lorenz discovered that very slight differences in initial conditions can produce very different forecast results.

(continued)



FAQ 1.2, Figure 1. *Schematic view of the components of the climate system, their processes and interactions.*

This is the so-called butterfly effect: a butterfly flapping its wings (or some other small phenomenon) in one place can, in principle, alter the subsequent weather pattern in a distant place. At the core of this effect is chaos theory, which deals with how small changes in certain variables can cause apparent randomness in complex systems.

Nevertheless, chaos theory does not imply a total lack of order. For example, slightly different conditions early in its history might alter the day a storm system would arrive or the exact path it would take, but the average temperature and precipitation (that is, climate) would still be about the same for that region and that period of time. Because a significant problem facing weather forecasting is knowing all the conditions at the start of the forecast period, it can be useful to think of climate as dealing with the background conditions for weather. More precisely, climate can be viewed as concerning the status of the entire Earth system, including the atmosphere, land, oceans, snow, ice and living things (see Figure 1) that serve as the global background conditions that determine weather patterns. An example of this would be an El Niño affecting the weather in coastal Peru. The El Niño sets limits on the probable evolution of weather patterns that random effects can produce. A La Niña would set different limits.

Another example is found in the familiar contrast between summer and winter. The march of the seasons is due to changes in the geographical patterns of energy absorbed and radiated away by the Earth system. Likewise, projections of future climate are shaped by fundamental changes in heat energy in the Earth system, in particular the increasing intensity of the greenhouse effect that traps heat near Earth's surface, determined by the amount of carbon dioxide and other greenhouse gases in the atmosphere. Projecting changes in climate due to changes in greenhouse gases 50 years from now is a very different and much more easily solved problem than forecasting weather patterns just weeks from now. To put it another way, long-term variations brought about by changes in the composition of the atmosphere are much more predictable than individual weather events. As an example, while we cannot predict the outcome of a single coin toss or roll of the dice, we can predict the statistical behaviour of a large number of such trials.

While many factors continue to influence climate, scientists have determined that human activities have become a dominant force, and are responsible for most of the warming observed over the past 50 years. Human-caused climate change has resulted primarily from changes in the amounts of greenhouse gases in the atmosphere, but also from changes in small particles (aerosols), as well as from changes in land use, for example. As climate changes, the probabilities of certain types of weather events are affected. For example, as Earth's average temperature has increased, some weather phenomena have become more frequent and intense (e.g., heat waves and heavy downpours), while others have become less frequent and intense (e.g., extreme cold events).

reveal'. In 1895, Svante Arrhenius (1896) followed with a climate prediction based on greenhouse gases, suggesting that a 40% increase or decrease in the atmospheric abundance of the trace gas CO_2 might trigger the glacial advances and retreats. One hundred years later, it would be found that CO_2 did indeed vary by this amount between glacial and interglacial periods. However, it now appears that the initial climatic change preceded the change in CO_2 but was enhanced by it (Section 6.4).

G. S. Callendar (1938) solved a set of equations linking greenhouse gases and climate change. He found that a doubling of atmospheric CO_2 concentration resulted in an increase in the mean global temperature of 2°C, with considerably more warming at the poles, and linked increasing fossil fuel combustion with a rise in CO_2 and its greenhouse effects: 'As man is now changing the composition of the atmosphere at a rate which must be very exceptional on the geological time scale, it is natural to seek for the probable effects of such a change. From the best laboratory observations it appears that the principal result of increasing atmospheric carbon dioxide… would be a gradual increase in the mean temperature of the colder regions of the Earth.' In 1947, Ahlmann reported a 1.3°C warming in the North Atlantic sector of the Arctic since the 19th century and mistakenly believed this climate variation could be explained entirely by greenhouse gas warming. Similar model predictions were echoed by Plass in 1956 (see Fleming, 1998): 'If at the end of this century, measurements show that the carbon dioxide content of the atmosphere has risen appreciably and at the same time the temperature has continued to rise throughout the world, it will be firmly established that carbon dioxide is an important factor in causing climatic change' (see Chapter 9).

In trying to understand the carbon cycle, and specifically how fossil fuel emissions would change atmospheric CO_2, the interdisciplinary field of carbon cycle science began. One of the first problems addressed was the atmosphere-ocean exchange of CO_2. Revelle and Suess (1957) explained why part of the emitted CO_2 was observed to accumulate in the atmosphere rather than being completely absorbed by the oceans. While CO_2 can be mixed rapidly into the upper layers of the ocean, the time to mix with the deep ocean is many centuries. By the time of the TAR, the interaction of climate change with the oceanic circulation and biogeochemistry was projected to reduce the fraction of anthropogenic CO_2 emissions taken up by the oceans in the future, leaving a greater fraction in the atmosphere (Sections 7.1, 7.3 and 10.4).

In the 1950s, the greenhouse gases of concern remained CO_2 and H_2O, the same two identified by Tyndall a century earlier. It was not until the 1970s that other greenhouse gases – CH_4, N_2O and CFCs – were widely recognised as important anthropogenic greenhouse gases (Ramanathan, 1975; Wang et al., 1976; Section 2.3). By the 1970s, the importance of aerosol-cloud effects in reflecting sunlight was known (Twomey, 1977), and atmospheric aerosols (suspended small particles) were being proposed as climate-forcing constituents. Charlson and others (summarised in Charlson et al., 1990) built a consensus that sulphate aerosols were, by themselves, cooling the Earth's surface by directly reflecting sunlight. Moreover, the increases in sulphate aerosols were anthropogenic and linked with the main source of CO_2, burning of fossil fuels (Section 2.4). Thus, the current picture of the atmospheric constituents driving climate change contains a much more diverse mix of greenhouse agents.

1.4.2 Past Climate Observations, Astronomical Theory and Abrupt Climate Changes

Throughout the 19th and 20th centuries, a wide range of geomorphology and palaeontology studies has provided new insight into the Earth's past climates, covering periods of hundreds of millions of years. The Palaeozoic Era, beginning 600 Ma, displayed evidence of both warmer and colder climatic conditions than the present; the Tertiary Period (65 to 2.6 Ma) was generally warmer; and the Quaternary Period (2.6 Ma to the present – the ice ages) showed oscillations between glacial and interglacial conditions. Louis Agassiz (1837) developed the hypothesis that Europe had experienced past glacial ages, and there has since been a growing awareness that long-term climate observations can advance the understanding of the physical mechanisms affecting climate change. The scientific study of one such mechanism – modifications in the geographical and temporal patterns of solar energy reaching the Earth's surface due to changes in the Earth's orbital parameters – has a long history. The pioneering contributions of Milankovitch (1941) to this astronomical theory of climate change are widely known, and the historical review of Imbrie and Imbrie (1979) calls attention to much earlier contributions, such as those of James Croll, originating in 1864.

The pace of palaeoclimatic research has accelerated over recent decades. Quantitative and well-dated records of climate fluctuations over the last 100 kyr have brought a more comprehensive view of how climate changes occur, as well as the means to test elements of the astronomical theory. By the 1950s, studies of deep-sea cores suggested that the ocean temperatures may have been different during glacial times (Emiliani, 1955). Ewing and Donn (1956) proposed that changes in ocean circulation actually could initiate an ice age. In the 1960s, the works of Emiliani (1969) and Shackleton (1967) showed the potential of isotopic measurements in deep-sea sediments to help explain Quaternary changes. In the 1970s, it became possible to analyse a deep-sea core time series of more than 700 kyr, thereby using the last reversal of the Earth's magnetic field to establish a dated chronology. This deep-sea observational record clearly showed the same periodicities found in the astronomical forcing, immediately providing strong support to Milankovitch's theory (Hays et al., 1976).

Ice cores provide key information about past climates, including surface temperatures and atmospheric chemical composition. The bubbles sealed in the ice are the only available samples of these past atmospheres. The first deep ice cores from Vostok in Antarctica (Barnola et al., 1987; Jouzel et al., 1987, 1993) provided additional evidence of the role of astronomical forcing. They also revealed a highly correlated evolution of temperature changes and atmospheric composition, which was subsequently confirmed over the past 400 kyr (Petit et al., 1999) and now extends to almost 1 Myr. This discovery drove research to understand the causal links between greenhouse gases and climate change. The same data that confirmed the astronomical theory also revealed its limits: a linear response of the climate system to astronomical forcing could not explain entirely the observed fluctuations of rapid ice-age terminations preceded by longer cycles of glaciations.

The importance of other sources of climate variability was heightened by the discovery of abrupt climate changes. In this context, 'abrupt' designates regional events of large amplitude, typically a few degrees celsius, which occurred within several decades – much shorter than the thousand-year time scales that characterise changes in astronomical forcing. Abrupt temperature changes were first revealed by the analysis of deep ice cores from Greenland (Dansgaard et al., 1984). Oeschger et al. (1984) recognised that the abrupt changes during the termination of the last ice age correlated with cooling in Gerzensee (Switzerland) and suggested that regime shifts in the Atlantic Ocean circulation were causing these widespread changes. The synthesis of palaeoclimatic observations by Broecker and Denton (1989) invigorated the community over the next decade. By the end of the 1990s, it became clear that the abrupt climate changes during the last ice age, particularly in the North Atlantic regions as found in the Greenland ice cores, were numerous (Dansgaard et al., 1993), indeed abrupt (Alley et al., 1993) and of large amplitude (Severinghaus and Brook, 1999). They are now referred to as Dansgaard-Oeschger events. A similar variability is seen in the North Atlantic Ocean, with north-south oscillations of the polar front (Bond et al., 1992) and associated changes in ocean temperature and salinity (Cortijo et al., 1999). With no obvious external forcing, these changes are thought to be manifestations of the internal variability of the climate system.

The importance of internal variability and processes was reinforced in the early 1990s with analysis of records with high temporal resolution. New ice cores (Greenland Ice Core Project, Johnsen et al., 1992; Greenland Ice Sheet Project 2, Grootes et al., 1993), new ocean cores from regions with high sedimentation rates, as well as lacustrine sediments and cave stalagmites produced additional evidence for unforced climate changes, and revealed a large number of abrupt changes in many regions throughout the last glacial cycle. Long sediment cores from the deep ocean were used to reconstruct the thermohaline circulation connecting deep and surface waters (Bond et al., 1992; Broecker, 1997) and to demonstrate the participation of the ocean in these abrupt climate changes during glacial periods.

By the end of the 1990s, palaeoclimate proxies for a range of climate observations had expanded greatly. The analysis of deep corals provided indicators for nutrient content and mass exchange from the surface to deep water (Adkins et al., 1998), showing abrupt variations characterised by synchronous changes in surface and deep-water properties (Shackleton et al., 2000). Precise measurements of the CH_4 abundances (a global quantity) in polar ice cores showed that they changed in concert with the Dansgaard-Oeschger events and thus allowed for synchronisation of the dating across ice cores (Blunier et al., 1998). The characteristics of the antarctic temperature variations and their relation to the Dansgaard-Oeschger events in Greenland were consistent with the simple concept of a bipolar seesaw caused by changes in the thermohaline circulation of the Atlantic Ocean (Stocker, 1998). This work underlined the role of the ocean in transmitting the signals of abrupt climate change.

Abrupt changes are often regional, for example, severe droughts lasting for many years have changed civilizations, and have occurred during the last 10 kyr of stable warm climate (deMenocal, 2001). This result has altered the notion of a stable climate during warm epochs, as previously suggested by the polar ice cores. The emerging picture of an unstable ocean-atmosphere system has opened the debate of whether human interference through greenhouse gases and aerosols could trigger such events (Broecker, 1997).

Palaeoclimate reconstructions cited in the FAR were based on various data, including pollen records, insect and animal remains, oxygen isotopes and other geological data from lake varves, loess, ocean sediments, ice cores and glacier termini. These records provided estimates of climate variability on time scales up to millions of years. A climate proxy is a local quantitative record (e.g., thickness and chemical properties of tree rings, pollen of different species) that is interpreted as a climate variable (e.g., temperature or rainfall) using a transfer function that is based on physical principles and recently observed correlations between the two records. The combination of instrumental and proxy data began in the 1960s with the investigation of the influence of climate on the proxy data, including tree rings (Fritts, 1962), corals (Weber and Woodhead, 1972; Dunbar and Wellington, 1981) and ice cores (Dansgaard et al., 1984; Jouzel et al., 1987). Phenological and historical data (e.g., blossoming dates, harvest dates, grain prices, ships' logs, newspapers, weather diaries, ancient manuscripts) are also a valuable source of climatic reconstruction for the period before instrumental records became available. Such documentary data also need calibration against instrumental data to extend and reconstruct the instrumental record (Lamb, 1969; Zhu, 1973; van den Dool, 1978; Brazdil, 1992; Pfister, 1992). With the development of multi-proxy reconstructions, the climate data were extended not only from local to global, but also from instrumental data to patterns of climate variability (Wanner et al., 1995; Mann et al., 1998; Luterbacher et al., 1999). Most of these reconstructions were at single sites and only loose efforts had been made to consolidate records. Mann et al. (1998) made a notable advance in the use of proxy data by ensuring that the dating of different records lined up. Thus, the true spatial patterns of temperature variability and change could be derived, and estimates of NH average surface temperatures were obtained.

The Working Group I (WGI) WGI FAR noted that past climates could provide analogues. Fifteen years of research since that assessment has identified a range of variations and instabilities in the climate system that occurred during the last 2 Myr of glacial-interglacial cycles and in the super-warm period of 50 Ma. These past climates do not appear to be analogues of the immediate future, yet they do reveal a wide range of climate processes that need to be understood when projecting 21st-century climate change (see Chapter 6).

1.4.3 Solar Variability and the Total Solar Irradiance

Measurement of the absolute value of total solar irradiance (TSI) is difficult from the Earth's surface because of the need to correct for the influence of the atmosphere. Langley (1884) attempted to minimise the atmospheric effects by taking measurements from high on Mt. Whitney in California, and to estimate the correction for atmospheric effects by taking measurements at several times of day, for example, with the solar radiation having passed through different atmospheric pathlengths. Between 1902 and 1957, Charles Abbot and a number of other scientists around the globe made thousands of measurements of TSI from mountain sites. Values ranged from 1,322 to 1,465 W m^{-2}, which encompasses the current estimate of 1,365 W m^{-2}. Foukal et al. (1977) deduced from Abbot's daily observations that higher values of TSI were associated with more solar faculae (e.g., Abbot, 1910).

In 1978, the Nimbus-7 satellite was launched with a cavity radiometer and provided evidence of variations in TSI (Hickey et al., 1980). Additional observations were made with an active cavity radiometer on the Solar Maximum Mission, launched in 1980 (Willson et al., 1980). Both of these missions showed that the passage of sunspots and faculae across the Sun's disk influenced TSI. At the maximum of the 11-year solar activity cycle, the TSI is larger by about 0.1% than at the minimum. The observation that TSI is highest when sunspots are at their maximum is the opposite of Langley's (1876) hypothesis.

As early as 1910, Abbot believed that he had detected a downward trend in TSI that coincided with a general cooling of climate. The solar cycle variation in irradiance corresponds to an 11-year cycle in radiative forcing which varies by about 0.2 W m^{-2}. There is increasingly reliable evidence of its influence on atmospheric temperatures and circulations, particularly in the higher atmosphere (Reid, 1991; Brasseur, 1993; Balachandran and Rind, 1995; Haigh, 1996; Labitzke and van Loon, 1997; van Loon and Labitzke, 2000). Calculations with three-dimensional models (Wetherald and Manabe, 1975; Cubasch et al., 1997; Lean and Rind, 1998; Tett et al., 1999; Cubasch and Voss, 2000) suggest that the changes in solar radiation could cause surface temperature changes of the order of a few tenths of a degree celsius.

For the time before satellite measurements became available, the solar radiation variations can be inferred from cosmogenic isotopes (^{10}Be, ^{14}C) and from the sunspot number. Naked-eye observations of sunspots date back to ancient times, but it was only after the invention of the telescope in 1607 that it became possible to routinely monitor the number, size and position of these 'stains' on the surface of the Sun. Throughout the 17th and 18th centuries, numerous observers noted the variable concentrations and ephemeral nature of sunspots, but very few sightings were reported between 1672 and 1699 (for an overview see Hoyt et al., 1994). This period of low solar activity, now known as the Maunder Minimum, occurred during the climate period now commonly referred to as the Little Ice Age (Eddy, 1976). There is no exact agreement as to which dates mark the beginning and end of the Little Ice Age, but from about 1350 to about 1850 is one reasonable estimate.

During the latter part of the 18th century, Wilhelm Herschel (1801) noted the presence not only of sunspots but of bright patches, now referred to as faculae, and of granulations on the solar surface. He believed that when these indicators of activity were more numerous, solar emissions of light and heat were greater and could affect the weather on Earth. Heinrich Schwabe (1844) published his discovery of a '10-year cycle' in sunspot numbers. Samuel Langley (1876) compared the brightness of sunspots with that of the surrounding photosphere. He concluded that they would block the emission of radiation and estimated that at sunspot cycle maximum the Sun would be about 0.1% less bright than at the minimum of the cycle, and that the Earth would be 0.1°C to 0.3°C cooler.

These satellite data have been used in combination with the historically recorded sunspot number, records of cosmogenic isotopes, and the characteristics of other Sun-like stars to estimate the solar radiation over the last 1,000 years (Eddy, 1976; Hoyt and Schatten, 1993, 1997; Lean et al., 1995; Lean, 1997). These data sets indicated quasi-periodic changes in solar radiation of 0.24 to 0.30% on the centennial time scale. These values have recently been re-assessed (see, e.g., Chapter 2).

The TAR states that the changes in solar irradiance are not the major cause of the temperature changes in the second half of the 20th century unless those changes can induce unknown large feedbacks in the climate system. The effects of galactic cosmic rays on the atmosphere (via cloud nucleation) and those due to shifts in the solar spectrum towards the ultraviolet (UV) range, at times of high solar activity, are largely unknown. The latter may produce changes in tropospheric circulation via changes in static stability resulting from the interaction of the increased UV radiation with stratospheric ozone. More research to investigate the effects of solar behaviour on climate is needed before the magnitude of solar effects on climate can be stated with certainty.

1.4.4 Biogeochemistry and Radiative Forcing

The modern scientific understanding of the complex and interconnected roles of greenhouse gases and aerosols in climate change has undergone rapid evolution over the last two decades. While the concepts were recognised and outlined in the 1970s (see Sections 1.3.1 and 1.4.1), the publication of generally accepted quantitative results coincides with, and was driven in part by, the questions asked by the IPCC beginning in 1988. Thus, it is instructive to view the evolution of this topic as it has been treated in the successive IPCC reports.

The WGI FAR codified the key physical and biogeochemical processes in the Earth system that relate a changing climate to atmospheric composition, chemistry, the carbon cycle and natural ecosystems. The science of the time, as summarised in the FAR, made a clear case for anthropogenic interference with the climate system. In terms of greenhouse agents, the main conclusions from the WGI FAR Policymakers Summary are still valid today: (1) 'emissions resulting from human activities are substantially increasing the atmospheric concentrations of the greenhouse gases: CO_2, CH_4, CFCs, N_2O'; (2) 'some gases are potentially more effective (at greenhouse warming)'; (3) feedbacks between the carbon cycle, ecosystems and atmospheric greenhouse gases in a warmer world will affect CO_2 abundances; and (4) GWPs provide a metric for comparing the climatic impact of different greenhouse gases, one that integrates both the radiative influence and biogeochemical cycles. The climatic importance of tropospheric ozone, sulphate aerosols and atmospheric chemical feedbacks were proposed by scientists at the time and noted in the assessment. For example, early global chemical modelling results argued that global tropospheric ozone, a greenhouse gas, was controlled by emissions of the highly reactive gases nitrogen oxides (NO_x), carbon monoxide (CO) and non-methane hydrocarbons (NMHC, also known as volatile organic compounds, VOC). In terms of sulphate aerosols, both the direct radiative effects and the indirect effects on clouds were acknowledged, but the importance of carbonaceous aerosols from fossil fuel and biomass combustion was not recognised (Chapters 2, 7 and 10).

The concept of radiative forcing (RF) as the radiative imbalance (W m^{-2}) in the climate system at the top of the atmosphere caused by the addition of a greenhouse gas (or other change) was established at the time and summarised in Chapter 2 of the WGI FAR. Agents of RF included the direct greenhouse gases, solar radiation, aerosols and the Earth's surface albedo. What was new and only briefly mentioned was that 'many gases produce indirect effects on the global radiative forcing'. The innovative global modelling work of Derwent (1990) showed that emissions of the reactive but non-greenhouse gases – NO_x, CO and NMHCs – altered atmospheric chemistry and thus changed the abundance of other greenhouse gases. Indirect GWPs for NO_x, CO and VOCs were proposed. The projected chemical feedbacks were limited to short-lived increases in tropospheric ozone. By 1990, it was clear that the RF from tropospheric ozone had increased over the 20th century and stratospheric ozone had decreased since 1980 (e.g., Lacis et al., 1990), but the associated RFs were not evaluated in the assessments. Neither was the effect of anthropogenic sulphate aerosols, except to note in the FAR that 'it is conceivable that this radiative forcing has been of a comparable magnitude, but of opposite sign, to the greenhouse forcing earlier in the century'. Reflecting in general the community's concerns about this relatively new measure of climate forcing, RF bar charts appear only in the underlying FAR chapters, but not in the FAR Summary. Only the long-lived greenhouse gases are shown, although sulphate aerosols direct effect in the future is noted with a question mark (i.e., dependent on future emissions) (Chapters 2, 7 and 10).

The cases for more complex chemical and aerosol effects were becoming clear, but the scientific community was unable at the time to reach general agreement on the existence, scale and magnitude of these indirect effects. Nevertheless, these early discoveries drove the research agendas in the early 1990s. The widespread development and application of global chemistry-transport models had just begun with international workshops (Pyle et al., 1996; Jacob et al., 1997; Rasch, 2000). In the Supplementary Report (IPCC, 1992) to the FAR, the indirect chemical effects of CO, NO_x and VOC were reaffirmed, and the feedback effect of CH_4 on the tropospheric hydroxyl radical (OH) was noted, but the indirect RF values from the FAR were retracted and denoted in a table with '+', '0' or '–'. Aerosol-climate interactions still focused on sulphates, and the assessment of their direct RF for the NH (i.e., a cooling) was now somewhat quantitative as compared to the FAR. Stratospheric ozone depletion was noted as causing a significant and negative RF, but not quantified. Ecosystems research at this time was identifying the responses to climate change and CO_2 increases, as well as altered CH_4 and N_2O fluxes from natural systems; however, in terms of a community assessment it remained qualitative.

By 1994, with work on SAR progressing, the Special Report on Radiative Forcing (IPCC, 1995) reported significant breakthroughs in a set of chapters limited to assessment of the carbon cycle, atmospheric chemistry, aerosols and RF. The carbon budget for the 1980s was analysed not only from bottom-up emissions estimates, but also from a top-down approach including carbon isotopes. A first carbon cycle assessment was performed through an international model and analysis workshop examining terrestrial and oceanic uptake to better quantify the relationship between CO_2 emissions and the resulting increase in atmospheric abundance. Similarly, expanded analyses of the global budgets of trace gases and aerosols from both natural and anthropogenic sources highlighted the rapid expansion of biogeochemical research. The first RF bar chart appears, comparing all the major components of RF change from the pre-industrial period to the present. Anthropogenic soot aerosol, with a positive RF, was not in the 1995 Special Report but was added to the SAR. In terms of atmospheric chemistry, the first open-invitation modelling study for the IPCC recruited 21 atmospheric chemistry models to participate in a controlled study of photochemistry and chemical feedbacks. These studies (e.g., Olson et al., 1997) demonstrated a robust consensus about some indirect effects, such as the CH_4 impact on atmospheric chemistry, but great uncertainty about others, such as the prediction of tropospheric ozone changes. The model studies plus the theory of chemical feedbacks in the CH_4-CO-OH system (Prather, 1994) firmly established that the atmospheric lifetime of a perturbation (and hence climate impact and GWP) of CH_4 emissions was about 50% greater than reported in the FAR. There was still no consensus on quantifying the past or future changes in tropospheric ozone or OH (the primary sink for CH_4) (Chapters 2, 7 and 10).

In the early 1990s, research on aerosols as climate forcing agents expanded. Based on new research, the range of climate-relevant aerosols was extended for the first time beyond sulphates to include nitrates, organics, soot, mineral dust and sea salt. Quantitative estimates of sulphate aerosol indirect effects on cloud properties and hence RF were sufficiently well established to be included in assessments, and carbonaceous aerosols from biomass burning were recognised as being comparable in importance to sulphate (Penner et al., 1992). Ranges are given in the special report (IPCC, 1995) for direct sulphate RF (–0.25 to –0.9 W m^{-2}) and biomass-burning aerosols (–0.05 to –0.6 W m^{-2}). The aerosol indirect RF was estimated to be about equal to the direct RF, but with larger uncertainty. The injection of stratospheric aerosols from the eruption of Mt. Pinatubo was noted as the first modern test of a known radiative forcing, and indeed one climate model accurately predicted the temperature response (Hansen et al., 1992). In the one-year interval between the special report and the SAR, the scientific understanding of aerosols grew. The direct anthropogenic aerosol forcing (from sulphate, fossil-fuel soot and biomass-burning aerosols) was reduced to –0.5 W m^{-2}. The RF bar chart was now broken into aerosol components (sulphate, fossil-fuel soot and biomass burning aerosols) with a separate range for indirect effects (Chapters 2 and 7; Sections 8.2 and 9.2).

Throughout the 1990s, there were concerted research programs in the USA and EU to evaluate the global environmental impacts of aviation. Several national assessments culminated in the IPCC Special Report on Aviation and the Global Atmosphere (IPCC, 1999), which assessed the impacts on climate and global air quality. An open invitation for atmospheric model participation resulted in community participation and a consensus on many of the environmental impacts of aviation (e.g., the increase in tropospheric ozone and decrease in CH_4 due to NO_x emissions were quantified). The direct RF of sulphate and of soot aerosols was likewise quantified along with that of contrails, but the impact on cirrus clouds that are sometimes generated downwind of contrails was not. The assessment re-affirmed that RF was a first-order metric for the global mean surface temperature response, but noted that it was inadequate for regional climate change, especially in view of the largely regional forcing from aerosols and tropospheric ozone (Sections 2.6, 2.8 and 10.2).

By the end of the 1990s, research on atmospheric composition and climate forcing had made many important advances. The TAR was able to provide a more quantitative evaluation in some areas. For example, a large, open-invitation modelling workshop was held for both aerosols (11 global models) and tropospheric ozone-OH chemistry (14 global models). This workshop brought together as collaborating authors most of the international scientific community involved in developing and testing global models of atmospheric composition. In terms of atmospheric chemistry, a strong consensus was reached for the first time that science could predict the changes in tropospheric ozone in response to scenarios for CH_4 and the indirect greenhouse gases (CO, NO_x, VOC) and that a quantitative GWP for CO could be reported. Further, combining these models with observational analysis, an estimate of the change in tropospheric ozone since the pre-industrial era – with uncertainties – was reported. The aerosol workshop made similar advances in evaluating the impact of different aerosol types. There were many different representations of uncertainty (e.g., a range in models versus an expert judgment) in the TAR, and the consensus RF bar chart did not generate a total RF or uncertainties for use in the subsequent IPCC Synthesis Report (IPCC, 2001b) (Chapters 2 and 7; Section 9.2).

1.4.5 Cryospheric Topics

The cryosphere, which includes the ice sheets of Greenland and Antarctica, continental (including tropical) glaciers, snow, sea ice, river and lake ice, permafrost and seasonally frozen ground, is an important component of the climate system. The cryosphere derives its importance to the climate system from a variety of effects, including its high reflectivity (albedo) for solar radiation, its low thermal conductivity, its large thermal inertia, its potential for affecting ocean circulation (through exchange of freshwater and heat) and atmospheric circulation (through topographic changes), its large potential for affecting sea level (through growth and melt of land ice), and its potential for affecting greenhouse gases (through changes in permafrost) (Chapter 4).

Studies of the cryospheric albedo feedback have a long history. The albedo is the fraction of solar energy reflected back to space. Over snow and ice, the albedo (about 0.7 to 0.9) is large compared to that over the oceans (<0.1). In a warming climate, it is anticipated that the cryosphere would shrink, the Earth's overall albedo would decrease and more solar energy would be absorbed to warm the Earth still further. This powerful feedback loop was recognised in the 19th century by Croll (1890) and was first introduced in climate models by Budyko (1969) and Sellers (1969). But although the principle of the albedo feedback is simple, a quantitative understanding of the effect is still far from complete. For instance, it is not clear whether this mechanism is the main reason for the high-latitude amplification of the warming signal.

The potential cryospheric impact on ocean circulation and sea level are of particular importance. There may be 'large-scale discontinuities' (IPCC, 2001a) resulting from both the shutdown of the large-scale meridional circulation of the world oceans (see Section 1.4.6) and the disintegration of large continental ice sheets. Mercer (1968, 1978) proposed that atmospheric warming could cause the ice shelves of western Antarctica to disintegrate and that as a consequence the entire West Antarctic Ice Sheet (10% of the antarctic ice volume) would lose its land connection and come afloat, causing a sea level rise of about five metres.

The importance of permafrost-climate feedbacks came to be realised widely only in the 1990s, starting with the works of Kvenvolden (1988, 1993), MacDonald (1990) and Harriss et al. (1993). As permafrost thaws due to a warmer climate, CO_2 and CH_4 trapped in permafrost are released to the atmosphere. Since CO_2 and CH_4 are greenhouse gases, atmospheric temperature is likely to increase in turn, resulting in a feedback loop with more permafrost thawing. The permafrost and seasonally thawed soil layers at high latitudes contain a significant amount (about one-quarter) of the global total amount of soil carbon. Because global warming signals are amplified in high-latitude regions, the potential for permafrost thawing and consequent greenhouse gas releases is thus large.

In situ monitoring of the cryosphere has a long tradition. For instance, it is important for fisheries and agriculture. Seagoing communities have documented sea ice extent for centuries. Records of thaw and freeze dates for lake and river ice start with Lake Suwa in Japan in 1444, and extensive records of snowfall in China were made during the Qing Dynasty (1644–1912). Records of glacial length go back to the mid-1500s. Internationally coordinated, long-term glacier observations started in 1894 with the establishment of the International Glacier Commission in Zurich, Switzerland. The longest time series of a glacial mass balance was started in 1946 at the Storglaciären in northern Sweden, followed by Storbreen in Norway (begun in 1949). Today a global network of mass balance monitoring for some 60 glaciers is coordinated through the World Glacier Monitoring Service. Systematic measurements of permafrost (thermal state and active layer) began in earnest around 1950 and were coordinated under the Global Terrestrial Network for Permafrost.

The main climate variables of the cryosphere (extent, albedo, topography and mass) are in principle observable from space, given proper calibration and validation through *in situ* observing efforts. Indeed, satellite data are required in order to have full global coverage. The polar-orbiting Nimbus 5 satellite, launched in 1972, yielded the earliest all-weather, all-season imagery of global sea ice, using microwave instruments (Parkinson et al., 1987), and enabled a major advance in the scientific understanding of the dynamics of the cryosphere. Launched in 1978, the Television Infrared Observation Satellite (TIROS-N) yielded the first monitoring from space of snow on land surfaces (Dozier et al., 1981). The number of cryospheric elements now routinely monitored from space is growing, and current satellites are now addressing one of the more challenging elements, variability of ice volume.

Climate modelling results have pointed to high-latitude regions as areas of particular importance and ecological vulnerability to global climate change. It might seem logical to expect that the cryosphere overall would shrink in a warming climate or expand in a cooling climate. However, potential changes in precipitation, for instance due to an altered hydrological cycle, may counter this effect both regionally and globally. By the time of the TAR, several climate models incorporated physically based treatments of ice dynamics, although the land ice processes were only rudimentary. Improving representation of the cryosphere in climate models is still an area of intense research and continuing progress (Chapter 8).

1.4.6 Ocean and Coupled Ocean-Atmosphere Dynamics

Developments in the understanding of the oceanic and atmospheric circulations, as well as their interactions, constitute a striking example of the continuous interplay among theory, observations and, more recently, model simulations. The atmosphere and ocean surface circulations were observed and analysed globally as early as the 16th and 17th centuries, in close association with the development of worldwide trade based on sailing. These efforts led to a number of important conceptual and theoretical works. For example, Edmund Halley first published a description of the tropical atmospheric cells in 1686, and George Hadley proposed a theory linking the existence of the trade winds with those cells in 1735. These early studies helped to forge concepts that are still useful in analysing and understanding both the atmospheric general circulation itself and model simulations (Lorenz, 1967; Holton, 1992).

A comprehensive description of these circulations was delayed by the lack of necessary observations in the higher atmosphere or deeper ocean. The balloon record of Gay-Lussac, who reached an altitude of 7,016 m in 1804, remained unbroken for more than 50 years. The stratosphere was independently discovered near the turn of the 20th century by Aßmann (1902) and Teisserenc de Bort (1902), and the first manned balloon flight into the stratosphere was made in 1901 (Berson and Süring, 1901). Even though it was recognised over 200 years ago (Rumford, 1800; see also Warren, 1981) that the oceans' cold subsurface waters must originate at high latitudes, it was not appreciated until the 20th century that the strength of the deep circulation might vary over time, or that the ocean's Meridional Overturning Circulation (MOC; often loosely referred to as the 'thermohaline circulation', see the Glossary for more information) may be very important for Earth's climate.

By the 1950s, studies of deep-sea cores suggested that the deep ocean temperatures had varied in the distant past. Technology also evolved to enable measurements that could confirm that the deep ocean is not only not static, but in fact quite dynamic (Swallow and Stommel's 1960 subsurface float experiment Aries, referred to by Crease, 1962). By the late 1970s, current meters could monitor deep currents for substantial amounts of time, and the first ocean observing satellite (SeaSat) revealed that significant information about subsurface ocean variability is imprinted on the sea surface. At the same time, the first estimates of the strength of the meridional transport of heat and mass were made (Oort and Vonder Haar, 1976; Wunsch, 1978), using a combination of models and data. Since then the technological developments have accelerated, but monitoring the MOC directly remains a substantial challenge (see Chapter 5), and routine observations of the subsurface ocean remain scarce compared to that of the atmosphere.

In parallel with the technological developments yielding new insights through observations, theoretical and numerical explorations of multiple (stable or unstable) equilibria began. Chamberlain (1906) suggested that deep ocean currents could reverse in direction, and might affect climate. The idea did not gain momentum until fifty years later, when Stommel (1961) presented a mechanism, based on the opposing effects that temperature and salinity have on density, by which ocean circulation can fluctuate between states. Numerical climate models incorporating models of the ocean circulation were developed during this period, including the pioneering work of Bryan (1969) and Manabe and Bryan (1969). The idea that the ocean circulation could change radically, and might perhaps even feel the attraction of different equilibrium states, gained further support through the simulations of coupled climate models (Bryan and Spelman, 1985; Bryan, 1986; Manabe and Stouffer, 1988). Model simulations using a hierarchy of models showed that the ocean circulation system appeared to be particularly vulnerable to changes in the freshwater balance, either by direct addition of freshwater or by changes in the hydrological cycle. A strong case emerged for the hypothesis that rapid changes in the Atlantic meridional circulation were responsible for the abrupt Dansgaard-Oeschger climate change events.

Although scientists now better appreciate the strength and variability of the global-scale ocean circulation, its roles in climate are still hotly debated. Is it a passive recipient of atmospheric forcing and so merely a diagnostic consequence of climate change, or is it an active contributor? Observational evidence for the latter proposition was presented by Sutton and Allen (1997), who noticed SST anomalies propagating along the Gulf Stream/North Atlantic Current system for years, and therefore implicated internal oceanic time scales. Is a radical change in the MOC likely in the near future? Brewer et al. (1983) and Lazier (1995) showed that the water masses of the North Atlantic were indeed changing (some becoming significantly fresher) in the modern observational record, a phenomenon that at least raises the possibility that ocean conditions may be approaching the point where the circulation might shift into Stommel's other stable regime. Recent developments in the ocean's various roles in climate can be found in Chapters 5, 6, 9 and 10.

Studying the interactions between atmosphere and ocean circulations was also facilitated through continuous interactions between observations, theories and simulations, as is dramatically illustrated by the century-long history of the advances in understanding the El Niño-Southern Oscillation (ENSO) phenomenon. This coupled air-sea phenomenon originates in the Pacific but affects climate globally, and has raised concern since at least the 19th century. Sir Gilbert Walker (1928) describes how H. H. Hildebrandsson (1897) noted large-scale relationships between interannual trends in pressure data from a worldwide network of 68 weather stations, and how Lockyer and Lockyer (1902) confirmed Hildebrandsson's discovery of an apparent 'seesaw' in pressure between South America and the Indonesian region. Walker named this seesaw pattern the 'Southern Oscillation' and related it to occurrences of drought and heavy rains in India, Australia, Indonesia and Africa. He also proposed that there must be a certain level of predictive skill in that system.

El Niño is the name given to the rather unusual oceanic conditions involving anomalously warm waters occurring in the eastern tropical Pacific off the coast of Peru every few years. The 1957–1958 International Geophysical Year coincided with a large El Niño, allowing a remarkable set of observations of the phenomenon. A decade later, a mechanism was presented that connected Walker's observations to El Niño (Bjerknes, 1969). This mechanism involved the interaction, through the SST field, between the east-west atmospheric circulation of which Walker's Southern Oscillation was an indicator (Bjerknes appropriately referred to this as the 'Walker Circulation') and variability in the pool of equatorial warm water of the Pacific Ocean. Observations made in the 1970s (e.g., Wyrtki, 1975) showed that prior to ENSO warm phases, the sea level in the western Pacific often rises significantly. By the mid-1980s, after an unusually disruptive El Niño struck in 1982 and 1983, an observing system (the Tropical Ocean Global Atmosphere (TOGA) array; see McPhaden et al., 1998) had been put in place to monitor ENSO. The resulting data confirmed the idea that the phenomenon was inherently one involving coupled atmosphere-ocean interactions and yielded much-needed detailed observational insights. By 1986, the first experimental ENSO forecasts were made (Cane et al., 1986; Zebiak and Cane, 1987).

The mechanisms and predictive skill of ENSO are still under discussion. In particular, it is not clear how ENSO changes with, and perhaps interacts with, a changing climate. The TAR states '...increasing evidence suggests the ENSO plays a fundamental role in global climate and its interannual variability, and increased credibility in both regional and global climate projections will be gained once realistic ENSOs and their changes are simulated'.

Just as the phenomenon of El Niño has been familiar to the people of tropical South America for centuries, a spatial pattern affecting climate variability in the North Atlantic has similarly been known by the people of Northern Europe for a long time. The Danish missionary Hans Egede made the following well-known diary entry in the mid-18th century: 'In Greenland, all winters are severe, yet they are not alike. The Danes have noticed that when the winter in Denmark was severe, as we perceive it, the winter in Greenland in its manner was mild, and conversely' (van Loon and Rogers, 1978).

Teisserenc de Bort, Hann, Exner, Defant and Walker all contributed to the discovery of the underlying dynamic structure. Walker, in his studies in the Indian Ocean, actually studied global maps of sea level pressure correlations, and named not only the Southern Oscillation, but also a Northern Oscillation, which he subsequently divided into a North Pacific and a North Atlantic Oscillation (Walker, 1924). However, it was Exner (1913, 1924) who made the first correlation maps showing the spatial structure in the NH, where the North Atlantic Oscillation (NAO) pattern stands out clearly as a north-south oscillation in atmospheric mass with centres of action near Iceland and Portugal.

The NAO significantly affects weather and climate, ecosystems and human activities of the North Atlantic sector. But what is the underlying mechanism? The recognition that the NAO is associated with variability and latitudinal shifts in the westerly flow of the jet stream originates with the works of Willett, Namias, Lorenz, Rossby and others in the 1930s, 1940s and 1950s (reviewed by Stephenson et al., 2003). Because atmospheric planetary waves are hemispheric in nature, changes in one region are often connected with changes in other regions, a phenomenon dubbed 'teleconnection' (Wallace and Gutzler, 1981).

The NAO may be partly described as a high-frequency stochastic process internal to the atmosphere. This understanding is evidenced by numerous atmosphere-only model simulations. It is also considered an expression of one of Earth's 'annular modes' (See Chapter 3). It is, however, the low-frequency variability of this phenomenon (Hurrell, 1995) that fuels continued investigations by climate scientists. The long time scales are the indication of potential predictive skill in the NAO. The mechanisms responsible for the correspondingly long 'memory' are still debated, although they are likely to have a local or remote oceanic origin. Bjerknes (1964) recognised the connection between the NAO index (which he referred to as the 'zonal index') and sea surface conditions. He speculated that ocean heat advection could play a role on longer time scales. The circulation of the Atlantic Ocean is radically different from that of the Indian and Pacific Oceans, in that the MOC is strongest in the Atlantic with warm water flowing northwards, even south of the equator, and cold water returning at depth. It would therefore not be surprising if the oceanic contributions to the NAO and to the Southern Oscillation were different.

Earth's climate is characterised by many modes of variability, involving both the atmosphere and ocean, and also the cryosphere and biosphere. Understanding the physical processes involved in producing low-frequency variability is crucial for improving scientists' ability to accurately predict climate change and for allowing the separation of anthropogenic and natural variability, thereby improving the ability to detect and attribute anthropogenic climate change. One central question for climate scientists, addressed in particular in Chapter 9, is to determine how human activities influence the dynamic nature of Earth's climate, and to identify what would have happened without any human influence at all.

1.5 Examples of Progress in Modelling the Climate

1.5.1 Model Evolution and Model Hierarchies

Climate scenarios rely upon the use of numerical models. The continuous evolution of these models over recent decades has been enabled by a considerable increase in computational capacity, with supercomputer speeds increasing by roughly a factor of a million in the three decades from the 1970s to the present. This computational progress has permitted a corresponding increase in model complexity (by including more and more components and processes, as depicted in Figure 1.2), in the length of the simulations, and in spatial resolution, as shown in Figure 1.4. The models used to evaluate future climate changes have therefore evolved over time. Most of the pioneering work on CO_2-induced climate change was based on atmospheric general circulation models coupled to simple 'slab' ocean models (i.e., models omitting ocean dynamics), from the early work of Manabe and Wetherald (1975) to the review of Schlesinger and Mitchell (1987). At the same time the physical content of the models has become more comprehensive (see in Section 1.5.2 the example of clouds). Similarly, most of the results presented in the FAR were from atmospheric models, rather than from models of the coupled climate system, and were used to analyse changes in the equilibrium climate resulting from a doubling of the atmospheric CO_2 concentration. Current climate projections can investigate time-dependent scenarios of climate evolution and can make use of much more complex coupled ocean-atmosphere models, sometimes even including interactive chemical or biochemical components.

A parallel evolution toward increased complexity and resolution has occurred in the domain of numerical weather prediction, and has resulted in a large and verifiable improvement in operational weather forecast quality. This example alone shows that present models are more realistic than were those of a decade ago. There is also, however, a continuing awareness that models do not provide a perfect simulation of reality, because resolving all important spatial or time scales remains far beyond current capabilities, and also because the behaviour of such a complex nonlinear system may in general be chaotic.

It has been known since the work of Lorenz (1963) that even simple models may display intricate behaviour because of their nonlinearities. The inherent nonlinear behaviour of the climate system appears in climate simulations at all time scales (Ghil, 1989). In fact, the study of nonlinear dynamical systems has become important for a wide range of scientific disciplines, and the corresponding mathematical developments are essential to interdisciplinary studies. Simple models of ocean-atmosphere interactions, climate-biosphere interactions or climate-economy interactions may exhibit a similar behaviour, characterised by partial unpredictability, bifurcations and transition to chaos.

In addition, many of the key processes that control climate sensitivity or abrupt climate changes (e.g., clouds, vegetation, oceanic convection) depend on very small spatial scales. They cannot be represented in full detail in the context of global models, and scientific understanding of them is still notably incomplete. Consequently, there is a continuing need to assist in the use and interpretation of complex models through models that are either conceptually simpler, or limited to a number of processes or to a specific region, therefore enabling a deeper understanding of the processes at work or a more relevant comparison with observations. With the development of computer capacities, simpler models have not disappeared; on the contrary, a stronger emphasis has been given to the concept of a 'hierarchy of models' as the only way to provide a linkage between theoretical understanding and the complexity of realistic models (Held, 2005).

The list of these 'simpler' models is very long. Simplicity may lie in the reduced number of equations (e.g., a single

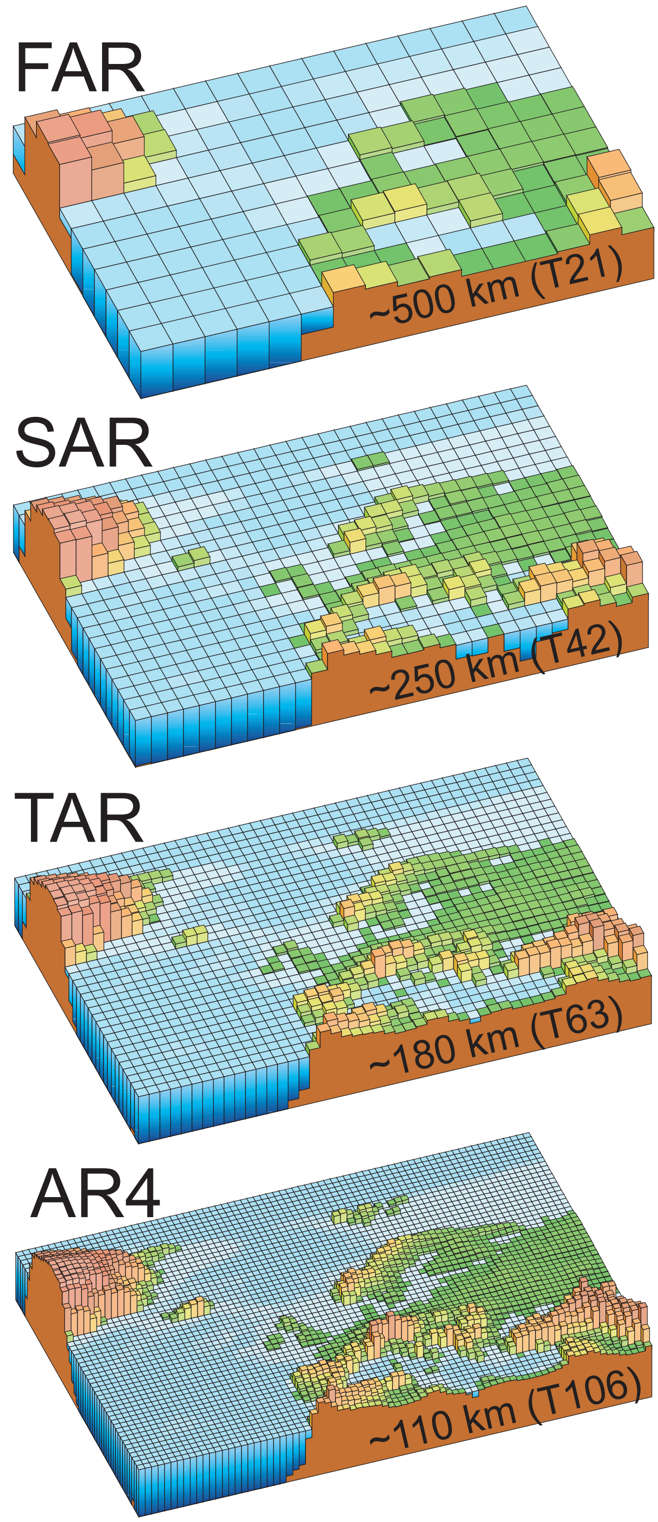


Figure 1.4. *Geographic resolution characteristic of the generations of climate models used in the IPCC Assessment Reports: FAR (IPCC, 1990), SAR (IPCC, 1996), TAR (IPCC, 2001a), and AR4 (2007). The figures above show how successive generations of these global models increasingly resolved northern Europe. These illustrations are representative of the most detailed horizontal resolution used for short-term climate simulations. The century-long simulations cited in IPCC Assessment Reports after the FAR were typically run with the previous generation's resolution. Vertical resolution in both atmosphere and ocean models is not shown, but it has increased comparably with the horizontal resolution, beginning typically with a single-layer slab ocean and ten atmospheric layers in the FAR and progressing to about thirty levels in both atmosphere and ocean.*

equation for the global surface temperature); in the reduced dimensionality of the problem (one-dimension vertical, one-dimension latitudinal, two-dimension); or in the restriction to a few processes (e.g., a mid-latitude quasi-geostrophic atmosphere with or without the inclusion of moist processes). The notion of model hierarchy is also linked to the idea of scale: global circulation models are complemented by regional models that exhibit a higher resolution over a given area, or process oriented models, such as cloud resolving models or large eddy simulations. Earth Models of Intermediate Complexity are used to investigate long time scales, such as those corresponding to glacial to interglacial oscillations (Berger et al., 1998). This distinction between models according to scale is evolving quickly, driven by the increase in computer capacities. For example, global models explicitly resolving the dynamics of convective clouds may soon become computationally feasible.

Many important scientific debates in recent years have had their origin in the use of conceptually simple models. The study of idealised atmospheric representations of the tropical climate, for example by Pierrehumbert (1995) who introduced a separate representation of the areas with ascending and subsiding circulation in the tropics, has significantly improved the understanding of the feedbacks that control climate. Simple linearized models of the atmospheric circulation have been used to investigate potential new feedback effects. Ocean box models have played an important role in improving the understanding of the possible slowing down of the Atlantic thermohaline circulation (Birchfield et al., 1990), as emphasized in the TAR. Simple models have also played a central role in the interpretation of IPCC scenarios: the investigation of climate scenarios presented in the SAR or the TAR has been extended to larger ensembles of cases using idealised models.

1.5.2 Model Clouds and Climate Sensitivity

The modelling of cloud processes and feedbacks provides a striking example of the irregular pace of progress in climate science. Representation of clouds may constitute the area in which atmospheric models have been modified most continuously to take into account increasingly complex physical processes. At the time of the TAR clouds remained a major source of uncertainty in the simulation of climate changes (as they still are at present: e.g., Sections 2.4, 2.6, 3.4.3, 7.5, 8.2, 8.4.11, 8.6.2.2, 8.6.3.2, 9.2.1.2, 9.4.1.8, 10.2.1.2, 10.3.2.2, 10.5.4.3, 11.8.1.3, 11.8.2.2).

In the early 1980s, most models were still using prescribed cloud amounts, as functions of location and altitude, and prescribed cloud radiative properties, to compute atmospheric radiation. The cloud amounts were very often derived from the zonally averaged climatology of London (1957). Succeeding generations of models have used relative humidity or other simple predictors to diagnose cloudiness (Slingo, 1987), thus providing a foundation of increased realism for the models, but at the same time possibly causing inconsistencies in the representation of the multiple roles of clouds as bodies interacting with radiation, generating precipitation and influencing small-scale convective or turbulent circulations. Following the pioneering studies of Sundqvist (1978), an explicit representation of clouds was progressively introduced into climate models, beginning in the late 1980s. Models first used simplified representations of cloud microphysics, following, for example, Kessler (1969), but more recent generations of models generally incorporate a much more comprehensive and detailed representation of clouds, based on consistent physical principles. Comparisons of model results with observational data presented in the TAR have shown that, based on zonal averages, the representation of clouds in most climate models was also more realistic in 2000 than had been the case only a few years before.

In spite of this undeniable progress, the amplitude and even the sign of cloud feedbacks was noted in the TAR as highly uncertain, and this uncertainty was cited as one of the key factors explaining the spread in model simulations of future climate for a given emission scenario. This cannot be regarded as a surprise: that the sensitivity of the Earth's climate to changing atmospheric greenhouse gas concentrations must depend strongly on cloud feedbacks can be illustrated on the simplest theoretical grounds, using data that have been available for a long time. Satellite measurements have indeed provided meaningful estimates of Earth's radiation budget since the early 1970s (Vonder Haar and Suomi, 1971). Clouds, which cover about 60% of the Earth's surface, are responsible for up to two-thirds of the planetary albedo, which is about 30%. An albedo decrease of only 1%, bringing the Earth's albedo from 30% to 29%, would cause an increase in the black-body radiative equilibrium temperature of about 1°C, a highly significant value, roughly equivalent to the direct radiative effect of a doubling of the atmospheric CO_2 concentration. Simultaneously, clouds make an important contribution to the planetary greenhouse effect. In addition, changes in cloud cover constitute only one of the many parameters that affect cloud radiative interactions: cloud optical thickness, cloud height and cloud microphysical properties can also be modified by atmospheric temperature changes, which adds to the complexity of feedbacks, as evidenced, for example, through satellite observations analysed by Tselioudis and Rossow (1994).

The importance of simulated cloud feedbacks was revealed by the analysis of model results (Manabe and Wetherald, 1975; Hansen et al, 1984), and the first extensive model intercomparisons (Cess et al., 1989) also showed a substantial model dependency. The strong effect of cloud processes on climate model sensitivities to greenhouse gases was emphasized further through a now-classic set of General Circulation Model (GCM) experiments, carried out by Senior and Mitchell (1993). They produced global average surface temperature changes (due to doubled atmospheric CO_2 concentration) ranging from 1.9°C to 5.4°C, simply by altering the way that cloud radiative properties were treated in the model. It is somewhat unsettling that the results of a complex climate model can be so drastically altered by substituting one reasonable cloud parametrization for another, thereby approximately replicating the overall inter-model range of sensitivities. Other GCM groups have also

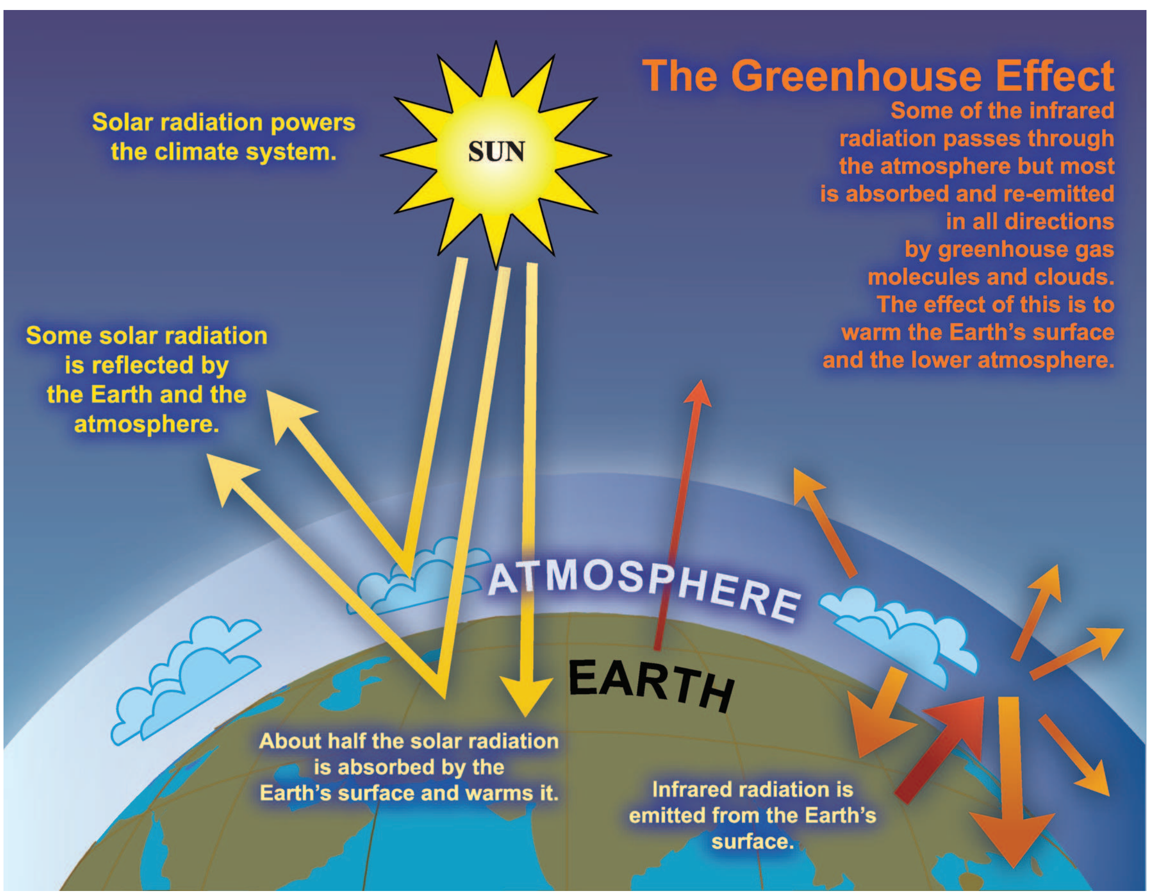
Frequently Asked Question 1.3

What is the Greenhouse Effect?

The Sun powers Earth's climate, radiating energy at very short wavelengths, predominately in the visible or near-visible (e.g., ultraviolet) part of the spectrum. Roughly one-third of the solar energy that reaches the top of Earth's atmosphere is reflected directly back to space. The remaining two-thirds is absorbed by the surface and, to a lesser extent, by the atmosphere. To balance the absorbed incoming energy, the Earth must, on average, radiate the same amount of energy back to space. Because the Earth is much colder than the Sun, it radiates at much longer wavelengths, primarily in the infrared part of the spectrum (see Figure 1). Much of this thermal radiation emitted by the land and ocean is absorbed by the atmosphere, including clouds, and reradiated back to Earth. This is called the greenhouse effect. The glass walls in a greenhouse reduce airflow and increase the temperature of the air inside. Analogously, but through a different physical process, the Earth's greenhouse effect warms the surface of the planet. Without the natural greenhouse effect, the average temperature at Earth's surface would be below the freezing point of water. Thus, Earth's natural greenhouse effect makes life as we know it possible. However, human activities, primarily the burning of fossil fuels and clearing of forests, have greatly intensified the natural greenhouse effect, causing global warming.

The two most abundant gases in the atmosphere, nitrogen (comprising 78% of the dry atmosphere) and oxygen (comprising 21%), exert almost no greenhouse effect. Instead, the greenhouse effect comes from molecules that are more complex and much less common. Water vapour is the most important greenhouse gas, and carbon dioxide (CO_2) is the second-most important one. Methane, nitrous oxide, ozone and several other gases present in the atmosphere in small amounts also contribute to the greenhouse effect. In the humid equatorial regions, where there is so much water vapour in the air that the greenhouse effect is very large, adding a small additional amount of CO_2 or water vapour has only a small direct impact on downward infrared radiation. However, in the cold, dry polar regions, the effect of a small increase in CO_2 or

(continued)



FAQ 1.3, Figure 1. *An idealised model of the natural greenhouse effect. See text for explanation.*

water vapour is much greater. The same is true for the cold, dry upper atmosphere where a small increase in water vapour has a greater influence on the greenhouse effect than the same change in water vapour would have near the surface.

Several components of the climate system, notably the oceans and living things, affect atmospheric concentrations of greenhouse gases. A prime example of this is plants taking CO_2 out of the atmosphere and converting it (and water) into carbohydrates via photosynthesis. In the industrial era, human activities have added greenhouse gases to the atmosphere, primarily through the burning of fossil fuels and clearing of forests.

Adding more of a greenhouse gas, such as CO_2, to the atmosphere intensifies the greenhouse effect, thus warming Earth's climate. The amount of warming depends on various feedback mechanisms. For example, as the atmosphere warms due to rising levels of greenhouse gases, its concentration of water vapour increases, further intensifying the greenhouse effect. This in turn causes more warming, which causes an additional increase in water vapour, in a self-reinforcing cycle. This water vapour feedback may be strong enough to approximately double the increase in the greenhouse effect due to the added CO_2 alone.

Additional important feedback mechanisms involve clouds. Clouds are effective at absorbing infrared radiation and therefore exert a large greenhouse effect, thus warming the Earth. Clouds are also effective at reflecting away incoming solar radiation, thus cooling the Earth. A change in almost any aspect of clouds, such as their type, location, water content, cloud altitude, particle size and shape, or lifetimes, affects the degree to which clouds warm or cool the Earth. Some changes amplify warming while others diminish it. Much research is in progress to better understand how clouds change in response to climate warming, and how these changes affect climate through various feedback mechanisms.

consistently obtained widely varying results by trying other techniques of incorporating cloud microphysical processes and their radiative interactions (e.g., Roeckner et al., 1987; Le Treut and Li, 1991), which differed from the approach of Senior and Mitchell (1993) through the treatment of partial cloudiness or mixed-phase properties. The model intercomparisons presented in the TAR showed no clear resolution of this unsatisfactory situation.

The scientific community realised long ago that using adequate data to constrain models was the only way to solve this problem. Using climate changes in the distant past to constrain the amplitude of cloud feedback has definite limitations (Ramstein et al., 1998). The study of cloud changes at decadal, interannual or seasonal time scales therefore remains a necessary path to constrain models. A long history of cloud observations now runs parallel to that of model development. Operational ground-based measurements, carried out for the purpose of weather prediction, constitute a valuable source of information that has been gathered and analysed by Warren et al. (1986, 1988). The International Satellite Cloud Climatology Project (ISCCP; Rossow and Schiffer, 1991) has developed an analysis of cloud cover and cloud properties using the measurements of operational meteorological satellites over a period of more than two decades. These data have been complemented by other satellite remote sensing data sets, such as those associated with the Nimbus-7 Temperature Humidity Infrared Radiometer (THIR) instrument (Stowe et al., 1988), with high-resolution spectrometers such as the High Resolution Infrared Radiation Sounder (HIRS) (Susskind et al., 1987), and with microwave absorption, as used by the Special Sensor Microwave/Imager (SSM/I). Chapter 8 provides an update of this ongoing observational effort.

A parallel effort has been carried out to develop a wider range of ground-based measurements, not only to provide an adequate reference for satellite observations, but also to make possible a detailed and empirically based analysis of the entire range of space and time scales involved in cloud processes. The longest-lasting and most comprehensive effort has been the Atmospheric Radiation Measurement (ARM) Program in the USA, which has established elaborately instrumented observational sites to monitor the full complexity of cloud systems on a long-term basis (Ackerman and Stokes, 2003). Shorter field campaigns dedicated to the observation of specific phenomena have also been established, such as the TOGA Coupled Ocean-Atmosphere Response Experiment (COARE) for convective systems (Webster and Lukas, 1992), or the Atlantic Stratocumulus Transition Experiment (ASTEX) for stratocumulus (Albrecht et al., 1995).

Observational data have clearly helped the development of models. The ISCCP data have greatly aided the development of cloud representations in climate models since the mid-1980s (e.g., Le Treut and Li, 1988; Del Genio et al., 1996). However, existing data have not yet brought about any reduction in the existing range of simulated cloud feedbacks. More recently, new theoretical tools have been developed to aid in validating parametrizations in a mode that emphasizes the role of cloud processes participating in climatic feedbacks. One such approach has been to focus on comprehensively observed episodes of cloudiness for which the large-scale forcing is observationally known, using single-column models (Randall et al., 1996; Somerville, 2000) and higher-resolution cloud-resolving models to evaluate GCM parametrizations. Another approach is to make use of the more global and continuous satellite data, on a statistical basis, through an investigation of the correlation between climate forcing and cloud parameters (Bony et al., 1997), in such a way as to provide a test of feedbacks between different climate variables. Chapter 8 assesses recent progress in this area.

1.5.3 Coupled Models: Evolution, Use, Assessment

The first National Academy of Sciences of the USA report on global warming (Charney et al., 1979), on the basis of two models simulating the impact of doubled atmospheric CO_2 concentrations, spoke of a range of global mean equilibrium surface temperature increase of between 1.5°C and 4.5°C, a range that has remained part of conventional wisdom at least as recently as the TAR. These climate projections, as well as those treated later in the comparison of three models by Schlesinger and Mitchell (1987) and most of those presented in the FAR, were the results of atmospheric models coupled with simple 'slab' ocean models (i.e., models omitting all changes in ocean dynamics).

The first attempts at coupling atmospheric and oceanic models were carried out during the late 1960s and early 1970s (Manabe and Bryan, 1969; Bryan et al., 1975; Manabe et al., 1975). Replacing 'slab' ocean models by fully coupled ocean-atmosphere models may arguably have constituted one of the most significant leaps forward in climate modelling during the last 20 years (Trenberth, 1993), although both the atmospheric and oceanic components themselves have undergone highly significant improvements. This advance has led to significant modifications in the patterns of simulated climate change, particularly in oceanic regions. It has also opened up the possibility of exploring transient climate scenarios, and it constitutes a step toward the development of comprehensive 'Earth-system models' that include explicit representations of chemical and biogeochemical cycles.

Throughout their short history, coupled models have faced difficulties that have considerably impeded their development, including: (i) the initial state of the ocean is not precisely known; (ii) a surface flux imbalance (in either energy, momentum or fresh water) much smaller than the observational accuracy is enough to cause a drifting of coupled GCM simulations into unrealistic states; and (iii) there is no direct stabilising feedback that can compensate for any errors in the simulated salinity. The strong emphasis placed on the realism of the simulated base state provided a rationale for introducing 'flux adjustments' or 'flux corrections' (Manabe and Stouffer, 1988; Sausen et al., 1988) in early simulations. These were essentially empirical corrections that could not be justified on physical principles, and that consisted of arbitrary additions of surface fluxes of heat and salinity in order to prevent the drift of the simulated climate away from a realistic state. The National Center for Atmospheric Research model may have been the first to realise non-flux-corrected coupled simulations systematically, and it was able to achieve simulations of climate change into the 21st century, in spite of a persistent drift that still affected many of its early simulations. Both the FAR and the SAR pointed out the apparent need for flux adjustments as a problematic feature of climate modelling (Cubasch et al., 1990; Gates et al., 1996).

By the time of the TAR, however, the situation had evolved, and about half the coupled GCMs assessed in the TAR did not employ flux adjustments. That report noted that 'some non-flux-adjusted models are now able to maintain stable climatologies of comparable quality to flux-adjusted models' (McAvaney et al., 2001). Since that time, evolution away from flux correction (or flux adjustment) has continued at some modelling centres, although a number of state-of-the-art models continue to rely on it. The design of the coupled model simulations is also strongly linked with the methods chosen for model initialisation. In flux-adjusted models, the initial ocean state is necessarily the result of preliminary and typically thousand-year-long simulations to bring the ocean model into equilibrium. Non-flux-adjusted models often employ a simpler procedure based on ocean observations, such as those compiled by Levitus et al. (1994), although some spin-up phase is even then necessary. One argument brought forward is that non-adjusted models made use of *ad hoc* tuning of radiative parameters (i.e., an implicit flux adjustment).

This considerable advance in model design has not diminished the existence of a range of model results. This is not a surprise, however, because it is known that climate predictions are intrinsically affected by uncertainty (Lorenz, 1963). Two distinct kinds of prediction problems were defined by Lorenz (1975). The first kind was defined as the prediction of the actual properties of the climate system in response to a given initial state. Predictions of the first kind are initial-value problems and, because of the nonlinearity and instability of the governing equations, such systems are not predictable indefinitely into the future. Predictions of the second kind deal with the determination of the response of the climate system to changes in the external forcings. These predictions are not concerned directly with the chronological evolution of the climate state, but rather with the long-term average of the statistical properties of climate. Originally, it was thought that predictions of the second kind do not at all depend on initial conditions. Instead, they are intended to determine how the statistical properties of the climate system (e.g., the average annual global mean temperature, or the expected number of winter storms or hurricanes, or the average monsoon rainfall) change as some external forcing parameter, for example CO_2 content, is altered. Estimates of future climate scenarios as a function of the concentration of atmospheric greenhouse gases are typical examples of predictions of the second kind. However, ensemble simulations show that the projections tend to form clusters around a number of attractors as a function of their initial state (see Chapter 10).

Uncertainties in climate predictions (of the second kind) arise mainly from model uncertainties and errors. To assess and disentangle these effects, the scientific community has organised a series of systematic comparisons of the different existing models, and it has worked to achieve an increase in the number and range of simulations being carried out in order to more fully explore the factors affecting the accuracy of the simulations.

An early example of systematic comparison of models is provided by Cess et al. (1989), who compared results of documented differences among model simulations in their representation of cloud feedback to show how the consequent effects on atmospheric radiation resulted in different model response to doubling of the CO_2 concentration. A number of ambitious and comprehensive 'model intercomparison projects' (MIPs) were set up in the 1990s under the auspices of the World Climate Research Programme to undertake controlled conditions for model evaluation. One of the first was the Atmospheric Model Intercomparison Project (AMIP), which studied atmospheric GCMs. The development of coupled models induced the development of the Coupled Model Intercomparison Project (CMIP), which studied coupled ocean-atmosphere GCMs and their response to idealised forcings, such as a 1% yearly increase in the atmospheric CO_2 concentration. It proved important in carrying out the various MIPs to standardise the model forcing parameters and the model output so that file formats, variable names, units, etc., are easily recognised by data users. The fact that the model results were stored separately and independently of the modelling centres, and that the analysis of the model output was performed mainly by research groups independent of the modellers, has added confidence in the results. Summary diagnostic products such as the Taylor (2001) diagram were developed for MIPs.

The establishment of the AMIP and CMIP projects opened a new era for climate modelling, setting standards of quality control, providing organisational continuity and ensuring that results are generally reproducible. Results from AMIP have provided a number of insights into climate model behaviour (Gates et al., 1999) and quantified improved agreement between simulated and observed atmospheric properties as new versions of models are developed. In general, results of the MIPs suggest that the most problematic areas of coupled model simulations involve cloud-radiation processes, the cryosphere, the deep ocean and ocean-atmosphere interactions.

Comparing different models is not sufficient, however. Using multiple simulations from a single model (the so-called Monte Carlo, or ensemble, approach) has proved a necessary and complementary approach to assess the stochastic nature of the climate system. The first ensemble climate change simulations with global GCMs used a set of different initial and boundary conditions (Cubasch et al., 1994; Barnett, 1995). Computational constraints limited early ensembles to a relatively small number of samples (fewer than 10). These ensemble simulations clearly indicated that even with a single model a large spread in the climate projections can be obtained.

Intercomparison of existing models and ensemble model studies (i.e., those involving many integrations of the same model) are still undergoing rapid development. Running ensembles was essentially impossible until recent advances in computer power occurred, as these systematic comprehensive climate model studies are exceptionally demanding on computer resources. Their progress has marked the evolution from the FAR to the TAR, and is likely to continue in the years to come.

1.6 The IPCC Assessments of Climate Change and Uncertainties

The WMO and the United Nations Environment Programme (UNEP) established the IPCC in 1988 with the assigned role of assessing the scientific, technical and socioeconomic information relevant for understanding the risk of human-induced climate change. The original 1988 mandate for the IPCC was extensive: '(a) Identification of uncertainties and gaps in our present knowledge with regard to climate changes and its potential impacts, and preparation of a plan of action over the short-term in filling these gaps; (b) Identification of information needed to evaluate policy implications of climate change and response strategies; (c) Review of current and planned national/international policies related to the greenhouse gas issue; (d) Scientific and environmental assessments of all aspects of the greenhouse gas issue and the transfer of these assessments and other relevant information to governments and intergovernmental organisations to be taken into account in their policies on social and economic development and environmental programs.' The IPCC is open to all members of UNEP and WMO. It does not directly support new research or monitor climate-related data. However, the IPCC process of synthesis and assessment has often inspired scientific research leading to new findings.

The IPCC has three Working Groups and a Task Force. Working Group I (WGI) assesses the scientific aspects of the climate system and climate change, while Working Groups II (WGII) and III (WGIII) assess the vulnerability and adaptation of socioeconomic and natural systems to climate change, and the mitigation options for limiting greenhouse gas emissions, respectively. The Task Force is responsible for the IPCC National Greenhouse Gas Inventories Programme. This brief history focuses on WGI and how it has described uncertainty in the quantities presented (See Box 1.1).

A main activity of the IPCC is to provide on a regular basis an assessment of the state of knowledge on climate change, and this volume is the fourth such Assessment Report of WGI. The IPCC also prepares Special Reports and Technical Papers on topics for which independent scientific information and advice is deemed necessary, and it supports the United Nations Framework Convention on Climate Change (UNFCCC) through its work on methodologies for National Greenhouse Gas Inventories. The FAR played an important role in the discussions of the Intergovernmental Negotiating Committee for the UNFCCC. The UNFCCC was adopted in 1992 and entered into force in 1994. It provides the overall policy framework and legal basis for addressing the climate change issue.

The WGI FAR was completed under the leadership of Bert Bolin (IPCC Chair) and John Houghton (WGI Chair) in a plenary at Windsor, UK in May 1990. In a mere 365 pages with eight colour plates, it made a persuasive, but not quantitative, case for anthropogenic interference with the climate system. Most conclusions from the FAR were non-quantitative and remain valid today (see also Section 1.4.4). For example, in terms of the greenhouse gases, 'emissions resulting from human activities are substantially increasing the atmospheric concentrations of the greenhouse gases: CO_2, CH_4, CFCs, N_2O' (see Chapters 2 and 3; Section 7.1). On the other hand, the FAR did not foresee the phase-out of CFCs, missed the importance of biomass-burning aerosols and dust to climate and stated that unequivocal detection of the enhanced greenhouse effect was more than a decade away. The latter two areas highlight the advance of climate science and in particular the merging of models and observations in the new field of detection and attribution (see Section 9.1).

The Policymakers Summary of the WGI FAR gave a broad overview of climate change science and its Executive Summary separated key findings into areas of varying levels of confidence ranging from 'certainty' to providing an expert 'judgment'. Much of the summary is not quantitative (e.g., the radiative forcing bar charts do not appear in the summary). Similarly, scientific uncertainty is hardly mentioned; when ranges are given, as in the projected temperature increases of 0.2°C to 0.5°C per decade, no probability or likelihood is assigned to explain the range (see Chapter 10). In discussion of the climate sensitivity to doubled atmospheric CO_2 concentration, the combined subjective and objective criteria are explained: the range of model results was 1.9°C to 5.2°C; most were close to 4.0°C; but the newer model results were lower; and hence the best estimate was 2.5°C with a range of 1.5°C to 4.5°C. The likelihood of the value being within this range was not defined. However, the importance of identifying those areas where climate scientists had high confidence was recognised in the Policymakers Summary.

The Supplementary Report (IPCC, 1992) re-evaluated the RF values of the FAR and included the new IPCC scenarios for future emissions, designated IS92a–f. It also included updated chapters on climate observations and modelling (see Chapters 3, 4, 5, 6 and 8). The treatment of scientific uncertainty remained as in the FAR. For example, the calculated increase in global mean surface temperature since the 19th century was given as 0.45°C ± 0.15°C, with no quantitative likelihood for this range (see Section 3.2).

The SAR, under Bert Bolin (IPCC Chair) and John Houghton and Gylvan Meira Filho (WGI Co-chairs), was planned with and coupled to a preliminary Special Report (IPCC, 1995) that contained intensive chapters on the carbon cycle, atmospheric chemistry, aerosols and radiative forcing. The WGI SAR culminated in the government plenary in Madrid in November 1995. The most cited finding from that plenary, on attribution of climate change, has been consistently reaffirmed by subsequent research: 'The balance of evidence suggests a discernible human influence on global climate' (see Chapter 9). The SAR provided key input to the negotiations that led to the adoption in 1997 of the Kyoto Protocol to the UNFCCC.

Uncertainty in the WGI SAR was defined in a number of ways. The carbon cycle budgets used symmetric plus/minus ranges explicitly defined as 90% confidence intervals, whereas the RF bar chart reported a 'mid-range' bar along with a plus/minus range that was estimated largely on the spread of published values. The likelihood, or confidence interval, of the spread of published results was not given. These uncertainties were additionally modified by a declaration that the confidence of the RF being within the specified range was indicated by a stated confidence level that ranged from 'high' (greenhouse gases) to 'very low' (aerosols). Due to the difficulty in approving such a long draft in plenary, the Summary for Policy Makers (SPM) became a short document with no figures and few numbers. The use of scientific uncertainty in the SPM was thus limited and similar to the FAR: a range in the mean surface temperature increase since 1900 was given as 0.3°C to 0.6°C with no explanation as to likelihood of this range. While the underlying report showed projected future warming for a range of different climate models, the Technical Summary focused on a central estimate.

The IPCC Special Report on Aviation and the Global Atmosphere (IPCC, 1999) was a major interim assessment involving both WGI and WGIII and the Scientific Assessment Panel to the Montreal Protocol on Substances that Deplete the Ozone Layer. It assessed the impacts of civil aviation in terms of climate change and global air quality as well as looking at the effect of technology options for the future fleet. It was the first complete assessment of an industrial sub-sector. The summary related aviation's role relative to all human influence on the climate system: 'The best estimate of the radiative forcing in 1992 by aircraft is 0.05 W m^{-2} or about 3.5% of the total radiative forcing by all anthropogenic activities.' The authors took a uniform approach to assigning and propagating uncertainty in these RF values based on mixed objective and subjective criteria. In addition to a best value, a two-thirds likelihood (67% confidence) interval is given. This interval is similar to a one-sigma (i.e., one standard deviation) normal error distribution, but it was explicitly noted that the probability distribution outside this interval was not evaluated and might not have a normal distribution. A bar chart with 'whiskers' (two-thirds likelihood range) showing the components and total (without cirrus effects) RF for aviation in 1992 appeared in the SPM (see Sections 2.6 and 10.2).

The TAR, under Robert Watson (IPCC Chair) and John Houghton and Ding YiHui (WGI Co-chairs), was approved at the government plenary in Shanghai in January 2001. The predominant summary statements from the TAR WGI strengthened the SAR's attribution statement: 'An increasing body of observations gives a collective picture of a warming world and other changes in the climate system', and 'There is new and stronger evidence that most of the warming observed over the last 50 years is attributable to human activities.' The TAR Synthesis Report (IPCC, 2001b) combined the assessment reports from the three Working Groups. By combining data on global (WGI) and regional (WGII) climate change, the Synthesis Report was able to strengthen the conclusion regarding human influence: 'The Earth's climate system has demonstrably changed on both global and regional scales since the pre-industrial era, with some of these changes attributable to human activities' (see Chapter 9).

Box 1.1: Treatment of Uncertainties in the Working Group I Assessment

The importance of consistent and transparent treatment of uncertainties is clearly recognised by the IPCC in preparing its assessments of climate change. The increasing attention given to formal treatments of uncertainty in previous assessments is addressed in Section 1.6. To promote consistency in the general treatment of uncertainty across all three Working Groups, authors of the Fourth Assessment Report have been asked to follow a brief set of guidance notes on determining and describing uncertainties in the context of an assessment .[1] This box summarises the way that Working Group I has applied those guidelines and covers some aspects of the treatment of uncertainty specific to material assessed here.

Uncertainties can be classified in several different ways according to their origin. Two primary types are 'value uncertainties' and 'structural uncertainties'. Value uncertainties arise from the incomplete determination of particular values or results, for example, when data are inaccurate or not fully representative of the phenomenon of interest. Structural uncertainties arise from an incomplete understanding of the processes that control particular values or results, for example, when the conceptual framework or model used for analysis does not include all the relevant processes or relationships. Value uncertainties are generally estimated using statistical techniques and expressed probabilistically. Structural uncertainties are generally described by giving the authors' collective judgment of their confidence in the correctness of a result. In both cases, estimating uncertainties is intrinsically about describing the limits to knowledge and for this reason involves expert judgment about the state of that knowledge. A different type of uncertainty arises in systems that are either chaotic or not fully deterministic in nature and this also limits our ability to project all aspects of climate change.

The scientific literature assessed here uses a variety of other generic ways of categorising uncertainties. Uncertainties associated with 'random errors' have the characteristic of decreasing as additional measurements are accumulated, whereas those associated with 'systematic errors' do not. In dealing with climate records, considerable attention has been given to the identification of systematic errors or unintended biases arising from data sampling issues and methods of analysing and combining data. Specialised statistical methods based on quantitative analysis have been developed for the detection and attribution of climate change and for producing probabilistic projections of future climate parameters. These are summarised in the relevant chapters.

The uncertainty guidance provided for the Fourth Assessment Report draws, for the first time, a careful distinction between levels of confidence in scientific understanding and the likelihoods of specific results. This allows authors to express high confidence that an event is extremely unlikely (e.g., rolling a dice twice and getting a six both times), as well as high confidence that an event is about as likely as not (e.g., a tossed coin coming up heads). Confidence and likelihood as used here are distinct concepts but are often linked in practice.

The standard terms used to define levels of confidence in this report are as given in the IPCC Uncertainty Guidance Note, namely:

Confidence Terminology	Degree of confidence in being correct
Very high confidence	At least 9 out of 10 chance
High confidence	About 8 out of 10 chance
Medium confidence	About 5 out of 10 chance
Low confidence	About 2 out of 10 chance
Very low confidence	Less than 1 out of 10 chance

Note that 'low confidence' and 'very low confidence' are only used for areas of major concern and where a risk-based perspective is justified.

Chapter 2 of this report uses a related term 'level of scientific understanding' when describing uncertainties in different contributions to radiative forcing. This terminology is used for consistency with the Third Assessment Report, and the basis on which the authors have determined particular levels of scientific understanding uses a combination of approaches consistent with the uncertainty guidance note as explained in detail in Section 2.9.2 and Table 2.11.

[1] See Supplementary Material for this report

The standard terms used in this report to define the likelihood of an outcome or result where this can be estimated probabilistically are:

Likelihood Terminology	**Likelihood of the occurrence/ outcome**
Virtually certain	> 99% probability
Extremely likely	> 95% probability
Very likely	> 90% probability
Likely	> 66% probability
More likely than not	> 50% probability
About as likely as not	33 to 66% probability
Unlikely	< 33% probability
Very unlikely	< 10% probability
Extremely unlikely	< 5% probability
Exceptionally unlikely	< 1% probability

The terms 'extremely likely', 'extremely unlikely' and 'more likely than not' as defined above have been added to those given in the IPCC Uncertainty Guidance Note in order to provide a more specific assessment of aspects including attribution and radiative forcing.

Unless noted otherwise, values given in this report are assessed best estimates and their uncertainty ranges are 90% confidence intervals (i.e., there is an estimated 5% likelihood of the value being below the lower end of the range or above the upper end of the range). Note that in some cases the nature of the constraints on a value, or other information available, may indicate an asymmetric distribution of the uncertainty range around a best estimate.

In an effort to promote consistency, a guidance paper on uncertainty (Moss and Schneider, 2000) was distributed to all Working Group authors during the drafting of the TAR. The WGI TAR made some effort at consistency, noting in the SPM that when ranges were given they generally denoted 95% confidence intervals, although the carbon budget uncertainties were specified as ±1 standard deviation (68% likelihood). The range of 1.5°C to 4.5°C for climate sensitivity to atmospheric CO_2 doubling was reiterated but with no confidence assigned; however, it was clear that the level of scientific understanding had increased since that same range was first given in the Charney et al. (1979) report. The RF bar chart noted that the RF components could not be summed (except for the long-lived greenhouse gases) and that the 'whiskers' on the RF bars each meant something different (e.g., some were the range of models, some were uncertainties). Another failure in dealing with uncertainty was the projection of 21st-century warming: it was reported as a range covering (i) six Special Report on Emission Scenarios (SRES) emissions scenarios and (ii) nine atmosphere-ocean climate models using two grey envelopes without estimates of likelihood levels. The full range (i.e., scenario plus climate model range) of 1.4°C to 5.8°C is a much-cited finding of the WGI TAR but the lack of discussion of associated likelihood in the report makes the interpretation and useful application of this result difficult.

1.7 Summary

As this chapter shows, the history of the centuries-long effort to document and understand climate change is often complex, marked by successes and failures, and has followed a very uneven pace. Testing scientific findings and openly discussing the test results have been the key to the remarkable progress that is now accelerating in all domains, in spite of inherent limitations to predictive capacity. Climate change science is now contributing to the foundation of a new interdisciplinary approach to understanding our environment. Consequently, much published research and many notable scientific advances have occurred since the TAR, including advances in the understanding and treatment of uncertainty. Key aspects of recent climate change research are assessed in Chapters 2 through 11 of this report.

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Chapter I

[EPA–HQ–OAR–2009–0171; FRL–9091–8]

RIN 2060–ZA14

Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Administrator finds that six greenhouse gases taken in combination endanger both the public health and the public welfare of current and future generations. The Administrator also finds that the combined emissions of these greenhouse gases from new motor vehicles and new motor vehicle engines contribute to the greenhouse gas air pollution that endangers public health and welfare under CAA section 202(a). These Findings are based on careful consideration of the full weight of scientific evidence and a thorough review of numerous public comments received on the Proposed Findings published April 24, 2009.

DATES: These Findings are effective on January 14, 2010.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2009–0171. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Jeremy Martinich, Climate Change Division, Office of Atmospheric Programs (MC–6207J), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; telephone number: (202) 343–9927; fax number: (202) 343–2202; e-mail address: *ghgendangerment@epa.gov*. For additional information regarding these Findings, please go to the Web site *http://www.epa.gov/climatechange/endangerment.html*.

SUPPLEMENTARY INFORMATION:

Judicial Review

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by February 16, 2010. Under CAA section 307(d)(7)(B), only an objection to this final action that was raised with reasonable specificity during the period for public comment can be raised during judicial review. This section also provides a mechanism for us to convene a proceeding for reconsideration, " '[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of this rule.' " Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20004.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

ACUS Administrative Conference of the United States
ANPR Advance Notice of Proposed Rulemaking
APA Administrative Procedure Act
CAA Clean Air Act
CAFE Corporate Average Fuel Economy
CAIT Climate Analysis Indicators Tool
CASAC Clean Air Scientific Advisory Committee
CBI Confidential Business Information
CCSP Climate Change Science Program
CFCs chlorofluorocarbons
CFR Code of Federal Regulations
CH_4 methane
CO_2 carbon dioxide
CO_2e CO_2-equivalent
CRU Climate Research Unit
DOT U.S. Department of Transportation
EO Executive Order
EPA U.S. Environmental Protection Agency
FR **Federal Register**
GHG greenhouse gas
GWP global warming potential
HadCRUT Hadley Centre/Climate Research Unit (CRU) temperature record
HCFCs hydrochlorofluorocarbons
HFCs hydrofluorocarbons
IA Interim Assessment report
IPCC Intergovernmental Panel on Climate Change
MPG miles per gallon
MWP Medieval Warm Period
N_2O nitrous oxide
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NASA National Aeronautics and Space Administration
NF_3 nitrogen trifluoride
NHTSA National Highway Traffic Safety Administration
NOAA National Oceanic and Atmospheric Administration
NOI Notice of Intent
NO_X nitrogen oxides
NRC National Research Council
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act of 1995
OMB Office of Management and Budget
PFCs perfluorocarbons
PM particulate matter
PSD Prevention of Significant Deterioration
RFA Regulatory Flexibility Act
SF_6 sulfur hexafluoride
SIP State Implementation Plan
TSD technical support document
U.S. United States
UMRA Unfunded Mandates Reform Act of 1995
UNFCCC United Nations Framework Convention on Climate Change
USGCRP U.S. Global Climate Research Program
VOC volatile organic compound(s)
WCI Western Climate Initiative
WRI World Resources Institute

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I. Introduction

A. Overview

Pursuant to CAA section 202(a), the Administrator finds that greenhouse gases in the atmosphere may reasonably be anticipated both to endanger public health and to endanger public welfare. Specifically, the Administrator is defining the ''air pollution'' referred to in CAA section 202(a) to be the mix of six long-lived and directly-emitted greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). In this document, these six greenhouse gases are referred to as ''well-mixed greenhouse gases'' in this document (with more precise meanings of ''long lived'' and ''well mixed'' provided in Section IV.A).

The Administrator has determined that the body of scientific evidence compellingly supports this finding. The major assessments by the U.S. Global Climate Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) serve as the primary scientific basis supporting the Administrator's endangerment finding.[1] The Administrator reached her determination by considering both observed and projected effects of greenhouse gases in the atmosphere, their effect on climate, and the public health and welfare risks and impacts associated with such climate change. The Administrator's assessment focused on public health and public welfare impacts within the United States. She also examined the evidence with respect to impacts in other world regions, and she concluded that these impacts strengthen the case for endangerment to public health and welfare because impacts in other world regions can in turn adversely affect the United States.

The Administrator recognizes that human-induced climate change has the potential to be far-reaching and multi-dimensional, and in light of existing knowledge, that not all risks and potential impacts can be quantified or characterized with uniform metrics. There is variety not only in the nature and potential magnitude of risks and impacts, but also in our ability to characterize, quantify and project such impacts into the future. The Administrator is using her judgment, based on existing science, to weigh the threat for each of the identifiable risks, to weigh the potential benefits where relevant, and ultimately to assess whether these risks and effects, when viewed in total, endanger public health or welfare.

The Administrator has considered how elevated concentrations of the well-mixed greenhouse gases and associated climate change affect public health by evaluating the risks associated with changes in air quality, increases in temperatures, changes in extreme weather events, increases in food- and water-borne pathogens, and changes in aeroallergens. The evidence concerning adverse air quality impacts provides strong and clear support for an endangerment finding. Increases in ambient ozone are expected to occur over broad areas of the country, and they are expected to increase serious adverse health effects in large population areas that are and may continue to be in nonattainment. The evaluation of the potential risks associated with increases in ozone in attainment areas also supports such a finding.

The impact on mortality and morbidity associated with increases in average temperatures, which increase the likelihood of heat waves, also provides support for a public health endangerment finding. There are uncertainties over the net health impacts of a temperature increase due to decreases in cold-related mortality, but some recent evidence suggests that the net impact on mortality is more likely to be adverse, in a context where heat is already the leading cause of weather-related deaths in the United States.

The evidence concerning how human-induced climate change may alter extreme weather events also clearly supports a finding of endangerment, given the serious adverse impacts that can result from such events and the increase in risk, even if small, of the occurrence and intensity of events such as hurricanes and floods. Additionally, public health is expected to be

[1] Section III of these Findings discusses the science on which these Findings are based. In addition, the Technical Support Document (TSD) accompanying these Findings summarizes the major assessments from the USGCRP, IPCC, and NRC.

adversely affected by an increase in the severity of coastal storm events due to rising sea levels.

There is some evidence that elevated carbon dioxide concentrations and climate changes can lead to changes in aeroallergens that could increase the potential for allergenic illnesses. The evidence on pathogen borne disease vectors provides directional support for an endangerment finding. The Administrator acknowledges the many uncertainties in these areas. Although these adverse effects provide some support for an endangerment finding, the Administrator is not placing primary weight on these factors.

Finally, the Administrator places weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to these climate-related health effects.

The Administrator has considered how elevated concentrations of the well-mixed greenhouse gases and associated climate change affect public welfare by evaluating numerous and far-ranging risks to food production and agriculture, forestry, water resources, sea level rise and coastal areas, energy, infrastructure, and settlements, and ecosystems and wildlife. For each of these sectors, the evidence provides support for a finding of endangerment to public welfare. The evidence concerning adverse impacts in the areas of water resources and sea level rise and coastal areas provides the clearest and strongest support for an endangerment finding, both for current and future generations. Strong support is also found in the evidence concerning infrastructure and settlements, as well ecosystems and wildlife. Across the sectors, the potential serious adverse impacts of extreme events, such as wildfires, flooding, drought, and extreme weather conditions, provide strong support for such a finding.

Water resources across large areas of the country are at serious risk from climate change, with effects on water supplies, water quality, and adverse effects from extreme events such as floods and droughts. Even areas of the country where an increase in water flow is projected could face water resource problems from the supply and water quality problems associated with temperature increases and precipitation variability, as well as the increased risk of serious adverse effects from extreme events, such as floods and drought. The severity of risks and impacts is likely to increase over time with accumulating greenhouse gas concentrations and associated temperature increases and precipitation changes.

Overall, the evidence on risk of adverse impacts for coastal areas provides clear support for a finding that greenhouse gas air pollution endangers the welfare of current and future generations. The most serious potential adverse effects are the increased risk of storm surge and flooding in coastal areas from sea level rise and more intense storms. Observed sea level rise is already increasing the risk of storm surge and flooding in some coastal areas. The conclusion in the assessment literature that there is the potential for hurricanes to become more intense (and even some evidence that Atlantic hurricanes have already become more intense) reinforces the judgment that coastal communities are now endangered by human-induced climate change, and may face substantially greater risk in the future. Even if there is a low probability of raising the destructive power of hurricanes, this threat is enough to support a finding that coastal communities are endangered by greenhouse gas air pollution. In addition, coastal areas face other adverse impacts from sea level rise such as land loss due to inundation, erosion, wetland submergence, and habitat loss. The increased risk associated with these adverse impacts also endangers public welfare, with an increasing risk of greater adverse impacts in the future.

Strong support for an endangerment finding is also found in the evidence concerning energy, infrastructure, and settlements, as well ecosystems and wildlife. While the impacts on net energy demand may be viewed as generally neutral for purposes of making an endangerment determination, climate change is expected to result in an increase in electricity production, especially supply for peak demand. This may be exacerbated by the potential for adverse impacts from climate change on hydropower resources as well as the potential risk of serious adverse effects on energy infrastructure from extreme events. Changes in extreme weather events threaten energy, transportation, and water resource infrastructure. Vulnerabilities of industry, infrastructure, and settlements to climate change are generally greater in high-risk locations, particularly coastal and riverine areas, and areas whose economies are closely linked with climate-sensitive resources. Climate change will likely interact with and possibly exacerbate ongoing environmental change and environmental pressures in settlements, particularly in Alaska where indigenous communities are facing major environmental and cultural impacts on their historic lifestyles. Over the 21st century, changes in climate will cause some species to shift north and to higher elevations and fundamentally rearrange U.S. ecosystems. Differential capacities for range shifts and constraints from development, habitat fragmentation, invasive species, and broken ecological connections will likely alter ecosystem structure, function, and services, leading to predominantly negative consequences for biodiversity and the provision of ecosystem goods and services.

There is a potential for a net benefit in the near term [2] for certain crops, but there is significant uncertainty about whether this benefit will be achieved given the various potential adverse impacts of climate change on crop yield, such as the increasing risk of extreme weather events. Other aspects of this sector may be adversely affected by climate change, including livestock management and irrigation requirements, and there is a risk of adverse effect on a large segment of the total crop market. For the near term, the concern over the potential for adverse effects in certain parts of the agriculture sector appears generally comparable to the potential for benefits for certain crops. However, The body of evidence points towards increasing risk of net adverse impacts on U.S. food production and agriculture over time, with the potential for significant disruptions and crop failure in the future.

For the near term, the Administrator finds the beneficial impact on forest growth and productivity in certain parts of the country from elevated carbon dioxide concentrations and temperature increases to date is offset by the clear risk from the observed increases in wildfires, combined with risks from the spread of destructive pests and disease. For the longer term, the risk from adverse effects increases over time, such that overall climate change presents serious adverse risks for forest productivity. There is compelling reason to find that the support for a positive endangerment finding increases as one considers expected future conditions where temperatures continue to rise.

Looking across all of the sectors discussed above, the evidence provides compelling support for finding that greenhouse gas air pollution endangers the public welfare of both current and

[2] The temporal scope of impacts is discussed in more detail in Section III.C. The phrase ''near term'' as used in this document generally refers to the current time period from and the next few decades. The phrase ''long term'' generally refers to a time frame extending beyond that to approximately the middle to the end of this century.

future generations. The risk and the severity of adverse impacts on public welfare are expected to increase over time.

The Administrator also finds that emissions of well-mixed greenhouse gases from the transportation sources covered under CAA section 202(a) [3] contribute to the total greenhouse gas air pollution, and thus to the climate change problem, which is reasonably anticipated to endanger public health and welfare. The Administrator is defining the air pollutant that contributes to climate change as the aggregate group of the well-mixed greenhouse gases. The definition of air pollutant used by the Administrator is based on the similar attributes of these substances. These attributes include the fact that they are sufficiently long-lived to be well mixed globally in the atmosphere, that they are directly emitted, and that they exert a climate warming effect by trapping outgoing, infrared heat that would otherwise escape to space, and that they are the focus of climate change science and policy.

In order to determine if emissions of the well-mixed greenhouse gases from CAA section 202(a) source categories contribute to the air pollution that endangers public health and welfare, the Administrator compared the emissions from these CAA section 202(a) source categories to total global and total U.S. greenhouse gas emissions, finding that these source categories are responsible for about 4 percent of total global well-mixed greenhouse gas emissions and just over 23 percent of total U.S. well-mixed greenhouse gas emissions. The Administrator found that these comparisons, independently and together, clearly establish that these emissions contribute to greenhouse gas concentrations. For example, the emissions of well-mixed greenhouse gases from CAA section 202(a) sources are larger in magnitude than the total well-mixed greenhouse gas emissions from every other individual nation with the exception of China, Russia, and India, and are the second largest emitter within the United States behind the electricity generating sector. As the Supreme Court noted, ''[j]udged by any standard, U.S. motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming.'' *Massachusetts* v. *EPA,* 549 U.S. 497, 525 (2007).

[3] Section 202(a) source categories include passenger cars, heavy-, medium and light-duty trucks, motorcycles, and buses.

The Administrator's findings are in response to the Supreme Court's decision in *Massachusetts* v. *EPA.* That case involved a 1999 petition submitted by the International Center for Technology Assessment and 18 other environmental and renewable energy industry organizations requesting that EPA issue standards under CAA section 202(a) for the emissions of carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons from new motor vehicles and engines. The Administrator's findings are in response to this petition and are for purposes of CAA section 202(a).

B. Background Information Helpful To Understand These Findings

This section provides some basic information regarding greenhouse gases and the CAA section 202(a) source categories, as well as the ongoing joint-rulemaking on greenhouse gases by EPA and the Department of Transportation. Additional technical and legal background, including a summary of the Supreme Court's *Massachusetts* v. *EPA* decision, can be found in the Proposed Endangerment and Contribution Findings (74 FR 18886, April 24, 2009).

1. Greenhouse Gases and Transportation Sources Under CAA Section 202(a)

Greenhouse gases are naturally present in the atmosphere and are also emitted by human activities. Greenhouse gases trap the Earth's heat that would otherwise escape from the atmosphere, and thus form the greenhouse effect that helps keep the Earth warm enough for life. Human activities are intensifying the naturally-occurring greenhouse effect by adding greenhouse gases to the atmosphere. The primary greenhouse gases of concern that are directly emitted by human activities include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. Other pollutants (such as aerosols) and other human activities, such as land use changes that alter the reflectivity of the Earth's surface, also cause climatic warming and cooling effects. In these Findings, the term ''climate change'' generally refers to the global warming effect plus other associated changes (*e.g.,* precipitation effects, sea level rise, changes in the frequency and severity of extreme weather events) being induced by human activities, including activities that emit greenhouse gases. Natural causes also, contribute to climate change and climatic changes have occurred throughout the Earth's history. The concern now, however, is that the changes taking place in our atmosphere as a result of the well-documented buildup of greenhouse gases due to human activities are changing the climate at a pace and in a way that threatens human health, society, and the natural environment. Further detail on the state of climate change science can be found in Section III of these Findings as well as the technical support document (TSD) that accompanies this action (*www.epa.gov/climatechange/endangerment.html*).

The transportation sector is a major source of greenhouse gas emissions both in the United States and in the rest of the world. The transportation sources covered under CAA section 202(a)—the section of the CAA under which these Findings occur—include passenger cars, light- and heavy-duty trucks, buses, and motorcycles. These transportation sources emit four key greenhouse gases: carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons. Together, these transportation sources are responsible for 23 percent of total annual U.S. greenhouse gas emissions, making this source the second largest in the United States behind electricity generation.[4]

Further discussion of the emissions data supporting the Administrator's cause or contribute finding can be found in Section V of these Findings, and the detailed greenhouse gas emissions data for section 202(a) source categories can be found in Appendix B of EPA's TSD.

2. Joint EPA and Department of Transportation Proposed Greenhouse Gas Rule

On September 15, 2009, EPA and the Department of Transportation's National Highway Safety Administration (NHTSA) proposed a National Program that would dramatically reduce greenhouse gas emissions and improve fuel economy for new cars and trucks sold in the United States. The combined EPA and NHTSA standards that make up this proposed National Program would apply to passenger cars, light-duty trucks, and medium-duty passenger vehicles, covering model years 2012 through 2016. They proposed to require these vehicles to meet an estimated combined average

[4] The units for greenhouse gas emissions in these findings are provided in carbon dioxide equivalent units, where carbon dioxide is the reference gas and every other greenhouse gas is converted to its carbon dioxide equivalent by using the 100-year global warming potential (as estimated by the Intergovernmental Panel on Climate Change (IPCC). assigned to each gas. The reference gas used is CO_2, and therefore Global Warming Potential (GWP)-weighted emissions are measured in teragrams of CO_2 equivalent (Tg CO_2 eq.). In accordance with UNFCCC reporting procedures, the United States quantifies greenhouse gas emissions using the 100-year time frame values for GWPs established in the IPCC Second Assessment Report.

emissions level of 250 grams of carbon dioxide per mile, equivalent to 35.5 miles per gallon (MPG) if the automobile industry were to meet this carbon dioxide level solely through fuel economy improvements. Together, these proposed standards would cut carbon dioxide emissions by an estimated 950 million metric tons and 1.8 billion barrels of oil over the lifetime of the vehicles sold under the program (model years 2012–2016). The proposed rulemaking can be viewed at (74 FR 49454, September 28, 2009).

C. Public Involvement

In response to the Supreme Court's decision, EPA has been examining the scientific and technical basis for the endangerment and cause or contribute decisions under CAA section 202(a) since 2007. The science informing the decision-making process has grown stronger since our work began. EPA's approach to evaluating the science, including comments submitted during the public comment period, is further discussed in Section III.A of these Findings. Public review and comment has always been a major component of EPA's process.

1. EPA's Initial Work on Endangerment

As part of the *Advance Notice of Proposed Rulemaking: Regulating Greenhouse Gas Emissions under the Clean Air Act* (73 FR 44353) published in July 2008, EPA provided a thorough discussion of the issues and options pertaining to endangerment and cause or contribute findings under the CAA. The Agency also issued a TSD providing an overview of all the major scientific assessments available at the time and emission inventory data relevant to the contribution finding (Docket ID No. EPA–HQ–OAR–2008–0318). The comment period for that *Advance Notice* was 120 days, and it provided an opportunity for EPA to hear from the public with regard to the issues involved in endangerment and cause or contribute findings as well as the supporting science. EPA received, reviewed and considered numerous comments at that time and this public input was reflected in the Findings that the Administrator proposed in April 2009. In addition, many comments were received on the TSD released with the *Advance Notice* and reflected in revisions to the TSD released in April 2009 to accompany the Administrator's proposal. All public comments on the *Advance Notice* are contained in the public docket for this action (Docket ID No. EPA–HQ–OAR–2008–0318) accessible through *www.regulations.gov.*

2. Public Involvement Since the April 2009 Proposed Endangerment Finding

The Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases (Proposed Findings) was published on April 24, 2009 (74 FR 18886). The Administrator's proposal was subject to a 60-day public comment period, which ended June 23, 2009, and also included two public hearings. Over 380,000 public comments were received on the Administrator's proposed endangerment and cause or contribute findings, including comments on the elements of the Administrator's April 2009 proposal, the legal issues pertaining to the Administrator's decisions, and the underlying TSD containing the scientific and technical information.

A majority of the comments (approximately 370,000) were the result of mass mail campaigns, which are defined as groups of comments that are identical or very similar in form and content. Overall, about two-thirds of the mass-mail comments received are supportive of the Findings and generally encouraged the Administrator both to make a positive endangerment determination and implement greenhouse gas emission regulations. Of the mass mail campaigns in disagreement with the Proposed Findings most either oppose the proposal on economic grounds (*e.g.,* due to concern for regulatory measures following an endangerment finding) or take issue with the proposed finding that atmospheric greenhouse gas concentrations endanger public health and welfare. Please note that for mass mailer campaigns, a representative copy of the comment is posted in the public docket for this Action (Docket ID No. EPA–HQ–OAR–2009–0171) at *www.regulations.gov.*

Approximately 11,000 other public comments were received. These comments raised a variety of issues related to the scientific and technical information EPA relied upon in making the Proposed Findings, legal and procedural issues, the content of the Proposed Findings, and the implications of the Proposed Findings.

In light of the very large number of comments received and the significant overlap between many comments, EPA has not responded to each comment individually. Rather, EPA has summarized and provided responses to each significant argument, assertion and question contained within the totality of the comments. EPA's responses to some of the most significant comments are provided in these Findings. Responses to all significant issues raised by the comments are contained in the 11 volumes of the Response to Comments document, organized by subject area (found in docket EPA–HQ–OAR–2009–0171).

3. Issues Raised Regarding the Rulemaking Process

EPA received numerous comments on process-related issues, including comments urging the Administrator to delay issuing the final findings, arguing that it was improper for the Administrator to sever the endangerment and cause or contribute findings from the attendant section 202(a) standards, arguing the final decision was preordained by the President's May vehicle announcement, and questioning the adequacy of the comment period. Summaries of key comments and EPA's responses are discussed in this section. Additional and more detailed responses can be found in the Response to Comments document, Volume 11. As noted in the Response to Comments document, EPA also received comments supporting the overall process.

a. It Is Reasonable for the Administrator To Issue the Endangerment and Cause or Contribute Findings Now

Though the Supreme Court did not establish a specific deadline for EPA to act, more than two and a half years have passed since the remand from the Supreme Court, and it has been 10 years since EPA received the original petition requesting that EPA regulate greenhouse gas emissions from new motor vehicles. EPA has a responsibility to respond to the Supreme Court's decision and to fulfill its obligations under current law, and there is good reason to act now given the urgency of the threat of climate change and the compelling scientific evidence.

Many commenters urge EPA to delay making final findings for a variety of reasons. They note that the Supreme Court did not establish a deadline for EPA to act on remand. Commenters also argue that the Supreme Court's decision does not require that EPA make a final endangerment finding, and thus that EPA has discretionary power and may decline to issue an endangerment finding, not only if the science is too uncertain, but also if EPA can provide "some reasonable explanation" for exercising its discretion. These commenters interpret the Supreme Court decision not as rejecting all policy reasons for declining to undertake an endangerment finding, but rather as dismissing solely the policy reasons EPA set forth in 2003. Some commenters cite language in the

Supreme Court decision regarding EPA's discretion regarding ''the manner, timing, content, and coordination of its regulations,'' and the Court's declining to rule on ''whether policy concerns can inform EPA's actions in the event that it makes'' a CAA section 202(a) finding to support their position.

Commenters then suggest a variety of policy reasons that EPA can and should make to support a decision not to undertake a finding of endangerment under CAA section 202(a)(1). For example, they argue that a finding of endangerment would trigger several other regulatory programs—such as the Prevention of Significant Deterioration (PSD) provisions—that would impose an unreasonable burden on the economy and government, without providing a benefit to the environment. Some commenters contend that EPA should defer issuing a final endangerment finding while Congress considers legislation. Many commenters note the ongoing international discussions regarding climate change and state their belief that unilateral EPA action would interfere with those negotiations. Others suggest deferring the EPA portion of the joint U.S. Department of Transportation (DOT)/EPA rulemaking because they argue that the new Corporate Average Fuel Economy (CAFE) standards will effectively result in lower greenhouse gas emissions from new motor vehicles, while avoiding the inevitable problems and concerns of regulating greenhouse gases under the CAA.

Other commenters argue that the endangerment determination has to be made on the basis of scientific considerations only. These commenters state that the Court was clear that ''[t]he statutory question is whether sufficient information exists to make an endangerment finding,'' and thus, only if ''the scientific uncertainty is so profound that it precludes EPA from making a reasoned judgment as to whether greenhouse gases contribute to global warming,'' may EPA avoid making a positive or negative endangerment finding. Many commenters urge EPA to take action quickly. They note that it has been 10 years since the original petition requesting that EPA regulate greenhouse gas emissions from motor vehicles was submitted to EPA. They argue that climate change is a serious problem that requires immediate action.

EPA agrees with the commenters who argue that the Supreme Court decision held that EPA is limited to consideration of science when undertaking an endangerment finding, and that we cannot delay issuing a finding due to policy concerns if the science is sufficiently certain (as it is here). The Supreme Court stated that ''EPA can avoid taking further action only if it determines that greenhouse gases do not contribute to climate change or if it provides some reasonable explanation as to why it cannot or will not exercise its discretion to determine whether they do'' 549 U.S. at 533. Some commenters point to this last provision, arguing that the policy reasons they provide are a ''reasonable explanation'' for not moving forward at this time. However, this ignores other language in the decision that clearly indicates that the Court interprets the statute to allow for the consideration only of science. For example, in rejecting the policy concerns expressed by EPA in its 2003 denial of the rulemaking petition, the Court noted that ''it is evident [the policy considerations] have nothing to do with whether greenhouse gas emissions contribute to climate change. Still less do they amount to a reasoned justification for declining to form *a scientific judgment'' Id.* at 533–34 (emphasis added).

Moreover, the Court also held that ''[t]he statutory question is whether sufficient information exists to make an endangerment finding'' *Id.* at 534. Taken as a whole, the Supreme Court's decision clearly indicates that policy reasons do not justify the Administrator avoiding taking further action on the question here.

We also note that the language many commenters quoted from the Supreme Court decision about EPA's discretion regarding the manner, timing and content of Agency actions, and the ability to consider policy concerns, relate to the motor vehicle standards required in the event that EPA makes a positive endangerment finding, and not the finding itself. EPA has long taken the position that it does have such discretion in the standard-setting step under CAA section 202(a).

b. The Administrator Reasonably Proceeded With the Endangerment and Cause or Contribute Findings Separate From the CAA Section 202(a) Standard Rulemaking

As discussed in the Proposed Findings, typically endangerment and cause or contribute findings have been proposed concurrently with proposed standards under various sections of the CAA, including CAA section 202(a). EPA received numerous comments on its decision to propose the endangerment and cause or contribute findings separate from any standards under CAA section 202(a).

Commenters argue that EPA has no authority to issue an endangerment determination under CAA section 202(a) separate and apart from the rulemaking to establish emissions standards under CAA section 202(a). According to these commenters, CAA section 202(a) provides only one reason to issue an endangerment determination, and that is as the basis for promulgating emissions standards for new motor vehicles; thus, it does not authorize such a stand-alone endangerment finding, and EPA may not create its own procedural rules completely divorced from the statutory text. They continue by stating that while CAA section 202(a) says EPA may issue emissions standards conditioned on such a finding, it does not say EPA may first issue an endangerment determination and then issue emissions standards. In addition, they contend, the endangerment proposal and the emissions standards proposal need to be issued together so commenters can fully understand the implications of the endangerment determination. Failure to do so, they argue, deprives the commenters of the opportunity to assess the regulations that will presumably follow from an endangerment finding. They also argue that the expected overlap between reductions in emissions of greenhouse gases from CAA section 202(a) standards issued by EPA and CAFE standards issued by DOT calls into question the basis for the CAA section 202(a) standards and the related endangerment finding, and that EPA is improperly motivated by an attempt to trigger a cascade of regulations under the CAA and/or to promote legislation by Congress.

EPA disagrees with the commenters' claims and arguments. The text of CAA section 202(a) is silent on this issue. It does not specify the timing of an endangerment finding, other than to be clear that emissions standards may not be issued unless such a determination has been made. EPA is exercising the procedural discretion that is provided by CAA section 202(a)'s lack of specific direction. The text of CAA section 202(a) envisions two separate actions by the Administrator: (1) A determination on whether emissions from classes or categories of new motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger, and (2) a separate decision on issuance of appropriate emissions standards for such classes or categories. The procedure followed in this rulemaking, and the companion rulemaking involving emissions standards for light duty motor vehicles, is consistent with CAA section 202(a). EPA will issue final emissions standards for new motor vehicles only if affirmative findings are made concerning contribution and endangerment, and such emissions standards will not be finalized prior to making any such determinations. While it would also be consistent with CAA section 202(a) to issue the greenhouse gas endangerment and contribution findings and emissions standards for new light-duty vehicles in the same rulemaking, *e.g.,* a single proposal covering them and a single final rule covering them, nothing in CAA section 202(a) requires such a procedural approach, and nothing in the approach taken in this case violates the text of CAA section 202(a). Since Congress was silent on this issue, and more than one procedural approach may accomplish the requirements of CAA section 202(a), EPA has the discretion to use the approach considered appropriate in this case. Once the final affirmative contribution and endangerment findings are made, EPA has the authority to issue the final emissions standards for new light-duty motor vehicles; however, as the Supreme Court has noted, the agency has 'significant latitude as to the manner, timing, [and] content * * * of its regulations . * * *' *Massachusetts v. EPA,* 549 U.S. at 533. That includes the discretion to issue them in a separate rulemaking.

Commenters' argument would also lead to the conclusion that EPA could not make an endangerment finding for the entire category of new motor vehicles, as it is doing here, unless EPA also conducted a rulemaking that set emissions standards for all the classes and categories of new motor vehicles at the same time. This narrow procedural limitation would improperly remove discretion that CAA section 202(a) provides to EPA.

EPA has the discretion under CAA section 202(a) to consider classes or categories of new motor vehicles separately or together in making a contribution and endangerment determination. This discretion would be removed under commenters' interpretation, by limiting this to only those cases in which EPA was also ready to issue emissions standards for all of the classes or categories covered by the endangerment finding. However, nothing in the text of CAA section 202(a) places such a limit on EPA's discretion in determining how to group classes or categories of new motor vehicles for purposes of the contribution and endangerment findings. This limitation would not be appropriate, because the issues of contribution and endangerment are separate and distinct from the issues of setting emissions standards. EPA, in this case, is fully prepared to go forward with the contribution and endangerment determination, while it is not ready to proceed with rulemaking for each and every category of new motor vehicles in the first rulemaking to set emissions standards. Section 202(a) of the CAA provides EPA discretion with regard to when and how it conducts its rulemakings to make contribution and endangerment findings, and to set emissions standards, and the text of CAA section 202(a) does not support commenters attempt to limit such discretion.

Concerns have been raised that the failure to issue the proposed endangerment finding and the proposed emissions standard together preclude commenters from assessing and considering the implications of the endangerment finding and the regulations that would likely flow from such a finding. However, commenters have failed to explain how this interferes in any way with their ability to comment on the endangerment finding. In fact it does not interfere, because the two proposals address separate and distinct issues. The endangerment finding concerns the contribution of new motor vehicles to air pollution and the effect of that air pollution on public health or welfare. The emissions standards, which have been proposed (74 FR 49454, September 28, 2009), concern the appropriate regulatory emissions standards if affirmative findings are made on contribution and endangerment. These two proposals address different issues. While commenters have the opportunity to comment on the proposed emissions standards in that rulemaking, they have not shown, and cannot show, that they need to have the emissions standards proposal before them in order to provide relevant comments on the proposed contribution or endangerment findings. Further discussion of this issue can be found in Section II of these Findings, and discussion of the timing of this action and its relationship to other CAA provisions and Congressional action can be found in Section III of these Findings and Volume 11 of the Response to Comments document.

c. The Administrator's Final Decision Was Not Preordained by the President's May Vehicle Announcement

EPA received numerous comments arguing that the President's announcement of a new ''National Fuel Efficiency Policy'' on May 19, 2009 seriously undermines EPA's ability to provide objective consideration of and a legally adequate response to comments objecting to the previously proposed endangerment findings.

Commenters' conclusion is based on the view that the President's announced policy requires EPA to promulgate greenhouse gas emissions standards under CAA section 202(a), that the President's and Administrator Jackson's announcement indicated that the endangerment rulemaking was but a formality and that a final endangerment finding was a fait accompli. Commenters argue that this means the result of this rulemaking has been preordained and the merits of the issues have been prejudged.

EPA disagrees. Commenters' arguments wholly exaggerate and mischaracterize the circumstances. In the April 24, 2009 endangerment proposal EPA was clear that the two steps in the endangerment provision have to be satisfied in order for EPA to issue emissions standards for new motor vehicles under CAA section 202(a) (74 FR at 18888, April 24, 2009). This was repeated when EPA issued the Notice of Upcoming Joint Rulemaking to Establish Vehicle GHG Emissions and CAFE Standards (74 FR 24007 May 22, 2009) (Notice of Intent or NOI). This was repeated again when EPA issued proposed greenhouse gas emissions standards for certain new motor vehicles (74 FR 49454, September 28, 2009). EPA has consistently made it clear that issuance of new motor vehicle standards requires and is contingent upon satisfaction of the two-part endangerment test.

On May 19, 2009 EPA issued the joint Notice of Intent, which indicated EPA's intention to propose new motor vehicle standards. All of the major motor vehicle manufacturers, their trade associations, the State of California, and several environmental organizations announced their full support for the upcoming rulemaking. Not surprisingly, on the same day the President also announced his full support for this action. Commenters, however, erroneously equate this Presidential support with a Presidential directive that requires EPA to prejudge and preordain the result of this rulemaking.

The only evidence they point to are simply indications of Presidential support. Commenters point to a press release, which unsurprisingly refers to the Agency's announcement as delivering on the President's commitment to enact more stringent fuel economy standards, by bringing ''all stakeholders to the table and [coming] up with a plan'' for solving a serious problem. The plan that was announced, of course, was a plan to conduct notice and comment rulemaking. The press release itself states that President Obama ''set in motion a new national policy,'' with the policy ''aimed'' at reducing greenhouse gas emissions for new cars and trucks. What was ''set in motion'' was a notice and comment rulemaking described in the NOI issued by EPA on the same day. Neither the President nor EPA announced a final rule or a final direction that day, but instead did no more than announce a plan to go forward with a notice and comment rulemaking. That is how the plan ''delivers on the President's commitment'' to enact more stringent standards. The announcement was that a notice and comment rulemaking would be initiated with the aim of adopting certain emissions standards.

That is no different from what EPA or any other agency states when it issues a notice of proposed rulemaking. It starts a process that has the aim of issuing final regulations if they are deemed appropriate at the end of the public process. The fact that an Agency proposes a certain result, and expects that a final rule will be the result of setting such a process in motion, is the ordinary course of affairs in notice and comment rulemakings. This does not translate into prejudging the final result or having a preordained result that de facto negates the public comment process. The President's press release of May 19, 2009 was a recognition that this notice and comment rulemaking process would be set in motion, as well as providing his full support for the Agency to go forward in this direction; it was no more than that.

The various stakeholders who announced their support for the plan that had been set in motion all recognized that full notice and comment rulemaking was part of the plan, and they all reserved their rights to participate in such notice and comment rulemaking. For example, see the letter of support from Ford Motor Company, which states that ''Ford fully supports proposal and adoption of such a National Program, which we understand will be subject to full notice-and-comment rulemaking, affording all interested parties including Ford the right to participate fully, comment, and submit information, the results of which are not pre-determined but depend upon processes set by law.''

d. The Notice and Comment Period Was Adequate

Many commenters argue that the 60-day comment period was inadequate. Commenters claim that a 60-day period was insufficient time to fully evaluate the science and other information that informed the Administrator's proposal. Some commenters assert that because the comment period for the Proposed Finding substantially overlapped with the comment period for the Mandatory Greenhouse Gas Reporting Rule, as well as Congress' consideration of climate legislation, their ability to fully participate in the notice and comment period was ''seriously compromised.'' Moreover, they continue, because EPA had not yet proposed CAA section 202(a) standards, there was no valid reason to fail to extend the comment period. Several commenters and other entities had also requested that EPA extend the comment period.

Some commenters assert that the notice provided by this rulemaking was ''defective'' because the **Federal Register** notice announcing the proposal had an error in the e-mail address for the docket. At least one commenter suggests that this error deprives potential commenters of their Due Process under the Fifth Amendment of the Constitution, citing *Armstrong* v. *Manzo,* 380 U.S. 545, 552 (1965), and that failure to ''correct'' the minor typographical error in the e-mail address and extend the comment period would make the rule ''subject to reversal'' in violation of the CAA, Administrative Procedure Act (APA), the Due Process clause of the Constitution, and EO 12866.

Finally, for many of the same reasons that commenters argue a 60-day comment period was inadequate, several commenters request that EPA reopen and/or extend the comment period. One commenter requests that the comment period be reopened because there was new information regarding data used by EPA in the Proposed Findings. In particular, the commenter alleges that it recently became aware that one of the sources of global climate data had destroyed the raw data for its data set of global surface temperatures. The commenter argues that this alleged destruction of raw data violates scientific standards, calls into question EPA's reliance on that data in these Findings, and necessitates a reopening of the proceedings. Other commenters request that the comment period be extended and/or reopened due to the release of a Federal government document on the impact of climate change in the United States near the end of the comment period, as well as the release of an internal EPA staff document discussing the science.

The official public comment period on the proposed rule was adequate. First, a 60-day comment period satisfies the procedural requirements of CAA section 307 of the CAA, which requires a 30-day comment period, and that the docket be kept open to receive rebuttal or supplemental information as follow-up to any hearings for 30 days following the hearings. EPA met those obligations here—the comment period opened on April 24, 2009, the last hearing was on May 21, 2009 and the comment period closed June 23, 2009.

Second, as explained in letters denying requests to extend the comment period, a very large part of the information and analyses for the Proposed Findings had been previously released in July 30, 2008, as part of the *Advance Notice of Proposed Rulemaking: Regulating Greenhouse Gas Emissions under the Clean Air Act (ANPR)* (73 FR 44353). The public comment period for the ANPR is discussed above in Section I.C.1 of these Findings. The Administrator explained that the comment period for that ANPR was 120 days and that the major recent scientific assessments that EPA relied upon in the TSD released with the ANPR had previously each gone through their own public review processes and have been publicly available for some time. In other words, EPA has provided ample time for review, particularly with regard to the technical support for the Findings. See, for example, EPA Letter to Congressman Issa dated June 17, 2009, a copy of which is available at *http://epa.gov/climatechange/endangerment.html*.

Moreover, the comment period was not rendered insufficient merely because other climate-related proceedings were occurring simultaneously.

While one commenter suggests that the convergence of several different climate-related activities has ''seriously compromised'' their ability to participate in the comment process, that commenter was able to submit an 89 page comment on this proposal alone. Moreover, it is hardly rare that more than one rule is out for comment at the same time. As noted above, EPA has received a substantial number of significant comments on the Proposed Findings, and has thoroughly considered and responded to significant comments.

EPA finds no evidence that a typographical error in the docket e-mail address of the **Federal Register** notice announcing the proposal prevented the public from having a meaningful opportunity to comment, and therefore deprived them of due process. Although the minor error—which involved a word processing auto-correction that turned a short dash into a long dash—appeared in the FR version of the Proposed Findings, the e-mail address is correct in the signature version of the Proposed Findings posted on EPA's Web site until publication in the **Federal Register,** and in the ''Instructions for Submitting Written Comments'' document on the Web site for the rulemaking. EPA has received over 190,000 e-mails to the docket e-mail address to date, so the minor typographical error appearing in only one location has not been an impediment to interested parties' e-mailing comments. Moreover, EPA provided many other avenues for interested parties to submit comments in addition to the docket e-mail address, including via *www.regulations.gov,* mail, and fax; each of these options have been utilized by many commenters. EPA is confident that the minor typographical error did not prevent anyone from submitting written comments, by e-mail or otherwise, and that the public was provided ''meaningful participation in the regulatory process'' as mentioned in EO 12866.

Our response regarding the request to reopen the comment period due to concerns about alleged destruction of raw global surface data is discussed more fully in the Response to Comments document, Volume 11. The commenter did not provide any compelling reason to conclude that the absence of these data would materially affect the trends in the temperature records or conclusions drawn about them in the assessment literature and reflected in the TSD. The Hadley Centre/Climate Research Unit (CRU) temperature record (referred to as HadCRUT) is just one of three global surface temperature records that EPA and the assessment literature refer to and cite. National Oceanic and Atmospheric Administration (NOAA) and National Aeronautics and Space Administration (NASA) also produce temperature records, and all three temperature records have been extensively peer reviewed. Analyses of the three global temperature records produce essentially the same long-term trends as noted in the Climate Change Science Program (CCSP) (2006) report ''Temperature Trends in the Lower Atmosphere,'' IPCC (2007), and NOAA's study [5] ''State of the Climate in 2008''. Furthermore, the commenter did not demonstrate that the allegedly destroyed data would materially alter the HadCRUT record or meaningfully hinder its replication. The raw data, a small part of which has not been public (for reasons described at: *https://www.uea.ac.uk/mac/comm/media/press/2009/nov/CRUupdate*), are available in a quality-controlled (or homogenized, value-added) format and the methodology for developing the quality-controlled data is described in the peer reviewed literature (as documented at *http://www.cru.uea.ac.uk/cru/data/temperature/*).

The release of the U.S. Global Climate Research Program (USGCRP) report on impacts of climate change in the United States in June 2009 also did not necessitate extending the comment period. This report was issued by the USGCRP, formerly the Climate Change Science Program (CCSP), and synthesized information contained in prior CCSP reports and other synthesis reports, many of which had already been published (and were included in the TSD for the Proposed Findings). Further, the USGCRP report itself underwent notice and comment before it was finalized and released.

Regarding the internal EPA staff paper that came to light during the comment period, several commenters submitted a copy of the EPA staff paper with their comments; EPA's response to the issues raised by the staff paper are discussed in the Response to Comments document, Volume 1. The fact that some internal agency deliberations were made public during the comment period does not in and of itself call into question those deliberations. As our responses to comments explain, EPA considered the concerns noted in the staff paper during the proposal stage, as well as when finalizing the Findings. There was nothing about those internal comments that required an extension or reopening of the comment period.

Thus, the opportunity for comment fully satisfies the CAA and Constitutional requirement of Due Process. Cases cited by commenters do not indicate otherwise. The comment period and thorough response to comment documents in the docket indicate that EPA has given people an opportunity to be heard in a ''meaningful time and a meaningful matter.'' *Armstrong* v. *Manzo,* 380 U.S. 545, 552 (1965). Interested parties had full notice of the rulemaking proceedings and a significant opportunity to participate through the comment process and multiple hearings.

For all the above reasons, EPA's denial of the requests for extension or reopening of the comment period was entirely reasonable in light of the extensive opportunity for public comment and heavy amount of public participation during the comment period. EPA has fully complied with all applicable public participation requirements for this rulemaking.

e. These Findings Did Not Necessitate a Formal Rulemaking Under the Administrative Procedure Act

One commenter, with the support of others, requests that EPA undertake a formal rulemaking process for the Findings, on the record, in accordance with the procedures described in sections 556–557 of the Administrative Procedure Act (APA). The commenter requests a multi-step process, involving additional public notice, an on-the-record proceeding (*e.g.,* formal administrative hearing) with the right of appeal, utilization of the Clean Air Scientific Advisory Committee (CASAC) and its advisory proceedings, and designation of representatives from other executive branch agencies to participate in the formal proceeding and any CASAC advisory proceeding.

The commenter asserts that while EPA is not obligated under the CAA to undertake these additional procedures, the Agency nonetheless has the legal authority to engage in such a proceeding. The commenter believes this proceeding would show that EPA is ''truly committed to scientific integrity and transparency.'' The commenter cites several cases to argue that refusal to proceed on the record would be ''arbitrary and capricious'' or would be an ''abuse of discretion.'' The allegation at the core of the commenter's argument is that profound and wide-ranging scientific uncertainties exist in the Proposed Findings and in the impacts on health and welfare discussed in the TSD. To support this argument, the commenter provides lengthy criticisms of the science. The commenter also argues that the regulatory cascade that would be ''unleashed'' by a positive endangerment finding warrants the more formal proceedings.

Finally, the commenter suggests that EPA engage in ''formal rulemaking'' procedures in part due to the Administrative Conference of the United States' (ACUS) recommended factors for engaging in formal rulemaking. The commenter argues that the current action is ''complex,'' ''open-ended,'' and the costs that errors in the action may pose are ''significant.''

EPA is denying the request to undertake an ''on the record'' formal rulemaking. EPA is under no obligation to follow the extraordinarily rarely used formal rulemaking provisions of the APA. First, CAA section 307(d) of the CAA clearly states that the rulemaking provisions of CAA section 307(d), *not* APA sections 553 through 557, apply to certain specified actions, such as this

[5] Peterson, T.C., and M.O. Baringer (Eds.) (2009) State of the Climate in 2008. *Bull. Amer. Meteor. Soc.,* 90, S1–S196.

one. EPA has satisfied all the requirements of CAA section 307(d). Indeed, the commenter itself ''is not asserting that the Clean Air Act expressly requires'' the additional procedures it requests. Moreover, the commenter does not discuss how the suggested formal proceeding would fit into the informal rulemaking requirements of CAA section 307(d) that do apply.

Formal rulemaking is very rarely used by Federal agencies. The formal rulemaking provisions of the APA are only triggered when the statute explicitly calls for proceedings ''on the record after opportunity for an agency hearing.'' *United States* v. *Florida East Coast Ry. Co.,* 410 U.S. 224, 241 (1973). The mere mention of the word ''hearing'' does not trigger the formal rulemaking provisions of the APA. *Id.* The CAA does not include the statutory phrase required to trigger the formal rulemaking provisions of the APA (and as noted above the APA does not apply in the first place). Congress specified that certain rulemakings under the CAA follow the rulemaking procedures outlined in CAA section 307(d) rather than the APA ''formal rulemaking'' commenter suggests.

Despite the inapplicability of the formal rulemaking provisions to this action, commenters suggest that to refuse to voluntarily undertake rulemaking provisions not preferred by Congress would make EPA's rulemaking action an ''abuse of discretion.'' EPA disagrees with this claim, and cases cited by the commenter do not indicate otherwise. To support the idea that an agency decision to engage in informal rulemaking could be an abuse of discretion, commenter cites *Ford Motor Co.* v. *FTC,* 673 F.2d 1008 (9th Cir. 1981). In *Ford Motor Co.,* the court ruled that the FTC's decision regarding an automobile dealership should have been resolved through a rulemaking rather than an individualized adjudication. *Id.* at 1010. In that instance, the court favored ''rulemaking'' over adjudication—not ''formal rulemaking'' over the far more common ''informal rulemaking.'' The case stands only for the non-controversial proposition that sometimes agency use of *adjudications* may rise to an abuse of discretion where a *rulemaking* would be more appropriate—whether formal or informal. The Commenter does not cite a single judicial opinion stating that an agency abused its discretion by following the time-tested and Congressionally-favored informal rulemaking provisions of the CAA or the APA instead of the rarely used formal APA rulemaking provisions.

The commenter also alludes to the possibility that the choice of informal rulemaking may be ''arbitrary and capricious. EPA disagrees that the choice to follow the frequently used, and CAA required, informal rulemaking procedures is arbitrary and capricious. The commenter cites *Vermont Yankee Nuclear Power Corp.* v. *NRDC,* 435 U.S. 519 (1978) for the proposition that ''extremely compelling circumstances'' could lead to a court overturning agency action for declining to follow extraneous procedures. As the commenter notes, in *Vermont Yankee* the Supreme Court overturned a lower court decision for imposing additional requirements not required by applicable statutes. Even if the dicta in *Vermont Yankee* could be applied contrary to the holding of the case in the way the commenter suggests, EPA's decision to follow frequently used informal rulemaking procedures for this action is highly reasonable.

As for the ACUS factors the commenter cites in support of its request, as the commenter notes, the ACUS factors are mere recommendations. While EPA certainly respects the views of ACUS, the recommendations are not binding on the Agency. In addition, EPA has engaged in a thorough, traditional rulemaking process that ensures that any concerns expressed by the commenter have been addressed. EPA has fully satisfied all applicable law in their consideration of this rulemaking.

Finally, as explained in Section III of these Findings and the Response to Comments document, EPA's approach to evaluating the evidence before it was entirely reasonable, and did not require a formal hearing. EPA relied primarily on robust synthesis reports that have undergone peer review and comment. The Agency also carefully considered the comments received on the Proposed Findings and TSD, including review of attached studies and documents. The public has had ample opportunity to provide its views on the science, and the record supporting these final findings indicates that EPA carefully considered and responded to significant public comments. To the extent the commenter's concern is that a formal proceeding will help ensure the *right* action in response to climate change is taken, that is not an issue for these Findings. As discussed in Section III of these Findings, this science-based judgment is not the forum for considering the potential mitigation options or their impact.

II. Legal Framework for This Action

As discussed in the Proposed Findings, two statutory provisions of the CAA govern the Administrator's Findings. Section 202(a) of the CAA sets forth a two-part test for regulatory action under that provision: Endangerment and cause or contribute. Section 302 of the CAA contains definitions of the terms ''air pollutant'' and ''effects on welfare''. Below is a brief discussion of these statutory provisions and how they govern the Administrator's decision, as well as a summary of significant legal comments and EPA's responses to them.

A. Section 202(a) of the CAA—Endangerment and Cause or Contribute

1. The Statutory Framework

Section 202(a)(1) of the CAA states that:

The Administrator shall by regulation prescribe (and from time to time revise) standards applicable to the emission of any air pollutant from any class or classes of new motor vehicles or new motor vehicle engines, which in [her] judgment cause, or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare.

Based on the text of CAA section 202(a) and its legislative history, the Administrator interprets the two-part test as follows. Further discussion of this two-part test can be found in Section II of the preamble for the Proposed Findings. First, the Administrator is required to protect public health and welfare, but she is not asked to wait until harm has occurred. EPA must be ready to take regulatory action to prevent harm before it occurs. Section 202(a)(1) requires the Administrator to ''anticipate'' ''danger'' to public health or welfare. The Administrator is thus to consider both current and future risks. Second, the Administrator is to exercise judgment by weighing risks, assessing potential harms, and making reasonable projections of future trends and possibilities. It follows that when exercising her judgment the Administrator balances the likelihood and severity of effects. This balance involves a sliding scale; on one end the severity of the effects may be of great concern, but the likelihood low, while on the other end the severity may be less, but the likelihood high. Under either scenario, the Administrator is permitted to find endangerment. If the harm would be catastrophic, the Administrator is permitted to find endangerment even if the likelihood is small.

Because scientific knowledge is constantly evolving, the Administrator may be called upon to make decisions while recognizing the uncertainties and limitations of the data or information available, as risks to public health or welfare may involve the frontiers of scientific or medical knowledge. At the same time, the Administrator must exercise reasoned decision making, and avoid speculative inquiries. Third, as discussed further below, the Administrator is to consider the cumulative impact of sources of a pollutant in assessing the risks from air pollution, and is not to look only at the risks attributable to a single source or class of sources. Fourth, the Administrator is to consider the risks to all parts of our population, including those who are at greater risk for reasons such as increased susceptibility to adverse health effects. If vulnerable subpopulations are especially at risk, the Administrator is entitled to take that point into account in deciding the question of endangerment. Here too, both likelihood and severity of adverse effects are relevant, including catastrophic scenarios and their probabilities as well as the less severe effects. As explained below, vulnerable subpopulations face serious health risks as a result of climate change.

In addition, by instructing the Administrator to consider whether emissions of an air pollutant cause or contribute to air pollution, the statute is clear that she need not find that emissions from any one sector or group of sources are the sole or even the major part of an air pollution problem. The use of the term ''contribute'' clearly indicates a lower threshold than the sole or major cause. Moreover, the statutory language in CAA section 202(a) does not contain a modifier on its use of the term contribute. Unlike other CAA provisions, it does not require ''significant'' contribution. See, *e.g.,* CAA sections 111(b); 213(a)(2), (4). To be sure, any finding of a ''contribution'' requires some threshold to be met; a truly trivial or de minimis ''contribution'' might not count as such. The Administrator therefore has ample discretion in exercising her reasonable judgment in determining whether, under the circumstances presented, the cause or contribute criterion has been met. Congress made it clear that the Administrator is to exercise her judgment in determining contribution, and authorized regulatory controls to address air pollution even if the air pollution problem results from a wide variety of sources. While the endangerment test looks at the entire air pollution problem and the risks it poses, the cause or contribute test is designed to authorize EPA to identify and then address what may well be many different sectors or groups of sources that are each part of—and thus contributing to—the problem.

This framework recognizes that regulatory agencies such as EPA must be able to deal with the reality that ''[m]an's ability to alter his environment has developed far more rapidly than his ability to foresee with certainty the effects of his alterations.'' See *Ethyl Corp* v. *EPA,* 541 F.2d 1, 6 (DC Cir.), *cert. denied* 426 U.S. 941 (1976). Both ''the Clean Air Act 'and common sense * * * demand regulatory action to prevent harm, even if the regulator is less than certain that harm is otherwise inevitable.' '' See *Massachusetts* v. *EPA,* 549 U.S. at 506, n.7 (citing *Ethyl Corp.*).

The Administrator recognizes that the context for this action is unique. There is a very large and comprehensive base of scientific information that has been developed over many years through a global consensus process involving numerous scientists from many countries and representing many disciplines. She also recognizes that there are varying degrees of uncertainty across many of these scientific issues. It is in this context that she is exercising her judgment and applying the statutory framework. As discussed in the Proposed Findings, this interpretation is based on and supported by the language in CAA section 202(a), its legislative history and case law.

2. Summary of Response to Key Legal Comments on the Interpretation of the CAA Section 202(a) Endangerment and Cause or Contribute Test

EPA received numerous comments regarding the interpretation of CAA section 202(a) set forth in the Proposed Findings. Below is a brief discussion of some of the key adverse legal comments and EPA's responses. Other key legal comments and EPA's responses are provided in later sections discussing the Administrator's findings.

Additional and more detailed summaries and responses can be found in the Response to Comments document. As noted in the Response to Comments document, EPA also received comments supporting its legal interpretations.

a. The Administrator Properly Interpreted the Precautionary and Preventive Nature of the Statutory Language

Various commenters argue either that the endangerment test under CAA section 202(a) is not precautionary and preventive in nature, or that EPA's interpretation and application is so extreme that it is contrary to what Congress intended in 1977, and effectively guarantees an affirmative endangerment finding. Commenters also argue that the endangerment test improperly shifts the burdens to the opponents of an endangerment finding and is tantamount to assuming the air pollution is harmful unless it is shown to be safe.

EPA rejects the argument that the endangerment test in CAA section 202(a) is not precautionary or preventive in nature. As discussed in more detail in the proposal, Congress relied heavily on the en banc decision in Ethyl when it revised section 202(a) and other CAA provisions to adopt the current language on endangerment and contribution. 74 FR 18886, 18891–2. The Ethyl court could not have been clearer on the precautionary nature of a criteria based on endangerment. The court rejected the argument that EPA had to find actual harm was occurring before it could make the required endangerment finding. The court stated that:

> *The Precautionary Nature of ''Will Endanger.''* Simply as a matter of plain meaning, we have difficulty crediting petitioners' reading of the ''will endanger'' standard. The meaning of ''endanger'' is not disputed. Case law and dictionary definition agree that endanger means something less than actual harm. When one is endangered, harm is *threatened;* no actual injury need ever occur. Thus, for example, a town may be ''endangered'' by a threatening plague or hurricane and yet emerge from the danger completely unscathed. A statute allowing for regulation in the face of danger is, necessarily, a precautionary statute. Regulatory action may be taken before the threatened harm occurs; indeed, the very existence of such precautionary legislation would seem to *demand* that regulatory action precede, and, optimally, prevent, the perceived threat. As should be apparent, the ''will endanger'' language of Section 211(c)(1)(A) makes it such a precautionary statute. *Ethyl* at 13 (footnotes omitted).

Similarly, the court stated that ''[i]n sum, based on the plain meaning of the statute, the juxtaposition of CAA section 211 with CAA sections 108 and 202, and the *Reserve Mining* precedent, we conclude that the ''will endanger'' standard is precautionary in nature and does not require proof of actual harm before regulation is appropriate.'' *Ethyl* at 17. It is this authority to act before harm has occurred that makes it a preventive, precautionary provision.

It is important to note that this statement was in the context of rejecting an argument that EPA had to prove actual harm before it could adopt fuel control regulations under then CAA section 211(c)(1). The court likewise rejected the argument that EPA had to show that such harm was ''probable.''

The court made it clear that determining endangerment entails judgments involving both the risk or likelihood of harm and the severity of the harm if it were to occur. Nowhere did the court indicate that the burden was on the opponents of an endangerment finding to show that there was no endangerment. The opinion focuses on describing the burden the statute places on EPA, rejecting *Ethyl's* arguments of a burden to show actual or probable harm.

Congress intentionally adopted a precautionary and preventive approach. It stated that the purpose of the 1977 amendments was to ''emphasize the preventive or precautionary nature of the act, *i.e.,* to assure that regulatory action can effectively prevent harm before it occurs; to emphasize the predominate value of protection to public health.'' [6] Congress also stated that it authorized the Administrator to weigh risks and make projections of future trends, a ''middle road between those who would impose a nearly impossible standard of proof on the Administrator before he may move to protect public health and those who would shift the burden of proof for all pollutants to make the pollutant source prove the safety of its emissions as a condition of operation.'' Leg. His. at 2516.

Thus, EPA rejects commenters' arguments. Congress intended this provision to be preventive and precautionary in nature, however it did not shift the burden of proof to opponents of an endangerment finding to show safety or no endangerment. Moreover, as is demonstrated in the following, EPA has not shifted the burden of proof in the final endangerment finding, but rather is weighing the likelihood and severity of harms to arrive at the final finding. EPA has not applied an exaggerated or dramatically expanded precautionary principle, and instead has exercised judgment by weighing and balancing the factors that are relevant under this provision.

b. The Administrator Does Not Need To Find That the Control Measures Following an Endangerment Finding Would Prevent at Least a Substantial Part of the Danger in Order To Find Endangerment

Several commenters argue that it is unlawful for EPA to make an affirmative endangerment finding unless EPA finds that the regulatory control measures contemplated to follow such a finding would prevent at least a substantial part of the danger from the global climate change at which the regulation is aimed. This hurdle is also described by commenters as the regulation ''achieving the statutory objective of preventing damage'', or ''fruitfully attacking'' the environmental and public health danger at hand by meaningfully and substantially reducing it. Commenters point to *Ethyl Corp.* v. *EPA,* 541 F.2d 1 (DC Cir. 1976) (en banc) as support for this view, as well as portions of the legislative history of this provision.

Commenters contend that EPA has failed to show that this required degree of meaningful reduction of endangerment would be achieved through regulation of new motor vehicles based on an endangerment finding. In making any such showing, commenters argue that EPA would need to account for the following: (1) The fact that any regulation would be limited to *new* motor vehicles, if not the subset of new motor vehicles discussed in the President's May 2009 announcement, (2) any increase in emissions from purchasers delaying purchases of new vehicles subject to any greenhouse gas emissions standards, or increasing the miles traveled of new vehicles with greater fuel economy, (3) the fact that only a limited portion of the new motor vehicle emissions of greenhouse gases would be controlled, (4) the fact that CAFE standards would effectively achieve the same reductions, and (5) the fact that any vehicle standards would not themselves reduce global temperatures. Some commenters refer to EPA's proposal for greenhouse gas emissions standards for new motor vehicles as support for these arguments, claiming the proposed new motor vehicle emission standards are largely duplicative of the standards proposed by the National Highway Traffic Safety Administration (NHTSA), and the estimates of the impacts of the proposed standards confirm that EPA's proposed standards cannot ''fruitfully attack'' global climate change (74 FR 49454, September 28, 2009).

Commenters attempt to read into the statute a requirement that is not there. EPA interprets the endangerment provision of CAA section 202(a) as not requiring any such finding or showing as described by commenters. The text of CAA section 202(a) does not support such an interpretation. The endangerment provision calls for EPA, in its judgment, to determine whether air pollution is reasonably anticipated to endanger public health or welfare, and whether emissions from certain sources cause or contribute to such air pollution. If EPA makes an affirmative finding, then it shall set emissions standards applicable to emissions of such air pollutants from new motor vehicles. There is no reference in the text of the endangerment or cause or contribute provision to anything concerning the degree of reductions that would be achieved by the emissions standards that would follow such a finding. The Administrator's judgment is directed at the issues of endangerment and cause or contribute, not at how effective the resulting emissions control standards will be.

As in the several other similar provisions adopted in the 1977 amendments, in CAA section 202(a) Congress explicitly separated two different decisions to be made, providing different criteria for them. The first decision involves the air pollution and the endangerment criteria, and the contribution to the air pollution by the sources. The second decision involves how to regulate the sources to control the emissions if an affirmative endangerment and contribution finding are made. In all of the various provisions, there is broad similarity in the phrasing of the endangerment and contribution decision. However, for the decision on how to regulate, there are a wide variety of different approaches adopted by Congress. In some case, EPA has discretion whether to issue standards or not, while in other cases, as in CAA section 202(a), EPA is required to issue standards. In some cases, the regulatory criteria are general, as in CAA section 202(a); in others, they provide significantly more direction as to how standards are to be set, as in CAA section 213(a)(4).

As the Supreme Court made clear in *Massachusetts* v. *EPA,* EPA's judgment in making the endangerment and contribution findings is constrained by the statute, and EPA is to decide these issues based solely on the scientific and other evidence relevant to that decision. EPA may not ''rest[] on reasoning divorced from the statutory text,'' and instead EPA's exercise of judgment must relate to whether an air pollutant causes or contributes to air pollution that endangers. *Massachusetts* v. *EPA,* 549 U.S. at 532. As the Supreme Court noted, EPA must ''exercise discretion within defined statutory limits.'' Id. at 533. EPA's belief one way or the other regarding whether regulation of greenhouse gases from new motor vehicles would be ''effective'' is irrelevant in making the endangerment and contribution decisions before EPA. Id. Instead ''[t]he statutory question is

[6] The Supreme Court recognized that the current language in section 202(a), adopted in 1977, is ''more protective'' than the 1970 version that was similar to the section 211 language before the DC Circuit in *Ethyl. Massachusetts* v. *EPA,* 549 U.S. at 506, fn 7.

whether sufficient information exists to make an endangerment finding'' Id. at 534.

The effectiveness of a potential future control strategy is not relevant to deciding whether air pollution levels in the atmosphere endanger. It is also not relevant to deciding whether emissions of greenhouse gases from new motor vehicles contribute to such air pollution. Commenters argue that Congress implicitly imposed a third requirement, that the future control strategy have a certain degree of effectiveness in reducing the endangerment before EPA could make the affirmative findings that would authorize such regulation. There is no statutory text that supports such an interpretation, and the Supreme Court makes it clear that EPA has no discretion to read this kind of additional factor into CAA section 202(a)'s endangerment and contribution criteria. In fact, the Supreme Court rejected similar arguments that EPA had the discretion to consider various other factors besides endangerment and contribution in deciding whether to deny a petition. *Massachusetts* v. *EPA,* 549 U.S. at 532–35.

Commenters point to language from the *Ethyl* case to support their position, noting that the DC Circuit referred to the emissions control regulation adopted by EPA under CAA section 211(c) as one that would ''fruitfully attack'' the environmental and public health danger by meaningfully and substantially reducing the danger. It is important to understand the context for this discussion in *Ethyl.* The petitioner *Ethyl Corp.* argued that EPA had to show that the health threat from the emissions of lead from the fuel additive being regulated had to be considered in isolation, and the threat ''in and of itself'' from the additive had to meet the test of endangerment in CAA section 211(c). EPA had rejected this approach, and had interpreted CAA section 211(c)(1) as calling for EPA to look at the cumulative impact of lead, and to consider the impact of lead from emissions related to use of the fuel additive in the context all other human exposure to lead. The court rejected *Ethyl's* approach and supported EPA's interpretation. The DC Circuit noted that Congress was fully aware that the burden of lead on the body was caused by multiple sources and that it would be of no value to try and determine the effect on human health from the lead automobile emissions by themselves. The court specifically noted that ''the incremental effect of lead emissions on the total body lead burden is of no practical value in determining whether health is endangered,'' but recognized that this incremental effect is of value ''in deciding whether the lead exposure problem can fruitfully be attacked through control of lead additives.'' *Ethyl,* 541 F.2d at 31 fn 62. The court made clear that the factor that was critically important to determining the effectiveness of the resulting control strategy—the incremental effect of automobile lead emissions on total body burden—was irrelevant and of no value in determining whether the endangerment criteria was met. Thus it is clear that the court in *Ethyl* did not interpret then CAA section 211(c)(1)(A) as requiring EPA to make a showing of the effectiveness of the resulting emissions control strategy, and instead found just the opposite, that the factors that would determine effectiveness are irrelevant to determining endangerment.

Commenters also cite to the legislative history, noting that Congress referred to the ''preventive or precautionary nature of the Act, *i.e.,* to assure that regulatory action can effectively prevent harm before it occurs.'' Leg. Hist. at 2516. However, this statement by Congress is presented as an answer to the question on page 2515, ''Should the Administrator act to prevent harm before it occurs or should he be authorized to regulate an air pollutant only if he finds actual harm has already occurred.'' Leg. Hist. at 2515. In this context, the discussion on page 2516 clearly indicates that there is no opportunity for prevention or precaution if the test is one of actual harm already occurring. This discussion does not say or imply that even if the harm has not occurred, you can not act unless you also show that your action will effectively address it. This discussion concerns the endangerment test, not the criteria for standard setting. The criteria for standard setting address how the agency should act to address the harm, and as the *Ethyl* case notes, the factors relevant to how to ''fruitfully attack'' the harm are irrelevant to determining whether the harm is one that endangers the public health or welfare.

As with current CAA section 202(a), there is no basis to conflate these two separate decisions and to read into the endangerment criteria an obligation that EPA show that the resulting emissions control strategy or strategies will have some significant degree of harm reduction or effectiveness in addressing the endangerment. The conflating of the two decisions is not supported in the text of this provision, by the Supreme Court in *Massachusetts* v. *EPA,* by the DC Circuit in *Ethyl,* or by Congress in the legislative history of this provision. It would be an unworkable interpretation, calling for EPA to project out the result of perhaps not one, but even several, future rulemakings stretching over perhaps a decade or decades. Especially in the context of global climate change, the effectiveness of a control strategy for new motor vehicles would have to be viewed in the context of a number of future motor vehicle regulations, as well as in the larger context of the CAA and perhaps even global context. That would be an unworkable and speculative requirement to impose on EPA as a precondition to answering the public health and welfare issues before it, as they are separate and apart from the issues involved with developing, implementing and evaluating the effectiveness of emissions control strategies.

c. The Administrator Does Not Need To Find There Is Significant Risk of Harm

Commenters argue that Congress established a minimum requirement that there be a ''significant risk of harm'' to find endangerment. They contend that this requirement stemmed from the *Ethyl* case, and that Congress adopted this view. According to the commenters, the risk is the function of two variables: the nature of the hazard at issue and the likelihood of its occurrence. Commenters argue that Congress imposed a requirement that this balance demonstrate a ''significant risk of harm'' to strike a balance between the precautionary nature of the CAA and the burdensome economic and societal consequences of regulation.

There are two basic problems with the commenters' arguments. First, commenters equate ''significant risk of harm'' as the overall test for endangerment, however the *Ethyl* case and the legislative history treat the risk of harm as only one of the two components that are to be considered in determining endangerment.—, The two components are the likelihood or risk of a harm occurring, and the severity of harm if it were to occur. Second, commenters equate it to a minimum statutory requirement. However, while the court in the *Ethyl* case made it clear that the facts in that case met the then applicable endangerment criteria, it also clearly said it was not determining what other facts or circumstances might amount to endangerment, including cases where the likelihood of a harm occurring was less than a significant risk of the harm.

In the EPA rulemaking that led to the *Ethyl* case, EPA stated that the requirement to reduce lead in gasoline ''is based on the finding that lead particle emissions from motor vehicles present a significant risk of harm to the health of urban populations, particularly to the health of city children'' (38 FR 33734, December 6, 1973). The court in *Ethyl* supported EPA's determination, and addressed a variety of issues. First, it determined that the ''will endanger'' criteria of then CAA section 211(c) was intended to be precautionary in nature. It rejected arguments that EPA had to show proof of actual harm, or probable harm. *Ethyl,* 541 F.2d at 13–20. It was in this context, evaluating petitioner's arguments on whether the likelihood of a harm occurring had to rise to the level of actual or probable harm, that the court approved of EPA's view that a significant risk of harm could satisfy the statutory criteria. The precautionary nature of the provision meant that EPA did not need to show that either harm was actually occurring or was probable.

Instead, the court made it clear that the concept of endangerment is ''composed of reciprocal elements of risk and harm,'' *Ethyl* at 18. This means ''the public health may properly be found endangered both by a lesser risk of a greater harm and by a greater risk of lesser harm. Danger depends upon the relation between the risk and harm presented by each case, and cannot legitimately be pegged to 'probable' harm, regardless of whether that harm be great or small.'' The Ethyl court pointed to the decision by the 8th Circuit in *Reserve Mining Co.* v. *EPA,* 514 F.2d 492 (8th Cir, 1975), which interpreted similar language under the Federal Water Pollution Control Act, where the 8th Circuit upheld an endangerment finding in a case involving ''reasonable medical concern,'' or a ''potential'' showing of harm. This was further evidence that a minimum ''probable'' likelihood of harm was not required.

The Ethyl court made it clear that there was no specific magnitude of risk of harm occurring that was required. ''Reserve Mining convincingly demonstrates that the magnitude of risk sufficient to justify regulation is inversely proportional to the harm to be avoided.'' *Ethyl* at 19. This means there is no minimum requirement that the magnitude of risk be ''significant'' or another specific level of likelihood of occurrence. You need to evaluate the risk of harm in the context of the severity of the harm if it were to occur. In the case before it, the Ethyl court noted that ''the harm caused by lead poisoning is severe.'' Even with harm as severe as lead poisoning, EPA did not rely on ''potential'' risk or a ''reasonable medical concern.'' Instead, EPA found that there was a significant risk of this harm to health. This finding of a significant risk was less than the level of ''probable'' harm called for by the petitioner Ethyl Corporation but was ''considerably more certain than the risk that justified regulation in Reserve Mining of a comparably 'fright-laden' harm.'' *Ethyl* at 19–20. The Ethyl court concluded that this combination of risk (likelihood of harm) and severity of harm was sufficient under CAA section 211(c). ''Thus we conclude that however far the parameters of risk and harm inherent in the 'will endanger' standard might reach in an appropriate case, they certainly present a 'danger' that can be regulated when the harm to be avoided is widespread lead poisoning and the risk of that occurrence is 'significant'.'' *Ethyl* at 20.

Thus, the court made it clear that the endangerment criteria was intended to be precautionary in nature, that the risk of harm was one of the elements to consider in determining endangerment, and that the risk of harm needed to be considered in the context of the severity of the potential harm. It also concluded that a significant risk of harm coupled with an appropriate severity of the potential harm would satisfy the statutory criteria, and in the case before it the Administrator was clearly authorized to determine endangerment where there was a significant risk of harm that was coupled with a severe harm such as lead poisoning.

Importantly, the court also made it clear that it was not determining a minimum threshold that always had to be met. Instead, it emphasized that the risk of harm and severity of the potential harm had to be evaluated on a case by case basis. The court specifically said it was not determining ''however far the parameters of risk and harm * * * might reach in an appropriate case.'' *Ethyl* at 20. Also see *Ethyl* fn 17 at 13. The court recognized that this balancing of risk and harm ''must be confined to reasonable limits'' and even absolute certainty of a de minimis harm might not justify government action. However, ''whether a particular combination of slight risk and great harm, or great risk and slight harm constitutes a danger must depend on the facts of each case.'' *Ethyl* at fn 32 at 18.[7]

In some cases, commenters confuse matters by switching the terminology, and instead refer to effects that ''significantly harm'' the public health or welfare. As with the reference to ''significant risk of harm,'' commenters fail to recognize that there are two different aspects that must be considered, risk of harm and severity of harm, and neither of these aspects has a requirement that there be a finding of ''significance.'' The DC Circuit in *Ethyl* makes clear that it is the combination of these two aspects that must be evaluated for purposes of endangerment, and there is no requirement of ''significance'' assigned to either of the two aspects that must instead be evaluated in combination. Congress addressed concerns over burdensome economic and societal consequences in the various statutory provisions that provide the criteria for standard setting or other agency action if there is an affirmative endangerment finding. Those statutory provisions, for example, make standard setting discretionary or specify how cost and other factors are to be taken into consideration in setting standards. However, the issues of risk of harm and severity of harm if it were to occur are separate from the issues of the economic impacts of any resulting regulatory provisions (*see* below).

As is clear in the prior summary of the endangerment findings and the more detailed discussion later, the breadth of the sectors of our society that are affected by climate change and the time frames at issue mean there is a very wide range of risks and harms that need to be considered, from evidence of various harms occurring now to evidence of risks of future harms. The Administrator has determined that the body of scientific evidence compellingly supports her endangerment finding.

B. Air Pollutant, Public Health and Welfare

The CAA defines both ''air pollutant'' and ''effects on welfare.'' We provide both definitions here again for convenience.

Air pollutant is defined as:

[7] Commenters point to *Amer. Farm Bureau Ass'n* v. *EPA,* 559 F.3d 512, 533 (DC Cir. 2009) as supporting their argument. However, in that case the Court made clear that EPA's action was not subject to the endangerment criterion in CAA section 108 but instead was subject to CAA section 109's requirement that the primary NAAQS be requisite to protect the public health with an adequate margin of safety. Under that provision and its case law, the Court upheld EPA's reasoned balancing of the uncertainty regarding the link between non-urban thoracic coarse PM and adverse health effects, the large population groups potentially exposed to these particles, and the nature and degree of the health effects at issue. Citing to EPA's reasoning at 71 FR 61193 in the final PM rule, the court explained that EPA need not wait for conclusive proof of harm before setting a NAAQS under section 109 for this kind of coarse PM. The Court's reference to EPA's belief that there may be a significant risk to public health is not stated as any sort of statutory minimum, but instead refers to the Agency's reasoning at 71 FR 61193, which displays a reasoned balancing of possibility of harm and severity of harm if it were to occur.

"Any air pollution agent or combination of such agents, including any physical, chemical, biological, radioactive (including source material, special nuclear material, and byproduct material) substance or matter which is emitted into or otherwise enters the ambient air. Such term includes any precursors to the formation of any air pollutant, to the extent the Administrator has identified such precursor or precursors for the particular purpose for which the term "air pollutant" is used." CAA section 302(g). As the Supreme Court held, greenhouse gases fit well within this capacious definition. *See Massachusetts* v. *EPA,* 549 U.S. at 532. They are "without a doubt" physical chemical substances emitted into the ambient air. *Id.* at 529.

"Regarding 'effects on welfare', the CAA states that [a]ll language referring to effects on welfare includes, but is not limited to, effects on soils, water, crops, vegetation, man-made materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being, whether caused by transformation, conversion, or combination with other air pollutants." CAA section 302(h).

As noted in the Proposed Findings, this definition is quite broad. Importantly, it is not an exclusive list due to the use of the term "includes, but is not limited to, * * * ." Effects other than those listed here may also be considered effects on welfare. Moreover, the terms contained within the definition are themselves expansive.

Although the CAA defines "effects on welfare" as discussed above, there are no definitions of "public health" or "public welfare" in the CAA. The Supreme Court has discussed the concept of public health in the context of whether costs of implementation can be considered when setting the health based primary National Ambient Air Quality Standards. *Whitman v. American Trucking Ass'n,* 531 U.S. 457 (2001). In *Whitman,* the Court imbued the term with its most natural meaning: "the health of the public. *Id.* at 466. In the past, when considering public health, EPA has looked at morbidity, such as impairment of lung function, aggravation of respiratory and cardiovascular disease, and other acute and chronic health effects, as well as mortality. *See, e.g., Final National Ambient Air Quality Standard for Ozone,* (73 FR 16436, 2007).

EPA received numerous comments regarding its proposed interpretations of air pollutant and public health and welfare. Summaries of key comments and EPA's responses are discussed in Sections IV and V of these Findings. Additional and more detailed summaries and responses can be found in the Response to Comments document. As noted in the Response to Comments document, EPA also received comments supporting its legal interpretations.

III. EPA's Approach for Evaluating the Evidence Before It

This section discusses EPA's approach to evaluating the evidence before it, including the approach taken to the scientific evidence, the legal framework for this decision making, and several issues critical to determining the scope of the evaluation performed.

A. The Science on Which the Decisions Are Based

In 2007, EPA initiated its assessment of the science and other technical information to use in addressing the endangerment and cause or contribute issues before it under CAA section 202(a). This scientific and technical information was developed in the form of a TSD in 2007. An earlier draft of this document was released as part of the ANPR published July 30, 2008 (73 FR 44353). That earlier draft of the TSD relied heavily on the IPCC Fourth Assessment Report of 2007, key NRC reports, and a limited number of then-available synthesis and assessment products of the U.S. Climate Change Science Program (CCSP; now encompassed by USGCRP). EPA received a number of comments specifically focused on the TSD during the 120-day public comment period for the ANPR.

EPA revised and updated the TSD in preparing the Proposed Findings on endangerment and cause or contribute. Many of the comments received on the ANPR were reflected in the draft TSD released in April 2009 that served as the underlying scientific and technical basis for the Administrator's Proposed Findings, published April 24, 2009 (74 FR 18886). The draft TSD released in April 2009 also reflected the findings of 11 new synthesis and assessment products under the U.S. CCSP that had been published since July 2008.

The TSD that summarizes scientific findings from the major assessments of the USGCRP, the IPCC, and the NRC accompanies these Findings. The TSD is available at *www.epa.gov/climatechange/endangerment.html* and in the docket for this action. It also includes the most recent comprehensive assessment of the USGCRP, *Global Climate Change Impacts in the United States,*[8] published in June 2009. In addition, the TSD incorporates up-to-date observational data for a number of key climate variables from the NOAA, and the most up-to-date emissions data from EPA's annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks,* published in April, 2009.[9] And finally, as discussed in Section I.B of these Findings, EPA received a large number of public comments on the Administrator's Proposed Findings, many of which addressed science issues either generally or specifically as reflected in the draft TSD released with the April 2009 proposal. A number of edits and updates were made to the draft TSD as a result of these comments.[10]

EPA is giving careful consideration to all of the scientific and technical information in the record, as discussed below. However, the Administrator is relying on the major assessments of the USGCRP, IPCC, and NRC as the primary scientific and technical basis of her endangerment decision for a number of reasons.

First, these assessments address the scientific issues that the Administrator must examine for the endangerment analysis. When viewed in total, these assessments address the issue of greenhouse gas endangerment by providing data and information on: (1) The amount of greenhouse gases being emitted by human activities; (2) how greenhouse gases have been and continue to accumulate in the atmosphere as a result of human activities; (3) changes to the Earth's energy balance as a result of the buildup of atmospheric greenhouse gases; (4) observed temperature and other climatic changes at the global and regional scales; (5) observed changes in other climate-sensitive sectors and systems of the human and natural environment; (6) the extent to which observed climate change and other changes in climate-sensitive systems can be attributed to the human-induced buildup of atmospheric greenhouse gases; (7) future projected climate change under a range of different scenarios of changing greenhouse gas emission rates; and (8) the projected risks and impacts to

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[8] Karl, T., J. Melillo, and T. Peterson (Eds.) (2009) Global Climate Change Impacts in the United States. Cambridge University Press, Cambridge, United Kingdom.

[9] U.S. EPA (2009) *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2007.* EPA–430–R–09–004, Washington, DC.

[10] EPA has placed within the docket a separate memo "Summary of Major Changes to the Technical Support Document" identifying where within the TSD such changes were made relative to the draft TSD released in April 2009.

human health, society and the environment.

Second, as indicated above, these assessments are recent and represent the current state of knowledge on the key elements for the endangerment analysis. It is worth noting that the June 2009 assessment of the USGCRP incorporates a number of key findings from the 2007 IPCC Fourth Assessment Report; such findings include the attribution of observed climate change to human emissions of greenhouse gases, and the future projected scenarios of climate change for the global and regional scales. This demonstrates that much of the underlying science that EPA has been utilizing since 2007 has not only been in the public domain for some time, but also has remained relevant and robust.

Third, these assessments are comprehensive in their coverage of the greenhouse gas and climate change problem, and address the different stages of the emissions-to-potential-harm chain necessary for the endangerment analysis. In so doing, they evaluate the findings of numerous individual peer-reviewed studies in order to draw more general and overarching conclusions about the state of science. The USGCRP, IPCC, and NRC assessments synthesize literally thousands of individual studies and convey the consensus conclusions on what the body of scientific literature tells us.

Fourth, these assessment reports undergo a rigorous and exacting standard of peer review by the expert community, as well as rigorous levels of U.S. government review and acceptance. Individual studies that appear in scientific journals, even if peer reviewed, do not go through as many review stages, nor are they reviewed and commented on by as many scientists. The review processes of the IPCC, USGCRP, and NRC (explained in fuller detail in the TSD and the Response to Comments document, Volume 1) provide EPA with strong assurance that this material has been well vetted by both the climate change research community and by the U.S. government. These assessments therefore essentially represent the U.S. government's view of the state of knowledge on greenhouse gases and climate change. For example, with regard to government acceptance and approval of IPCC assessment reports, the USGCRP Web site states that: ''When governments accept the IPCC reports and approve their Summary for Policymakers, they acknowledge the legitimacy of their scientific content.'' [11] It is the Administrator's view that such review and acceptance by the U.S. Government lends further support for placing primary weight on these major assessments.

It is EPA's view that the scientific assessments of the IPCC, USGRCP, and the NRC represent the best reference materials for determining the general state of knowledge on the scientific and technical issues before the agency in making an endangerment decision. No other source of information provides such a comprehensive and in-depth analysis across such a large body of scientific studies, adheres to such a high and exacting standard of peer review, and synthesizes the resulting consensus view of a large body of scientific experts across the world. For these reasons, the Administrator is placing primary and significant weight on these assessment reports in making her decision on endangerment.

A number of commenters called upon EPA to perform a new and independent assessment of all of the underlying climate change science, separate and apart from USGCRP, IPCC, and NRC. In effect, commenters suggest that EPA is either required to or should ignore the attributes discussed above concerning these assessment reports, and should instead perform its own assessment of all of the underlying studies and information.

In addition to the significant reasons discussed above for relying on and placing primary weight on these assessment reports, EPA has been a very active part of the U.S. government climate change research enterprise, and has taken an active part in the review, writing, and approval of these assessments. EPA was the lead agency for three significant reports under the USGCRP [12], and recently completed an assessment addressing the climate change impacts on U.S. air quality—a report on which the TSD heavily relies for that particular issue. EPA was also involved in review of the IPCC Fourth Assessment Report, and in particular took part in the approval of the summary for policymakers for the Working Group II Volume, *Impacts, Adaptation and Vulnerability.*[13] The USGCRP, IPCC, and NRC assessments have been reviewed and formally accepted by, commissioned by, or in some cases authored by, U.S. government agencies and individual government scientists. These reports already reflect significant input from EPA's scientists and the scientists of many other government agencies.

EPA has no reason to believe that the assessment reports do not represent the best source material to determine the state of science and the consensus view of the world's scientific experts on the issues central to making an endangerment decision with respect to greenhouse gases. EPA also has no reason to believe that putting this significant body of work aside and attempting to develop a new and separate assessment would provide any better basis for making the endangerment decision, especially because any such new assessment by EPA would still have to give proper weight to these same consensus assessment reports.

In summary, EPA concludes that its reliance on existing and recent synthesis and assessment reports is entirely reasonable and allows EPA to rely on the best available science.[14] EPA also recognizes that scientific research is very active in many areas addressed in the TSD (*e.g.,* aerosol effects on climate, climate feedbacks such as water vapor, and internal and external climate forcing mechanisms), as well as for some emerging issues (*e.g.,* ocean acidification and climate change effects on water quality). EPA recognizes the potential importance of new scientific research, and the value of an ongoing process to take more recent science into account. EPA reviewed new literature in

[11] *http://www.globalchange.gov/publications/reports/ipcc-reports.*

[12] CCSP (2009) *Coastal Sensitivity to Sea-Level Rise: A Focus on the Mid-Atlantic Region.* A Report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. [James G. Titus (Coordinating Lead Author), K. Eric Anderson, Donald R. Cahoon, Dean B. Gesch, Stephen K. Gill, Benjamin T. Gutierrez, E. Robert Thieler, and S. Jeffress Williams (Lead Authors)], U.S. Environmental Protection Agency, Washington DC, USA, 320 pp. CCSP (2008) *Preliminary review of adaptation options for climate-sensitive ecosystems and resources.* A Report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. [Julius, S.H., J.M. West (eds.), J.S. Baron, B. Griffith, L.A. Joyce, P. Kareiva, B.D. Keller, M.A. Palmer, C.H. Peterson, and J.M. Scott (Authors)]. U.S. Environmental Protection Agency, Washington, DC, USA, 873 pp. CCSP (2008) *Analyses of the effects of global change on human health and welfare and human systems.* A Report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. [Gamble, J.L. (ed.), K.L. Ebi, F.G. Sussman, T.J. Wilbanks, (Authors)]. U.S. Environmental Protection Agency, Washington, DC, USA.

[13] IPCC (2007) Climate Change 2007: *Impacts, Adaptation and Vulnerability.* Contribution of Working Group II to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, M.L. Parry, O.F. Canziani, J.P. Palutikof, P.J. van der Linden and C.E. Hanson, Eds., Cambridge University Press, Cambridge, UK, 976pp.

[14] It maintains the highest level of adherence to Agency and OMB guidelines for data and scientific integrity and transparency. This is discussed in greater detail in EPA's Response to Comments document.

preparation of this TSD to evaluate its consistency with recent scientific assessments. We also considered public comments received and studies incorporated by reference. In a number of cases, the TSD was updated based on such information to add context for assessment literature findings, which includes supporting information and/or qualifying statements. In other cases, material that was not incorporated into the TSD is discussed within the Response to Comments document.

EPA reviewed these individual studies that were not considered or reflected in these major assessments to evaluate how they inform our understanding of how greenhouse gas emissions affect climate change, and how climate change may affect public health and welfare. Given the very large body of studies reviewed and assessed in developing the assessment reports, and the rigor and breadth of that review and assessment, EPA placed limited weight on the much smaller number of individual studies that were not considered or reflected in the major assessments. EPA reviewed them largely to see if they would lead EPA to change or place less weight on the judgments reflected in the assessment report. While EPA recognizes that some studies are more useful or informative than others, and gave each study it reviewed the weight it was due, the overall conclusion EPA drew from its review of studies submitted by commenters was that the studies did not change the various conclusions or judgments EPA would draw based on the assessment reports.

Many comments focus on the scientific and technical data underlying the Proposed Findings, such as climate change science and greenhouse gas emissions data. These comments cover a range of topics and are summarized and responded to in the Response to Public Comments document. The responses note those cases where a technical or scientific comment resulted in an editorial or substantive change to the TSD. The final TSD reflects all changes made as a result of public comments.

B. The Law on Which the Decisions Are Based

In addition to grounding these determinations on the science, they are also firmly grounded in EPA's legal authority. Section II of these Findings provides an in-depth discussion of the legal framework for the endangerment and cause or contribute decisions under CAA section 202(a), with additional discussion in Section II of the Proposed Finding (74 FR 18886, 18890, April 24, 2009). A variety of important legal issues are also discussed in Sections III, IV, and V of these Findings, as well as in the Response to Comments document, Volume 11. Section IV and V of these Findings explain the Administrator's decisions, and how she exercised her judgment in making the endangerment and contribution determinations, based on the entire scientific record before her and the legal framework structuring her decision making.

C. Adaptation and Mitigation

Following the language of CAA section 202(a), in which the Administrator, in her judgment, must determine if greenhouse gases constitute the air pollution that may be reasonably anticipated to endanger public health or welfare, EPA evaluated, based primarily on the scientific reports discussed above, how greenhouse gases and other climate-relevant substances are affecting the atmosphere and climate, and how these climate changes affect public health and welfare, now and in the future. Consistent with EPA's scientific approach underlying the Administrator's Proposed Findings, EPA did not undertake a separate analysis to evaluate potential societal and policy responses to any threat (*i.e.,* the endangerment) that may exist due to anthropogenic emissions of greenhouse gases. Risk reduction through adaptation and greenhouse gas mitigation measures is of course a strong focal area of scientists and policy makers, including EPA; however, EPA considers adaptation and mitigation to be potential responses to endangerment, and as such has determined that they are outside the scope of the endangerment analysis.

The Administrator's position is not that adaptation will not occur or cannot help protect public health and welfare from certain impacts of climate change, as some commenters intimated. To the contrary, EPA recognizes that some level of autonomous adaptation [15] will occur, and commenters are correct that autonomous adaptation can affect the severity of climate change impacts. Indeed, there are some cases in the TSD in which some degree of adaptation is accounted for; these cases occur where the literature on which the TSD relies already uses assumptions about autonomous adaptation when projecting the future effects of climate change. Such cases are noted in the TSD. We also view planned adaptation as an important near-term risk-minimizing strategy given that some degree of climate change will continue to occur as a result of past and current emissions of greenhouse gases that remain in the atmosphere for decades to centuries.

However, it is the Administrator's position that projections of adaptation and mitigation in response to risks and impacts associated with climate change are not appropriate for EPA to consider in making a decision on whether the air pollution endangers. The issue before EPA involves evaluating the risks to public health and welfare from the air pollution if we do not take action to address it. Adaptation and mitigation address an important but different issue—how much risk will remain assuming some projection of how people and society will respond to the threat.

Several commenters argue that it is arbitrary not to consider adaptation in determining endangerment. They contend that because endangerment is a forward-looking exercise, the fundamental inquiry concerns the type and extent of harm that is believed likely to occur in the future. Just as the Administrator makes projections of potential harms in the future, these commenters contend that the Administrator needs to consider the literature on adaptation that addresses the likelihood and the severity of potential effects. Commenters also note that since adaption is one of the likely impacts of climate change, it is irrational to exclude it from consideration when the goal is to evaluate the risks and harms in the real world in the future, not the risks and harms in the hypothetical scenario that result if you ignore adaptation.

According to commenters, the Administrator must consider both autonomous adaptation and anticipatory adaptation. They contend that literature on adaptation makes it clear there is a significant potential for adaptation, and that it can reduce the likelihood or severity of various effects, including health effects, and could even avert what might otherwise constitute endangerment. Commenters note that EPA considered the adaptation of species in nature, and it is arbitrary to not also consider adaptation by humans. Moreover, they argue that there is great

[15] The IPCC definition of adaptation: "Adaptation to climate change takes place through adjustments to reduce vulnerability or enhance resilience in response to observed or expected changes in climate and associated extreme weather events. Adaptation occurs in physical, ecological and human systems. It involves changes in social and environmental processes, perceptions of climate risk, practices and functions to reduce potential damages or to realize new opportunities." The IPCC defines autonomous adaptation as "Adaptation that does not constitute a conscious response to climatic stimuli but is triggered by ecological changes in natural systems and by market or welfare changes in human systems."

certainty that adaptation will occur, and thus EPA is required to address it and make projections. They recommend that EPA look to historic responses to changes in conditions as an analogue in making projections, recognizing that life in the United States is likely to be quite different 50 or 100 years from now, irrespective of climate change.

Commenters argue that adaption needs to be considered because it is central to the statutory requirements governing the endangerment inquiry. EPA is charged to determine the type and extent of harms that are likely to occur, and they argue that this can not rationally be considered without considering adaptation. Since some degree of adaptation is likely to occur, they continue that such a projection of future actual conditions requires consideration of adaption to evaluate whether the future conditions amount to endangerment from the air pollution.

According to commenters, the issue therefore is focused on human and societal adaptation, which can come in a wide variety of forms, ranging from changes in personal behavioral patterns to expenditures of resources to change infrastructure, such as building and maintaining barriers to protect against sea level rise.

With regard to mitigation, commenters argue that EPA should consider mitigation strategies and their potential to alleviate harm from greenhouse gas emissions. They contend that it is unreasonable for EPA to assume that society will not undertake mitigation.

Section 202(a) of the CAA reflects the basic approach of many CAA sections—the threshold inquiry is whether the endangerment and cause or contribute criteria are satisfied, and only if they are met do the criteria for regulatory action go into effect. This reflects the basic separation of two different decisions—is this a health and welfare problem that should be addressed, and if so what are the appropriate mechanisms to address it? There is a division between identifying the health and welfare problem associated with the air pollution, and identifying the mechanisms used to address or solve the problem.

In evaluating endangerment, EPA is determining whether the risks to health and welfare from the air pollution amount to endangerment. As commenters recognize, that calls for evaluating and projecting the nature and types of risks from the air pollution, including the probability or likelihood of the occurrence of an impact and the degree of adversity (or benefit) of such an impact. This issue focuses on how EPA makes such an evaluation in determining endangerment—does EPA look at the risks assuming no planned adaptation and/or mitigation, although EPA projects some degree is likely to occur, or does EPA look at the risks remaining after some projection of adaptation and/or mitigation?

These two approaches reflect different views of the core question EPA is trying to answer. The first approach most clearly focuses on just the air pollution and its impacts, and aims to separate this from the human and societal responses that may or should be taken in response to the risks from the air pollution. By its nature, this separation means this approach may not reflect the actual conditions in the real world in the future, because adaptation and/or mitigation may occur and change the risks. For example, adaptation would not change the atmospheric concentrations, or the likelihood or probability of various impacts occurring (*e.g.*, it would not change the degree of sea level rise), but adaptation has the potential to reduce the adversity of the effects that do occur from these impacts. Mitigation could reduce the atmospheric concentrations that would otherwise occur, having the potential to reduce the likelihood or probability of various impacts occurring. Under this approach, the evaluation of risk is focused on the risk if we do not address the problem. It does not answer the question of how much risk we project will remain after we do address the problem, through either adaptation or mitigation or some combination of the two.

The second approach, suggested by commenters, would call for EPA to project into the future adaptation and/or mitigation, and the effect of these measures in reducing the risks to health or welfare from the air pollution. Commenters argue this will better reflect likely real world conditions, and therefore is needed to allow for an appropriate determination of whether EPA should, at this time, make an affirmative endangerment finding. However, this approach would not separate the air pollution and its impacts from the human and societal responses to the air pollution. It would intentionally and inextricably intertwine them. It would inexorably change the focus from how serious is the air pollution problem we need to address to how good a job are people and society likely to do in addressing or solving the problem. In addition it would dramatically increase the complexity of the issues before EPA.

The context for this endangerment finding is a time span of several decades into the future. It involves a wide variety of differing health and welfare effects, and almost every sector in our society. This somewhat unique context tends to amplify the differences between the two different approaches. It also means that it is hard to cleanly implement either approach. For example, it is hard under the first approach to clearly separate impacts with and without adaption, given the nature of the scientific studies and information before us. Under the second approach it would be extremely hard to make a reasoned projection of human and societal adaptation and mitigation responses, because these are basically not scientific or technical judgments, but are largely political judgments for society or individual personal judgments.

However, the context for this endangerment finding does not change the fact that at their core the two different approaches are aimed at answering different questions. The first approach is focused on answering the question of what are the risks to public health and welfare from the air pollution if we do not take action to address it. The second approach is focused on answering the question of how much risk will remain assuming some projection of how people and society will respond.

EPA believes that it is appropriate and reasonable to interpret CAA section 202(a) as calling for the first approach. The structure of CAA section 202(a) and the various other similar provisions indicate an intention by Congress to separate the question of what is the problem we need to address from the question of what is the appropriate way to address it. The first approach is clearly more consistent with this statutory structure. The amount of reduction in risk that might be achieved through adaptation and/or mitigation is closely related to the way to address a problem, and is not focused on what is the problem that needs to be addressed. It helps gauge the likelihood of success in addressing a problem, and how good a job society may do in reducing risk; it is not at all as useful in determining the severity of the problem that needs to be addressed.

The endangerment issue at its core is a decision on whether there is a risk to health and welfare that needs to be addressed, and the second approach would tend to indicate that the more likely a society is to solve a problem, the less likely there is a problem that needs to be addressed. This would mask the issue and provide a directionally wrong signal. Assume two different situations, both presenting the same serious risks to public health or welfare without consideration of adaptation or mitigation. The more successful society is projected to be in solving the serious problem in the future would mean the less likely we would be to make an endangerment finding at the inception identifying it as a problem that needs to be addressed. This is much less consistent with the logic embodied in CAA section 202(a), which separates the issue of whether there is a problem from the issue of what can be done to successfully address it.

In addition, the second approach would dramatically increase the complexity of the issues to resolve, and would do this by bringing in issues that are not the subject of the kind of scientific or technical judgments that Congress envisioned for the endangerment test. The legislative history indicates Congress was focused on issues of science and medicine, including issues at the frontiers of these fields. It referred to data, research resources, science and medicine, chemistry, biology, and statistics. There is no indication Congress envisioned exercising judgment on the very different types of issues involved in projecting the political actions likely to be taken by various local, State, and Federal governments, or judgments on the business or other decisions that are likely to be made by companies or other organizations, or the changes in personal behavior that may be occasioned by the adverse impacts of air pollution. The second approach would take EPA far away from the kind of judgments Congress envisioned for the endangerment test.

D. Geographic Scope of Impacts

It is the Administrator's view that the primary focus of the vulnerability, risk, and impact assessment is the United States. As described in Section IV of these Findings, the Administrator gives some consideration to climate change effects in world regions outside of the United States. Given the global nature of climate change, she has also examined potential impacts in other regions of the world. Greenhouse gases, once emitted, become well mixed in the atmosphere, meaning U.S. emissions can affect not only the U.S. population and environment, but other regions of the world as well. Likewise, emissions in other countries can affect the United States. Furthermore, impacts in other regions of the world may have consequences that in turn raise humanitarian, trade, and national security concerns for the United States.

Commenters argue that EPA does not have the authority to consider international effects. They contend that the burden is on EPA is to show endangerment based on impacts in the United States. They note that EPA proposed this approach, which is the only relevant issue for EPA. The purpose of CAA section 202(a), as the stated purpose of the CAA, commenters note, is to protect the quality of the nation's air resources and to protect the health and welfare of the U.S. population. Thus, they continue, international public health and welfare are not listed or stated, and are not encompassed by these provisions. Moreover, they argue that Congress addressed international impacts expressly in two other provisions of the CAA. They note that under CAA section 115, EPA considers emissions of pollutants that cause or contribute to air pollution that is reasonably anticipated to endanger public health or welfare in a foreign country, and that CAA section 179B addresses emissions of air pollutants in foreign countries that interfere with attainment of a National Ambient Air Quality Standards (NAAQS) in the United States. Because Congress intentionally addressed international impacts in those provision, commenters argue that the absence of this direction in CAA section 202(a) means that EPA is not to consider international effects when assessing endangerment under this provision.

Commenters fail to recognize that EPA's consideration of international effects is directed at evaluating their impact on the public health and welfare of the U.S. population. EPA is not considering international effects to determine whether the health and welfare of the public in a foreign country is endangered. Instead, EPA's consideration of international effects for purposes of determining endangerment is limited to how those international effects impact the health and welfare of the U.S. population.

The Administrator looked first at impacts in the United States itself, and determined that these impacts are reasonably anticipated to endanger the public health and the welfare of the U.S. population. That remains the Administrator's position, and by itself supports her determination of endangerment. The Administrator also considered the effects of global climate change outside the borders of the United States and evaluated them to determine whether these international effects impact the U.S. population, and if so whether it impacts the U.S. population in a manner that supports or does not support endangerment to the health and welfare of the U.S. public. She is not evaluating international effects to determine whether populations in a foreign country are endangered. The Administrator is looking at international effects solely for the purpose of evaluating their effects on the U.S. population.

For example, the U.S. population can be impacted by effects in other countries. These international effects can impact U.S. economic, trade, and humanitarian and national security interests. These would be potential effects on the U.S. population, brought about by the effects of climate change occurring outside the United States. It is fully reasonable and rational to expect that events occurring outside our borders can affect the U.S. population.

Thus, commenters misunderstand the role that international effects played in the proposal. The Administrator is not evaluating the impact of international effects on populations outside the United States; she is considering what impact these international effects could have on the U.S. population. That is fully consistent with the CAA's stated purpose of protecting the health and welfare of this nation's population.

E. Temporal Scope of Impacts

An additional parameter of the endangerment analysis is the timeframe. The Administrator's view is that the timeframe over which vulnerabilities, risks, and impacts are considered should be consistent with the timeframe over which greenhouse gases, once emitted, have an effect on climate. Thus the relevant time frame is decades to centuries for the primary greenhouse gases of concern. Therefore, in addition to reviewing recent observations, the underlying science upon which the Administrator is basing her findings generally considers the next several decades—the time period out to around 2100, and for certain impacts, the time period beyond 2100. How the accumulation of atmospheric greenhouse gases and resultant climate change may affect current and future generations is discussed in section IV in these Findings. By current generations we mean a near-term time frame of approximately the next 10 to 20 years; by future generations we mean a longer-term time frame extending beyond that. Some public comments were received that questioned making an endangerment finding based on current conditions, while others questioned EPA's ability to make an endangerment finding based on future projected conditions. Some of these comments are likewise addressed in Section IV in these Findings; and all comments on these temporal issues are addressed in the Response to Comments document.

F. Impacts of Potential Future Regulations and Processes That Generate Greenhouse Gas Emissions

This action is a stand-alone set of findings regarding endangerment and cause or contribute for greenhouse gases under CAA section 202(a), and does not contain any regulatory requirements. Therefore, this action does not attempt to assess the impacts of any future regulation. Although EPA would evaluate any future proposed regulation, many commenters argue that such a regulatory analysis should be part of the endangerment analysis.

Numerous commenters argue that EPA must fully consider the adverse and beneficial impacts of regulation together with the impacts of inaction, and describe this balancing as ''risk-risk analysis,'' ''health-health analysis,'' and most predominantly ''risk tradeoff analysis.'' Commenters argue that EPA's final endangerment finding would be arbitrary unless EPA undertakes this type of risk trade-off analysis.

Commenters specifically argue that EPA must consider the economic impact of regulation, including the Prevention of Significant Deterioration (PSD) permitting program for major stationary sources because it is triggered by a CAA section 202(a) standard, when assessing whether there is endangerment to public welfare. In other words, they argue that the Administrator should determine if finding endangerment and regulating greenhouse gases under the CAA would be worse for public health and welfare than not regulating. Commenters also argue that the reference to ''public'' health or welfare in CAA section 202, as well as the fact that impacts on the economy should be considered impacts to welfare, especially requires EPA to consider the full range of possible impacts of regulation. Commenters provide various predictions regarding how regulating greenhouse gases under the CAA more broadly will impact the public, industry, states the overall economy, and thus, they conclude, public health and welfare. Examples of commenters' predictions include potential adverse impacts on (1) the housing industry and the availability of affordable housing, (2) jobs and income due to industry moving overseas, (3) the agriculture industry and its ability to provide affordable food, and (4) the nation's energy supply. They also cite to the letter from the Office of Management and Budget provided with the ANPR, as well as interagency comments on the draft Proposed Findings, in support of their argument.

At least one commenter argues that EPA fails to discuss the public health or welfare benefits of the processes that *produce* the emissions. The commenter contends that for purposes of CAA section 202(a), this process would be the combustion of gasoline or other transportation fuel in new motor vehicles, and that for purposes of other CAA provisions with similar endangerment finding triggers, the processes would be the combustion of fossil fuel for electric generation and other activities. The commenter continues that EPA's decision to limit its analysis to the perceived detrimental aspects of emissions after they enter the atmosphere—as opposed to the possible positive aspects of emissions because of the processes that create the emissions—is based on EPA's overly narrow interpretation of both the meaning of the term ''emission'' in CAA section 202(a) (and therefore in other endangerment finding provisions) and the intent of these provisions. The commenter states that logically, it makes little sense to limit the definition of the term ''emission'' to only the ''air pollutants'' that are emitted. The commenter concludes that when EPA assesses whether the emission of greenhouse gases endanger public health and welfare, EPA must assess the dangers and benefits on both sides of the point where the emissions occur: in the atmosphere where the emissions lodge and, on the other side of the emitting stack or structure, in the processes that create the emissions. Otherwise, EPA will not be able to accurately assess whether the fact that society emits greenhouse gases is a benefit or a detriment. The commenter states that because greenhouse gas emissions, particularly carbon dioxide emissions, are so closely tied with all facets of modern life, a finding that greenhouse gas emissions endanger public health and welfare is akin to saying that modern life endangers public health or welfare. The commenter states that simply cannot be true because the lack of industrial activity that causes greenhouse gas emissions would pose other, almost certainly more serious health and welfare consequences.

Finally, some commenters argue that the impact of regulating under CAA section 202(a) supports making a final, negative endangerment finding. These commenters contend that the incredible costs associated with using the inflexible regulatory structure of the CAA will harm public health and welfare, and therefore EPA should exercise its discretion and find that greenhouse gases do not endanger public health and welfare because once EPA makes an endangerment finding under CAA section 202(a), it will be forced to regulate greenhouse gases under a number of other sections of the CAA, resulting in regulatory chaos.

At their core, these comments are not about whether commenters believe greenhouse gases may reasonably be anticipated to endanger public health or welfare, but rather about commenters' dissatisfaction with the decisions that Congress made regarding *the response* to any endangerment finding that EPA makes under CAA section 202(a). These comments do not discuss the science of greenhouse gases or climate change, or the impacts of climate change on public health or welfare. Instead they muddle the rather straightforward scientific judgment about whether there may be endangerment by throwing the potential impact of responding to the danger into the initial question. To use an analogy, the question of whether the cure is worse than the illness is different than the question of whether there is an illness in the first place. The question of whether there is endangerment is like the question of whether there is an illness. Once one knows there is an illness, then the next question is what to do, if anything, in response to that illness.

What these comments object to is that Congress has already made some decisions about next steps after a finding of endangerment, and commenters are displeased with the results. But if this is the case, commenters should take up their concerns with Congress, not EPA. EPA's charge is to issue new motor vehicle standards under CAA section 202(a) applicable to emissions of air pollutants that cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare. It is not to find that there is no endangerment in order to avoid issuing those standards, and dealing with any additional regulatory impact.

Indeed, commenters' argument would insert policy considerations into the endangerment decision, an approach already rejected by the Supreme Court. First, as discussed in Section I.B of these Findings, in *Massachusetts* v. *EPA*, the court clearly indicated that the Administrator's decision must be a ''scientific judgment.'' 549 U.S. at 534. She must base her decision about endangerment on the science, and not on policy considerations about the repercussions or impact of such a finding.

Second, in considering whether the CAA allowed for economic considerations to play a role in the promulgation of the NAAQS, the

Supreme Court rejected arguments that because many more factors than air pollution might affect public health, EPA should consider compliance costs that produce health losses in setting the NAAQS. *Whitman* v. *ATA*, 531 U.S. at 457, 466 (2001). To be sure, the language in CAA section 109(b) applicable to the setting of a NAAQS is different than that in CAA section 202(a) regarding endangerment. But the concepts are similar—the NAAQS are about setting standards at a level requisite to protect public health (with an adequate margin of safety) and public welfare, and endangerment is about whether the current or projected future levels may reasonably be anticipated to endanger public health or welfare. In other words, both decisions essentially are based on assessing the harm associated with a certain level of air pollution.

Given this similarity in purpose, as well as the Court's instructions in *Massachusetts* v. *EPA* that the Administrator should base her decision on the science, EPA reasonably interprets the statutory endangerment language to be analogous to setting the NAAQS. Therefore, it is reasonable to interpret the endangerment test as not requiring the consideration of the impacts of implementing the statute in the event of an endangerment finding as part of the endangerment finding itself.[16]

Moreover, EPA does not believe that the impact of regulation under the CAA as a whole, let alone that which will result from this particular endangerment finding, will lead to the panoply of adverse consequences that commenters predict. EPA has the ability to fashion a reasonable and common-sense approach to address greenhouse gas emissions and climate change. The Administrator thinks that EPA has and will continue to take a measured approach to address greenhouse gas emissions. For example, the Agency's recent Mandatory Greenhouse Gas Reporting Rule focuses on only the largest sources of greenhouse gases in order to reduce the burden on smaller facilities.[17]

We also note that commenters' approach also is another version of the argument that EPA must consider adaptation and mitigation in the endangerment determination. Just as EPA should consider whether mitigation would *reduce* endangerment, commenters argue we should consider whether mitigation would *increase* endangerment. But as discussed previously, EPA disagrees and believes its approach better achieves the goals of the statute.

Finally, EPA simply disagrees with the commenter who argues that because we are better off now than before the industrial revolution, greenhouse gases cannot be found to endanger public health or welfare. As the DC Circuit noted in the *Ethyl* decision, ''[m]an's ability to alter his environment has developed far more rapidly than his ability to foresee with certainty the effects of his alterations.'' See *Ethyl Corp.,* 541 F.2d at 6. The fact that we as a society are better off now than 100 years ago, and that processes that produce greenhouse gases are a large part of this improvement, does not mean that those processes do not have unintended adverse impacts. It also was entirely reasonable for EPA to look at ''emissions'' as the pollution once it is emitted from the source into the air, and not also as the process that generates the pollution. Indeed, the definition of ''air pollutant'' talks in terms of substances ''emitted into or otherwise enter[ing] the ambient air'' (CAA section 302(g)). It is entirely appropriate for EPA to consider only the substance being emitted as the air pollution or air pollutant.

IV. The Administrator's Finding That Greenhouse Gases Endanger Public Health and Welfare

The Administrator finds that elevated concentrations of greenhouse gases in the atmosphere may reasonably be anticipated to endanger the public health and to endanger the public welfare of current and future generations. The Administrator is making this finding specifically with regard to six key directly-emitted, long-lived and well-mixed greenhouse gases: Carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The Administrator is making this judgment based on both current observations and projected risks and impacts into the future. Furthermore, the Administrator is basing this finding on impacts of climate change within the United States. However, the Administrator finds that when she considers the impacts on the U.S. population of risks and impacts occurring in other world regions, the case for endangerment to public health and welfare is only strengthened.

A. The Air Pollution Consists of Six Key Greenhouse Gases

The Administrator must define the scope and nature of the relevant air pollution for the endangerment finding under CAA section 202(a). In this final action, the Administrator finds that the air pollution is the combined mix of six key directly-emitted, long-lived and well-mixed greenhouse gases (henceforth ''well-mixed greenhouse gases''), which together, constitute the root cause of human-induced climate change and the resulting impacts on public health and welfare. These six greenhouse gases are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

EPA received public comments on this definition of air pollution from the Proposed Findings, and summarizes responses to some of those key comments below; fuller responses to public comments can be found in EPA's Response to Comments document, Volume 9. The Administrator acknowledges that other anthropogenic climate forcers also play a role in climate change. Many public comments either supported or opposed inclusion of other substances in addition to the six greenhouse gases for the definition of air pollution. EPA's responses to those comments are also summarized below, and in volume 9 of the Response to Comments document.

The Administrator explained her rationale for defining air pollution under CAA section 202(a) as the combined mix of the six greenhouse gases in the Proposed Findings. After review of the public comments, the Administrator is using the same definition of the air pollution in the

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[16] Indeed, some persons may argue that due to the similarities between setting a NAAQS and making an endangerment finding, EPA cannot consider the impacts of implementation of the statute.

[17] Note that it is EPA's current position that these Final Findings do not make well-mixed greenhouse gases ''subject to regulation'' for purposes of the CAA's Prevention of Significant Deterioration (PSD) and title V programs. *See, e.g.*, memorandum entitled ''EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program'' (Dec. 18, 2008). While EPA is reconsidering this memorandum and is seeking public comment on the issues raised in it generally, including whether a final endangerment finding should trigger PSD, the effectiveness of the positions provided in the memorandum was not stayed pending that reconsideration. Prevention of Significant Deterioration (PSD): Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program, 74 FR 515135, 51543–44 (Oct. 7, 2009). In addition, EPA has proposed new temporary thresholds for greenhouse gas emissions that define when PSD and title V permits are required for new or existing facilities. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (74 FR 55292, October 27, 2009). The proposed thresholds would ''tailor'' the permit programs to limit which facilities would be required to obtain PSD and title V permits. As noted in the preamble for the tailoring rule proposal, EPA also intends to evaluate ways to streamline the process for identifying GHG emissions control requirements and issuing permits. See the Response to Comments Document, Volume 11, and the Tailoring Rule, for more information.

final finding, for the following reasons: (1) These six greenhouse gas share common properties regarding their climate effects; (2) these six greenhouse gases have been estimated to be the primary cause of human-induced climate change, are the best understood drivers of climate change, and are expected to remain the key driver of future climate change; (3) these six greenhouse gases are the common focus of climate change science research and policy analyses and discussions; (4) using the combined mix of these gases as the definition (versus an individual gas-by-gas approach) is consistent with the science, because risks and impacts associated with greenhouse gas-induced climate change are not assessed on an individual gas approach; and (5) using the combined mix of these gases is consistent with past EPA practice, where separate substances from different sources, but with common properties, may be treated as a class (*e.g.,* oxides of nitrogen).

1. Common Physical Properties of the Six Greenhouse Gases

The common physical properties relevant to the climate change problem shared by the six greenhouse gases include the fact that they are long-lived in the atmosphere. ''Long-lived'' is used here to mean that the gas has a lifetime in the atmosphere sufficient to become globally well mixed throughout the entire atmosphere, which requires a minimum atmospheric lifetime of about one year.[18] Thus, this definition of air pollution is global in nature because the greenhouse gas emissions emitted from the United States (or from any other region of the world) become globally well mixed, such that it would not be meaningful to define the air pollution as the greenhouse gas concentrations over the United States as somehow being distinct from the greenhouse gas concentrations over other regions of the world.

It is also well established that each of these gases can exert a warming effect on the climate by trapping in heat that would otherwise escape to space. These six gases are directly emitted as greenhouse gases rather than forming as a greenhouse gas in the atmosphere after emission of a pre-cursor gas. Given these properties, the magnitude of the warming effect of each of these gases is generally better understood than other climate forcing agents that do not share these same properties (addressed in more detail below). The ozone-depleting substances that include chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HFCs) also share the same physical attributes discussed here, but for reasons discussed throughout the remainder of this section are not being included in the Administrator's definition of air pollution for this finding.

2. Evidence That the Six Greenhouse Gases Are the Primary Driver of Current and Projected Climate Change

a. Key Observations Driven Primarily by the Six Greenhouse Gases

The latest assessment of the USGCRP, as summarized in EPA's TSD, confirms the evidence presented in the Proposed Findings that current atmospheric greenhouse gas concentrations are now at elevated and essentially unprecedented levels as a result of both historic and current anthropogenic emissions. The global atmospheric carbon dioxide concentration has increased about 38 percent from pre-industrial levels to 2009, and almost all of the increase is due to anthropogenic emissions. The global atmospheric concentration of methane has increased by 149 percent since pre-industrial levels (through 2007); and the nitrous oxide concentration has increased 23 percent (through 2007). The observed concentration increase in these gases can also be attributed primarily to anthropogenic emissions. The industrial fluorinated gases have relatively low concentrations, but these concentrations have also been increasing and are almost entirely anthropogenic in origin.

Historic data show that current atmospheric concentrations of the two most important directly emitted, long-lived greenhouse gases (carbon dioxide and methane) are well above the natural range of atmospheric concentrations compared to at least the last 650,000 years. Atmospheric greenhouse gas concentrations have been increasing because anthropogenic emissions are outpacing the rate at which greenhouse gases are removed from the atmosphere by natural processes over timescales of decades to centuries. It also remains clear that these high atmospheric concentrations of greenhouse gases are the unambiguous result of human activities.

Together the six well-mixed greenhouse gases constitute the largest anthropogenic driver of climate change.[19] Of the total anthropogenic heating effect caused by the accumulation of the six well-mixed greenhouse gases plus other warming agents (that do not meet all of the Administrator's criteria that pertain to the six greenhouse gases) since pre-industrial times, the combined heating effect of the six well-mixed greenhouses is responsible for roughly 75 percent, and it is expected that this share may grow larger over time, as discussed below.

Warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global average sea level. Global mean surface temperatures have risen by 0.74 °C (1.3 °F) (±0.18 °C) over the last 100 years. Eight of the 10 warmest years on record have occurred since 2001. Global mean surface temperature was higher during the last few decades of the 20th century than during any comparable period during the preceding four centuries.

The global surface temperature record relies on three major global temperature datasets, developed by NOAA, NASA, and the United Kingdom's Hadley Center. All three show an unambiguous warming trend over the last 100 years, with the greatest warming occurring over the past 30 years.[20] Furthermore, all three datasets show that eight of the 10 warmest years on record have occurred since 2001; that the 10 warmest years have all occurred in the past 12 years; and that the 20 warmest years have all occurred since 1981. Though most of the warmest years on record have occurred in the last decade in all available datasets, the rate of warming has, for a short time in the

[18] The IPCC also refers to these six GHGs as long-lived. Methane has an atmospheric lifetime of roughly a decade. One of the most commonly used hydrofluorocarbons (HFC–134a) has a lifetime of 14 years. Nitrous oxide has a lifetime of 114 years; sulfur hexafluoride over 3,000 years; and some PFCs up to 10,000 to 50,000 years. Carbon dioxide in the atmosphere is sometimes approximated as having a lifetime of roughly 100 years, but for a given amount of carbon dioxide emitted a better description is that some fraction of the atmospheric increase in concentration is quickly absorbed by the oceans and terrestrial vegetation, some fraction of the atmospheric increase will only slowly decrease over a number of years, and a small portion of the increase will remain for many centuries or more.

[19] As summarized in EPA's TSD, the global average net effect of the increase in atmospheric greenhouse gas concentrations, plus other human activities (*e.g.,* land use change and aerosol emissions), on the global energy balance since 1750 has been one of warming. This total net heating effect, referred to as forcing, is estimated to be +1.6 (+0.6 to +2.4) Watts per square meter (W/m^2), with much of the range surrounding this estimate due to uncertainties about the cooling and warming effects of aerosols. The combined radiative forcing due to the cumulative (*i.e.,* 1750 to 2005) increase in atmospheric concentrations of CO_2, CH_4, and N_2O is estimated to be +2.30 (+2.07 to +2.53) W/m^2. The rate of increase in positive radiative forcing due to these three GHGs during the industrial era is very likely to have been unprecedented in more than 10,000 years.

[20] *See* section 4 of the TSD for more detailed information about the three global temperature datasets.

Hadley Center record, slowed. However, the NOAA and NASA trends do not show the same marked slowdown for the 1999–2008 period. Year-to-year fluctuations in natural weather and climate patterns can produce a period that does not follow the long-term trend. Thus, each year may not necessarily be warmer than every year before it, though the long-term warming trend continues.[21]

The scientific evidence is compelling that elevated concentrations of heat-trapping greenhouse gases are the root cause of recently observed climate change. The IPCC conclusion from 2007 has been re-confirmed by the June 2009 USGCRP assessment that most of the observed increase in global average temperatures since the mid-20th century is very likely[22] due to the observed increase in anthropogenic greenhouse gas concentrations. Climate model simulations suggest natural forcing alone (*e.g.,* changes in solar irradiance) cannot explain the observed warming.

The attribution of observed climate change to anthropogenic activities is based on multiple lines of evidence. The first line of evidence arises from our basic physical understanding of the effects of changing concentrations of greenhouse gases, natural factors, and other human impacts on the climate system. The second line of evidence arises from indirect, historical estimates of past climate changes that suggest that the changes in global surface temperature over the last several decades are unusual.[23] The third line of evidence arises from the use of computer-based climate models to simulate the likely patterns of response of the climate system to different forcing mechanisms (both natural and anthropogenic).

The claim that natural internal variability or known natural external forcings can explain most (more than half) of the observed global warming of the past 50 years is inconsistent with the vast majority of the scientific literature, which has been synthesized in several assessment reports. Based on analyses of widespread temperature increases throughout the climate system and changes in other climate variables, the IPCC has reached the following conclusions about external climate forcing: ''It is extremely unlikely (<5 percent) that the global pattern of warming during the past half century can be explained without external forcing, and very unlikely that it is due to known natural external causes alone'' (Hegerl *et al.,* 2007). With respect to internal variability, the IPCC reports the following: ''The simultaneous increase in energy content of all the major components of the climate system as well as the magnitude and pattern of warming within and across the different components supports the conclusion that the cause of the [20th century] warming is extremely unlikely (<5 percent) to be the result of internal processes'' (Hegerl *et al.,* 2007). As noted in the TSD, the observed warming can only be reproduced with models that contain both natural and anthropogenic forcings, and the warming of the past half century has taken place at a time when known natural forcing factors alone (solar activity and volcanoes) would likely have produced cooling, not warming.

United States temperatures also warmed during the 20th and into the 21st century; temperatures are now approximately 0.7 °C (1.3 °F) warmer than at the start of the 20th century, with an increased rate of warming over the past 30 years. Both the IPCC and CCSP reports attributed recent North American warming to elevated greenhouse gas concentrations. The CCSP (2008g) report finds that for North America, ''more than half of this warming [for the period 1951–2006] is likely the result of human-caused greenhouse gas forcing of climate change.''

Observations show that changes are occurring in the amount, intensity, frequency, and type of precipitation. Over the contiguous United States, total annual precipitation increased by 6.1 percent from 1901–2008. It is likely that there have been increases in the number of heavy precipitation events within many land regions, even in those where there has been a reduction in total precipitation amount, consistent with a warming climate.

There is strong evidence that global sea level gradually rose in the 20th century and is currently rising at an increased rate. It is very likely that the response to anthropogenic forcing contributed to sea level rise during the latter half of the 20th century. It is not clear whether the increasing rate of sea level rise is a reflection of short-term variability or an increase in the longer-term trend. Nearly all of the Atlantic Ocean shows sea level rise during the last 50 years with the rate of rise reaching a maximum (over 2 mm per year) in a band along the U.S. east coast running east-northeast.

Satellite data since 1979 show that annual average Arctic sea ice extent has shrunk by 4.1 percent per decade. The size and speed of recent Arctic summer sea ice loss is highly anomalous relative to the previous few thousands of years.

Widespread changes in extreme temperatures have been observed in the last 50 years across all world regions including the United States. Cold days, cold nights, and frost have become less frequent, while hot days, hot nights, and heat waves have become more frequent.

Observational evidence from all continents and most oceans shows that many natural systems are being affected by regional climate changes, particularly temperature increases. However, directly attributing specific regional changes in climate to emissions of greenhouse gases from human activities is difficult, especially for precipitation.

Ocean carbon dioxide uptake has lowered the average ocean pH (increased the acidity) level by approximately 0.1 since 1750. Consequences for marine ecosystems may include reduced calcification by shell-forming organisms, and in the longer term, the dissolution of carbonate sediments.

Observations show that climate change is currently affecting U.S. physical and biological systems in significant ways. The consistency of these observed changes in physical and biological systems and the observed significant warming likely cannot be explained entirely due to natural variability or other confounding non-climate factors.

b. Key Projections Based Primarily on Future Scenarios of the Six Greenhouse Gases

There continues to be no reason to expect that, without substantial and near-term efforts to significantly reduce emissions, atmospheric levels of greenhouse gases will not continue to climb, and thus lead to ever greater rates of climate change. Given the long atmospheric lifetime of the six greenhouse gases, which range from roughly a decade to centuries, future atmospheric greenhouse gas

[21] Karl T. *et al.,* (2009).

[22] The IPCC Fourth Assessment Report uses specific terminology to convey likelihood and confidence. Likelihood refers to a probability that the statement is correct or that something will occur. ''Virtually certain'' conveys greater than 99 percent probability of occurrence; ''very likely'' 90 to 99 percent; ''likely'' 66 to 90 percent. IPCC assigns confidence levels as to the correctness of a statement. ''Very high confidence'' conveys at least 9 out of 10 chance of being correct; ''high confidence'' about 8 out of 10 chance; ''medium confidence'' about 5 out of 10 chance. The USGCRP uses the same or similar terminology in its reports. See also Box 1.2 of the TSD. Throughout this document, this terminology is used in conjunction with statements from the IPCC and USGCRP reports to convey the same meaning that those reports intended. In instances where a word such as ''likely'' may appear outside the context of a specific IPCC or USGCRP statement, it is not meant to necessarily convey the same quantitative meaning as the IPCC terminology.

[23] Karl T. *et al.* (2009).

concentrations for the remainder of this century and beyond will be influenced not only by future emissions but indeed by present-day and near-term emissions. Consideration of future plausible scenarios, and how our current greenhouse gas emissions essentially commit present and future generations to cope with an altered atmosphere and climate, reinforces the Administrator's judgment that it is appropriate to define the combination of the six key greenhouse gases as the air pollution.

Most future scenarios that assume no explicit greenhouse gas mitigation actions (beyond those already enacted) project increasing global greenhouse gas emissions over the century, which in turn result in climbing greenhouse gas concentrations. Under the range of future emission scenarios evaluated by the assessment literature, carbon dioxide is expected to remain the dominant anthropogenic greenhouse gas, and thus driver of climate change, over the course of the 21st century. In fact, carbon dioxide is projected to be the largest contributor to total radiative forcing in all periods and the radiative forcing associated with carbon dioxide is projected to be the fastest growing. For the year 2030, projections of the six greenhouse gases show an increase of 25 to 90 percent compared with 2000 emissions. Concentrations of carbon dioxide and the other well-mixed gases increase even for those scenarios where annual emissions toward the end of the century are assumed to be lower than current annual emissions. The radiative forcing associated with the non-carbon dioxide well-mixed greenhouse gases is still important and increasing over time. Emissions of the ozone-depleting substances are projected to continue decreasing due to the phase-out schedule under the Montreal Protocol on Substances that Deplete the Ozone Layer. Considerable uncertainties surround the estimates and future projections of anthropogenic aerosols; future atmospheric concentrations of aerosols, and thus their respective heating or cooling effects, will depend much more on assumptions about future emissions because of their short atmospheric lifetimes compared to the six well-mixed greenhouse gases.

Future warming over the course of the 21st century, even under scenarios of low emissions growth, is very likely to be greater than observed warming over the past century. According to climate model simulations summarized by the IPCC, through about 2030, the global warming rate is affected little by the choice of different future emission scenarios. By the end of the century, projected average global warming (compared to average temperature around 1990) varies significantly depending on emissions scenario and climate sensitivity assumptions, ranging from 1.8 to 4.0 °C (3.2 to 7.2 °F), with an uncertainty range of 1.1 to 6.4 °C (2.0 to 11.5 °F).

All of the United States is very likely to warm during this century, and most areas of the United States are expected to warm by more than the global average. The largest warming is projected to occur in winter over northern parts of Alaska. In western, central and eastern regions of North America, the projected warming has less seasonal variation and is not as large, especially near the coast, consistent with less warming over the oceans.

3. The Six Greenhouse Gases Are Currently the Common Focus of the Climate Change Science and Policy Communities

The well-mixed greenhouse gases are currently the common focus of climate science and policy analyses and discussions. For example, the United Nations Framework Convention on Climate Change (UNFCCC), signed and ratified by the United States in 1992, requires its signatories to "develop, periodically update, publish and make available * * * national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies * * *" [24] [25] To date, the focus of UNFCCC actions and discussions has been on the six greenhouse gases that are the same focus of these Findings.

Because of these common properties, it has also become common practice to compare these gases on a carbon dioxide equivalent basis, based on each gas's warming effect relative to carbon dioxide (the designated reference gas) over a specified timeframe. For example, both the annual *Inventory of U.S. Greenhouse Gases and Sinks* published by EPA and the recently finalized EPA Mandatory Greenhouse Gas Reporting Rule (74 FR 56260), use the carbon dioxide equivalent metric to sum and compare these gases, and thus accept the common climate-relevant properties of these gases for their treatment as a group. This is also common practice internationally as the UNFCCC reporting guidelines for developed countries, and the Clean Development Mechanism procedures for developing countries both require the use of global warming potentials published by the IPCC to convert the six greenhouse gases into their respective carbon dioxide equivalent units.

4. Defining Air Pollution as the Aggregate Group of Six Greenhouse Gases Is Consistent With Evaluation of Risks and Impacts Due to Human-Induced Climate Change

Because the well-mixed greenhouse gases are collectively the primary driver of current and projected human-induced climate change, all current and future risks due to human-induced climate change—whether these risks are associated with increases in temperature, changes in precipitation, a rise in sea levels, changes in the frequency and intensity of weather events, or more directly with the elevated greenhouse gas concentrations themselves—can be associated with this definition of air pollution.

5. Defining the Air Pollution as the Aggregate Group of Six Greenhouse Gases Is Consistent With Past EPA Practice

Treating the air pollution as the aggregate of the well-mixed greenhouse gases is consistent with other provisions of the CAA and previous EPA practice under the CAA, where separate emissions from different sources but with common properties may be treated as a class (*e.g.,* particulate matter (PM)). This approach addresses the total, cumulative effect that the elevated concentrations of the six well-mixed greenhouse gases have on climate, and thus on different elements of health, society and the environment.[24]

EPA treats, for example, PM as a common class of air pollution; PM is a complex mixture of extremely small particles and liquid droplets. Particle pollution is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles.

6. Other Climate Forcers Not Being Included in the Definition of Air Pollution for This Finding

Though the well-mixed greenhouse gases that make up the definition of air pollution for purposes of making the endangerment decision under CAA section 202(a) constitute the primary

[24] Due to the cumulative purpose of the statutory language, even if the Administrator were to look at the atmospheric concentration of each greenhouse gas individually, she would still consider the impact of the concentration of a single greenhouse gas in combination with that caused by the other greenhouse gases.

[25] The range of uncertainty in the current magnitude of black carbon's climate forcing effect is evidenced by the ranges presented by the IPCC Fourth Assessment Report (2007) and the more recent study by Ramanathan, V. and Carmichael, G. (2008) Global and regional climate changes due to black carbon. Nature Geoscience, 1(4): 221–227.

driver of human-induced climate change, there are other substances emitted from human activities that contribute to climate change and deserve careful attention, but are not being included in the air pollution definition for this particular action. These substances are discussed immediately below.

a. Black Carbon

Several commenters request that black carbon be included in the definition of air pollution because of its warming effect on the climate. Black carbon is not a greenhouse gas, rather, it is an aerosol particle that results from the incomplete combustion of carbon contained in fossil fuels and biomass, and remains in the atmosphere for only about a week. Unlike any of the greenhouse gases being addressed by this action, black carbon is a component of particulate matter (PM), where PM is a criteria air pollutant under section 108 of the CAA. The extent to which black carbon makes up total PM varies by emission source, where, for example, diesel vehicle PM emissions contain a higher fraction of black carbon compared to most other PM emission sources. Black carbon causes a warming effect primarily by absorbing incoming and reflected sunlight (whereas greenhouse gases cause warming by trapping outgoing, infrared heat), and by darkening bright surfaces such as snow and ice, which reduces reflectivity. This latter effect, in particular, has been raising concerns about the role black carbon may be playing in observed warming and ice melt in the Arctic.

As stated in the April 2009 Proposed Findings, there remain some significant scientific uncertainties about black carbon's total climate effect,[25] as well as concerns about how to treat the short-lived black carbon emissions alongside the long-lived, well-mixed greenhouse gases in a common framework (*e.g.,* what are the appropriate metrics to compare the warming and/or climate effects of the different substances, given that, unlike greenhouse gases, the magnitude of aerosol effects can vary immensely with location and season of emissions). Nevertheless, the Administrator recognizes that black carbon is an important climate forcing agent and takes very seriously the emerging science on black carbon's contribution to global climate change in general and the high rates of observed climate change in the Arctic in particular. As noted in the Proposed Findings, EPA has various pending petitions under the CAA calling on the Agency to make an endangerment finding and regulate black carbon emissions.

b. Other Climate Forcers

There are other climate forcers that play a role in human-induced climate change that were mentioned in the Proposed Findings, and were the subject of some public comments. These include the stratospheric ozone-depleting substances, nitrogen trifluoride (NF_3), water vapor, and tropospheric ozone.

As mentioned above, the ozone-depleting substances (CFCs and HCFCs) do share the same physical, climate-relevant attributes as the six well-mixed greenhouse gases; however, emissions of these substances are playing a diminishing role in human-induced climate change. They are being controlled and phased out under the Montreal Protocol on Substances that Deplete the Ozone Layer. Because of this, the major scientific assessment reports such as those from IPCC focus primarily on the same six well-mixed greenhouse gases included in the definition of air pollution in these Findings. It is also worth noting that the UNFCCC, to which the United States is a signatory, addresses ''all greenhouse gases not controlled by the Montreal Protocol.''[26] One commenter noted that because the Montreal Protocol controls production and consumption of ozone-depleting substances, but not existing banks of the substances, that CFCs should be included in the definition of air pollution in this finding, which might, in turn, create some future action under the CAA to address the banks of ozone-depleting substances as a climate issue. However, the primary criteria for defining the air pollution in this finding is the focus on the core of the climate change problem, and concerns over future actions to control depletion of stratospheric ozone are separate from and not central to the air pollution causing climate change.

Nitrogen trifluoride also shares the same climate-relevant attributes as the six well-mixed greenhouse gases, and it is also included in EPA's Mandatory Greenhouse Gas Reporting Rule (FR 74 56260). However, the Administrator is maintaining the reasoning laid out in the Proposed Findings to not include NF_3 in the definition of air pollution for this finding because the overall magnitude of its forcing effect on climate is not yet well quantified. EPA will continue to track the science on NF_3.

A number of public comments question the exclusion of water vapor from the definition of air pollution because it is the most important greenhouse gas responsible for the natural, background greenhouse effect. The Administrator's reasoning for excluding water vapor, was described in the Proposed Findings and is summarized here with additional information in Volume 10 of the Response to Comments document. First, climate change is being driven by the buildup in the atmosphere of greenhouse gases. The direct emissions primarily responsible for this are the six well-mixed greenhouse gases. Direct anthropogenic emissions of water vapor, in general, have a negligible effect and are thus not considered a primary driver of human-induced climate change. EPA plans to further evaluate the issues of emissions of water that are implicated in the formation of contrails and also changes in water vapor due to local irrigation. At this time, however, the findings of the IPCC state that the total forcing from these sources is small and that the level of understanding is low.

Water produced as a byproduct of combustion at low altitudes has a negligible contribution to climate change. The residence time of water vapor is very short (days) and the water content of the air in the long term is a function of temperature and partial pressure, with emissions playing no role. Additionally, the radiative forcing of a given mass of water at low altitudes is much less than the same mass of carbon dioxide. Water produced at higher altitudes could potentially have a larger impact. The IPCC estimated the contribution of changes in stratospheric water vapor due to methane and other sources, as well as high altitude contributions from contrails, but concluded that both contributions were small, with a low level of understanding. The report also addressed anthropogenic contributions to water vapor arising from large scale irrigation, but assigned it a very low level of understanding, and suggested that the cooling from evaporation might outweigh the warming from its small radiative contribution.

Increases in tropospheric ozone concentrations have exerted a significant anthropogenic warming effect since pre-industrial times. However, as explained in the Proposed Findings, tropospheric ozone is not a long-lived, well-mixed greenhouse gas, and it is not directly emitted. Rather it forms in the atmosphere from emissions of pre-cursor gases. There is increasing attention in climate change research and the policy community about the extent to which further reductions in tropospheric ozone levels may help

[26] UNFCCC, Art. 4.1(b).

slow down climate change in the near term. The Administrator views this issue seriously but maintains that tropospheric ozone is sufficiently different such that it deserves an evaluation and treatment separate from this finding.

7. Summary of Key Comments on Definition of Air Pollution

a. It Is Reasonable for the Administrator To Define the Air Pollution as Global Concentrations of the Well-Mixed Greenhouse Gases

Many commenters argue that EPA does not have the authority to establish domestic rights and obligations based on environmental conditions that are largely attributed to foreign nations and entities that are outside the jurisdiction of EPA under the CAA. They contend that in this case, the bulk of emissions that would lead to mandatory emissions controls under the CAA would not and could not be regulated under the CAA. They state that CAA requirements cannot be enforced against foreign sources of air pollution, and likewise domestic obligations under the CAA cannot be caused by foreign emissions that are outside the United States. The commenters argue that EPA committed procedural error by not addressing this legal issue of authority in the proposal.

Commenters cite no statutory text or judicial authority for this argument, and instead rely entirely on an analogy to the issues concerning the exercise of extra-territorial jurisdiction. The text of CAA section 202(a), however, does not support this claim. Nothing in CAA section 202(a) limits the term air pollution to those air pollution matters that are caused solely or in large part by domestic emissions. The only issue under CAA section 202(a) is whether the air pollution is reasonably anticipated to endanger, and whether emissions from one domestic source category—new motor vehicles—cause or contribute to this air pollution. Commenters would read into this an additional cause or contribute test—whether foreign sources cause or contribute to the air pollution in such a way that the air pollution is largely attributable to the foreign emissions, or the bulk of emissions causing the air pollution are from foreign sources. There is no such provision in CAA section 202(a). Congress was explicit about the contribution test it imposed, and the only source that is relevant for purposes of contribution is new motor vehicles. Commenters suggest an ill-defined criterion that is not in the statute.

In addition, as discussed in Section II of these Findings, Congress intentionally meant the agency to judge the air pollution endangerment criteria based on the ''cumulative impact of all sources of a pollutant,'' and not an incremental look at just the endangerment from a subset of sources. Commenters' arguments appear to lead to this result. Under the commenters' approach, in those cases where the bulk of emissions which form the air pollution come from foreign sources, EPA apparently would have no authority to make an endangerment finding. Logically, EPA would be left with the option of identifying and evaluating the air pollution attributable to domestic sources alone, and determining whether that narrowly defined form of air pollution endangers public health or welfare. This is the kind of unworkable, incremental approach that was rejected by the court in *Ethyl* and by Congress in the 1977 amendments adopting this provision.

The analogy to extra-territorial jurisdiction is also not appropriate. The endangerment finding itself does not exercise jurisdiction over any source, domestic or foreign. It is a judgment that is a precondition for exercising regulatory authority. Under CAA section 202(a), any exercise of regulatory authority following from this endangerment finding would be for new motor vehicles either manufactured in the United States or imported into the United States. There would be no extra-territorial exercise of jurisdiction. The core issues for endangerment focus on impacts inside the United States, not outside the United States. In addition, the contribution finding is based solely on the contribution from new motor vehicles built in or imported to the United States. The core judgments that need to be made under CAA section 202(a) are all focused on actions and impacts inside the United States. This does not raise any concerns about an extra-territorial exercise of jurisdiction. The basis for the endangerment and contribution findings is fully consistent with the principles underlying the desire to avoid exercises of extra-territorial jurisdiction. Any limitations on the ability to exercise control over foreign sources of emissions does not, however, call into question the authority under CAA section 202 to exercise control over domestic sources of emissions based on their contribution to an air pollution problem that is judged to endanger public health or welfare based on impacts occurring in the United States or otherwise affecting the United States and its citizens.

In essence, commenters are concerned about the effectiveness of the domestic control strategies that can be adopted to address a global air pollution problem that is caused only in part by domestic sources of emissions. While that is a quite valid and important policy concern, it does not translate into a legal limitation on EPA's authority to make an endangerment finding. Neither the text nor the legislative history of CAA section 202(a) support such an interpretation and Congress explicitly separated the decision on endangerment from the decision on what controls are required or appropriate once an affirmative endangerment finding has been made. The effectiveness of the resulting regulatory controls is not a relevant factor to determining endangerment.

EPA also committed no procedural flaw as argued by commenters. The proposal fully explored the interpretation of endangerment and cause or contribution under CAA section 202(a), and was very clear that EPA was considering air pollution to mean the elevated global concentration of greenhouse gases in the atmosphere, recognizing that these atmospheric concentrations were the result of world wide emissions, not just or even largely U.S. emissions. The separation of the effectiveness of the control strategy from the endangerment criteria, and the need to consider the cumulative impact of all sources in evaluating endangerment was clearly discussed. Commenters received fair notice of EPA's proposal and the basis for it.

Similarly, some commenters argue that EPA's proposal defines air pollution as global air pollution, but EPA is limited to evaluating domestic air only; in other words that EPA may only regulate domestic emissions with localized effects. They argue this limitation derives from the purpose of the CAA—to enhance the quality of the Nation's air resources, recognizing that air pollution prevention and control focus on the sources of the emissions, and are the primary responsibility of States and local governments. Therefore, commenters continue, that ''air pollution'' has to be air pollution that originates domestically and is to be addressed only at the domestic source. Sections 115 and 179B of the CAA, as discussed below, reflect this intention as well. The result, they conclude, is that ''air pollution'' as used in CAA section 202(a), includes only pollution that originates domestically, where the effects occur locally. They argue EPA has improperly circumvented this by a ''local-global-local'' analysis that injects global air pollution into the middle of the endangerment test.

The statutory arguments made by the commenters attempt to read an unrealistic limitation into the general provisions discussed. The issues are similar in nature to those raised by the commenters arguing that EPA has no authority to establish domestic rights and obligations based on environmental conditions that are largely attributable to emissions from foreign nations and entities that are outside the jurisdiction of EPA under the CAA. In both cases, the question is whether EPA has authority to make an endangerment finding when the air pollution of concern is a relatively homogenous atmospheric concentration of greenhouse gases. According to the commenters, although this global pool includes the air over the United States, and leads to impacts in the United States and on the U.S. population, Congress prohibited EPA from addressing this air pollution problem because of its global aspects.

The text of the CAA does not specifically address this, as the term air pollution is not defined. EPA interprets this term as including the air pollution problem involved in this case—elevated atmospheric concentration of greenhouse gases that occur in the air above the United States as well as across the globe, and where this pool of global gases leads to impacts in the United States and on the U.S. population. This is fully consistent with the statutory provisions discussed by commenters. This approach seeks to protect the Nation's air resources, as clearly the Nation's air resources are an integral part of this global pool. The Nation's air resources by definition are not an isolated atmosphere that only contains molecules emitted within the United States, or an atmosphere that bears no relationship to the rest of the globe's atmosphere. There is no such real world body of air. Protecting the Nation's resources of clean air means to protect the air in the real world, not an artificial construct of ''air'' that ignores the many situations where the air over our borders includes compounds and pollutants emitted outside our borders, and in this case to ignore the fact that the air over our borders will by definition have elevated concentrations of greenhouse gases only when the air around the globe also has such concentrations. The suggested narrow view of ''air pollution'' does not further the protection of the Nation's air resources, but instead attempts to limit such protection by defining these resources in a scientifically artificial way that does not comport with how the air in the atmosphere is formed or changes over time, how it relates to and interacts with air around the globe, and how the result of this can affect the U.S. population.

The approach suggested by commenters fails to provide an actual definition for EPA to follow—for example, would U.S. or domestic ''air pollution'' be limited to only those air concentrations composed of molecules that originated in the United States? Is there a degree of external gases or compounds that could be allowed? Would it ignore the interaction and relationship between the air over the U.S. borders and the air around the rest of the globe? The latter approach appears to be the one suggested by commenters. Commenters' approach presumably would call for EPA to only consider the effects that derive solely from the air over our borders, and to ignore any effects that occur within the United States that are caused by air around the globe. However the air over the United States will by definition affect climate change only in circumstances where the air around the world is also doing so. The impacts of the air over the United States cannot be assessed separately from the impacts from the global pool, as they occur together and work together to affect the climate. Ignoring the real world nature of the Nation's air resources, in the manner presumably suggested by the commenters, would involve the kind of unworkable, incremental, and artificially isolating approach that was rejected by the court in *Ethyl* and by Congress in 1977. Congress intended EPA to interpret this provision by looking at air pollutants and air pollution problems in a broad manner, not narrowly, to evaluate problems within their broader context and not to attempt to isolate matters in an artificial way that fails to account for the real world context that lead to health and welfare impacts on the public. Commenters' suggested interpretation fails to implement this intention of Congress.

Commenters in various places refer to the control of the pollution, and the need for it to be aimed at local sources. That is addressed in the standard setting portion of CAA section 202(a), as in other similar provisions. The endangerment provision does not address how the air pollution problem should be addressed—who should be regulated and how they should be regulated. The endangerment provision addresses a different issue—is there an air pollution problem that should be addressed? In that context, EPA rejects the artificially narrow interpretation suggested by the commenters, and believes its broader interpretation in this case is reasonable and consistent with the intention of Congress.

b. Consideration of Greenhouse Gases as Air Pollution Given Their Impact Is Through Climate Rather Than Direct Toxic Effects

A number of commenters argue that carbon dioxide and the other greenhouse gases should not be defined as the air pollution because these gases do not cause direct human health effects, such as through inhalation. Responses to such comments are summarized in Section IV.B.1 of these Findings in the discussion of the public health and welfare nature of the endangerment finding.

c. The Administrator's Reliance on the Global Temperature Data Is a Reasonable Indicator of Human-Induced Climate Change

We received many comments suggesting global temperatures have stopped warming. The commenters base this conclusion on temperature trends over only the last decade. While there have not been strong trends over the last seven to ten years in global surface temperature or lower troposphere temperatures measured by satellites, this pause in warming should not be interpreted as a sign that the Earth is cooling or that the science supporting continued warming is in error. Year-to-year variability in natural weather and climate patterns make it impossible to draw any conclusions about whether the climate system is warming or cooling from such a limited analysis. Historical data indicate short-term trends in long-term time series occasionally run counter to the overall trend. All three major global surface temperature records show a continuation of long-term warming. Over the last century, the global average temperature has warmed at the rate of about 0.13 °F (0.072 °C) per decade in all three records. Over the last 30 years, the global average surface temperature has warmed by about 0.30 °F (0.17 °C) per decade. Eight of the 10 warmest years on record have occurred since 2001 and the 20 warmest years have all occurred since 1981. Satellite measurements of the troposphere also indicate warming over the last 30 years at a rate of 0.20 to 0.27 °F (0.11 °C to 0.15 °C) per decade. Please see the relevant volume of the Response to Comments document for more detailed responses.

Some commenters indicate the global surface temperature records are biased by urbanization, poor siting of instruments, observation methods, and other factors. Our review of the literature suggests that these biases have in many cases been corrected for, are largely random where they remain, and therefore cancel out over large regions. Furthermore, we note that though the three global surface temperature records use differing techniques to analyze much of the same data, they produce almost the same results, increasing our confidence in their legitimacy. The assessment literature has concluded that warming of the climate system is unequivocal. The warming trend that is evident in all of the temperature records is confirmed by other independent observations, such as the melting of Arctic sea ice, the retreat of mountain glaciers on every continent, reductions in the extent of snow cover, earlier blooming of plants in the spring, and increased melting of the Greenland and Antarctic ice sheets. Please see the relevant volume of the Response to Comments document for more detailed responses.

A number of commenters argue that the warmth of the late 20th century is not unusual relative to the past 1,000 years. They maintain temperatures were comparably warm during the Medieval Warm Period (MWP) centered around 1000 A.D. We agree there was a Medieval Warm Period in many regions but find the evidence is insufficient to assess whether it was globally coherent. Our review of the available evidence suggests that Northern Hemisphere temperatures in the MWP were probably between 0.1 °C and 0.2 °C below the 1961–1990 mean and significantly below the level shown by instrumental data after 1980. However, we note significant uncertainty in the temperature record prior to 1600 A.D. Please see the relevant volume of the Response to Comments document for more detailed responses.

d. Ability To Attribute Observed Climate Change to Anthropogenic, Well-Mixed Greenhouse Gases

Many commenters question the link between observed temperatures and anthropogenic greenhouse gas emissions. They suggest internal variability of the climate system and natural forcings explain observed temperature trends and that anthropogenic greenhouse gases play, at most, a minor role. However, the attribution of most of the recent warming to anthropogenic activities is based on multiple lines of evidence. The first line of evidence arises from our basic physical understanding of the effects of changing concentrations of greenhouse gases, natural factors, and other human impacts on the climate system. Greenhouse gas concentrations have indisputably increased and their radiative properties are well established. The second line of evidence arises from indirect, historical estimates of past climate changes that suggest that the changes in global surface temperature over the last several decades are unusual. The third line of evidence arises from the use of computer-based climate models to simulate the likely patterns of response of the climate system to different forcing mechanisms (both natural and anthropogenic). These models are unable to replicate the observed warming unless anthropogenic emissions of greenhouse gases are included in the simulations. Natural forcing alone cannot explain the observed warming. In fact, the assessment literature [27] indicates the sum of solar and volcanic forcing in the past half century would likely have produced cooling, not warming. Please see the relevant volume of the Response to Comments for more detailed responses.

B. The Air Pollution Is Reasonably Anticipated To Endanger Both Public Health and Welfare

The Administrator finds that the elevated atmospheric concentrations of the well-mixed greenhouse gases may reasonably be anticipated to endanger the public health and welfare of current and future generations. This section describes the major pieces of scientific evidence supporting the Administrator's endangerment finding, discusses both the public health and welfare nature of the endangerment finding, and addresses a number of key issues the Administrator considered when evaluating the state of the science as well as key public comments on the Proposed Findings. Additional detail can be found in the TSD and the Response to Comments document.

As described in Section II of these Findings, the endangerment test under CAA section 202(a) does not require the Administrator to identify a bright line, quantitative threshold above which a positive endangerment finding can be made. The statutory language explicitly calls upon the Administrator to use her judgment. This section describes the general approach used by the Administrator in reaching the judgment that a positive endangerment finding should be made, as well as the specific rationale for finding that the greenhouse gas air pollution may reasonably be anticipated to endanger both public health and welfare.

First, the Administrator finds the scientific evidence linking human emissions and resulting elevated atmospheric concentrations of the six well-mixed greenhouse gases to observed global and regional temperature increases and other climate changes to be sufficiently robust and compelling. This evidence is briefly explained in more detail in Section V of these Findings. The Administrator recognizes that the climate change associated with elevated atmospheric concentrations of carbon dioxide and the other well-mixed greenhouse gases have the potential to affect essentially every aspect of human health, society and the natural environment. The Administrator is therefore not limiting her consideration of potential risks and impacts associated with human emissions of greenhouse gases to any one particular element of human health, sector of the economy, region of the country, or to any one particular aspect of the natural environment. Rather, the Administrator is basing her finding on the total weight of scientific evidence, and what the science has to say regarding the nature and potential magnitude of the risks and impacts across all climate-sensitive elements of public health and welfare, now and projected out into the foreseeable future.

The Administrator has considered the state of the science on how human emissions and the resulting elevated atmospheric concentrations of well-mixed greenhouse gases may affect each of the major risk categories, *i.e.,* those that are described in the TSD, which include human health, air quality, food production and agriculture, forestry, water resources, sea level rise and coastal areas, the energy sector, infrastructure and settlements, and ecosystems and wildlife. The Administrator understands that the nature and potential severity of impacts can vary across these different elements of public health and welfare, and that they can vary by region, as well as over time.

The Administrator is therefore aware that, because human-induced climate change has the potential to be far-reaching and multi-dimensional, not all

[27] Solomon, S., D. Qin, M. Manning, R.B. Alley, T. Berntsen, N.L. Bindoff, Z. Chen, A. Chidthaisong, J.M. Gregory, G.C. Hegerl, M. Heimann, B. Hewitson, B.J. Hoskins, F. Joos, J. Jouzel, V. Kattsov, U. Lohmann, T. Matsuno, M. Molina, N. Nicholls, J. Overpeck, G. Raga, V. Ramaswamy, J. Ren, M. Rusticucci, R. Somerville, T.F. Stocker, P. Whetton, R.A. Wood and D. Wratt (2007) Technical Summary. In: *Climate Change 2007: The Physical Science Basis.* Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor, and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Karl, T. et al. (2009).

risks and potential impacts can be characterized with a uniform level of quantification or understanding, nor can they be characterized with uniform metrics. Given this variety in not only the nature and potential magnitude of risks and impacts, but also in our ability to characterize, quantify and project into the future such impacts, the Administrator must use her judgment to weigh the threat in each of the risk categories, weigh the potential benefits where relevant, and ultimately judge whether these risks and benefits, when viewed in total, are judged to be endangerment to public health and/or welfare.

This has a number of implications for the Administrator's approach in assessing the nature and magnitude of risk and impacts across each of the risk categories. First, the Administrator has not established a specific threshold metric for each category of risk and impacts. Also, the Administrator is not necessarily placing the greatest weight on those risks and impacts which have been the subject of the most study or quantification.

Part of the variation in risks and impacts is the fact that climbing atmospheric concentrations of greenhouse gases and associated temperature increases can bring about some potential benefits to public health and welfare in addition to adverse risks. The current understanding of any potential benefits associated with human-induced climate change is described in the TSD and is taken into consideration here. The potential for both adverse and beneficial effects are considered, as well as the relative magnitude of such effects, to the extent that the relative magnitudes can be quantified or characterized. Furthermore, given the multiple ways in which the buildup of atmospheric greenhouse gases can cause effects (*e.g.,* via elevated carbon dioxide concentrations, via temperature increases, via precipitation increases, via sea level rise, and via changes in extreme events), these multiple pathways are considered. For example, elevated carbon dioxide concentrations may be beneficial to crop yields, but changes in temperature and precipitation may be adverse and must also be considered. Likewise, modest temperature increases may have some public health benefits as well as harms, and other pathways such as changes in air quality and extreme events must also be considered.

The Administrator has balanced and weighed the varying risks and effects for each sector. She has judged whether there is a pattern across the sector that supports or does not support an endangerment finding, and if so whether the support is of more or less weight. In cases where there is both a potential for benefits and risks of harm, the Administrator has balanced these factors by determining whether there appears to be any directional trend in the overall evidence that would support placing more weight on one than the other, taking into consideration all that is known about the likelihood of the various risks and effects and their seriousness. In all of these cases, the judgment is largely qualitative in nature, and is not reducible to precise metrics or quantification.

Regarding the timeframe for the endangerment test, it is the Administrator's view that both current and future conditions must be considered. The Administrator is thus taking the view that the endangerment period of analysis extend from the current time to the next several decades, and in some cases to the end of this century. This consideration is also consistent with the timeframes used in the underlying scientific assessments. The future timeframe under consideration is consistent with the atmospheric lifetime and climate effects of the six well-mixed greenhouse gases, and also with our ability to make reasonable and plausible projections of future conditions.

The Administrator acknowledges that some aspects of climate change science and the projected impacts are more certain than others. Our state of knowledge is strongest for recently observed, large-scale changes. Uncertainty tends to increase in characterizing changes at smaller (regional) scales relative to large (global) scales. Uncertainty also increases as the temporal scales move away from present, either backward, but more importantly forward in time. Nonetheless, the current state of knowledge of observed and past climate changes and their causes enables projections of plausible future changes under different scenarios of anthropogenic forcing for a range of spatial and temporal scales.

In some cases, where the level of sensitivity to climate of a particular sector has been extensively studied, future impacts can be quantified whereas in other instances only a qualitative description of a directional change, if that, may be possible. The inherent uncertainty in the direction, magnitude, and/or rate of certain future climate change impacts opens up the possibility that some changes could be more or less severe than expected, and the possibility of unanticipated outcomes. In some cases, low probability, high impact outcomes (*i.e.,* known unknowns) are possibilities but cannot be explicitly assessed.

1. The Air Pollution Is Reasonably Anticipated To Endanger Public Health

The Administrator finds that the well-mixed greenhouse gas air pollution is reasonably anticipated to endanger public health, for both current and future generations. The Administrator finds that the public health of current generations is endangered and that the threat to public health for both current and future generations will likely mount over time as greenhouse gases continue to accumulate in the atmosphere and result in ever greater rates of climate change.

After review of public comments, the Administrator continues to believe that climate change can increase the risk of morbidity and mortality and that these public health impacts can and should be considered when determining endangerment to public health under CAA section 202(a). As described in Section IV.B.1 of these Findings, the Administrator is not limited to only considering whether there are any direct health effects such as respiratory or toxic effects associated with exposure to greenhouse gases.

In making this public health finding, the Administrator considered direct temperature effects, air quality effects, the potential for changes in vector-borne diseases, and the potential for changes in the severity and frequency of extreme weather events. In addition, the Administrator considered whether and how susceptible populations may be particularly at risk. The current state of science on these effects from the major assessment reports is described in greater detail in the TSD, and our responses to public comments are provided in the Response to Comments Documents.

a. Direct Temperature Effects

It has been estimated that unusually hot days and heat waves are becoming more frequent, and that unusually cold days are becoming less frequent, as noted above. Heat is already the leading cause of weather-related deaths in the United States. In the future, severe heat waves are projected to intensify in magnitude and duration over the portions of the United States where these events already occur. Heat waves are associated with marked short-term increases in mortality. Hot temperatures have also been associated with increased morbidity. The projected warming is therefore projected to increase heat related mortality and morbidity, especially among the elderly, young and frail. The populations most sensitive to hot temperatures are older adults, the chronically sick, the very young, city-dwellers, those taking medications that disrupt thermoregulation, the mentally ill, those lacking access to air conditioning, those working or playing outdoors, and socially isolated persons. As warming increases over time, these adverse effects would be expected to increase as the serious heat events become more serious.

Increases in temperature are also expected to lead to some reduction in the risk of death related to extreme cold. Cold waves continue to pose health risks in northern latitudes in temperature regions where very low temperatures can be reached in a few hours and extend over long periods. Globally, the IPCC projects reduced human mortality from cold exposure through 2100. It is not clear whether reduced mortality in the United States from cold would be greater or less than increased heat-related mortality in the United States due to climate change. However, there is a risk that projections of cold-related deaths, and the potential for decreasing their numbers due to warmer winters, can be overestimated unless they take into account the effects of season and influenza, which is not strongly associated with monthly winter temperature. In addition, the latest USGCRP report refers to a study that analyzed daily mortality and weather data in 50 U.S. cities from 1989 to 2000 and found that, on average, cold snaps in the United States increased death rates by 1.6 percent, while heat waves triggered a 5.7 percent increase in death rates. The study concludes that increases in heat-related mortality due to global warming in the United States are unlikely to be compensated for by decreases in cold-related mortality.

b. Air Quality Effects

Increases in regional ozone pollution relative to ozone levels without climate change are expected due to higher temperatures and weaker circulation in the United States relative to air quality levels without climate change. Climate change is expected to increase regional ozone pollution, with associated risks in respiratory illnesses and premature death. In addition to human health effects, tropospheric ozone has significant adverse effects on crop yields, pasture and forest growth, and species composition. The directional effect of climate change on ambient particulate matter levels remains less certain.

Climate change can affect ozone by modifying emissions of precursors, atmospheric chemistry, and transport and removal. There is now consistent evidence from models and observations that 21st century climate change will worsen summertime surface ozone in polluted regions of North America compared to a future with no climate change.

Modeling studies discussed in EPA's Interim Assessment [28] show that simulated climate change causes increases in summertime ozone concentrations over substantial regions of the country, though this was not uniform, and some areas showed little change or decreases, though the decreases tend to be less pronounced than the increases. For those regions that showed climate-induced increases, the increase in maximum daily 8-hour average ozone concentration, a key metric for regulating U.S. air quality, was in the range of 2 to 8 ppb, averaged over the summer season. The increases were substantially greater than this during the peak pollution episodes that tend to occur over a number of days each summer. The overall effect of climate change was projected to increase ozone levels, compared to what would occur without this climate change, over broad areas of the country, especially on the highest ozone days and in the largest metropolitan areas with the worst ozone problems. Ozone decreases are projected to be less pronounced, and generally to be limited to some regions of the country with smaller population.

c. Effects on Extreme Weather Events

In addition to the direct effects of temperature on heat- and cold-related mortality, the Administrator considers the potential for increased deaths, injuries, infectious diseases, and stress-related disorders and other adverse effects associated with social disruption and migration from more frequent extreme weather. The Administrator notes that the vulnerability to weather disasters depends on the attributes of the people at risk (including where they live, age, income, education, and disability) and on broader social and environmental factors (level of disaster preparedness, health sector responses, and environmental degradation). The IPCC finds the following with regard to extreme events and human health:

Increases in the frequency of heavy precipitation events are associated with increased risk of deaths and injuries as well as infectious, respiratory, and skin diseases. Floods are low-probability, high-impact events that can overwhelm physical infrastructure, human resilience, and social organization. Flood health impacts include deaths, injuries, infectious diseases, intoxications, and mental health problems.

Increases in tropical cyclone intensity are linked to increases in the risk of deaths, injuries, waterborne and food borne diseases, as well as post-traumatic stress disorders. Drowning by storm surge, heightened by rising sea levels and more intense storms (as projected by IPCC), is the major killer in coastal storms where there are large numbers of deaths. Flooding can cause health impacts including direct injuries as well as increased incidence of waterborne diseases due to pathogens such as *Cryptosporidium and Giardia.*

d. Effects on Climate-Sensitive Diseases and Aeroallergens

According to the assessment literature, there will likely be an increase in the spread of several food and water-borne pathogens among susceptible populations depending on the pathogens' survival, persistence, habitat range and transmission under changing climate and environmental conditions. Food borne diseases show some relationship with temperature, and the range of some zoonotic disease carriers such as the Lyme disease carrying tick may increase with temperature.

Climate change, including changes in carbon dioxide concentrations, could impact the production, distribution, dispersion and allergenicity of aeroallergens and the growth and distribution of weeds, grasses, and trees that produce them. These changes in aeroallergens and subsequent human exposures could affect the prevalence and severity of allergy symptoms. However, the scientific literature does not provide definitive data or conclusions on how climate change might impact aeroallergens and subsequently the prevalence of allergenic illnesses in the United States.

It has generally been observed that the presence of elevated carbon dioxide concentrations and temperatures stimulate plants to increase photosynthesis, biomass, water use efficiency, and reproductive effort. The IPCC concluded that pollens are likely to increase with elevated temperature and carbon dioxide.

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[28] U.S. EPA (2009) *Assessment of the Impacts of Global Change on Regional U.S. Air Quality: A Synthesis of Climate Change Impacts on Ground-Level Ozone*. An Interim Report of the U.S. EPA Global Change Research Program. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–07/094.

e. Summary of the Administrator's Finding of Endangerment to Public Health

The Administrator has considered how elevated concentrations of the well-mixed greenhouse gases and associated climate change affect public health by evaluating the risks associated with changes in air quality, increases in temperatures, changes in extreme weather events, increases in food and water borne pathogens, and changes in aeroallergens. The evidence concerning adverse air quality impacts provides strong and clear support for an endangerment finding. Increases in ambient ozone are expected to occur over broad areas of the country, and they are expected to increase serious adverse health effects in large population areas that are and may continue to be in nonattainment. The evaluation of the potential risks associated with increases in ozone in attainment areas also supports such a finding.

The impact on mortality and morbidity associated with increases in average temperatures which increase the likelihood of heat waves also provides support for a public health endangerment finding. There are uncertainties over the net health impacts of a temperature increase due to decreases in cold-related mortality, but there is some recent evidence that suggests that the net impact on mortality is more likely to be adverse, in a context where heat is already the leading cause of weather-related deaths in the United States.

The evidence concerning how human-induced climate change may alter extreme weather events also clearly supports a finding of endangerment, given the serious adverse impacts that can result from such events and the increase in risk, even if small, of the occurrence and intensity of events such as hurricanes and floods. Additionally, public health is expected to be adversely affected by an increase in the severity of coastal storm events due to rising sea levels.

There is some evidence that elevated carbon dioxide concentrations and climate changes can lead to changes in aeroallergens that could increase the potential for allergenic illnesses. The evidence on pathogen borne disease vectors provides directional support for an endangerment finding. The Administrator acknowledges the many uncertainties in these areas. Although these adverse effects, provide some support for an endangerment finding, the Administrator is not placing primary weight on these factors.

Finally, the Administrator places weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to these climate-related health effects.

f. Key Comments on the Finding of Endangerment to Public Health

EPA received many comments on public health issues and the proposed finding of endangerment to public health.

i. EPA's Consideration of the Climate Impacts as Public Health Issues Is Reasonable

Several commenters argue that EPA may only consider the health effects from direct exposure to pollutants in determining whether a pollutant endangers public health. The commenters state that EPA's proposal acknowledges that there is no evidence that greenhouse gases directly cause health effects, citing 74 FR 18901. To support their claim that EPA can only consider health effects that result from direct exposure to a pollutant, commenters cite several sources, discussed below.

Clean Air Act and Legislative History. Several commenters argue that the text of the CAA and the legislative history of the 1977 amendments demonstrate that Congress intended public health effects to relate to risks from direct exposure to a pollutant. They also argue that by considering health effects that result from welfare effects, EPA was essentially combining the two categories into one, contrary to the statute and Congressional intent.

Commenters state that the CAA, including CAA section 202(a)(1), requires EPA to consider endangerment of public health separately from endangerment of public welfare. Commenters note that while the CAA does not provide a definition of public health, CAA section 302(h) addresses the meaning of ''welfare,'' which includes weather and climate. Thus, they argue, Congress has instructed that effects on weather and climate are to be considered as potentially endangering welfare—not human health. They continue that Congress surely knew that weather and climatic events such as flooding and heat waves could affect human health, but Congress nonetheless classified air pollutants' effects on weather and climate as effects on welfare.

Commenters also argue that the legislative history confirms that Congress intended for the definition of ''public health'' to only include the consequences of direct human exposure to ambient air pollutants. They note an early version of section 109(b) would have required only a single NAAQS standard to protect ''public health,'' with the protection of ''welfare'' being a co-benefit of the single standard. Commenters note that the proponents of this early bill explained, ''[i]n many cases, a level of protection of health would take care of the welfare situation'' Sen. Hearing, Subcommittee on Air and Water Pollution, Comm. On Public Works (Mar. 17, 1970) (statement of Dr. Middleton, Comm'r, Nat'l Air Pollution Control Admin., HEW), 1970 Leg. Hist. 1194. Commenters state that the Senate bill that ultimately passed rejected this combined standard, requiring separate national ambient air quality standards and national ambient air quality goals. Commenters contend that Congress intended that the national ambient air quality goals be set ''to protect the public health and welfare from any known or anticipated effects associated with'' air pollution, including the list of ''welfare'' effects currently found in CAA section 302(h), such as effects on water, vegetation, animals, wildlife, weather and climate. Commenters note the Senate Committee Report stated that the national ambient air quality *standards* were created to protect public health, while the national ambient air quality *goals* were intended to address broader issues because ''the Committee also recognizes that man's natural and man-made environment must be preserved and protected. Therefore, the bill provides for the setting of national ambient air quality goals at levels necessary to protect public health and welfare from any known or anticipated adverse effects of air pollution—including effects on soils, water, vegetation, man-made materials, animals, wildlife, visibility, climate, and economic values.'' Commenters argue this statement is clearly the source of the current definition of welfare effects in CAA section 302(h), which also includes ''personal comfort and well being.'' They argue the Senate bill contemplated the NAAQS would include only direct health effects, while the *goals* would encompass effects on both the public health and welfare. Commenters continue that considering both public health effects and welfare effects under a combined standard, as the Administrator attempts to do in the proposed endangerment finding, would resurrect the combined approach to NAAQS that the Senate emphatically rejected.

The commenters also cite language from the House Report in support of their view that Congress only intended that EPA consider direct health effects when assessing endangerment to public health: ''By the words 'cause or contribute to air pollution,' the committee intends to require the Administrator to consider all sources of the contaminant which contributes to air pollution and to consider all sources of exposure to the contaminant—food, water, air, etc.—in determining health risks'' 7 H.R. Rep. No. 95–294, at 49–50 (1977). Commenters also cite language in the Senate Report: ''Knowledge of the relationship between the exposure to many air pollution agents and acute and chronic health effects is sufficient to develop air quality criteria related to such effects'' S. Rep. No. 91–1196, at 7 (1970).

The specific issue here is whether an effect on human health that results from a change in climate should be considered when EPA determines whether the air pollution of well-mixed greenhouse gases is reasonably anticipated to endanger public health. In this case, the air pollution has an effect on climate. For example the air pollution raises surface, air, and water temperatures. Among the many effects that flow from this is the expectation that there will be an increase in the risk of mortality and morbidity associated with increased intensity of heat waves. In addition, there is an expectation that there will be an increase in levels of ambient ozone, leading to increased risk of morbidity and mortality from exposure to ozone. All of these are effects on human health, and all of them are associated with the effect on climate from elevated atmospheric concentrations of greenhouse gases. None of these human health effects are associated with direct exposure to greenhouse gases.

In the past, EPA has not had to resolve the issue presented here, as it has been clear whether the effects relate to public health or relate to public welfare, with no confusion over what category was at issue. In those cases EPA has routinely looked at what effect the air pollution has on people. If the effect on people is to their health, we have considered it an issue of public health. If the effect on people is to their interest in matters other than health, we have considered it public welfare.

For example, there are serious health risks associated with inhalation of ozone, and they have logically been considered as public health issues. Ambient levels of ozone have also raised the question of indirect health benefits through screening of harmful UVB rays. EPA has also considered this indirect health effect of ozone to be a public health issue.[29] Ozone pollution also affects people by impacting their interests in various vegetation through foliar damage to trees, reduced crop yield, adverse impacts on horticultural plants, and the like. EPA has consistently considered these issues when evaluating the public welfare based NAAQS standards under CAA section 109.

In all of these situations the use of the term ''public'' has focused EPA on how people are affected by the air pollution. If the effect on people is to their health then we have considered it a public health issue. If the effect on people is to their interest in matters other than health, then we have treated it as a public welfare issue.

The situation presented here is somewhat unique. The focus again is on the effect the air pollution has on people. Here the effect on people is to their health. However this effect flows from the change in climate and effects on climate are included in the definition of effects on welfare. That raises the issue of how to categorize the health effects—should we consider them when evaluating endangerment to public health? When we evaluate endangerment to public welfare? Or both?

The text of the CAA does not resolve this question. While Congress defined ''effects on welfare,'' it did not define either ''public health'' or ''public welfare''. In addition, the definition of ''effects on welfare'' does not clearly address how to categorize health effects that flow from effects on soils, water, crops, vegetation, weather, climate, or any of the other factors listed in CAA section 302(h). It is clear that effects on climate are an effect on welfare, but the definition does not address whether health impacts that are caused by these changes in climate are also effects on welfare. The health effects at issue are not themselves effects on soils, water, crops, vegetation, weather, or climate. They are instead effects on health. They derive from the effects on climate, but they are not themselves effects on climate or on anything else listed in CAA section 302(h). So the definition of effects on welfare does not address whether an effect on health, which is not itself listed in CAA section 302(h), is also an effect on welfare if it results from an effect on welfare. The text of the CAA also does not address the issue of direct and indirect health effects. Contrary to commenters' assertions, the legislative history does not address or resolve this issue.

In this context, EPA is interpreting the endangerment provision in CAA section 202(a) as meaning that the effects on peoples' health from changes to climate can and should be included in EPA's evaluation of whether the air pollution at issue endangers public health. EPA is not deciding whether these health effects also could or should be considered in evaluating endangerment to public welfare.

The stating of the issue makes the answer seem straightforward. If air pollution causes sickness or death, then these health effects should be considered when evaluating whether the air pollution endangers public health. The term public health is undefined, and by itself this is an eminently reasonable way to interpret it. This focuses on the actual effect on people, as compared to ignoring that and focusing on the pathway from the air pollution to the effect. The question then becomes whether there is a valid basis in the CAA to take the different approach suggested by commenters, an approach contrary to the common sense meaning of public health.

Notably, the term ''public welfare'' is undefined. While it clearly means something other than public health, there is no obvious indication whether Congress intended there to be a clear boundary between the two terms or whether there might be some overlap where some impacts could be considered both a public health and a public welfare impact. Neither the text nor the legislative history resolves this issue. Under either approach, EPA believes the proper interpretation is that these effects on health should be considered when evaluating endangerment to public health.

If we assume Congress intended that effects on public welfare could not include effects on public health and vice versa, then the effects at issue here should most reasonably be considered in the public health category. Indisputably they are health effects, and the plain meaning of the term public health would call for their inclusion in that term. The term public welfare is

[29] As discussed later, in the past EPA took the position that this kind of potential indirect beneficial impact on public health should not be considered when setting the primary health based NAAQS for ozone. This was not based on the view that it was not a potential public health impact, or that it was a public welfare impact instead of a public health impact. Instead EPA was interpreting the NAAQS standard setting provisions of section 109, and argued that they were intended to address only certain public health impacts, those that were adverse, and were not intended to address indirect, beneficial public health impacts. This interpretation of section 109 was rejected in *ATA* v. *EPA*, 175 F.3d 1027 (1999) *reh'g granted in part and denied in part*, 195 F.3d 4 (DC Cir. 1999). The court made it clear that the potential indirect beneficial impact of ambient ozone on public health from screening UVB rays needed to be considered when setting the NAAQS to protect public health.

undefined. If Congress intended that public welfare not include matters included in the public health category, then a reasonable interpretation of this undefined term would include those effects on welfare that impact people in ways other than impacting their health.

The definition of ''effects on welfare'' does not clearly address how to categorize health effects that flow from effects on water, soil, land, climate, or weather. As noted above, the definition does not address whether health impacts that are caused by these changes in climate are also ''effects on welfare.'' Certainly effects on health are not included in the list in CAA section 302(h). The lack of clarity in the definition of effects on welfare, combined with the lack of definition of public welfare, do not warrant interpreting the term public health differently from its straightforward and common sense meaning.

The inclusion of the phrase ''effects on * * * personal comfort and well-being'' as an effect on welfare supports this view. The term would logically mean something other than the different term public health. The term ''well-being'' is not defined, and generally has a broader and different connotation of positive physical, emotional, and mental status. The most straightforward meaning of this term, in a context where Congress used the different term public health in a wide variety of other provisions, would be to include effects on people that do not rise to the level of health effects, but otherwise impact their physical, emotional, and mental status. This gives full meaning to both terms.

The term well-being is a general term, and in isolation arguably could include health effects. However there is no textual basis to say it would include some health effects but not others, as argued by commenters. If sickness impacts your well-being, then it impacts your well-being whether it results directly or indirectly from the pollution in the air. Nothing in CAA section 302(h) limits the term well-being to indirect impacts on people, or to health effects that occur because of other welfare effects, such as climate change. It is listed as its own effect on welfare. Instead of interpreting well-being as including all health effects, or some health effects, the much more logical way to interpret this provision in the context of all of the other provisions of the CAA is to interpret it as meaning effects on people other than health effects.

Thus, if Congress intended to draw a strict line between the two categories of public health and public welfare, for purposes of determining endangerment under CAA section 202(a), then EPA believes that its interpretation is a reasonable and straightforward way to categorize the health effects at issue here. This gives weight to the common sense meaning of the term public health, where the terms public health and public welfare are undefined and the definition of effects on welfare is at best ambiguous on this issue.

In the alternative, if Congress did not intend any such bright line between these two categories and there could be an overlap, then it is also reasonable for EPA to include these health effects in its consideration of whether the air pollution endangers public health. Neither approach condenses or conflates the two different terms. Under either approach EPA's interpretation, as demonstrated in this rulemaking, would still consider numerous and varied effects from climate change as indisputable impacts on public welfare and not impacts on public health. In addition, this interpretation will not change the fact that in almost all cases impacts on public health would not also be considered impacts on public welfare.

Prior EPA actions. Several commenters argue that EPA's decision to include health impacts that occur because of climate change is inconsistent with its past approach, which has been to treat indirect health effects as welfare effects. Commenters contend that in the latest Criteria Document for ozone EPA listed tropospheric ozone's effects on UVB-induced human diseases, as well as its effects on climate change, as welfare effects, even though the agency acknowledged significant health effects such as sunburn and skin cancer. Commenters also argue that EPA listed ''risks to human health'' from toxins released by algal blooms due to excess nitrogen as ''ecological and other welfare effects'' in the recent Criteria Document for oxides of nitrogen and sulfur. Finally, commenters argue that EPA's proposed action was contrary to the Agency decision to list new municipal solid waste landfills as a source category under CAA section 111. Commenters state that EPA listed climate change as a welfare effect in that action, (citing 56 FR 24469).

The Agency's recent approach regarding UVB-induced health effects is consistent with the endangerment findings, and demonstrates that the Agency considers indirect effects on human health as public health issues rather than public welfare issues. While the ozone Criteria Document may have placed the discussion of UV–B related health effects among chapters on welfare effects, in evaluating the evidence presented in the Criteria Document for purposes of preparing the policy assessment document, EPA staff clearly viewed UVB-induced effects as human health effects that were relevant in determining the public health based primary NAAQS for ozone, rather than welfare effects, regardless of which chapter in the Criteria Document described those effects. The evaluation of the UVB-related evidence is discussed with other human health effects evidence. The policy assessment document noted that Chapter 10 of the Criteria Document, ''provides a thorough analysis of the current understanding of the relationship between reducing tropospheric [ozone] concentrations and the potential impact these reductions might have on UV–B surface fluxes and *indirectly contributing to increased UV–B related health effects.'' See*, *Review of the National Ambient Air Quality Standards for Ozone: Policy Assessment of Scientific and Technical Information*, p 3–36 (January 2007) (emphasis added).

EPA repeated this view in the 2007 proposed ozone NAAQS rule. In presenting its evaluation of the human health evidence for purposes of setting the public health based primary NAAQS, EPA stated: ''This section also summarizes the uncertainty about the *potential indirect effects on public health* associated with changes due to increases in UV–B radiation exposure, such as UV–B radiation-related skin cancers, that may be associated with reductions in ambient levels of ground-level [ozone], as discussed in chapter 10 of the Criteria Document and chapter 3 of the Staff Paper.'' 72 FR 37818, 37827. *See* also, 72 FR 37837 (''* * * the Criteria Document also assesses the potential indirect effects related to the presence of [ozone] in the ambient air by considering the role of ground-level [ozone] in mediating human health effects that may be directly attributable to exposure to solar ultraviolet radiation (UV–B).'')

Thus, EPA's approach to UV–B related health effects clearly shows the Agency has treated indirect health effects not as welfare effects, as commenters suggest, but as human health effects that need to be evaluated when setting the public health based primary NAAQS. In this ozone NAAQS rulemaking, EPA did not draw a line between direct and indirect health effects for purposes of evaluating UV–B related health effects and the public health based primary NAAQS.

Similarly, the NO_X/SO_X criteria document does not establish a precedent that indirect human health effects are welfare effects. Toxic algal blooms themselves are a welfare effect, so it is not surprising a discussion of algal blooms appears in sections dealing with welfare effects. The more relevant question is how EPA evaluated information regarding human health risks resulting from algal blooms. In the case of the Criteria Document, the role of nitrogen in causing algal blooms was unclear. As a result, the Agency did not have occasion to evaluate any resulting human health effects and the Criteria Document does not support the view that EPA treats indirect health effects as anything other than a public health issue.

Finally, EPA disagrees that its action here is at odds with the listing of municipal solid waste landfills under CAA section 111. In the landfills New Source Performance Standard (NSPS) EPA did not consider health effects resulting from climate change much less draw any conclusions about health effects from climate change being health or welfare effects. If anything, the landfills NSPS is consistent with EPA's approach. In the proposed rule, EPA stated: ''The EPA has documented many cases of acute injury and death caused by explosions and fires related to municipal landfill gas emissions. In addition to these health effects, the associated property damage is a welfare effect'' (56 FR 24474). EPA considered injury and death from fires resulting from landfill gasses to be health effects. Yet the injury did not result from direct exposure to the pollutant (landfill gas). Instead, the injury resulted from the combustion of the pollutant—the injury is essentially an indirect effect of the pollutant. Yet, as with this action, EPA considered the injury as a human health effect.

Case law. Several commenters argue that EPA's proposed endangerment finding was inconsistent with *NRDC* v. *EPA*, 902 F.2d 962 (DC Cir 1990). Commenters argue that in rejecting the argument that EPA must consider the health effects of increased unemployment that could result from a more stringent primary NAAQS standard, the DC Circuit explained that, ''[i]t is only the health effects relating to pollutants in the air that EPA may consider.'' *Id.* at 973. Several commenters further argue that EPA later relied on that holding to defend its decision to set a primary NAAQS for ozone based solely on direct health effects of ozone. Citing, *EPA Pet'n for Rehearing, Am. Trucking Ass'n* v. *EPA*, No. 97–1440 (DC Cir. June 28, 1999) (''ATA I'') (arguing that the primary NAAQS should be set through consideration of only ''direct adverse effects on public health, and not indirect, allegedly beneficial effects.'')

The *NRDC* case is not contrary to EPA's endangerment finding. In *NRDC*, petitioner American Iron and Steel Institute argued that EPA had to consider the costs of health consequences that might arise from increased unemployment. The court ruled that, ''[c]onsideration of costs associated with alleged health risks from unemployment would be flatly inconsistent with the statute, legislative history and case law on this point.'' 902 F.2d at 973. The cases cited by the court in support of its decision all hold that EPA may not consider economic or technological feasibility in establishing a NAAQS. The *NRDC* decision does not establish a precedent that the CAA prohibits EPA from considering indirect health effects as a public health issue rather than a public welfare issue.

EPA also believes reliance on the Agency's petition for rehearing in noted above is misplaced. In that case, EPA did not argue that indirect beneficial health effects were not public health issues. Instead EPA argued that under the CAA, it did not have to consider such indirect beneficial health effects of an air pollutant when setting the health based primary NAAQS. EPA was interpreting the NAAQS standard setting provisions of CAA section 109, and argued that they were intended to address only certain public health impacts, those that were adverse, and were not intended to address indirect, beneficial public health impacts. The issue in the case was not whether indirect health effects are relevant for purposes of making an endangerment decision concerning public health, but rather whether EPA must consider such beneficial health effects in establishing a primary NAAQS under CAA section 109. EPA's interpretation of CAA section 109 was rejected in *ATA* v. *EPA*, 175 F.3d at 1027 (1999) *reh'g granted in part and denied in part*, 195 F.3d at 4 (DC Cir. 1999). The court made it clear that the potential indirect beneficial impact of ambient ozone on public health from screening UVB rays needed to be considered when setting the NAAQS to protect public health. As discussed above, EPA has done just that as noted above in the UV–B context. Moreover, as discussed in Section II of these Findings, EPA is doing that here as well (*e.g.*, considering any benefits from reduced cold weather related deaths).

ii. EPA's Treatment and Balancing of Heat- vs. Cold-Related Public Health Risks Was Reasonable

A number of public commenters maintain that the risk of heat waves in the future will be modulated by adaptive measures. The Administrator is aware of the potential benefits of adaptation in reducing heat-related morbidity and mortality and recognizes most heat-related deaths are preventable. Nonetheless, the Administrator notes the assessment literature [30] indicates heat is the leading weather-related killer in the United States even though countermeasures have been employed in many vulnerable areas. Given projections for heat waves of greater frequency, magnitude, and duration coupled with a growing population of older adults (among the most vulnerable groups to this hazard), the risk of adverse health outcomes from heat waves is expected to increase. Intervention and response measures could certainly reduce the risk, but as we have noted, the need to adapt supports an increase in risk or endangerment. For a general discussion about EPA's treatment of adaptation see Section III.C of these Findings.

Several commenters also suggest cold-related mortality will decrease more than heat-related mortality will increase, which indicates a net reduction in temperature-related mortality. Some commenters point to research suggesting migration to warmer climates has contributed to the increased longevity of some Americans, implying climate warming will have benefits for health. The Administrator is very clear that the exact balance of how heat- versus cold-related mortality will change in the future is uncertain; however, the assessment literature points to evidence suggesting that the increased risk from heat would exceed the decreased risk from cold in a warming climate. The Administrator does not dispute research indicating the benefits of migration to a warmer climate and nor that average climate warming may indeed provide health benefits in some areas. These points are reflected in the TSD's statement projecting less cold-related health effects. The Administrator considers these potential warming benefits independent of the potential negative effects of extreme heat events which are projected to increase under future climate change scenarios affecting vulnerable groups and communities.

[30] Karl *et al.* (2009).

iii. EPA Was Reasonable To Find That the Air Quality Impacts of Climate Change Contribute to the Endangerment of Public Health

Several commenters suggest that air quality effects of climate change will be addressed through the CAA's NAAQS process, as implemented by the State Implementation Plans (SIP) and national regulatory programs. According to these commenters, these programs will ensure no adverse impact on public health due to climate change. Though climate change may cause certain air pollutant ambient concentrations to increase, States will continue to be compelled to meet the standards. So, while additional measures may be necessary, and result in increased costs, these commenters assert that, ultimately, public health will be protected by the continued existence of the NAAQS and therefore no endangerment with respect to this particular climate change-related impact will occur. One commenter states that EPA inappropriately assigns air quality risk to climate change that will be addressed through other programs. The CAA provides a mechanism to meet the standards and additional control measures consistent with the CAA will be adopted in the future, keeping pollution below unhealthy levels. The commenters state that the fact that NAAQS are in place that require EPA to fulfill its legal obligation to prevent this particular form of endangerment to public health.

EPA does have in place NAAQS for ozone, which are premised on the harmfulness of ozone to public health and welfare. These standards and their accompanying regulatory regime have helped to reduce the dangers from ozone in the United States. However, substantial challenges remain with respect to achieving the air quality protection promised by the NAAQS for ozone. It is the Administrator's view that these challenges will be exacerbated by climate change.

In addition, the control measures to achieve attainment with a NAAQS are a mitigation measure aimed at reducing emissions of ozone precursors. As discussed in Section III.C of these Findings, EPA is not considering the impacts of mitigation with respect to future reductions in emissions of greenhouse gases. For the same reasons, EPA is reasonably not considering mitigation in the form of the control measures that will need to be adopted in the future to reduce emissions of ozone precursors and thereby address the increased ambient ozone levels that can occur because of climate change.

It is important to note that controls to meet the NAAQS are typically put in place only *after* air quality concentrations exceeding the standard are detected. Furthermore, implementation of controls to reduce ambient concentrations of pollutants occurs over an extended time period, ranging from three years to more than twenty years depending on the pollutant and the seriousness of the nonattainment problem. Thus, while the CAA provides mechanisms for addressing adverse health effects and the underlying air quality exacerbation over time, it will not prevent the adverse impacts in the interim. Given the serious nature of the health effects at issue—including respiratory and cardiovascular disease leading to hospital admissions, emergency department visits, and premature mortality—this increase in adverse impacts during the time before additional controls can be implemented is a serious public health concern. Historically, a large segment of the U.S. population has lived in areas exceeding the NAAQS, despite the CAA and its implementation efforts. Half of all Americans, 158 million people, live in counties where air pollution exceeds national health standards.[31] Where attainment of the NAAQS is especially difficult, leading to delays in meeting attainment deadlines, the health effects of increased ozone due to climate change may be substantial.

It is also important to note that it may not be possible for States and Tribes to plan accurately for the impacts of climate change in developing control strategies for nonattainment areas. As noted in the TSD and EPA's 2009 Interim Assessment report (IA), climate change is projected to lead to an increase in the variability of weather, and this may increase peak pollution events including increases in ozone exceedances. While the modeling studies in the IA all show significant future changes in meteorological quantities, there is also significant variability across the simulations in the spatial patterns of these future changes, making it difficult to select a set of future meteorological data for planning purposes. At this time, models used to develop plans to attain the NAAQS do not take potential changes in future meteorology into consideration. Inability to predict the frequency and magnitude of such events could lead to an underestimation of the controls needed to bring areas into attainment, and a prolonged period during which adverse health impacts continue to occur.

Even in areas that meet the NAAQS currently, air quality may deteriorate sufficiently to cause adverse health effects for some individuals. Some at-risk individuals, for example those with preexisting health conditions or other characteristics which increase their risk for adverse effects upon exposure to PM or ozone, may experience health effects at levels below the standard. Current evidence suggests that there is no threshold for PM or ozone concentrations below which no effects can be observed. Therefore, increases in ozone or PM in locations that currently meet the standards would likely result in additional adverse health effects for some individuals, even though the pollution increase might not be sufficient to cause the area to be designated nonattainment. While the NAAQS is set to protect public health with an adequate margin of safety, it is recognized that in attainment areas there may be individuals who remain at greater risk from an increase in ozone levels. The clear risk to the public from ozone increases in nonattainment areas, in combination with the risk to some individuals in attainment areas, supports the finding that overall the public health is endangered by increases in ozone resulting from climate change.

Finally, it is also important to note that not all air pollution events are subject to CAA controls under the NAAQS implementation provisions. ''Exceptional events'' are events for which the normal planning and regulatory process established by the CAA is not appropriate (72 FR 13561). Emissions from some events, including some wildfires, are not reasonably controllable or preventable. Such emissions, however, can adversely impact public health and welfare and are expected to increase due to climate change. As described in the TSD, PM emissions from wildfires can contribute to acute and chronic illnesses of the respiratory system, particularly in children, including pneumonia, upper respiratory diseases, asthma and chronic obstructive pulmonary disease. The IPCC (Field et al., 2007) reported with very high confidence that in North America, disturbances like wildfires are increasing and are likely to intensify in a warmer future with drier soils and longer growing seasons.

2. The Air Pollution Is Reasonably Anticipated to Endanger Public Welfare

The Administrator also finds that the well-mixed greenhouse gas air pollution may reasonably be anticipated to

[31] U.S. EPA (2008) National Air Quality: Status and Trends Through 2007. EPA–454/R–08–006, November 2008.

endanger public welfare, both for current and future generations.

As with public health, the Administrator considered the multiple pathways in which the greenhouse gas air pollution and resultant climate change affect climate-sensitive sectors, and the impact this may have on public welfare. These sectors include food production and agriculture; forestry; water resources; sea level rise and coastal areas; energy, infrastructure, and settlements; and ecosystems and wildlife. The Administrator also considered impacts on the U.S. population from climate change effects occurring outside of the United States, such as national security concerns for the United States that may arise as a result of climate change impacts in other regions of the world. The Administrator examined each climate-sensitive sector individually, informed by the summary of the scientific assessments contained in the TSD, and the full record before EPA, and weighed the extent to which the risks and impacts within each sector support or do not support a positive endangerment finding in her judgment. The Administer then viewed the full weight of evidence looking across all sectors to reach her decision regarding endangerment to public welfare.

a. Food Production and Agriculture

Food production and agriculture within the United States is a sector that will be affected by the combined effects of elevated carbon dioxide concentrations and associated climate change. The Administrator considered how these effects, both adverse and beneficial, are affecting the agricultural sector now and in the future, and over different regions of the United States, taking into account that different regions of the country specialize in different agricultural products with varying degrees of sensitivity and vulnerability to elevated carbon dioxide levels and associated climate change.

Elevated carbon dioxide concentrations can have a stimulatory effect on grain and oilseed crop yield, as may modest temperature increases and a longer growing season that results. A report under the USGCRP concluded that, with increased carbon dioxide and temperature, the life cycle of grain and oilseed crops will likely progress more rapidly. However, such beneficial influences need to be considered in light of various other effects. For example, the literature indicates that elevated carbon dioxide concentrations may also enhance pest and weed growth. Pests and weeds can reduce crop yields, cause economic losses to farmers, and require management control options. How climate change (elevated carbon dioxide, increased temperatures, altered precipitation patterns, and changes in the frequency and intensity of extreme events) may affect the prevalence of pests and weeds is an issue of concern for food production and the agricultural sector. Research on the combined effects of elevated carbon dioxide and climate change on pests, weeds, and disease is still limited. In addition, higher temperature increases, changing precipitation patterns and variability, and any increases in ground-level ozone induced by higher temperatures, can work to counteract any direct stimulatory carbon dioxide effect, as well as lead to their own adverse impacts. There may be large regional variability in the response of food production and agriculture to climate change.

For grain and oilseed crop yields, there is support for the view that in the near term climate change may have a beneficial effect, largely through increased temperature and increased carbon dioxide levels. However there are also factors noted above, some of which are less well studied and understood, which would tend to offset any near term benefit, leaving significant uncertainty about the actual magnitude of any overall benefit. The USGCRP report also concluded that as temperature rises, these crops will increasingly begin to experience failure, especially if climate variability increases and precipitation lessens or becomes more variable.

A key uncertainty is how human-induced climate change may affect the intensity and frequency of extreme weather events such as droughts and heavy storms. These events have the potential to have serious negative impact on U.S. food production and agriculture, but are not always taken into account in studies that examine how average conditions may change as a result of carbon dioxide and temperature increases. Changing precipitation patterns, in addition to increasing temperatures and longer growing seasons, can change the demand for irrigation requirements, potentially increasing irrigation demand.

Another key uncertainty concerns the many horticultural crops (*e.g.,* tomatoes, onions, fruits), which make up roughly 40 percent of total crop value in the United States. There is relatively little information on their response to carbon dioxide, and few crop simulation models, but according to the literature, they are very likely to be more sensitive to the various effects of climate change than grain and oilseed crops.

With respect to livestock, higher temperatures will very likely reduce livestock production during the summer season in some areas, but these losses will very likely be partially offset by warmer temperatures during the winter season. The impact on livestock productivity due to increased variability in weather patterns will likely be far greater than effects associated with the average change in climatic conditions. Cold-water fisheries will likely be negatively affected; warm-water fisheries will generally benefit; and the results for cool-water fisheries will be mixed, with gains in the northern and losses in the southern portions of ranges.

Finally, with respect to irrigation requirements, the adverse impacts of climate change on irrigation water requirements may be significant.

There is support for the view that there may be a benefit in the near term in the crop yield for certain crops. This potential benefit is subject to significant uncertainty, however, given the offsetting impact on the yield of these crops from a variety of other climate change impacts that are less well understood and more variable. Any potential net benefit is expected to change to a disbenefit in the longer term. In addition, there is clear risk that the sensitivity of a major segment of the total crop market, the horticultural sector, may lead to adverse affects from climate change. With respect to livestock production and irrigation requirements, climate change is likely to have adverse effects in both the near and long terms. The impact on fisheries varies, and would appear to be best viewed as neutral overall.

There is a potential for a net benefit in the near term for certain crops, but there is significant uncertainty about whether this benefit will be achieved given the various potential adverse impacts of climate change on crop yield, such as the increasing risk of extreme weather events. Other aspects of this sector are expected to be adversely affected by climate change, including livestock management and irrigation requirements, and there is a risk of adverse effect on a large segment of the total crop market. For the near term, the concern over the potential for adverse effects in certain parts of the agriculture sector appears generally comparable to the potential for benefits for certain crops.

However, considering the trend over near- and long-term future conditions, the Administrator finds that the body of evidence points towards increasing risk of net adverse impacts on U.S. food production and agriculture, with the potential for significant disruptions and crop failure in the future.

b. Forestry

The factors that the Administrator considered for the U.S. forest sector are similar to those for food production and agriculture. There is the potential for beneficial effects due to elevated concentrations of carbon dioxide and increased temperature, as well as the potential for adverse effects from increasing temperatures, changing precipitation patterns, increased insects and disease, and the potential for more frequent and severe extreme weather events. The potential beneficial effects are better understood and studied, and are limited to certain areas of the country and types of forests. The adverse effects are less certain, more variable, and also include some of the most serious adverse effects such as increased wildfire, drought, and major losses from insects and disease. As with food production and agriculture, the judgment to be made is largely a qualitative one, balancing impacts that vary in certainty and magnitude, with the end result being a judgment as to the overall direction and general level of concern.

According to the underlying science assessment reports, climate change has very likely increased the size and number of wildfires, insect outbreaks, and tree mortality in the Interior West, the Southwest, and Alaska, and will continue to do so. Rising atmospheric carbon dioxide levels will very likely increase photosynthesis for forests, but the increased photosynthesis will likely only increase wood production in young forests on fertile soils. Nitrogen deposition and warmer temperatures have very likely increased forest growth where water is not limiting and will continue to do so in the near future.

An increased frequency of disturbance (such as drought, storms, insect-outbreaks, and wildfire) is at least as important to forest ecosystem function as incremental changes in temperature, precipitation, atmospheric carbon dioxide, nitrogen deposition, and ozone pollution. Disturbances partially or completely change forest ecosystem structure and species composition, cause short-term productivity and carbon storage loss, allow better opportunities for invasive alien species to become established, and command more public and management attention and resources. The combined effects of expected increased temperature, carbon dioxide, nitrogen deposition, ozone, and forest disturbance on soil processes and soil carbon storage remain unclear.

Precipitation and weather extremes are key to many forestry impacts, accounting for part of the regional variability in forest response. If existing trends in precipitation continue, it is expected that forest productivity will likely decrease in the Interior West, the Southwest, eastern portions of the Southeast, and Alaska, and that forest productivity will likely increase in the northeastern United States, the Lake States, and in western portions of the Southeast. An increase in drought events will very likely reduce forest productivity wherever such events occur.

Changes in disturbance patterns are expected to have a substantial impact on overall gains or losses. More prevalent wildfire disturbances have recently been observed in the United States. Wildfires and droughts, among other extreme events (*e.g.,* hurricanes) that can cause forest damage, pose the largest threats over time to forest ecosystems.

For the near term, the Administrator believes the beneficial impact on forest growth and productivity in certain parts of the country from climate change to be more than offset by the clear risk from the more significant and serious adverse effects from the observed increases in wildfires, combined with the adverse impacts on growth and productivity in other areas of the country and the serious risks from the spread of destructive pests and disease. Increased wildfires can also increase particulate matter and thus create public health concerns as well. For the longer term, the Administrator views the risk from adverse effects to increase over time, such that overall climate change presents serious adverse risks for forest productivity. The Administrator therefore finds there is compelling reason to find that the greenhouse gas air pollution endangers U.S. forestry in both the near and long term, with the support for a positive endangerment finding only increasing as one considers expected future conditions in which temperatures continue to rise.

c. Water Resources

The sensitivity of water resources to climate change is very important given the increasing demand for adequate water supplies and services for agricultural, municipal, and energy and industrial uses, and the current strains on this resource in many parts of the country.

According to the assessment literature, climate change has already altered, and will likely continue to alter, the water cycle, affecting where, when, and how much water is available for all uses. With higher temperatures, the water-holding capacity of the atmosphere and evaporation into the atmosphere increase, and this favors increased climate variability, with more intense precipitation and more droughts.

Climate change is causing and will increasingly cause shrinking snowpack induced by increasing temperature. In the western United States, there is already well-documented evidence of shrinking snowpack due to warming. Earlier meltings, with increased runoff in the winter and early spring, increase flood concerns and also result in substantially decreased summer flows. This pattern of reduced snowpack and changes to the flow regime pose very serious risks to major population regions, such as California, that rely on snowmelt-dominated watersheds for their water supply. While increased precipitation is expected to increase water flow levels in some eastern areas, this may be tempered by increased variability in the precipitation and the accompanying increased risk of floods and other concerns such as water pollution.

Warmer temperatures and decreasing precipitation in other parts of the country, such as the Southwest, can sustain and amplify drought impacts. Although drought has been more frequent and intense in the western part of the United States, the East is also vulnerable to droughts and attendant reductions in water supply, changes in water quality and ecosystem function, and challenges in allocation. The stress on water supplies on islands is expected to increase.

The impact of climate change on groundwater as a water supply is regionally variable; efforts to offset declining surface water availability due to increasing precipitation variability may be hampered by the fact that groundwater recharge will decrease considerably in some already water-stressed regions. In coastal areas, the increased salinization from intrusion of salt water is projected to have negative effects on the supply of fresh water.

Climate change is expected to have adverse effects on water quality. The IPCC concluded with high confidence that higher water temperatures, increased precipitation intensity, and longer periods of low flows exacerbate many forms of water pollution and can impact ecosystems, human health, and water system reliability and operating costs. These changes will also exacerbate many forms of water pollution, potentially making attainment of water quality goals more difficult. Water pollutants of concern that are particularly relevant to climate change effects include sediment, nutrients, organic matter, pathogens, pesticides, salt, and thermal pollution. As waters become warmer, the aquatic life they now support will be replaced by other species better adapted to warmer water. In the long term, warmer water, changing flows, and decreased water quality may result in deterioration of aquatic ecosystems.

Climate change will likely further constrain already over-allocated water resources in some regions of the United States, increasing competition among agricultural, municipal, industrial, and ecological uses. Although water management practices in the United States are generally advanced, particularly in the West, the reliance on past conditions as the basis for current and future planning may no longer be appropriate, as climate change increasingly creates conditions well outside of historical observations. Increased incidence of extreme weather and floods may also overwhelm or damage water treatment and management systems, resulting in water quality impairments. In the Great Lakes and major river systems, lower water levels are likely to exacerbate challenges relating to water quality, navigation, recreation, hydropower generation, water transfers, and bi-national relationships.

The Administrator finds that the total scientific literature provides compelling support for finding that greenhouse gas air pollution endangers the water resources important for public welfare in the United States, both for current and future generations. The adequacy of water supplies across large areas of the country is at serious risk from climate change. Even areas of the country where an increase in water flow is projected could face water resource problems from the variability of the supply and water quality problems associated with precipitation variability, and could face the serious adverse effects from risks from floods and drought. Climate change is expected to adversely affect water quality. There is an increased risk of serious adverse effects from extreme events of flooding and drought. The severity of risks and impacts may only increase over time with accumulating greenhouse gas concentrations and associated temperature increases and precipitation changes.

d. Sea Level Rise and Coastal Areas

A large percentage of the U.S. population lives in coastal areas, which are particularly vulnerable to the risks posed by climate change. The most vulnerable areas are the Atlantic and Gulf Coasts, the Pacific Islands, and parts of Alaska.

According to the assessment literature, sea level is rising along much of the U.S. coast, and the rate of change will very likely increase in the future, exacerbating the impacts of progressive inundation, storm-surge flooding, and shoreline erosion. Cities such as New Orleans, Miami, and New York are particularly at risk, and could have difficulty coping with the sea level rise projected by the end of the century under a higher emissions scenario. Population growth and the rising value of infrastructure increases the vulnerability to climate variability and future climate change in coastal areas. Adverse impacts on islands present concerns for Hawaii and the U.S. territories. Reductions in Arctic sea ice increases extreme coastal erosion in Alaska, due to the increased exposure of the coastline to strong wave action. In the Great Lakes, where sea level rise is not a concern, both extremely high and low water levels resulting from changes to the hydrological cycle have been damaging and disruptive to shoreline communities.

Coastal wetland loss is being observed in the United States where these ecosystems are squeezed between natural and artificial landward boundaries and rising sea levels. Up to 21 percent of the remaining coastal wetlands in the U.S. mid-Atlantic region are potentially at risk of inundation between 2000 and 2100. Coastal habitats will likely be increasingly stressed by climate change impacts interacting with development and pollution.

Although increases in mean sea level over the 21st century and beyond will inundate unprotected, low-lying areas, the most devastating impacts are likely to be associated with storm surge. Superimposed on expected rates of sea level rise, projected storm intensity, wave height, and storm surge suggest more severe coastal flooding and erosion hazards. Higher sea level provides an elevated base for storm surges to build upon and diminishes the rate at which low-lying areas drain, thereby increasing the risk of flooding from rainstorms. In New York City and Long Island, flooding from a combination of sea level rise and storm surge could be several meters deep. Projections suggest that the return period of a 100-year flood event in this area might be reduced to 19–68 years, on average, by the 2050s, and to 4–60 years by the 2080s. Additionally, some major urban centers in the United States, such as areas of New Orleans are situated in low-lying flood plains, presenting increased risk from storm surges.

The Administrator finds that the most serious risk of adverse effects is presented by the increased risk of storm surge and flooding in coastal areas from sea level rise. Current observations of sea level rise are now contributing to increased risk of storm surge and flooding in coastal areas, and there is reason to find that these areas are now endangered by human-induced climate change. The conclusion in the assessment literature that there is the potential for hurricanes to become more intense with increasing temperatures (and even some evidence that Atlantic hurricanes have already become more intense) reinforces the judgment that coastal communities are now endangered by human-induced climate change, and may face substantially greater risk in the future. The Administrator has concluded that even if there is a low probability of raising the destructive power of hurricanes, this threat is enough to support a finding that coastal communities are endangered by greenhouse gas air pollution.

In addition, coastal areas face other adverse impacts from sea level rise such as shoreline retreat, erosion, wetland loss and other effects. The increased risk associated with these adverse impacts also endangers the welfare of current and future generations, with an increasing risk of greater adverse impacts in the future.

Overall, the evidence on risk of adverse impacts for coastal areas from sea level rise provides clear support for finding that greenhouse gas air pollution endangers the welfare of current and future generations.

e. Energy, Infrastructure and Settlements

The Administrator also considered the impacts of climate change on energy consumption and production, and on key climate-sensitive aspects of the nation's infrastructure and settlements.

For the energy sector, the Administrator finds clear evidence that temperature increases will change heating and cooling demand, and to varying degrees across the country; however, under current conditions it is unclear whether or not net demand will increase or decrease. While the impacts on net energy demand may be viewed as generally neutral for purposes of making an endangerment determination, climate change is expected to call for an increase in electricity production, especially supply for peak demand. The U.S. energy sector, which relies heavily on water for cooling capacity and hydropower, may be adversely impacted by changes to water supply in reservoirs and other water bodies.

With respect to infrastructure, climate change vulnerabilities of industry, settlement and society are mainly related to extreme weather events rather than to gradual climate change. The significance of gradual climate change, *e.g.*, increases in the mean temperature, lies mainly in changes in the intensity and frequency of extreme events. Extreme weather events could threaten U.S. energy infrastructure (transmission and distribution), transportation infrastructure (roads, bridges, airports and seaports), water infrastructure, and other built aspects of human settlements. Moreover, soil subsidence caused by the melting of permafrost in the Arctic region is a risk to gas and oil pipelines, electrical transmission towers, roads, and water systems. Vulnerabilities for industry, infrastructures, settlements, and society to climate change are generally greater in certain high-risk locations, particularly coastal and riverine areas, and areas whose economies are closely linked with climate-sensitive resources. Additionally, infrastructures are often connected, meaning that an impact on one can also affect others.

A significant fraction of U.S. infrastructure is located in coastal areas. In these locations, rising sea levels are likely to lead to direct losses (*e.g.,* equipment damage from flooding) as well as indirect effects such as the costs associated with raising vulnerable assets to higher levels. Water infrastructure, including drinking water and wastewater treatment plants, and sewer and storm water management systems, may be at greater risk of flooding, sea level rise and storm surge, low flows, saltwater intrusion, and other factors that could impair performance and damage costly investments.

Within settlements experiencing climate change stressors, certain parts of the population may be especially vulnerable based on their circumstances. These include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. In Alaska, indigenous communities are likely to experience disruptive impacts, including shifts in the range or abundance of wild species crucial to their livelihoods and well-being.

Overall, the evidence strongly supports the view that climate change presents risks of serious adverse impacts on public welfare from the risk to energy production and distribution as well as risks to infrastructure and settlements.

f. Ecosystems and Wildlife

The Administrator considered the impacts of climate change on ecosystems and wildlife and the services they provide. The Administrator finds clear evidence that climate change is exerting major influences on natural environments and biodiversity, and these influences are generally expected to grow with increased warming. Observed changes in the life cycles of plants and animals include shifts in habitat ranges, timing of migration patterns, and changes in reproductive timing and behavior.

The underlying assessment literature finds with high confidence that substantial changes in the structure and functioning of terrestrial ecosystems are very likely to occur with a global warming greater than 2 to 3 °C above pre-industrial levels, with predominantly negative consequences for biodiversity and the provisioning of ecosystem goods and services. With global average temperature changes above 2 °C, many terrestrial, freshwater, and marine species (particularly endemic species) are at a far greater risk of extinction than in the geological past. Climate change and ocean acidification will likely impair a wide range of planktonic and other marine calcifiers such as corals. Even without ocean acidification effects, increases in sea surface temperature of about 1–3 °C are projected to result in more frequent coral bleaching events and widespread mortality. In the Arctic, wildlife faces great challenges from the effects of climatic warming, as projected reductions in sea ice will drastically shrink marine habitat for polar bears, ice-inhabiting seals, and other animals.

Some common forest types are projected to expand, such as oak-hickory, while others are projected to contract, such as maple-beech-birch. Still others, such as spruce-fir, are likely to disappear from the contiguous United States. Changes in plant species composition in response to climate change can increase ecosystem vulnerability to other disturbances, including wildfires and biological invasion. Disturbances such as wildfires and insect outbreaks are increasing in the United States and are likely to intensify in a warmer future with warmer winters, drier soils and longer growing seasons. The areal extent of drought-limited ecosystems is projected to increase 11 percent per °C warming in the United States. In California, temperature increases greater than 2 °C may lead to conversion of shrubland into desert and grassland ecosystems and evergreen conifer forests into mixed deciduous forests. Greater intensity of extreme events may alter disturbance regimes in coastal ecosystems leading to changes in diversity and ecosystem functioning. Species inhabiting salt marshes, mangroves, and coral reefs are likely to be particularly vulnerable to these effects.

The Administrator finds that the total scientific record provides compelling support for finding that the greenhouse gas air pollution leads to predominantly negative consequences for biodiversity and the provisioning of ecosystem goods and services for ecosystems and wildlife important for public welfare in the U.S., both for current and future generations. The severity of risks and impacts may only increase over time with accumulating greenhouse gas concentrations and associated temperature increases and precipitation changes.

g. Summary of the Administrator's Finding of Endangerment to Public Welfare

The Administrator has considered how elevated concentrations of the well-mixed greenhouse gases and associated climate change affect public welfare by evaluating numerous and far-ranging risks to food production and agriculture, forestry, water resources, sea level rise and coastal areas, energy, infrastructure, and settlements, and ecosystems and wildlife. For each of these sectors, the evidence provides support for a finding of endangerment to public welfare. The evidence concerning adverse impacts in the areas of water resources and sea level rise and coastal areas provide the clearest and strongest support for an endangerment finding, both for current and future generations. Strong support is also found in the evidence concerning infrastructure and settlements, as well ecosystems and wildlife. Across the sectors, the potential serious adverse impacts of extreme events, such as wildfires, flooding, drought, and extreme weather conditions provide strong support for such a finding.

Water resources across large areas of the country are at serious risk from climate change, with effects on water supplies, water quality, and adverse effects from extreme events such as floods and droughts. Even areas of the country where an increase in water flow is projected could face water resource problems from the supply and water quality problems associated with temperature increases and precipitation variability, and could face the increased risk of serious adverse effects from extreme events, such as floods and drought. The severity of risks and impacts is likely to increase over time with accumulating greenhouse gas concentrations and associated temperature increases and precipitation changes.

Overall, the evidence on risk of adverse impacts for coastal areas provides clear support for a finding that greenhouse gas air pollution endangers the welfare of current and future generations. The most serious potential adverse effects are the increased risk of storm surge and flooding in coastal areas from sea level rise and more intense storms. Observed sea level rise is already increasing the risk of storm surge and flooding in some coastal areas. The conclusion in the assessment literature that there is the potential for hurricanes to become more intense (and even some evidence that Atlantic hurricanes have already become more intense) reinforces the judgment that coastal communities are now endangered by human-induced climate change, and may face substantially greater risk in the future. Even if there is a low probability of increasing the destructive power of hurricanes, this threat is enough to support a finding that coastal communities are endangered by greenhouse gas air pollution. In addition, coastal areas face other adverse impacts from sea level rise such as land loss due to inundation, erosion, wetland submergence, and habitat loss. The increased risk associated with these adverse impacts also endangers public welfare, with an increasing risk of greater adverse impacts in the future.

Strong support for an endangerment finding is also found in the evidence concerning energy, infrastructure, and settlements, as well ecosystems and wildlife. While the impacts on net energy demand may be viewed as generally neutral for purposes of making an endangerment determination, climate change is expected to result in an increase in electricity production, especially to meet peak demand. This increase may be exacerbated by the potential for adverse impacts from climate change on hydropower resources as well as the potential risk of serious adverse effects on energy infrastructure from extreme events. Changes in extreme weather events threaten energy, transportation, and water resource infrastructure. Vulnerabilities of industry, infrastructure, and settlements to climate change are generally greater in high-risk locations, particularly coastal and riverine areas, and areas whose economies are closely linked with climate-sensitive resources. Climate change will likely interact with and possibly exacerbate ongoing environmental change and environmental pressures in settlements, particularly in Alaska where indigenous communities are facing major environmental and cultural impacts on their historic lifestyles. Over the 21st century, changes in climate will cause some species to shift north and to higher elevations and fundamentally rearrange U.S. ecosystems. Differential capacities for range shifts and constraints from development, habitat fragmentation, invasive species, and broken ecological connections will likely alter ecosystem structure, function, and services, leading to predominantly negative consequences for biodiversity and the provision of ecosystem goods and services.

With respect to food production and agriculture, there is a potential for a net benefit in the near term for certain crops, but there is significant uncertainty about whether this benefit will be achieved given the various potential adverse impacts of climate change on crop yield, such as the increasing risk of extreme weather events. Other aspects of this sector may be adversely affected by climate change, including livestock management and irrigation requirements, and there is a risk of adverse effect on a large segment of the total crop market. For the near term, the concern over the potential for adverse effects in certain parts of the agriculture sector appears generally comparable to the potential for benefits for certain crops. However, the body of evidence points towards increasing risk of net adverse impacts on U.S. food production and agriculture over time, with the potential for significant disruptions and crop failure in the future.

For the near term, the Administrator finds the beneficial impact on forest growth and productivity in certain parts of the country from elevated carbon dioxide concentrations and temperature increases to date is offset by the clear risk from the observed increases in wildfires, combined with risks from the spread of destructive pests and disease. For the longer term, the risk from adverse effects increases over time, such that overall climate change presents serious adverse risks for forest productivity. There is compelling reason to find that the support for a positive endangerment finding increases as one considers expected future conditions where temperatures continue to rise.

Looking across all of the sectors discussed above, the evidence provides compelling support for finding that greenhouse gas air pollution endangers the public welfare of both current and future generations. The risk and the severity of adverse impacts on public welfare are expected to increase over time.

h. Impacts in Other World Regions That Can Affect the U.S Population

While the finding of endangerment to public health and welfare discussed above is based on impacts in the United States, the Administrator also considered how human-induced climate change in other regions of the world may in turn affect public welfare in the United States. According to the USGCRP report of June 2009 and other sources, climate change impacts in certain regions of the world may exacerbate problems that raise humanitarian, trade, and national security issues for the United States.[32] The IPCC identifies the most vulnerable world regions as the Arctic, because of the effects of high rates of projected warming on natural systems; Africa, especially the sub-Saharan region, because of current low adaptive capacity as well as climate change; small islands, due to high exposure of population and infrastructure to risk of sea-level rise and increased storm surge; and Asian mega-deltas, such as the Ganges-Brahmaputra and the Zhujiang, due to large populations and high exposure to sea level rise, storm surge, and river flooding. Climate change has been described as a potential threat multiplier with regard to national security issues.

The Administrator acknowledges these kinds of risks do not readily lend themselves to precise analyses or future projections. However, given the unavoidable global nature of the climate change problem, it is appropriate and prudent to consider how impacts in other world regions may present risks to the U.S. population. Because human-induced climate change has the potential to aggravate natural resource, trade, and humanitarian issues in other world regions, which in turn may contribute to the endangerment of public welfare in the United States, this provides additional support for the Administrator's finding that the greenhouse gas air pollution is reasonably anticipated to endanger the public welfare of current and future

[32] ''In an increasingly interdependent world, U.S. vulnerability to climate change is linked to the fates of other nations. For example, conflicts or mass migrations of people resulting from food scarcity and other resource limits, health impacts or environmental stresses in other parts of the world could threaten U.S. national security.'' (Karl *et al.*, 2009).

generations of the United States population.

i. Summary of Key Public Comments on Endangerment to Public Welfare

Several public commenters point out the anticipated benefits that increasing carbon dioxide levels and temperatures will have on agricultural crops. In addition, commenters note how U.S. agricultural productivity, in particular, has been steadily rising over the last 100 years. Responses to major comments are found here and more detailed responses are found in the Response to Comments document.

The Administrator acknowledges that plants including agricultural crops respond to carbon dioxide positively based on numerous well-documented studies. However, previous assessments of food production and agriculture have been modified to highlight increasing vulnerability, stress, and adverse impacts from climate change over time, based on improvements in the understanding of plant physiology, concern over impacts on plant pests and pathogens, and the implications of changes in average temperatures for temperature extremes and for changes in the patterns of precipitation and evaporation. While it is still the case today and for the next few years that climate change benefits agriculture in some places and harms them in others, the Administrator considers that the far larger temperature increases expected over coming decades and beyond on the ''business as usual'' trajectory will put significant stresses on agriculture and land resources in all regions of the United States. The Administrator prudently considers increased climate variability associated with a warming climate, which may overwhelm the positive plant responses from elevated carbon dioxide over time. Further, the effects of climate change on weeds, insect pests, and pathogens are recognized as key factors in determining plant damage in future decades. The Administrator also notes that scientific literature clearly supports the finding that drought frequency and severity are projected to increase in the future over much of the United States, which will likely reduce crop yields because of excesses or deficits of water. Vulnerability to extended drought, according to IPCC, has been documented as already increasing across North America. Further, based on review of the assessment literature, the Administrator considers multiple stresses, such as limited availability of water resources, loss of biodiversity, and air pollution, which are likely to increase sensitivity and reduce resilience in the agricultural sector to climate change over time.

Similar to food production and agriculture, public commenters often noted that forest productivity is projected to increase in the coming years due to the direct stimulatory effect of carbon dioxide on plant growth combined with warmer temperatures and thus extended growing seasons. The Administrator notes this phenomenon has been well documented by numerous studies but recognizes that increased productivity will be associated with significant variation at local and regional scales. The Administrator considers that climate strongly influences forest productivity and composition, and the frequency and magnitude of disturbances that impact forests. Based on the most recent IPCC assessment of the scientific literature, several recent studies confirm previous findings that temperature and precipitation changes in future decades will modify, and often limit, direct carbon dioxide effects on plants. For example, increased temperatures may reduce carbon dioxide effects indirectly, by increasing water demand. The Administrator also considers that new research more firmly establishes the negative impacts of increased climate variability. Projected changes in the frequency and severity of extreme climate events have significant consequences for forestry production and amplify existing stresses to land resources in the future.

Several public commenters maintain that wildfires are primarily the result of natural climatic factors and not climate change and dispute that they are or will increase in the future. The Administrator notes the scientific literature and assessment reports provide several lines of evidence that suggest wildfires will likely increase in frequency over the next several decades because of climate warming. Wildfires and droughts, among other extreme events (*e.g.,* hurricanes) that cause forest damage, pose the largest threats over time to forest ecosystems. The assessment literature suggests that large, stand-replacing wildfires will likely increase in frequency over the next several decades because of climate warming and general climate warming encourages wildfires by extending the summer period that dries fuels, promoting easier ignition and faster spread. Furthermore, current climate modeling studies suggest that increased temperatures and longer growing seasons will elevate wildfire risk in connection with increased aridity.

V. The Administrator's Finding That Emissions of Greenhouse Gases From CAA Section 202(a) Sources Cause or Contribute to the Endangerment of Public Health and Welfare

As discussed in Section IV.A of these Findings, the Administrator is defining the air pollution for purposes of the endangerment finding to be the elevated concentration of well-mixed greenhouse gases in the atmosphere. The second step of the two-part endangerment test is for the Administrator to determine whether the emission of any air pollutant emitted from new motor vehicles cause or contribute to this air pollution. This is referred to as the cause or contribute finding, and is the second finding by the Administrator in this action.

Section V.A of these Findings describes the Administrator's definition and scope of the air pollutant ''well-mixed greenhouse gases.'' Section V.B of these Findings puts forth the Administrator's finding that emissions of well-mixed greenhouse gases from new motor vehicles contribute to the air pollution which is reasonably anticipated to endanger public health and welfare. Section V.C of these Findings provides responses to some of the key comments on these issues. See Response to Comments document Volume 10 for responses to other significant comments on the cause or contribute finding. More detailed emissions data summarized in the discussion below can be found in Appendix B of the TSD.

A. The Administrator's Definition of the ''Air Pollutant''

As discussed in the Proposed Findings, to help appreciate the distinction between air pollution and air pollutant, the *air pollution* can be thought of as the total, cumulative stock in the atmosphere, while the *air pollutant,* can be thought of as the flow that changes the size of the total stock. Given this relationship, it is not surprising that the Administrator is defining the air pollutant similar to the air pollution; while the air pollution is the concentration (*e.g.,* stock) of the well-mixed greenhouse gases in the atmosphere, the air pollutant is the same combined grouping of the well-mixed greenhouse gases, the emissions of which are analyzed for contribution (*e.g.,* the flow into the stock).

Thus, the Administrator is defining the air pollutant as the aggregate group of the same six long-lived and directly-emitted greenhouse gases: Carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. As noted above, this definition of a single air pollutant made up of these well-mixed greenhouse gases is similar to definitions of other air pollutants that are comprised of substances that share common attributes with similar effects on public health or welfare (*e.g.,* particulate matter and volatile organic compounds).

The common attributes shared by these six greenhouse gases are discussed in detail in Section IV.A of these Findings, where the Administrator defined the ''air pollution'' for purposes of the endangerment finding. These same common attributes support the Administrator grouping these six greenhouse gases for purposes of defining a single air pollutant as well. These attributes include the fact that they are all greenhouse gases that are directly emitted (*i.e.,* they are not formed through secondary processes in the atmosphere from precursor emissions); they are sufficiently long-lived in the atmosphere such that, once emitted, concentrations of each gas become well mixed throughout the entire global atmosphere; and they exert a climate warming effect by trapping outgoing, infrared heat that would otherwise escape to space. Moreover, the radiative forcing effect of these six greenhouse gases is well understood.

Furthermore, these six greenhouse gases are currently the common focus of climate science and policy. For example, the UNFCCC, signed and ratified by the U.S. in 1992, requires its signatories to ''develop, periodically update, publish and make available * * * national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol [33], using comparable methodologies * * * '' [34] To date, the focus of UNFCCC actions and discussions has been on the six greenhouse gases that are the same focus of these findings. As a Party to the UNFCCC, EPA annually submits the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* to the Convention, which reports on national emissions of anthropogenic emissions of the well-mixed greenhouse gases. International discussions about a post-Kyoto agreement also focus on the well-mixed greenhouse gases.

[33] The Montreal Protocol covers ozone-depleting substances which may also share physical attributes of the six key greenhouse gases in this action, but they do not share other attributes such as being the focus of climate science and policy. See section * * *.

[34] UNFCCC Art. 4.1(b).

As noted above, grouping of many substances with common attributes as a single pollutant is common practice under the CAA. Thus, doing so here is not novel. Indeed CAA section 302(g) defines air pollutant as ''any air pollutant agent or *combination of such agents,* * * * '' CAA § 302(g) (emphasis added). Thus, it is clear that the term ''air pollutant'' is not limited to individual chemical compounds. In determining that greenhouse gases are within the scope of this definition, the Supreme Court described section 302(g) as a ''sweeping'' and ''capacious'' definition that unambiguously included greenhouse gases, that are ''unquestionably 'agents' of air pollution.'' *Massachusetts* v. *EPA,* 549 U.S. at 528, 532, 529 n.26. Although the Court did not interpret the term ''combination of'' air pollution agents, there is no reason this phrase would be interpreted any less broadly. Congress used the term ''any'', and did not qualify the kind of combinations that the agency could define as a single air pollutant. Congress provided EPA broad discretion to determine appropriate combinations of compounds that should be treated as a singe air pollutant.[35]

For the same reasons discussed in Section IV.A above, at this time, only carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride share all of these common attributes and thus they are the only substances that the Administrator finds to meet the definition of ''well-mixed greenhouse gas'' at this time.[36] Also as noted above, if in the future other substances are shown to meet the same criteria they may be added to the definition of this single air pollutant.

The Administrator is aware that CAA section 202(a) source categories do not emit all of the substances meeting the definition of well-mixed greenhouse gases. But that does not change the fact that all of these greenhouse gases share the attributes that make grouping them as a single air pollutant reasonable. As discussed further below, the reasonableness of this grouping does not turn on the particular source category being evaluated in a contribution finding.

[35] Indeed, the greenhouse gases hydrofluorocarbons and perfluorocarbons each are already a combination of multiple compounds.

[36] The term ''well-mixed greenhouse gases'' is based on one of the shared attributes discussed above—these greenhouse gases are sufficiently long-lived in the atmosphere such that, once emitted, concentrations of each gas become well mixed throughout the entire global atmosphere. Defining the air pollutant to be the combination of these six well-mixed greenhouse gases is based in part on this attribute—after the gases are emitted, they are sufficiently long-lived in the atmosphere to become well mixed as part of the air pollution.

B. The Administrator's Finding Regarding Whether Emissions of the Air Pollutant From Section 202(a) Source Categories Cause or Contribute to the Air Pollution That May Be Reasonably Anticipated To Endanger Public Health and Welfare

The Administrator finds that emissions of the well-mixed greenhouse gases from new motor vehicles contribute to the air pollution that may reasonably be anticipated to endanger public health and welfare. This contribution finding is for all of the CAA section 202(a) source categories and the Administrator considered emissions from all of these source categories. The relevant mobile sources under CAA section 202 (a)(1) are ''any class or classes of new motor vehicles or new motor vehicle engines, * * *.'' CAA section 202(a)(1) (emphasis added). The new motor vehicles and new motor vehicle engines (hereinafter ''CAA section 202(a) source categories'') addressed are: Passenger cars, light-duty trucks, motorcycles, buses, and medium and heavy-duty trucks. Detailed combined greenhouse gas emissions data for CAA section 202(a) source categories are presented in Appendix B of the TSD.[37]

The Administrator reached her decision after reviewing emissions data on the contribution of CAA section 202(a) source categories relative to both global greenhouse gas emissions and U.S. greenhouse gas emissions. Given that CAA section 202(a) source categories are responsible for about 4 percent of total global greenhouse gas emissions, and for just over 23 percent of total U.S. greenhouse gas emissions, the Administrator finds that both of these comparisons, independently and together, support a finding that CAA section 202(a) source categories contribute to the air pollution that may be reasonably anticipated to endanger public health and welfare. The Administrator is not placing primary weight on either approach; rather she finds that both approaches clearly establish that emissions of the well-mixed greenhouse gases from section 202(a) source categories contribute to air pollution with may reasonably be anticipated to endanger public health and welfare. As the Supreme Court noted, ''[j]udged by any standard, U.S.

[37] For section 202(a) source categories, only the hydrofluorocarbon emissions related to passenger compartment cooling are included. Emissions from refrigeration units that may be attached to trucks are considered emissions from nonroad engines under CAA section 213.

motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming.'' *Massachusetts v. EPA,* 549 U.S. at 525.[38]

1. Administrator's Approach in Making This Finding

Section 202(a) of the CAA source categories consist of passenger cars, light-duty trucks, motorcycles, buses, and heavy- and medium-duty trucks. As noted in the Proposed Findings, in the past the requisite contribution findings have been proposed concurrently with proposing emission standards for the relevant mobile source category. Thus, prior contribution findings often focused on a subset of the CAA section 202(a) (or other section) source categories. This final cause or contribute finding, however, is for all of the CAA section 202(a) source categories. The Administrator is considering emissions from all of these source categories in the determination.

Section 202(a) source categories emit the following well-mixed greenhouse gases: carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons. As the basis for the Administrator's determination, EPA analyzed historical data of emissions of the well-mixed greenhouse gases for motor vehicles and motor vehicle engines in the United States from 1990 to 2007.

The Proposed Findings discussed a number of possible ways of assessing cause or contribute and the point was made that no single approach is required by the statute or has been used exclusively in previous determinations under the CAA. The Administrator also discussed how, consistent with prior cause or contribute findings and the science, she is using emissions as a proxy for contributions to atmospheric concentrations. This approach is reasonable for the well-mixed greenhouse gases, because cumulative emissions are responsible for the cumulative change in the concentrations in the atmosphere. Similarly, annual emissions are a perfectly reasonable proxy for annual incremental changes in atmospheric concentrations.

In making a judgment about the contribution of emissions from CAA section 202(a) source categories, the Administrator focused on making a reasoned overall comparison of emissions from the CAA section 202(a) source categories to emissions from other sources of greenhouse gases. This allows a determination of how the CAA section 202(a) source categories compare to all of the other sources that together as a group make up the total emissions contributors to the air pollution problem. The relative importance of the CAA section 202(a) source categories is central to making the contribution determination. Both the magnitude of these emissions and the comparison of these emissions to other sources provide the basis to determine whether the CAA section 202(a) source categories may reasonably be judged as contributing to the air pollution problem.

In many cases EPA makes this kind of comparison of source categories by a simple percentage calculation that compares the emissions from the source category at issue to a larger total group of emissions. Depending on the circumstances, a larger percentage often means a greater relative impact from that source category compared to the other sources that make up the total of emissions, and vice versa. However, the actual numerical percentages may have little meaning when viewed in isolation. The context of the comparison is needed to ensure the information is useful in evaluating the relative impact of one source compared to others. For example, the number of sources involved and the distribution of emissions across all of the sources can make a significant difference when evaluating the results of a percentage calculation. In some cases a certain percentage might mean almost all other sources are larger or much larger than the source at issue, while in other circumstances the same percentage could mean that the source at issue is in fact one of the larger contributors to the total.

The Administrator therefore considered the totality of the circumstances in order to best understand the role played by CAA section 202(a) source categories. This is consistent with Congress' intention for EPA to consider the cumulative impact of all sources of pollution. In that context, the global nature of the air pollution problem and the breadth of countries and sources emitting greenhouse gases means that no single country and no single source category dominate or are even close to dominating on a global scale. For example, the United States as a country is the second largest emitter of greenhouse gases, and emits approximately 18 percent of the world's total greenhouse gases. The total emissions of greenhouse gases worldwide are from numerous sources and countries, with each country and each source category contributing a relatively small percentage of the total emissions. That means that the relative ranking of countries or sources is not at all obvious from the magnitude of the percentage by itself. A country or a source may be a large contributor, in comparison to other countries or sources, even though its percentage contribution may appear relatively small.

In this situation, addressing a global air pollution problem may call for many different sources and countries to address emissions even if none by itself dominates or comes close to dominating the global inventory. A somewhat analogous situation can be found in the ozone air pollution problem in the United States. Emissions of NOx and volatile organic compounds (VOCs) often come from numerous small sources, as well as certain large source categories. We have learned that successful ozone control strategies often need to take this into account, and address both the larger sources of NOx and VOCs as well as the many smaller sources, given the breadth of sources that as a group lead to the total inventory of VOCs and NOx.

The global aspects of the greenhouse gas air pollution problem amplify this kind of situation many times over, where no single country or source category dominates or comes close to dominating the global inventory of greenhouse gas emissions. These unique, global aspects of the climate change problem tend to support consideration of contribution at lower percentage levels of emissions than might otherwise be considered appropriate when addressing a more typical local or regional air pollution problem. In this situation it is quite reasonable to consider emissions from source categories that are more important in relation to other sources, even if their absolute contribution initially may appear to be small.

In addition, the Administrator is aware of the fact that the United States is the second largest emitter of well-mixed greenhouse gases in the world. As the United States evaluates how to address climate change, the Administrator will analyze the various sources of emissions and the source's share of U.S. emissions. Thus, when analyzing whether a source category that emits well-mixed greenhouse gases in the United States contributes to the global problem, it is appropriate for the Administrator to consider how that source category fits into the larger picture of U.S. emissions. This ranking process within the United States allows the importance of the source category to

[38] Because the Administrator is defining the air pollutant as the combination of well-mixed greenhouse gases, she is not issuing a final contribution finding based on the alternative definition discussed in the proposed findings (*e.g.*, each greenhouse gas as an individual air pollutant).

be seen compared to other U.S. sources, informing the judgment of the importance of emissions from this source category in any overall national strategy to address greenhouse gas emissions.

It is in this broader context that EPA considered the contribution of CAA section 202(a) sources. This provides useful information in determining the importance that should be attached to the emissions from the CAA section 202(a) sources.

In reaching her determination, the Administrator used two simple and straightforward comparisons to assess cause or contribute for CAA section 202(a) source categories: (1) As a share of total current global aggregate emissions of the well-mixed greenhouse gases; and (2) as a share of total current U.S. aggregate emissions of the well-mixed greenhouse gases.

Total well-mixed greenhouse gas emissions from CAA section 202(a) source categories were compared to total global emissions of the well-mixed greenhouse gases. The total air pollution problem, as already discussed, is the elevated and climbing levels of the six greenhouse gas concentrations in the atmosphere, which are global in nature because these concentrations are globally well mixed (whether they are emitted from CAA section 202(a) source categories or any other source within or outside the United States). In addition, comparisons were also made to U.S. total well-mixed greenhouse gases emissions to appreciate how CAA section 202(a) source categories fit into the larger U.S. contribution to the global problem. It is typical for the Administrator to consider these kinds of comparisons of emissions of a pollutant in evaluating contribution to air pollution, such as the concentrations of that same pollutant in the atmosphere (*e.g.,* the Administrator analyzes $PM_{2.5}$ emissions to determine if a source category contributes to $PM_{2.5}$ air pollution). When viewed in the circumstances discussed above, both of these comparisons provide useful information in determining whether these source categories should be judged as contributing to the total air pollution problem.

a. Section 202(a) of the CAA—Share of Global Aggregate Emissions of the Well-Mixed Greenhouse Gases

Global emissions of well-mixed greenhouse gases have been increasing, and are projected to continue increasing unless the major emitters take action to reduce emissions. Total global emissions of well-mixed greenhouse gases in 2005 (the most recent year for which data for all countries and all greenhouse gases are available) [39] were 38,726 teragrams of CO_2-equivlant ($TgCO_2eq.$) [40] This represents an increase in global greenhouse gas emissions of about 26 percent since 1990 (excluding land use, land use change and forestry). In 2005, total U.S. emissions of well-mixed greenhouse gases were responsible for 18 percent of global emissions, ranking only behind China, which was responsible for 19 percent of global emissions of well-mixed greenhouse gases.

In 2005 emissions of the well-mixed greenhouse gas pollutant from CAA section 202(a) source categories represented 4.3 percent of total global well-mixed greenhouse gas emissions and 28 percent of global transport well-mixed greenhouse gas emissions (Table 1 of these Findings). If CAA section 202(a) source categories' emissions of well-mixed greenhouse gas were ranked against total well-mixed greenhouse gas emissions for entire countries, CAA section 202(a) source category emissions would rank behind only China, the United States as a whole, Russia, and India, and would rank ahead of Japan, Brazil, Germany and every other country in the world. Indeed, countries with lower emissions than the CAA section 202(a) source categories are members of the 17 ''major economies'' ''that meet to advance the exploration of concrete initiatives and joint ventures that increase the supply of clean energy while cutting greenhouse gas emissions.'' *See http://www.state.gov/g/oes/climate/mem/*. It would be anomalous, to say the least, to consider Japan and these other countries as major players in the global climate change community and an integral part of the solution, but not find that CAA section 202(a) source category emissions contribute to the global problem. Thus, the Administrator finds that emission of well-mixed greenhouse gases from CAA section 202(a) source categories contribute to the air pollution of well-mixed greenhouse gases.

TABLE 1—COMPARISON TO GLOBAL GREENHOUSE GAS (GHG) EMISSIONS (TG CO_2E)

	2005	Sec 202(a) share (percent)
All U.S. GHG emissions	7,109	23.5
Global transport GHG emissions	5,968	28.0
All global GHG emissions	38,726	4.3

b. Section 202(a) of the CAA—Share of U.S. Aggregate Emissions of the Well-Mixed Greenhouse Gases

The Administrator considered compared total emissions of the well-mixed greenhouse gases from CAA section 202(a) source categories to total U.S. emissions of the well-mixed greenhouse gases as an indication of the role these sources play in the total U.S. contribution to the air pollution problem causing climate change.[41]

In 2007, U.S. well-mixed greenhouse gas emissions were 7,150 $TgCO_2eq$. The dominant gas emitted was carbon dioxide, mostly from fossil fuel combustion. Methane was the second largest well-mixed greenhouse gas, followed by N_2O, and the fluorinated gases (HFCs, PFCs, and SF_6). Electricity generation was the largest emitting sector (2,445 $TgCO_2eq$ or 34 percent of

[39] The source of global greenhouse gas emissions data, against which comparisons are made, is the Climate Analysis Indicators Tool of the World Resources Institute (WRI) (2007). Note that for global comparisons, all emissions are from the year 2005, the most recent year for which data for all greenhouse gas emissions and all countries are available. WRI (2007) Climate Analysis Indicators Tool (CAIT). Available at *http://cait.wri.org*. Accessed August 5, 2009.

[40] One teragram (Tg) = 1 million metric tons. 1 metric ton = 1,000 kg = 1.102 short tons = 2,205 lbs. Long-lived greenhouse gases are compared and summed together on a CO_2 equivalent basis by multiplying each gas by its Global Warming Potential (GWPs), as estimated by IPCC. In accordance with UNFCCC reporting procedures, the U.S. quantifies greenhouse gas emissions using the 100-year time frame values for GWPs established in the IPCC Second Assessment Report.

[41] Greenhouse gas emissions data for the United States in this section have been updated since the Proposed Findings to reflect EPA's most up-to-date information, which includes data for the year 2007. The source of the U.S. greenhouse gas emissions data is the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2007,* published in 2009 (hereinafter ''U.S. Inventory'').

total U.S. greenhouse gas emissions), followed by transportation (1,995 $TgCO_2eq$ or 28 percent) and industry (1,386 $TgCO_2eq$ or 19 percent). Emissions from the CAA section 202(a) source categories constitute the major part of the transportation sector. Land use, land use change, and forestry offset almost 15 percent of total U.S. emissions through net sequestration. Total U.S. well-mixed greenhouse gas emissions have increased by over 17 percent between 1990 and 2007. The electricity generation and transportation sectors have contributed the most to this increase.

In 2007 emissions of well-mixed greenhouse gases from CAA section 202(a) source categories collectively were the second largest emitter of well-mixed greenhouse gases within the United States (behind the electricity generating sector), emitting 1,663 $TgCO_2eq$ and representing 23 percent of total U.S. emissions of well-mixed greenhouse gases (Table 2 of these Findings). The Administrator is keenly aware that the United States is the second largest emitter of well-mixed greenhouse gases. Part of analyzing whether a sector within the United States contributes to the global problem is to see how those emissions fit into the contribution from the United States as a whole. This informs her judgment as to the importance of emissions from this source category in any overall national strategy to address greenhouse gas emissions. Thus, it is relevant that CAA section 202(a) source categories are the second largest emitter of well-mixed greenhouse gases in the country. This is part of the Administrator looking at the totality of the circumstances. Based on this the Administrator finds that emission of well-mixed greenhouse gases from CAA section 202(a) source categories contribute to the air pollution of well-mixed greenhouse gases.

TABLE 2—SECTORAL COMPARISON TO TOTAL U.S. GREENHOUSE GAS (GHG) EMISSIONS (TG CO_2E)

U.S. emissions	1990	1995	2000	2005	2006	2007
Section 202(a) GHG emissions	1231.9	1364.4	1568.1	1670.5	1665.7	1663.1
Share of U.S. (%)	20.2%	21.1%	22.4%	23.5%	23.6%	23.3%
Electricity Sector emissions	1859.1	1989.0	2329.3	2429.4	2375.5	2445.1
Share of U.S. (%)	30.5%	30.8%	33.2%	34.2%	33.7%	34.2%
Industrial Sector emissions	1496.0	1524.5	1467.5	1364.9	1388.4	1386.3
Share of U.S. (%)	24.5%	23.6%	20.9%	19.2%	19.7%	19.4%
Total U.S. GHG emissions	6098.7	6463.3	7008.2	7108.6	7051.1	7150.1

C. Response to Key Comments on the Administrator's Cause or Contribute Finding

EPA received numerous public comments regarding the Administrator's proposed cause or contribute finding. Below is a brief discussion of some of the key comments. Responses to comments on this issue are also contained in the Response to Comments document, Volume 10.

1. The Administrator Reasonably Defined the ''Air Pollutant'' for the Cause or Contribute Analysis

a. The Supreme Court Held that Greenhouse Gases Fit Within the Definition of ''Air Pollutant'' in the CAA

Several commenters reiterate arguments already rejected by the Supreme Court, arguing that greenhouse gases do not fit into the definition of ''air pollutant'' under the CAA. In particular, at least one commenter contends that EPA must show how greenhouse gases impact or materially change ''ambient air'' when defining air pollutant and making the endangerment finding. This commenter argues that because carbon dioxide is a naturally occurring and necessary element in the atmosphere, it cannot be considered to materially change air.

These and similar arguments were already rejected by the Supreme Court in *Massachusetts* v. *EPA*, 549 U.S. 497 (2007). Briefs before the Supreme Court also argued that carbon dioxide is an essential role for life on earth and therefore cannot be considered an air pollutant, and that the concentrations of greenhouse gases that are a potential problem are not in the ''ambient air'' that people breathe.

The Court rejected all of these and other arguments, noting that the statutory text forecloses these arguments. ''The Clean Air Act's sweeping definition of 'air pollutant' includes '*any* air pollution agent or combination of such agents, including *any* physical, chemical * * * substance or matter which is emitted into or otherwise enters the ambient air . * * *' § 7602(g) (emphasis added). On its face, the definition embraces all airborne compounds of whatever stripe, and underscores that intent through the repeated use of the word 'any.' Carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons are without a doubt 'physical [and] chemical * * * substance[s] which [are] emitted into * * * the ambient air.' The statute is unambiguous.''

547 U.S. at 529–30 (footnotes omitted); see also *id.* at 530, n26 (the distinction regarding ambient air, however, finds no support in the text of the statute, which uses the phrase ''the ambient air'' without distinguishing between atmospheric layer.). Thus, the question of whether greenhouse gases fit within the definition of air pollutant under the CAA has been decided by the Supreme Court and is not being revisited here.

b. The Definition of Air Pollutant May Include Substances Not Emitted by CAA Section 202(a) Sources

Many commenters argue that the definition of ''air pollutant''—here well-mixed greenhouse gases—cannot include PFCs and SF6 because they are not emitted by CAA section 202(a) motor vehicles and hence, cannot be part of any ''air pollutant'' emitted by such sources. They argue that by improperly defining ''air pollutant'' to include substances that are not present in motor vehicle emissions, the Agency has exceeded its statutory authority under CAA section 202(a). Commenters contend that past endangerment findings under CAA section 202(a) demonstrate EPA's consistent approach of defining ''air pollutant(s)'' in accordance with the CAA's clear direction, to include only those pollutants emitted from the relevant source category (citing Notice of Proposed Rulemaking for Heavy-Duty Engine and Vehicle Standards finding that ''emissions of NO_X, VOCs, SO_X, and PM from heavy-duty trucks can reasonably be anticipated to endanger the public health or welfare.'' (65 FR 35436, June 2, 2000). Commenters argue that EPA itself is inconsistent in the Proposed Findings, sometimes referring to ''air pollutant'' as the group of six greenhouse gases, and other times falling back on the four greenhouse gases emitted by motor vehicles.

EPA acknowledges that the Proposed Findings could have been clearer regarding the proposed definition of air pollutant, and how it was being applied to CAA section 202(a) sources, which emit only four of the six substances that meet the definition of well-mixed greenhouse gases. However, our interpretation does not exceed EPA's authority under CAA section 202(a). It is reasonable to define the air pollutant under CAA section 202(a) to include substances that have similar attributes (as discussed above), even if not all of the substances that meet that definition are emitted by motor vehicles. For example, as commenters note, EPA has heavy duty truck standards applicable to VOCs and PM, but it is highly unlikely that heavy duty trucks emit *every* substance that is included in the group defined as VOC or PM. *See* 40 CFR 51.100(s) (defining volatile organic compound (VOC) as ''any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions'', a list of exemptions are also included in the definition); 40 CFR 51.100(oo) (defining particulate matter (PM) as ''any airborne finely divided solid or liquid material with an aerodynamic diameter smaller than 100 micrometers'').

In this circumstance the number of substances included in the definition of well-mixed greenhouse gases is much smaller than other ''group'' air pollutants (*e.g.,* six greenhouse gases versus hundreds of VOCs), and CAA section 202(a) sources emit an easily discernible number of these six substances. However, this does not mean that the definition of the well-mixed greenhouse gases as the air pollutant is unreasonable. By defining well-mixed greenhouse gases as a single air pollutant comprised of six substances with common attributes, the Administrator is giving effect to these shared attributes and how they are relevant to the air pollution to which they contribute. The fact that these six substances share these common, relevant attributes is true regardless of the source category being evaluated for contribution. Grouping these six substances as one air pollutant is reasonable regardless of whether a contribution analysis is undertaken for CAA section 202(a) sources that emit one subset of the six substances (*e.g.*, carbon dioxide, CH_4, N_20 and HFCs, but not PFCs and SF_6), or for another category of sources that may emit another subset. For example, electronics manufacturers that may emit N_2O, PFCs, HFCs, SF_6 and other fluorinated compounds, but not carbon dioxide or CH_4 unless there is on-site fuel combustion. In other words, it is not necessarily the source category being evaluated for contribution that determines the reasonableness of defining a group air pollutant based on the shared attributes of the group.

Even if EPA agreed with commenters, and defined the air pollutant as the group of four compounds emitted by CAA section 202(a) sources, it would not change the result. The Administrator would make the same contribution finding as it would have no material effect on the emissions comparisons discussed above.

c. It Was Reasonable for the Administrator To Define the Single Air Pollutant as the Group of Substances With Common Attributes

Several commenters disagree with EPA's proposed definition of a single air pollutant composed of the six well-mixed greenhouse gases as a class. Commenters argue that the analogy to VOCs is misplaced because VOCs are all part of a defined group of chemicals, for which there are established quantification procedures, and for which there were extensive data showing that the group of compounds had demonstrated and quantifiable effects on ambient air and human health and welfare, and for which verifiable dispersion models existed. They contend this is in stark contrast to the entirely diverse set of organic and inorganic compounds EPA has lumped together for purposes of the Proposed Findings, and for which no model can accurately predict or quantify the actual impact or improvement resulting from controlling the compounds. Moreover, they argue that the gases EPA is proposing to list together as one pollutant are all generated by different processes and, if regulated, would require different types of controls; the four gases emitted by mobile sources can generally be limited only by using controls that are specific to each.

At least one commenter argues that EPA cannot combine greenhouse gases into one pollutant because their common attribute is not a ''physical, chemical, biological or radioactive property'' (quoting from CAA section 302(g)), but rather their effect or impacts on the environment. They say this differs from VOCs, which share the common attribute of volatility, or PM which shares the physical property of being particles.

As discussed above, the well-mixed greenhouse gases share physical attributes, as well as attributes based on sound policy considerations. The definition of ''air pollutant'' in CAA section 302(g) does not limit consideration of common attributes to those that are ''physical, chemical, biological or radioactive property'' as one commenter claims. Rather, the definition's use of the adjectives ''physical, chemical, biological or radioactive'' refer to the different types of substance or matter that is emitted. It is not a limitation on what characteristics the Administrator may consider when deciding how to group similar substances when defining a single air pollutant.

The common attributes that the Administrator considered when defining the well-mixed greenhouse gases are reasonable. While these six substances may originate from different processes, and require different control strategies, that does not detract from the fact that they are all long-lived, well-mixed in the atmosphere, directly emitted, of well-known radiative forcing, and generally grouped and considered together in climate change scientific and policy forums. Indeed, other group pollutants also originate from a variety of processes and a result may require different control technologies. For example, both a power plant and a dirt road can result in PM emissions, and the method to control such emissions at each source would be different. But these differences in origin or control do not undermine the reasonableness of considering PM as a single air pollutant. The fact that there are differences, as well as similarities, among the well-mixed greenhouse gases does not render the decision to group them together as one air pollutant unreasonable.

2. The Administrator's Cause or Contribute Analysis Was Reasonable

a. The Administrator Does Not Need To Find Significant Contribution, or Establish a Bright Line

Many commenters essentially argue that EPA must establish a bright line below which it would never find contribution regardless of the air pollutant, air pollution, and other factors before the Agency. For example, some commenters argue that EPA must provide some basis for determining de minimis amounts that fall below the threshold of ''contributing'' to the endangerment of public health and welfare under CAA section 202(a).

Commenters take issue with EPA's statement that it ''need not determine at this time the circumstances in which emissions would be trivial or de minimis and would not warrant a finding of contribution.'' Commenters argue that EPA cannot act arbitrarily by determining that a constituent contributing a certain percent to endangerment in one instance is de minimis and in another is contributing to endangerment of public health and welfare. They request that EPA revise the preamble language to make clear that the regulated community can rely on its past determinations with respect to ''contribution'' determinations to predict future agency action and argue that EPA should promulgate guidance on how it determines whether a contribution exceeds a de minimis level for purposes of CAA section 202(a) before finalizing the proposal.

The commenters that argue that the air pollution EPA must analyze to determine endangerment is limited to the air pollution resulting from new motor vehicles also argue that as a result, the contribution of emissions from new motor vehicles must be significant. They essentially contend that the endangerment and cause or contribute tests are inter-related and the universe of both tests is the same. In support of their argument, commenters argue that because the clause ''cause, or contribute to, air pollution'' is in plural form, it must be referring back to ''any class or classes of new motor vehicles or new motor vehicle engines,'' demonstrating that EPA must consider only the emissions from new motor vehicles which emit the air pollution which endangers.

Since the Administrator issued the Proposed Findings, the DC Circuit issued another opinion discussing the concept of contribution. See *Catawba County* v. *EPA*, 571 F.3d 20 (DC Cir. 2009). This decision, along with others, supports the Administrator's interpretation that the level of contribution under CAA section 202(a) does not need to be significant. The Administrator is not required to establish a bright line below which she would never find contribution under any circumstances. Finally, it is reasonable for the Administrator to apply a ''totality-of-the-circumstances test to implement a statute that confers broad discretionary authority, even if the test lacks a definite 'threshold' or 'clear line of demarcation to define an open-ended term.'' *Id.* at 39 (citations omitted).

In upholding EPA's $PM_{2.5}$ attainment and nonattainment designation decisions, the DC Circuit analyzed CAA section 107(d), which requires EPA to designate an area as nonattainment if it ''contributes to ambient air quality in a nearby area'' not attaining the national ambient air quality standards. *Id.* at 35. The court noted that it had previously held that the term ''contributes'' is ambiguous in the context of CAA language. *See EDF* v. *EPA*, 82 F.3d 451, 459 (DC Cir. 1996). ''[A]mbiguities in statutes within an agency's jurisdiction to administer are delegations of authority to the agency to fill the statutory gap in reasonable fashion.'' 571 F.3d at 35 (citing *Nat's Cable & Telecomms. Ass'c* v. *Brand X Internet Servs,* 545 U.S. 967, 980 (2005)).

The court then proceeded to consider and reject petitioners' argument that the verb ''contributes'' in CAA section 107(d) necessarily connotes a significant causal relationship. Specifically, the DC Circuit again noted that the term is ambiguous, leaving it to EPA to interpret in a reasonable manner. In the context of this discussion, the court noted that ''a contribution may simply exacerbate a problem rather than cause it * * * '' 571 F.3d at 39. This is consistent with the DC Circuit's decision in *Bluewater Network* v. *EPA,* 370 F.3d 1 (DC Cir. 2004), in which the court noted that the term contribute in CAA section 213(a)(3) ''[s]tanding alone, * * * has no inherent connotation as to the magnitude or importance of the relevant 'share' in the effect; certainly it does not incorporate any 'significance' requirement.'' 370 F.3d at 13. The court found that the bare ''contribute'' language invests the Administrator with discretion to exercise judgment regarding what constitutes a sufficient contribution for the purpose of making an endangerment finding. *Id.* at 14.

Finally, in *Catawba County,* the DC Circuit also rejected ''petitioners' argument that EPA violated the statute by failing to articulate a quantified amount of contribution that would trigger'' the regulatory action. 571 F.3d at 39. Although petitioners preferred that EPA establish a bright-line test, the court recognized that the statute did not require that EPA ''quantify a uniform amount of contribution.'' *Id.*

Given this context, it is entirely reasonable for the Administrator to interpret CAA section 202(a) to require some level of contribution that, while more than de minimis or trivial, does not rise to the level of significance. Moreover, the approach suggested by at least one commenter collapses the two prongs of the test by requiring that contribution must be significant because any climate change impacts upon which an endangerment determination is made result solely from the greenhouse gas emissions of motor vehicles. It essentially eliminates the ''contribute'' part of the ''cause or contribute'' portion of the test. This approach was clearly rejected by the en banc court in *Ethyl.* 541 F.2d at 29 (rejecting the argument that the emissions of the fuel additive to be regulated must ''in and of itself, *i.e.* considered in isolation, endanger[ ] public health.''); see also *Catawba County,* 571 F.3d at 39 (noting that even if the test required significant contribution it would be reasonable for EPA to find a county's addition of $PM_{2.5}$ is significant even though the problem would persist in its absence). It is the commenter, not EPA that is ignoring the statutory language. Whether or not the clause ''cause, or contribute to, air pollution'' refers back to ''any class or classes of new motor vehicles or new motor vehicle engines,'' or to ''emission of any air pollutant,'' the language of CAA section 202(a) clearly contemplates that emission of an air pollutant from any class or classes may merely contribute to, versus cause, the air pollution which endangers.

It is also reasonable for EPA to decline to establish a ''bright-line 'objective' test of contribution.'' 571 F.3d at 39. As noted in the Proposed Findings, when exercising her judgment, the Administrator not only considers the cumulative impact, but also looks at the totality of the circumstances (*e.g.,* the air pollutant, the air pollution, the nature of the endangerment, the type of source category, the number of sources in the source category, and the number and type of other source categories that may emit the air pollutant) when determining whether the emissions justify regulation under the CAA. *Id.* (It is reasonable for an agency to adopt a totality-of-the-circumstances test).

Even if EPA agreed that a level of significance was required to find contribution, for the reasons discussed above, EPA would find that the contribution from CAA section 202(a) source categories is significant. Their emissions are larger than the great majority of emitting countries, larger than several major emitting countries, and they constitute one of the largest parts of the U.S. emissions inventory.

b. The Unique Global Aspects of Climate Change Are an Appropriate Consideration in the Contribution Analysis

Some commenters disagree with statements in the Proposed Findings that the ''unique, global aspects of the climate change problem tend to support a finding that lower levels of emissions should be considered to contribute to the air pollution than might otherwise be appropriate when considering contribution to a local or regional air pollution problem.'' They argue there is no basis in the CAA or existing EPA policy for this position, and that it reveals an apparent effort to expand EPA's authority to the ''truly trivial or de minimis'' sources that are acknowledged to be outside the scope of regulation, in that it expands EPA's authority to regulate pollutants to address global effects.

Commenters also assert that contrary to EPA's position, lower contribution numbers are appropriate when looking at local pollution, like nonattainment concerns—in other words, in the context of a statutory provision like CAA section 213 specifically aimed at targeting small source categories to help nonattainment areas meet air quality standards. However, they conclude this policy is simply inapplicable in the context of global climate change.

As discussed above, the term ''contribute'' is ambiguous and subject to the Administrator's reasonable interpretation. It is entirely appropriate for the Administrator to look at the totality of the circumstances when making a finding of contribution. In this case, the Administrator believes that the global nature of the problem justifies looking at contribution in a way that takes account of these circumstances. More specifically, because climate change is a global problem that results from global greenhouse gas emissions, there are more sources emitting greenhouse gases (in terms both of absolute numbers of sources and types of sources) than EPA typically encounters when analyzing contribution towards a more localized air pollution problem. From a percentage perspective, there are no dominating sources and fewer sources that would even be considered to be close to dominating. The global problem is much more the result of numerous and varied sources each of which emit what might seem to be smaller percentage amounts when compared to the total. The Administrator's approach recognizes this reality, and focuses on evaluating the relative importance of the CAA section 202(a) source categories compared to other sources when viewed in this context.

This recognition of the unique totality of the circumstances before the Administrator now as compared to previous contribution decisions is entirely appropriate. It is not an attempt by the Administrator to regulate ''truly trivial or de minimis'' sources, or to regulate sources based on their global effects. The Administrator is determining whether greenhouse gas emissions from CAA section 202(a) sources contribute to an air pollution problem is endangering U.S. public health and welfare. As discussed in the Proposed Findings, no single greenhouse gas source category dominates on the global scale, and many (if not all) individual greenhouse gas source categories could appear small in comparison to the total, when, in fact, they could be very important contributors in terms of both absolute emissions or in comparison to other source categories, globally or within the United States. If the United States and the rest of the world are to combat the risks associated with global climate change, contributors must do their part even if their contributions to the global problem, measured in terms of percentage, are smaller than typically encountered when tackling solely regional or local environmental issues. The commenters' approach, if used globally, would effectively lead to a tragedy of the commons, whereby no country or source category would be accountable for contributing to the global problem of climate change, and nobody would take action as the problem persists and worsens. The Administrator's approach, on the contrary, avoids this kind of approach, and is a reasonable exercise of her discretion to determine contribution in the global context in which this issue arises.

Importantly, as discussed above, the contribution from CAA section 202(a) sources is anything but trivial or de minimis under any interpretation of contribution. See, *Massachusetts v. EPA,* 549 U.S. at 1457–58 (''Judged by any standard, U.S. motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming'').

c. The Administrator Reasonably Relied on Comparisons of Emissions From Existing CAA Section 202(a) Source Categories

i. It Was Reasonable To Use Existing Emissions From Existing CAA Section 202(a) Source Categories Instead of Projecting Future Emissions From New CAA Section 202(a) Source Categories

Many commenters argue that EPA improperly evaluated the emissions from the entire motor vehicle fleet, and it is required to limit its calculation to just emissions from new motor vehicles. Thus the emissions that EPA should consider in the cause or contribute determination is far less than the 4.3 percent of U.S. greenhouse gas emissions attributed to motor vehicles in the Proposed Findings, because this number includes both new and existing motor vehicles. One commenter calculated the emissions from new motor vehicles as being 1.8 percent of global emissions, assuming approximately one year of new motor vehicle production in the United States (11 million vehicles) in a total global count currently of approximately 600 million motor vehicles.

In the Proposed Findings, EPA determined the emissions from the entire fleet of motor vehicles in the United States for a certain calendar year. EPA explained that, consistent with its traditional practice, it used the recent motor vehicle emissions inventory for the entire fleet as a surrogate for estimates of emissions for just new motor vehicles and engines. This was appropriate because future projected emissions are uncertain and current emissions data are a reasonable proxy for near-term emissions.

In effect, EPA is using the inventory for the current fleet of motor vehicles as a reasonable surrogate for a projection of the inventory from new motor vehicles over the upcoming years. New motor vehicles are produced year in and year out, and over time the fleet changes over to a fleet composed of such vehicles. This occurs in a relatively short time frame, compared to the time period at issue for endangerment. Because new motor vehicles are produced each year, and continue to emit over their entire life, over a relatively short period of time the emission from the entire fleet is from vehicles produced after a certain date. In addition, the emissions from new motor vehicles are not limited to the emissions that occur only during the one year when they are new, but are emissions over the entire life of the vehicle.

In such cases, EPA has traditionally used the recent emissions from the entire current fleet of motor vehicles as a reasonable surrogate for such a projection instead of trying to project and model those emissions. While this introduces some limited degree of uncertainty, the difference between recent actual emissions from the fleet and projected future emissions from the fleet is not expected to differ in any way that would substantively change the decision made concerning cause or contribution. There is not a specific numerical bright line that must be achieved, and the numerical percentages are not treated and do not need to be treated as precise values. This approach provides a reasonable and clear indication of the relative magnitudes involved, and EPA does not believe that attempting to make future projections (for both vehicles and the emissions value they are compared to) would provide any greater degree of accuracy or precision in developing such a relative comparison.

ii. The Administrator Did Not Have To Use a Subset or Reduced Emissions Estimate From Existing CAA Section 202(a) Source Categories

Several commenters note that although EPA looks at emissions from all motor vehicles regulated under CAA section 202(a) in its contribution analysis, the Presidential announcement in May 2009 indicated that EPA was planning to regulate only a subset of 202(a) sources. Thus, they question whether the correct contribution analysis should look only at the emissions from that subset and not all CAA section 202(a) sources. Some commenters also argue that because emission standards will not eliminate all greenhouse gas emissions from motor vehicles, the comparison should compare the amount of greenhouse gas emissions ''reduced'' by those standards to the global greenhouse emissions. They also contend that the cost of the new standards will cause individual consumers, businesses, and other vehicle purchasers to hold on to their existing vehicles to a greater extent, thereby decreasing the amount of emissions reductions attributable to the standard and appropriately considered in the contribution analysis. Some commenters go further and contend that EPA also can only include that incremental reduction that the EPA regulations will achieve beyond any reductions resulting from CAFE standards that NHTSA will set.

Although the May announcement and September proposed rule involved only the light duty motor vehicle sector, the Administrator is making this finding for all classes of new motor vehicles under CAA section 202(a). Thus, although the announcement and proposed rule involve light duty vehicles, EPA is working to develop standards for the rest of the classes of new motor vehicles under CAA section 202(a). As the Supreme Court noted, EPA has ''significant latitude as to the manner, timing, content, and coordination of its regulations with those of other agencies. *Massachusetts* v. *EPA,* 549 U.S. at 533.

The argument that the Administrator can only look at that portion of emissions that will be reduced by any CAA section 202(a) standards, and even then only the reduction beyond those attributable to CAFE rules, finds no basis in the statutory language. The language in CAA section 202(a) requires that the Administrator set ''standards applicable to the emission of any air pollutant from [new motor vehicles], which in [her] judgment cause, or contribute to, air pollution which [endangers].'' It does not say set ''standards applicable to the emission of any air pollutant from [new motor vehicles], if in [her] judgment the emissions of that air pollutant as reduced by that standard cause, or contribute to, air pollution which [endangers].'' As discussed above, the decisions on cause or contribute and endangerment are separate and distinct from the decisions on what emissions standards to set under CAA section 202(a). The commenter's approach would improperly integrate these separate decisions. Indeed, because, as discussed above, the Administrator does not have to propose standards concurrent with the endangerment and cause or contribute findings, she would have to be prescient to know at the time of the contribution finding exactly the amount of the reduction that would be achieved by the standards to be set. As discussed above, for purposes of these findings we look at what would be the emissions from new motor vehicles if no action were taken. Current emissions from the existing CAA section 202(a) vehicle fleet are an appropriate estimate.

d. The Administrator Reasonably Compared CAA Section 202(a) Source Emissions to Both Global and Domestic Emissions of Well-Mixed Greenhouse Gases

EPA received many comments on the appropriate comparison(s) for the contribution analysis. Several commenters argue that in order to get around the ''problem'' of basing an endangerment finding upon a source category that contributes only 1.8 percent annually to global greenhouse gas emissions, EPA inappropriately also made comparisons to total U.S. greenhouse gas emissions. These commenters argue that a comparison of CAA section 202(a) source emissions to U.S. greenhouse gas emissions, versus global emissions, is arbitrary for purposes of the cause or contribute analysis, because it conflicts with the Administrator's definition of ''air pollution,'' as well as the nature of global warming. They note that throughout the Proposed Findings, the Administrator focuses on the global nature of greenhouse gas. Thus, they continue, while the percentage share of motor vehicle emissions at the U.S. level may be relevant for some purposes, it is irrelevant to a finding of whether these emissions contribute to the air pollution, which the Administrator has proposed to define on a global rather than a domestic basis. Commenters also accuse EPA of arbitrarily picking and choosing when it takes a global approach (*e.g.,* endangerment finding) and when it does not (*e.g.,* contribution findings).

The language of CAA section 202(a) is silent regarding how the Administrator is to make her contribution analysis. While it requires that the Administrator assess whether emission of an air pollutant contributes to air pollution which endangers, it does not limit *how* she may undertake that assessment. It surely is reasonable that the Administrator look at how CAA section 202(a) source category emissions compare to global emissions on an absolute basis, by themselves. But the United States as a nation is the second largest emitter of greenhouse gases. It is entirely appropriate for the Administrator to decide that part of understanding how a U.S. source category emitting greenhouse gases fits into the bigger picture of global climate change is to appreciate how that source category fits into the contribution from the United States as a whole, where the United States as a country is a major emitter of greenhouse gases. Knowing that CAA section 202(a) source categories are the second largest emitter of well-mixed greenhouse gases in the country is relevant to understanding what role they play in the global problem and hence whether they ''contribute'' to the global problem. Moreover, the Administrator is not ''picking and choosing'' when she applies a global or domestic approach in these Findings. Rather, she is looking at both of these emissions comparisons as appropriate under the applicable science, facts, and law.

e. The Amount of Well-Mixed Greenhouse Gas Emissions From CAA Section 202(a) Sources Reasonably Supports a Finding of Contribution

Many commenters argue that the ''cause or contribute'' prong of the Proposal's endangerment analysis fails to satisfy the applicable legal standard, which requires more than a minimal contribution to the ''air pollution reasonably anticipated to endanger public health or welfare.'' They contend that emissions representing approximately four percent of total global greenhouse gas emissions are a minimal contribution to global greenhouse gas concentrations.

EPA disagrees. As stated above, CAA section 202(a) source category total emissions of well-mixed greenhouse gases are higher than most countries in the world; countries that the U.S. and others believe play a major role in the global climate change problem. Moreover, the percent of global well-mixed greenhouse gas emissions that CAA section 202(a) source categories represent is higher than percentages that the EPA has found contribute to air pollution problems. *See Bluewater Network,* 370 F.3d at 15 (''For Fairbanks, this contribution was equivalent to 1.2 percent of the total daily CO inventory for 2001.'') As noted above, there is no bright line for assessing contribution, but as discussed in the Proposed Findings and above, when looking at a global problem like climate change, with many sources of emissions and no dominating sources from a global perspective, it is reasonable to consider that lower percentages contribute than one may consider when looking at a local or regional problem involving fewer sources of emissions. The Administrator agrees that ''[j]udged by any standard, U.S. motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming.'' *Massachusetts v. EPA,* 549 U.S. at 525.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is a ''significant regulatory action'' because it raises novel policy issues. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to Office of Management and Budget (OMB) recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* Burden is defined at 5 CFR 1320.3(b). These Findings do not impose an information collection request on any person.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this action on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Because these Findings do not impose any requirements, the Administrator certifies that this action will not have a significant economic impact on a substantial number of small entities. This action does not impose any requirements on small entities. The endangerment and cause or contribute findings do not in-and-of-themselves impose any new requirements but rather set forth the Administrator's determination on whether greenhouse gases in the atmosphere may reasonably be anticipated to endanger public health or welfare, and whether emissions of greenhouse gases from new motor vehicles and engines contribute to this air pollution. Accordingly, the action affords no opportunity for EPA to fashion for small entities less burdensome compliance or reporting requirements or timetables or exemptions from all or part of the Findings.

D. Unfunded Mandates Reform Act

This action contains no Federal mandates under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for State, local, or tribal governments or the private sector. The action imposes no enforceable duty on any State, local or tribal governments or the private sector. Therefore, this action is not subject to the requirements of sections 202 or 205 of the UMRA.

This action is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This finding does not impose any requirements on industry or other entities.

E. Executive Order 13132: Federalism

This action does not have federalism implications. Because this action does not impose requirements on any entities, it will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this action.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). This action does not have substantial direct effects on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, nor does it impose any enforceable duties on any Indian tribes. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks. Although the Administrator considered health and safety risks as part of these Findings, the Findings themselves do not impose a standard intended to mitigate those risks.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy because it does not impose any requirements.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 104–113, 12(d) (15 U.S.C. at 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (EO) 12898 (59 FR 7629, Feb. 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that these Findings will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. Although the Administrator considered climate change risks to minority or low-income populations as part of these Findings, this action does not impose a standard intended to mitigate those risks and does not impose requirements on any entities.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective January 14, 2010.

Dated: December 7, 2009.

Lisa P. Jackson,

Administrator.

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Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements

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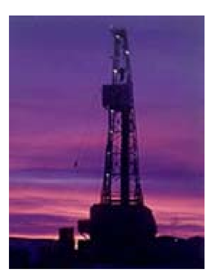


1.0 EXECUTIVE SUMMARY

Natural gas production in the Barnett Shale region of Texas has increased rapidly since 1999, and as of June 2008, over 7700 oil and gas wells had been installed and another 4700 wells were pending. Gas production in 2007 was approximately 923 Bcf from wells in 21 counties. Natural gas is a critical feedstock to many chemical production processes, and it has many environmental benefits over coal as a fuel for electricity generation, including lower emissions of sulfur, metal compounds, and carbon dioxide. Nevertheless, oil and gas production from the Barnett Shale area can impact local air quality and release greenhouse gases into the atmosphere. The objectives of this study were to develop an emissions inventory of air pollutants from oil and gas production in the Barnett Shale area, and to identify cost-effective emissions control options.

Emission sources from the oil and gas sector in the Barnett Shale area were divided into point sources, which included compressor engine exhausts and oil/condensate tanks, as well as fugitive and intermittent sources, which included production equipment fugitives, well drilling and fracing engines, well completions, gas processing, and transmission fugitives. The air pollutants considered in this inventory were smog-forming compounds (NO_x and VOC), greenhouse gases, and air toxic chemicals.

For 2009, emissions of smog-forming compounds from compressor engine exhausts and tanks were predicted to be approximately 96 tons per day (tpd) on an annual average, with peak summer emissions of 212 tpd. Emissions during the summer increase because of the effects of temperature on volatile organic compound emissions from storage tanks. Emissions of smog-forming compounds in 2009 from all oil and gas sources were estimated to be approximately 191 tpd on an annual average, with peak summer emissions of 307 tpd. The portion of those emissions originating from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 165 tpd during the summer.

For comparison, 2009 emission inventories recently used by state and federal regulators estimated smog-forming emissions from all airports in the Dallas-Fort Worth metropolitan area to be 16 tpd. In addition, these same inventories had emission estimates for on-road motor vehicles (cars, trucks, etc.) in the 9-county Dallas-Fort Worth metropolitan area of 273 tpd. The portion of on-road motor vehicle emissions from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 121 tpd, indicating that the oil and gas sector likely has greater emissions than motor vehicles in these counties.

The emission rate of air toxic compounds (like benzene and formaldehyde) from Barnett Shale activities was predicted to be approximately 6 tpd on an annual average, and 17 tpd during peak summer days. The largest contributors to air toxic emissions were the condensate tanks, followed by the engine exhausts.

In addition, predicted 2009 emissions of greenhouse gases like carbon dioxide and methane were approximately 33,000 tons per day of CO_2 equivalent. This is roughly equivalent to the expected greenhouse gas impact from two 750 MW coal-fired power plants. The largest contributors to the Barnett Shale greenhouse gas impact were CO_2 emissions from compressor engine exhausts and fugitive CH_4 emissions from all source types.

Cost effective control strategies are readily available that can substantially reduce emissions, and in some cases, reduce costs for oil and gas operators. These options include:

- use of "green completions" to capture methane and VOC compounds during well completions,
- phasing in electric motors as an alternative to internal-combustion engines to drive compressors,
- the control of VOC emissions from condensate tanks with vapor recovery units, and
- replacement of high-bleed pneumatic valves and fittings on the pipeline networks with no-bleed alternatives.

2.0 BACKGROUND

2.1 Barnett Shale Natural Gas Production

The Barnett Shale is a geological formation that the Texas Railroad Commission (RRC) estimates to extend 5000 square miles in parts of at least 21 Texas counties. The hydrocarbon productive region of the Barnett Shale has been designated as the Newark East Field, and large scale development of the natural gas resources in the field began in the late 1990's. Figure 1 shows the rapid and continuing development of natural gas from the Barnett Shale over the last 10 years.(1)

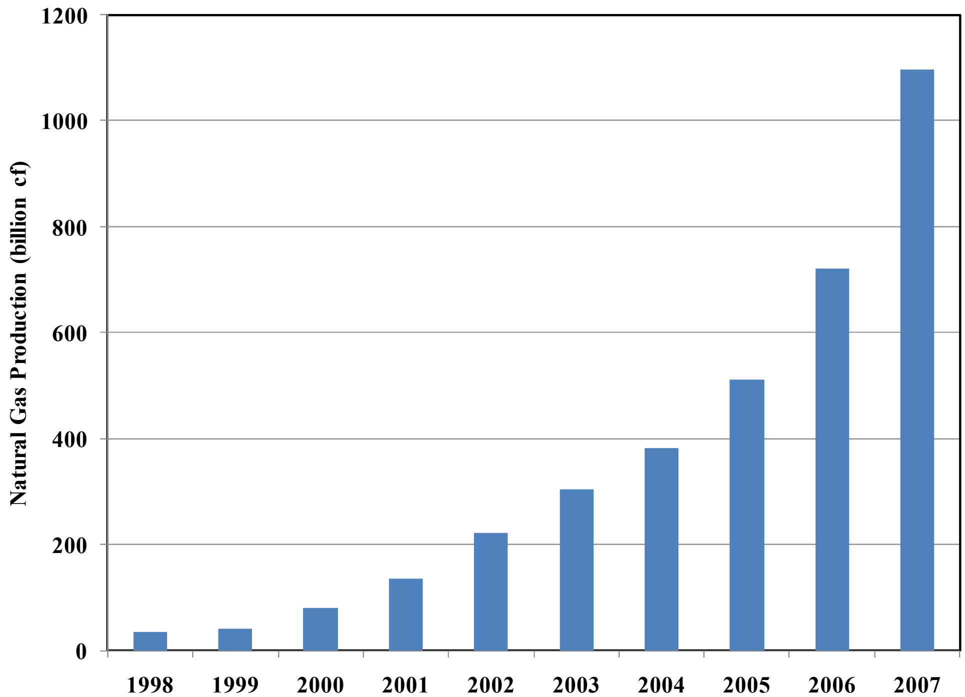


Figure 1. Barnett Shale Natural Gas Production, 1998-2007.

In addition to the recent development of the Barnett Shale, oil and gas production from other geologic formations and conventional sources in north central Texas existed before 1998 and continues to the present time. Production from the Barnett Shale is currently the dominant source of hydrocarbon production in the area from oil and gas activities in the area. Emission sources for all oil and gas activities are considered together in this report.

The issuance of new Barnett Shale area drilling permits has been following the upward trend of increasing natural gas production. The RRC issued 1112 well permits in 2004, 1629 in 2005, 2507 in 2006, 3657 in 2007, and they are on-track to issue over 4000 permits in 2008. The vast majority of the wells and permits are for natural gas production, but a small number of oil wells are also in operation or permitted in the area, and some oil wells co-produce casinghead gas. As of June 2008, over 7700 wells had been registered with the RRC, and the permit issuance rates are summarized in Table 1-1.(1) Annual oil, gas, condensate, and casinghead gas production rates for 21 counties in the Barnett Shale area are shown in Table 1-2.(1) The majority of Barnett Shale wells and well permits are located in six counties near the city of Fort Worth: Tarrant, Denton, Wise, Parker, Hood, and Johnson Counties. Figure 2 shows a RRC map of wells and well permits in the Barnett Shale.(2)

The top three gas producing counties in 2007 were Johnson, Tarrant and Wise, and the top three condensate producing counties were Wise, Denton, and Parker.

Nine (9) counties surrounding the cities of Fort Worth and Dallas have been designated by the U.S. EPA as the D-FW ozone nonattainment area (Tarrant, Denton, Parker, Johnson, Ellis, Collin, Dallas, Rockwall, and Kaufman). Four of these counties (Tarrant, Denton, Parker, and Johnson) have substantial oil or gas production. In this report, these 9 counties are referred to as the D-FW metropolitan area. The areas outside these 9-counties with significant Barnett Shale oil or gas production are generally more rural counties to the south, west, and northwest of the city of Fort Worth. The counties inside and outside the D-FW metropolitan area with oil and gas production are listed in Table 1-3.

Table 1-1. Barnett Shale Area Drilling Permits Issued, 2004-2008.(1)

year	new drilling permits
2004	1112
2005	1629
2006	2507
2007	3657
2008	4000+

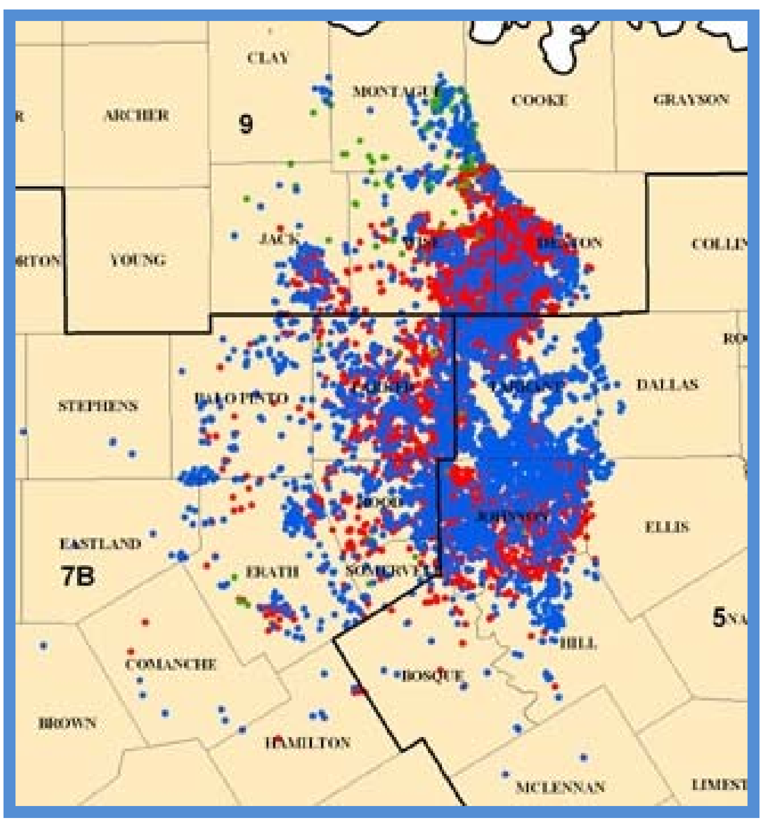
Table 1-2. Hydrocarbon Production in the Barnett Shale Area in 2007.(1)

County	Gas Production (MCF)	Condensate (BBL)	Casinghead Gas (MCF)	Oil Production (BBL)
Johnson	282,545,748	28,046	0	0
Tarrant	246,257,349	35,834	0	0
Wise	181,577,163	674,607	6,705,809	393,250
Denton	168,020,626	454,096	934,932	52,363
Parker	80,356,792	344,634	729,472	11,099
Hood	32,726,694	225,244	40,271	526
Jack	16,986,319	139,009	2,471,113	634,348
Palo Pinto	12,447,321	78,498	1,082,030	152,685
Stephens	11,149,910	56,183	3,244,894	2,276,637
Hill	7,191,823	148	0	0
Erath	4,930,753	11,437	65,425	5,073
Eastland	4,129,761	130,386	754,774	259,937
Somervell	4,018,269	6,317	0	0
Ellis	1,715,821	0	17,797	10
Comanche	560,733	1,584	52,546	7,055
Cooke	352,012	11,745	2,880,571	2,045,505
Montague	261,734	11,501	3,585,404	1,677,303
Clay	261,324	12,046	350,706	611,671
Hamilton	162,060	224	0	237
Bosque	135,116	59	0	0
Kaufman	0	0	3,002	61,963

Table 1-3. Relationship Between the D-FW Metropolitan Area and Counties Producing Oil/Gas in the Barnett Shale Area

D-FW 9-County Metropolitan Area	D-FW Metro. Counties Producing Barnett Area Oil/Gas	Rural Counties Producing Barnett Area Oil/Gas
Tarrant	Tarrant	Wise
Denton	Denton	Hood
Parker	Parker	Jack
Johnson	Johnson	Palo Pinto
Ellis	Ellis	Stephens
Collin		Hill
Dallas		Eastland
Rockwall		Somervell
Kaufman		Comanche
		Cooke
		Montague
		Clay
		Hamilton
		Bosque

Figure 2. Texas RRC Map of Well and Well Permit Locations in the Barnett Shale Area (red = gas wells, green = oil wells, blue = permits. RRC district 5, 7B, & 9 boundaries shown in black.)



2.2 Air Pollutants and Air Quality Regulatory Efforts

Oil and gas activities in the Barnett Shale area have the potential to emit a variety of air pollutants, including greenhouse gases, ozone and fine particle smog-forming compounds, and air toxic chemicals. The state of Texas has the highest greenhouse gas (GHG) emissions in the U.S., and future federal efforts to reduce national GHG emissions are likely to require emissions reductions from sources in the state. The three anthropogenic greenhouse gases of greatest concern, carbon dioxide, methane, and nitrous oxide, are emitted from oil and gas sources in the Barnett Shale area.

At present, air quality monitors in the Dallas-Fort Worth area show the area to be in compliance with the 1997 fine particulate matter ($PM_{2.5}$) air quality standard, which is 15 micrograms per cubic meter ($\mu g/m^3$) on an annual average basis. In 2006, the Clean Air Scientific Advisory Committee for EPA recommended tightening the standard to as low as 13 $\mu g/m^3$ to protect public health, but the EPA administrator kept the standard at the 1997 level. Fine particle air quality monitors in the Dallas-Fort Worth area have been above the 13 $\mu g/m^3$ level several times during the 2000-2007 time period, and tightening of the fine particle standard by future EPA administrators will focus regulatory attention at sources that emit fine particles or fine particle-forming compounds like NO_x and VOC gases.

2.3 Primary Emission Sources Involved in Barnett Shale Oil and Gas Production

There are a variety of activities that potentially create air emissions during oil and gas production in the Barnett Shale area. The primary emission sources in the Barnett Shale oil and gas sector include compressor engine exhausts, oil and condensate tank vents, production well fugitives, well drilling and hydraulic fracturing, well completions, natural gas processing, and transmission fugitives. Figure 3 shows a diagram of the major machinery and process units in the natural gas system.(3)

2.3.1 – Point Sources

i. Compressor Engine Exhausts

Internal combustion engines provide the power to run compressors that assist in the production of natural gas from wells, pressurize natural gas from wells to the pressure of lateral lines, and power compressors that move natural gas in large pipelines to and from processing plants and through the interstate pipeline network. The engines are often fired with raw or processed natural gas, and the combustion of the natural gas in these engines results in air emissions. Most of the engines driving compressors in the Barnett Shale area are between 100 and 500 hp in size, but some large engines of 1000+ hp are also used.

ii. Condensate and Oil Tanks

Fluids that are brought to the surface at Barnett Shale natural gas wells are a mixture of natural gas, other gases, water, and hydrocarbon liquids. Some gas wells produce little or no condensate, while others produce large quantities. The mixture typically is sent first to a separator unit, which reduces the pressure of the fluids and separates the natural gas and other gases from any entrained water and hydrocarbon liquids. The gases are collected off the top of the separator, while the water and hydrocarbon liquids fall to the bottom and are then stored on-site in storage tanks. The hydrocarbon liquid is known as condensate.

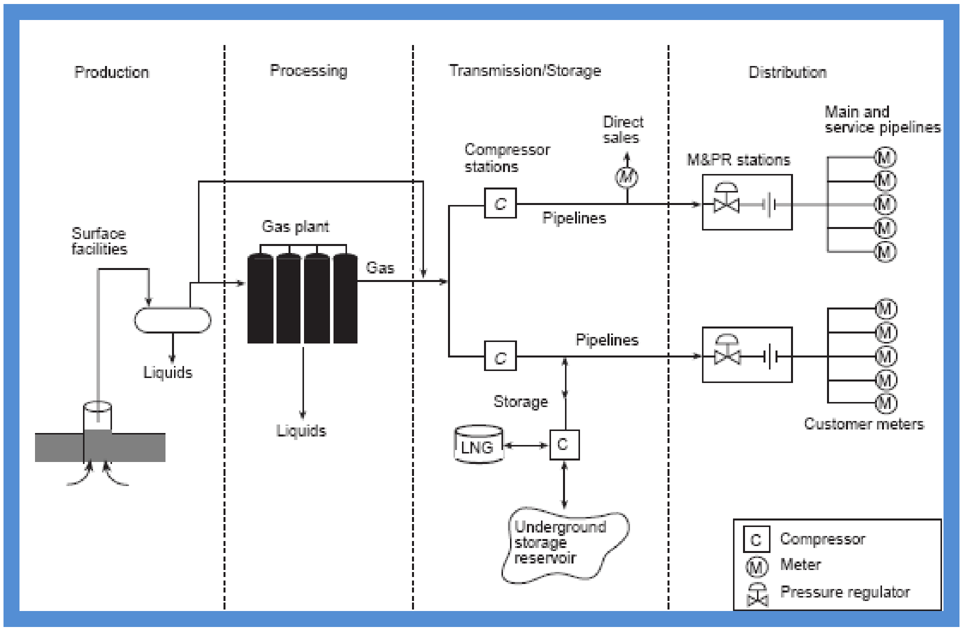


Figure 3. Major Units in The Natural Gas Industry From Wells to Customers. [3]

The condensate tanks at Barnett Shale wells are typically 10,000 to 20,000 gallons and hydrocarbons vapors from the condensate tanks can be emitted to the atmosphere through vents on the tanks. Condensate liquid is periodically collected by truck and transported to refineries for incorporation into liquid fuels, or to other processors. At oil wells, tanks are used to store crude oil on-site before the oil is transported to refiners. Like the condensate tanks, oil tanks can be sources of hydrocarbon vapor emissions to the atmosphere through tank vents.

2.3.2 – Fugitive and Intermittent Sources

i. Production Fugitive Emissions

Natural gas wells can contain a large number of individual components, including pumps, flanges, valves, gauges, pipe connectors, compressors, and other pieces. These components are generally intended to be tight, but leaks are not uncommon and some leaks can result in large emissions of hydrocarbons and methane to the atmosphere. The emissions from such leaks are called "fugitive" emissions. These fugitive emissions can be caused by routine wear, rust and corrosion, improper installation or maintenance, or overpressure of the gases or liquids in the piping. In addition to the unintended fugitive emissions, pneumatic valves which operate on pressurized natural gas leak small quantities of natural gas by design during normal operation. Natural gas wells, processing plants, and pipelines often contain large numbers of these kinds of pneumatic valves, and the accumulated emissions from all the valves in a system can be significant.

ii. Well Drilling, Hydraulic Fracturing, and Completions

Oil and gas drilling rigs require substantial power to from wellbores by driving drill bits to the depths of hydrocarbon deposits. In the Barnett Shale, this power is typically provided by transportable diesel engines, and operation of these engines generates exhaust from the burning of diesel fuel. After the wellbore is formed, additional power is needed to operate the pumps that move large quantities of water, sand/glass, or chemicals into the wellbore at high pressure to hydraulically fracture the shale to increase its surface area and release natural gas.

After the wellbore is formed and the shale fractured, an initial mixture of gas, hydrocarbon liquids, water, sand, or other materials comes to the surface. The standard hardware typically used at a gas well, including the piping, separator, and tanks, are not designed to handle this initial mixture of wet and abrasive fluid that comes to the surface. Standard practice has been to vent or flare the natural gas during this "well completion" process, and direct the sand, water, and other liquids into ponds or tanks. After some time, the mixture coming to the surface will be largely free of the water and sand, and then the well will be connected to the permanent gas collecting hardware at the well site. During well completions, the venting/flaring of the gas coming to the surface results in a loss of potential revenue and also in substantial methane and VOC emissions to the atmosphere.

iii. Natural Gas Processing

Natural gas produced from wells is a mixture of a large number of gases and vapors. Wellhead natural gas is often delivered to processing plants where higher molecular weight hydrocarbons, water, nitrogen, and other compounds are largely removed if they are present. Processing results in a gas stream that is enriched in methane at concentrations of usually more than 80%. Not all natural gas requires processing, and gas that is already low in higher hydrocarbons, water, and other compounds can bypass processing.

Processing plants typically include one or more glycol dehydrators, process units that dry the natural gas. In addition to water, the glycol absorbent usually collects significant quantities of hydrocarbons, which can be emitted to the atmosphere when the glycol is regenerated with heat. The glycol dehydrators, pumps, and other machinery used in natural gas processing can release methane and hydrocarbons into the atmosphere, and emissions also originate from the numerous flanges, valves, and other fittings.

iv. Natural Gas Transmission Fugitives

Natural gas is transported from wells in mostly underground gathering lines that form networks that can eventually collect gas from hundreds or thousands of well locations. Gas is transported in pipeline networks from wells to processing plants, compressor stations, storage formations, and/or the interstate pipeline network for eventual delivery to customers. Leaks from pipeline networks, from microscopic holes, corrosion, welds and other connections, as well as from compressor intake and outlet seals, compressor rod packing, blow and purge operations, pipeline pigging, and from the large number of pneumatic devices on the pipeline network can result in large emissions of methane and hydrocarbons into the atmosphere and lost revenue for producers.

2.4 Objectives

Barnett Shale area oil and gas production can emit pollutants to the atmosphere which contribute to ozone and fine particulate matter smog, are known toxic chemicals, or contribute to climate change. The objectives of this study were to examine Barnett Shale oil and gas activities and : (1) estimate emissions of volatile organic compounds, nitrogen oxides, hazardous air pollutants, methane, carbon dioxide, and nitrous oxide; (2) evaluate the current state of regulatory controls and engineering techniques used to control emissions from the oil and gas sector in the Barnett Shale; (3) identify new approaches that can be taken to reduce emissions from Barnett Shale activities; and (4) estimate the emissions reductions and cost effectiveness of implementation of new emission reduction methods.

3.0 TECHNICAL APPROACH

3.1 Pollutants

Estimates were made of 2007 and 2009 emissions of smog forming, air toxic, and greenhouse gas compounds, including nitrogen oxides (NO_x), volatile organic compounds (VOCs), air toxics a.k.a. hazardous air pollutants (HAPs), methane (CH_4), nitrous oxide (N_2O), and carbon dioxide (CO_2). Volatile organic compounds are generally carbon and hydrogen-based chemicals that exist in the gas phase or can evaporate from liquids. VOCs can react in the atmosphere to form ozone and fine particulate matter. Methane and ethane are specifically excluded from the definition of VOC because they react slower than the other VOC compounds to produce ozone and fine particles, but they are ozone-causing compounds nonetheless. The HAPs analyzed in this report are a subset of the VOC compounds, and include those compounds that are known or believed to cause human health effects at low doses. An example of a HAP compound is benzene, which is an organic compound known to contribute to the development of cancer.

Emissions of the greenhouse gases CO_2, CH_4, and N_2O were determined individually, and then combined as carbon dioxide equivalent tons (CO_2e). In the combination, CH_4 tons were scaled by 21 and N_2O tons by 310 to account for the higher greenhouse gas potentials of these gases.[(4)]

Emissions in 2009 were estimated by examining recent trends in Barnett Shale hydrocarbon production, and where appropriate, extrapolating production out to 2009.

State regulatory programs are different for compressor engines inside the D-FW 9-county metropolitan area compared to outside. Engine emissions were determined separately for the two groups.

3.2 Hydrocarbon Production

Production rates in 2007 for oil, gas, casinghead gas, and condensate were obtained from the Texas Railroad Commission for each county in the Barnett Shale area.[(5)] The large amount of production from wells producing from the Barnett Shale, as well as the smaller amounts of production from conventional formations in the area were taken together. The area was analyzed in whole, as well as by counties inside and outside the D-FW 9-county metropolitan area. Production rates in 2009 were predicted by plotting production rates from 2000-2007 and fitting a 2^{nd}-order polynomial to the production rates via the least-squares method and extrapolating out to 2009.

3.3 Compressor Engine Exhausts - Emission Factors and Emission Estimates

Emissions from the natural-gas fired compressor engines in the Barnett Shale were calculated for two types of engines: the generally large engines that had previously reported emissions into the TCEQ's Point Source Emissions Inventory (PSEI) prior to 2007 (a.k.a. PSEI Engines), and the generally smaller engines that had not previously reported emissions (a.k.a. non-PSEI Engines). Both these engine types are located in the D-FW 9-county metropolitan area (a.k.a. D-FW Metro Area), as well as in the rural counties outside the metropolitan area (a.k.a. Outside D-FW Metro Area). The four categories of engines are summarized in Figure 4 and the methods used to estimate emissions from the engines are described in the following sections.

Figure 4. Engine Categories.

Non-PSEI Engines in D-FW Metro Area	PSEI Engines in D-FW Metro Area	PSEI Engines Outside D-FW Metro Area	Non-PSEI Engines Outside D-FW Metro Area

i. Non-PSEI Engines in D-FW Metropolitan Area

Large natural gas compressor engines, located primarily at compressor stations and also some at well sites, have typically reported emissions to the Texas Commission on Environmental Quality (TCEQ) in annual Point Source Emissions Inventory (PSEI) reports. However, prior to 2007, many other stationary engines in the Barnett Shale area had not reported emissions to the PSEI and their contribution to regional air quality was unknown. In late 2007, the TCEQ conducted an engine survey for counties in the D-FW metropolitan area as part as efforts to amend the state clean air plan for ozone. Engine operators reported engine counts, engine sizes, NO_x emissions, and other data to TCEQ. Data summarized by TCEQ from the survey was used for this report to estimate emissions from natural gas engines in the Barnett Shale area that had previously not reported emissions into the annual PSEI.(6) Data obtained from TCEQ included total operating engine power in the metropolitan area, grouped by rich vs. lean burn engines, and also grouped by engines smaller than 50 hp, between 50 - 500 hp, and larger than 500 hp.

Regulations adopted by TCEQ and scheduled to take effect in early 2009 will limit NO_x emissions in the D-FW metropolitan area for engines larger than 50 horsepower.(7) Rich burn engines will be restricted to 0.5 g/hp-hr, lean burn engines installed or moved before June 2007 will be restricted to 0.7 g/hp-hr, and lean burn engines installed or moved after June 2007 will be limited to 0.5 g/hp-hr. For this report, emissions in 2009 from the engines in the metropolitan area subject to the new rules were estimated assuming 97% compliance with the upcoming rules and a 3% noncompliance factor for engines continuing to emit at pre-2009 levels.

Emissions for 2007 were estimated using NO_x emission factors provided by operators to TCEQ in the 2007 survey.(6) Emissions of VOCs were determined using TCEQ-determined emission factors, and emissions of HAPs, CH_4, and CO_2 were determined using emission factors from EPA's AP-42 document.(8,9) In AP-42, EPA provides emission factors for HAP compounds that are created by incomplete fuel combustion. For this report only those factors which were judged by EPA to be of high quality, "A" or "B" ratings, were used to estimate emissions. Emission factors for the greenhouse gas N_2O were from an emissions inventory report issued by the American Petroleum Institute.(10)

Beginning in 2009, many engines subject to the new NO_x limits are expected to reduce their emissions with the installation of non-selective catalytic reduction units (NSCR), a.k.a. three-way catalysts. NSCR units are essentially modified versions of the "catalytic converters" that are standard equipment on every gasoline-engine passenger vehicle in the U.S.

A likely co-benefit of NSCR installation will be the simultaneous reduction of VOC, HAP, and CH_4 emissions. Emissions from engines expected to install NSCR units were determined using a 75% emissions reduction factor for VOC, HAPs, and CH_4. Conversely, NSCR units are known to increase N_2O emissions, and N_2O emissions were estimated using a 3.4x factor increase over uncontrolled emission factors.(10) Table 2 summarizes the emission factors used to calculate emissions from the compressor engines identified in the 2007 survey.

Table 2. Emission Factors for Engines Identified in the D-FW 2007 Engine Survey

Table 2-1. Emission Factors for 2007 Emissions

engine type	engine size	NO_x (g/hp-hr)[a]	VOC (g/hp-hr)[b]	HAPs (g/hp-hr)[c]	CH_4 (g/hp-hr)[d]	CO_2 (g-hp-hr)[e]	N_2O (g-hp-hr)[f]
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	13.6	0.43	0.088	0.89	424	0.0077
rich	>500	0.9	0.43	0.088	0.89	424	0.0077
lean	<500	6.2	1.6	0.27	4.8	424	0.012
lean	>500	0.9	1.6	0.27	4.8	424	0.012

Table 2-2. Emission Factors for 2009 Emissions

engine type	engine size	NO_x (g/hp-hr)[i]	VOC (g/hp-hr)[j]	HAPs (g/hp-hr)[k]	CH_4 (g/hp-hr)[l]	CO_2 (g-hp-hr)[m]	N_2O (g-hp-hr)[n]
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	0.5	0.11	0.022	0.22	424	0.026
rich	>500	0.5	0.11	0.022	0.22	424	0.026
lean[g]	<500	0.62	1.6	0.27	4.8	424	0.012
lean[h]	<500	0.5	1.6	0.27	4.8	424	0.012
lean[g]	>500	0.7	1.45	0.27	4.8	424	0.012
lean[h]	>500	0.5	1.45	0.27	4.8	424	0.012

notes:
a: email from TCEQ to SMU, August 1, 2008, summary of results from 2007 engine survey (reference 6).
b: email from TCEQ to SMU, August 6, 2008 (reference 8).
c: EPA, AP-42, quality A and B emission factors; rich engine HAPs = benzene, formaldehyde, toluene; lean engine HAPs = acetaldehyde, acrolein, xylene, benzene, formaldehyde, methanol, toluene, xylene (reference 9).
d: EPA, AP-42 (reference 9).
e: EPA, AP-42 (reference 9).
f: API Compendium Report (reference 10).
g: engines installed or moved before June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).
h: engines installed or moved after June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).
i: rich (<50) factor from email from TCEQ to SMU, August 1, 2008 (reference 6); rich (50-500), rich (>500), lean (<500, post-2007), lean (>500, pre-2007), and lean (>500, post-2007) from TCEQ regulatory limits (reference 7); lean (<500, pre-2007) estimated with 90% control.
j: rich (<50) from email from TCEQ to SMU (reference 8); rich (50-500) and rich (>500) estimated with 75% NSCR control VOC co-benefit; lean EFs from email from TCEQ to SMU (reference 8). Large lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.
k: EPA, AP-42 (reference 9); rich (50-500) and rich (>500) estimated with 75% control co-benefit.
l: EPA, AP-42 (reference 9); rich (50-500) and rich (>500) estimated with 75% control co-benefit.
m: EPA, AP-42 (reference 9).
n: API Compendium Report (reference 10); rich (50-500) and rich (>500) estimated with 3.4x N_2O emissions increase over uncontrolled rate.

Annual emissions from the engines identified in the 2007 survey were estimated using the pollutant-specific emission factors from Table 1 together with Equation 1,

$$M_{E,i} = 1.10E\text{-}06 * E_i * P_{cap} * F_{hl} \qquad (1)$$

where $M_{E,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in grams/hp-hr, P_{cap} is installed engine capacity in hp, and F_{hl} is a factor to adjust for annual hours of operation and typical load conditions.

Installed engine capacity in 2007 was determined for six type/size categories using TCEQ estimates from the 2007 engine survey - two engine types (rich vs. lean) and three engine size ranges (<50, 50-500, >500 hp) were included.(6) TCEQ estimates of the average engine sizes and the numbers of engines in each size category were used to calculate the installed engine capacity for each category, as shown in Table 3. The F_{hl} factor was used to account for typical hours of annual operation and average engine loads. A F_{hl} value of 0.5 was used for this study, based on 8000 hours per year of average engine operation (8000/8760 = 0.91) and operating engine loads of 55% of rated capacity, giving an overall hours-load factor of 0.91x 0.55 = 0.5.(11)

Table 3. Installed Engine Capacity in 2007 D-FW Engine Survey by Engine Type and Size

engine type	engine size (hp)	number of engines[q]	typical size[q] (hp)	installed capacity[r] (hp)
rich	<50	12	50	585
rich	50-500	724	140	101,000
rich	>500	200	1400	280,000
lean[o]	<500	14	185	2540
lean[p]	<500	13	185	2400
lean[o]	>500	103	1425	147,000
lean[p]	>500	103	1425	147,000

notes:
o: engines installed or moved before June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).
p: engines installed or moved after June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).
q: rich (<50) installed capacity based on HARC October 2006 H68 report which found that small rich burn engines comprise no more than 1% of engines in East Texas; rich (50-500) and rich (>500) installed capacity from email TCEQ to SMU in August 1, 2008 (reference 6); lean burn installed capacity from email TCEQ to SMU in August 1, 2008 (reference 6) along with RRC data suggesting that 50% of engines in 2009 will be subject to the post-June 2007 NOx rule.
r: installed capacity = number of engines x typical size

ii. PSEI Engines in D-FW Metropolitan Area

In addition to the engines identified in the 2007 TCEQ survey of the D-FW 9-county metropolitan area, many other stationary engines are also in use in the area. These include engines that had already been reporting annual emissions to TCEQ in the PSEI, which are principally large engines at compressor stations.(12)

Emissions of NO_x from large engines in the D-FW metropolitan area that were reporting to the TCEQ PSEI were obtained from the 2006 Annual PSEI, the most recent calendar year available.(12) Emissions for 2007 and 2009 were estimated by extrapolating 2006 emissions upward to account for increases in gas production and compression needs from 2006-2009. For NO_x emissions in 2006 and 2007, an average emission factor of 0.9 g/hp-hr was obtained from TCEQ.(8) Emissions in 2009 were adjusted by accounting for the 0.5 g/hp-hr TCEQ regulatory limit scheduled to take effect in early 2009 for the D-FW metropolitan area.(7)

Unlike NO_x emission, emissions of VOC were not taken directly from the PSEI. Estimates of future VOC emissions required accounting for the effects that the new TCEQ engine NO_x limits will have on future VOC emissions. A compressor engine capacity production factor of 205 hp/(MMcf/day) was obtained from TCEQ that gives a ratio of installed horsepower capacity to the natural gas production. The 205 hp/(MMcf/day) factor was based on previous TCEQ studies of gas production and installed large engine capacity. The factor was used with 2006 gas production values to estimate installed PSEI engine capacities for each county in the Barnett Shale area.(8) Engine capacities were divided between rich burn engines smaller and larger than 500 hp, and lean burn engines. To estimate 2009 emissions, rich burn engines smaller than 500 hp are expected to have NSCR units by 2009 and get 75% VOC, HAP, and CH_4 control. Table 4 summarizes the VOC, HAP, and greenhouse gas emission factors used for the PSEI engines in the D-FW metropolitan area. Table 5 summarizes the estimates of installed engine capacity for each engine category.

Table 4. VOC, HAP, GHG Emission Factors for PSEI Engines in D-FW Metropolitan Area

Table 4-1. Emission Factors for 2007 Emissions

engine type	engine size	VOC EFs (g/hp-hr)[s]	HAPs EF (g/hp-hr)[t]	CH_4 EF (g/hp-hr)[u]	CO_2 EF (g/hp-hr)[v]	N_2O (g/hp-hr)[w]
rich	<500	0.43	0.088	0.89	424	0.0077
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.6	0.27	4.8	424	0.012

Table 4-2. Emission Factors for 2009 Emissions

engine type	engine size	VOC EFs (g/hp-hr)[s]	HAPs EF (g/hp-hr)[t]	CH_4 EF (g/hp-hr)[u]	CO_2 EF (g/hp-hr)[v]	N_2O (g/hp-hr)[w]
rich	<500	0.11	0.022	0.22	424	0.026
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.47	0.27	4.8	424	0.012

notes:

s: email from TCEQ to SMU, August 6, 2008; 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 8). Large lean engine VOC emission factor adjusted from 1.6 to 1.47 to account for the effects of NSPS JJJJ rules on VOC emissions.

t: EPA, AP-42 (reference 9); 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 9).

u: EPA, AP-42 (reference 9) ; 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 9).

v: EPA, AP-42 (reference 9).

w: API Compendium Report; 2007 rich (>500), and 2009 rich (>500) and 2009 rich (<500) engines estimated with 3.4x N_2O emissions increase over uncontrolled rate (reference 10).

Table 5. Installed Engine Capacity in 2007 for PSEI Engines Inside D-FW Metropolitan Area

engine type	engine size (hp)	installed capacity (%)[x]	installed capacity (hp)[y]
rich	<500	0.14	59,500
rich	>500	0.52	221,000
lean	all	0.34	144,000

notes:
x: distribution of engine types and sizes estimated from October 2006 HARC study (reference 13).
y: estimated as the installed capacity (%) x the total installed capacity based on the TCEQ compressor engine capacity production factor of 205 hp/(MMcf/day) (references 5,8).

iii. PSEI Engines Outside D-FW Metropolitan Area

Emissions of NO_x from large engines outside the D-FW metropolitan area reporting to the TCEQ were obtained from the 2006 PSEI.(12) Emissions for 2007 and 2009 were estimated by extrapolating 2006 emissions upward to account for increases in gas production from 2006-2009. Unlike engines inside the metropolitan area, the engines outside the metropolitan area are not subject to the new D-FW engine rules scheduled to take effect in 2009.

In addition to the D-FW engine rules, in 2007 the TCEQ passed the East Texas Combustion Rule that limited NO_x emissions from rich-burn natural gas engines larger than 240 hp in certain east Texas counties. Lean burn engines and engines smaller than 240 hp were exempted. The initial proposed rule would have applied to some counties in the Barnett Shale production area, including Cooke, Wise, Hood, Somervell, Bosque, and Hill, but in the final version of the rule these counties were removed from applicability, with the exception of Hill, which is still covered by the rule. Since gas production from Hill County is less than 3.5% of all the Barnett Shale area gas produced outside the D-FW metropolitan area, the East Texas Combustion Rule has limited impact to emissions from Barnett Shale area activity.

Emissions of VOC, HAPs, and greenhouse gases for large engines outside the D-FW metropolitan area were not obtained from the 2006 PSEI. A process similar to the one used to estimate emissions from large engines inside the metropolitan area was used, whereby the TCEQ compressor engine capacity production factor, 205 hp/(MMcf/day), was used along with actual 2007 production rates to estimate total installed engine capacity as well as installed capacity in each county for different engine categories. Pollutant-specific emission factors were applied to the capacity estimates for each category to estimate emissions. Table 6 summarizes the emission factors used to estimate emissions from engines in the PSEI outside the D-FW metropolitan area. The engine capacities used to estimate emissions are shown in Table 7.

Table 6. VOC, HAP, GHG Emission Factors for PSEI Engines Outside D-FW Metropolitan Area

engine type	engine size	VOC (g/hp-hr)[z]	HAPs (g/hp-hr)[aa]	CH_4 (g/hp-hr)[aa]	CO_2 (g-hp-hr)[bb]	N_2O (g-hp-hr)[cc]
rich	<500	0.43	0.088	0.89	424	0.0077
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.45	0.27	4.8	424	0.012

notes:
z: email from TCEQ to SMU, August 6, 2008; 75% control applied to rich (>500) engines (reference 8). Large lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.
aa: EPA, AP-42; 75% control applied to rich (>500) engines (reference 9).

bb. EPA, AP-42 (reference 9).
cc. API Compendium Report; rich (>500) engines estimated with 3.4x N_2O emissions increase over uncontrolled rate (reference 10).

Table 7. Installed Engine Capacity in 2007 for PSEI Engines Outside D-FW Metropolitan Area

engine type	engine size (hp)	installed capacity (%)[dd]	installed capacity (hp)[ee]
rich	<500	0.14	17,000
rich	>500	0.52	62,000
lean	all	0.34	41,000

notes:
dd: distribution of engine types and sizes estimated from October 2006 HARC study (reference 13).
ee: estimated as the installed capacity (%) x the total installed capacity based on the TCEQ compressor engine capacity production factor of 205 hp/(MMcf/day) (references 5,8).

iv. Non-PSEI Engines Outside the D-FW Metropolitan Area

The Point Source Emissions Inventory (PSEI) only contains emissions from a fraction of the stationary engines in the Barnett Shale area, principally the larger compressor engines with emissions above the PSEI reporting thresholds. The 2007 TCEQ engine survey of engines inside the D-FW metropolitan area demonstrated that the PSEI does not include a substantial fraction of total engine emissions. Most of the missing engines in the metropolitan area were units with emissions individually below the TCEQ reporting thresholds, but the combined emissions from large numbers of smaller engines can be substantial. The results of the 2007 survey indicated that there were approximately 680,000 hp of installed engine capacity in the D-FW metropolitan area not previously reporting to the PSEI.[(6)]

Natural gas and casinghead gas production from metropolitan counties in 2007 was approximately 1,000 Bcf . A "non-PSEI" compressor engine capacity production factor of 226 hp/(MMcf/day) was determined for the Barnett Shale area. This capacity factor accounts for all the small previously hidden engines that the 2007 survey showed come into use in oil and gas production activities in the area. This production factor was used along with 2007 gas production rates for the counties outside the D-FW metropolitan area to estimate non-PSEI engine emissions from these counties. The new production factor accounts for the fact that counties outside the metro area likely contain previously unreported engine capacity in the same proportion to the unreported engine capacity that was identified during the 2007 engine survey inside the metro area. Without a detailed engine survey in the rural counties of the same scope as the 2007 survey performed within the D-FW metropolitan counties, use of the non-PSEI production factor provides a way to estimate emissions from engines not yet in state or federal inventories. The capacity of non-PSEI reporting engines in the rural counties of the Barnett Shale was determined by this method to be 132,000 hp. Emission factors used to estimate emissions from these engines, and the breakdown of total installed engine capacity into engine type and size categories, are shown in Tables 8 and 9.

Table 8. Emission Factors for Non-PSEI Engines Outside D-FW Metropolitan Area

engine type	engine size	NO_x (g/hp-hr)[ff]	VOC (g/hp-hr)[gg]	HAPs (g/hp-hr)[hh]	CH_4 (g/hp-hr)[hh]	CO_2 (g-hp-hr)[ii]	N_2O (g-hp-hr)[jj]
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	10.3	0.43	0.088	0.89	424	0.0077
rich	>500	0.89	0.11	0.022	0.22	424	0.026
lean	<500	5.2	1.45	0.27	4.8	424	0.012
lean	>500	0.9	1.6	0.27	4.8	424	0.012

notes:
ff: email from TCEQ to SMU, August 1, 2008 (reference 6). Rich burn engines 50-500 hp NOx emission factor adjusted from 13.6 to 10.3 to account for the effects of NSPS JJJJ rules on NOx emissions and the effect of the TCEQ East Texas Combustion Rule on Hill County production. Rich burn engines >500 adjusted from 0.9 to 0.89 to account for the effect of the TCEQ East Texas Combustion Rule on Hill County production. Lean burn <500 hp engine post-2007 emission factor adjusted from 6.2 to 5.15 to account for the effects of NSPS JJJJ rules on NOx emissions.
gg: email from TCEQ to SMU, August 6, 2008; rich (>500) based on 75% control (reference 8). Small lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.
hh: EPA, AP-42; rich (>500) based on 75% control (reference 9).
ii: EPA, AP-42 (reference 9).
jj: API Compendium Report; rich (>500) estimated with 3.4x N_2O emissions increase over uncontrolled rate (reference 10).

Table 9. Installed Engine Capacity for Non-PSEI Engines Outside Metropolitan Area by Engine Type/Size

engine type	engine size (hp)	installed capacity (%)	installed capacity (hp)
rich	<50	0.01	110
rich	50-500	15	20,000
rich	>500	41	55,000
lean	<500	0.73	970
lean	>500	43	57,000

3.2 Condensate and Oil Tanks - Emission Factors and Emission Estimates

Condensate and oil tanks can be significant emitters of VOC, methane, and HAPs. A report was published in 2006 by URS Corporation which presented the results of a large investigation of emissions from condensate and oil tanks in Texas.[(14)] Tanks were sampled from 33 locations across East Texas, including locations in the Barnett Shale area. Condensate tanks in the Barnett Shale were sampled in Denton and Parker Counties, and oil tanks were sampled in Montague County. The results from the URS investigation were used in this study to calculate Barnett Shale-specific emission factors for VOC, CH_4, HAPs, and CO_2, instead of using a more general Texas-wide emission factor. The URS study was conducted during daylight hours in July 2006, when temperatures in North Texas are significantly above the annual average. Therefore, the results of the URS investigation were used to calculate "Peak Summer" emissions. The HAPs identified in the URS study included n-hexane, benzene, trimethylpentane, toluene, ethylbenzene, and xylene. The emission factors used to calculate peak summer emissions from Barnett

Shale condensate and oil tanks are shown in Table 10-1. Figure 5 shows a condensate tank battery from the 2006 URS study report.

Figure 5. Example Storage Tank Battery (left), Separators (right), and Piping.[14]

Computer modeling data were provided during personal communications with a Barnett Shale gas producer who estimated VOC, CH_4, HAPs, and CO_2 emissions from a number of their condensate tanks.[15] The tanks were modeled with ambient temperatures of 60 F, which the producer used to represent annual hourly mean temperatures in the D-FW area. These modeling results were used in this report to predict annual average condensate tank emission factors for the Barnett Shale area. The annual average emission factors are shown in Table 10-2.

Table 10. Condensate and Oil Tank Emission Factors for the Barnett Shale.

Table 10-1. Peak Summer Emission Factors.[14]

	VOC (lbs/bbl)	HAPs (lbs/bbl)	CH_4 (lbs/bbl)	CO_2 (lbs/bbl)
condensate	48	3.7	5.6	0.87
oil	6.1	0.25	0.84	2.7

Table 10-2. Annual Average Emission Factors.[15]

	VOC (lbs/bbl)	HAPs (lbs/bbl)	CH_4 (lbs/bbl)	CO_2 (lbs/bbl)
condensate	10	0.20	1.7	0.23
oil	1.3	0.013	0.26	0.70

Emissions for 2007 were calculated for each county in the Barnett Shale area, using condensate and oil production rates from the RRC.[5] Emissions for 2009 were estimated with the extrapolated 2000-2007 production rates for the year 2009. Emissions were calculated with Equation 2,

$$M_{T,i} = E_i * P_c * C / 2000 \qquad (2)$$

where $M_{T,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/bbl, P_c was the production rate of condensate or oil, and C was a factor to account for the reduction in emissions due to vapor-emissions controls on some tanks. For this report, the use of vapor-emissions controls on some tanks was estimated to provide a 25% reduction in overall area-wide emissions.

3.3 Production Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from production wells vary from well to well depending on many factors, including the tightness of casing heads and fittings, the age and condition of well components, and the numbers of flanges, valves, pneumatic devices, or other components per well. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.[15] Fugitive emissions of natural gas from the entire natural gas network were estimated to be 1.4% of gross production. Production fugitives, excluding emissions from condensate tanks (which are covered in another section of this report), were estimated by the GRI/EPA study to be approximately 20% of total fugitives, or 0.28% of gross production.

Production fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.28% of gross natural gas and casinghead gas production of 1098 Bcf/yr. Volume emissions were converted to mass emissions with a density of 0.0483 lb/scf. Multiple Barnett Shale gas producers provided gas composition, heat content data, and area-wide maps of gas composition. The area-wide maps of gas composition were used to estimate gas composition for each producing county. These county-level data were weighted by the fraction of total area production that originated from each county to calculate area-wide emission factors. Table 11 presents the production fugitives emission factors.

Table 11. Production Fugitives Emission Factors for the Barnett Shale.

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH_4 (lbs/MMcf)	CO_2 (lbs/MMcf)
11	0.26	99	1.9

Emissions were calculated with Equation 3,

$$M_{F,i} = E_i * P_g / 2000 \qquad (3)$$

where $M_{F,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/MMcf, and P_g was the production rate of natural and casinghead gas. The area-wide unprocessed natural gas composition based on data from gas producers was 74% CH_4, 8.2% VOC, 1.4% CO_2, and 0.20% HAPs, on a mass % basis. HAPs in unprocessed natural gas can include low levels of n-hexane, benzene, or other compounds.

3.4 Well Drilling, Hydraulic Fracturing Pump Engines, and Well Completions - Emission Factors and Emission Estimates

Emissions from the diesel engines used to operate well drilling rigs and from the diesel engines that power the hydraulic fracturing pumps were estimated based on discussions with gas producers and other published data. Well drilling engine emissions were based on 25 days of engine operation for a typical well, with 1000 hp of engine capacity, a load factor of 50%, and operation for 12 hours per day. Hydraulic fracturing engine emissions were based on 4.5 days of operation for a typical well, with 1000 hp of capacity, a load factor of 50%, and operation for 12 hours per day. Some well sites in the D-FW are being drilled with electric-powered rigs, with electricity provided off the electrical grid. Engines emission estimates in this report were reduced by 25% to account for the number of wells being drilled without diesel-engine power.

In addition to emissions from drilling and fracing engines, previous studies have examined emissions of natural gas during well completions. These studies include one by the Williams gas company, which estimated that a typical well completion could vent 24,000 Mcf of natural gas.[18] A report by the EPA Natural Gas Star program estimated that 3000 Mcf could be produced from typical well completions.[19] A report by ENVIRON published in 2006 describes emission factors used in Wyoming and Colorado to estimate emissions from well completions, which were equivalent to 1000 to 5000 Mcf natural gas/well.[20] Another report published in the June 2005 issue of the Journal of Petroleum Technology estimated that well completion operations could produce 7,000 Mcf. [21] Unless companies bring special equipment to the well site to capture the natural gas and liquids that are produced during well completions, these gases will be vented to the atmosphere or flared.

Discussions with Barnett Shale gas producers that are currently employing "green completion" methods to capture natural gas and reduce emissions during well completions suggests that typical well completions in the Barnett Shale area can release approximately 5000 Mcf of natural gas/well. This value, which is very close to the median value obtained from previous studies (References 18-21), was used to estimate well completion emissions in this report.

The number of completed gas wells reporting to the RRC was plotted for the Feb. 2004 – Feb. 2008 time period.[22] A least-squares regression line was fit to the data, and the slope of the line provides the approximate number of new completions every year. A value of 1042 completions/year was relatively steady throughout the 2004-2008 time period (linear $R^2 = 0.9915$). Emissions in 2007 and 2009 from well completions were estimated using 1000 new well completions/year for each year. Emission estimates were prepared for the entire Barnett Shale area, as well as inside and outside the D-FW metropolitan area. The data from 2004-2008 show that 71 percent of new wells are being installed in the D-FW metropolitan area, 29 percent of new wells are outside the metropolitan area, and the rate of new completions has been steady since 2004. Emissions of VOC, HAPs, CH_4, and CO_2 were estimated using the same natural gas composition used for production fugitive emissions.

Some gas producers are using green completion techniques to reduce emissions, while others destroy natural gas produced during well completions by flaring. To account for the use of green completions and control by flaring, natural gas emission estimates during well completions were reduced by 25% in this report.

3.5 Processing Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from natural gas processing will vary from processing plant to processing plant, depending on the age of the plants, whether they are subject to federal rules such as the NSPS Subpart KKK requirements, the chemical composition of the gas being processed, the processing capacity of the plants, and other factors. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.[15] Fugitive emissions of natural gas from the entire natural gas industry were estimated to be 1.4% of gross production. Processing fugitives, excluding compressor engine exhaust emissions that were previously addressed in this report, were estimated to be approximately 9.7% of total fugitives, or 0.14% of gross production.

Processing fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.14% of the portion of gas production that is processed, estimated as 519 Bcf/yr. Emission factors for VOC, HAPs, CH_4, and CO_2 were estimated with an area-wide natural gas composition, excluding the gas from areas of the Barnett Shale that does not require any processing. Volume emissions were converted to mass emissions with a natural gas density of 0.0514 lb/scf. Table 12 presents the processing fugitives emission factors.

Table 12. Processing Fugitives Emission Factors for the Barnett Shale.

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH_4 (lbs/MMcf)	CO_2 (lbs/MMcf)
14	0.3	45	1.0

Processing fugitive emissions were calculated with Equation 4,

$$M_{P,i} = E_i * P_g / 2000 \qquad (4)$$

where $M_{P,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/MMcf, and P_g was the production rate of natural and casinghead gas. The composition of the natural gas produced in the Barnett Shale that is processed was estimated to be 65% CH_4, 1.5% CO_2, 20% VOC, and 0.48% HAPs, on a mass % basis. Not all natural gas from the Barnett Shale area requires processing.

3.6 Transmission Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from the transmission of natural gas will vary depending on the pressure of pipelines, the integrity of the piping, fittings, and valves, the chemical composition of the gas being transported, the tightness of compressor seals and rod packing, the frequency of blow down events, and other factors. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.[15] Fugitive emissions of natural gas from the entire natural gas industry were estimated to be 1.4% of gross production. Transmission fugitives, excluding compressor engine exhaust emissions that were previously addressed in this report, were estimated to be approximately 35% of total fugitive emissions, or 0.49% of gross production. Transmission includes the movement of natural gas from the wells to processing plants, and the processing plants to compressor stations. It does not include flow past the primary metering and pressure regulating (M&PR) stations and final distribution lines to customers. Final distribution of gas produced in the Barnett Shale can happen anywhere in the North American natural gas distribution system, and fugitive emissions from these lines are beyond the scope of this report.

Transmission fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.49% of gross natural gas and casinghead gas production of 1098 Bcf/yr. Emission factors for VOC, HAPs, CH_4, and CO_2 were developed considering that a significant portion of the gas moving through the network does not require processing, while the portion of the gas with higher molecular weight compounds will go through processing. In addition, all gas will have a dry (high methane) composition after processing as it moves to compressor stations and then on to customers. Overall area-wide transmission fugitive emissions were calculated with a gas composition of 76% CH_4, 5.1% VOC, 1.4% CO_2, and 0.12% HAPs, by mass %. Table 13 presents the transmission fugitives emission factors.

Table 13. Transmission Fugitives Emission Factors for the Barnett Shale.

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH_4 (lbs/MMcf)	CO_2 (lbs/MMcf)
12	0.28	175	3.3

Transmission fugitive emissions were calculated with Equation 5,

$$M_{tr,i} = E_i * P_g / 2000 \qquad (5)$$

where $M_{tr,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/MMcf, and P_g was the production rate of natural and casinghead gas.

4.0 RESULTS

4.1 Point Sources

i. Compressor Engine Exhausts

Emissions from compressor engines in the Barnett Shale area are summarized in Tables 14 and 15. Results indicate that engines are significant sources of ozone and particulate matter precursors (NO_x and VOC), with 2007 emissions of 66 tpd. Emissions of NO_x are expected to fall 50% from 32 to 16 tpd for engines in the Dallas-Fort Worth metropolitan area because of regulations scheduled to take effect in 2009 and the installation of NSCR units on many engines. Large reductions are unlikely because of the growth in natural gas production. For engines outside the D-FW metropolitan area counties, NO_x emissions will rise from 19 tpd to 30 tpd because of the projected growth in natural gas production and the fact that engines in these counties are not subject to the same regulations as those inside the metropolitan area.

Emissions of volatile organic compounds are expected to increase from 15 to 21 tpd from 2007 to 2009, because of increasing natural gas production. The 2009 engine regulations for the metropolitan area counties do have the effect of reducing VOC emissions from some engines, but growth in production compensates for the reductions and VOC emissions from engines as a whole increase.

HAP emissions, which include toxic compounds such as formaldehyde and benzene, are expected to increase from 2.7 to 3.6 tpd from 2007 to 2009.

Greenhouse gas emissions from compressor engines are shown in Table 15. Emissions in 2007 as carbon dioxide equivalent tons were approximately 8900 tpd, and emissions are estimated to increase to nearly 14,000 tpd by 2009. Carbon dioxide contributed the most to the greenhouse gas emissions, accounting for approximately 90% of the CO_2 equivalent tons. The methane contribution to greenhouse gases was smaller for the engine exhausts than for the other sources reviewed in this report.

Table 14. Emissions from Compressor Engine Exhausts.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
D-FW Metro Engines	32	13	2.2	35	7261	16	16	2.9	49	11294
Outside Metro Engines	19	2.5	0.45	7.4	1649	30	3.8	0.70	12	2583
Engines Total	**51**	**15**	**2.7**	**43**	**8910**	**46**	**19**	**3.6**	**61**	**13877**

Table 15. Greenhouse Gas Emissions Details.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	CO2	CH4	N2O	CO2e	CO2	CH4	N2O	CO2e
D-FW Metro Engines	6455	35	0.20	7261	10112	49	0.28	11294
Outside Metro Engines	1475	7.4	0.062	1649	2310	12	0.10	2583
Engines Total	**7930**	**43**	**0.26**	**8910**	**12422**	**61**	**0.38**	**13877**

ii. Oil and Condensate Tanks

Emissions from condensate and oil tanks are shown in Tables 16-1 and 16-2. Annual average emissions are shown in Table 16-1, and peak summer emissions are shown in Table 16-2.

On an annual average, emissions of VOCs from the tanks were 19 tpd in 2007, and emissions will increase to 30 tpd in 2009. Because of the effects of temperature on hydrocarbon liquid vapor pressures, peak summer emissions of VOC were 93 tpd in 2007, and summer emissions will increase to 146 tpd in 2009.

Substantial HAP emissions during the summer were determined for the tanks, with 2007 emissions of 7.2 tpd and 2009 emissions of 11 tpd. Greenhouse gas emissions from the tanks are almost entirely from CH_4, with a small contribution from CO_2. Annual average greenhouse gas emissions were 95 tpd in 2007, and will increase to 149 tpd in 2009.

Table 16. Emissions from Condensate and Oil Tanks.

Table 16-1. Annual Average Tank Emissions

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Tanks	8.9	0.18	2.1	44	14	0.28	3.2	69
Outside Metro Tanks	10	0.21	2.4	51	16	0.32	3.8	80
Tanks Total	**19**	**0.39**	**4.5**	**95**	**30**	**0.60**	**7.0**	**149**

Table 16-2. Peak Summer Tank Emissions

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Tanks	43	3.3	6.7	142	67	5.2	10	222
Outside Metro Tanks	50	3.8	7.8	166	79	6.0	12	261
Tanks Total	**93**	**7.2**	**15**	**308**	**146**	**11**	**23**	**483**

<u>4.2 Fugitive and Intermittent Sources</u>

i. Production Fugitives

Emissions from fugitive sources at Barnett Shale production sites are shown in Table 17. Production fugitives are significant sources of VOC emissions, with VOC emissions expected to grow from 2007 to 2009 from 17 to 26 tpd. Production fugitives are also very large sources of methane emissions, leading to large CO_2 equivalent greenhouse gas emissions. Greenhouse gas emissions were 3100 tpd in 2007 and will be 4900 tpd in 2009.

Table 17. Emissions from Production Fugitives.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Production Fugitives	11	0.27	102	2147	18	0.43	160	3363
Outside Metro Production Fugitives	5.2	0.12	46	971	8.1	0.19	72	1521
Production Fugitives Total	**17**	**0.40**	**148**	**3118**	**26**	**0.62**	**232**	**4884**

ii. Well Drilling, Hydraulic Fracturing, and Well Completions

Emissions from well drilling engines, hydraulic fracturing pump engines, and well completions are shown in Table 18. These activities are significant sources of the ozone and fine particulate precursors, as well as very large sources of greenhouse gases, mostly from methane venting during well completions. Greenhouse gas emissions are estimated to be greater than 4000 CO_2 equivalent tons per year. Based on 2000-2007 drilling trends, approximately 71% of the well drilling, fracing, and completion emissions will be coming from counties in the D-FW metropolitan area, with the remaining 29% coming from counties outside the metropolitan area.

Table 18. Emissions from Well Drilling, Hydraulic Fracturing, and Well Completions.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
D-FW Metro Well Drilling and Well Completion	3.9	15	0.35	130	2883	3.9	15	0.35	130	2883
Outside Metro Well Drilling and Well Completions	1.6	6.1	0.14	53	1178	1.6	6.1	0.14	53	1178
Well Drilling and Completions Emissions Total	**5.5**	**21**	**0.49**	**183**	**4061**	**5.5**	**21**	**0.49**	**183**	**4061**

iii. Natural Gas Processing

Processing of Barnett Shale natural gas results in significant emissions of VOC and greenhouse gases, which are summarized in Table 19. Emissions of VOC were 10 tpd in 2007 and are expected to increase to 15 tpd by 2009. Greenhouse gas emissions, largely resulting from fugitive releases of methane, were approximately 670 tpd in 2007 and will be approximately 1100 tpd in 2009.

Table 19. Emissions from Natural Gas Processing.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Processing Fugitives	6.7	0.16	22	464	10	0.26	35	727
Outside Metro Processing Fugitives	3.0	0.07	10	210	4.7	0.12	16	329
Processing Fugitives Total	**10**	**0.24**	**32**	**674**	**15**	**0.37**	**50**	**1056**

iv. Transmission Fugitives

Transmission of Barnett Shale natural gas results in significant emissions of greenhouse gases and VOC. Greenhouse gas emissions from transmission fugitives are larger than from any other source category except compressor engine exhausts. Emissions of VOC in 2007 from transmission were approximately 18 tpd in 2007 and are estimated to be 28 tpd in 2009. Greenhouse gas emissions from methane fugitives result in emissions of approximately 5500 tpd in 2007 and 8600 tpd in 2009. Emissions are summarized in Table 20.

Table 20. Emissions from Natural Gas Transmission Fugitives.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Transmission Fugitives	12	0.29	181	3799	19	0.46	283	5952
Outside Metro Transmission Fugitives	5.5	0.13	82	1718	8.6	0.21	128	2691
Transmission Fugitives Total	**18**	**0.43**	**262**	**5517**	**28**	**0.67**	**411**	**8643**

4.3 All Sources Emission Summary

Emissions from all source categories in the Barnett Shale area are summarized in Table 21-1 on an annual average basis, and are summarized in Table 12-2 on a peak summer basis. Annual average emissions for 2009 of ozone and particulate precursors (NO_x and VOC) were approximately 191 tpd, and peak summer emissions of these compounds were 307 tpd. The portion of those emissions originating from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 133 tpd during the summer (Tarrant, Denton, Parker, Johnson, and Ellis).

Estimates of greenhouse gas emissions from the sector as a whole were quite large, with 2009 emissions of approximately 33,000 tpd. The greenhouse gas contribution from compressor engines was dominated by carbon dioxide, while the greenhouse gas contribution from all other sources was dominated by methane. Emissions of HAPs were significant from Barnett Shale activities, with emissions in 2009 of 6.4 tpd in 2009 on an annual average, and peak summer emissions of 17 tpd.

Table 21. Emissions Summary for All Source Categories.

Table 21-1. Annual Average Emissions from All Sources.

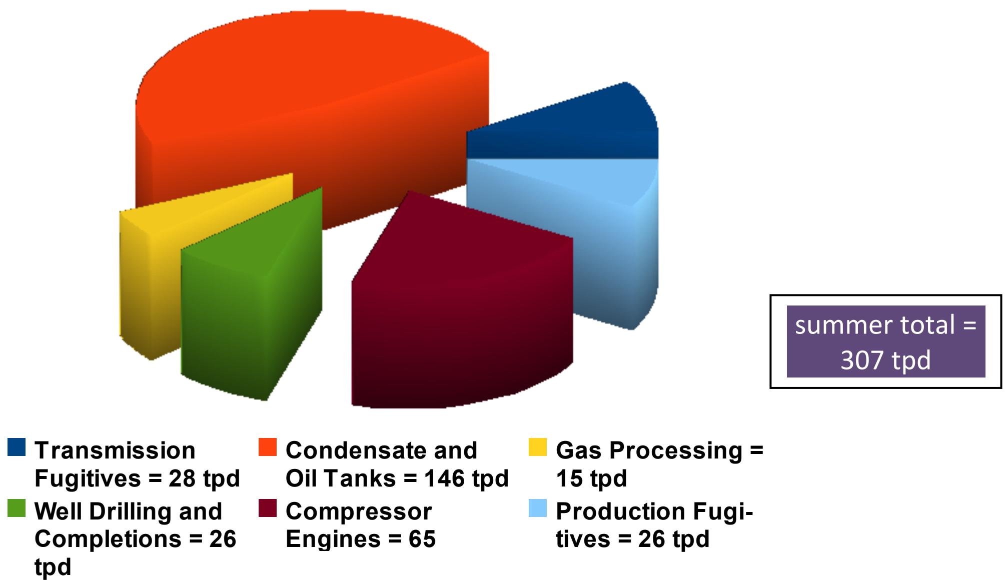
	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
Compressor Engine Exhausts	51	15	2.7	43	8910	46	19	3.6	61	13877
Condensate and Oil Tanks	0	19	0.39	4.5	95	0	30	0.60	7.0	149
Production Fugitives	0	17	0.40	148	3118	0	26	0.62	232	4884
Well Drilling and Completions	5.5	21	0.49	183	4061	5.5	21	0.49	183	4061
Gas Processing	0	10	0.24	32	674	0	15	0.37	50	1056
Transmission Fugitives	0	18	0.43	262	5517	0	28	0.67	411	8643
Total Daily Emissions (tpd)	**56**	**100**	**4.6**	**673**	**22375**	**51**	**139**	**6.4**	**945**	**32670**

Table 21-2. Peak Summer Emissions from All Sources.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
Compressor Engine Exhausts	51	15	2.7	43	8910	46	19	3.6	61	13877
Condensate and Oil Tanks	0	93	7.2	15	308	0	146	11	23	483
Production Fugitives	0	17	0.40	148	3118	0	26	0.62	232	4884
Well Drilling and Completions	5.5	21	0.49	183	4061	5.5	21	0.49	183	4061
Gas Processing	0	10	0.24	32	674	0	15	0.37	50	1056
Transmission Fugitives	0	18	0.43	262	5517	0	28	0.67	411	8643
Total Daily Emissions (tpd)	**56**	**174**	**11**	**683**	**22588**	**51**	**255**	**17**	**961**	**33004**

Emissions of nitrogen oxides from oil and gas production in the Barnett Shale were dominated by emissions from compressor engines, with a smaller contribution from well drilling and fracing pump engines. All source categories in the Barnett Shale contributed to VOC emissions, but the largest group of VOC sources was condensate tank vents. Figure 6 presents the combined emissions of NO_x and VOC during the summer from all source categories in the Barnett Shale.

Figure 6. Summer Emissions of Ozone & Fine Particulate Matter Precursors (NO_x and VOC) from Barnett Shale Sources in 2009.



4.4 Perspective on the Scale of Barnett Shale Air Emissions

Barnett Shale oil and gas production activities are significant sources of air emissions in the north-central Texas area. To help put the levels of Barnett Shale emissions into context, recent government emissions inventories for the area were reviewed, and emission rates of smog precursor emissions were examined.

The Dallas-Fort Worth area is home to two large airports, Dallas Love Field and Dallas-Fort Worth International Airport, plus a number of smaller airports. A recent emissions inventory has estimated 2009 NO_x emissions from all area airports to be approximately 14 tpd, with VOC emissions at approximately 2.6 tpd, resulting in total ozone and particulate matter precursor emissions of approximately 16 tpd. [22-24] For comparison, emissions of VOC + NO_x in summer 2009 from just the compressor engines in the Barnett Shale area will be approximately 65 tpd, and summer condensate tanks emissions will be approximately 146 tpd. In 2009, even after regulatory efforts to reduce NO_x emissions from certain compressor engine types, Barnett Shale oil and gas emissions will be many times the airports' emissions.

Recent state inventories have also compiled emissions from on-road mobile sources like cars, trucks, etc., in the 9-county D-FW metropolitan area.[25] By 2009, NO_x + VOC emissions from mobile sources in the 9-county area were estimated by the TCEQ to be approximately 273 tpd. The portion of on-road motor vehicle emissions from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 121 tpd (Denton, Tarrant, Parker, Johnson, and Ellis). As indicated earlier, summer oil and gas emissions in the 5-counties of the D-FW metropolitan area with significant oil and gas production was estimated to be 165 tpd, indicating that the oil and gas sector likely has greater emissions than motor vehicles in these counties (165 vs. 121 tpd).

Emissions of NO_x and VOC in the summer of 2009 from all oil and gas sources in the Barnett Shale 21-county area will exceed emissions from on-road mobile sources in the D-FW metropolitan area by more than 30 tpd (307 vs. 273 tpd).

Figure 7 summarizes summer Barnett Shale-related emissions, plus TCEQ emission estimates from the airports and on-road mobile sources. Figure 8 presents annual average emissions from these sources.

Figure 7. Barnett Shale Activity, D-FW Area Airports, & Mobile Sources (Summer 2009 Emissions).

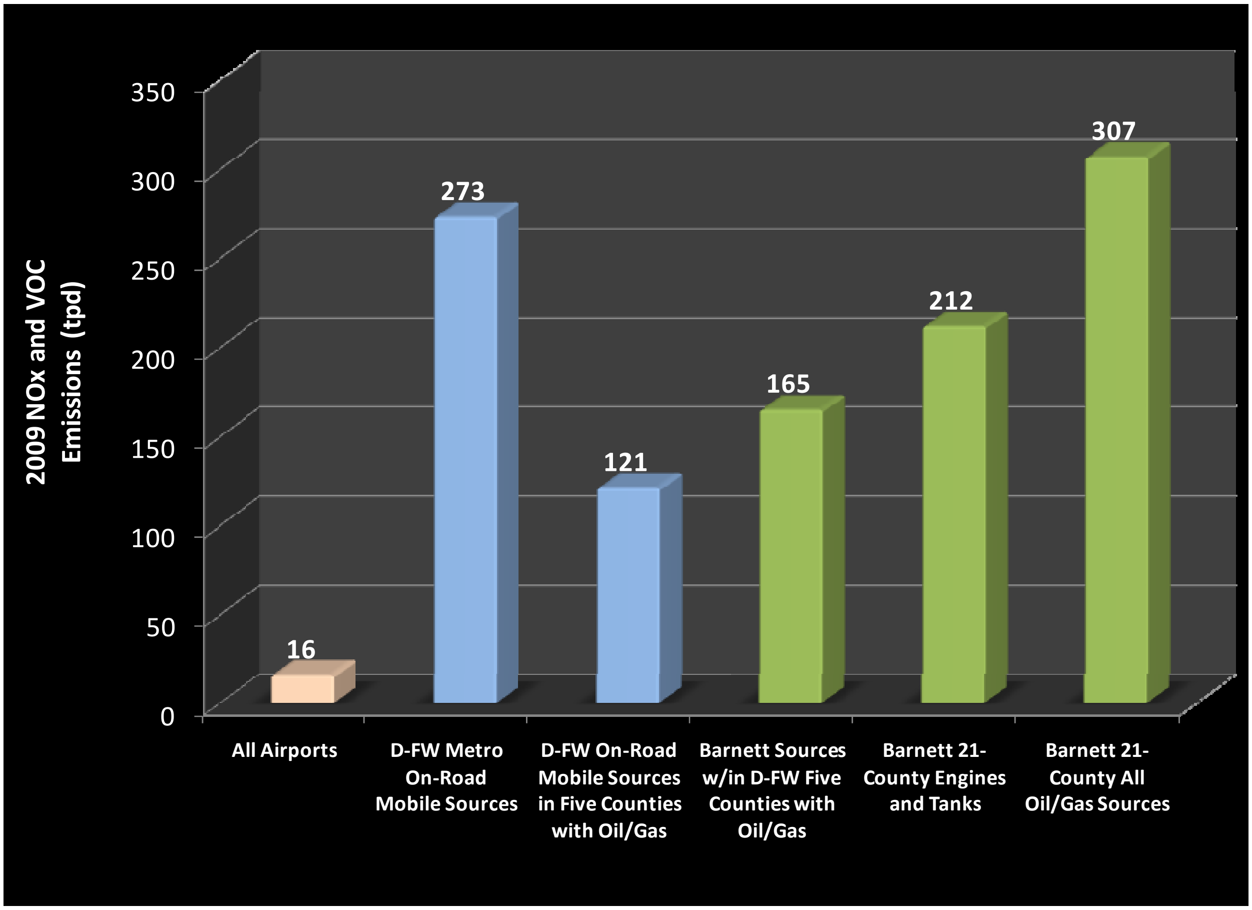
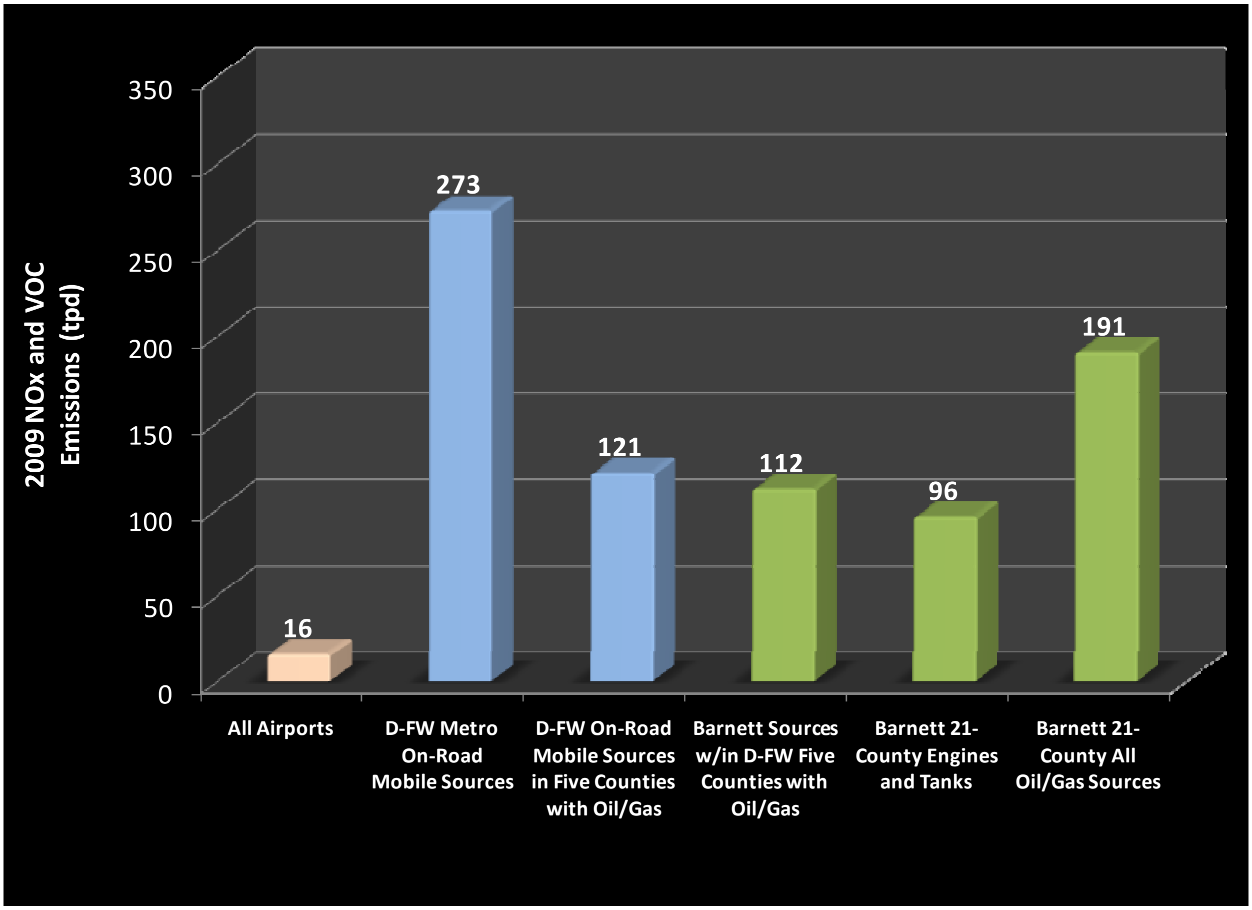


Figure 8. Barnett Shale Activity, D-FW Area Airports, & Mobile Sources (Annual Average 2009 Emissions).



5.0 EMISSIONS REDUCTION OPPORTUNITIES

The previous sections of this report have estimated the emission rates of ozone and particulate matter precursor compounds, air toxic compounds, and greenhouse gases from different oil and gas sources in the Barnett Shale area. For several of these source categories, off-the-shelf options are available which could significantly reduce emissions, resulting in important air quality benefits. Some of these emissions reductions would also result in increased production of natural gas and condensate, providing an economic payback for efforts to reduce emissions.

5.1 Compressor Engine Exhausts

Compressors in oil and gas service in the Barnett Shale perform vital roles, to either help get oil and gas out of the shale, to increase pressures of gas at the surface, and to provide the power for the large interstate pipeline systems that move high volumes of gas from production to processing and to customers. At present, most of the work to operate the compressors comes from natural gas-fired internal combustion engines, and these engines can be significant sources of emissions.

New TCEQ rules are scheduled to become effective in early 2009 and they will reduce NO_x, VOC, and other emissions from a subset of the engines in the Barnett Shale – those that are currently in the D-FW metropolitan area that had typically not reported into the Texas point source emissions inventory for major sources. These rules are a good first step in addressing emissions from these sources, which had previously gone unnoticed in state emission inventory and regulatory efforts.

However, engines outside the D-FW metropolitan area are not subject to the rule. And even within the metropolitan area, the rule will not have the effect of greatly reducing emissions in 2009 compared to 2007 levels, since growth in oil and gas production (and the new engines that are going to be required to power the growth) will begin to overtake the benefits that come from reducing emissions from the pre-2009 fleet (see Table 14).

Two available options for reducing emissions from engines in the Barnett Shale area are: (1) extending the TCEQ 2009 engine regulation to all engines in the Barnett Shale, and (2) replacing internal combustion engines with electric motors as the sources of compression power.

i. Extending the 2009 Engine Rule to Counties Outside the D-FW Metropolitan Area

Regulations adopted by TCEQ for the D-FW metropolitan area and scheduled to take effect in early 2009 will limit NO_x emissions from engines larger than 50 horsepower.[(7)] Rich burn engines will be restricted to 0.5 g/hp-hr, lean burn engines installed or moved before June 2007 will be restricted to 0.7 g/hp-hr, and lean burn engines installed or moved after June 2007 will be limited to 0.5 g/hp-hr. Applying these rules to engines outside the metropolitan area would reduce 2009 NO_x emissions from a large number of engines, in particular, rich burn engines between 50 to 500 hp. Emissions of NO_x in 2009 from the engines outside the metropolitan area would drop by approximately 6.5 tpd by extending the D-FW engine rule, an amount greater than mobile source emissions in all of Johnson County (4 tpd), or more than 50% of the emissions from Dallas-Fort Worth International Airport (12.6 tpd).

Extending the D-FW engine rule to counties outside the metropolitan area would likely result in many engine operators installing NSCR systems on rich burn engine exhausts. These systems would not only reduce emissions of NO_x, but they would also be expected to reduce emissions of VOC, the other ozone and particulate matter precursor, by approximately 75% or greater.[(26a)] Additional co-benefits of NSCR installations would include lower emissions of organic HAP compounds like benzene and formaldehyde, lower emissions of methane, and lower emissions of carbon monoxide. The level of HAP, methane, and carbon monoxide control would also be expected to be 75% or greater with typical NSCR installations.[26a]

Analyses of NSCR installations and operating costs by numerous agencies have indicated that the technology is very cost effective. For example, the Illinois Environmental Protection Agency estimated in 2007 that NSCR could control NO_x from 500 hp engines at approximately \$330/ton.[26b] The U.S. EPA in 2006 estimated that NSCR could control NO_x from 500 hp engines at approximately \$92 to 105/ton.[27] A 2005 report examining emissions reductions from compressor engines in northeast Texas estimated NO_x cost effectiveness for NSCR at \$112-183/ton and identified VOC reductions as an important co-benefit.[28] These costs are well under the cost effectiveness values of \$10,000 to \$20,000 per ton often used as upper limits in $PM_{2.5}$, ozone, and regional haze (visibility) regulatory programs. The simultaneous HAPs and methane removal that would occur with NSCR use provide further justification for extending the D-FW engine rule to counties outside the metropolitan area.

ii. Electric Motors Instead of Combustion Engines for Compressor Power

When considering NO_x, VOC, HAPs, and greenhouse gas emissions from compressor engines, it is important to understand that the work to move the gas in the pipelines is performed by the compressors, which by themselves produce no direct combustion emissions. The emissions come from the exhaust of the internal combustion engines, which are fueled with a small amount of the available natural gas. These engines provide the mechanical power to run the compressors. The 2007 TCEQ engine survey and the most recent point source emissions inventory indicate that installed compressor engine capacity throughout the Barnett Shale was approximately 1,400,000 hp in 2007, and capacity is likely to increase to over 2,100,000 hp by 2009.

As an alternative to operating the compressors in the Barnett Shale with millions of hp of natural gas burning-engines, the compressors could be operated with electrically-driven motors. The electrification of the wellhead and compressor station engine fleet in the Barnett Shale area has the potential to deliver significant reductions in emissions in North Central Texas. The use of electric motors instead of internal combustion engines to drive natural gas compressors is not new to the natural gas industry, and numerous compressors driven by electric motors are operational throughout Texas. Unfortunately, current regulations have not yet required their use in the Barnett Shale.

A few of the many examples of electrically-driven natural gas compressors, positive technical assessments, and industrial experience with their use in Texas and throughout the U.S., include:

- The Interstate Natural Gas Association of America: "One advantage of electric motors is they need no air emission permit since no hydrocarbons are burned as fuel. However, a highly reliable source of electric power must be available, and near the station, for such units to be considered for an application." [29]
- The Williams natural gas company: "The gas turbine and reciprocating engines typically use natural gas from the pipeline, where the electric motor uses power from an electric transmission line. Selection of this piece of equipment is based on air quality, available power, and the type of compressor selected. Typically electric motors are used when air quality is an issue." [30]
- JARSCO Engineering Corp.: "The gas transmission industry needs to upgrade equipment for more capacity. The new high-speed electric motor technology provides means for upgrading, at a fraction of the life cycle costs of conventional gas powered equipment."[31]
- Pipeline and Gas Journal, June 2007: "Important factors in favor of electric-driven compressor stations that should be considered in the feasibility analysis include the fact that the fuel gas for

gas turbine compressor stations will be transformed into capacity increase for the electrically-driven compressor station, and will therefore add revenue to this alternative..." [32]

- Prime mover example: Installations in 2007 at Kinder Morgan stations in Colorado of +10,000 hp electric-driven compressor units. [33]
- Wellhead example: Installations in Texas of wellhead capacity (5 to 400 hp) electrically-driven compressors. [34,35]
- Mechanical Engineering Magazine, December 1996: "Gas pipeline companies historically have used gas-fired internal-combustion engines and gas turbines to drive their compressors. However, this equipment emits nitrogen oxides....According to the Electric Power Research Institute, it is more efficient to send natural gas to a combined-cycle power plant to generate electricity transmitted back to the pipeline compressor station than to burn the natural gas directly in gas-fired compressor engines."[36]
- The Dresser-Rand Corporation: "New DATUM-C electric motor-driven compressor provides quiet, emissions free solution for natural gas pipeline applications – An idea whose time had come." [37]
- Occidental Oil and Gas Corporation: "Converting Gas-Fired Wellhead IC Engines to Electric Motor Drives: Savings $23,400/yr/unit." [38]

The use of an electric motor instead of a gas-fired engine to drive gas compression eliminates combustion emissions from the wellhead or compressor station. Electric motors do require electricity from the grid, and in so far as electricity produced by power plants that emits pollutants, the use of electric motors is not completely emissions free. However, electric motor use does have important environmental benefits compared to using gas-fired engines.

Modern gas-fired internal-combustion engines have mechanical efficiencies in the 30-35% range, values that have been relatively static for decades. It is doubtful that dramatic increases in efficiency (for example, to 80 or 90%) are possible anytime in the near future. This means that carbon dioxide emissions from natural gas-fired engines at wellheads and compressor stations are not likely to drop substantially because of efficiency improvements. In addition, the scrubbing technology that is used in some large industrial applications to separate CO_2 from other gases also is unlikely to find rapid rollout to the thousands of comparatively-smaller exhaust stacks at natural gas wellheads and compressor stations. The two facts combined suggest that the greenhouse gas impacts from using internal combustion engines to drive compressors are likely to be a fixed function of compression demand, with little opportunity for large future improvements.

In contrast, the generators of grid electric power are under increasing pressure to lower greenhouse gas emissions. Wind energy production is increasing in Texas and other areas. Solar and nuclear power projects are receiving renewed interest from investors and regulators. As the electricity in the grid is produced by sources with lower carbon dioxide emissions, so then the use of electric motors to drive natural gas pipelines becomes more and more climate friendly.

Stated another way, carbon dioxide emissions from gas-fired engines are unlikely to undergo rapid decreases in coming years, whereas the electricity for operating electric motors is at a likely carbon-maximum right now. Electric-powered compression has a long-term potential for decreased climate impact, as non-fossil fuel alternatives for grid electricity generation expand in the future.

Costs: Estimates were made of the costs were switching from IC engines to electric motors for compression. Costs at sites in the Barnett Shale are highly time and site specific, depending on the cost of electricity and the value of natural gas, the numbers of hours of operation per year, the number and sizes of compressors operated, and other factors.

For this report, sample values were determined for capital, operating and maintenance, and operating costs of 500 hp of either IC engine capacity or electric motor capacity for a gas compressor to operate for 8000 hours per year at a 0.55 load factor. Electric power costs were based on $8/month/kW demand charge, $0.08/kWh electricity cost, and 95% motor mechanical efficiency. Natural gas fuel costs were based on $7.26/MMBtu wellhead natural gas price and a BSFC of 0.0085 MMBtu/hp-hr.

With these inputs, the wellhead value of the natural gas needed to operate a 500 hp compressor with an IC engine for 1 year is approximately $136,000. This is lower than the costs for electricity to run a comparable electric motor, which would be approximately $174,000. In addition to these energy costs, it is important to also consider operating and maintenance (O&M) and capital costs. With an IC engine O&M cost factor of $0.016/hp in 2009 dollars, O&M costs would be approximately $35,000. With an electric motor O&M cost factor of $0.0036/kWh in 2009 dollars, O&M costs would be approximately $6200, providing a savings of nearly $30,000 per year in O&M costs for electrical compression, nearly enough to compensate for the additional energy cost incurred from the additional price premium on electricity in Texas compared to natural gas.

With an IC engine capital cost factor of $750/hp in 2009 dollars, the cost of a 500 hp compressor engine would be approximately $370,000. With an electric motor cost factor of $700/kW, the cost of 500 hp of electrically-powered compression would be approximately $260,000.

The combined energy (electricity or natural gas), O&M, and capital costs for the two options are shown in Table 22, assuming a straight 5-year amortization of capital costs. The data show that there is little cost difference in this example, with a slight cost benefit of around $12,000/year for generating the compression power with an electric motor instead of an IC engine. While this estimate would vary from site to site within the Barnett Shale, there appears to be cost savings, driven mostly by reduced initial capital cost, in favor of electrical compression in the Barnett Shale. In addition to the potential cost savings of electrical compression over engine compression, the lack of an overwhelming economic driver one way or the other allows the environmental benefits of electric motors over combustion engines to be the deciding factor on how to provide compression power in the area.

Table 22. Costs of IC Engine and Electric Motor Compression [example of 500 hp installed capacity].

	IC Engine ($/year)	Electric Motor ($/year)
energy (NG or electricity)	136,000	174,000
O&M	35,000	6,200
capital	74,000	52,000
Total	**245,000**	**232,000**

5.2 Oil and Condensate Tanks

Oil and condensate tanks in the Barnett Shale are significant sources of multiple air pollutants, especially VOC, HAPs, and methane. Multiple options exist for reducing emissions from oil and condensate tanks, including options that can result in increased production and revenue for well operators.[14] This section will discuss two of these options: flares and vapor recovery units.

i. Vapor Recovery Units

Vapor recovery units (VRU) can be highly effective systems for capturing and separating vapors and gases produced by oil and condensate tanks. Gases and vapors from the tanks are directed to the inlet side of a compressor, which increases the pressure of the mixture to the point that many of the moderate and higher molecular weight compounds recondense back into liquid form. The methane and other light gases are directed to the inlet (suction) side of the well site production compressors to join the main flow of natural gas being produced at the well. In this way, VRU use increases the total production of gas at the well, leading to an increase in gas available for metering and revenue production. In addition, liquids produced by the VRU are directed back into the liquid phase in the condensate tank, increasing condensate production and the income potential from this revenue stream. Vapor recovery units are estimated to have control efficiencies of greater than 98%.[14]

The gases and vapors emitted by oil and condensate tanks are significant sources of air pollutants, and the escape of these compounds into the atmosphere also reduces income from hydrocarbon production. With a wellhead value of approximately $7/MMBtu, the 7 tpd of methane that is estimated to be emitted in 2009 from condensate tanks in the Barnett Shale have a value of over $800,000 per year. Even more significantly, a price of condensate at $100/bbl makes the 30 tpd of VOC emissions in 2009 from the tanks in the Barnett Shale potentially worth over $10 million per year.

While flaring emissions from tanks in the Barnett Shale would provide substantial environmental benefits, especially in terms of VOC and methane emissions, capturing these hydrocarbons and directing them into the natural gas and condensate distribution systems would provide both an environmental benefit and a very large potential revenue stream to oil and gas producers.

ii. Enclosed Flares

Enclosed flares are common pollution control and flammable gas destruction devices. Enclosed flares get their name because the flame used to ignite the gases is generated by burner tips installed within the stack well below the top. The flames from enclosed flares are usually not visible from the outside, except during upset conditions, making them less objectionable to the surrounding community compared to open (unenclosed) flares.

Using a flare to control emissions from tanks involves connecting the vents of a tank or tank battery to the bottom of the flare stack. The vapors from oil and condensate tanks are sent to the flare, and air is also added to provide oxygen for combustion. The vapors and air are ignited by natural gas pilot flames, and much of the HAP, VOC, and methane content of the tank vapors can be destroyed. The destruction efficiency for flares can vary greatly depending on residence time, temperature profile, mixing, and other factors. Properly designed and operated flares have been reported to achieve 98% destruction efficiencies.

Applying 98% destruction efficiency to the Barnett Shale oil and condensate tanks emissions estimates shown in Table 16 results in potential emission reductions of 30 tpd of VOC, 0.6 tpd of HAPs, and 7 tpd of methane. These reductions are substantial and would provide large benefits to the ozone and PM precursor, HAPs, and greenhouse gas emission inventory of the Barnett Shale area. The use of flares, however, also has several drawbacks. One of these is that tank vapor flares need a continuous supply of pilot light natural gas, and reports have estimated pilot light gas consumption at around 20 scfh/flare.(14)

Table 23 presents a summary of the results of an economic analysis performed in 2006 by URS Corporation for using flares or vapor recovery units to control emissions from a tank battery in Texas.(14) Capital costs were estimated by URS with a 5-year straightline amortization of capital. Flow from the tank battery was 25Mscf/day and VOC emissions were approximately 211 tpy. Costs were in 2006 dollars.

Table 23. Economics of Flares and Vapor Recovery Units.

Control Option	Total Installed Capital Cost ($)	Annual Installed Operating Cost ($/yr)	Operating Cost ($/yr)	Value Recovered ($/yr)	VOC Destruction Cost Effectiveness ($/ton VOC)
Enclosed Flare	40,000	8000	900	NA	40
VRU	60,000	12000	11,400	91,300	($320)*

*VRU produces positive revenue, resulting in zero cost for VOC control, after accounting for value of recovered products.

The URS analysis indicated that flares were able to cost effectively reduce VOC emissions at $40/ton, while VRU units produced no real costs and quickly generated additional revenue from the products recovered by VRU operation. There was a less-than 1 year payback on the use of a VRU system, followed by years of the pollution control device becoming steady revenue source.

5.3 Well Completions

Procedures have been developed to reduce emissions of natural gas during well completions. These procedures are known by a variety of terms, including "the green flowback process" and "green completions." (39,40) To reduce emissions, the gases and liquids brought to the surface during the completion process are collected, filtered, and then placed into production pipelines and tanks, instead of being dumped, vented, or flared. The gas cleanup during a "green" completion is done with special temporary equipment at the well site, and after a period of time (days) the gas and liquids being produced at the well are directed to the permanent separators, tanks, and piping and meters that are installed at the well site. Green completion methods are not complex technology and can be very cost effective in the Barnett Shale. The infrastructure is well-established and gathering line placement for the initial collection of gas is not a substantial risk since wells are successfully drilled with a very low failure rate.

Emissions during well completions depend on numerous site-specific factors, including the pressure of the fluids brought to the surface, the effectiveness of on-site gas capturing equipment, the control efficiency of any flaring that is done, the chemical composition of the gas and hydrocarbon liquids at the drill site, and the duration of drilling and completion work before the start of regular production.

Some recent reports of the effectiveness of green completions in the U.S. are available, including one by the U.S. EPA which estimated 70% capture of formerly released gases with green completions, and another report by Williams Corporation which found that 61% to 98% of gases formerly released during well completions were captured with green completions.(40-41) Barnett Shale producer Devon Energy is using green completions on its wells, and they reported $20 million in profits from natural gas and condensate recovered by green completed wells in a 3 year period.(42)

If green completion procedures can capture 61% to 98% of the gases formerly released during well completions, the process would be a more environmentally friendly alternative to flaring of the gases, since flaring destroys a valuable commodity and prevents its beneficial use. Green completions would also certainly be more beneficial than venting of the gases, since this can release very large quantities of methane and VOCs to the atmosphere. Another factor in favor of capturing instead of flaring is that flaring can produce carbon dioxide (a greenhouse gas), carbon monoxide, polycyclic aromatic hydrocarbons, and particulate matter (soot) emissions.

5.4 Fugitive Emissions from Production Wells, Gas Processing, and Transmission

Fugitive emissions from the production wells, gas processing plants, gas compressors, and transmission lines in the Barnett Shale can be minimized with aggressive efforts at leak detection and repair. Unlike controlling emissions from comparatively smaller numbers of engines or tanks (numbering in the hundreds or low thousands per county), fugitive emissions can originate from tens of thousands of valves, flanges, pump seals, and numerous other leak points. While no single valve or flange is likely to emit as much pollution as a condensate tank or engine exhaust stack, the cumulative mass of all these fugitives can be substantial. There are readily-available measures that can reduce fugitive emissions.

i. Enhanced Leak Detection and Repair Program

The federal government has established New Source Performance Standards for natural gas processing plants a.k.a. NSPS Subpart KKK.[43] These standards require regularly scheduled leak detection, and if needed, repair activities for items such as pumps, compressors, pressure-relief valves, open-ended lines, vapor recovery systems, and flares. The NSPS applies to plants constructed or modified after January 20, 1984. The procedures and standards in the processing plant NSPS are generally based on the standards developed for the synthetic organic manufacturing chemicals industry.[44]

Fugitive emissions from oil and gas wells, separators, tanks, and metering stations are not covered by the processing plant NSPS. Nonetheless, the leak detection and repair protocols established in the NSPS could certainly be used to identify fugitive emissions from these other items. Leak detection at processing plants covered by the NSPS is performed using handheld organic vapor meters (OVMs), and inspections are required to be done on a specified schedule. These same procedures could be used at every point along the oil and gas system in the Barnett Shale to identify and reduce emissions of VOCs and methane. Doing so would reduce emissions, and by doing so, increase production and revenue to producers.

It is difficult to estimate the exact degree of emission reductions that are possible with fugitive emission reduction programs. The large and varied nature of fugitive emission points (valves, fittings, etc.) at production wells, processing plants, and transmission lines means that each oil and gas related facility in the Barnett Shale will have different options for reducing fugitive emissions. In general, leak detection and repair programs can help identify faulty units and greatly reduce their emissions.

ii. Eliminating Natural Gas-Actuated Pneumatic Devices

The State of Colorado is currently adopting and implementing VOC control strategies to reduce ambient levels of ozone in the Denver metropolitan area and to protect the numerous national parks and wilderness areas in the state. As part of this effort, the state investigated the air quality impacts of oil and gas development, including the impacts of the pneumatically-controlled valves and other devices that are found throughout gas production, processing, and transmission systems. The State of Colorado confirmed the basic conclusions arrived at earlier by EPA and GRI in 1995, that these pneumatic devices can be substantial sources of CH_4, VOC, and HAP emissions.[45,46] Much of the following information on these devices and the strategies to control emissions is based on a review of the recent work in Colorado.

Valves and similar devices are used throughout the oil and gas production, processing, and transmission systems to regulate temperature, pressure, flow, and other process parameters. These devices can be operated mechanically, pneumatically, or electrically. Many of the devices used in the natural gas sector are pneumatically operated. Instrument air (i.e. compressed regular air) is used to power pneumatic devices at many gas processing facilities, but most of the pneumatic devices at production wells and along transmission systems are powered by natural gas.[46] Other uses of pneumatic devices are for shutoff valves, for small pumps, and with compressor engine starters.

As part of normal operation, most pneumatic devices release or "bleed"gas to the atmosphere. The release can be either continuously or intermittently, depending on the kind of device. In 2003 U.S. EPA estimated that emissions from the pneumatic devices found throughout the production, processing, and transmission systems were collectively one of the largest sources of methane emissions in the natural gas industry. Some U.S. natural gas producers have reduced natural gas emissions significantly by replacing or retrofitting "high-bleed" pneumatic devices. High-bleed pneumatic devices emit at least 6 standard cubic feet gas per hour.[46] Actual field experience is demonstrating that up to 80 percent of all high-bleed devices in natural gas systems can be replaced or retrofitted with low-bleed equipment.

The replacement of high-bleed pneumatic devices with low-bleed or no-bleed devices can reduce natural gas emissions to atmosphere by approximately 88 or 98 percent, respectively.[21, 47] Anadarko Petroleum Corporation estimated that VOC emissions from their pneumatic devices will be reduced by 464 tpy once 548 of their pneumatic controllers are retrofitted in Colorado.[46]

It may not be possible, however, to replace all high-bleed devices with low or no bleed alternatives. In the state of Colorado, it was estimates that perhaps up to 20 percent of high-bleed devices could not be retrofitted or replaced with low-bleed devices. Some of these included very large devices requiring fast and/or precise responses to process changes which could not yet be achieved with low-bleed devices.

But even for these devices that appear to require high-bleed operation, alternatives are available. Natural gas emissions from both high bleed and low bleed devices can be reduced by routing pneumatic discharge ports into a fuel gas supply line or into a closed loop controlled system. Another alternative is replacing the natural gas as the pneumatic pressure fluid with pressurized air. Instrument pressurized air systems are sometimes installed at facilities that have a high concentration of pneumatic devices, full-time operator presence, and are on a power grid. In an instrument pressurized air system, atmospheric air is compressed, stored in a volume tank, filtered, and dried. The advantage of a pressurized air system for operating pneumatic devices is that operation is the same whether they air or natural gas is used. Existing pneumatic gas supply piping, control instruments, and valve actuators can be reused when converting from natural gas to compressed air.

The U.S. EPA runs a voluntary program, EPA Natural Gas STAR, for companies adopting strategies to reduce their methane emissions. Experience from companies participating in the program indicates that strategies to reduce emissions from pneumatic devices are highly cost effective, and many even pay for themselves in a matter of months.[46] EPA reports that one company replaced 70 high-bleed pneumatic devices with low-bleed devices and retrofitted 330 high-bleed devices, which resulted in an emission reduction of 1,405 thousand cubic meters per year. At $105/m^3$, this resulted in a savings of $148,800 per year. The cost, including materials and labor for the retrofit and replacement, was $118,500, and therefore, the payback period was less than one year. Early replacement (replacing prior to projected end-of-service-life) of a high-bleed valve with a low-bleed valve is estimated to cost $1,350. Based on $3/m^3$ gas, the payback was estimated to take 21 months. For new installations or end of service life replacement, the incremental cost difference of high-bleed devices versus low-bleed devices was $150 to $250. Based on $3 per Mcf gas, the payback was estimated to take 5 to 12 months.[46]

Overall, cost-effective strategies are available for reducing emissions and enhance gas collection from pneumatic devices in Barnett Shale area operations. These strategies include:

- Installing low- or no-bleed pneumatic devices at all new facilities and along all new transmission lines;
- Retrofitting or replacing existing high-bleed pneumatic devices with low- or no-bleed pneumatic devices;
- Ensuring that all natural gas actuated devices discharge into sales lines or closed loops, instead of venting to the atmosphere;
- Using pressurized instrument air as the pneumatic fluid instead of natural gas.

6.0 CONCLUSIONS

Oil and gas production in the Barnett Shale region of Texas has increased rapidly over the last 10 years. The great financial benefits and natural resource production that comes from the Barnett Shale brings with it a responsibility to minimize local, regional, and global air quality impacts. This report examined emissions of smog forming compounds, air toxic compounds, and greenhouse gases from oil and gas activity in the Barnett Shale area, and identified methods for reducing emissions.

Emissions of ozone and fine particle smog forming compounds (NOx and VOC) will be approximately 191 tons per day on an annual average basis in 2009. During the summer, VOC emissions will increase, raising the NOx + VOC total to 307 tpd, greater than the combined emissions from the major airports and on-road motor vehicles in the D-FW metropolitan area.

Emissions in 2009 of air toxic compounds from Barnett Shale activities will be approximately 6 tpd on an annual average, with peak summer emissions of 17 tpd.

Emissions of greenhouse gases like carbon dioxide and methane will be approximately 33,000 CO_2 equivalent tons per day. This is roughly comparable to the greenhouse gas emissions expected from two 750 MW coal-fired power plants.

Cost effective emission control methods are available with the potential to significantly reduce emissions from many of the sources in the Barnett Shale area, including

- the use of "green completions" to capture methane and VOC compounds during well completions,
- phasing in of electric motors as an alternative to internal-combustion engines to drive gas compressors,
- the control of VOC emissions from condensate tanks with vapor recovery units, and
- replacement of high-bleed pneumatic valves and fittings on the pipeline networks with no-bleed alternatives.

Large reductions in greenhouse gas emissions could be achieved through the use of green completion methods on all well completions, with the potential to eliminate almost 200 tpd of methane emissions while increasing revenue for producers by recovering saleable gas. In addition, the replacement of internal combustion engines with electric motors for compression power could reduce smog-forming emissions in the D-FW metropolitan area by 65 tpd. Significant emission reductions could also be achieved with the use of vapor recovery units on oil and condensate tanks, which could eliminate large amounts of VOC emissions. Vapor recovery units on condensate tanks would pay for themselves in a matter of months by generating additional revenue to producers from the gas and condensate that would be captured instead of released to the atmosphere. Fugitive emissions of methane, VOC, and HAPs could be reduced with a program to replace natural gas actuated pneumatic valves with units actuated with compressed air. For those devices in locations where compressed air is impractical to implement, connection of the bleed vents of the devices to sales lines also could greatly reduce emissions.

There are significant opportunities available to improve local and regional air quality and reduce greenhouse gas emissions by applying readily available methods to oil and gas production activities in the Barnett Shale.

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Author's Notes:

A draft version of this report was prepared in September 2008 and distributed for review and comment to oil and gas producers, state and federal regulators, authors of some of the references used in this report, and others. The author appreciates the comments received by those reviewers and the time they took to provide feedback. For the purpose of full disclosure, the author notes that he was an employee with Radian International LLC working on projects for several gas industry clients, including the Gas Research Institute and gas pipeline companies, during the time that "Methane Emissions from the Natural Gas Industry" (Reference 15) was published. The authors of Reference 15 were also employees of Radian International LLC, working as contractors for the Gas Research Institute and the Environmental Protection Agency. The author of this study notes that he did not work on or participate in the GRI/EPA project performed by the other Radian International personnel.

Images on the cover page from the Texas Railroad Commission and the U.S. Department of Energy.

Some typos and spreadsheet errors fixed on 2/8/2009.

Finally, the statements and recommendations in this study are those of the author, and do not represent the official positions of Southern Methodist University.

Air Quality Impact Analysis Technical Support Document for the

FINAL
Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project

Sublette County, Wyoming

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

June 2008

2.0 EMISSIONS INVENTORY

2.1 PROJECT EMISSIONS

The direct project emissions inventory for the PAPA is divided into four sections in Appendix:

- 2005 Actual Emissions Inventory (Section.1),
- 2005 Potential Emissions Inventory (Section 2),
- Proposed Action Emissions Inventory (Section 3), and
- No Action Emissions Inventory (Section 4).

Calculation methods are similar for each emissions inventory except as noted in the following sections. Specific details for each inventory are provided in the respective sections of Appendix F.

Criteria pollutant and hazardous air pollutant (HAP) emissions were inventoried for construction activities, production activities, and ancillary facilities. Criteria pollutants included nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOCs), particulate matter less than 10 microns in diameter (PM_{10}), and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). HAPs consist of n-hexane; benzene, toluene, ethylbenzene, and xylene (BTEX); and formaldehyde. All emission calculations were completed in accordance with WDEQ-AQD oil and gas guidance (WDEQ-AQD 2001), WDEQ-AQD additional guidance for the Jonah and Pinedale Anticline Gas Fields (WDEQ-AQD 2004), stack test data, EPA's AP-42, or other accepted engineering methods (see Appendix F, Section1). Actual 2005 emissions were obtained from emissions inventories submitted by PAPA Operators to WDEQ-AQD, when available. Emissions not quantified in these inventories were conservatively assumed to be equal to those calculated for the 2005 potential emissions inventory.

2.1.1 Construction Emissions

Construction activities are a source of primarily criteria pollutants. Emissions would occur from construction (well pads, roads, gathering pipelines, and ancillary facilities), drilling, completion/testing, traffic, and wind erosion. Well development rates were provided by the Operators based on their future projections for both the Proposed Action Alternative and the No Action Alternative. These well development rates vary by alternative. Detailed well development rates per year can be found in the tables of Appendix F.

Emissions from construction of well pads and roads and traffic include fugitive PM_{10} and $PM_{2.5}$. Other criteria pollutant emissions would occur from diesel combustion in haul trucks and heavy construction equipment. On well pads and resource roads, water would be used for fugitive dust control, with a control efficiency of 50%. On local roads, magnesium chloride would be used for dust control, with a control efficiency of 85%.

After the well pad is constructed, rig-move/drilling would begin. Emissions would include fugitives from unpaved road travel to and from the drilling site. There would be emissions from diesel drilling engines and from boilers in the winter months. Emissions from well completion and testing would include fugitive PM_{10} and $PM_{2.5}$ from traffic. It would also include combustion emissions from diesel fracturing engines and haul truck tailpipes. All completions would be “green completions” with no flaring other than for upset/emergency conditions.

Pollutant emissions would also occur from gathering pipeline installation activities, including general construction activities, travel to and from the pipeline construction site, and diesel combustion from on-site construction equipment.

Construction emission calculations are provided in detail, showing all emission factors, input parameters, and assumptions, in Appendix F.

2.1.2 Production Emissions

Field production equipment and operations would be a source of criteria pollutants and HAPs including BTEX, n-hexane, and formaldehyde. Pollutant emission sources during field production would include:

- combustion engine emissions and fugitive dust from road travel to and from production sites;
- diesel combustion emissions from haul trucks;
- combustion emissions from production site heaters;
- fugitive VOC/HAP emissions from production site equipment leaks;
- condensate storage tank flashing and flashing control;
- glycol dehydrator still vent flashing;
- wind erosion from well pad disturbed areas
- processing units at gas plants; and
- natural gas-fired reciprocating internal combustion compressor engines

Fugitive PM_{10} and $PM_{2.5}$ emissions would occur from road travel and wind erosion from well pad disturbances. Criteria pollutant emissions would occur from diesel combustion in haul trucks traveling in the field during production.

Heaters required at production facilities include separator/indirect line heaters and dehydrator reboiler heaters. These heaters are sources of mainly NO_x and CO as well as small amounts of VOCs. Emissions from these sources were calculated on run-time percentages for both the summer and winter seasons based on data provided by Operators.

VOC and HAP emissions would occur from fugitive equipment leaks (i.e., valves, flanges, connections, pump seals, and opened lines). Condensate storage tank flashing and glycol dehydrator still vent flashing emissions also would include VOC/HAP emissions. VOC and HAP emissions would decrease over the life of an individual well due to declines in condensate and gas production. Emissions from these sources were based on information provided by Operators.

Production emission calculations are provided in detail, showing all emission factors, input parameters, and assumptions, in Appendix F.

2.1.3 Total Field Emissions

Estimates of maximum potential annual emissions in the PAPA under the No Action and Proposed Action alternatives, and for year 2005 are shown in Table 2.1. Maximum potential annual emissions assume construction and production occurring simultaneously in the field for the maximum emissions year for each project alternative.

Table 2.1 Estimated Potential Emissions by Alternative (tpy), Pinedale Anticline Project.

Source	Pollutant	Year 2005	Alternative A (No Action) 2007	Alternative B (Proposed Action) 2009
Construction Emissions				
Drill Rigs	NO_x	2590.9	4066.5	3232.6
	CO	2031.6	2445.2	2307.0
	SO_2	221.0	48.5	55.7
	PM_{10}	133.5	160.4	130.3
	$PM_{2.5}$	133.5	160.4	130.3
	VOC	244.5	292.9	271.3
Fugitives	NO_x	427.4	641.8	559.4
(Pad/Road Construction, Traffic, Completions, etc...)	CO	305.3	493.5	428.1
	SO_2	10.6	15.6	14.4
	PM_{10}	682.2	712.6	415.9
	$PM_{2.5}$	144.8	143.7	82.7
	VOC	192.9	66.1	57.0
Production Emissions				
Compression:	NO_x	421.9	472.2	532.1
	CO	157.7	175.7	235.5
	SO_2	0.0	0.0`	0.0
	PM_{10}	0.0	0.0	0.0
	$PM_{2.5}$	0.0	0.0	0.0
	VOC	320.5	353..5	357.1
Granger Gas Plant	NO_x	301.7	301.7	301.7
(Expansion)	CO	322.8	322.8	322.8
	SO_2	0.0	0.0	0.0
	PM_{10}	0.0	0.0	0.0
	$PM_{2.5}$	0.0	0.0	0.0
	VOC	140.2	140.2	140.2
Wind Erosion	PM_{10}	254.8	357.2	440.8
	$PM_{2.5}$	101.9	142.9	176.3
Fugitives	NO_x	72.2	119.8	108.8
(Heaters, dehys, tanks, traffic, other production equipment, etc…)	CO	251.1	318.7	54.8
	SO_2	0.2	0.5	0.6
	PM_{10}	128.5	311.7	73.7
	$PM_{2.5}$	21.2	51.3	17.8
	VOC	1736.5	1396.2	1150.7
Total	NO_x	3512.4	5602.0	4734.6
	CO	2745.7	3755.9	2978.3
	SO_2	231.8	64.6	70.7
	PM_{10}	1199.0	1541.9	1060.7
	$PM_{2.5}$	401.4	498.3	407.1
	VOC	2494.4	2248.9	1976.3

Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado

Colorado Air Pollution Control Division

<u>Revised Regional Haze Plan</u>
Air Quality Control Commission, approved 01/07/2011

Table of Contents

Preface/Disclaimer

The following document contains Colorado's State Implementation Plan for Regional Haze. Unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described. Many of these controls are neither being submitted to EPA for approval nor being incorporated into the SIP as federally enforceable measures and are mentioned only as examples or references to Colorado air quality programs.

In developing and updating its Long Term Strategy (LTS) for reasonable progress, the State of Colorado takes into account the visibility impacts of several ongoing state programs that are not federally enforceable. These include statewide Colorado requirements applying to open burning, wildland fire smoke management, and renewable energy.

References in this SIP revision to such programs are intended to provide information that Colorado considers in developing its LTS and in its reasonable progress process. These programs are neither being submitted for EPA approval, nor for incorporation into the SIP by reference, nor are they intended to be federally enforceable. The Air Quality Control Commission Rules that govern them implement Colorado's programs and are not federally required. The state is precluded from submitting such programs for incorporation into this SIP by 25-7-105.1, C.R.S.

The following dates reflect actions by the Air Quality Control Commission associated with Colorado State Implementation Plan for Regional Haze:

Regional Haze Plan	Approval Date
Original	12/21/2007
First Revision	12/19/2008
Second Revision (Fully Replaces All Previous RH Plans)	01/07/2011

Chapter 1 Overview

1.1 Introduction

The Clean Air Act (CAA) defines the general concept of protecting visibility in each of the 156 Mandatory Class I Federal Areas across the nation. Section 169A from the 1977 CAA set forth the following national visibility goal:

> "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution."

The federal visibility regulations (40 CFR Part 51 Subpart P – Visibility Protection 51.300 - 309) detail a two-phased process to determine existing impairment in each of the Class I areas; how to remedy such impairment; and how to establish goals to restore visibility to 'natural conditions' by the year 2064. The federal regulations require states to prepare a State Implementation Plan (SIP) to:

- include a monitoring strategy
- address existing impairment from major stationary facilities (Reasonably Attributable Visibility Impairment)
- prevent future impairment from proposed facilities
- address Best Available Retrofit Technology (BART) for certain stationary sources
- consider other major sources of visibility impairment
- calculate baseline current and natural visibility conditions
- consult with the Federal Land Managers (FLMs) in the development or change to the SIP
- develop a long-term strategy to address issues facing the state
- set and achieve reasonable progress goals for each Class I area
- review the SIP every five years

Phase 1 of the visibility program, also known as Reasonably Attributable Visibility Impairment (RAVI), addresses impacts in Class I areas by establishing a process to evaluate source specific visibility impacts, or *plume blight*, from individual sources or small groups of sources. Part of that process relates to evaluation of sources prior to construction through the Prevention of Significant Deterioration (PSD) permit program looking at major stationary sources. The plume blight part of the Phase 1 program also allows for the evaluation, and possible control, of reasonably attributable impairment from existing sources.

Section 169B was added to the Clean Air Act Amendments of 1990 to address Regional Haze. Since Regional Haze and visibility problems do not respect state and tribal boundaries, the amendments authorized EPA to establish visibility transport regions as a way to combat regional haze.

Phase 2 of the visibility program addresses Regional Haze. This form of visibility impairment focuses on overall decreases in visual range, clarity, color, and ability to discern texture and details in Class I areas. The responsible air pollutants can be generated in the local vicinity or carried by the wind often many hundreds or even thousands of miles from where they originated. For technical and legal reasons the second part of the visibility program was not implemented in regulation until 1999. In 1999 the EPA finalized the Regional Haze Rule (RHR) requiring States to adopt a State Implementation Plans (SIPs) to address this other aspect of visibility impairment in the Class I areas. Under current rules the Regional Haze SIP were to be submitted to the EPA by December 31st, 2007. Colorado adopted key components of the Regional Haze SIP in 2007 and 2008 which were submitted to EPA in 2008 and 2009, respectively. EPA subsequently noted deficiencies in the BART determination and Reasonable Further Progress elements, as well as other, more minor issues. Colorado has proceeded to take steps to remedy these alleged deficiencies. This SIP addresses EPA's concerns. Updates to the BART evaluations and Reasonable Further Progress analyses constitute the major revisions to this 2010 plan. In addition, revisions to other chapters have been made to update emissions and monitoring data and descriptions of program changes impacting emissions regulations favoring improved visibility in the State.

The Regional Haze Rule envisions a long period, covered by several planning phases, to ultimately meet the congressionally established National Visibility Goal targeted to be met in 2064. Thus, the approach taken by Colorado, and other states, in preparing the plan is to set this initial planning period (2007-2018) as the "foundational plan" for the subsequent planning periods. This is an important concept when considering the nature of this SIP revision as compared to a SIP revision developed to address a nonattainment condition. The nonattainment plan must demonstrate necessary measures are implemented to meet the NAAQS by a specific time. On the other hand, the Regional Haze SIP must, among other things, set a Reasonable Progress Goal for each Class I area to protect the best days and to improve visibility on the worst days during the applicable time period for this SIP (2007-2018).

Colorado developed, and EPA approved, a SIP for the first Phase 1 of the visibility program. This Plan updates Phase 1 as well as establishing Phase 2 of the program, Regional Haze. The two key requirements of the Regional Haze program are:

- Improve visibility for the most impaired days, and
- Ensure no degradation in visibility for the least impaired days.

Though national visibility goals are targeted to be achieved by the year 2064,this plan is designed to meet the two requirements stated above for the period ending in 2018 (the first planning period in the federal rule), while also establishing enforceable controls to that will help to address the long term goal.

This SIP is intended to meet the requirements of EPA's Regional Haze rules that were adopted to comply with requirements set forth in the Clean Air Act. Elements of this Plan address the core requirements pursuant to 40 CFR 51.308(d) and the Best Available Retrofit Technology (BART) components of 40 CFR 50.308(e). In addition, this SIP addresses Regional Planning, State/Tribe and Federal Land Manager coordination, and contains a commitment to provide Plan revisions and adequacy determinations.

1.2 Visibility Impairment

Most visibility impairment occurs when pollution in the form of small particles scatter or absorb light. Air pollutants come from a variety of natural and anthropogenic sources. Natural sources can include windblown dust and smoke from wildfires. Anthropogenic sources can include motor vehicles and other transportation sources, electric utility and industrial fuel burning, minerals, oil and gas extraction and processing and manufacturing operations. More pollutants mean more absorption and scattering of light which reduces the clarity and color of a scene. Some types of particles such as sulfates scatter more light, particularly during humid conditions. Other particles like elemental carbon from combustion processes are highly efficient at absorbing light. Commonly, the receptor is the human eye and the object may be a single viewing target or a scene.

In the 156 Class I areas across the country, visual range has been substantially reduced by air pollution. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles. In the West, visual range has decreased from an average of 140 miles to 35-90 miles. Colorado has some of the best visibility in the West but also has a number of areas where visibility is impaired due to a variety of sources. This SIP is designed to address regional haze requirements for the twelve mandatory Federal Class I areas in Colorado.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are transported many miles from the source of the pollutants. Some haze forming pollutants are also linked to human health problems and other environmental damage. Exposure to increased levels of very small particles in the air has been linked with increased respiratory illness, decreased lung function, and premature death. In addition, particles such as nitrates and sulfates contribute to acid deposition potentially making lakes, rivers, and streams less suitable for some forms of aquatic life and impacting flora in the ecosystem. These same acid particles can also erode materials such as paint, buildings or other natural and manmade structures.

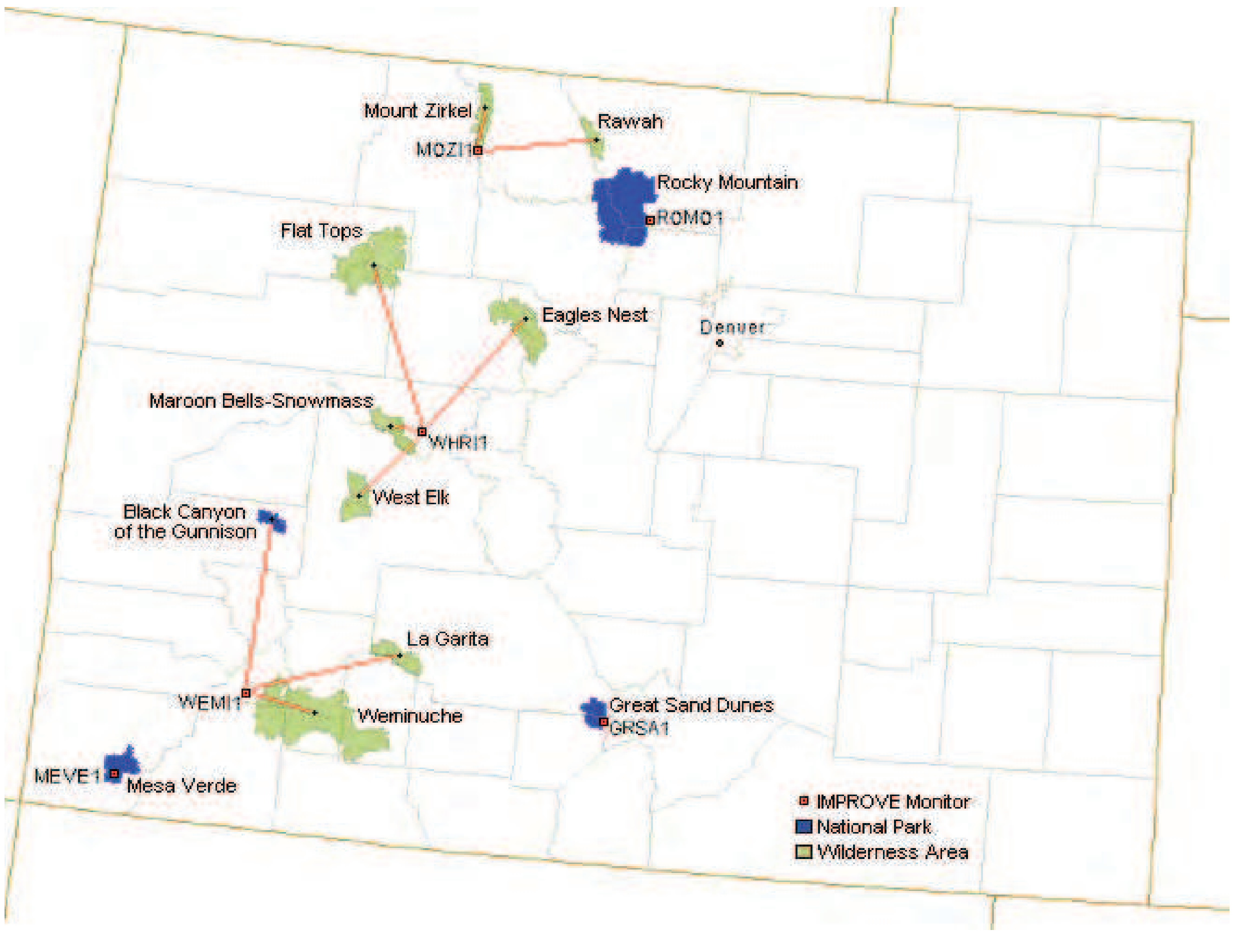
1.3 Description of Colorado's Class I Areas

There are 12 Mandatory Federal Class I Areas in the State of Colorado:

Black Canyon of the Gunnison National Park
Eagles Nest Wilderness Area
Flat Tops Wilderness Area
Great Sand Dunes National Park
La Garita Wilderness Area
Maroon Bells-Snowmass Wilderness Area
Mesa Verde National Park
Mount Zirkel Wilderness Area
Rawah Wilderness Area
Rocky Mountain National Park
Weminuche Wilderness Area
West Elk Wilderness Area

A detailed description of each of these areas, along with photographs, summaries of monitoring data containing an overview of current visibility conditions and sources of pollution in each area, is contained in individual Technical Support Documents (TSDs) for this plan (see list in Chapter 10). Each Class I area has been designated as impaired for visual air quality by the Federal Land Manager responsible for that area. Under the federal visibility regulations, the Colorado visibility SIP needs to address the visibility status of and control programs specific to each area. Figure 1-1 shows the location of these areas and the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring site that measures particulate air pollution representative of each Class I area.

Figure 1-1 Colorado Class I Areas and IMPROVE Monitor Locations



1.4 Programs to Address Visibility Impairment

Colorado adopted a Phase 1 visibility SIP to address the PSD permitting, source specific haze, and plume blight aspects of visibility in 1987. The most recent plan update was approved by the EPA in December 2006.

As stated in the preface to this Plan, unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described and are neither being submitted to EPA for approval nor being incorporated into the SIP as Federally enforceable measures. This comprehensive visibility plan, which now contains both Phase 1 and Phase 2 visibility requirements, addresses all aspects of Colorado's visibility improvement program. Colorado has numerous emission control programs to improve and protect visibility in Class I areas. In addition to the traditional Title V, New Source Performance Standards, Maximum Achievable Control Technology and new source review permitting programs for stationary sources, Colorado also has Statewide emission control requirements for oil and gas sources, open burning, wildland fire, smoke management, automobile emissions for Front Range communities, and residential woodburning, as well as PM10 nonattainment/maintenance area requirements, dust suppression for construction areas and unpaved roads and renewable energy requirements.

Colorado adopted legislation to address renewable energy by establishing long-term energy production goals. This program is expected to reduce future expected and real emissions from coal-fired power plants. This renewable energy measure was considered a key feature of the Grand Canyon Visibility Transport Commission's recommendations. Although the Colorado renewable energy program was not specifically adopted to meet regional haze requirements, emissions from fossil-fuel fired electricity generation are avoided in the future.

Colorado is also setting emission limits (as part of this plan) for those sources subject to Best Available Retrofit Technology (BART) requirements of Phase 2 of the visibility regulations for Regional Haze (described in detail in Chapter 6 of this plan). To comply with these BART limits sources subject to BART are required to install

and operate BART as expeditiously as practicable, but not later than 5 years after EPA's approval of the implementation plan revision.

As such, this Plan documents those programs, regulations, processes and controls deemed appropriate as measures to reduce regional haze and protect good visibility in the State toward meeting the 2018 and 2064 goals established in EPA regulations and the CAA.

1.5 Reasonable Progress Towards the 2064 Visibility Goals

As described in detail in Chapters 8 and 9 of this plan, reasonable progress goals for each Class I area have been established. The Division has worked with the Western Regional Air Partnership (WRAP) and with the WRAP's ongoing modeling program to establish and refine Reasonable Progress Goals (RPGs) for Colorado Class I Areas.

Technical analyses described in this Plan demonstrate emissions both inside and outside of Colorado have an appreciable impact on the State's Class I areas. Emission controls from many sources outside Colorado are reflected in emission inventory and modeling scenarios for future cases as detailed in the WRAP 2018 PRP18b control case. Progress toward the 2064 goal is determined based on emission control scenarios described in the WRAP inventory documentation plus the state's BART and reasonable progress determinations.

Chapter 2 Plan Development and Consultation

This chapter discusses the process Colorado participated in to address consultation requirements with the federal land managers, tribes and other states in the Western Regional Air Partnership (WRAP) during the development of this Plan and future commitments for consultation.

Colorado has been a participating member of the WRAP since its inception. The WRAP completed a long-term strategic plan in 2003.[1] The Strategic Plan provides the overall schedule and objectives of the annual work plans and may be revised as appropriate. Among other things, the Strategic Plan (1) identifies major products and milestones; (2) serves as an instrument of coordination; (3) provides the direction and transparency needed to foster stakeholder participation and consensus-based decision making, which are key features of the WRAP process; and (4) provides guidance to the individual plans of WRAP forums and committees.

Much of the WRAP's effort is focused on regional technical analysis serving as the basis for developing strategies to meet the RHR requirement to demonstrate reasonable progress towards natural visibility conditions in Class I national parks and wilderness areas. This includes the compilation of emission inventories, air quality modeling, and ambient monitoring and data analysis. The WRAP is committed to using the most recent and scientifically acceptable data and methods. The WRAP does not sponsor basic research, but WRAP committees and forums interact with the research community to refine and incorporate the best available tools and information pertaining to western haze.

2.1 Consultation with Federal Land Managers (FLM)

Section 51.308(i) requires coordination between states and the Federal Land Managers (FLMs). Colorado has provided agency contacts to the Federal Land Managers as required. In development of this Plan, the Federal Land Managers were consulted in accordance with the provisions of 51.308(i)(2). Specifically, the rule requires the State to provide the Federal Land Manager with an opportunity for consultation, in person, and at least 60 days prior to holding any public hearing on an implementation plan or plan revision for regional haze. This consultation must include the opportunity for the affected Federal Land Managers to discuss their assessment of impairment of visibility in any mandatory Class I Federal area and recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment. The State must include a description of how it addressed any comments provided by the Federal Land Managers. Finally, the plan or revision must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required including development and review of implementation plan revisions and 5-year progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas.

[1] See http://www.wrapair.org/forums/sp/docs.html

Colorado participated in the WRAP to develop many elements of the SIP. The WRAP represents a conglomeration of stakeholder representing FLMs, industry, States, Tribes environmental groups and the general public. Through participation in this process, a significant portion of the consultation process with FLMs and other states has been met. In the WRAP process these stakeholders participated in various forums to help develop a coordinated emissions inventory and analysis of the impacts sources have on regional haze in the west. Coordination and evaluation of monitoring data and modeling processes were also overseen by WRAP participants. Through these coordinated technical evaluations, a regional haze-oriented evaluation of Colorado's Class I areas was constructed. Summaries of this information are available in the technical support documents of this Plan.

Public meetings were held at the Colorado Air Quality Control Commission in 2007 and 2008 to provide a comprehensive review of the technical basis for the Plan. Following these meetings, additional meetings were held with the FLMs directly concerning each of the affected Class I areas and the development of the SIP. Prior to the requests for a public hearing on the Regional Haze SIP in August and September 2010, the Division again met with the FLMs to review additions, corrections and changes to the SIP made to address both FLM concerns over the analysis of additional controls on sources not subject to BART and the completion of BART analyses occurring after the 2008 hearings (these new analyses and inventories are reflected later on in this SIP document).

The FLMs have provided comments to the Division regarding proposed regional haze determinations over the course of several years in 2007 and 2008, and again in 2010. The state has carefully considered these comments and has made changes to many of its proposed determinations based in part on these comments. For example, the state has deleted its regulatory prohibition on consideration of post-combustion controls as part of the BART analysis. The state also revisited its earlier BART determinations that relied in some respects on EPA's so called 'presumptive' emission limits for NOx and SO2, and in turn conducted robust facility-specific 5 and 4 factor analyses under BART and RP.

Most recently, the FLMs formally commented on the revised, proposed BART and RP determinations, as well as reasonable progress goals, in November and December 2010. The National Park Service, the Fish and Wildlife Service and the U.S. Forest Service provided support for the modeling approach used by the state in the BART determinations, complimented the state on thorough 5 and 4 factor analyses, clear criteria, area source evaluations, and comprehensive/improved BART and RP determinations, and presented recommendations for cost/emission limit re-evaluations. The state appreciates the supportive input from the FLMs, especially in the areas of modeling and the establishment of the RPGs. The state gave serious consideration to the recent recommendations for revising cost estimates and lowering emission limits, but the comments ultimately did not alter the state's conclusions and resulting proposals.

Regarding the costs of control, the FLMs provided numerous recommendations for revising BART and RP control costs. The state notes that there is no regulatory approach for determining costs of controls. The state considered the relevant factors for BART and RP determinations as set forth in the statute, the regulations and guidance, and consistent with the discretion expressly afforded to states under the statute and regulations. The state received detailed source-specific information for the facilities evaluated, checked this information using many different resources, and made adjustments/normalization when appropriate. The state employed engineering judgment and discretion when preparing BART and RP determinations, and found that the relevant present day and estimated future costs generally fell within the range of typical control costs nationwide. The state considered broader cost survey information to be relevant, and considered such information but did not find it dispositive; the state was informed more on facility-specific information as provided to the state to support its analyses and determinations. For most facilities even if different cost assumptions were employed or were re-assessed, expected visibility from the relevant control did not satisfy the state's guidance criteria for visibility improvement, and thus would not change the state's determination. Further, the state finds metrics like dollar per kilowatt hours or dollar per deciview of improvement of limited utility in considering the 5 or 4 factors, and opted to use its own more straightforward approach to balance and weigh costs of control and related visibility improvement. The costs used by the state were determined to be appropriate and reasonable, were balanced with the state's consideration of related visibility improvement, and further revisions based on FLM comments were not incorporated. The resulting emissions reductions from the state's BART and RP determinations for NOx and SO2 are significant and will benefit Class I Areas.

Regarding CALPUFF modeling, the FLMs provided support for the state's BART and RP modeling efforts, including the modeling protocol and methodologies. However, the state respectfully disagrees with the FLMs recommendations to cumulate visibility improvement impacts from emission controls across multiple Class I Areas. It is the state's position that the approach employed is consistent with a straightforward application of the regional haze regulation, and that the approach suggested by the FLMs, while an option that could be considered, as a general rule is not appropriate. The Commission in making its determinations on certain BART sources was aware that emissions reductions would have some level of visibility improvement in other than the most impacted Class I Area. The CALPUFF modeling output files have been and continue to be available to the FLMs or to the public to perform such analyses.

Regarding BART and RP emission limits, the FLMs provided numerous comments to the state, identifying opportunities for tightening most of the proposed limits. The state notes that there is no regulatory formula for establishing limits in the Regional Haze rule and the state applied professional judgment and utilized appropriate and delegated discretion in establishing appropriate emission limits. The stringency of the limits are tight enough to satisfy BART and RP requirements, but are not operationally unachievable. The emission limits fall within the range of limits adopted nationwide and were developed considering the requirements of the Regional Haze rule and related guidance.

Thus, between the WRAP, AQCC and individual meetings with the FLMs, the State has met the FLM consultation requirements.

Colorado commits to continued coordination and consultation with the Federal Land Managers during the development of future progress reports and Plan revisions, in accordance with the requirements of 51.308(i)(4).

2.2 Collaboration with Tribes

The Southern Ute Tribal lands in the southwest corner of Colorado are adjacent to Mesa Verde National Park, one of Colorado's Class I areas. As described above, Colorado participated in the collaborative WRAP process where Tribes were represented in all levels of the process. In addition, the Colorado Air Quality Control Commission had joint meetings with the Tribal Air Quality Council concerning regulatory and other processes related to air quality control and planning. The Southern Ute Tribe has numerous major and minor sources operating on their lands. Major source permitting is coordinated through a joint agreement with EPA Region IX. Minor sources on Tribal lands in Colorado are subject to the jurisdiction of the Tribes and this Plan contains no regulatory provisions for sources on Southern Ute lands in Colorado. The Tribes have the opportunity to develop Tribal Implementation Plans to address sources of pollution impacting visibility in their area.

2.3 Consultation with Other States

Pursuant to 40 CFR Section 51.308(d)(iv), Colorado consulted with other states during ongoing participation in the Regional Planning Organization, the Western Regional Air Partnership (WRAP), in developing the SIP. The WRAP is a collaborative effort of tribal governments, state governments and various federal agencies to implement the Grand Canyon Visibility Transport Commission's recommendations and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. EPA's regional haze regulations. The WRAP is administered jointly by the Western Governors' Association and the National Tribal Environmental Council. WRAP activities are conducted by a network of committees and forums composed of WRAP members and stakeholders who represent a wide range of viewpoints. The WRAP recognizes that residents have the most to gain from improved visibility and that many solutions are best implemented at the local, state, tribal or regional level with public participation. Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming have agreed to work together to address regional haze in the western United States. Colorado held specific discussions with states that have a primary impact on Colorado Class I areas. These include California, Utah, New Mexico and Arizona regarding the impacts from sources in these states on Colorado Class I areas.

The major amount of state consultation in the development of SIPs was through the Implementation Work Group (IWG) of the WRAP. Colorado participated in the IWG which took the products of the WRAP technical analysis and consultation process discussed above and developed a process for establishing reasonable progress goals in the western Class I areas. A description of that process is discussed in Chapter 8 -- Reasonable Progress Section of the State SIP.

Through the WRAP consultation process Colorado has reviewed and analyzed contributions from other states that reasonably may cause or contribute to visibility impairment in Colorado's Class I areas. While emissions from sources outside of Colorado have resulted in a slower rate of improvement in visibility than the rate that would be needed to attain natural conditions by 2064, most of these emissions are beyond the control of any state in the regional planning area of the WRAP. The emission sources include: emissions from outside the WRAP domain; emissions from Canada and Mexico; emissions from wildfires and windblown dust; and emissions from offshore shipping. Colorado anticipates that the long-term strategies when adopted by other states in their SIPs and approved by EPA will include emission reductions from a variety of sources that will reduce visibility impairment in Colorado's Class I areas.

Colorado's analysis of interstate impacts from specific nearby sources indicated the need for specific consultation with Nebraska, Wyoming, Utah, New Mexico and Arizona and California. In Nebraska the Gerald Gentleman Power Plant was analyzed for BART as part of the Nebraska RH process. Colorado commented to the State of Nebraska on this BART determination since emissions from this plant were indicated to impact Rocky Mountain National Park. Colorado similarly communicated with the State of Wyoming concerning BART determinations for its sources since impacts from Wyoming power plants were indicated to impact the Mt. Zirkel Wilderness Area. Colorado participated in the Four Corners Task force with Utah, New Mexico and Arizona and Tribal representatives to identify sources in the region adversely affecting air quality in the region. One element of that process was to consider sources impacting Mesa Verde or other Colorado Class I areas specifically for regional haze purposes. Through this process these States were made aware of Colorado's concerns about emissions from the Four Corners Power Plant, as it significantly impacts Mesa Verde. EPA Region IX was notified of Colorado's concerns with this facility since they are responsible for issuing and overseeing permits on this facility. Finally, California was contacted to discuss NOx emissions impacting Colorado Class I areas. California identified measures being taken in the State to reduce NOx emissions from mobile and other sources. Additional details concerning the Four Corners Task Force can be found in Section 9.5.5.3 of this Regional Haze SIP.

During the 2010 public hearing process, Colorado provided notification to the WRAP-member states and to other nearby states that a Regional Haze SIP revision had been prepared and invited review and comment on the plan and supporting documents.

By participating in the WRAP and the Four Corner's Task Force, and through specific comments and communications with the participating states, Colorado has satisfied the state consultation requirement.

2.4 General Consultation

As part of the regional haze SIP development process Colorado will continue to coordinate and consult with parties as summarized in the long-term strategy described in Chapter 9.

Chapter 3 Monitoring Strategy

Federal regulations in 40 CFR 51.305 and 51.308(d)(4) require states to have a monitoring strategy in the SIP sufficient to characterize reasonable progress at each of the Class I areas, specifically Phase 1: reasonably attributable visibility impairment (RAVI) and Phase 2: regional haze visibility impairment in federal Class I areas within the state. Because Colorado adopted a visibility SIP to address the Phase 1 requirements (51.305), a monitoring strategy is currently in place through an approved SIP. The State of Colorado utilizes data from the IMPROVE monitoring system which is designed to provide a representative measure of visibility in each of Colorado's Class I areas.

3.1 RAVI Monitoring Strategy in Current Colorado LTS

States are required by EPA to have a monitoring strategy for evaluating visibility in any Class I area by visual observation or other appropriate monitoring techniques. The monitoring strategy in the RAVI LTS is based on meeting the following four goals:

1. To provide information for new source visibility impact analysis.
2. To determine existing conditions in Class I areas and the source(s) of any certified impairment.
3. To determine actual affects from the operation of new sources or modifications to major sources on nearby Class I areas.
4. To establish visibility trends in Class I areas to evaluate progress towards meeting the national visibility goal.

Potential new major source operators must conduct visibility analyses utilizing existing visibility data. If data are adequate and/or representative of the potentially impacted Class I area(s), the permit holder will be notified of the visibility levels against which impacts are to be assessed. If visibility data are not adequate, pre-construction monitoring of visibility may be required.

If the Federal Land Managers (FLMs) or the State of Colorado certifies existing impairment in a Class I area, the Division will determine if emissions from a local source(s) operator(s) can be reasonably attributed to cause or contribute to the documented visibility impairment. In making this determination the Division will consider all available data including the following:

1. Data supplied by the FLM;
2. The number and type of sources likely to impact visibility in the Class I area;
3. The existing emissions and control measures on the source(s);
4. The prevailing meteorology near the Class I area; and
5. Any modeling that may have been done for other air quality programs.

If available information is insufficient to make a decision regarding "reasonable attribution" of visibility impairment from an existing source(s) the State will initiate cooperative studies to help make such a determination. Such studies could involve the FLMs, the potentially affected source(s), the EPA, and others.

The monitoring strategy also included a commitment from the State to sponsor or share in the operation of visibility monitoring stations with FLMs as the need arises and resources allow.

The State commits to periodically compile information about visibility monitoring conducted by various entities throughout the State and assembling and evaluating visibility data.

Colorado law (C.R.S. 25-7-212(3)(a)) requires the federal land management agencies of Class I areas in Colorado (i.e., U.S.D.I. National Park Service and U.S.D.A. Forest Service) to “develop a plan for evaluating visibility in that area by visual observation or other appropriate monitoring technique approved by the federal environmental protection agency and shall submit such plan for approval by the division for incorporation by the commission as part of the state implementation plan.” The agencies indicated they developed, adopted, and implemented a monitoring plan through the Class I visibility monitoring collaborative known as IMPROVE. EPA’s Regional Haze Rule (40 CFR 51.308(d)(4)) indicates, “The State must submit with the Implementation Plan a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment representative of all mandatory Class I Federal areas within the State….Compliance with this requirement may be met through participating in the Interagency Monitoring of Protected Visual Environments [IMPROVE] network.” The federal agencies’ monitoring plan relies on this network and ensures each Class I area in Colorado will have a monitor representative of visibility in the Class I area. In the LTS revision, submitted to EPA in 2008, the Division provided letters from the federal land managers and approval letters from the Division indicating this requirement was being met.

3.2 Regional Haze Visibility Impairment Monitoring Strategy

Under 40 CFR 51.308(d), a State must develop a monitoring strategy in the RH SIP to measure, characterize, and report regional haze visibility impairment representative of all federal Class I areas within the State. This monitoring strategy must be coordinated with the monitoring strategy described in Section 3.1 above, and will be met by participating in the IMPROVE network.

Colorado’s monitoring strategy is to participate in the IMPROVE monitoring network. To insure coordination with the RAVI monitoring strategy, it includes the same four goals as in the RAVI LTS plus an additional goal:

> To provide regional haze monitoring representing all visibility-protected federal Class I areas

3.3 Associated Monitoring Strategy Requirements

Other associated monitoring strategy requirements in 40 CFR 51.308(d)(4) and Colorado's associated SIP commitment are enumerated below:

1. Establishment of any additional monitoring sites or equipment to evaluate achievement of reasonable progress goals [40 CFR 51.308(d)(4)(i)].
   a. Colorado will work collaboratively with IMPROVE, EPA, the Federal Land Managers and other potential sponsors to ensure that representative monitoring continues for all of its Class I areas. If necessary, additional monitoring sites or equipment will be established to evaluate the achievement of reasonable progress goals.
   b. If funding for a site(s) is eliminated by EPA, the Division will consult with FLMs and IMPROVE to determine the best remaining site to use to represent the orphaned Class I areas.
2. Procedures describing how monitoring data and other information are used in determining the State's contribution of emissions to visibility impairment in any federal Class I area [40 CFR 51.308(d)(4)(ii)].
   a. Colorado has participated extensively in the WRAP. One of the Regional Modeling Center (RMC) tools is the PSAT (PM Source Apportionment Technology) that relates emission sources to relative impacts at Class I areas. Details about PSAT are contained in the Technical Support Documents for each Class I area. Colorado will utilize the PSAT method and other models as needed and recommended by EPA modeling guidance for visibility evaluations, or other tools, to assist in determining the State's emission contribution to visibility impairment in any federal Class I area. As part of this process the State commits to consult with the EPA and FLMs or other entities as deemed appropriate when using monitoring and other data to determine the State's contribution of emissions to impairment in any Class I area.
   b. Colorado will continue to review monitoring data from the IMPROVE sites and examine the chemical composition of individual specie concentrations and trends, to help understand the relative contribution of emissions from upwind states on Colorado Class I areas and any contributions from Colorado to downwind Class I areas in other states. This will occur no less than every five years in association with periodic SIP, LTS and monitoring strategy progress reports and reviews.
3. Provisions for annually reporting visibility monitoring data to EPA [40 CFR 51.308(d)(4)(iv)].
   a. IMPROVE data are centrally compiled and made available to EPA, states and the public via various electronic formats and websites including IMPROVE (http://vista.cira.colostate.edu/improve/) and VIEWS (http://vista.cira.colostate.edu/views/)Through participation in the IMPROVE network, Colorado will partially satisfies the requirement to annually report to EPA visibility data for each of Colorado's Class I areas.

b. An annual compilation of the Colorado data will be prepared and reported to the EPA electronically.

4. A statewide emissions inventory of pollutants reasonably expected to cause or contribute to visibility impairment for a baseline year, most recent year data is available, and future projected year [40 CFR 51.308(d)(4)(v)].

   a. Section 5.4 of this Plan includes a summary of Colorado statewide emissions by pollutant and source category. The inventory includes air pollution sources that can reasonably be expected to cause or contribute to visibility impairment to federal Class I areas.

      i. The WRAP-developed Plan02d (March 2008) inventory is both the baseline and most recent year of data available for a statewide inventory. It is an inventory intended to represent typical annual emissions during the baseline period, 2000-2004. From the baseline/current inventory, projections were made to 2018. The WRAP's 2018 Base Case or PRP18b inventory was utilized for final model projections. This represented the most recent BART determinations reported by the States and EPA offices, projection of future fossil-fuel electric generation plants, revised control strategy rulemaking and updated permit limits for point and area sources in the WRAP region as of Spring 2009 (http://www.wrapedms.org/InventoryDesc.aspx). The emission inventory information was collaboratively developed between Division staff and the WRAP. A summarized western state and boundary condition inventory is available at: http://vista.cira.colostate.edu/TSS/Results/emis_smry_p02c_b18b_a5.xls

5. Commitment to update the emissions inventory [40 CFR 51.308(d)(4)(v)].

   a. Colorado will update its portion of the regional inventory, on the tri-annual cycle as dictated by the Air Emissions Reporting Rule (AERR) (see section 3.5) in order to track emission change commitments and trends as well as for input to regional modeling exercises.

6. Any additional reporting, recordkeeping, and measures necessary to evaluate and report on visibility [40 CFR 51.308(d)(4)(vi)].

   a. Colorado will provide any additional reporting, recordkeeping and measures necessary to evaluate and report on visibility but is unaware of the need for any specific commitment at this time beyond those made in this section and in the LTS section.

3.4 Overview of the IMPROVE Monitoring Network

In the mid-1980's, the IMPROVE program was established to measure visibility impairment in mandatory Class I Federal areas throughout the United States. The monitoring sites are operated and maintained through a formal cooperative relationship between the EPA, National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management, and U.S. Forest Service. In 1991, several additional organizations joined the effort: State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials, Western States Air Resources

Council, Mid-Atlantic Regional Air Management Association, and Northeast States for Coordinated Air Use Management.

The objectives of the IMPROVE program include establishing the current visibility and aerosol conditions in mandatory Class I federal areas; identifying the chemical species and emission sources responsible for existing human-made visibility impairment; documenting long-term trends for assessing progress towards the national visibility goals; and support the requirements of the federal visibility rules by providing regional haze monitoring representing all visibility-protected federal Class I areas where practical.

The data collected at the IMPROVE monitoring sites are used by land managers, industry planners, scientists, consultants, public interest groups, and air quality regulators to better understand and protect the visual air quality resource in Class I areas. Most importantly, the IMPROVE Program scientifically documents for American citizens, the visual air quality of their wilderness areas and national parks.

In Colorado, there are six IMPROVE monitors that are listed under the site name in Figure 3-1. As shown, some monitors serve multiple Class I areas. For example, the monitor with site name Mount Zirkel is located just south of the Mount Zirkel Wilderness Area (on Buffalo Pass) but this monitor is also designated to represent the Rawah Wilderness Area.

Figure 3-1 Colorado Class I Areas and IMPROVE Monitor Locations

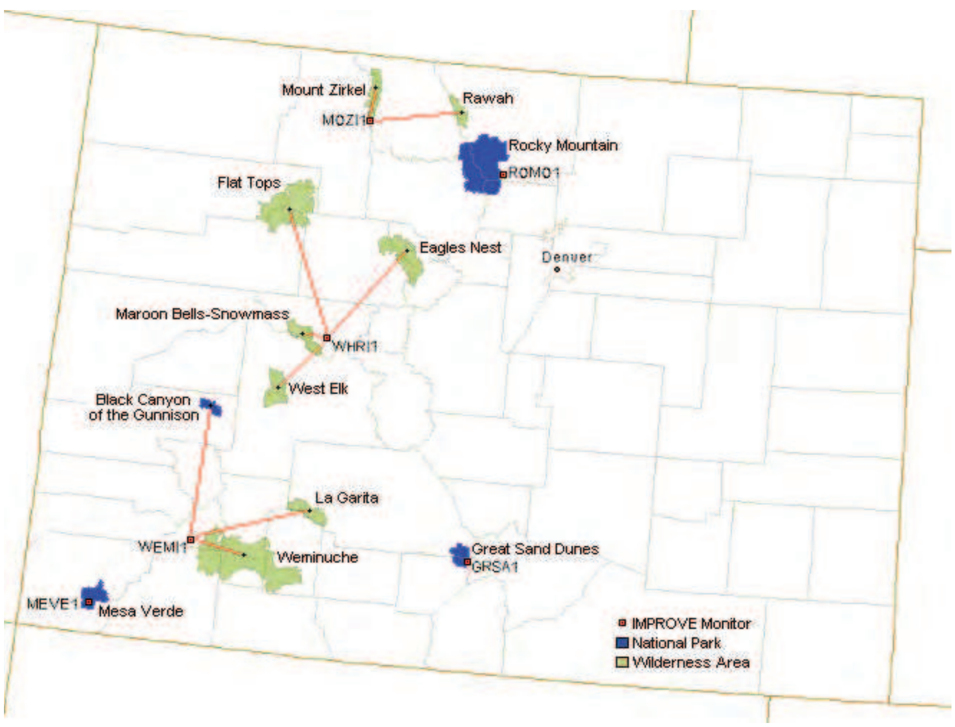


Figure 3-2 includes summary information for each IMPROVE monitor. The National Park Service (NPS) and the U.S. Forest Service (USFS) each operate and maintain three IMPROVE monitors in the State.

Figure 3-2 Colorado IMPROVE Monitoring Site Information

Mandatory Class I Federal Area	Operating Agency	IMPROVE Monitor	Elevation [ft]	Start Date
Great Sand Dunes National Park	NPS	GRSA1	8,215	5/4/1988
Mesa Verde National Park	NPS	MEVE1	7,142	3/5/1988
Mount Zirkel Wilderness	USFS	MOZI1	10,640	7/30/1994
Rawah Wilderness				
Rocky Mountain National Park	NPS	ROMO1	9,039	9/19/1990
Weminuche Wilderness	USFS	WEMI1	9,072	3/2/1988
Black Canyon of Gunnison NP				
La Garita Wilderness				
Eagles Nest Wilderness	USFS	WHRI1	11,214	7/17/2000
Flat Tops Wilderness				
Maroon Bells-Snowmass Wilderness				
West Elk Wilderness				

3.5 Commitment for Future Monitoring

The State commits to continue utilizing the IMPROVE monitoring data and emission data to track reasonable progress. The State commits to providing summary visibility data in electronic format to the EPA on an annual basis from the IMPROVE monitoring, or other relevant sites. Also, the State commits to continue developing updated emission inventories on a tri-annual basis as required under the Air Emissions Reporting Rule sufficient to allow for the tracking of emission increases or decreases attributable to adopted strategies or other factors such as growth, economic downturn, or voluntary or permit related issues. These monitoring and emissions data will be available for electronic processing in future modeling or other emission tracking processes. Information collected from the monitoring system and emission inventory work will be made available to the public.

Colorado will depend on the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring program[2] to collect and report aerosol monitoring data for reasonable progress tracking as specified in the Regional Haze Rule (RHR). Because the RHR is a long-term tracking program with an implementation period nominally set for 60 years, the state expects the configuration of the monitors, sampling site locations, laboratory analysis methods and data quality assurance, and network operation protocols will not change, or if changed, will remain directly comparable to those operated by the IMPROVE program during the 2000-04 RHR baseline period. Technical analyses and reasonable progress goals in RHR plans are based on data from these sites. The state must be notified and agree to any changes in the IMPROVE program affecting the RHR tracking sites, before changes are made. Further, the state notes resources to operate a complete and representative monitoring network of these long-term reasonable progress tracking sites is currently the responsibility of the Federal government. Colorado is satisfying the monitoring requirements by participating in the IMPROVE network. Colorado will continue to work with EPA in refining monitoring

[2] http://vista.cira.colostate.edu/improve/

strategies as new technologies become available in the future. If resource allocations change in supporting the monitoring network the state will work with the EPA and FLMs to address future monitoring requirements.

Colorado depends on IMPROVE program-operated monitors at six sites as identified in Figures 3.1 and 3.2 for tracking RHR reasonable progress. Colorado will depend on the routine timely reporting of monitoring data by the IMPROVE program for the reasonable progress tracking sites. Colorado commits to provide a yearly electronic report to the EPA of representative visibility data from the Colorado sites based on data availability from this network.

As required under 40 CFR 51.308(d)(4)(v) the State of Colorado has prepared a statewide inventory of emissions reasonably expected to cause or contribute to visibility impairment in Federal Class I Areas. Section 5.4 of this Plan summarizes the emissions by pollutant and source category.

The State of Colorado commits to updating statewide emissions on a tri-annual basis as required under the December 17, 2008 Air Emissions Reporting Rule (AERR). The updates will be used for state tracking of emission changes, trends, and input into any regional evaluation of whether reasonable progress goals are being achieved. Should no regional coordinating/planning agency exist in the future, Colorado commits to continue providing required emission updates as specified in the AERR and 40 CFR 51.308(d)(4)(v).

The State will use the Fire Emissions Tracking System (FETS)[3] to store and access fire emissions data. Should this system become unavailable Colorado will work with the FLMs and the EPA to establish a process to track and report fire emissions data if continued use of such information is deemed necessary. The State will also depend upon periodic collective emissions inventory efforts by other states meeting emission reporting requirements of the AERR to provide a regional inventory for future modeling and evaluations of regional haze impacts. Colorado recognizes that other inventories of a nature more sophisticated than available from the AERR may be required for future regional haze or other visibility modeling applications. In the past, such inventories were developed through joint efforts of states with the WRAP, and it is currently beyond available resources to provide an expanded regional haze modeling quality inventory if one is needed for future evaluations. The State will continue to depend on and use the capabilities of the WRAP-sponsored Regional Modeling Center (RMC)[4] or other similar joint modeling efforts to simulate the air quality impacts of emissions for haze planning purposes. The State notes the resources to ensure data preparation, storage, and analysis by the state and regional coordinating agencies such as the WRAP will require adequate ongoing resources. Colorado commits to work with other states, tribes, the FLMs and the EPA to help ensure future multi-state modeling, monitoring or inventory processes can be met but makes no commitment in this SIP to fund such processes. Colorado will track data related to RHR haze plan implementation for sources for which the state has regulatory authority.

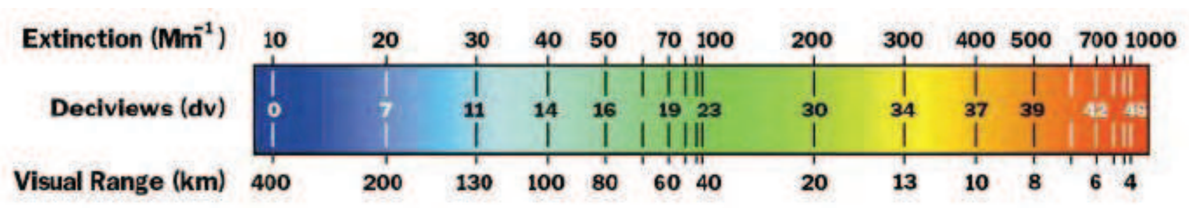
[3] http://www.wrapfets.org/
[4] http://pah.cert.ucr.edu/aqm/308/

Chapter 4 Baseline and Natural Visibility Conditions in Colorado, and Uniform Progress for Each Class I Area

4.1 The Deciview

Each IMPROVE monitor collects particulate concentration data which are converted into reconstructed light extinction through a complex calculation using the IMPROVE equation (see Technical Support Documents for any Class I area). Reconstructed light extinction (denoted as b_{ext}) is expressed in units of inverse megameters (1/Mm or Mm^{-1}). The Regional Haze Rule requires the tracking of visibility conditions in terms of the Haze Index (HI) metric expressed in ***the deciview (dv)*** unit [(40 CFR 51.308(d)(2)]. Generally, a one deciview change in the haze index is likely humanly perceptible under ideal conditions regardless of background visibility conditions.

The relationship between extinction (Mm^{-1}), haze index (dv) and visual range (km) are indicated by the following scale:



4.2 Baseline and Current Visibility Conditions

EPA requires the calculation of baseline conditions [(40 CFR 51.308(d)(2)(i) and (ii)]. The baseline condition for each Colorado Class I area is defined as the five year average (annual values for 2000 - 2004) of IMPROVE monitoring data (expressed in deciviews) for the most-impaired (20% worst) days and the least-impaired (20% best) days. For this first regional haze SIP submittal, the baseline conditions are the reference point against which visibility improvement is tracked. For subsequent RH SIP updates (in the year 2018 and every 10 years thereafter), baseline conditions are used to calculate progress from the beginning of the regional haze program.

Current conditions for the best and worst days are calculated from a multiyear average, based on the most recent 5-years of monitored data available [40 CFR 51.308(f)(1)]. This value will be revised at the time of each periodic SIP revision, and will be used to illustrate: (1) The amount of progress made since the last SIP revision, and (2) the amount of progress made from the baseline period of the program.

Colorado has established baseline visibility for the cleanest and worst visibility days for each Class I area based on, on-site data from the IMPROVE monitoring sites. A five-year average (2000 to 2004) was calculated for each value (both best and worst). The calculations were made in accordance with 40 CFR 51.308(d)(2) and EPA's *Guidance for Tracking Progress Under the Regional Haze Rule* (EPA-454/B-03-004, September 2003). The IMPROVE II algorithm as described in the TSDs has been utilized for the calculation of Uniform Rate of Progress glide slopes for all Class I areas. Figure 4-4 contains the baseline conditions for each IMPROVE monitor site in Colorado.

4.3 Monitoring Data

Visibility-impairing pollutants both reflect and absorb light in the atmosphere, thereby affecting the clarity of objects viewed at a distance by the human eye. Each haze pollutant has a different light extinction capability. In addition, relative humidity changes the effective light extinction of both nitrates and sulfates. Since haze pollutants can be present in varying amounts at different locations throughout the year, aerosol measurements of each visibility-impairing pollutant are made every three days at the IMPROVE monitors located in or near each Class I area.

In addition to extinction, the Regional Haze Rule requires another metric for analyzing visibility impairment, known as the “Haze Index”, which is based on the smallest unit of uniform visibility change that can be perceived by the human eye. The unit of measure is the deciview (denoted dv).

More detailed information on the methodology for reconstructing light extinction along with converting between the haze index and reconstructed light extinction can be found in the Technical Support Documents for any of Colorado’s twelve Class I areas.

The haze pollutants reported by the IMPROVE monitoring program are sulfates, nitrates, organic carbon, elemental carbon, fine soil and coarse mass. Summary data in Figures 4-1 and 4-2 are provided below for the worst and best days from the 6 IMPROVE monitors for the 6 haze pollutants.

Figure 4-1 Reconstructed Aerosol Components for 20% Worst Days (2000-2004)

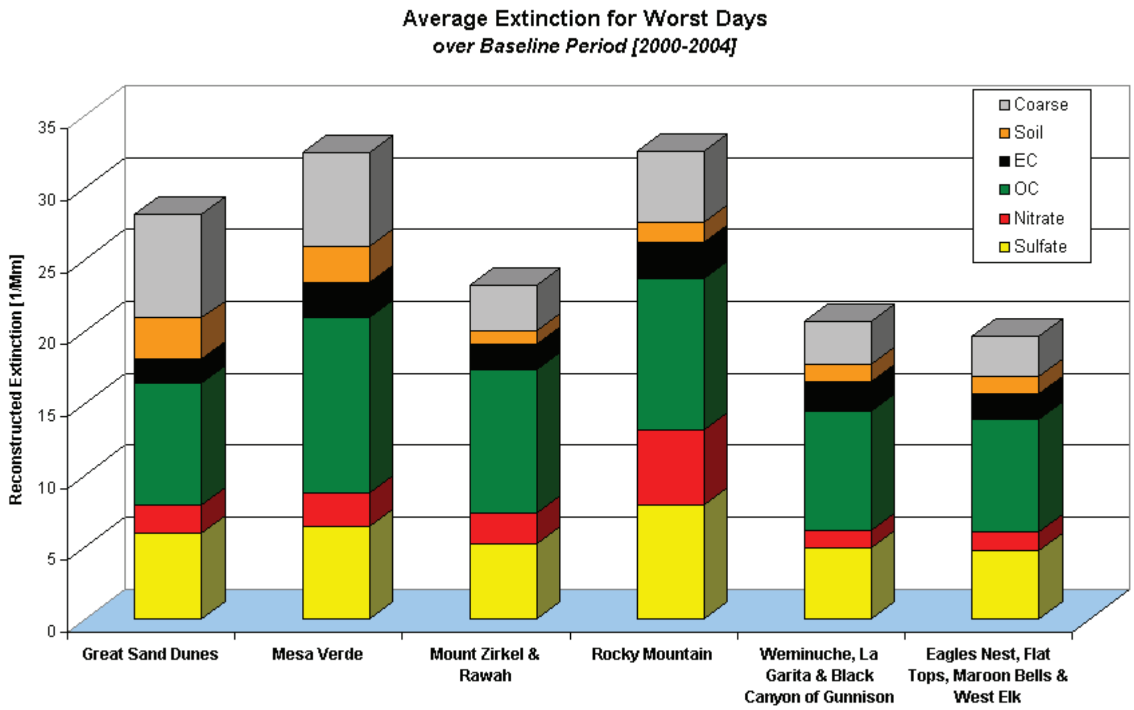
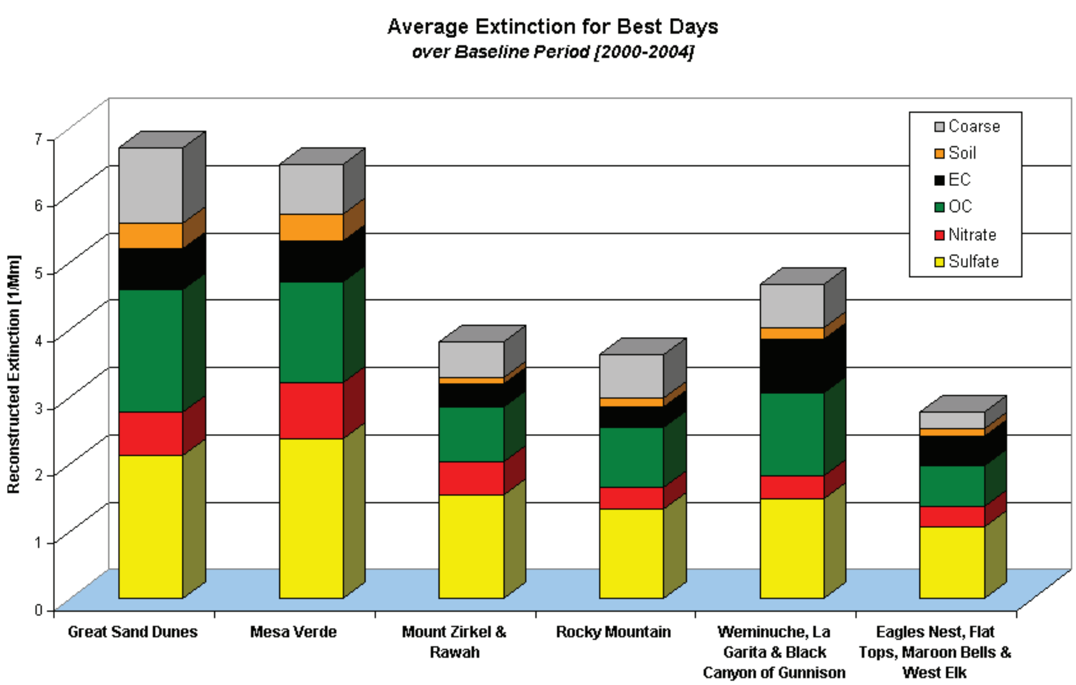


Figure 4-2 Reconstructed Aerosol Components for 20% Best Days (2000-2004)



More detailed information on reconstructed extinction for each Class I area can be found in the Technical Support Document.

4.4 Natural Visibility Conditions

The natural condition for each Class I area represents the visibility goal expressed in deciviews for the most-impaired (20% worst) days and the least-impaired (20% best) days that would exist if there were only naturally occurring impairment. Natural visibility conditions must be calculated by estimating the degree of visibility impairment existing under natural conditions for the most impaired and least impaired days, based on available monitoring information and appropriate data analysis techniques. [(40 CFR 51.308(d)(iii)].

Figure 4-3, lists the 2064 natural conditions goal in deciviews for each Colorado Class I area. The natural conditions estimates were calculated consistent with EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA-454/B-03-005, September 2003). The natural conditions goal can be adjusted as new visibility information becomes available. The Natural Haze Level II Committee methodology was utilized as described in the TSD.

Figure 4-3: 2064 Natural Conditions Goal for Worst Days

Mandatory Class I Federal Areas in Colorado	2064 Natural Conditions for 20% Worst Days [Deciview]
Great Sand Dunes National Park & Preserve	6.66
Mesa Verde National Park	6.81
Mount Zirkel & Rawah Wilderness Areas	6.08
Rocky Mountain National Park	7.15
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	6.21
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	6.06

4.5 Uniform Progress

For the worst days, uniform progress for each Colorado Class I area is the calculation of a uniform rate of progress per year to achieve natural conditions in 60 years [(40 CFR 51.308(d)(1)(i)(B)]. In this initial SIP submittal, the first benchmark is the 2018 deciview level based on the uniform rate of progress applied to the first fourteen years of the program. This is also shown in Figure 4-4 in the column "2018 Uniform Progress Goal (Deciview)".

For the 20% worst days, the uniform rate of progress (URP) in deciviews per year (i.e. slope of the glide path) is determined by the following equation:

URP = [Baseline Condition - Natural Condition] / 60 years

By multiplying the URP by the number of years in the 1st planning period one can calculate the uniform progress needed by 2018 to be on the path to achieving natural visibility conditions by 2064:

2018 UPG = [URP] x [14 years]

The 14 years comprising the 1st planning period includes the 4 years between the end of the baseline period and the SIP submittal date plus the standard 10-year planning period for subsequent SIP revisions.

More detailed information on the worst days along with the calculations and glide slope associated with each CIA can be found in Section 3 of the Technical Support Documents for any of Colorado's twelve Class I areas. This calculation is consistent with EPA's *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Rule* (June 1, 2007).

For the best days at each Class I area, the State must ensure no degradation in visibility for the least-impaired (20% best) days over the same period. More detailed information on the best days, along with the determination of the best day's baseline for a particular CIA, can be found in Section 3 of the Technical Support Document.

Figure 4-4 provides the 2018 uniform rate of progress chart for the worst days and the baseline that must not be exceeded over the years in order to maintain the best days. As with natural conditions, uniform rate of progress can be adjusted as new visibility information becomes available.

Figure 4-4: Uniform Rate of Progress for Each Colorado Class I Area

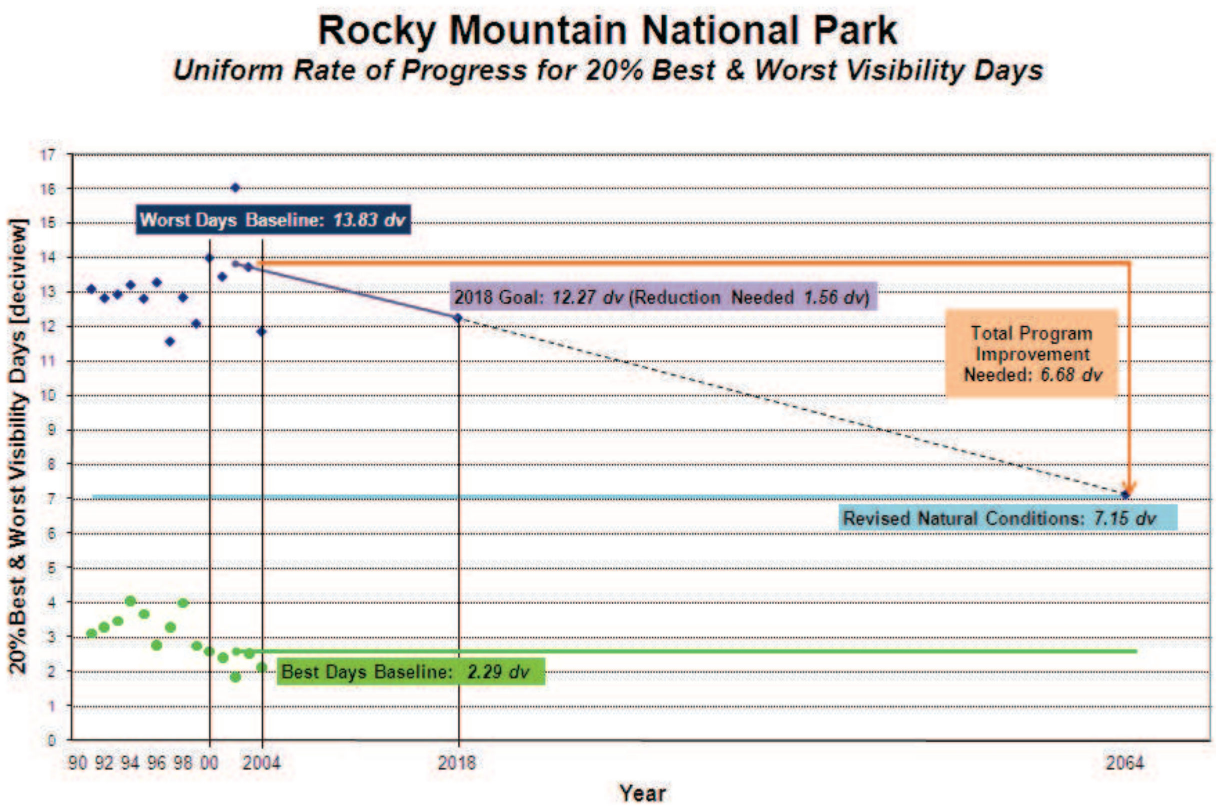
Baseline Summary of Best & Worst Days in Haze Index Metric

Baseline Period (2000-2004)

	20% Worst Days					20% Best Days
Mandatory Class I Federal Area	Baseline Condition [Deciview]	2018 Uniform Progress Goal [Deciview]	2018 Goal Delta [Deciview]	2064 Natural Conditions [deciview]	2064 Delta (Baseline - 2064 NC) [deciview]	Best Days Baseline Condition [Deciview]
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	6.66	6.12	4.50
Mesa Verde National Park	13.03	11.58	1.45	6.81	6.22	4.32
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	6.08	4.44	1.61
Rocky Mountain National Park	13.83	12.27	1.56	7.15	6.68	2.29
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	6.21	4.12	3.11
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	6.06	3.55	0.70

Figure 4-5 provides a visual example of 2018 uniform progress glide slope for the worst days and the best days baseline.

Figure 4-5: Example of Uniform Progress for 20% Best & Worst Days at Rocky Mountain National Park



Chapter 5 Sources of Impairment in Colorado

5.1 Natural Sources of Visibility Impairment

Natural sources of visibility impairment include anything not directly attributed to human-caused emissions of visibility-impairing pollutants. Natural events (e.g. windblown dust, wildfire, volcanic activity, biogenic emissions) also introduce pollutants contributing to haze in the atmosphere. Natural visibility conditions are not constant; they vary with changing natural processes throughout the year. Specific natural events can lead to high short-term concentrations of visibility-impairing particulate matter and its precursors. Natural visibility conditions, for the purpose of Colorado's regional haze program, are represented by a long-term average of conditions expected to occur in the absence of emissions normally attributed to human activities. Natural visibility conditions reflect contemporary vegetated landscape, land-use patterns, and meteorological/climatic conditions. The 2064 goal is the natural visibility conditions for the 20% worst natural conditions days.

Natural sources contribute to visibility impairment but natural emissions cannot be realistically controlled or prevented by Colorado and therefore are beyond the scope of this plan. Current methods of analysis of IMPROVE data do not provide a distinction between natural and anthropogenic emissions. Instead, for the purposes of this SIP, they are estimated as described in Section 4.4.

5.2 Anthropogenic Sources of Visibility Impairment

Anthropogenic or human-caused sources of visibility impairment include anything directly attributable to human-caused activities producing emissions of visibility-impairing pollutants. Some examples include transportation, agriculture activities, mining operations, and fuel combustion. Anthropogenic visibility conditions are not constant and vary with changing human activities throughout the year. Generally anthropogenic emissions include not only those anthropogenic emissions generated or originating within the boundaries of the United States but also international emissions transported into a state. Some examples include emissions from Mexico, Canada, and maritime shipping emissions in the Pacific Ocean.

Although anthropogenic sources contribute to visibility impairment, international emissions cannot be regulated, controlled or prevented by the states and therefore are beyond the scope of this planning document. Any reductions in international emissions would likely fall under the purview of the U.S. EPA administrator.

5.3 Overview of Emission Inventory System -TSS

The Western Regional Air Partnership (WRAP) developed the Technical Support System (TSS) as an Internet access portal to all the data and analysis associated with the development of the technical foundations of Regional Haze plans across the Western US. The TSS provides state, county, and grid cell level emissions information for typical criteria pollutants such as SO2 & NOx and other secondary particulate forming pollutants such as VOC and NH3. Eleven different emission inventories were developed comprising the following source categories: point, area, on-road mobile, off-road mobile, oil and gas, anthropogenic fire, natural fire, biogenic, road dust, fugitive dust and windblown dust. Summaries of the emissions data for sources in Colorado are contained in subsequent Figures 5-1 through 5-8 in this section. In addition the Emissions Inventory TSD in this SIP contains a more detailed accounting of sources in Colorado used in the modeling exercise.

In the WRAP process, member states and the EPA agreed the tremendous amount of data collected, analyzed and maintained by the WRAP and the Regional Modeling Center would be impracticable and nearly infeasible to include in individual TSDs for individual States. For the purposes of administrative efficiency, WRAP data and analysis upon which the member states built their Regional Haze SIPs are available through the WRAP on the TSS Web site. For a more complete description of the emission inventory and process and for access information related to the web site containing comprehensive detail about the inventory please refer to the Emissions Inventory TSD in this SIP.

5.4 Emissions in Colorado

Federal visibility regulations (40 CFR 51.308(d)(4)(v)) require a statewide emission inventory of pollutants reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The pollutants inventoried by the WRAP that Colorado used for this SIP include sulfur dioxide (SO2), nitrogen oxides (NOx), volatile organic compounds (VOC), primary organic aerosol (POA), elemental carbon (EC), fine particulate (Soil-PM2.5), coarse particulate (PM-2.5 to PM-10), and ammonia (NH3). An inventory was developed for the baseline year 2002, and projections of future emissions have been made for 2018. Colorado will provide updates to the EPA on this inventory on a three year basis as required by the AERR. Not all of the categories used for modeling purposes are contained in the AERR. A summary of the inventory results follows; the complete emission inventory is included in Section 5 of the Technical Support Document.

Emission inventories form one leg of the analysis stool to evaluate sources' impacts on visibility. Emission inventories are created for all of critical chemicals or species known to directly or indirectly impact visual air quality. These inventories become inputs to air quality models predicting concentrations of pollutants over a given space and time. For this SIP, the WRAP developed emission inventories for each state with input from participating stakeholders. A complete description of the development and content of the emission inventories can be found on the WRAP Technical Support System web site: http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx and a summary description of the inventory is found in the Emission Inventory TSD.

Dispersion modeling predicts daily atmospheric concentrations of pollutants for the baseline year and these modeled results are compared to monitored data taken from the IMPROVE network. A second inventory is created to predict emissions in 2018 based on expected controls, growth, or other factors. Additional inventories are created for future years to simulate the impact of different control strategies. The process for inventorying sources is similar for all species of interest. The number and types of sources is identified by various methods. For example, major stationary sources report actual annual emission rates to the EPA national emissions database. Colorado collects annual emission data from both major and minor sources and this information is used as input into the emissions inventory. In other cases, such as mobile sources, an EPA mobile source emissions model is used to develop emission projections. Colorado vehicle registration, vehicle mile traveled information and other vehicle data are used to tailor the mobile source data to best represent statewide and area specific emissions. Population, employment and household data are used in other parts of the emissions modeling to characterize emissions from area sources such as home heating. Thus, for each source type, emissions are calculated based on an emission rate and the amount of time the source is operating. Emission rates can be based on actual measurements from the source, or EPA emission factors based on data from tests of similar types of emission sources. In essence all sources go through the same process. The number of sources is identified, emission rates are determined by measurements of those types of sources and the time of operation is determined. By multiplying the emission rate times the hours of operation in a day, a daily emission rate can be calculated.

It is noted that certain source categories are more difficult to make current and future projections for. This is simply because market dynamics, growth factors, improvements in emission factors, types and number of sources, improvements in controls and changes in regulations make the future less predictable. Oil and gas sources in Colorado can be substantial for selected pollutants and significant efforts went into this SIP to improve emissions estimates for Colorado and other western states to help make the modeling as reflective as possible of known and future emissions. Future SIP updates will take into account any new information related to this, and other, source categories.

The following presents the Colorado emissions from the TSS, as provided to the WRAP early 2009. The “Plan 2002(d)” and “PRP 2018(b)” phrases on each of the emission inventory tables signify the version of inventories by year. A detailed explanation of each plan can be found in the Emission Inventory TSD. These inventories do not reflect the additional emission reductions that will result from the 2010 revised Best Available Retrofit Technology and reasonable progress determinations. An accounting of these emission reductions are presented in Chapter 9 of this plan.

Figure 5-1 Colorado SO2 Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide SO2 Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	97,984	44,062	-55%
Area	6,533	7,644	17%
On-Road Mobile	4,389	677	-85%
Off-Road Mobile	3,015	754	-75%
WRAP Area O&G	118	11	-91%
Road Dust	4	6	34%
Fugitive Dust	6	5	-13%
Anthro Fire	108	91	-15%
Natural Fire	3,335	3,335	0%
Biogenic	-	-	-
Total:	**115,492**	**56,585**	**-51%**

Sulfur dioxide emissions produce sulfate particles in the atmosphere. Ammonium sulfate particles have a significantly greater impact on visibility than pollutants like dust from unpaved roads due to the physical characteristics causing greater light scattering from the particles. Sulfur dioxide emissions come primarily from coal combustion at electrical generation facilities but smaller amounts come from natural gas combustion, mobile sources and even wood combustion. Other than natural fire there are no biogenic SO2 emissions of significance in Colorado. Even allowing for those fire-related sulfur dioxide emissions to be counted as 'natural' these represent only 3% of the statewide inventory. A 51% statewide reduction in SO2 emissions is expected by 2018 due to planned controls on existing point sources, even with a growth consideration for electrical generating capacity for the State. Similar reductions in the West are expected from other states as BART or other planned controls take effect by 2018. The only sulfur dioxide category expected to increase is area sources. Area sources of sulfur oxides are linked to population growth as the activity factor. As population increases in Colorado from the base case to 2018, this category is expected to increase. A typical area source for sulfur dioxide would be home heating.

Figure 5-2 Colorado NO_x Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide NOx Emissions		
	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	118,667	101,818	-14%
Area	11,729	16,360	39%
On-Road Mobile	141,883	45,249	-68%
Off-Road Mobile	62,448	37,916	-39%
WRAP Area O&G	23,518	33,517	43%
Road Dust	1	1	32%
Fugitive Dust	16	14	-13%
Anthro Fire	520	408	-21%
Natural Fire	9,377	9,377	0%
Biogenic	37,349	37,349	0%
Total:	**405,507**	**282,010**	**-30%**

Nitrogen oxides (NOx) are generated during any combustion process where nitrogen and oxygen from the atmosphere combine together under high temperature to form nitric oxide, and to a lesser degree nitrogen dioxide. Other odd oxides of nitrogen are also produced to a much smaller degree. Nitrogen oxides react in the atmosphere to form nitrate particles. Larger nitrate particles have a slightly greater impact on visibility than do sulfate particles of the same size and are much more effective at scattering light than mineral dust particles. Nitrogen oxide emissions in Colorado are expected to decline by 2018, primarily due to significant emission reductions from point, mobile and area sources. Off-road and on-road vehicles emissions will decline by more than 80,000 tons per year from the base case emissions total of 204,000 tons per year. Increases in area sources, as with sulfur dioxide, are related to population growth with an expected 4,000 tons per year increase by 2018. Again, home heating would be a typical area source of NOx with growth in emissions related to population increases. Oil and gas development by 2018 is also expected to increase statewide emissions by about 10,000 tons per year.

Figure 5-3 Colorado VOC Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide VOC Emissions		
	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	91,750	77,312	-16%
Area	99,191	136,032	37%
On-Road Mobile	100,860	41,489	-59%
Off-Road Mobile	38,401	24,684	-36%
WRAP Area O&G	27,259	43,639	60%
Road Dust	-	-	-
Fugitive Dust	-	-	-
Anthro Fire	915	666	-27%
Natural Fire	20,404	20,404	0%
Biogenic	804,777	804,777	0%
Total:	**1,183,557**	**1,149,002**	**-3%**

Volatile organic compounds (VOCs) are expected to decline slightly by 2018. Among other sources, volatile organic compounds from automobiles, industrial and commercial facilities, solvent use, and refueling automobiles all contribute to VOC loading in the atmosphere. Substantial natural emissions of VOCs come from vegetation. VOCs can directly impact visibility as emissions condense in the atmosphere to form an aerosol. Of more significance is the role VOCs play in the photochemical production of ozone in the troposphere. Volatile organic compounds react with nitrogen oxides to produce nitrated organic particles that impact visibility in the same series of chemical events that lead to ozone. Thus, strategies to reduce ozone in the atmosphere often lead to visibility improvements. The large increase in area sources is again related to population increases. Use of solvents such as in painting, dry cleaning, charcoal lighter, and windshield washer fluids, and many home use products, show up in the area source category and increases in this area are linked to population growth.

Figure 5-4 Colorado Primary Organic Aerosol (POA) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
	Statewide POA Emissions		
Source Category	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	17	3	-83%
Area	8,432	8,738	4%
On-Road Mobile	1,280	1,288	1%
Off-Road Mobile	1,286	843	-34%
WRAP Area O&G	-	-	-
Road Dust	102	135	33%
Fugitive Dust	777	677	-13%
Anthro Fire	850	621	-27%
Natural Fire	30,581	30,581	0%
Biogenic	-	-	-
Total:	**43,325**	**42,886**	**-1%**

Primary Organic Aerosols (POAs) are organic carbon particles emitted directly from the combustion of organic material. A wide variety of sources contribute to this classification including cooking of meat to diesel emissions and combustion byproducts from wood and agricultural burning. Area sources and automobile emissions dominate this classification. Increases in areas sources are due to population increases. These increases are offset by expected improvements in automobile emissions and by 2018 emissions from this category are expected to decline by about 5%.

Figure 5-5 Colorado Elemental Carbon (EC) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
	Statewide EC Emissions		
Source Category	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	-	-	-
Area	1,264	1,325	5%
On-Road Mobile	1,448	408	-72%
Off-Road Mobile	3,175	1,344	-58%
WRAP Area O&G	-	-	-
Road Dust	9	11	33%
Fugitive Dust	53	46	-13%
Anthro Fire	92	74	-20%
Natural Fire	6,337	6,337	0%
Biogenic	-	-	-
Total:	**12,377**	**9,545**	**-23%**

Elemental carbon is the carbon black, or soot, a byproduct of incomplete combustion. It is the partner to primary organic aerosols and represents the more complete combustion of fuel producing carbon particulate matter as the end product. A carbon particle has a sixteen times greater impact on visibility than a coarse particle of granite has. Emissions, and reductions, in this category are dominated by mobile sources and expected new federal emission standards for mobile sources, especially for diesel engines, along with fleet replacement are the reason for these reductions.

Figure 5-6 Colorado Soil (PM Fine) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide Soil (fine PM) Emissions		
	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	6	85	1404%
Area	4,170	4,311	3%
On-Road Mobile	-	-	-
Off-Road Mobile	-	-	-
WRAP Area O&G	-	-	-
Road Dust	1,082	1,435	33%
Fugitive Dust	13,401	11,679	-13%
Windblown Dust	15,105	15,105	0%
Anthro Fire	253	169	-33%
Natural Fire	1,948	1,948	0%
Biogenic	-	-	-
Total:	**35,964**	**34,732**	**-3%**

Fine soil emissions are largely related to agricultural and mining activities, windblown dust from construction areas and emissions from unpaved and paved roads. A particle of fine dust has a relative impact on visibility one tenth as great as a particle of elemental carbon. Monitoring at all sites in Colorado indicates soil is present as a small but measurable part of the visibility problem. On any given visibility event where poor visual air quality is present in a scene, the impact of dust can vary widely. Overall, on the 20% worst days, fine soil has about the same impact as nitrate particles. Agricultural activities, dust from unpaved roads and construction are prevalent in this source category and changes in emissions are tied to population and vehicle miles traveled. Since soil emissions are not directly from the tailpipe of the vehicle, the category of mobile sources does not show any emissions and all vehicle related emissions from paved and unpaved roads show up in the fugitive dust category.

Figure 5-7 Colorado Coarse Mass (PM Coarse) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide Coarse PM Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	21,096	26,828	27%
Area	1,363	1,388	2%
On-Road Mobile	794	917	15%
Off-Road Mobile	-	-	-
WRAP Area O&G	-	-	-
Road Dust	8,930	11,826	32%
Fugitive Dust	67,642	67,910	0%
Windblown Dust	135,945	135,945	0%
Anthro Fire	51	32	-37%
Natural Fire	5,973	5,973	0%
Biogenic	-	-	-
Total:	**241,794**	**250,818**	**4%**

Particulate matter, also identified as coarse mass particles emissions, are closely related to the same sources as fine soil emissions but other activities like rock crushing and processing, material transfer, open pit mining and unpaved road emissions can be prominent sources. Coarse mass particles travel shorter distances in the atmosphere than some other smaller particles but can remain in the atmosphere sufficiently long enough to play a role in regional haze. Coarse mass particulate matter has the smallest direct impact on regional haze on a particle-by-particle basis where one particle of coarse mass has a relative visibility weight of 0.6 compared to a carbon particle having a weight of 10. Nevertheless, they are commonly present at all monitoring sites and are a greater contributor to regional haze than the fine soil component. Substantial increases in coarse mass are seen in the fugitive dust category. This is due to the fact that construction and emissions from paved and unpaved roads are lined to population, vehicle miles traveled and employment data. Growth in these factors results in these categories increasing from 2002 to 2018. For this planning period, the state evaluated PM from stationary sources, but not from natural sources.

Figure 5-8 Colorado Ammonia (NH3) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide Ammonia Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	453	571	26%
Area	60,771	60,791	0%
On-Road Mobile	4,317	5,894	37%
Off-Road Mobile	43	60	38%
WRAP Area O&G	-	-	-
Road Dust	-	-	-
Fugitive Dust	-	-	-
Anthro Fire	137	95	-31%
Natural Fire	1,965	1,965	0%
Biogenic	-	-	-
Total:	**67,686**	**69,375**	**2%**

Ammonia emissions come from a variety of sources including wastewater treatment facilities, livestock operations, and fertilizer application and to a small extent, mobile sources. Increases in ammonia emission from the base case year to 2018 are linked to population statistics and increased vehicular traffic. Ammonia is directly linked to the production of ammonium nitrate and ammonium sulfate particles in the atmosphere when sulfur dioxide and nitrogen oxides eventually convert over to these forms of particles. Expected growth in the mobile source emissions from 2002 to 2018 is due to the fact that no specific controls on mobile sources are implemented and increases in vehicle miles traveled links directly to increased ammonia emissions.

Chapter 6 Best Available Retrofit Technology

6.1 Introduction

One of the principal elements of Section 169A of the 1977 Clean Air Act Amendments addresses the installation of Best Available Retrofit Technology (BART) for certain existing sources of pollution. The provision, 169A (b)(2), demonstrates Congress' intent to focus attention directly on pollution from a specific group of existing sources. The U.S. Environmental Protection Agency's (EPA) Regional Haze Rule requires certain emission sources that may reasonably be anticipated to cause or contribute to visibility impairment in downwind Class I areas to install BART. *See* 40 CFR §51.308(e); *see also* 64 Fed. Reg. 35714 *et seq.* (July 1, 1999). These requirements are intended to reduce emissions from certain large sources that, due to age, were exempted from other requirements of the Clean Air Act.

BART requirements pertain to 26 specified major point source categories including power plants, cement kilns and industrial boilers. To be considered BART-eligible, sources from these categories must have the potential to emit 250 tons or more of haze forming pollution and must have commenced operation in the 15-year period prior to August 7, 1977.

Because of the regional focus of this requirement in the Regional Haze Rule, BART applies to a larger number of sources than the Phase 1 reasonably attributable visibility impairment requirements. In addition to source-by-source command and control BART implementation, EPA has allowed for more flexible alternatives if they achieve greater progress toward the state's visibility goals than the standard BART approach.

This document demonstrates how Colorado has satisfied the BART requirements in EPA's Regional Haze Rule. Colorado's review process is described and a list of BART-eligible sources is provided. A list of sources that are subject to BART is also provided, along with the requisite modeling analysis approach and justification.

6.2 Overview of Colorado's BART Regulation

Colorado's Air Quality Control Commission approved a State-only BART regulation (Regulation 3 Part F) on March 16, 2006, that became effective in May 2006. A summary of the Colorado BART program and determinations is set out below, in Section 6.3. More detail is provided in Regulation Number 3 Part F, Appendix C to this document, the Technical Support Document (TSD), and at the Division's BART website at: http://www.cdphe.state.co.us/ap/RegionalHazeBART.html.

Colorado's BART Rule includes the following major provisions:

1. Visibility impairing pollutants are defined to include SO2, NOx and particulate matter.
2. Visibility impact levels are established for determining whether a given source causes or contributes to visibility impairment for purposes of the source being

subject-to-BART (or excluded). The causation threshold is 1.0 deciview and the contribution threshold is 0.5 deciview. Individual sources are exempt from BART if the 98th percentile daily change in visibility from the facility, as compared against natural background conditions, is less than 0.5 deciview at all Class I federal areas for each year modeled and for the entire multi-year modeling period.

3. BART controls are established based on a case-by-case analysis taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, the remaining useful life of the source or unit, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. These factors are established in the definition of Best Available Retrofit Technology.
4. Provision that the installation of regional haze BART controls exempts a source from additional BART controls for regional haze, but does not exempt a source from additional controls or emission reductions that may be necessary to make reasonable progress under the regional haze SIP.

6.3 Summary of Colorado's BART Determinations

Colorado's Air Quality Control Commission elected to assume that all BART-eligible sources are subject to BART, but required the Division to perform modeling to determine whether BART-eligible sources will cause or contribute to visibility impairment at any Class I area. The threshold for causing or contributing to impairment was 0.5 or greater deciview impact. BART-eligible sources that did not cause or contribute 0.5 or greater deciview impact would not be subject to BART.

Once the complete list of eligible sources had been assembled, the list was reviewed to determine the current status of each source. A number of sources were eliminated for various reasons. One plant was being shut down. Two others were found not to be subject to BART because the size of the boilers was less than the 250 MMBtu/hour limit identified in the EPA BART Rule. Two sources were not subject to BART because they had been re-constructed after the BART period, and two were exempt because VOCs are not a visibility impairing pollutant under Colorado's BART Rule. The final list of sources was modeled by the Division to determine if they met the "cause or contribute" criteria. The results of this modeling are reflected in Table 6 - 1 below.

Table 6 - 1 Results of Subject-to-BART Modeling

Modeled BART–Eligible Source	Division Modeling (98th percentile delta-deciview value)	Division Approved Refined Modeling from Source Operator (98^{th} percentile delta-deciview value)	Contribution Threshold (deciviews)	Impact Equal to or Greater Than Contribution Threshold?
CEMEX - Lyons Cement Kiln & Dryer	1.533		0.5	Yes
CENC (Trigen-Colorado) Units 4 & 5	1.255		0.5	Yes
Cherokee Station – Unit 4	1.460		0.5	Yes
Comanche Station – Units 1 and 2	0.701		0.5	Yes
Craig Station – Units 1 & 2	2.689		0.5	Yes
Hayden Station – Units 1 & 2	2.538		0.5	Yes
Lamar Light & Power – Unit 6	0.064		0.5	No
Martin Drake Power Plant – Units 5, 6 & 7	1.041		0.5	Yes
Pawnee Station – Unit 1	1.189		0.5	Yes
Ray D. Nixon Power Plant – Unit 1	0.570	0.481	0.5	No
Suncor Denver Refinery	0.239		0.5	No
Valmont Station – Unit 5	1.591		0.5	Yes
Notes:				
1. The contribution threshold has an implied level of precision equal to the level of precision reported from the model.				
2. Source operator modeling results are shown only if modeling has been approved by Division.				
3. Roche is not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment.				
4. Denver Steam is not included because it is exempt by rule (natural gas only <250 MMBtu).				
5. Holcim Cement (Florence) and Rocky Mountain Steel Mills (Pueblo) are not included because of facility reconstruction.				
6. Changes to the Ray D. Nixon Power Plant modeling included refinement of the meteorological fields and emission rates. The Division has issued a permit modification for this facility that includes a 30-day rolling emission limit for SO2.				
7. Suncor Denver Refinery (including the former Valero Refinery) was not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment. Moreover, Suncor has installed controls to comply with MACT standards.				

Of the BART-eligible sources listed above, those sources with a visibility contribution threshold equal to or greater than 0.5 deciview were determined to be subject-to-BART. Tables 6 - 2 and 6 - 3 include the BART determinations that will apply to each source.

Table 6 - 2 BART Determinations for Colorado Sources					
Emission Unit	**Assumed ** NOx Control Type**	**NOx Emission Limit**	**Assumed ** SO_2 Control Type**	**SO_2 Emission Limit**	**Assumed ** Particulate Control and Emission Limit**
Cemex - Lyons Kiln	Selective Non-Catalytic Reduction System	255.3 lbs/hr (30-day rolling average) 901.0 tons/yr (12-month rolling average)	None	25.3 lbs/hr (12-month rolling average) 95.0 tons/yr (12-month rolling average)	Fabric Filter Baghouse * 0.275 lb/ton of dry feed 20% opacity
Cemex - Lyons Dryer	None	13.9 tons/yr	None	36.7 tons/yr	Fabric Filter Baghouse* 22.8 tons/yr 10% opacity
CENC Unit 4	Low NOx Burners with Separated Over-Fire Air	0.37 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
CENC Unit 5	Low NOx Burners with Separated Over-Fire Air, and Selective Non-Catalytic Reduction System	0.19 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
Comanche Unit 1	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu

Table 6 - 2 BART Determinations for Colorado Sources					
Emission Unit	**Assumed ** NOx Control Type**	**NOx Emission Limit**	**Assumed ** SO_2 Control Type**	**SO_2 Emission Limit**	**Assumed ** Particulate Control and Emission Limit**
Comanche Unit 2	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 1	Selective Non-Catalytic Reduction System	0.28 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 2	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 1	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 2	Selective Catalytic Reduction System	0.07 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 5	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Dry Sorbent Injection	0.26 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 6	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 7	Ultra Low-NOx Burners (including Over-Fire Air)	0.29 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu

* Controls are already operating

** Based on the state's BART analysis, the "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

Table 6 - 3 BART Determinations for PSCo's BART Alternative Sources [5, 6, 7]					
Emission Unit	**NOx Control Type**	**NOx Emission Limit**	**SO_2 Control Type**	**SO_2 Emission Limit**	**Particulate Control and Emission Limit**
Cherokee Unit 1	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012
Cherokee Unit 2	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011
Cherokee Unit 3	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016
Cherokee Unit 4	Natural Gas Operation 12/31/2017	0.12 lb/MMBtu (30-day rolling average) by 12/31/2017	Natural Gas Operation 12/31/2017	7.81 tpy (rolling 12 month average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas Operation 12/31/2017
Valmont Unit 5	Shutdown 12/31/2017	0	Shutdown 12/31/2017	0	Shutdown 12/31/2017
Pawnee Unit 1	SCR**	0.07 lb/MMBtu (30-day rolling average) by 12/31/2014	Lime Spray Dryer**	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	Fabric Filter Baghouse* 0.03 lbs/MMBtu
Arapahoe Unit 3	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Arapahoe Unit 4	Natural Gas Operation	600 tpy (rolling 12 month average) 12/31/2014	Natural Gas operation 12/31/2014	1.28 tpy (rolling 12 month average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas operation 12/31/2014

* Controls are already operating

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the above table is not a requirement.

For all BART and BART alternative determinations, approved in the Federal State Implementation Plan, the state affirms that the BART emission limits satisfy Regional Haze requirements for this planning period (through 2017) and that no other Regional

[5] Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.
[6] 500 tpy NOx will be reserved from Cherokee station for netting or offsets.
[7] 300 tpy NOx will be reserved from Arapahoe station for netting or offsets for additional natural gas generation.

Haze analyses or Regional Haze controls will be required by the state during this timeframe.

6.4 Overview of Colorado's BART Determinations

Colorado has been evaluating BART issues for many years and has closely followed EPA's proposals and final rules. The list of Colorado BART-eligible sources has been well known since the 1990's, based on EPA's expected applicability dates of between August 7, 1962 and August 7, 1977. Colorado has been involved in four BART-like proceedings involving known BART sources. Two of these determinations resulted from actions related to the Hayden and Craig power plants. These plants were identified in a certification of impairment made by the U.S. Forest Service regarding visibility impacts at Mt. Zirkel Wilderness Area, located northeast of Steamboat Springs. Colorado conducted two additional BART proceedings for all sources in 2007 and in 2008, which were submitted to EPA for approval. A number of these determinations were revised in 2010 based on adverse comments from EPA; Table 6-2 presents the 2010 BART determinations.

6.4.1 The State's Consideration of BART Factors

In identifying a level of control as BART, States are required by section 169A(g) of the Clean Air Act to "take into consideration" the following factors:

(1) The costs of compliance,
(2) The energy and non-air quality environmental impacts of compliance,
(3) Any existing pollution control technology in use at the source,
(4) The remaining useful life of the source, and
(5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

42 U.S.C. § 7491(g)(2).

Colorado's BART regulation requires that the five statutory factors be considered for all BART sources. *See,* Regulation No. 3, Part E, Section IV.B.1. In making its BART determination for each Colorado source, the state took into consideration the five statutory factors on a case-by case basis, and for significant NOx controls the Division also utilized the guidance criteria set forth in Section 6.4.3 consistent with the five factors. Summaries of the state's facility-specific consideration of the five factors and resulting determinations for each BART source are provided in this Chapter 6. Documentation reflecting the state's analyses and supporting the state's BART determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix C of this document.

6.4.1.1 The costs of compliance. The Division requested, and the companies provided, source-specific cost information for each BART unit. The cost information ranged from the installation and operation of new SO2 and NOx control equipment to upgrade analyses of existing SO2 controls. The cost for each unit is summarized below, and the state's consideration of this factor for each source is presented in detail in Appendix C.

6.4.1.2 The energy and non-air quality environmental impacts of compliance. This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each BART unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO2, as further described below.

6.4.1.3 Any existing pollution control technology in use at the source. The state has taken into consideration the existing PM, SO2 and NOx pollution control equipment in use at each Colorado source, as part of its BART determination process.

The Division has reviewed available particulate controls. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM" s*ee* 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix C.

The Division also reviewed various SO2 controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 6, in Appendix C and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. *See* 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix C.

With respect to NOx controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NOx controls, as appropriate

When determining the emission rates for each source, the state referred to and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that BART relates to retrofitting sources (vs. new or reconstructed facilities), a review of other determinations was used to better substantiate the source specific information provided by the source.

6.4.1.4 The remaining useful life of the source. None of Colorado's BART sources are expected to retire over the next twenty years. Therefore, this factor did not affect any of the state's BART determinations.

6.4.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of BART. The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of BART. Modeling information for each BART determination is presented below and in Appendix C.

6.4.2 SIP Requirements from EPA's Regional Haze Rule

The following section includes information addressing the SIP elements contained in EPA's Regional Haze Rule. The section numbers refer to provisions in 40 CFR § 51.308(e), the BART provision of the Regional Haze Rule.

(i) A list of all BART-eligible sources within the State.

Table 6 - 3 below lists the initial group of Colorado sources subject to BART. This initial list was created based on historical information contained in the Division's source files and is based on the 1962-1977 time frame and source category list contained in Appendix Y. This list was then examined to see if any of the sources identified would be exempt from BART. EPA allows sources to be exempt from BART if they have undergone permitted reconstruction, emit *de minimis* levels of pollution, or are fossil-fuel boilers with an individual heat input rating below 250 million Btu/hour. Colorado's BART rule allows sources to be exempt from BART if modeling demonstrates the impact at any Class I area is below the "cause or contribute" thresholds of 1.0 and 0.5 deciviews. Table 6 - 3 lists the current status of the original BART sources and notes which sources were exempted and why.

Table 6 - 4 Colorado's BART Eligible Sources

Plant Name	Source Owner	Rating, Heat Input or Source type	Start Year	Current Status
Cemex - Lyons Kiln	Cemex	Portland Cement	<1977	Subject-to-BART
Cemex - Lyons Dryer	Cemex	Portland Cement	<1977	Subject-to-BART
CENC Unit 4	Colorado Energy Nations Company (CENC)	360 MMBtu/hr	1975	Subject-to-BART
CENC Unit 5	CENC	650 MMBtu/hr	1979	Subject-to-BART
Cherokee Unit 4	Public Service Company of Colorado (PSCO)	350 MW	1968	Subject-to-BART
Comanche Unit 1	PSCO	350 MW	1973	Subject-to-BART
Comanche Unit 2	PSCO	350 MW	1976	Subject-to-BART
Craig Unit 1	Tri-State Generation and	446 MW	1979	Subject-to-BART

Table 6 - 4 Colorado's BART Eligible Sources				
Plant Name	**Source Owner**	**Rating, Heat Input or Source type**	**Start Year**	**Current Status**
	Transmission, Inc.			
Craig Unit 2	Tri-State	446 MW	1979	Subject-to-BART
Hayden Unit 1	PSCO	190 MW	1965	Subject-to-BART
Hayden Unit 2	PSCO	275 MW	1976	Subject-to-BART
Martin Drake Unit 5	Colorado Springs Utilities (CSU)	55 MW	1962	Subject-to-BART
Martin Drake Unit 6	CSU	85 MW	1968	Subject-to-BART
Martin Drake Unit 7	CSU	145 MW	1974	Subject-to-BART
Pawnee Unit 1	PSCO	500 MW	1981	BART Alternative
Valmont Unit 5	PSCO	188 MW	1964	Subject-to-BART
Denver Steam Unit 1	PSCO	Steam only 210 MMBtu/hr	1972	Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110
Denver Steam Unit 2	PSCO	Steam only 243 MMBtu/hr	1974	Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110
Holcim Kiln	Holcim	Portland Cement	<1977	Not subject-to-BART since Kiln built after BART time period. Other sources < 250 TPY total emissions.
Lamar Utilities	City of Lamar	25 MW	1972	Plant will be shutdown; so will no longer be subject.
Oregon Steel	Oregon Steel	Steel Mfg.	<1977	Not subject-to-BART since Arc furnace rebuilt after BART time period. Other sources < 250 TPY total emissions.
Ray Nixon Unit 1	CSU	227 MW	1980	Not Subject-to-BART (enforceable emission limitations and refined CALPUFF modeling result in less than 0.5 dv visibility impact)
Roche	Roche	Pharmaceutic al Mfg.	<1977	Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO
Suncor/Valero	Suncor	Refinery	<1977	Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO

(ii) *A determination of BART for each BART-eligible source.*

Table 6 - 2 lists the state's BART determinations for sources that cause or contribute to visibility impairment in Class I areas.

(iii) *The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

Summaries of the state's facility-specific consideration of the five factors and resulting determinations are provided in this chapter 6. Documentation reflecting the state's analyses and supporting the state's BART determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix C of this document.

(iv) *The determination of BART for fossil-fuel fired power plants having a total generating capacity greater than 750 megawatts must be made pursuant to the guidelines in Appendix Y of this part (Guidelines for BART Determinations Under the Regional Haze Rule).*

Colorado has only one source with two BART eligible EGUs that have a combined rating exceeding 750 MW, which is Tri-State Generation and Transmission Association's Craig plant located in Moffat County. The Division's BART determination for the Craig facility is discussed in more detail below.

(v) *A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.*

This requirement is addressed in Colorado's BART Rule, and Regulation No. 3 Part F Section VI.

(vi) *A requirement that each source subject-to-BART maintain the control equipment required by this subpart and establish procedures to ensure such equipment is properly operated and maintained.*

Operation and maintenance plans are required by the BART Rule, and Regulation No. 3. Part F Section VII.

6.4.3 Overview of the BART Determinations and the Five Factor Analyses for Each BART Source

This section presents an overview of the BART determinations for the subject to BART sources.

The Regional Haze rule requires states to make determinations about what is appropriate for BART, considering the five statutory factors:

(1) The costs of compliance,
(2) The energy and non-air quality environmental impacts of compliance,
(3) Any existing pollution control technology in use at the source,
(4) The remaining useful life of the source, and

(5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

The rule gives the states broad latitude on how the five factors are to be considered to determine the appropriate controls for BART. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the five factors in reaching a determination.[8] The manner and method of consideration is left to the state's discretion; states are free to determine the weight and significance to be assigned to each factor.[9]

For the purposes of the five factor review for the three pollutants that the state is assessing for BART, SO2 and PM have been assessed utilizing the five factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO2 and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NOx controls on BART electric generating units, for reasons described below, the state is employing guidance criteria to aid in its assessment and determination of BART using the five factors for these sources, largely because significant NOx add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of BART for these sources.

With respect to SO2 emissions, there are currently ten lime spray dryer (LSD) SO2 control systems operating at electric generating units in Colorado.[10] There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO2 emissions in the state and other non-air quality considerations. Each of these systems will meet EPA's presumptive limits, and in some cases surpass those limits.[11] The

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[8] The EPA "BART Guidelines" provide information relating to implementation of the Regional Haze rule, which the state has considered. However, Colorado also notes that Appendix Y is expressly not mandatory with respect to EGUs of less than 750 MWs in size, and Craig Station (Tri-State Generation and Transmission) is the only such BART electric generating unit in the state. *See* 70 Fed. Reg. at 39108. Thus, the state has substantial discretion in how it considers and applies the five factors (and any other factors that it deems relevant) to BART electric generating units in the state that are below this megawatt threshold, and for non-EGU sources. *See, e.g., id.* at 39108, 39131 and 39158.

[9] *See, e.g.*, 70 Fed. Reg. at 39170.

[10] EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, Valmont Unit 5.

[11] In preparing Appendix Y, EPA conducted extensive research and analysis of emission controls on BART sources nationwide, including all BART EGU sources in Colorado. *See* 70 Fed. Reg. at 39134. Based upon this analysis, EPA established presumptive limits that it deems to be appropriate for large EGU sources of greater than 750 MW, including sources greater than 200 MW located at such plants. EPA's position is that the presumptive limits are cost effective and will lead to a significant degree of visibility improvement. *Id. See also,* 69 Fed. Reg. 25184, 25202 (May 5, 2004); *Technical Support Document for BART NOx Limits for Electric Generating Units* and *Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet*, Memorandum to Docket OAR 2002-0076, April 15, 2006; *Technical Support Document for BART SO2 Limits for Electric Generating Units*,

Division has determined in the past that these systems can be cost-effective for Colorado's BART sources, and the Air Quality Control Commission approved LSD systems as BART for Colorado Springs Utilities' Martin Drake Units #6 and #7 in 2008. With this familiarity and use of the emissions control technology, the state has assessed SO2 emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources, typically exceeding a control efficiency of 95%. The emission limits for these units reflect the 95% or greater control efficiency and are therefore stringent and appropriate. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado, and the Air Quality Control Commission approved these systems as BART in 2007. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM emissions was not necessary for Colorado's BART-subject units.

With respect to NOx emissions, post-combustion controls for NOx are generally not employed in Colorado at BART or other significant coal-fired electric generating units. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NOx emissions.

In assessing and determining appropriate NOx BART controls for individual units for visibility improvement under the regional haze rule, the state has considered the five statutory factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight.[12] In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors. More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (*e.g.*, expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NOx) from the atmosphere, or $/ton of NOx removed); and, (ii) visibility improvement

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Memorandum to Docket OAR 2002-0076, April 1, 2006; and *Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations*, U.S. EPA, June 2005.

[12] *See* 70 Fed. Reg. at 39170 and 39137.

expected from the control options analyzed (*e.g.*, expressed as visibility improvement in delta deciview (Δdv) from CALPUFF air quality modeling).

- Accordingly, as part of its five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state's general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of BART on a case by case basis.

The cost criteria presented above is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls. For example, the $5,000/ton criterion is consistent with Colorado's retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.[13] In that case, a $5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.[14] The $5,000/ton criterion is also consistent and within the range of the state's implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control costs for Colorado RACT can be in the range of $5,000/ton (and lower), while control costs for Colorado BACT can be in the range of $5,000/ton (and higher).

In addition, as it considers the pertinent factors for regional haze, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NOx controls, *i.e.*, SCR, has the ability to provide significant NOx reductions, but also has initial capital dollar requirements that can

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[13] Air Quality Control Commission Regulation No. 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

[14] The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

approach or exceed $100 million per unit.[15] The lesser-performing post-combustion NOx controls, *e.g*., SNCR, reduce less NOx on a percentage basis, but also have substantially lower initial capital requirements, generally less than $10 million.[16] The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NOx controls (*i.e*., SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.[17] For the lesser-performing add-on NOx controls (*e.g*., SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area.

Employing the foregoing guidance criteria for post-combustion NOx controls, as part of considering the five factors under the Regional Haze rule, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

6.4.3.1 BART Determination for Cemex's Lyons Cement Plant

The Cemex facility manufactures Portland cement and is located in Lyons, Colorado, approximately 20 miles from Rocky Mountain National Park. The Lyons plant was originally constructed with a long dry kiln. This plant supplies approximately 25% of the clinker used in the regional cement market. There are two BART eligible units at the facility: the dryer and the kiln.

In 1980, the kiln was cut to one-half its original length, and a flash vessel was added with a single-stage preheater. The permitted kiln feed rate is 120 tons per hour of raw material (kiln feed), and on average yields approximately 62 tons of clinker per hour. The kiln is the main source of SO2 and NOx emissions. The raw material dryer emits minor amounts of SO2 and NOx; in 2008 Cemex reported SO2 and NOx emissions from the dryer as 0.89 and 10.41 tons per year respectively based on stack test results. Due to the low emission rates from the dryer the BART review focuses on the kiln.

Newer multistage preheater/precalciner kilns are designed to be more energy efficient and yield lower emissions per ton of clinker due to this when compared to the Cemex

[15] *See, e.g.,* Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, $83MM; Public Service of Colorado, Hayden Unit #2, $72MM; Tri-State Generation and Transmission, Craig Station Unit #1, $210MM.

[16] *See, e.g*., Appendix C, reflecting CENC (Tri-gen), Unit #4, $1.4MM; Public Service Company of Colorado, Hayden Unit #2, $4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, $13.1MM

[17] The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. The state relied upon this threshold when determining which Colorado's BART eligible sources became subject to BART. *See*, Air Quality Control Commission Regulation No. 3, Section III.B.1.b. Thus, a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

Lyons kiln. The newer Portland cement plants studied by EPA, utilize multistage preheater/precalciner designs that are not directly comparable. Cemex has a unique single stage preheater/precalciner system with different emission profiles and energy demands. New Portland cement plants have further developed the preheater/precalciner design with multiple stages to reduce emissions and energy requirements for the process. Additionally, new plant designs allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing NOx to elemental Nitrogen.

Cemex submitted a BART analysis to the Division on August 1, 2006, with revisions submitted on August 28, 2006; January 15, 2007; October 2007 and August 29, 2008. In response to a Division request, Cemex submitted additional information on July 27 and 28, 2010

CALPUFF modeling provided by the source, using a maximum SO2 emission rate of 123.4 lbs/hour for both the dryer and kiln combined indicates a 98th percentile visibility impact of 0.78 delta deciview (Δdv) at Rocky Mountain National Park. The modeled 98th percentile visibility impact from the kiln is 0.76 Δdv. Thus, the visibility impact of the dryer alone is the resultant difference which is 0.02 Δdv. Because the dryer uses the cleanest fossil fuel available and post combustion controls on such extremely low concentrations are not practical, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable controls on the dryer. Accordingly, the state has determined that no additional emission control analysis of the dryer is necessary or appropriate since the total elimination of the emissions would not result in any meaningful visibility improvement which is a fundamental factor in the BART evaluation. For the dryer, the BART SO2 emission limitation is 36.7 tpy and the BART NOx emission limitation is 13.9 tpy, which are listed in the existing Cemex Title V permit.

SO2 BART Determination for Cemex Lyons - Kiln

Lime addition to kiln feed, fuel substitution (coal with tire derived fuel), dry sorbent injection (DSI), and wet lime scrubbing (WLS) were determined to be technically feasible for reducing SO2 emissions from Portland cement kilns.

The following table lists the most feasible and effective options:

Cemex Lyons -Kiln				
SO2 Control Technology	Estimated Control Efficiency	Annual Controlled Hourly SO2 Emissions (lbs/hr)	Annual Controlled SO2 Emissions (tpy)	Annual Controlled SO2 Emissions (lb/ton of Clinker)
Baseline SO2 Emissions		25.3	95.0	0.40
Lime Addition to Kiln Feed	25%	18.9	71.3	0.30
Fuel Substitution (coal with TDF)	40%	15.2	57.0	0.24

Cemex Lyons -Kiln				
SO2 Control Technology	Estimated Control Efficiency	Annual Controlled Hourly SO2 Emissions (lbs/hr)	Annual Controlled SO2 Emissions (tpy)	Annual Controlled SO2 Emissions (lb/ton of Clinker)
Dry Sorbent Injection	50%	12.6	47.5	0.20
Wet Lime Scrubbing (Tailpipe scrubber)	90%	2.5	9.5	0.04

The energy and non-air quality impacts of the alternatives are as follows:

- Lime addition to kiln feed and dry sorbent injection - there are no energy or non-air quality impacts associated with these control options
- Wet lime scrubbing - significant water usage, an additional fan of considerable horsepower to move the flue gas through the scrubber, potential increase in PM emissions and sulfuric acid mist
- Tire-derived fuel – the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. *See,* Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.

There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period. Cemex's limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the SO2 emission reduction, annualized costs and the control cost effectiveness for the feasible controls:

Cemex Lyons - Kiln				
SO2 Control Technology	SO2 Emission Reduction (tons/yr)	Annualized Cost ($/yr)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline SO2 Emissions	-			
Lime Addition to Kiln Feed	23.8	$3,640,178	$153,271	
Fuel Substitution (coal supplemented with TDF)	38.0	$172,179	$4,531	$243,368
Dry Sorbent Injection	47.5	Not provided	-	
Wet Lime Scrubbing (Tailpipe scrubber)	85.5	$2,529,018	$29,579	$49,618

The following table lists the projected visibility improvements for SO2 controls:

Cemex Lyons - Kiln		
SO2 Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (Δdv)
Maximum (24-hr max)	0.760	
Baseline (95 tpy)*	0.731	-
Lime Addition to Kiln Feed (71.3 tpy)*	0.727	0.033
Fuel Substitution (57 tpy)*	0.725	0.034
Dry Sorbent Injection (47.5 tpy)*	0.725	0.036
Wet Lime Scrubbing (9.5 tpy)*	0.720	0.040

** Visibility impacts rescaled from original BART modeling*

For the kiln, based upon its consideration and weighing of the five factors, the state has determined that no additional SO2 emissions control is warranted as the added expense of these controls were determined to not be reasonable for the small incremental visibility improvement of less than 0.04 deciviews. However, the use of low sulfur coal and the inherent control resulting from the Portland cement process provides sufficient basis to establish annual BART SO2 emission limits for the kiln of:

25.3 lbs/hour and

95.0 tons of SO2 per year

No additional controls are warranted because 80% of the sulfur is captured in the clinker, making the inherent control of the process the SO2 control. Additional SO2 scrubbing is also provided by the limestone coating in the baghouse as the exhaust gas passes through the baghouse filter surface.

SO2 BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the SO2 BART requirement is 36.7 tpy, which is taken from the existing Title V permit.

Particulate Matter BART Determination for Cemex Lyons - Kiln and Dryer

The state has determined that the existing fabric filter baghouses and the existing regulatory emissions limits of 0.275 lb/ton of dry feed and 20% opacity for the kiln and 10% opacity for the dryer represent the most stringent control option. The kiln and dryer baghouses exceed a PM control efficiency of 95%, and the emission limits are BART for PM/PM_{10}. The state assumes that the BART emission limits can be achieved through the operation of the existing fabric filter baghouse.

NOx BART Determination for Cemex Lyons - Kiln

Water injection, firing coal supplemented with tire-derived fuel (TDF), indirect firing with low NOx burners, and selective non-catalytic reduction (SNCR) were determined to be technically feasible and appropriate for reducing NOx emissions from Portland cement kilns. As further discussed in Appendix C, the state has determined that SCR is not commercially available for Portland cement kilns. Presently, SCR has not been applied to a cement plant of any type in the United States. Cemex notes that the major SCR vendors have indicated that SCR is not commercially available for cement kilns at this time. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe, constitutes "available" control technology for purposes of BART. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is "available" for purposes of retrofitting such control technology on an existing source. Accordingly, the state has eliminated SCR as an available control technology for purposes of BART. Moreover, as further discussed in Appendix C, if SCR were considered commercially available, it is not technically feasible for the Lyons facility due to the unique design of the kiln.

The following table lists the most feasible and effective options:

Cemex Lyons - Kiln				
NOx Control Technology	Estimated Control Efficiency	Annual Controlled Hourly NOx Emissions (lbs/hr)	Annual Controlled NOx Emissions (tpy)	Annual Controlled NOx Emissions (lb/ton of Clinker)
Baseline NOx Emissions	-	464.3	1,747.1	7.39
Water Injection	7.0%	431.8	1,624.8	6.87
Coal w/TDF	10.0%	417.8	1,572.3	6.65
Indirect Firing with LNB	20.0%	371.4	1,397.6	5.91
SNCR (30-day rolling)	45.0%	255.3	960.9	4.06
SNCR (12-month rolling)	48.4%	239.4	901.0	3.81
SNCR w/LNB	55%	208.9	786.2	3.33

The energy and non-air quality impacts of the alternatives are as follows:

- Low-NOx burners - there are no energy or non-air quality impacts
- Water injection - significant water usage
- Tire-derived fuel – the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. *See,* Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.
- SNCR - none

There are no remaining useful life issues for the alternatives as the state has presumed that the source will remain in service for the 20-year amortization period. Cemex's limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

Cemex Lyons - Kiln				
NOx Control Technology	NOx Emission Reduction	Annualized Cost	Cost Effectiveness	Incremental Cost Effectiveness
	(tons/yr)	($/yr)	($/ton)	($/ton)
Baseline NOx Emissions	-			
Water Injection	122.3	$43,598	$356	-
Coal w/TDF	174.7	$172,179	$986	$2,453
Indirect Firing with LNB	349.4	$710,750	$2,034	$3,083
SNCR (45.0% control)	786.2	$1,636,636	$2,082	$2,120
SNCR (48.4% control)	846.1	$1,636,636	$1,934	$1,864
SNCR w/LNB (55.0% control w/uncertainty)	960.9	$1,686,395	$1,755	$434

The following table lists the projected visibility improvements for NOx controls for the kiln:

Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (from 24-hr Max) (Δdv)
24-hr Maximum (≈ 656.9 lbs/hr))	0.760	
Revised Baseline (≈ 464.3 lbs/hr)*	0.572	0.188
Original Baseline (≈ 446.8 lbs/hr)*	0.555	0.205
Water Injection (≈ 431.8 lbs/hr)*	0.540	0.220
Firing TDF (≈417.9 lbs/hr)*	0.526	0.234
Indirect Firing with LNB (≈ 371.4 lbs/hr)*	0.481	0.279
Original BART Limit – SNCR (≈ 268.0 lbs/hr)	0.380	0.380
Proposed BART Limit (30-day) – SNCR (≈ 255.3 lbs/hr)**	0.368	0.392
Proposed BART Limit (annual) – SNCR (≈ 239.0 lbs/hr)**	0.352	0.408
SNCR w/LNB (≈208.9 lbs/hr)**	0.322	0.438

The Cemex – Lyons facility is a unique kiln system most accurately described as a modified long dry kiln, the characteristics of a modified long dry kiln system are not similar to either a long wet kiln or a multi stage preheater/precalciner kiln. The temperature profile in a long dry kiln system (>1500°F) is significantly higher at the exit than a more typical preheater precalciner kiln (650°F). This is a significant distinction that limits the location and residence time available for an effective NOx control system. The combination of SNCR with LNB has an uncertain level of control due to unique nature of the Lyons kiln. Furthermore, the associated incremental reduction in NOx emissions associated with SNCR in combination with LNB would afford only a minimal or negligible visibility improvement (less than 0.03 delta deciview). Therefore, the Division believes that SNCR is the best NOx control system available for this kiln.

For the kiln, because of the unique characteristics of the Cemex facility, the state has determined that the BART emission limits for NOx are:

255.3 pounds per hour (30-day rolling average) and

901.0 tons per year (12-month rolling average)

The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This BART determination affords the most NOx reduction from the kiln (846.1 tpy) and contributes significant visibility improvement (0.38 Δdv). The determination affirms a prior Air Quality Control Commission BART determination for SNCR for this facility (2008). The state assumes that the BART emission limits can be achieved through the installation and operation of SNCR.

NOx BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the NOx BART requirement is 13.9 tpy, which is taken from the existing Title V permit.

A complete analysis that further supports the BART determination for the Cemex Lyons facility can be found in Appendix C.

6.4.3.2 BART Determination for Colorado Energy Nations Company (CENC)

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. Initial air dispersion modeling performed by the Division demonstrated that the CENC facility contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Trigen (now CENC) submitted a BART Analysis to the Division on July 31, 2006. CENC also provided information in its "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado" Submittal provided on November 16, 2009, as well as additional information upon the Division's request on February 8, 2010, and May 7, 2010.

The CENC facility includes two coal-fired boilers that supply steam and electrical power to Coors Brewery. The boilers are rated as follows: Unit 4 at 360 MMBtu/hr and Unit 5 at 650 MMBtu/hr. These are approximately equivalent to 35 and 65 MW power plant boilers, based on the design heat rates.

SO2 BART Determination for CENC - Boilers 4 and 5

Dry sorbent injection (DSI) and SO_2 emission management were determined to be technically feasible for reducing SO2 emissions from Boilers 4 and 5. These options were considered as potentially BART by the Division. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible. SO2 emissions management uses a variety of options to reduce SO2 emissions: dispatch natural gas-fired capacity, reduce total system load, and/or recue coal firing rate to maintain a new peak SO2 limit.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

CENC Boiler 4 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SO_2 Emissions Management	1.0	$44,299	$43,690
DSI – Trona	468.0	$1,766,000	$3,774

CENC Boiler 5 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SO_2 Emissions Management	0.8	$65,882	$78,095
DSI – Trona	844.0	$2,094,000	$2,482

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, and fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to DSI are as follows:

SO2 Control Method	CENC - Boiler 4		CENC - Boiler 5	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.90		0.98	
DSI – Trona (annual avg.)	0.26	0.08	0.29	0.13

SO2 emissions management was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement that would result from one tpy or less of SO2 reduction.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

CENC Boiler 4: 1.0 lb/MMBtu (30-day rolling average)

CENC Boiler 5: 1.0 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved without additional control technology. Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement afforded.

Particulate Matter BART Determination for CENC - Boilers 4 and 5

The Division has determined that for Boilers 4 and 5, an emission limit of 0.07 lb/MMBtu (PM/PM10) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM_{10}. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for CENC - Boilers 4 and 5

Low NOx burners (LNB), LNB plus separated overfire air (SOFA), selective non-catalytic reduction (SNCR), SNCR plus LNB plus SOFA, and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at CENC Boilers 4 and 5.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

CENC Boiler 4 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	0	$0
LNB	59.9	$193,433	$3,227
SNCR	179.8	$694,046	$3,860
LNB+SOFA	209.8	$678,305	$3,234
LNB+SOFA + SNCR	368.0	$1,372,351	$3,729
SCR	515.4	$4,201,038	$8,150

CENC Boiler 5 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
LNB	48.4	$249,858	$5,166
LNB+SOFA	127.3	$815,829	$6,383
SNCR	207.3	$923,996	$4,458
LNB+SOFA + SNCR	353.7	$1,739,825	$4,918
SCR	550.0	$6,469,610	$11,764

The energy and non-air quality impacts of the alternatives are as follows:

- LNB – not significant
- LNB + SOFA – may increase unburned carbon in the ash, commonly referred to as loss on ignition
- SNCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	CENC - Boiler 4		CENC - Boiler 5	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx I Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.67		0.66	
LNB (annual avg.)	0.45	0.05	0.30	0.17
SNCR (annual avg.)	0.35	0.07	0.24	0.21
LNB + SOFA (annual avg.)	0.32	0.08	0.24	0.21
LNB + SOFA + SNCR (annual avg.)	0.19	0.12	0.17	0.26
SCR	0.07	0.18	0.07	0.31

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 4 is the following NOx emission rates:

CENC Boiler 4: 0.37 lb/MMBtu (30-day rolling average)

Or

0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air.
Although the other alternatives achieve better emissions reductions, achieving lower limits through different controls was determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.04 dv for SNCR and 0.10 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Unit 4.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 5 is the following NOx emission rates:

CENC Boiler 5:	0.19 lb/MMBtu (30-day rolling average)
	Or
	0.26 lb/MMBtu Boiler 4 and 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air and selective non-catalytic reduction.

For the emission limits above, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria discussed above in section 6.4.3.

- Boiler 5: $4,918 per ton NOx removed; 0.26 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Though SCR achieves better emissions reductions, achieving lower limits through SCR was determined to not fall into the guidance cost and visibility improvement criteria discussed in section 6.4.3.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.05 dv). Thus, it is not warranted to select emission limits associated SCR for CENC Unit 5.

A complete analysis that supports the BART determination for the CENC facility can be found in Appendix C.

6.4.3.3 BART Determination for Public Service Company Comanche Units 1 and 2

Comanche Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. PSCo submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8,

2007. In response to a Division request, PSCo submitted additional information on May 25, and July 14, 2010.

SO2 BART Determination for Comanche - Units 1 and 2

Semi-Dry FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades should be considered for Comanche Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Comanche's dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Comanche, the use of performance additives on the scrubbers would not be expected to increase the SO_2 removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes SO_2 removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO_2. Since NO_2 is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO_2 removal rates, such as those experienced at Comanche. There are no known acceptable reagents without this side effect that would allow additional SO_2 removal in the dry scrubbing systems present at the Comanche Station.
- *Increase the pulverization level of sorbent* – PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system* - The supplier offers no upgrade in atomizer design to improve SO_2 removal at Comanche. PSCo asserts and the state agrees that a third scrubber module on Comanche Units 1 and 2 is not feasible due to the current layout of the ductwork and space constraints around the scrubbers.
- *Additional equipment and maintenance* - Comanche Units 1 and 2 are already achieving 30-day average emission rates of 0.12 lbs/MMBtu, 30-day rolling average, and 0.10 lbs/MMBtu, 12-month average for the two units combined, as adopted in 2007 by the Commission. It is not technically feasible to install an extra scrubber module at the site; therefore no additional equipment or maintenance will decrease SO2 emissions or achieve a lower limit.

Consequently, further capital upgrades to the current high performing SO2 removal system were deemed technically infeasible, and a lower emissions limit is not achievable.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Comanche – Unit 1		Comanche – Unit 2	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.75		0.74	
Semi-Dry FGD (LSD) (annual avg.)	0.12	0.35	0.12	0.33
Semi-Dry FGD (LSD) (annual avg.)	0.08	0.37	0.08	0.36

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that the following existing SO2 emission rates are BART:

Comanche Unit 1: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). A 30-day rolling SO2 limit of 0.12 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology. A complete analysis that supports the BART determination for the Comanche facility can be found in Appendix C.

Particulate Matter BART Determination for Comanche - Units 1 and 2

Based on recent BACT determinations, the state has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent level of available control for $PM/PM_{10.}$ The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM_{10} as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for Comanche - Units 1 and 2

SNCR and SCR were determined to be technically feasible for reducing NOx emissions at Comanche Unit 1, and only SCR was determined feasible at Unit 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Comanche Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	445.6	$1,624,100	$3,644
SCR	770.4	$12,265,014	$15,290

Comanche Unit 2 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SCR	1,480	$14,650,885	$9,900

The energy and non-air quality impacts of the alternatives are as follows:

- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Comanche – Unit 1		Comanche – Unit 2	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (1-yr) using new LNBs	0.20		0.20	
SNCR (annual avg.)	0.10	0.11	Not Feasible	–
SCR (annual avg.)	0.07	0.14	0.07	0.17

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following existing NOx emission rates:

Comanche Unit 1: 0.20 lb/MMBtu (30-day rolling average)
0.15 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.20 lb/MMBtu (30-day rolling average)
0.15 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing low NOx burners. Although the other alternatives achieve better emissions reductions, the added expense of achieving lower limits through different controls were determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement (under 0.2 delta deciview) afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the State's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.10 dv for SNCR and 0.13 dv for SCR for Unit 1, and 0.17 dv for SCR for Unit 2). SNCR was found not to be technically feasible for Comanche Unit 2. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Comanche Units 1 and 2.

A complete analysis that supports the BART determination for PSCo's Comanche Units 1 and 2 can be found in Appendix C.

6.4.3.4 BART Determination for Tri-State Generation and Transmission Association's Craig Facility

Craig Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 BART Determination for Craig - Units 1 and 2

Wet FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following wet scrubber upgrades were considered for Craig Units 1 and 2, if technically feasible.

- *Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations in 2003-2004.
- *Installation of liquid distribution rings:* TriState determined that installation of perforated trays, described below, accomplished the same objective.
- *Installation of perforated trays:* Upgrades during 2003-2004 included installation of a perforated plate tray in each scrubber module.
- *Use of organic acid additives:* Organic acid additives were considered but not selected for the following reasons:
  1. Dibasic Acid (DBA) has not been tested at the very low inlet SO_2 concentrations seen at Craig Units 1 and 2.
  2. DBA could cause changes in sulfite oxidation with impacts on SO_2 removal and solids settling and dewatering characteristics.

3. Installation of the perforated plate tray accomplished the same objective of increased SO_2 removal.

- *Improve or upgrade scrubber auxiliary equipment:* 2003-2004 upgrades included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:

1. Two vertical ball mills were installed for additional limestone processing capability for increased SO_2 removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high SO_2 removal rates.
2. Forced oxidation within the SO_2 removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
3. A ventilation system was installed for each reaction tank.
4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased SO_2 removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
7. Instrumentation and controls were modified to support all of the new equipment.

- *Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during 2003-2004. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, there are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 through the five-factor analysis and determined that a more stringent 30-day rolling SO_2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology based on current emissions and operations. The tighter emission limits are achievable without additional capital investment. An SO2 limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Craig – Unit 1		Craig – Unit 2	
	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.17		0.16	
Wet FGD	0.11	0.03	0.11	0.03
Wet FGD	0.07	0.05	0.07	0.05

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 1: 0.11 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The 30-day rolling SO2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

Particulate Matter BART Determination for Craig - Units 1 and 2

The Division has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for $PM/PM_{10.}$ The state assumes that the BART emission limit can be achieved through the operation of the existing pulse jet fabric filter baghouses.

NOx BART Determination for Craig - Units 1 and 2

Potential modifications to the ULNBs, neural network systems, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$3,797,000	$4,877
SCR	3,855	$25,036,709	$6,445

Craig Unit 2 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	806	$3,797,000	$4,712
SCR	3,975	$25,036,709	$6,299

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, and hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Craig – Unit 1		Craig – Unit 2	
	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.35		0.35	
SNCR	0.24	0.31	0.23	0.31
SCR	0.07	1.01	0.07	0.98

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART Alternative determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1: 0.27 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.27 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of SNCR. For the BART emission limits at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented above.

- Unit 1: $4,877 per ton NOx removed; 0.31 deciview of improvement
- Unit 2: $4,712 per ton NOx removed; 0.31 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements, leads the state to this determination. To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Although emission limits associated with SCR achieve better emissions reductions, the cost-effectiveness of SCR for this BART determination was determined to be excessive and above the cost guidance criteria presented above. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs.

Per Section 308(e)(2) of EPA's Regional Haze Rule, as an alternative to BART (or "BART alternative") it was proposed and the state agreed to a more stringent NOx emissions control plan for these BART units that consists of emission limits assumed to be associated with the operation of SNCR for Unit 1 and the operation of SCR for Unit 2. These NOx emission rates are as follows:

Craig Unit 1: 0.28 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.08 lb/MMBtu (30-day rolling average)

Unit 1's 0.28 lb/MMBtu NOx emission rate equates to a 14% control and a NOx reduction of 727 tons per year, which is slightly less than the 15% control and a NOx reduction of 779 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.

Unit 2's 0.08 lb/MMBtu NOx emission rate equates to a 74% control and a NOx reduction of 3,975 tons per year, which is much greater than the 15% control and a NOx reduction of 806 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.

The total NOx emission reduction resulting from the BART determination is 1,585 tons per year (779 + 806 = 1,585 tons per year). The total NOx emission reduction resulting from the BART Alternative is 4,702 tons per year (727 + 3,975 = 4,702 tons per year). Given the far greater emission reduction achieved by the BART Alternative when compared to the BART determinations for the individual units, the state determines, in accordance with the federal Regional Haze regulations, that the BART Alternative emission rates are appropriate for Craig Units 1 and 2 as providing greater reasonable progress than the application of BART as set forth in the federal BART Alternative regulation.

The state also evaluated the NOx emission reduction associated with both units (Craig 1 & 2) in contrast to the existing NOx rates, presumptive BART NOx rate, source-by-source determination, and the final RH determination to determine the total NOx reduction benefit. In the below table, the existing NOx emissions from both units is 10,562 tons/year which is much lower than the existing presumptive BART emissions of 14,849 tons/year. The source-by-source BART determination resulted in NOx emissions of 8,978 tons/year which is well above the 5,860 tons/year in NOx emissions calculated to result from application of the BART Alternative. These tons/year calculations provide an emissions based comparison to demonstrate that the Craig BART Alternative provides greater reasonable progress than, and is superior to, source by source BART for these units. The table below is illustrative for demonstration purposes only. The tons per year projections provide an emission based comparison and are not enforceable requirements.

NOx Analysis	Units	Craig 1	Craig 2	Total
Annual Average Heat Input*	*[MMBtu]*	36,933,572	39,214,982	
Annual Average NOx Rate*	*[lb/MMBtu]*	0.28	0.27	
Annual Average NOx Emissions*	*[tons/year]*	5,190.3	5,371.6	10,562
Presumptive NOx Rate	*[lb/MMBtu]*	0.39	0.39	
Presumptive NOx Emissions	*[tons/year]*	7,202.1	7,646.9	14,849
Source-by-Source Determination	*[lb/MMBtu]*	0.27	0.27	
Source-by-Source Determination	*[tons/year]*	4,411.8	4,565.9	8,978
Final Regional Haze Determination	*[lb/MMBtu]*	0.28	0.08	
Final Regional Haze Determination	*[tons/year]*	4,463.7	1,396.6	5,860

** Data from CAMD used for period (2006-2007)*

Based on the above analysis and demonstration, the BART Alternative (final RH determination) achieves more NOx emissions reductions, which are well below the source-by-source BART determinations for each unit. Consequently, the BART Alternative will result in more visibility improvement at nearby Class I areas, and the state adopts this BART Alternative as appropriate to comply with the Regional Haze rule for these units. The state notes that this BART Alternative is not a trading program per Section 308(e)(2) and provisions associated with trading are not applicable.

Under EPA's Alternative to BART rule (40 CFR § 51.308(e)(2)), a state must show that the alternative measure or alternative program achieves greater reasonable progress than would be achieved through the installation and operation of BART. The demonstration addresses these requirements, as follows. (A complete description of these federal requirements is presented in section 6.4.3.7 below.)

1) *51.308(e)(2)(i)(A)* A listing of all BART-eligible sources can be found in Table 6-3 above.
2) *51.308(e)(2)(i)(B)* The two BART-eligible sources are Craig Units 1 and 2.
3) *51.308(e)(2)(i)(C)* The BART determinations presented herein describe the control information and the projected total NOx reduction of 1,585 tons per year for source-by-source BART.
4) *51.308(e)(2)(i)(D)* The BART Alternative achieves a projected NOx reduction of 4,702 tons per year.
5) *51.308(e)(2)(i)(E)* The BART Alternative achieves more than 3,100 tons of projected NOx reduction per year over what would be achieved by the installation of BART.
6) *51.308(e)(2)(iii)* The Craig BART Alternative will be implemented as expeditiously as practicable but no later than five years after EPA's approval of this BART Alternative, as required by Regulation No. 3 Part F. The regulation requires that a compliance schedule be developed by the source and submitted to the state within six months from EPA's approval. The compliance and

monitoring provisions of the BART Alternative have also been incorporated into Regulation No. 3, Part F.

7) *51.308(e)(2)(iv)* The emission reductions associated with the Craig BART Alternative have not been used for other SIP purposes, thus they are surplus.

8) *51.308(e)(2)(v)* The state is not proposing a geographic enhancement for reasonably attributable impairment.

9) *51.308(e)(2)(vi)* Since Colorado is not using a trading program for the Craig BART Alternative, this section does not apply.

10) *51.308(e)(3)* There are only two units at the same facility under the Craig BART Alternative and thus there is no change in the distribution of emissions than under BART, and, as stated above, the alternative measure results in greater emission reductions than case-by-case BART. Therefore the Craig BART Alternative is deemed to achieve greater reasonable progress.

11) *51.308(e)(3)(i)* Since the Craig BART Alternative includes only two units at the same facility, the state has determined that visibility does not decline in any Class I area due to the Craig BART Alternative when compared to case-by-case BART.

12) *51.308(e)(3)(ii)* Because the Craig BART Alternative has been demonstrated to achieve more emission reductions than would occur through case-by-case BART, the state determines that there will be an overall improvement in visibility over all affected Class I areas.

13) *51.308(e)(4)* Colorado is not participating in the CAIR program and cannot rely on this program for the Craig BART Alternative.

14) The state acknowledges that the core requirements will otherwise apply as set forth in the Regional Haze Rule.

15) *51.308(e)(6)* No Colorado BART sources have applied for an exemption from BART.

A complete analysis that supports the BART determination and BART Alternative for Craig Station Units 1 and 2, including substantial cost information for NOx controls, can be found in Appendix C.

6.4.3.5 BART Determination for Public Service Company's Hayden Station

Hayden Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. Public Service Company (PSCo) submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8, 2007. In response to a Division request, PSCo submitted additional information on May 25, 2010.

SO2 BART Determination for Hayden - Units 1 and 2

Semi-Dry FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades were considered for Hayden Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Hayden's dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Hayden, the use of performance additives on the scrubbers would not be expected to increase the SO_2 removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes SO_2 removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO_2. Since NO_2 is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO_2 removal rates, such as those experienced at Hayden. This side effect is unacceptable in a region with numerous Class I areas in close proximity to the source. There are no known acceptable reagents without this side effect that would allow additional SO_2 removal in the dry scrubbing systems present at Hayden Station.
- *Increase the pulverization level of sorbent* – PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system -* The supplier offers no upgrade in atomizer design to improve SO_2 removal at Hayden. However, an additional scrubber module could be added along with spare parts and maintenance personnel in order to meet a lower emission limit. This option is technically feasible.
- *Additional equipment and maintenance* - Hayden Units 1 and 2 can achieve a lower 30-day average emission rate limit than the 2008 State-adopted BART emission limit of 0.16 lbs/MMBtu by purchasing additional spare atomizer parts and increasing annual operating and maintenance through increased labor and reagent requirements. This emissions limit is 0.13 lbs/MMBtu, which is the current rolling 90-day limit.

The additional scrubber module, and additional spare atomizer parts with additional operation and maintenance were determined to be technically feasible for reducing SO2 emissions from Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Hayden Unit 1 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Semi-Dry FGD Upgrade – Additional Equipment and Maintenance	61	$141,150	$2,317
Additional Scrubber Module	488	$4,142,538	$8,490

Hayden Unit 2 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Semi-Dry FGD Upgrade – Additional Equipment and Maintenance	39	$141,150	$3,626
Additional Scrubber Module	589	$4,808,896	$8,164

The additional scrubber module option was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement (less than 0.1 deciview) that would result from this upgrade.

There are no energy and non-air quality impact associated with the remaining semi-dry FGD upgrade alternative (additional equipment and maintenance).

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Hayden – Unit 1		Hayden – Unit 2	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.34		0.40	
Existing Semi-Dry FGD (LSD) (annual avg.)	0.16	0.09	0.16	0.18
Semi-Dry FGD Upgrade (annual avg.)	0.13	0.10	0.13	0.21
Additional Scrubber Module (annual avg.)	0.07	0.14	0.07	0.26

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Hayden Unit 1: 0.13 lb/MMBtu (30-day rolling average)

Hayden Unit 2: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The state evaluated the option of tightening the emission limit for Hayden Units 1 and 2 and determined that a more stringent 30-day rolling SO2 limit of 0.13 lbs/MMBtu represents an appropriate level of emissions control for semi-dry FGD control technology. The tighter emission rate for both units is achievable with a negligible investment and the facility operator has offered to undertake these actions to allow for refinement of the emissions rate appropriate for this technology at this source despite the lack of appreciable modeled visibility improvement, and the state accepts this.

Particulate Matter BART Determination for Hayden - Units 1 and 2

Based on recent BACT determinations, the state has determined that the existing Unit 1 and Unit 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent level of available control for PM/PM_{10}. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM_{10} as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for Hayden - Units 1 and 2

LNB upgrades, SNCR and SCR were determined to be technically feasible for reducing NOx emissions at Hayden Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Hayden Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
LNB	1,391	$572,010	$411
SNCR	1,391	$1,353,500	$973
SCR	3,120	$10,560,612	$3,385

Hayden Unit 2 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
LNB	1,303	$992,729	$762
SNCR	1,610	$1,893,258	$1,176
SCR	3,032	$12,321,491	$4,064

The energy and non-air quality impacts of the alternatives are as follows:

- LNB – not significant

- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Hayden – Unit 1		Hayden – Unit 2	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.61		0.37	
LNB (annual avg.)	0.26	0.69	0.21	0.40
SNCR (annual avg.)	0.26	0.69	0.18	0.48
SCR (annual avg.)	0.07	1.12	0.06	0.85

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Hayden Unit 1: 0.08 lb/MMBtu (30-day rolling average)

Hayden Unit 2: 0.07 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of selective catalytic reduction (SCR). For these emission limits, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented above.

- Unit 1: $3,385 per ton NOx removed; 1.12 deciview of improvement
- Unit 2: $4,064 per ton NOx removed; 0.85 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements leads the state to this determination. The NOx emission limits of 0.08 lb/MMBtu (30-day rolling average) for Unit 1; and 0.07 lb/MMBtu (30-day rolling average) for Unit 2; are technically feasible and have been determined to be BART for Hayden Units 1 and 2.

A complete analysis that supports the BART determination for PSCo's Hayden Units 1 and 2 can be found in Appendix C.

6.4.3.6 BART Determination for Colorado Springs Utilities' Martin Drake Plant

Colorado Springs Utilities' Boilers 5, 6, and 7 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. The combined emissions of these boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, all three boilers are subject-to-BART. Initial air dispersion modeling performed by the Division demonstrated that the Martin Drake Plant contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Colorado Springs Utilities (CSU) submitted a BART Analysis to the Division on August 1, 2006 with updated cost information submitted on March 29, 2007. CSU also provided information in its "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 as well as additional information upon the Division's request on February 21, 2010, March 21, 2010, May 10, 2010, May 28, 2010, June 2, 2010, and June 15, 2010.

SO2 BART Determination for Martin Drake - Units 5, 6 and 7

Dry sorbent injection (DSI) was determined to be feasible for all units and dry FGD were determined to be technically feasible for reducing SO2 emissions from Units 6, and 7. These options were considered as potential BART level controls by the Division. Lime or limestone-based wet FGD system is also technically feasible but was determined to be not reasonable due to adverse non-air quality impacts. Drake is conducting a trial on a new wet FGD system design (NeuStream-S) that uses much less water along with a smaller operational footprint that may provide, if successfully demonstrated, a reasonable alternative to traditional wet FGD systems.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Drake Unit 5 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI	762	$1,340,663	$1,760

Drake Unit 6 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI	1,671	$2,910,287	$1,741
Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average)	2,284	$6,186,854	$2,709
Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average)	2,368	$6,647,835	$2,808
Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average)	2,507	$7,452,788	$2,973

Drake Unit 7 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI	2,657	$3,723,826	$1,405
Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average)	3,632	$8,216,863	$2,263
Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average)	3,764	$8,829,321	$2,345
Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average)	3,986	$9,898,382	$2,483

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only
- Dry FGD – less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Drake – Unit 5		Drake – Unit 6		Drake – Unit 7	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.94		1.00		0.99	
DSI (annual avg.)	0.25	0.12	0.33	0.18	0.33	0.29
Dry FGD (LSD) (annual avg.)	Not feasible		0.12	0.24	0.12	0.39
Dry FGD (LSD) (annual avg.)	Not feasible		0.07	0.26	0.07	0.41

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART for Unit 5 is the following SO2 emission rate:

Drake Unit 5: 0.26 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limit can be achieved through the installation and operation of dry sorbent injection. Other alternatives are not feasible.

- Unit 5: $1,760 per ton SO2 removed; 0.12 deciview of improvement

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART for Unit 6 and Unit 7 is the following SO2 emission rates:

Drake Unit 6: 0.13 lb/MMBtu (30-day rolling average)

Drake Unit 7: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of lime spray dryers (LSD). A lower emissions rate for Units 6 and 7 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.02 delta deciview for both units respectively).

These emission rates for Units 6 and 7 provide 85% SO2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 6: $2,808 per ton SO2 removed; 0.24 deciview of improvement
- Unit 7: $2,345 per ton SO2 removed; 0.39 deciview of improvement

Particulate Matter BART Determination for Martin Drake - Units 5, 6 and 7

The state determines that the existing regulatory emissions limit of 0.03 lb/MMBtu (PM/PM10) for the three units represent the most stringent control options. The units are exceeding a PM control efficiency of 95%, and the emission limits are BART for $PM/PM_{10.}$ The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for Martin Drake - Units 5, 6 and 7

Ultra low NOx burners (ULNB), ULNB including OFA, SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Drake Units 5, 6 and 7.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Drake Unit 5 - NO_x Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Overfire air (OFA)	154	$141,844	$923
Ultra-low NOx burners (ULNBs)	200	$147,000	$736
ULNBs + OFA	215	$288,844	$1,342
Selective Non-Catalytic Reduction (SNCR)	231	$1,011,324	$4,387
ULNB/SCR layered approach	626	$4,467,000	$7,133
Selective Catalytic Reduction (SCR)	626	$4,580,000	$7,314

Drake Unit 6 - NOx Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Overfire air (OFA)	283	$104,951	$371
Selective Non-Catalytic Reduction (SNCR)	424	$1,208,302	$2,851
Ultra-low NOx burners (ULNBs)	452	$232,800	$515
ULNBs + OFA	509	$337,751	$664
ULNB/SCR layered approach	1,175	$6,182,800	$5,260
Selective Catalytic Reduction (SCR)	1,175	$6,340,000	$5,395

Drake Unit 7 - NOx Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Overfire air (OFA)	416	$75,217	$181
Ultra-low NOx burners (ULNBs)	583	$386,000	$662
Selective Non-Catalytic Reduction (SNCR)	624	$2,018,575	$3,233
ULNBs + OFA	749	$461,217	$616
ULNB/SCR layered approach	1,709	$8,196,000	$4,797
Selective Catalytic Reduction (SCR)	1,709	$8,510,000	$4,981

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB – not significant
- ULNB – not significant
- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Drake – Unit 5		Drake – Unit 6		Drake – Unit 7	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.62		0.83		0.71	
OFA (annual avg.)	0.30	0.07	0.33	0.18	0.31	0.22
ULNB (annual avg.)	0.28	0.08	0.28	0.193	0.28	0.24
ULNB + OFA (annual avg.)	0.27	0.08	0.27	0.20	0.25	0.26
SNCR (annual avg.)	0.27	0.08	0.29	0.19	0.28	0.24
ULNB + SCR	0.07	0.12	0.07	0.27	0.07	0.37
SCR (annual avg.)	0.07	0.12	0.07	0.27	0.07	0.37

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOX BART for Units 5, 6 and 7 is the following NOx emission rates:

Drake Units 5 and 6: 0.31 lb/MMBtu (30-day rolling average)

Drake Unit 7: 0.29 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of ultra low-NOx burners (including over-fire air).

- Unit 5: $1,342 per ton NOx removed
- Unit 6: $664 per ton NOx removed
- Unit 7: $616 per ton NOx removed

The extremely low dollars per ton control costs leads the state to selecting this emission rate for each of the Drake units. SNCR is not selected as that technology provides an equivalent emissions rate, similar level of NOx reduction coupled with equivalent visibility improvement at a much higher cost per ton of pollutant removed along with potential energy and non-air quality impacts. SCR is not selected as the cost/effectiveness ratios for Units 5 and 6 are too high and the visibility improvement at all units do not meet the criteria guidance described above (*e.g.* less than 0.50 Δdv)

For Drake Units 5 and 6, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.04 dv for SCR on Unit 5 and 0.07 dv for SCR on Unit 6). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Units 5 and 6.

For Drake Unit 7, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.11 dv for SCR). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Unit 7.

A complete analysis that supports the BART determination for CSU's Martin Drake Units 5, 6 and 7 can be found in Appendix C.

6.4.3.7 BART Determination for Public Service Company's Cherokee Unit 4, Valmont Unit 5 and the Pawnee Station as a BART Alternative, which Includes Reasonable Progress Determinations for Arapahoe Units 3 and 4 and Cherokee Units 1, 2 and 3

<u>Background</u>
Section 308(e)(2) of EPA's Regional Haze Rule allows a state to approve a BART alternative:

> *A State may opt to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. Such an emissions trading program or other alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. For all such emission trading programs or other alternative measures, the State must submit an implementation plan containing the following plan elements and include documentation for all required analyses: (i) A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the State and covered by the alternative program. This demonstration must be based on the following: (A) A list of all BART-eligible sources within the State. (B) A list of all BART-eligible sources and all BART source categories covered by the alternative program. The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program, but each BART-eligible source in the State must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with section 302(c) or paragraph (e)(1) of this section, or otherwise addressed under paragraphs (e)(1) or (e)(4) of this section.*

The PSCo BART Alternative Program (““PSCo BART Alternative”) was proposed by Public Service Company of Colorado (PSCo). The PSCo BART Alternative is not a trading program and does not include any complete source categories, although all facilities in the PSCo BART Alternative are electric generating units. The PSCo BART Alternative is based on reductions achieved as a result of a combination of unit shutdowns and the application of emissions controls planned as part of the Colorado HB 10-1365, the “Clean Air – Clean Jobs Act” (§ 40-3.2-201 C.R.S., *et. seq*.). The PSCo BART Alternative includes ten units at four facilities. The facilities included in the PSCo Alternative and the proposed controls are listed below.

Table 6-5: Actions and Dates under the PSCo Alternative

Facility	Unit	Action or Control	Effective Date
Arapahoe	Unit 3	Shutdown	12/31/2013
	Unit 4	Operation on Natural Gas only (peaking unit)	12/31/2014
Cherokee	Unit 1	Shutdown	No later than 7/1/2012
	Unit 2	Shutdown	12/31/2011
	Unit 3	Shutdown	No later than 12/31/2016
	Unit 4	Operation on Natural Gas only	12/31/2017
Valmont		Shutdown	12/31/2017
Pawnee		SCR & LSD	12/31/2014

The state in evaluating the PSCo Alternative followed the EPA July 6, 2005, BART guidelines and the EPA October 13, 2006, regulation referred to as Provisions Governing Alternative to Source-Specific BART Determinations (71Fed.Reg. 60612-60634 (10/13/2006); 40 CFR § 51.308(e)(2), “Alternative to BART rule”). Under the Alternative to BART rule, a state must show that the alternative measure or alternative program achieves greater reasonable progress than would be achieved through the installation and operation of BART. The demonstration must include five elements:

1) A list of all BART-eligible sources within the state;
2) A list of all BART-eligible sources and source categories covered by the alternative program;
3) An analysis of the best system of continuous emission control technology available and the associated reductions;
4) An analysis of the projected emissions reductions achievable through the alternative measure; and
5) A determination that the alternative measure achieves greater reasonable progress than would be achieved through the installation of BART.

The PSCo Alternative includes both BART and non-BART sources. The non-BART sources are older than the BART timeframe, and in effect will all be controlled and reduce their NOx and SO2 emissions as a result of enforceable facility retirement dates and, for one unit, operating only on natural gas as a “peaking” unit. The BART sources, Cherokee 4, Pawnee and Valmont, will all be either controlled within the first planning period or shutdown with enforceable facility retirement dates.

The state's alternative program satisfies the requirements of 40 CFR § 51.308, as further described in the preambles to the BART guidelines and the Alternative to BART rule. The state's analysis must include:

> *An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.*

40 CFR § 51.308(e)(2)(i)(C).

Colorado's alternative program was designed to meet a requirement other than BART; namely, Colorado's HB 10-1365. The express purpose of the legislation leading to the alternative program being proposed is:

> THE GENERAL ASSEMBLY HEREBY FINDS, DETERMINES, AND DECLARES THAT THE FEDERAL "CLEAN AIR ACT", 42 U.S.C. SEC. 7401 ET SEQ., WILL LIKELY REQUIRE REDUCTIONS IN EMISSIONS FROM COAL-FIRED POWER PLANTS OPERATED BY RATE-REGULATED UTILITIES IN COLORADO. A COORDINATED PLAN OF EMISSION REDUCTIONS FROM THESE COAL-FIRED POWER PLANTS WILL ENABLE COLORADO RATE-REGULATED UTILITIES TO MEET THE REQUIREMENTS OF THE FEDERAL ACT AND PROTECT PUBLIC HEALTH AND THE ENVIRONMENT AT A LOWER COST THAN A PIECEMEAL APPROACH. A COORDINATED PLAN OF REDUCTION OF EMISSIONS FOR COLORADO'S RATE-REGULATED UTILITIES WILL ALSO RESULT IN REDUCTIONS IN MANY AIR POLLUTANTS AND PROMOTE THE USE OF NATURAL GAS AND OTHER LOW-EMITTING RESOURCES TO MEET COLORADO'S ELECTRICITY NEEDS, WHICH WILL IN TURN PROMOTE DEVELOPMENT OF COLORADO'S ECONOMY AND INDUSTRY.

§ 40-3.2-202, C.R.S. Similarly, Colorado's Clean Air – Clean Jobs Act further specifies that it is intended to address both current and reasonably foreseeable future requirements of the federal Clean Air Act. *See,* § 40-3.2-204, C.R.S.

PSCo BART Alternative measure for the subject coal-fired electric generating units is thus designed to meet the requirements of the regional haze rule, including BART, but also to address requirements beyond BART. This includes, for example, a revised national standard for ozone to be promulgated in 2011, other revised or to be revised national ambient air quality standards, or federal sector-specific regulations for hazardous air pollutants, among other federal regulatory requirements. Accordingly, the state will determine whether the PSCo BART Alternative represents the best system of continuous emission control technology and associated emission reductions for the sources included in the alternative. In the preamble to the Alternative to BART rule, EPA discusses whether the option exists for states to use simplifying assumptions in determining the BART benchmark, or whether states must establish the BART benchmark through a source-by-source BART analysis. EPA states:

> [T]here is no need to develop a precise estimate of the emissions reductions that could be achieved by BART in order simply to compare two programs. As EPA did in the CAIR, States should have the ability to develop a BART benchmark based on simplifying assumptions as to what the most-stringent BART is likely to achieve. The regulations finalized today therefore provide that where an emission trading program has been designed to meet a requirement other than BART, including the reasonable progress requirement, the State may establish a BART benchmark based on an analysis that includes simplifying assumptions about BART control levels for sources within a source category.

71 Fed. Reg. 60612, 60618 (October 13, 2006). EPA has thus determined that source-by source BART is not required when it is not necessary where a state has determined that greater reasonable progress can be achieved by an alternative means. *See also,* 70 Fed. Reg. 39104, 39137 (July 6, 2005). Thus, there is no need for states to conduct an extensive source-by-source BART assessment, and to then also go through the additional, resource intensive steps of developing an alternative program to BART. *See,* 71 Fed. Reg. at 60617.

Colorado has looked at several options to establish the BART benchmark. EPA establishes some criteria for the BART benchmark in the Alternative to BART rule, where the agency discusses simplifying assumptions.

> In today's final rule, the regulations make clear that, with one exception, States must follow the approach for making BART determinations under section 51.308(e)(1) in establishing a BART benchmark. This includes the requirement for States to use the BART guidelines in making BART determinations for EGUs at power plants of a certain size. As discussed above, the one exception to this general approach is where the alternative program has been designed to meet requirements other than BART; in this case, States are not required to make BART determinations under § 51.308(e)(1) and may use simplifying assumptions in establishing a BART benchmark based on an analysis of what BART is likely to be for similar types of sources within a source category. Under either approach to establishing a BART benchmark, we believe that the presumptions for EGUs in the BART guidelines should be used for comparison to a trading program or other alternative measure, unless the State determines that such presumptions are not appropriate for particular EGUs.

71 Fed. Reg. at 60619 (October 13, 2006). *See also, id*. at 60615 ("Where a trading program or other similar alternative program has been designed primarily to meet a Federal or State requirement other than BART, the State can use a more simplified approach to demonstrating that the alternative program will make greater reasonable progress than BART. Such an approach may be appropriate where the State believes the alternative program is clearly superior to BART and a detailed BART analysis is not

necessary to assure that the alternative program will result in greater reasonable progress than BART.”).

The PSCo BART Alternative includes only EGUs and, based on EPA’s Alternative to BART rule, one option available is a comparison to the presumptive limits in the BART guidelines. *Id*. The presumptive limits represent a reasonable estimate of stringent case BART, particularly when developing a BART benchmark to assess an alternative program, because they are applied equally to EGU’s of varying size and distance from Class I areas, and with varying impacts on visibility. *Id.* Because not all of the sources in the PSCo BART Alternative are BART sources, the state also considered other benchmarks that might be appropriate. For example, as part of the BART and reasonable progress analysis, the state has established guidelines for NOx based on control technology costs and visibility improvements. The state’s analysis substantiates that the PSCo BART Alternative provides greater reasonable progress than would have been achieved without the alternative.

Analysis Under 40 CFR Part 51, § 308(e)

(2)(i)(A) A list of all Bart-eligible sources within the State.

A listing of all BART-eligible sources can be found in Table 6-3 in this Chapter 6 of the Regional Haze State Implementation Plan.

(2)(i)(B) A list of all BART-eligible sources and all BART source categories covered by the alternative program.

The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program. However, each BART-eligible source in the State covered by the PSCo BART Alternative in this case must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with section 302(c) or section 308(e)(1), or otherwise be addressed under section 308(e)(1) or (e)(4). The BART sources covered by the PSCo BART Alternative are shown in Table 6-6.

Table 6-6: Sources Included Within the PSCo Alternative

Facility	Unit	Action or Control
Arapahoe	Unit 3	Shutdown
	Unit 4	Operation on natural gas only
Cherokee	Unit 1	Shutdown
	Unit 2	Shutdown
	Unit 3	Shutdown
	Unit 4 (BART-eligible)	Operation on natural gas only
	New nat. gas-fired EGU	BACT where netting does not apply
Valmont	(BART-eligible)	Shutdown
Pawnee	(BART-eligible)	SCR & LSD

(2)(i)(C) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.

The PSCo BART Alternative includes the emission reductions achieved through Colorado HB 10-1365 (§ 40-3.2-201 C.R.S., *et seq*.). The PSCo BART Alternative was developed to address requirements other than BART, including to support the attainment of federal ambient air quality standards, to meet other federal requirements that can affect electric generating units, and improve air quality on the Front Range of Colorado. Since the PSCo BART Alternative was designed to address requirements other than BART, it meets the EPA SIP provision noted above that allows the state to determine the base case BART emissions using simplifying assumptions. This approach is discussed in EPA's Alternative to BART Rule. *See,* 71 Fed. Reg. at 60612 (October 13, 2006). Colorado has estimated base case BART emissions assuming that the plants included in the PSCo BART Alternative emit at the presumptive levels established by EPA for electric generating units of greater than 750 MW.[18] The emissions resulting from the PSCo BART Alternative are then compared to the analysis of base case BART emissions to indicate the degree of emissions reduction improvement provided by the PSCo BART Alternative.

(2)(i)(D) An analysis of the projected emissions reductions achievable through the trading program or other alternative measure.

The emission reductions achievable through PSCo's Alternative include the reductions associated with the combination of shutdowns and retrofit controls established under PSCo's emissions reduction plan, endorsed by the state Public Utilities Commission pursuant to HB 10-1365, and codified and made enforceable by the elements reflected in this State Implementation Plan. The following emissions reductions provided by the PSCo BART Alternative are reflected in Tables 6-7 and 6-8, below. With respect to SO2 emissions, the PSCo BART Alternative will reduce SO2 emissions from these units by 21,493 tons per

[18] None of the BART units included in this Alternative are larger than 750MW, thus the presumptive emissions standards for electric generating units set forth in EPA's BART guidelines are not mandatory for these units. *See, e.g.,* 70 Fed. Reg. at 39108. The non-BART units included in this Alternative are also not subject to the presumptive emissions standards as a mandatory element of Regional Haze. While not required as a matter of regulation the presumptive limits are employed in this instance solely for demonstrative and comparative purposes.

year in the first planning period (2010 to 2018). With respect to NOx emissions, the PSCo BART Alternative will reduce NOx emissions from these units by 15,994 tons per year in the first planning period (2010 to 2018).

(2)(i)(E) A determination under paragraph (e)(3) of this section or otherwise based on the clear weight of evidence that the trading program or other alternative measure achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources.

The PSCo BART Alternative has been evaluated according to the emissions based test discussed in EPA's Alternative to BART Rule. This is explained in further detail below, and demonstrates that for both SO2 and NOx, due to a combination of substantial retirements of coal-fired units and controls on other coal-fired units, the PSCo BART Alternative provides greater reasonable progress than would be afforded under BART at the covered sources.

(2)(ii) [Reserved]

(2)(iii) A requirement that all necessary emission reductions take place during the period of the first long-term strategy for regional haze. To meet this requirement, the State must provide a detailed description of the emissions trading program or other alternative measure, including schedules for implementation, the emission reductions required by the program, all necessary administrative and technical procedures for implementing the program, rules for accounting and monitoring emissions, and procedures for enforcement.

The PSCo BART Alternative for these electric generating units will be implemented during the first long-term strategy period, by December 31, 2017. The PSCo BART Alternative as set forth in this SIP establishes an expeditious implementation schedule for the coordinated shutdown of, and installation of retrofit emissions controls on the covered coal-fired electric generating units. As reflected in Table 6-12, emission limits for SO2 and NOx at Pawnee, operation on natural gas at Cherokee Unit 4, operation on natural gas at Arapahoe Unit 4 as a peaking unit only, and shutdowns at Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont, will all occur during the first planning period. Some of the NOx emissions reductions will be reserved, and are not used in this alternative measure demonstration and not reflected in the emissions reductions in this SIP, to allow for natural gas replacement power at Cherokee and future "netting" or "offsets". The compliance and monitoring provisions of the PSCo BART Alternative have been incorporated into Regulation No. 3, Part F. Compliance will be determined through the use of continuous emission monitors for those facilities that are not shutdown. Enforceability of the shutdown of coal-fired units under the PSCo BART Alternative is reflected in this State Implementation Plan, as well as in Regulation No. 3, Part F. Colorado will also amend the relevant permits to include enforceable shutdown dates.

(2)(iv) A demonstration that the emission reductions resulting from the emissions trading program or other alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.

The emission controls associated with the PSCo BART Alternative have not been used for other SIP purposes, thus they are surplus. The reductions from the shutdown of Arapahoe units 1 and 2 were used in an earlier PM SIP demonstration and are not included in this analysis.

(2)(v) At the State's option, a provision that the emissions trading program or other alternative measure may include a geographic enhancement to the program to address the requirement under §51.302(c) related to BART for reasonably attributable impairment from the pollutants covered under the emissions trading program or other alternative measure.

The Division is not proposing a geographic enhancement for reasonably attributable impairment.

(2)(vi) For plans that include an emissions trading program that establishes a cap on total annual emissions of SO2 or NOx from sources subject to the program, requires the owners and operators of sources to hold allowances or authorizations to emit equal to emissions, and allows the owners and operators of sources and other entities to purchase, sell, and transfer allowances, the following elements are required concerning the emissions covered by the cap:

Since Colorado is not using a trading program for the PSCo BART Alternative, this section does not apply. Electric generating units subject to this alternative have unit-specific compliance requirements reflected in this SIP and in Reg. No. 3, Part F.

(3) A State which opts under 40 CFR 51.308(e)(2) to implement an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART may satisfy the final step of the demonstration required by that section as follows: If the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emission reductions, then the alternative measure may be deemed to achieve greater reasonable progress. If the distribution of emissions is significantly different, the State must conduct dispersion modeling to determine differences in visibility between BART and the trading program for each impacted Class I area, for the worst and best 20 percent of days. The modeling would demonstrate "greater reasonable progress" if both of the following two criteria are met:

The Division has determined that the distribution of emissions under the PSCo BART Alternative is not substantially different than under BART, and the alternative measure results in greater emission reductions than case-by-case BART. The PSCo BART Alternative includes three BART units at four different facilities, all of which are in or immediately adjacent to the 8-Hour Ozone Non-Attainment Area in the Front Range of Colorado. Like the other three facilities, the fourth is the Arapahoe facility and it is central to the non-attainment area, and is only 17 kilometers from the Cherokee facility.

(3)(i) Visibility does not decline in any Class I area, and

Since the Metro Denver BART eligible sources are included in the PSCo BART Alternative along with other non–BART sources in the area, and the overall visibility-impairing pollutants from these units decrease substantially, the Division has determined that visibility does not decline in any Class I area in relation to this PSCo BART Alternative.

(3)(ii) There is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas.

The PSCo Alternative has been demonstrated to achieve more emission reductions than would occur through case-by-case BART. The reasons why the alternative provides greater reductions include:

a) Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont (BART eligible unit), will be shutdown during the first planning period.

b) Arapahoe Unit 4 will operate on natural gas as a peaking unit.

c) Cherokee Unit 4 (BART eligible unit) will operate on natural gas only.

d) Pawnee Unit 1(BART eligible unit) will install and operate an LSD to control SO2 emissions and SCR to control NOx emissions in 2014.

(4) A State that chooses to meet the emission reduction requirements of the Clean Air Interstate Rule (CAIR) by participating in one or more of EPA's CAIR trading programs

Colorado is not participating in the CAIR program.

(5) After a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the requirements of paragraph (d) of this section in the same manner as other sources.

The state acknowledges that the core requirements will otherwise apply as set forth in the Regional Haze Rule.

(6) Any BART-eligible facility subject to the requirement under paragraph (e) of this section to install, operate, and maintain BART may apply to the Administrator for an exemption from that requirement. An application for an exemption will be subject to the requirements of §51.303(a)(2)–(h).

No Colorado BART sources have applied for an exemption from BART.

Technical Analysis of the PSCo Alternative Emissions Reductions with Respect to the Section 308(e) Alternative Measure Demonstration

The following technical analysis of emissions reductions that result from the PSCo BART Alternative more fully demonstrates that the proposed alternative achieves greater reasonable progress than the installation of BART, as allowed under EPA's regional haze regulations. EPA's Regional Haze Rule requires that BART- eligible sources either install BART as determined for each source on a case-by-case basis, or install controls as required by a BART Alternative. EPA's BART guidance (70 Fed. Reg. 39104, July 6, 2005) and EPA's regulation on BART Alternatives (71 Fed. Reg. 60612, October 13, 2006) both provide guidance on how to evaluate whether a BART Alternative proposal achieves greater reasonable progress under the regulation. This determination can be made based on an emissions comparison or through a modeling analysis if the state determines that is appropriate. If the geographic distribution of emissions reductions from the programs is expected to be similar, the comparison can be made based on emissions alone. 70 Fed. Reg. at 39136; 71 Fed. Reg. at 60620. Because all the sources included in the PSCo BART Alternative are located in the same air shed and within a 100 mile area, the Division has determined that the BART eligible sources in the PSCo BART Alternative are in the same geographic region (namely, in the Denver Metro Area and also in or immediately adjacent to the existing 8-Hour Ozone Non-Attainment Area) for purposes of regional haze. Thus an emissions demonstration is appropriate and modeling is not warranted for an alternative measure demonstration.

EPA's BART guidance does not specify a quantity of emission reductions an alternative must exceed to satisfy the "achieves greater reasonable progress" criteria. In its BART guidance, EPA provides an emission-based demonstration of how EPA determined the Clean Air Interstate Rule (CAIR) to be better than case-by-case BART on individual sources. In that instance, EPA demonstrated that more tons of emission reductions would result from the CAIR rule than with source-by-source BART. *See, e.g.,* 70 Fed. Reg. at 39141. Similarly, the state has utilized the emission-based method to evaluate the PSCo BART Alternative. The state has determined that the PSCo BART Alternative achieves greater reasonable progress by evaluating the future emissions from the electric generating units under the operating scenarios reflected in the PSCo BART Alternative, and for demonstration purposes compared those emissions with the same units using the standard established by EPA of 95 percent removal or 0.15 lb/MMBtu for SO2 or a lb/MMBtu for NOx based on boiler and coal type. *See* 71 Fed. Reg. at 60619 ("States establishing a BART benchmark based on simplifying assumptions as to the most stringent BART for EGUs may rely on the presumptions, as EPA did in the CAIR rule.").

As previously discussed, the PSCo Alternative is based on a combination of emissions control retrofits and shutdowns resulting from Colorado HB 10-1365 and the PUC's actions. The PSCo BART Alternative includes Pawnee, Arapahoe Units 3 and 4, Valmont Unit 5, and Cherokee Units 1-4. Pawnee, Cherokee Unit 4 and Valmont Unit 5 are the only BART eligible units. The sources involved in the PSCo BART Alternative are either BART eligible sources or sources that precede the BART timeframe. For demonstration purposes, the emissions from the entire group of electric generating units in the PSCo BART Alternative were compared to the emissions from the units if the presumptive levels were applied, as allowed under EPA's regulation. Table 6-7 compares the tons of SO2 that would be emitted under the PSCo BART Alternative to the number of tons of SO2 that would be emitted by the same units if the standard of 0.15 lb SO2/MMBtu were applied. The 0.15 lb/MMBtu standard comes from the 70 Fed. Reg. 39132 (7/6/2005) in which EPA establishes "BART limits of 95 percent SO2 removal, or an emission rate of 0.15 lb SO2/MMBtu". The MMBtu used for the analysis is an average of the actual MMBtu reported by the units to the Clean Air Markets Division for 2006, 2007 and 2008. For units that will be shutdown or operated on natural gas (Arapahoe unit 4) under the PSCo BART Alternative an emissions factor of 0.0006 lb SO2/MMBtu was used for the alternative.

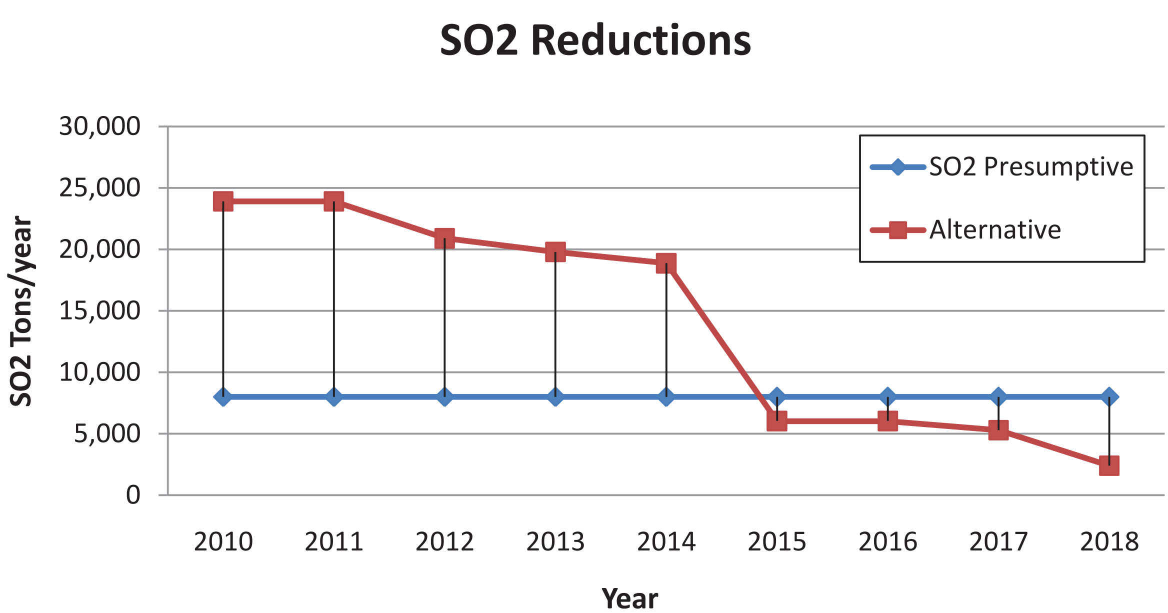
Table 6-7: SO2 Reductions Beyond Presumptive BART for PSCo Alternative

Facility	MMBtu Average 2006 to 2008	SO2 TPY Average 2006 to 2008	SO2 TPY at 0.15 lb/MMBtu Presumptive	SO2 TPY under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe					
Unit 3	4,380,121	924.97	328.51	0.00	100.00%
Unit 4	8,545,791	1,764.70	640.93	1.28[19]	99.8%
Cherokee					
Unit 1	8,311,352	2,220.80	623.35	0.00	100.00%
Unit 2	5,586,021	1,888.37	418.95	0.00	100.00%
Unit 3	8,159,889	743.00	611.99	0.00	100.00%
Unit 4	26,047,648	2,135.43	1,953.57	7.81	99.6 %
Valmont	13,722,507	758.47	1,029.19	0.00	100.00%
Pawnee	40,093,753	13,472.07	3,007.03	2,405.63	20.00%
Total	114,847,083	23,908	8,614	2,415	71.97%

The comparison with the standard of 0.15 lb SO2/MMBtu shows that the PSCo BART Alternative provides 72% lower SO2 emissions.

Figure 6-1 provides a year by year comparison of the PSCo BART Alternative to the 0.15 lb SO2/MMBtu standard for this planning period.

Figure 6-1: SO2 reductions beyond presumptive BART for PSCo Alternative



[19] Emission factor of 0.0006 lb SO2/MMBtu and 50% capacity factor.

A similar analysis was completed for NOx emissions. Table 6-8 compares the PSCo BART Alternative to a standard based on NOx limits established by EPA in 70 Fed. Reg. 39135 (7/6/2005). EPA provides a NOx lb/MMBtu level based on the boiler type and the coal type burned. The PSCo BART Alternative reflects 600 tpy of NOx emitted from Arapahoe 4 operating on natural gas as a "peaking" unit, 300 tpy of NOx reserved for "netting" or "offsets" from the Arapahoe facility, and 500 tpy of NOx reserved for "netting" or "offsets" from the Cherokee facility.

Table 6-8: NOx Reductions Beyond Presumptive BART for PSCo Alternative

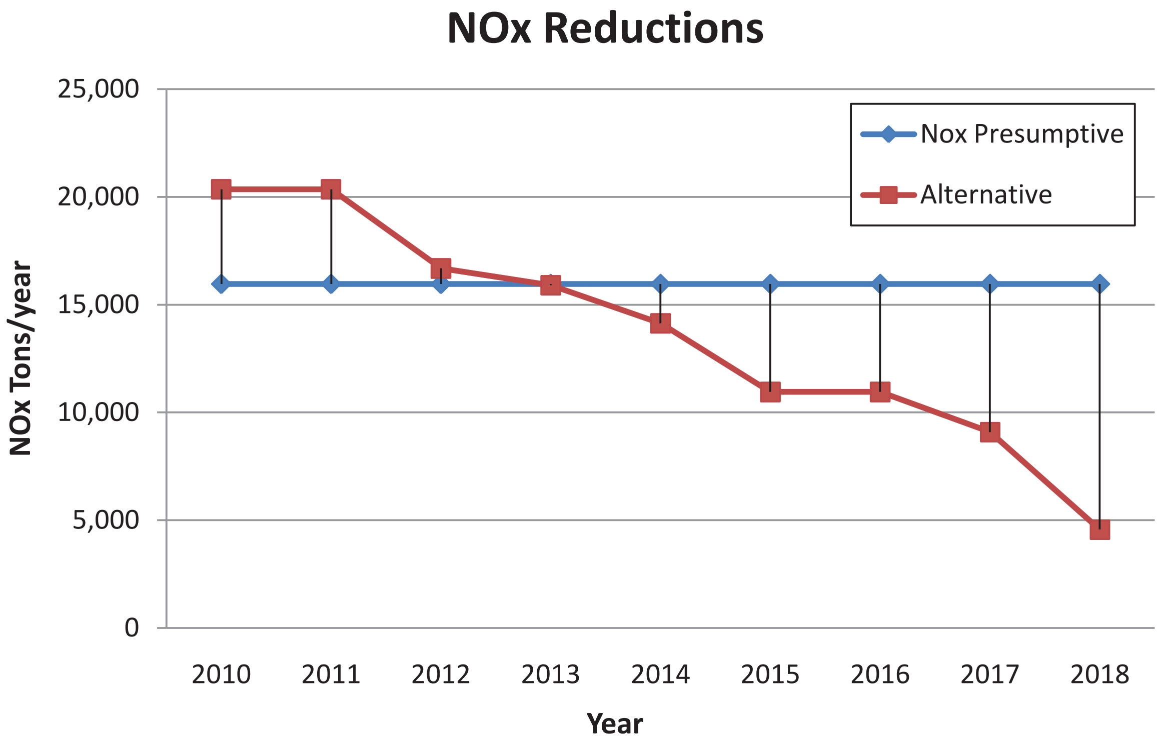
Facility	MMBtu Average 2006 to 2008	NOx TPY Average 2006 to 2008	NOx lb/MMBtu Standard	TPY NOx at Standard	TPY NOx Under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe						
Unit 3	4,380,121	1,770.47	0.23	503.71	0.00	100.00%
Unit 4	8,545,791	1,147.67	0.23	982.77	900.00[20]	8.42%
Cherokee						
Unit 1	8,311,352	1,556.23	0.39	1,620.71	0.00	100.00%
Unit 2	5,586,021	2,895.20	0.39	1,089.27	0.00	100.00%
Unit 3	8,159,889	1,865.50	0.39	1,591.18	0.00	100.00%
Unit 4	26,047,648	4,274.00	0.28	3,646.67	2,062.86[21]	43.43%
Valmont	13,722,507	2,313.73	0.28	1,921.15	0.00	100.00%
Pawnee	40,093,753	4,537.73	0.23	4,610.78	1,403.28	69.57%
Total	114,847,083	20,361		15,966	4,366	72.65%

Figure 6-2 illustrates the year by year reductions achieved by the PSCo BART Alternative as compared to the standard derived from the EPA standard based on the configuration of each unit and the coal type burned by the unit in the PSCo BART Alternative.

[20] 600 tpy NOx from operation of Arapahoe 4 on natural gas as a "peaking" unit and 300 tpy NOx reserved for "netting" and "offsets" for additional natural gas generation. The 300 tpy NOx is associated with unit 4 for illustrative purposes, but may be associated with either unit.

[21] Cherokee 4 operating on natural gas at 0.12 lb NOx/mmBTU and 500tpy NOx reserved for "netting" or "offsets". The 500 tpy NOx is associated with unit 4 for illustrative purposes, but may be associated with any combination of the units.

Figure 6-2: NOx Reductions Beyond Presumptive BART for PSCo Alternative



The PSCo BART Alternative provides a reduction of 15,994 tons per year of NOx and 21,493 tons per year of SO2 from the baseline (average of 2006-2008 actuals) (89% and 77% reduction, respectively). These SO2 and NOx reductions provide significantly greater reductions as compared to the application of the standard set forth in 70 Fed. Reg. 39132-39135 (7/6/2005) applied all the units in the PSCo BART Alternative. The PSCo BART Alternative provides a 71% improvement in NOx reductions (See Table 6-8) over the presumptive levels, and a 72% improvement in SO2 reductions (See Table 6-7) over the presumptive levels. This is a significantly higher reduction than would have been achieved through the application of the presumptive limits. The state's alternative program is thus "clearly superior" to source-specific BART. *See* 71 Fed. Reg. at 60615. It provides not only for further emission reductions at units, but reflects the closure of numerous units, and thus the complete elimination of emissions from those units. Because these measures will provide greater emission reductions and will occur within the first planning period, the state has determined that they also satisfy reasonable progress for these sources. In this regard, Colorado has reasonably concluded that any control requirements imposed in the BART context also satisfy the RP related requirements in the first planning period. *See* U.S. EPA, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," p. 4-2 (June 2007).

Supplemental Technical Analysis Supporting the Alternative measure demonstration for the PSCo Alternative

In addition to the foregoing demonstration that the PSCo BART Alternative satisfies the requirements of 40 CFR 51.308(e)(2) for an approvable alternative to EPA's BART regulation, the state undertook and provides the following additional technical analyses to support its determination that the PSCo BART Alternative demonstrates greater reasonable progress than the installation of BART on subject to BART units.

Colorado also evaluated the NOx reductions of the alternative program based on the criteria established by the state for BART and reasonable progress for NOx reductions. As part of its five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

For the PSCo BART Alternative sources included in the PSCo BART Alternative, SCR costs (where technically feasible) are greater than $5,000 per ton of NOx removed or the visibility improvement from SCR is less than 0.50 Δdv. See analysis in appendix C. Under the state's criteria this would eliminate SCR from further consideration as a control alternative for BART and reasonable progress. Thus, for demonstration purposes the state has compared the PSCo BART Alternative with the emission reductions achievable by SNCR. The division used study of SNCR on coal fired boilers in the size range of those in the PSCO BART Alternative. The study showed that the SNCR tested achieved a 35% reduction in NOx with less than 2ppm NH_3 slip and 54% reduction with a 10ppm NH_4 slip.[22] Because of the high ammonia slip at the higher range of NOx removal the division determined that 50% removal was appropriate for this comparison. Thus, for comparative purposes for the PSCo BART Alternative, the state will assume that SNCR is applied at a level of NOx reduction, of 50%, to assess performance of presumed SNCR on these units as against the PSCo BART Alternative for NOx.[23] Table 6-9 provides a comparison of the costs for SCR and SNCR as provided by PSCo, SNCR at a 50% reduction (calculated from an average of NOx actual from 2006-2008 as reported to the Clean Air Markets Division) and the PSCo BART Alternative.

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[22] Environmental Controls Conference, Pittsburgh, PA (5/16/2006 to 5/18/2006)

[23] This level of NOx control efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that SNCR on these particular electric generating units could, in fact, achieve this level of NOx reduction performance from application of SNCR.

Table 6-9: NOx reductions beyond state criteria for PSCo Alternative

Facility	SCR $/ton	SNCR $/ton	SNCR TPY at 50%[24]	PSCo Alternative TPY	% Reduction from SNCR at 50% Control
Arapahoe					
Unit 3			885.23	0	100.00%
Unit 4			573.83	900[25]	-56.84%
Cherokee					
Unit 1	N/A	$8,737	778.12	0	100.00%
Unit 2	N/A	$3,963	1,447.60	0	100.00%
Unit 3	$10,134	$3,485	932.75	0	100.00%
Unit 4	$6,252	$2,625	2,137.00	2,062[26]	3.47%
Valmont	$8,647	$3,328	1,156.87	0	100.00%
Pawnee	$4,371	$3,082	2,268.87	1,403	38.15%
Total			10,180	4,366	57.11%

The PSCo BART Alternative results in 55% more reduction in NOx than the assumed installation of SNCR at all units covered by the PSCo BART Alternative. A similar analysis was not completed for SO2 because the state did not look at SO2 controls for reasonable progress as all sources were already controlled.

For both SO2 and NOx the state also evaluated the PSCo BART Alternative against a source by source analysis. For SO2 the state has done source specific analyses for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 95% control level assumption to the uncontrolled emissions from those sources. The 95% was taken both from current operations and from uncontrolled emissions calculated using AP-42.[27] The analysis demonstrates that the alternative proposed is better than the source by source analysis by more than 52% as shown in Table 6-10. Figure 6-3 shows the reductions

[24] Fifty percent reduction was taken from an average of 2006-2008 actual NOx emissions as reported to the Clean Air Markets Division.

[25] 600 tpy NOx from operation of Arapahoe 4 on natural gas as a “peaking” unit and 300 tpy NOx reserved for “netting” and “offsets” for additional natural gas generation.

[26] Cherokee 4 operating on natural gas at 0.12 lb NOx/MMBtu and 500 tpy NOx reserved for “netting” or “offsets”.

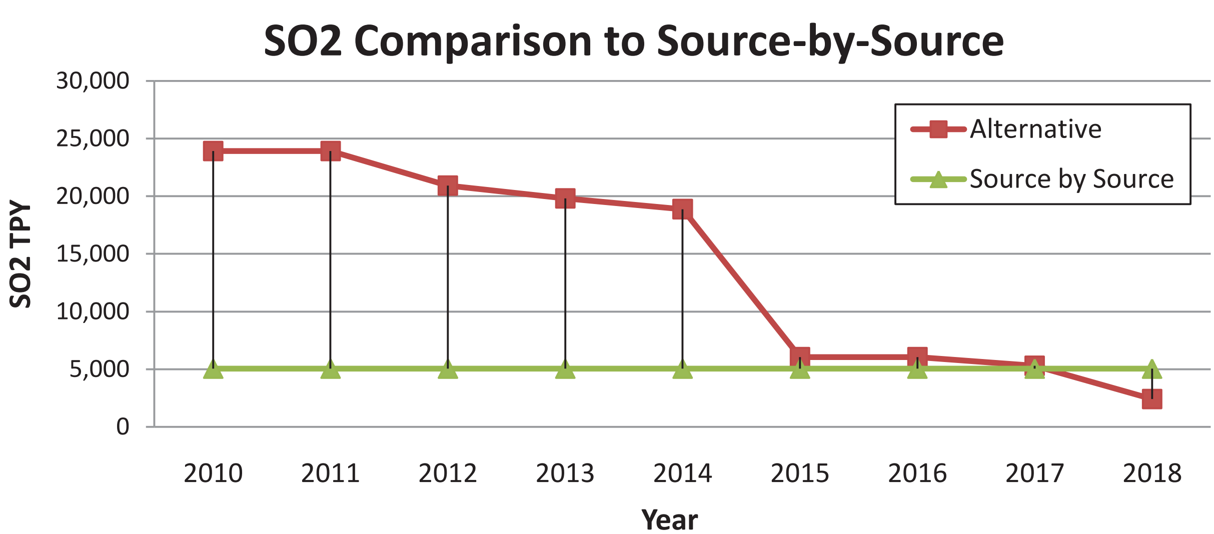
[27] This level of SO2 reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units burning low-sulfur western coal, could, in fact, achieve this level of SO2 reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities. This is different from the other analyses provided in this document, and when employing a 95% reduction assumption for demonstration purposes for an alternative measure makes the starting point for the sources in the Alternative more similar to uncontrolled eastern sources, where a higher sulfur content coal is generally utilized, which is more relevant to an assumed 95% reduction of SO2.

from the PSCo BART Alternative as compared to the source by source evaluation on a year to year basis.

Table 6-10: SO2 Reductions Beyond Source-By-Source BART for PSCo Alternative

Facility	SO2 TPY from AP-42	Source-by-Source	SO2 TPY from PSCo Alternative	% Reduction Beyond Source-by-Source
Arapahoe				
Unit 3	1,076.53	53.82	0.00	100.00%
Unit 4	2,322.21	1.28	1.28	0.00%
Cherokee				
Unit 1	2,803.67	140.18	0.00	100.00%
Unit 2	2,662.17	133.10	0.00	100.00%
Unit 3	3,438.79	171.93	0.00	100.00%
Unit 4	9,779.27	1,953.57[28]	7.81	99.6%
Valmont	3,822.73	191.13	0.00	100.00%
Pawnee	8,342.36	2,405.62[29]	2,405.63	0.00%
Total	34,248	5,051	2,415	52.19%

Figure 6-3: SO2 Reductions Beyond Source-By-Source BART for PSCo Alternative



[28] The Cherokee Unit 4 BART evaluation concluded that a 0.15 lb SO2/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

[29] The Pawnee BART evaluation concluded that a 0.12 lb SO2/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

For NOx the state looked at a source by source analysis for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 90% control level assumption to the sources. The 90% was taken from emissions calculated using AP-42.[30] The source by source analysis considered the operation of Arapahoe Unit 4 with natural gas as a peaking unit and retaining 300 tpy of NOx for future netting or offsets from Arapahoe, the operation of Cherokee Unit 4 on natural gas at 0.12 lb/MMBTU and retaining 500 tpy of NOx from Cherokee for future netting, and control of Pawnee with SCR at 0.07 lb/MMBTU. The results of the comparison indicate that the alternative proposed is 49% better than the source by source analysis.

Table 6-11: NOx Reductions Beyond Source-By-Source BART for PSCo Alternative

Facility	NOx TPY from AP-42	Source-by-Source	NOx TPY from PSCo Alternative	% Reduction Beyond Source-by-Source
Arapahoe				
Unit 3	2,149.15	214.91	0.00	100.00%
Unit 4	4,636.00	600	900.00[31]	-50.00%
Cherokee				
Unit 1	3,596.54	359.65	0.00	100.00%
Unit 2	3,415.03	341.50	0.00	100.00%
Unit 3	4,411.28	441.12	0.00	100.00%
Unit 4	7,878.04	2,735.00[32]	2,062.86[33]	24.58%
Valmont	2,061.04	206.10	0.00	100.00%
Pawnee	7,945.11	3,608.43	1,403.28	61.11%
Total	36,092	8,507	4,366	48.67%

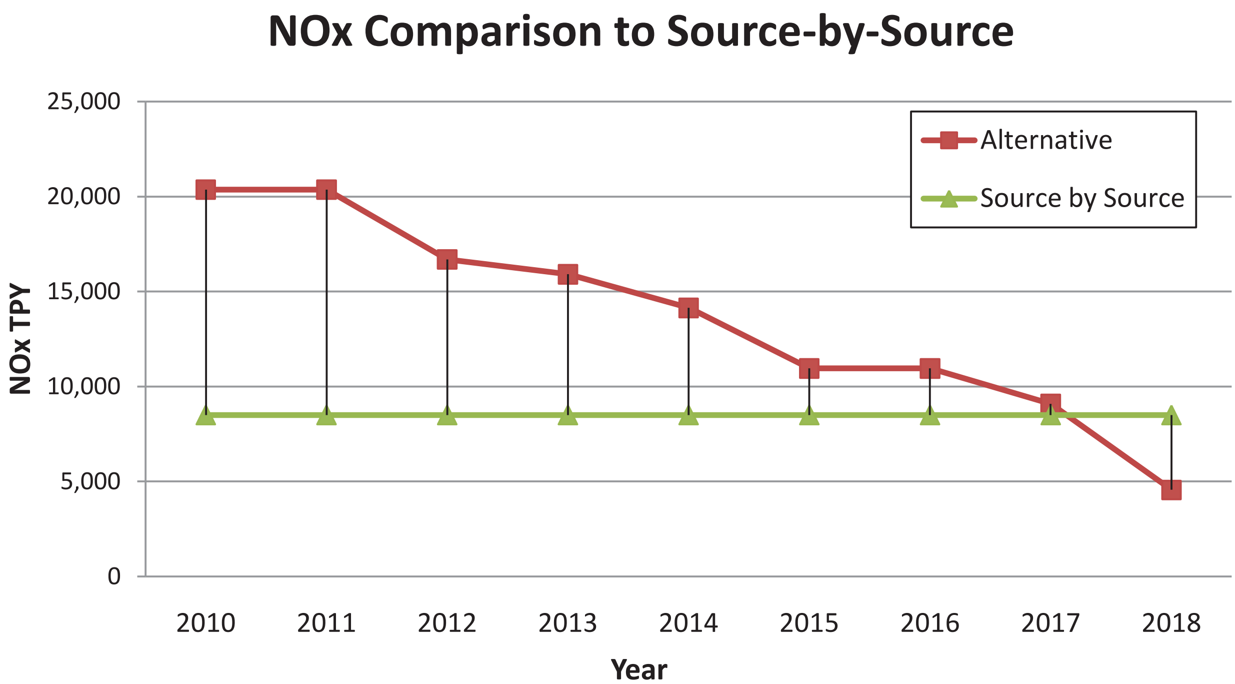
[30] This level of NOx reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units, could, in fact, achieve this level of NOx reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities.

[31] Natural gas operation as a peaking unit limited to 600 tpy with 300 tpy NOx reserved for offsets or netting for additional natural gas generation.

[32] Coal fired operation with SNCR at 0.21 lb NOx/MMBtu.

[33] Natural gas operation at 0.12 lb NOx/MMBtu with 500 tpy NOx reserved for offsets or netting.

Figure 6-4: NOx Reductions Beyond Source-By-Source BART for PSCo Alternative



Conclusion

Under EPA regional haze regulations, Colorado has utilized an emission based comparison to demonstrate that that the PSCo BART Alternative provides greater reasonable progress than, and is clearly superior to, source by source BART. Although not necessary, as a means of further supporting its demonstration, the state has utilized other methodologies to demonstrate that the PSCo BART Alternative achieves greater reasonable progress than BART or individual reasonable progress requirements. The PSCo BART Alternative will result in early and significant reductions of visibility impairing pollutants.

Table 6-12: PSCo Alternative Emissions Limits[34, 35, 36]

Unit	NOx Control Type	NOx Emission Limit	SO2 Control Type	SO2 Emission Limit	Particulate Type And Limit
Cherokee Unit 1	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012
Cherokee Unit 2	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011
Cherokee Unit 3	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016
Cherokee Unit 4	Natural Gas Operation	0.12 lb/MMBtu (30-day rolling average) by 12/31/2017	Natural Gas Operation 12/31/2017	7.81 tpy (12 month rolling average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas Operation 12/31/2017
Valmont Unit 5	Shutdown 12/31/2017	0	Shutdown 12/31/2017	0	Shutdown 12/31/2017
Pawnee Unit 1	SCR**	0.07 lb/MMBtu (30-day rolling average) by 12/31/2014	Lime Spray Dryer**	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	Fabric Filter Baghouse* 0.03 lbs/MMBtu
Arapahoe Unit 3	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Arapahoe Unit 4	Natural Gas Operation	600 tpy (12 month rolling average) by 12/31/2014	Natural Gas operation 12/31/2014	1.28 tpy (12 month rolling average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas operation 12/31/2014

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the above table is not a requirement.

[34] Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.

[35] 500 tpy NOx will be reserved from Cherokee Station for netting or offsets.

[36] 300 tpy NOx will be reserved from Arapahoe Station for netting or offsets for additional natural gas generation.

Chapter 7 Visibility Modeling and Apportionment

Modeling results and technical analyses indicate that Colorado sources contribute to visibility degradation at Class I areas. The modeling also shows out-of-state sources have the greatest impact on regional haze in Colorado. As such, this Plan anticipates local and regional solutions so that Colorado's 12 Class I areas make progress towards the 2018 and 2064 visibility goals.

7.1 Overview of the Community Multi-Scale Air Quality (CMAQ) Model

The Regional Modeling Center (RMC) Air Quality Modeling group is responsible the Regional Haze modeling for the WRAP. The RMC is located at the University of California - Riverside in the College of Engineering Center for Environmental Research and Technology.

The RMC modeling analysis is based on a model domain comprising the continental United States using the Community Multi-Scale Air Quality (CMAQ) model. The EPA developed the CMAQ modeling system in the late 1990s. CMAQ was designed as a "one atmosphere" modeling system to encompass modeling of multiple pollutants and issues, including ozone, PM, visibility, and air toxics. This is in contrast to many earlier air quality models that focused on single-pollutant issues (e.g., ozone modeling by the Urban Airshed Model). CMAQ is an Eulerian model - that is, it is a grid-based model in which the frame of reference is a fixed, three-dimensional (3-D) grid with uniformly sized horizontal grid cells and variable vertical layer thicknesses. The key science processes included in CMAQ are emissions, advection and dispersion, photochemical transformation, aerosol thermodynamics and phase transfer, aqueous chemistry, and wet and dry deposition of trace species.

A detailed summary of the CMAQ modeling for each Class I area is included in Section 6 of the Technical Support Document.

7.2 CMAQ Modeling Results for 2018

Figure 7-1 lists the 2018 Uniform Progress (UP) for each class I area along with the visibility modeling forecasts for 2018. These modeling results were released in 2006 by the WRAP and are preliminary; new modeling results with the latest emission estimates and control measure benefits are anticipated mid- to late 2007, and additional modeling is scheduled to be performed in 2008 and 2009. The results of this modeling will be utilized in defining (RPGs) for all 12 Colorado Class I areas by the year 2010 as described in Chapter 9.

As indicated by the 2006 modeling, reasonable progress for each Class I area falls short of meeting 2018 uniform progress for the 20% worst days, as indicated by the numbers in the blue highlighted box. Alternatively, all areas are forecast to maintain the best days in 2018.

More detailed information on the CMAQ modeling for a particular Class I area can be found in Section 6 of the Technical Support Document.

Figure 7-1 Summary of CMAQ Modeling Progress Towards 2018 UP

Colorado Mandatory Class I Federal Areas

Uniform Progress Summary in Haze Index Metric

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	20% Worst Days					20% Best Days		
	Worst Days Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2018 URP delta from Baseline [dv]	2018 Modeling Projection [dv]	CMAQ Modeling % Towards 2018 URP	Best Days Baseline Condition [dv]	2018 CMAQ Modeling Results [dv]	2018 CMAQ Modeling Below Baseline?
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

7.3 Overview of Particulate Matter Source Apportionment Technology (PSAT) Modeling

The Regional Modeling Center (RMC) at the University of California – Riverside developed the PSAT algorithm in the Comprehensive Air quality Model with extensions (CAMx) model to assess source attribution. The PSAT analysis is used to attribute particle species, particularly sulfate and nitrate from a specific location within the Western Regional Air Partnership (WRAP) modeling domain. The PSAT algorithm applies nitrate-sulfate-ammonia chemistry to a system of tracers or “tags” to track the chemical transformations, transport and removal of emissions.

Each state or region (i.e. Mexico, Canada) is assigned a unique number that is used to tag the emissions from each 36-kilometer grid cell within the WRAP modeling domain. Due to time and computational limitations, only point, mobile, area and fire emissions were tagged.

The PSAT algorithm was also used, in a limited application (e.g. no state or regional attribution) due to resource constraints, to track natural and anthropogenic species of organic aerosols at each CIA. The organic aerosol tracer tracked both primary and secondary organic aerosols (POA & SOA). Appendix H includes more information on PSAT methodology.

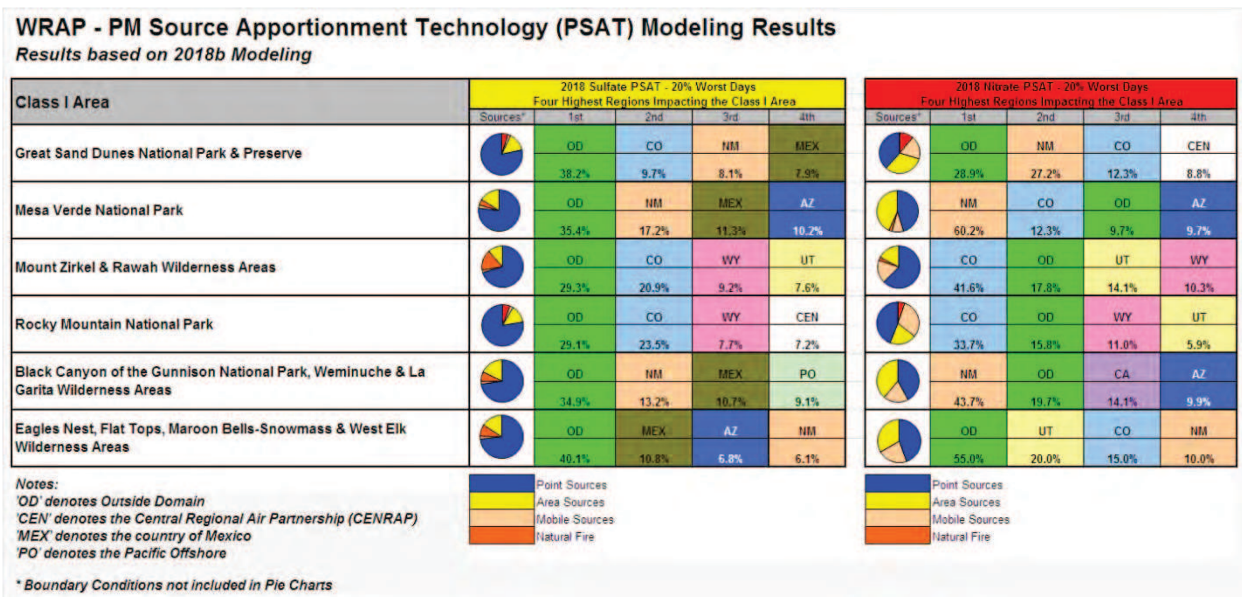
More detailed information on the PSAT modeling can be found in Section 7 of the Technical Support Document for each Class I area.

7.4 PSAT Modeling Results for 2018

Figure 7-2 provides the four highest source areas contributing sulfate and nitrate at each Class I area. As indicated, boundary conditions (BC) are the highest contributor to sulfate at all Colorado Class I areas. The boundary conditions represent the background concentrations of pollutants that enter the edge of the modeling domain. Depending on meteorology and the type of pollutant (particularly sulfate), these emissions can be transported great distances that can include regions such as Canada, Mexico, and the Pacific Ocean. Colorado appears to be a major contributor of particulate sulfate at those Class I areas near significant sources of SO2.

For nitrate, Colorado appears to be a major contributor at most of our Class I areas except for the Weminuche Wilderness, La Garita Wilderness and Black Canyon of Gunnison National Park. Although, boundary conditions also appear to be a major contributor of nitrate at all our Class I areas.

Figure 7-2 Summary of PSAT Modeling for 2018



WRAP - PM Source Apportionment Technology (PSAT) Modeling Results
Results based on 2018b Modeling

Class I Area	2018 Sulfate PSAT - 20% Worst Days Four Highest Regions Impacting the Class I Area					2018 Nitrate PSAT - 20% Worst Days Four Highest Regions Impacting the Class I Area				
	Sources*	1st	2nd	3rd	4th	Sources*	1st	2nd	3rd	4th
Great Sand Dunes National Park & Preserve		OD 38.2%	CO 9.7%	NM 8.1%	MEX 7.9%		OD 28.9%	NM 27.2%	CO 12.3%	CEN 8.8%
Mesa Verde National Park		OD 35.4%	NM 17.2%	MEX 11.3%	AZ 10.2%		NM 60.2%	CO 12.3%	OD 9.7%	AZ 9.7%
Mount Zirkel & Rawah Wilderness Areas		OD 29.3%	CO 20.9%	WY 9.2%	UT 7.6%		CO 41.6%	OD 17.8%	UT 14.1%	WY 10.3%
Rocky Mountain National Park		OD 29.1%	CO 23.5%	WY 7.7%	CEN 7.2%		CO 33.7%	OD 15.8%	WY 11.0%	UT 5.9%
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas		OD 34.9%	NM 13.2%	MEX 10.7%	PO 9.1%		NM 43.7%	OD 19.7%	CA 14.1%	AZ 9.9%
Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas		OD 40.1%	MEX 10.8%	AZ 6.8%	NM 6.1%		OD 55.0%	UT 20.0%	CO 15.0%	NM 10.0%

Notes:
'OD' denotes Outside Domain
'CEN' denotes the Central Regional Air Partnership (CENRAP)
'MEX' denotes the country of Mexico
'PO' denotes the Pacific Offshore

Point Sources
Area Sources
Mobile Sources
Natural Fire

** Boundary Conditions not included in Pie Charts*

Figure 7-3 identifies the change in the Colorado portion of particulate sulfate and nitrate concentrations, from 2002 to 2018 at each Class I area. For 2018, the PSAT modeling forecasts a reduction in the Colorado portion of sulfate at all Class I areas ranging from 25% to 33%. These particulate sulfate reductions are due to reductions from point and mobile source sulfur dioxide emissions (see Figure 5-1).

The 2018 forecasts for nitrate appear mixed with increases of 25% to 27% at the southwest Colorado Class I areas and nitrate reductions of 9% to 28% at all other areas. The increase in particulate nitrate in southwest Colorado is likely due to forecast increases in Colorado's and the region's NOx emissions from area sources and oil & gas development (see Figure 5-2). The projected particulate nitrate reductions at the remaining Class I areas are due to NOx reductions in mobile sources.

Figure 7-3 Colorado Share of Modeled Sulfate and Nitrate Changes for 2018

Change in Modeled Concentration for Colorado Share

Based PM Source Apportionment Technology (PSAT) Modeling Results (2018b)

Class I Area	Year	Total SO4 [ug/m3]	Colorado SO4 [ug/m3]	Colorado Share SO4	Colorado Sulfate Change	Total NO3 [ug/m3]	Colorado NO3 [ug/m3]	Colorado Share NO3	Colorado Nitrate Change
Great Sand Dunes National Park & Preserve	2002	0.440	0.057	13%		0.116	0.017	15%	
	2018	0.442	0.043	10%	-25%	0.114	0.014	12%	-18%
Mesa Verde National Park	2002	0.665	0.013	2%		0.249	0.026	10%	
	2018	0.644	0.009	1%	-31%	0.269	0.033	12%	+27%
Mount Zirkel & Rawah Wilderness Areas	2002	0.649	0.175	27%		0.214	0.085	40%	
	2018	0.621	0.130	21%	-26%	0.185	0.077	42%	-9%
Rocky Mountain National Park	2002	0.760	0.238	31%		0.339	0.128	38%	
	2018	0.677	0.159	23%	-33%	0.273	0.092	34%	-28%
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	2002	0.484	0.024	5%		0.080	0.004	5%	
	2018	0.484	0.018	4%	-25%	0.071	0.005	7%	+25%
Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas	2002	0.428	0.028	7%		0.020	0.004	20%	
	2018	0.424	0.021	5%	-25%	0.020	0.003	15%	-25%

Chapter 8 Reasonable Progress

8.1 Overview of Reasonable Progress Requirements

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals (expressed in deciviews) for each Class I area in Colorado that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. These reasonable progress goals (RPGs) are to provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

In establishing the RPGs, the state must consider four factors: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. As well, the state must include a demonstration showing how these factors were taken into consideration in selecting the goals.

In establishing RPGs, the state must estimate the 2018 uniform rate of progress (URP) for each Class I area. The state must consider the URP and the emission reductions needed to achieve URP for the period covered by the plan. If the state ultimately establishes a Reasonable Progress Goal that provides for a slower rate of visibility improvement than would be necessary to meet natural conditions by 2064, the state must demonstrate that the uniform rate is not reasonable and that the state's alternative goal is reasonable, based on an evaluation of the 4 factors. In addition, the state must provide to the public an assessment of the number of years it would take to achieve natural conditions if improvement continues at the rate selected by the state. The detailed discussion of Reasonable Progress Goals can be found in Chapter 9, "Long Term Strategy". The establishment of the pollutants for RP evaluations and the evaluation of significant sources for reasonable progress is presented below.

8.2 Visibility Impairing Pollutants Subject to Evaluation

The state conducted a detailed evaluation[37] of the six particulate pollutants; ammonium sulfate, ammonium nitrate, organic carbon (OC), elemental carbon (EC), fine soil and coarse mass (CM) (both of which are commonly known as particulate matter (PM)), contributing to visibility impairment at Colorado's 12 mandatory Class I federal areas, and determined that the first Regional Haze Plan RP evaluation should focus on significant point sources of SO2 (sulfate precursor), NOx (nitrate precursor) and PM emissions. Emission sources are best understood for these three visibility-impairing pollutants, and stationary, or "point" sources, dominate the emission inventories and apportionment modeling. This determination is based on the well documented point source emission inventories for SO2 and NOx, and the Regional Model performance for sulfate and nitrate was determined to be acceptable. Significant point source PM emissions are also evaluated because of the Q/d screening methodology (Q = total

[37] *Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas*, October 2, 2007. See the Technical support Document

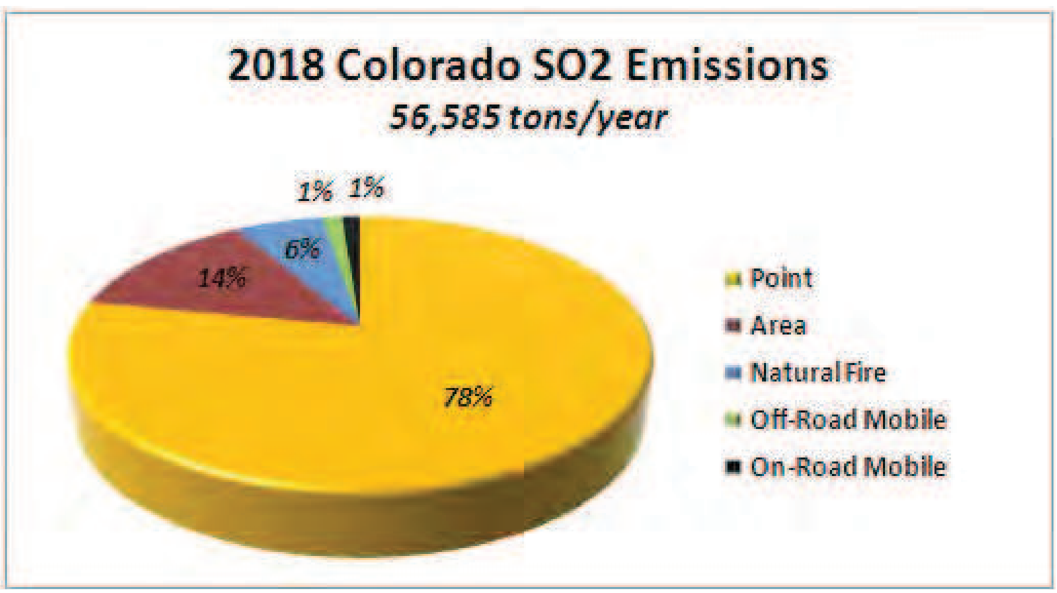
SO2, NOx and PM emissions; d = distance from the nearest Class I area, as further described in section 8.3), which includes PM emissions. PM emissions from other anthropogenic and natural sources are not being evaluated at this time.

Mobile and area sources were also identified as significant contributors to nitrates, and the RP evaluation of these two source categories is presented in section 8.2 above.

Generally, the sources of other visibility impairing pollutants, OC, EC, and PM, are not well documented because of emission inventory limitations associated with natural sources (predominantly wildfires), uncertainty of fugitive (windblown) emissions, and poor model performance for these constituents. Without a sound basis for making emission control determinations for sources that emit these three pollutants, Colorado determines that it is not reasonable in this planning period to recommend emission control measures; the State intends to address these pollutants and their emissions sources in future plan updates.

Figure 8-1 provides the statewide projected 2018 SO2 emissions, which reflects “on-the-books (OTB)” and “on-the-way (OTW)” emission control measures as of January 2009 (the latest year for a complete emissions inventory compiled by the Western Regional Air Partnership (WRAP)).

Figure 8-1: Relative Source Contributions to Colorado SO2 Emissions in 2018

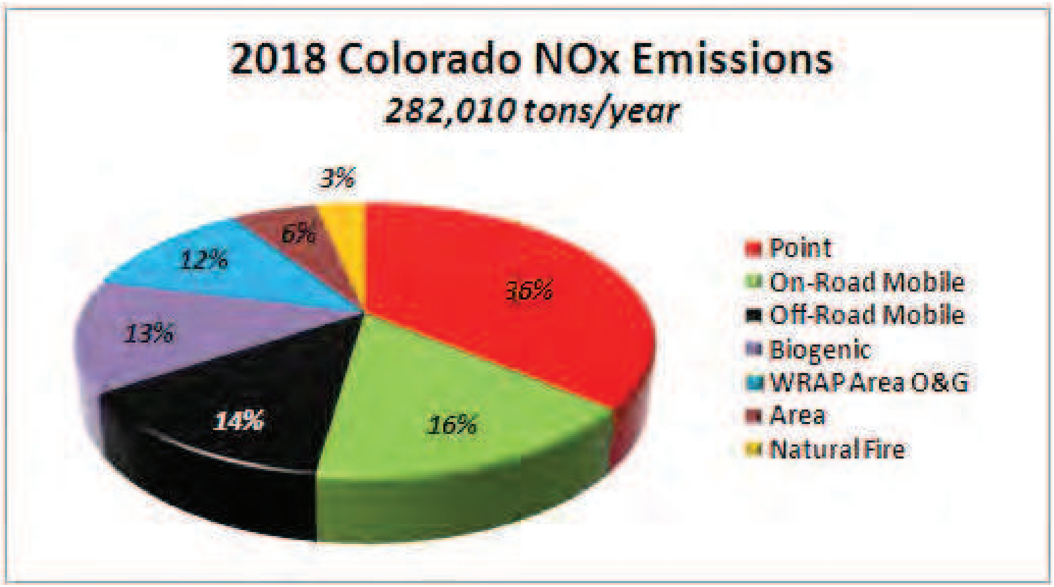


As indicated, 78% of total statewide SO2 emissions are from point sources – largely coal-fired boilers. Area source SO2 emissions (14%) are dominated by thousands of boilers and internal combustion engines statewide that burn distillate fuel. Depending on use and fuel grade, the maximum sulfur content of distillate fuel ranges between 500 ppm to 5000 ppm. SO2 emissions from natural fires are considered uncontrollable and vary from year-to-year depending on precipitation, fuel loading and lightning. Both off-road and on-road mobile sources are subject to federal ultra-low sulfur diesel (ULSD) fuel requirements that limit sulfur content to 15 ppm (0.0015 %) that was in widespread use after June 2010 for off-road mobile and June 2006 for on-road mobile.

The state has determined that point sources are the dominant source of emissions and, for this planning period, the only practical category to evaluate under reasonable progress for SO2.

Figure 8-2 provides the statewide projected 2018 NOx emissions, which reflects OTB and OTW emission control measures as of October 2009 (the latest year for a complete emissions inventory compiled by the WRAP).

Figure 8-2: Relative Source Contributions to Colorado NOx Emissions in 2018



Point sources comprise 36% of total NOx emissions that are mostly coal-fired external combustion boilers and natural gas-fired internal combustion engines (in oil and gas compression service). On-road and off-road mobile sources comprise 16% and 14% of statewide NOx emissions respectively. A portion of the on-road mobile source NOx emissions reflect some level of NOx control because of the Denver metro-area vehicle inspection program (IM-240). Both on/off road mobile also benefit from fleet turnover to cleaner vehicles resulting from more stringent federal emission standards. Because mobile exhaust emissions are primarily addressed, and will continue to be addressed, through federal programs, mobile sources will not be evaluated by Colorado for further RP control in this planning period. NOx emissions from biogenic activity and natural fire are considered uncontrollable and vary from year-to-year. Non-oil and gas area sources comprise about 6% of NOx emissions that involve thousands of combustion sources that are not practical to evaluate in this planning period.

The state has determined that large point sources are the dominant source of emissions and for this planning period are practical to evaluate under reasonable progress for NOx. Also, certain smaller point sources and area sources of NOx will also be evaluated under RP.

8.3 Evaluation of Smaller Point and Area Sources of NOx for Reasonable Progress

Oil and gas area source NOx emissions have been determined to significantly contribute to visibility impairment in Colorado's Class I areas. Because this source category is made up of numerous smaller sources, it is only practical to evaluate the category for RP control as a whole, unlike point sources where individual sources are evaluated separately. When reviewing O&G area sources, natural gas-fired heaters, and reciprocating internal combustion engines (RICE), are identified as the largest NOx emission sources. When reviewing point sources, natural gas-fired turbines were also identified as significant for review for RP.

8.3.1 Oil and Gas Heater Treaters

A heater-treater is a device used to remove contaminants from the natural gas at or near the well head before the gas is sent down the production line to a natural gas processing plant. It prevents the formation of ice and natural gas hydrates that may form under the high pressures associated with the gas well production process. These solids can plug the wellhead.

The latest 2018 emissions inventory for the state assumes approximately 23,000 tons of NOx per year from 26,000 natural gas heater-treaters in Colorado at an emissions level of 0.88 tpy NOx per gas well heater-treater.

Emissions control research and control application for this source category is not well developed and has focused primarily on methane reductions. Though there are some technically feasible control options, the costs of compliance and the control effectiveness cannot be confidently determined. While the cumulative emissions make this a significant source category, the state determines that, for this planning period, requiring the control of 26,000 individual sources less than one ton per year in size is not practical or reasonable for reasonable progress.

A detailed 4-factor analysis for heater treaters can be found in Appendix D.

8.3.2 Reciprocating Internal Combustion Engines

Power generated by large reciprocating internal combustion engines (RICE) is generally used to compress natural gas or to generate electricity in remote locations. The designation "large" refers to RICE that have an engine rating of at least 100 horsepower (hp) for the purpose of this reasonable progress analysis.

Stationary RICE produce power by combustion of fuel and are operated at various air-to-fuel ratios. If the stoichiometric ratio is used, the air and fuel are present at exactly the ratio to have complete combustion. RICE are operated with either fuel-rich ratios at or near stoichiometric, which are called rich-burn engines (RB), or air-rich ratios below stoichiometric, which are called lean-burn engines (LB). Undesirable emissions from RICE are primarily nitrogen oxides (NO_x; primarily nitric oxide and nitrogen dioxide), carbon monoxide (CO), and volatile organic compounds (VOCs). NO_x are formed by thermal oxidation of nitrogen from the air. CO and VOCs are formed from incomplete combustion. Rich-burn engines inherently have higher NOx emissions by design, and lean burn engines are designed to have relatively lower NOx emissions.

Colorado has undertaken regulatory initiatives to control NOx emissions from RICE, beginning in 2004. For the Denver metro area/North Front Range ozone control area, Regulation No. 7 was revised to require the installation of controls on new and existing rich burn and lean burn RICE larger than 500 hp by May 1, 2005. Controls for rich burn RICE are non-selective catalytic reduction (NSCR) and an air-to-fuel ratio controller, which effectively controls NOx (95%), CO and VOCs. Controls for lean burn RICE are oxidation catalyst reduction, which effectively control CO and VOCs. An exemption from control for lean burn RICE could be obtained upon demonstration that cost of emission control would exceed $5,000 per ton. Selective catalytic reduction was considered for the control of NOx from lean burn engines, but was dismissed due to the high cost/effectiveness at approximately $22,000/ton (see Appendix D for complete analysis). EPA approved this requirement as part of the Colorado SIP on August 19, 2005 (70 Fed. Reg. 48652 (8/19/05)).

In December 2008, Colorado proceeded to adopt into Regulation No. 7 similar provisions for all existing RICE over 500 hp throughout the state. By July 1, 2010 all existing engines in Colorado, had to install controls as described in the paragraph above, with the one exception that the $5,000 per ton exemption applied to both lean burn and rich burn engines. The state-only provision for rich-burn RICE (which reduces NOx emissions and is codified in Regulation No. 7, Sections XVII.E.3. and 3.a.) is being included as part of the Regional Haze SIP to become federally enforceable upon EPA approval.

For RICE NOx control under the Regional Haze rule, Colorado determines that the installation of NSCR on all rich burn RICE throughout the state satisfies RP requirements. The accompanying benefits of reducing VOCs and CO also support this RP determination. Additional NOx control for lean burn RICE throughout the state is not reasonable for this planning period.

For new and modified RICE of 100 hp or greater, the state is relying on emissions controls that are required by EPA's New Source Performance Standards (NSPS) Subpart JJJJ, 40 CFR Part 60 and EPA’s National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart ZZZZ, 40 CFR Part 63. Colorado determines that this federal control program satisfies reasonable progress for these sources in this planning period.

For existing RICE less than 500 hp throughout the state, the state determines that no additional control is necessary for RP in this planning period. Colorado’s emission inventory system indicates that in the 2007/2008 timeframe, there were 538 engines less than 500 hp in the state, and these engines emitted 5,464 tons/year of NOx. At an average of about 10 tons of NOx emissions per year, controlling engines of this size is not reasonable. Many of these smaller existing engines will eventually be brought into JJJJ and ZZZZ when modified in the future, so it is reasonable to assume that additional NOx reductions will occur.

The 2018 emissions inventory assumes approximately 16,199 tons of NOx per year from RICE of all sizes in Colorado. The NOx control achieved by controlling rich burn engines in the ozone control area (approximately 7,000 tons/year) is assumed in this number. Controlling the remaining rich burn engines statewide reduces the 2018 RICE

NOx emissions inventory by approximately 5,800 tons/year to approximately 10,400 tons/year. For new RICE subject to the NSPS and NESHAP, NOx emissions reductions have not been estimated. Because the 2018 estimate of 16,199 tons/year of NOx assumed growth in uncontrolled engines and did not account for th NSPS and NESHAP, the 10,400 ton/year emissions in 2018 should be even lower. The remaining NOx from engines is attributed to existing lean burn engines which are uncontrolled for NOx (though they will eventually be brought into JJJJ and ZZZZ when modified in the future), existing rich burn engines after control, small engines, and new RICE after the application of JJJJ and ZZZZ.

A detailed 4-factor analysis for RICE can be found in Appendix D.

8.3.3 Combustion Turbines

Combustion turbines fueled by natural gas or oil are either co-located with coal-fired electric generating units or as stand-alone facilities. These units are primarily used to supplement power supply during peak demand periods when electricity use is highest. Combustion turbine units start quickly and usually operate only for a short time. However, they are capable of operating for extended periods. Combustion turbine units are also capable of operating together or independently.

Information regarding combustion turbine emissions is well recorded in the state's air emissions inventory. Typical emissions for this source type may be significant for NOx, but pipeline quality natural gas is inherently clean and low-emitting for SO2 and PM10 emissions. Combustion turbines are subject to 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines, which limit sulfur content to 0.8 percent by weight, supported by monitoring and testing. Subpart GG also limits nitrogen oxides to 117.8 percent by volume at 15 percent oxygen on a dry basis (60.332(a)(1)), supported by monitoring and testing. The majority of combustion turbines are installed with Continuous Emissions Monitoring Systems (CEMs).

RP evaluations are triggered for turbines that are co-located at BART or RP sources that have been determined to be significant because they have a Q/d impact of greater than 20 (see section 8.3 below for a description of this "significance" determination). The state analyzed total state-wide combustion turbine emissions averaged over the 2006 – 2008 Reasonable Progress baseline period. There are five Reasonable Progress facilities with combustion turbines – PSCo Valmont Generating Station, PSCo Arapahoe Generating Station, Colorado Springs Utilities Nixon Plant, Platte River Power Authority Rawhide Energy Station, and PSCo Pawnee Generating Station. Of these, only two turbines located at the Nixon Plant emit significant levels of visibility impairing emissions, as defined by the federal Prevention of Significant Deterioration (PSD) significance levels:

- NO_x – 40 tons per year
- SO_2 – 40 tons per year
- PM_{10} – 15 tons per year

Facility – Turbine	Total 2006 – 2008 Averaged NOx Annual Emissions (tpy)	Total 2006 – 2008 Averaged SO2 Annual Emissions (tpy)	Total 2006 – 2008 Averaged PM10 Annual Emissions (tpy)	Greater than *de minimis* levels?
Front Range Power Plant – Turbine #1	159.6	2.9	4.9	Yes – NOx only
Front Range Power Plant – Turbine #2	147.9	2.8	4.9	Yes – NOx only

The combustion turbines at the Front Range Power Plant were installed with advanced dry-low NOx combustion systems, and based on 2006 – 2008 CEMs data and AP-42 emission factors, are achieving 89.4% and 90.1% NOx reductions, respectively.

There is one feasible emission control technology available for these turbines is adding post combustion technology – selective catalytic reduction (SCR) which, in good working order can achieve removal efficiencies ranging from 65 – 90 percent from uncontrolled levels.

Applying SCR would achieve up to an additional 90% control efficiency to both turbines and could result in about 275 tons of NOx reduced annually with a capital expenditure of at least $15 million. The state estimates that SCR for these turbines will range from approximately $57,000 - $62,000 per ton of NOx reduced annually. In the state's judgment for this planning period for Reasonable Progress, the potential 275 tons per year of NOx reductions are not cost-effective. The state has determined that NOx RP for combustion turbines is existing controls and emission limits.

A detailed 4-factor analysis for combustion turbines can be found in Appendix D.

8.4 Determination of Point Sources Subject to Reasonable Progress Evaluation

Colorado refined the RP analysis referred to in Section 8.2 (using the latest WRAP emission inventory data) to select specific point sources to evaluate for RP control[38]. This RP screening methodology involves a calculated ratio called "Q-over-d", that evaluates stationary source emissions (mathematical sum of actual SO2, NOx and PM emissions in tons per year, denoted as "Q") divided by the distance (in kilometers, denoted as "d") of the point source from the nearest Class I area.

The State evaluated the visibility impact sensitivity of different Q/d thresholds and determined that a Q/d ratio equal to or greater than "20" approximated a delta deciview (Δdv) impact ranging from 0.06 Δdv to 0.56 Δdv. The resultant average of the range is about 0.3 Δdv, which is a more conservative RP threshold than the 0.5 Δdv that was used in determining which sources would be subject-to-BART under the federal BART regulations. The delta deciview impact was determined by evaluating CALPUFF

[38] *Reasonable Progress Analysis of Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas,* March 31, 2010. See the Technical Support Document

modeling, conducted by the state in 2005, for the ten subject-to-BART stationary sources. Since the Q/d methodology involves consideration of PM emissions, the state has added PM (PM-10) emissions to the RP evaluation process.

The evaluation of potential RP sources involved all Colorado stationary sources with actual SO2, NOx or PM10 emissions over 100 tons per year based on Air Pollution Emissions Notice (APEN) reports from 2007. The one-hundred-thirteen (113) sources identified as exceeding the 100 tons/year threshold for any of the three pollutants (see Figure 8-3) were further analyzed, using ArcGIS mapping, to determine the exact distance from the centroid of the source to the nearest Class I area boundary. The Q/d was calculated for each source, and Table 8-1 lists the sixteen (16) point sources that are equal to or greater than the Q/d of 20 threshold. These sixteen sources will be referred to as “significant” sources for purposes of reasonable progress.

Figure 8-3: Point Sources with >100 TPY of Emissions

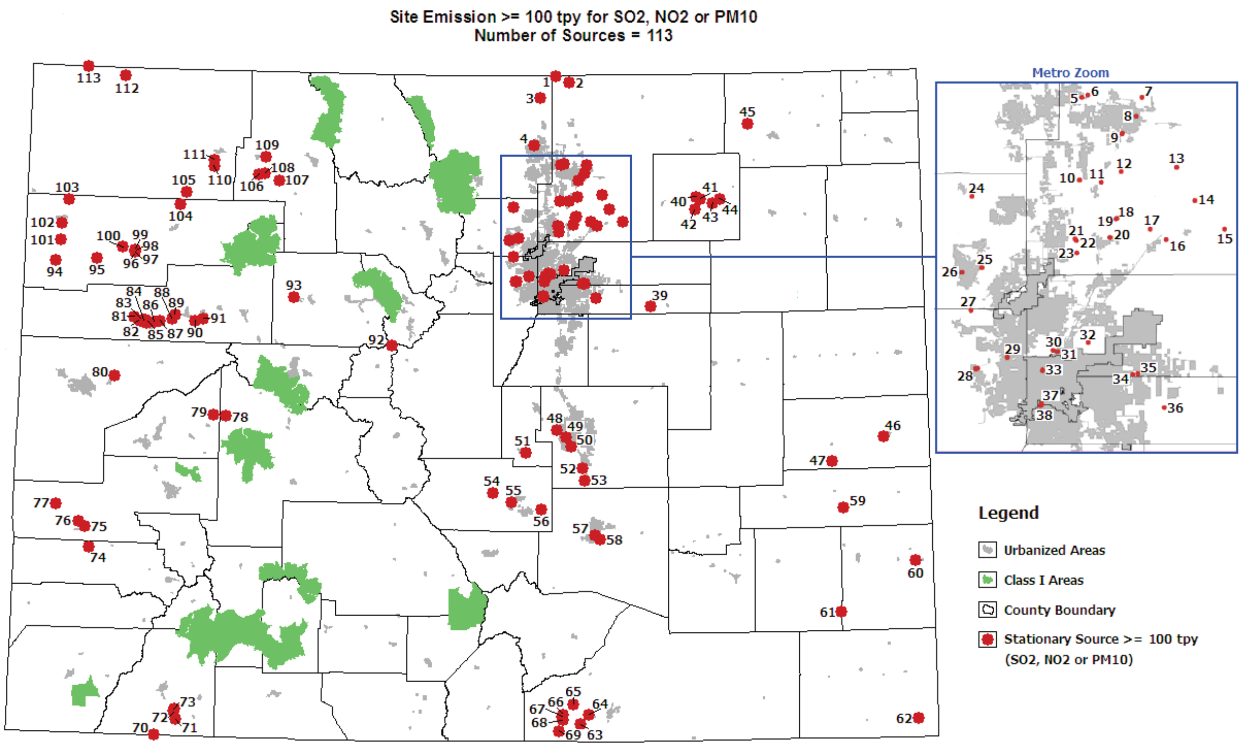


Table 8-1: Colorado Significant Point Sources with a Q/d ≥ 20

ArcGIS DATA - Statewide Sources over 100 tpy for SO2, NOx and PM10 (based on 2007 data)

Count	FACILITY NAME	SO2 [tpy]	NO2 [tpy]	PM10 [tpy]	Q [tpy]	Closest CIA	d [km]	Q/d
1	PLATTE RIVER POWER AUTHORITY - RAWHIDE	854	1,808	134	2,796	Rocky Mnt NP	56.0	49.9
2	CEMEX INC. - LYONS CEMENT	87	2,479	418	2,984	Rocky Mnt NP	24.8	120.3
3	PUBLIC SERVICE CO - VALMONT	749	2,355	58	3,162	Rocky Mnt NP	34.8	90.9
4	COLORADO ENERGY NATIONS CORPORATION	2,626	1,786	42	4,453	Rocky Mnt NP	54.5	81.7
5	PUBLIC SERVICE CO - CHEROKEE	7,116	10,205	261	17,581	Rocky Mnt NP	65.3	269.2
6	PUBLIC SERVICE CO - ARAPAHOE	2,496	2,922	178	5,595	Rocky Mnt NP	73.3	76.3
7	PUBLIC SERVICE CO - PAWNEE	13,073	4,645	193	17,911	Rocky Mnt NP	155.7	115.0
8	COLORADO SPRINGS UTILITIES - DRAKE	8,431	3,826	251	12,507	Great Sand Dunes NP	114.0	109.7
9	COLORADO SPRINGS UTILITIES - NIXON	3,883	2,656	129	6,668	Great Sand Dunes NP	104.4	63.9
10	AQUILA INC. - W.N. CLARK STATION	1,480	869	44	2,393	Great Sand Dunes NP	58.7	40.8
11	HOLCIM (US) INC. PORTLAND CEMENT	372	2,589	288	3,250	Great Sand Dunes NP	66.0	49.2
12	PUBLIC SERVICE CO - COMANCHE	13,854	8,415	178	22,447	Great Sand Dunes NP	84.5	265.6
13	TRI STATE GENERATION - NUCLA	1,509	1,716	101	3,327	Black Canyon NP	70.6	47.1
14	PUBLIC SERVICE CO - CAMEO	2,586	1,051	112	3,750	Black Canyon NP	70.5	53.2
15	PUBLIC SERVICE CO - HAYDEN	2,657	7,694	284	10,634	Mt Zirkel WA	31.6	336.5
16	TRI STATE GENERATION - CRAIG	3,586	16,807	235	20,628	Flat Tops WA	47.7	432.4
	Totals:	65,358	71,821	2,906				

Note that the APEN reports may not represent actual annual emissions, as Colorado Regulation 3 requires APEN reports to be updated every five years if no significant emissions increases have occurred at the source. Further, sources do not pay APEN emission fees on fugitive dust, thus sources with significant fugitive dust emissions may report potential rather than actual emissions in the APEN. The state contacted sources to ensure that actual emissions were used as much as possible since many sources over-estimate emissions in APENs. This ensures that correct emissions are used for the purposes of Reasonable Progress.

Set forth below are summaries of each of the sixteen significant sources. Many of these are BART sources, and emission control analyses and requirements for those sources are documented in Chapter 6 of this document. The BART determinations represent best available retrofit control and also satisfy RP requirements, and no further assessment of emissions controls for these facilities is necessary for reasonable progress during this planning period. In this regard, the state has already conducted BART analyses for its BART sources that are largely based on an assessment of the same factors to be addressed in establishing RPGs. Thus, Colorado has reasonably concluded that any control requirements imposed in the BART determination also satisfy the RP related requirements in the first planning period. *See* U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 4-2 (June 2007).

1. The state has determined that Platte River Power Authority's Rawhide Power Plant (unit 1) is a subject-to-RP source and has conducted an emission control analysis for the unit (see below).
2. The CEMEX Portland cement manufacturing facility in Lyons, Colorado, is a subject-to-BART source that the Division reviewed for best available retrofit controls for SO2, NOx and PM emissions. The state has determined that the CEMEX BART determinations for the kiln and the dryer (see Chapter 6) satisfy the SO2, NOx and PM BART/RP requirements in this planning period.
3. The Public Service Company of Colorado (PSCo) Valmont Power Plant (unit 5) is a subject-to-BART source that is included in a better than BART alternative for SO2

and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the state has determined that the facility's closure by 2018 satisfies the PM BART/RP requirements in this planning period.

4. The Colorado Energy Nations Corporation (CENC) operates two subject-to-BART industrial boilers (boilers 4 & 5) that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The CENC BART determination for these two boilers (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period. For boiler 3, the state has determined it to be subject-to-RP and has conducted an emission control analysis for the boiler (see below).
5. The PSCo Cherokee Power Plant has four units (1, 2, 3 & 4); unit 4 is a subject-to-BART source. All of the units are included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the closure of units 1, 2 and 3 by 2018 satisfies the PM RP requirements in this planning period. For unit 4, the BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
6. The PSCo Arapahoe Power Plant (units 3 & 4) is a subject-to-RP source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the closure of unit 3 by 2018 satisfies the PM RP requirements in this planning period; for unit 4 the conversion to repower from coal to natural gas satisfies the PM RP requirements in this planning period.
7. The PSCo Pawnee Power Plant (unit 1) is a subject-to-BART source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. The BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
8. The Colorado Springs Utilities (CSU) Drake Power Plant (units 5-7) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Drake BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.
9. The state has determined that the CSU Nixon Plant (unit 1) and the co-located Front Range Power Plant are subject-to-RP sources and has conducted emission control analyses for these sources (see below).
10. The state has determined that the Black Hills Energy Clark Power Plant (units 1 and 2) is a subject-to-RP source and has conducted an emission control analysis for the source (see below).
11. The state has determined that the Holcim Portland cement manufacturing facility (kiln and dryer) is subject-to-RP and has conducted an emission control analysis for the source (see below).
12. The PSCo Comanche Power Plant (units 1 and 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Comanche BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.

13. The state has determined that the Tri-State Generation and Transmission Association's Nucla Power Plant is subject-to-RP and has conducted an emission control analysis for the source (see below).
14. The state has determined that the PSCo Cameo Power Plant is subject-to-RP. With the closure of the facility by 2012, the SO2, NOx, and PM RP requirements are satisfied in this planning period. A regulatory closure requirement is contained in this chapter and in Regulation No. 3.
15. The PSCo Hayden Power Plant (units 1 & 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Hayden BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.
16. The Tri-State Generation and Transmission Association's Craig Power Plant has three units (1, 2, and 3); units 1 & 2 are subject-to-BART that the Division reviewed for best available retrofit controls for SO2, NOx and PM emissions. The BART determinations for units 1 and 2 (see Chapter 6) satisfy the SO2, NOx and PM BART/RP requirements in this planning period. The state has determined that unit 3 is subject-to-RP and has conducted an emission control analysis for the unit (see below).

Consequently, there are seven significant sources identified as subject-to-RP that Colorado has evaluated for controls in the RP analysis process:

- Rawhide Unit 1
- CENC Boiler 3
- Nixon Unit 1
- Clark Units 1, 2
- Holcim Kiln, Dryer
- Nucla
- Craig Unit 3

8.5 Evaluation of Point Sources for Reasonable Progress

In identifying an appropriate level of control for RP, Colorado took into consideration the following factors:

(1) The costs of compliance,
(2) The time necessary for compliance,
(3) The energy and non-air quality environmental impacts of compliance, and
(4) The remaining useful life of any potentially affected sources.

Colorado has concluded that it also appropriate to consider a fifth factor: the degree of visibility improvement that may reasonably be anticipated from the use of RP controls. States have flexibility in how they take these factors into consideration, as well as any other factors that the state determines to be relevant. *See* U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 5-1 (June 2007).

8.5.1 Rationale for Point Source RP Determinations

Similar to the process for determining BART as described in Chapter 6, in making its RP determination for each Colorado source, the state took into consideration the five factors on a case-by case basis, and for significant NOx controls the state also utilized the guidance criteria set forth in Section 6.4.3 consistent with the factors. Summaries of the state's facility-specific consideration of the factors and resulting determinations for each RP source are provided in this Chapter 8. Documentation reflecting the state's analyses and supporting the state's RP determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix D of this document and the TSD.

8.5.1.1 The costs of compliance. The Division requested, and the companies provided, source-specific cost information for each RP unit. The cost information relates primarily to the installation and operation of new SO2 and NOx control equipment. The cost for each unit is summarized below, and the state's consideration of this factor for each source is presented in detail in Appendix D.

8.5.1.2 The time necessary for compliance.

Regulation No 3, Part F, Section VI.B.4. requires facilities subject to RP determinations to submit a compliance plan within 60 days of SIP approval. Based on Colorado facility submittals, the Division anticipates that the time necessary for facilities to complete design, permitting, procurement, and system startup, after SIP approval, would be approximately 3 - 5 years. This timeframe may vary somewhat due to the necessary major maintenance outage with other regionally affected utilities.

8.5.1.3 The energy and non-air quality environmental impacts of compliance. This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each RP unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO2, as further described below.

8.5.1.4 The remaining useful life of the source. For those sources set to retire by 2018, the state established a regulatory closure requirement in this chapter and in Regulation No. 3. For those sources not expected to retire over the next twenty years, this factor did not affect any of the state's RP determinations.

8.5.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of RP. The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of RP control, where relevant and the information was available, although degree of visibility improvement is not an express element of four factors to be considered during reasonable progress under EPA's federal regulations and guidelines. Modeling information where relevant and available for each RP determination is presented below and in Appendix D.

8.5.1.6 Overview of the RP Determinations for Each Source. This section presents an overview of the RP determinations for the significant point sources not addressed in Chapter 6.

The regional haze rule gives the states broad latitude on how the four statutory factors, and any other factors a state deems to be relevant, may be considered to determine the appropriate controls for RP. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the factors in reaching a determination. The manner and method of consideration is left to the state's discretion; states are free to determine the weight and significance to be assigned to each factor.

The Division has reviewed available particulate controls applicable to RP facilities. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM". *See,* 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix D.

The Division also reviewed various SO2 controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 8, in Appendix D and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. *See,* 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix D.

With respect to NOx controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NOx controls, as appropriate.

When determining the emission rates for each source, the state referred to the available literature and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that RP relates to retrofitting sources (vs. new or reconstructed facilities), a review of other BART and RP determinations used to better substantiate the source specific information provided by the source.

For the purposes of the RP review for the three pollutants that the state is assessing for the seven facilities, SO2 and PM have been assessed utilizing the factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO2 and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NOx controls on reasonable progress electric generating units, for reasons described below, the state is employing guidance criteria to aid in its RP assessment, largely because significant NOx add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of control for these sources.

With respect to SO2 emissions, there are currently ten flue gas desulphurization lime spray dryer (LSD) SO2 control systems operating at electric generating units in Colorado.[39] There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO2 emissions in the state and other non-air quality considerations. The state has determined in the past that these systems can be cost-effective for sources in Colorado. With this familiarity and use of the emissions control technology, the state has assessed SO2 emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to NOx emissions, post-combustion controls for NOx are generally not employed in Colorado. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are currently no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NOx emissions.

In assessing and determining appropriate NOx controls at significant sources for individual units for visibility improvement under the Regional Haze rule, for reasonable progress, the state has considered the relevant factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight. In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors.

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[39] EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, Valmont Unit 5.

More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (*e.g.*, expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NOx) from the atmosphere, or $/ton of NOx removed); and, (ii) visibility improvement expected from the control options analyzed (*e.g.*, expressed as visibility improvement in delta deciview (Δdv) from CALPUFF air quality modeling).

Accordingly, as part of its reasonable progress factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state's general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of RP control on a case by case basis.

The cost criteria presented above is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls. For example, the $5,000/ton criterion is consistent with Colorado's retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.[40] In that case, a $5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.[41] The $5,000/ton criterion is also consistent with and within the range of the state's implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control

[40] Air Quality Control Commission Regulation No. 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

[41] The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

costs for Colorado RACT can be in the range of $5,000/ton (and lower), while control costs for Colorado BACT can be in the range of $5,000/ton (and higher).

In addition, as it considers the pertinent factors for reasonable progress, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NOx controls, *i.e.*, SCR, have the ability to provide significant NOx reductions, but also have initial capital dollar requirements that can approach or exceed $100 million per unit.[42] The lesser-performing post-combustion NOx controls, *e.g.*, SNCR, reduce less NOx on a percentage basis, but also have substantially lower initial capital requirements, generally less than $10 million.[43] The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NOx controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.[44] For the lesser-performing add-on NOx controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area.

Employing the foregoing guidance criteria for post-combustion NOx controls, as part of considering the relevant factors for reasonable progress, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

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[42] *See, e.g.,* Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, $83MM; Public Service of Colorado, Hayden Unit #2, $72MM; Tri-State Generation and Transmission, Craig Station Unit #1, $210MM.

[43] *See, e.g.*, Appendix C, reflecting CENC (Tri-gen), Unit #4, $1.4MM; Public Service Company of Colorado, Hayden Unit #2, $4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, $13.1MM

[44] The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. Colorado is applying these same criteria to RP sources, as a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

8.5.2 Point Source RP Determinations

The following summarizes the RP control determinations that will apply to each source.

Table 8-2 RP Control Determinations for Colorado Sources

Emission Unit	Assumed** NOx Control Type	NOx Emission Limit	Assumed** SO_2 Control Type	SO_2 Emission Limit	Assumed** Particulate Control and Emission Limit
Rawhide Unit 101	Enhanced Combustion Control*	0.145 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
CENC Unit 3	No Control	246 tons per year (12-month rolling total)	No Control	1.2 lbs/MMBtu	Fabric Filter Baghouse* 0.07 lb/MMBtu
Nixon Unit 1	Ultra-low NOx burners with Over-Fire Air	0.21 lb/MMBtu (30-day rolling average)	Lime Spray Dryer	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Clark Units 1 &2	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Holcim - Florence Kiln	SNCR	2.73 lbs/ton clinker (30-day rolling average) 2,086.8 tons/year	Wet Lime Scrubber*	1.30 lbs/ton clinker (30-day rolling average) 721.4 tons/year	Fabric Filter Baghouse* 246.3 tons/year
Nucla	No Control	0.5 lb/MMBtu (30-day rolling average)	Limestone Injection*	0.4 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 3	SNCR	0.28 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.15 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.013 lb/MMBtu filterable PM 0.012 lb/MMBtu PM10
Cameo	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011

* Controls are already operating

** Based on the state's RP analysis, the "assumed" technology reflects the control option found to render the RP emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

For all RP determinations, approved in the federal State Implementation Plan, the state affirms that the RP emission limits satisfy Regional Haze requirements for this planning period (through 2017) and that no other Regional Haze analyses or Regional Haze controls will be required by the state during this timeframe.

The following presents an overview of Colorado's RP control determinations:

8.5.2.1 RP Determination for Platte River Power Authority - Rawhide Unit 101

This facility is located in Larimer County approximately 10 miles north of the town of Wellington, Colorado. Unit 101 is a 305 MW boiler and is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Platte River Power Authority (PRPA) submitted a "Rawhide NOx Reduction Study" on January 22, 2009 as well as additional relevant information on May 5 and 6, 2010.

SO2 RP Determination for PRPA Rawhide Unit 101

Dry FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing control achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Rawhide Unit 101 operates a lime spray dryer FGD currently achieving over 72 percent SO2 reduction. The state has elected to consider EPA's BART Guidelines as relevant to the RP evaluation of Rawhide Unit 101 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. PRPA and the Division are not aware of SO_2 scrubber performance additives applicable to the Unit 101 SDA system.
- *Use of more reactive sorbent*: Lime quality is critical to achieving the current emission limit. PRPA utilizes premium lime at higher cost to ensure compliance with existing limits. The lime contract requires >92% reactivity (available calcium oxide) lime to ensure adequate scrubber performance. PRPA is already using a highly reactive sorbent, therefore this option is not technically feasible.
- *Increase the pulverization level of sorbent*: The fineness of sorbents used in dry-sorbent injection systems is a consideration and may improve performance for these types of scrubbers. Again, the Unit 101 SO_2 scrubber is a semi-dry SDA type scrubber that utilizes feed slurry that is primarily recycle-ash slurry with added lime slurry. PRPA recently completed SDA lime slaking sub-system improvements that are designed to improve the reactivity of the slaked lime-milk slurry.
- *Engineering redesign of atomizer or slurry injection system*: The Unit 101 SDA scrubber utilizes atomizers for slurry injection. The scrubber utilizes three reactor compartments, each with a single atomizer. PRPA maintains a spare atomizer to ensure high scrubber availability. The atomizers utilize the most current wheel-

nozzle design. The state and PRPA concur that PRPA utilizes optimal maintenance and operations; therefore, a lower SO2 emission cannot be achieved with improved maintenance and/or operations.

Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Rawhide Unit 101 – SO2 Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Fuel switching – NG	906	$237,424,331	$262,169

There are no energy and non-air quality impacts associated with this alternative.

There are no remaining useful life issues for the alternative as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to more stringent SO2 emission limits as a demonstration are as follows:

SO2 Control Method	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.11	
Existing Dry FGD	0.09	0.01
Dry FGD – tighter limit	0.07	0.03
Fuel switching – NG	0.00	0.87

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that SO2 RP is the following SO2 emission rates:

Rawhide Unit 101: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the installation and operation of lime spray dryers (LSD). The state has determined that these emissions rates are achievable without additional capital investment through the four-factor analysis. Upgrades to the existing SO2 control system were evaluated, and the state determines that meaningful upgrades to the system are not available. Lower SO2 limits would not result in significant visibility improvement (less than 0.02 delta deciview) and would likely result in frequent non-compliance events and, thus, are not reasonable.

Particulate Matter RP Determination for PRPA Rawhide

The state has determined that the existing Unit 101 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}.

The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx RP Determination for PRPA Rawhide

Enhanced combustion control (ECC), selective non-catalytic reduction (SNCR), fuel switching to natural gas (NG), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Rawhide Unit 101. Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Rawhide Unit 101 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
ECC	448	$288,450	$644
SNCR	504	$1,596,000	$3,168
Fuel switching – NG	545	$237,424,331	$435,681
SCR	1,185	$12,103,000	$10,214

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	NOx Annual Emission Rate (lb/MMBtu)	98^{th} Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.302	
ECC	0.126	0.45
SNCR	0.121	0.46
Fuel Switching – NG	0.118	0.47
SCR	0.061	0.59

It should be noted that the daily maximum (3-yr) value of 0.302 lb/MMBtu was a substituted value from CAMD. The next highest 24-hour value was 0.222 lb/MMBtu, 26% lower than the modeled value. However, the Division did not conduct revised modeling since it was determined that it would not change the State's RP determination.

Switching to natural gas was eliminated from consideration due to the excessive cost/effectiveness ratio and degree of visibility improvement less than 0.5 dV.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Rawhide Unit 101 is the following NOx emission rate:

Rawhide Unit 1: 0.145 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of enhanced combustion control. The dollars per ton control cost, coupled with notable visibility improvements of 0.45 delta dv, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. SNCR would achieve similar emissions reductions to enhanced combustion controls and would afford a minimal additional visibility benefit (0.01 delta deciview), but at a significantly higher dollar per ton control cost compared to the selected enhanced combustion controls, so SNCR was not determined to be reasonable by the state.

A complete analysis that supports the RP determination for the Rawhide facility can be found in Appendix D.

8.5.2.2 RP Determination for Colorado Energy Nations Company (CENC) Boiler 3

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boiler 3 is considered by the State to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. CENC submitted a "Reasonable Progress Control Evaluation" on May 7, 2010 as well as additional relevant information on February 8, 2010.

The CENC facility includes five coal-fired boilers that supply steam and electrical power to Coors Brewery. Three of the boilers emit above 40 tons or more of haze forming pollution. Of these three boilers, Units 4 and 5 are subject to BART, and Unit 3 is subject to RP. Unit 3 is rated as follows: 225 MMBtu/hr, which is approximately equivalent to 24 MW, based on the design heat rate.

SO2 RP Determination for CENC – Boiler 3

Dry sorbent injection (DSI) and fuel switching to natural gas were determined to be technically feasible for reducing SO2 emissions from Boiler 3. Dry FGD is not technically feasible for Boiler 3 due to space constraints onsite. These options were considered as potentially RP by the state. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by PRPA it was evaluated by the state.

Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

CENC Boiler 3 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI – Trona	147	$1,340,661	$9,114
Fuel Switching – Natural Gas	245	$1,428,911	$5,828

DSI – Trona and fuel switching to natural gas were eliminated from consideration due to excessive cost/effectiveness ratio.

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider.

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce minimal visibility impacts (<<0.10 dv).

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is an emission rate of:

CENC Boiler 3: 1.2 lbs/MMBtu

Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement (<< 0.10 dv) afforded.

Particulate Matter RP Determination for CENC – Boiler 3

The state has determined that the existing Boiler 3 regulatory emissions limit of 0.07 lb/MMBtu (PM/PM10) corresponding with the original Industrial Boiler MACT standard represents the most stringent control option. The units are exceeding a PM control efficiency of 90%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for CENC – Boiler 3

Flue gas recirculation (FGR), selective non-catalytic reduction (SNCR), rotating overfire air (ROFA) fuel switching to natural gas, and three options for selective catalytic reduction (RSCR, HTSCR, and LTSCR) were determined to be technically feasible for reducing NOx emissions at CENC Boiler 3. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by CENC it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

CENC Boiler 3 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
FGR	33.7	$1,042,941	$30,929
SNCR	50.6	$513,197	$10,146
Fuel switching – NG	84.3	$1,428,911	$16,950
ROFA w/ Rotamix	77	$978,065	$9,496
Regenerative SCR	96.3	$978,065	$10,160
High temperature SCR	125.6	$1,965,929	$15,651
Low temperature SCR	144.5	$2,772,286	$19,187

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce visibility impacts below the guidance visibility criteria discussed in section 8.4 above.

All NOx control options were eliminated from consideration due to the excessive cost/effectiveness ratios and small degree of visibility improvement.

Based on review of historical actual load characteristics of this boiler, the state determines to be appropriate an annual NOx ton/year limit based on 50% annual capacity utilization based on the maximum capacity year in the last decade (2000). This annual capacity utilization will then have a 20% contingency factor for a variety of reasons specific to Boiler 3 further explained in Appendix D.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Boiler 3 is the following NOx emission rate

CENC Boiler 3: 246 tons/year (12-month rolling total)

Though other controls achieve better emissions reductions, the expense of these options coupled with predicted minimal visibility improvement (<< 0.10 dv) were determined to be excessive and above the guidance cost criteria discussed in section 8.4 of the Regional Haze SIP, and thus not reasonable

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is likely below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively (as demonstrated in the BART determination for CENC Boiler 4). Moreover, the incremental visibility improvement associated with SNCR or SCR is likely not substantial when compared to the visibility improvement achieved by the selected limits. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Boiler 3.

A complete analysis that supports the RP determination for the CENC facility can be found in Appendix D.

8.5.2.3 RP Determination for Colorado Springs Utilities' - Nixon Unit 1

The Nixon plant is located in Fountain, Colorado in El Paso County. Nixon Unit 1 and two combustion turbines at the Front Range Power Plant are considered by the Division to be eligible for the purposes of Reasonable Progress, being industrial sources with the potential to individually emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Colorado Spring Utilities (CSU) provided RP information in "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 and additional relevant information on May 10, 2010.

SO2 RP Determination for CSU – Nixon

Dry sorbent injection (DSI) and dry FGD were determined to be technically feasible for reducing SO2 emissions from Nixon. These options were considered as potentially RP by the state. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Nixon Unit 1 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI – Trona	2,473	$9,438,692	$1,997
Dry FGD @ 78% control (0.10 lb/MMBtu annual average)	3,215	$12,036,604	$3,744
Dry FGD @ 85% control (0.07 lb/MMBtu annual average)	3,392	$13,399,590	$3,950

The energy and non-air quality impacts of the remaining alternatives are as follows:

- DSI – reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as replacement for concrete and rendering it landfill material only
- Dry FGD – less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Nixon – Unit 1	
	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.45	
DSI	0.18	0.44
Dry FGD (LSD)	0.10	0.46
Dry FGD (LSD)	0.07	0.50

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience, 30-day SO2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 5% for all SO2 emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is the following SO2 emission rate:

Nixon Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with semi dry FGD (LSD). A lower emissions rate for Unit 1 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.04 delta deciview). Also, stringent retrofit emission limits below 0.10 lb/MMBtu have not been demonstrated in Colorado, and the state determines that a lower emission limit is not reasonable in this planning period.

The LSD control for Unit 1 provides 78% SO_2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 1: $3,744 per ton SO_2 removed; 0.46 deciview of improvement

An alternate control technology that achieves the emissions limits of 0.11 lb/MMBtu, 30-day rolling average, may also be employed.

Particulate Matter RP Determination for CSU – Nixon

The state determines that the existing Unit 1 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limits is RP for $PM/PM_{10.}$ The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for CSU – Nixon

Ultra low NOx burners (ULNB), SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Nixon Unit 1.

The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Nixon Unit 1 - NO_x Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Ultra-low NOx Burners (ULNBs)	471	$567,000	$1,203
Overfire Air (OFA)	589	$403,000	$684
ULNBs+OFA	707	$907,000	$1,372
Selective Non-Catalytic Reduction (SNCR)	707	$3,266,877	$4,564
ULNB/SCR layered approach	1,720	$11,007,000	$6,398
Selective Catalytic Reduction (SCR)	1,720	$11,010,000	$6,400

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB – not significant
- ULNB – not significant
- SNCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Nixon – Unit 1	
	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.26	
ULNB	0.21	0.15
OFA	0.19	0.15
ULNB+OFA	0.18	0.16
SNCR	0.18	0.16
ULNB + SCR	0.07	0.24
SCR	0.07	0.24

SCR options were eliminated from consideration due to the excessive cost/effectiveness ratios and degree of visibility improvement.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Nixon Unit 1 is the following NOx emission rates:

Nixon Unit 1: 0.21 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with ultra-low NOx burners with over fire air control. The Division notes that the ultra-low NOx burners with over-fire air-based emissions limit is the appropriate RP determination for Nixon Unit 1 due to the low cost effectiveness. SNCR would achieve similar emissions reductions at an added expense. Therefore, SNCR was determined to not be reasonable considering the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above RP determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.01 dv for SNCR and 0.09 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Nixon Unit 1.

A complete analysis that supports the RP determination for the Nixon Plant can be found in Appendix D.

8.5.2.4 RP Determination for Black Hills Clark Facility Units 1 and 2

Black Hills/Colorado Electric Utility Company, LP informed the state that the Clark Station in the Cañon City, Colorado area will be shutdown 12/31/2013, resulting in SO2, NOx and PM reductions of approximately 1,457, 861, and 72 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

8.5.2.5 RP Determination for Holcim's Florence Cement Plant

The Holcim Portland cement plant is located near Florence, Colorado in Fremont County, approximately 20 kilometers southeast of Canon City, and 35 kilometers northwest of Pueblo, Colorado. The plant is located 66 kilometers from Great Sand Dunes National Park.

In May 2002, a newly constructed cement kiln at the Portland Plant commenced operation. This more energy-efficient 5-stage preheater/precalciner kiln replaced three older wet process kilns. As a result, Holcim was able to increase clinker production from approximately 800,000 tons of clinker per year to a permitted level of 1,873,898 tons of clinker per year, while reducing the level of NO_X, SO_2, and PM/PM_{10} emissions on a pound per ton of clinker produced basis. As a part of this project, Holcim also installed a wet lime scrubber to reduce the emissions of sulfur oxides.

The Portland Plant includes a quarry where major raw materials used to produce Portland cement, such as limestone, translime and sandstone, are mined, crushed and then conveyed to the plant site. The raw materials are further crushed and blended and then directed to the kiln feed bin from where the material is introduced into the kiln.

The dual string 5-stage preheater/precalciner/kiln system features a multi-stage combustion precalciner and a rotary kiln. The kiln system is rated at 950 MMBtu per hour of fuel input with a nominal clinker production rate of 5,950 tons per day. It is permitted to burn the following fuel types and amounts (with nominal fuel heat values, where reported):

- coal (269,262 tons per year [tpy] @ 11,185 Btu/pound);
- tire derived fuel (55,000 tpy @ 14,500 Btu/pound);
- petroleum coke (5,000 tpy @ 14,372 Btu/pound);
- natural gas (6,385 million standard cubic feet @ 1,000 Btu/standard cubic foot);
- dried cellulose (55,000 tpy); and
- oil, including non-hazardous used oil (4,000 tpy @ 12,000 Btu/pound).

The clinker produced by the kiln system is cooled, grounded and blended with additives and the resulting cement product is stored for shipment. The shipment of final product from the plant is made by both truck and rail.

Emissions from the kiln system, raw mill, coal mill, alkali bypass and clinker cooler are all routed through a common main stack for discharge to atmosphere. These emissions are currently controlled by fabric filters (i.e., baghouses) for PM/PM_{10}, by the inherent recycling and scrubbing of exhaust gases in the cement manufacturing process and by a tail-pipe wet lime scrubber for SO_2, by burning alternative fuels (i.e., tire-derived fuel [TDF]) and using a Low-NO_X precalciner, indirect firing, Low-NO_X burners, staged combustion and a Linkman Expert Control System for NO_X, and by the use of good combustion practices for both NO_X and SO_2.In addition to the kiln system/main stack emissions, there are two other process points whose PM/PM_{10} emissions exceed the Prevention of Significant Deterioration (PSD) significance level thresholds and were considered as a part of this Reasonable Progress analysis: 1) the raw material extraction and alkali bypass dust disposal operations associated with the quarry, and 2) the cement processing operations associated with the finish mill. Emissions from the quarry are currently controlled through a robust fugitive dust control plan and emissions from the finish mills are controlled by a series of baghouses.

Holcim did not initially complete a detailed four-factor analysis, though it did submit limited information on the feasibility of post-combustion NO_X controls for the kiln system. In late October through early December 2010, Holcim did submit detailed information, including data on baseline emissions, existing controls and additional control options, and visibility modeling to support the reasonable progress determination process. This section has been revised to reflect this additional information.

CALPUFF modeling was conducted by the Division for the kiln system, as a part of our original analysis, using a SO_2 emission rate of 99.17 lbs/hour, a NO_X emission rate of

837.96 pounds per hour (lbs/hour), and a PM_{10} emission rate of 19.83 lbs/hour. The modeling indicates a 98^{th} percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park. Holcim provided additional visibility modeling results in a submittal made in late October 2010.

Because of the high level of existing fugitive dust controls employed at the quarry and the baghouse controls already installed on the finish mill emission points, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable additional controls on these points. Accordingly, the state has determined that no additional visibility analysis is necessary or appropriate since even the total elimination of the emissions from the quarry and finish mill would not result in any meaningful visibility improvement. For the quarry, the current PM_{10} emission limitation is 47.9 tpy (fugitive) and for the finish mill it is 34.3 tpy (point source). These limitations are included in the existing Holcim Portland Plant construction permit.

SO_2 RP Determination for Holcim Portland Plant – Kiln System

In addition to good combustion practices and the inherent recycling and scrubbing of acid gases by the raw materials, such as limestone, used in the cement manufacturing process, the Portland Plant kiln system has a tail-pipe wet lime scrubber. Holcim has reported that this combination of controls achieves an overall sulfur removal rate of 98.3% for the kiln system, as measured by the total sulfur input in to the system versus the amount of sulfur emitted to atmosphere. Holcim has also reported that they estimate that the wet scrubber at the Portland Plant achieves an overall removal efficiency of over 90% of the SO_2 emissions entering the scrubber. This control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding SO2 emissions rates. The facility is currently permitted to emit 1,006.5 tpy of SO2 from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 1.08 pounds of SO2 per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for SO2). The actual kiln SO2 emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 0.51 pound of SO2 per ton of clinker, with a standard deviation of 0.26 pound per ton. The highest annual emission rate in the baseline years was 0.95 pound per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for SO_2. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emissions limit of 1.30 pounds of SO_2 per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability. The long-term annual limit was calculated at 721.4 tpy by multiplying the long-term baseline SO_2 value of 0.77 lb/ton (the mean of 0.51 pound per ton plus one standard deviation of 0.26 pound per ton) by the annual clinker limit of 1,873,898 tpy, and then dividing by 2,000 pounds per ton.

Because there are no changes to the existing controls for SO2, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

For the kiln system, based upon our consideration and weighing of the four factors, the state has determined that no additional SO2 emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technologies – the inherent recycling and scrubbing effect of the process itself followed by a tail-pipe wet lime scrubber. The RP analysis provides sufficient basis to establish a short-term SO_2 emission limit of 1.30 pound per ton of clinker on a 30-day rolling average basis and a long-term annual emission limit of 721.4 tons of SO_2 per year (12-month rolling total) for the kiln system. There is no specific visibility improvement associated with this emission limitation.

Finally, on August 9, 2010, EPA finalized changes to the New Source Performance Standards (NSPS) for Portland Cement Plants and to the Maximum Achievable Control Technology standards for the Portland Cement Manufacturing Industry (PC MACT). The NSPS requires, new, modified or reconstructed cement kilns to meet an emission standard of 0.4 pound of SO2 per ton of clinker on a 30-day rolling average or a 90% reduction as measured at the inlet and outlet of the control device. While the new NSPS does not apply to the Holcim Portland Plant because it is an existing facility, it is important to note that the estimated level of control achieved by Holcim's wet scrubber (~90%) is consistent with the level of control prescribed by the NSPS for new sources.

Particulate Matter RP Determination for Holcim Portland Plant – Kiln System

The state has determined that the existing fabric filter baghouses installed on the kiln system represent the most stringent control option. Holcim has reported a nominal control efficiency for the kiln system baghouses at 99.5%. The units are exceeding a PM control efficiency of 95% and this control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding PM_{10} emissions rates. The facility is currently permitted to emit 246.3 tpy of PM_{10} from the kiln system main stack (includes emissions from the clinker cooler). At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 0.26 pound of PM_{10} per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for PM_{10}). The actual kiln system PM_{10} emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) average to a rate of 0.16 pound of PM_{10} per ton of clinker (combined emissions from main stack). This value is derived from the limited annual stack test data, which are effectively snapshots in time, and does not take into account the short-term inherent variability in the manufacturing process, raw material and fuel.

Because there are no changes to the existing controls for PM_{10}, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

As a part of our original analysis, the state modeled possible visibility improvements associated with two emission rates – the baseline emission rate of 0.08 pound of PM_{10} per ton of clinker (19.83 lbs/hour) and a rate of 0.04 pound of PM_{10} per ton of clinker (9.92 lbs/hour). This analysis assumed the baseline emissions were all attributable to the kiln (i.e., no contribution from the clinker cooler) to assess the impact of a possible reduction of the kiln emission limit. There was no change to the 98th percentile impact deciview value from 19.83 lbs/hour to 9.92 lbs/hour and therefore, no visibility improvement associated with this change. The state's modeling results showed that the most significant contributors to the visibility impairment from the Portland Plant were nitrates (NO_3) followed by sulfates (SO_4).The contribution of PM_{10} to the total visibility impairment was insignificant in the analysis. The level of PM_{10} emissions evaluated had no discernable impact on visibility.

For the kiln system, based upon our consideration and weighing of the four factors and the very limited impact of PM_{10} emissions from the kiln system on visibility impairment, the state has determined that no additional PM_{10} emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technology – fabric filter baghouses. These baghouses and the current permit limit of 246.3 tpy of PM_{10} (12-month rolling total) from the kiln system main stack (including emissions from the clinker cooler) represent RP for this source. Furthermore, the Portland Plant is subject to the PC MACT and the recent amendments to the PC MACT include new, lower standards for PM emissions. As an existing facility, the Portland Plant kiln system will be subject to this standard once it becomes effective on September 9, 2013. Compliance with the new PC MACT PM emission standards will result in further reductions in the PM_{10} emissions.

NO_X RP Determination for Holcim Portland Plant – Kiln System

There are a number of technologies available to reduce NO_X emissions from the Portland Plant kiln system below the current baseline emissions level (the current configuration already includes indirect firing, low-NO_X burners, staged combustion, a low-NO_X precalciner, and a Linkman Process Control Expert system). These include water injection (the injection of water or steam into the main flame of a kiln to act as a heat sink to reduce the flame temperature), and selective non-catalytic reduction (SNCR). These technologies were determined to be technically feasible and appropriate for reducing NO_X emissions from Portland cement kilns.

As further discussed in Appendix D, the state has determined that selective catalytic reduction (SCR) is not commercially available for the Portland Plant cement kiln system. Presently, SCR has not been applied to a cement plant of any type in the United States. Holcim notes that the major SCR vendors have either indicated that SCR is not commercially available for cement kilns at this time, or if they are willing to provide a quotation for an SCR system, the associated limitations that are attached with the quote severely undercut the efficacy of the system. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe constitutes reasonable "available" control technology for purposes of RP at the Holcim Portland Plant. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is "available" for purposes of retrofitting such control technology on an existing source.

In the preamble to the recently finalized changes to the Portland Cement MACT/NSPS, EPA stated: "However, although SCR has been demonstrated at a few cement plants in Europe and has been demonstrated on coal-fired power plants in the US, the Agency is not satisfied that it has been sufficiently demonstrated as an off-the-shelf control technology that is readily applicable to cement kilns." Based on our research and EPA's analysis for the MACT/NSPS standards, the state has eliminated SCR as an available control technology for purposes of this RP analysis.

The design of the Holcim Portland Plant does allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia-like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing NO_X to elemental nitrogen. Holcim has indicated to the state that SNCR is technically and economically feasible for the Portland Plant. In April 2008, Holcim provided information to the state on SNCR systems that was based on trials that were conducted at the plant in the 4th quarter of 2006. Holcim estimated that NO_X emissions could be reduced in the general range of 60 to 80% (based on a 1,000 pound per hour emission rate) at an approximate cost of $1,028 per ton. This was based on a short-term testing and showed considerable ammonia slip which could cause significant environmental, safety and operational issues.

The facility is currently permitted to emit 3,185.7 tpy of NOX from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 3.40 pounds of NOX per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for NOX). The actual kiln NOX emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 3.43 pounds of NOX per ton of clinker, with a standard deviation of 0.21 pound per ton. The highest annual emission rate in the baseline years was 3.67 pounds per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for NOX. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emission rate of 4.47 pounds of NOX per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability.

Holcim is permitted to burn up to 55,000 tpy of TDF annually and has been using TDF during the baseline years. Use of TDF as a NOX control strategy has been well documented and recognized by EPA. A reduction in NOX emissions of up to 30% to 40% has been reported. Since the TDF market and possible associated TDF-use incentives are unpredictable and TDF's long-term future availability is unknown, the baseline emission rate was adjusted upward by a conservative factor of 10% to account for the NOX reduction in the baseline years as a result of the use of TDF during this baseline period that might not be available in future years. This increased the baseline 30-day rolling average emissions rate from 4.47 to 4.97 pounds of NOX per ton of clinker.

An SNCR control efficiency of 50% is feasible for the Portland Plant kiln that already has number of technologies available to reduce NOX emissions including indirect firing, low-NOX burners, staged combustion, a low-NOX precalciner, and a Linkman Process Control Expert system. However, to achieve the necessary system configuration and temperature profile, SNCR will be applied at the top of the preheater tower and thus the alkali bypass exhaust stream cannot be treated. To achieve the proper cement product specifications, the Portland Plant alkali bypass varies from 0 - 30% of main kiln gas flow. Adjusting by 10%, (conservative estimate) for the alkali bypass to account for the exhaust gas that is not treated (i.e., bypassed) by the SNCR system, the overall SNCR control efficiency for the main stack will be 45%.

Based on the above discussion, the 30-day rolling average short-term limit was calculated at 2.73 pounds of NOX per ton of clinker by adjusting upward the short-term baseline emission rate of 4.47 pounds of NOX per ton clinker by 10% for TDF and then accounting for SNCR 45% overall control efficiency [4.47/0.9*(1-0.45) = 2.73]. The long-term annual limit was calculated at 2,086.8 tpy by adjusting upward the annual baseline emission rate of 3.64 lbs/ton clinker (the mean of 3.43 pounds per ton plus one standard deviation of 0.21 pound per ton) by 10% for TDF and then accounting for SNCR 45% overall control efficiency [3.64/0.9*(1-0.45) = 2.23 lb/ton]. This calculated value of 2.23 pounds per ton was then multiplied by the annual clinker limit of 1,873,898 tpy, and then divided by 2,000 pounds per ton to arrive at the 2,086.8 tpy NOX limit.

Because SNCR with existing LNB is technically and economically feasible, the state did not further consider water injection because the level of control associated with this option is not as high as with SNCR.

The following table lists the most feasible and effective option (SNCR):

NOx Control Technology	Estimated Control Efficiency	30-day Rolling Average Emissions (lb/ton of Clinker)	Annual Controlled NOx Emissions (tpy)
Baseline NOx Emissions	-	4.97	3,185.7*
SNCR w/ existing LNB	45%**	2.73	2,086.8

* Defaulted to the permit limit since the calculated baseline was higher.

** This is calculated based on the 50% SNCR removal efficiency and 10% bypass

There are no significant associated energy and non-air quality impacts for SNCR in operation on a Portland cement plant. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

Holcim Portland Plant – Kiln System				
NOx Control Technology	NOx Emission Reduction (tons/yr)	Annualized Cost ($/yr)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline NOx Emissions	-			
SNCR w/existing LNB (45% control)	1,098.9	$2,520,000*	$2,293	-

* Annualized cost is based on the estimates provided by Holcim. The state believes that the $2,293/ton value is generally representative of control costs for the scenario evaluated in this RP analysis.

As a part of their late October 2010 submittals, Holcim provided modeling data for their proposed NO_X RP limitations. The following table lists the projected visibility improvements for NO_X controls, as identified by Holcim:

Holcim Portland Plant – Kiln System		
NOx Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (Δdv)
Maximum (24-hr max) (based on modeled emission rates of 1,363 lb/hr NOx, 586 lb/hr SO_2, 86.4 lb/hr PM_{10})	0.814	N/A
SNCR w/ existing LNB (45% overall NO_X control efficiency) Limits of **2.73 lb/ton** (30-day rolling average) and **2,086.8 tons per year** (based on modeled emission rates of 750 lb/hr NO_X, 586 lb/hr SO_2, 86.4 lb/hr PM_{10})	0.526	0.288

For the kiln, the state has determined that SNCR w/existing LNB is the best NO_X control system available with NO_X RP emission limits of 2.73 pounds per ton of clinker (30-day rolling average) and 2,086.8 tons per year (12-month rolling total). The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This RP determination affords the most NO_X reduction from the kiln system (1,098.9 tpy) and contributes to significant visibility improvement.

A complete analysis that further supports the RP determination for the Holcim Portland Plant can be found in Appendix D.

8.5.2.6 RP Determination for Tri-State Generation and Transmission Association's Nucla Facility

The Tri-State Nucla Station is located in Montrose County about 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 RP Determination for Nucla – Unit 4

Limestone injection improvements, a spray dry absorber (SDA) system (or dry FGD), limestone injection improvements with a SDA, hydrated ash reinjection (HAR), and HAR with limestone injection improvements were determined to be technically feasible for reducing SO2 emissions from Nucla Unit 4. Study-level information for HAR systems at Nucla or any other EGU in the western United States were not available for use in evaluating costs. Since the option to install a dry FGD alone (even without improving limestone injection) provides a better estimated control efficiency than a HAR system plus limestone injection improvements, the HAR system was not considered further in this analysis.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Nucla Unit 4 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Limestone Injection Improvements	526	$914,290	$4,161
Spray Dry Absorber (dry FGD)	1,162	$7,604,627	$6,547
Limestone Injection Improvements + dry FGD	1,254	$9,793,222	$7,808

A dry FGD system, or limestone injection improvements plus dry FGD system, were eliminated from consideration by the state as unreasonable during this planning period due to: 1) the excessive costs, 2) that they would require replacement of an existing system and installation of a completely new system (with attendant new capital costs and facility space considerations), and 3) the lack of modeled visibility affects associated with these particular SO2 reductions.

There is no energy and non-air quality impacts associated with limestone injection improvements. For dry FGD, the energy and non-air quality impacts include less mercury removal compared to unscrubbed units and significant water usage.

There are no remaining useful life issues for alternatives as the source will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO2 emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO2 capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed “limestone injection improvements”) was evaluated and determined to not be feasible under certain operating conditions. The system cannot be ‘run harder’ with more limestone to achieve a more stringent SO2 emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO2 system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that the existing permitted SO2 emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

PM10 RP Determination for Nucla – Unit 4

The state has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for Nucla – Unit 4

Selective non-catalytic reduction (SNCR) was determined to be technically feasible for reducing NOx emissions at Nucla Unit 4. SCR is not technically feasible on a circulating fluidized bed coal-fired boiler, and is otherwise not cost-effective, as discussed in Appendix D. With respect to SNCR, however, there is substantial uncertainty surrounding the potential control efficiency achievable by a full-scale SNCR system at a CFB boiler burning western United States coal. The state and Tri-State’s estimates vary between 10 – 40% NOx reduction potential, which correlates to between $3,000 - $17,000 per ton NOx reduced and may result in between 100 to 400 tons NOx reduced per year.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. There are several qualitative reasons that NOx controls may be warranted at Nucla. First, NOx control alternatives may result in between 100 – 400 tons of NOx reduced annually. Second, Nucla is within 100 kilometers in proximity to three Class I areas, depicted in the figure above, and within approximately 115 kilometers to five Class I areas, including Utah's Canyonlands and Arches National Parks. Third, Nucla has a limited, small-scale SNCR system for emissions trimming purposes installed.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Nucla Unit 4 is no control at the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

Additional Analyses of SO2 and NOx Controls for Nucla

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO2 and NOx control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO2 reduction performance, other relevant SO2 control technologies such as lime spray dryers and flue gas desulfurization, and all NOx control options. A final analysis that addresses the state's comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and, if deemed necessary by the state and the source, testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NOx control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts the different SO2 and NOx control scenarios for Nucla. Finally, Tri-State shall propose to the state any preferred SO2 and NOx emission control strategies for Nucla by January 1, 2013.

A complete analysis that supports the RP determination for the Nucla facility can be found in Appendix D.

8.5.2.7 RP Determination for Tri-State Generation and Transmission Association's Craig Facility Unit 3

The Tri-State Craig Station is located in Moffat County about 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively. Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. Craig Units 1 and 2 are subject to BART. Craig Unit 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2,

PM_{10}) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 RP Determination for Craig – Unit 3

Dry FGD Upgrades - As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Craig Unit 3 operates a [lime spray dryer FGD] currently achieving over 80 percent SO2 reduction. The state considers EPA's BART Guidelines relevant to the RP evaluation of Craig Unit 3 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. Tri-State and the Division are not aware of SO_2 scrubber performance additives applicable or commercially available for the Unit 3 SDA system.

- *Use of more reactive sorbent/Increase the pulverization level of sorbent*: The purchase and installation of two new vertical ball mill slakers improved the ability to supply high quality slaked (hydrated) lime. A higher quality slaked lime slurry means a more reactive sorbent. Typically, slakers are not designed for particle size reduction as part of the slaking process. However, the new vertical ball mill slakers are particularly suited for slaking lime that is a mixture of commercial pebble lime and lime fines. Fines are generated at the Craig facility in the pneumatic lime handling system. Therefore, the Division concurs that TriState cannot use a more reactive sorbent or increase the pulverization level of sorbent.

- *Engineering redesign of atomizer or slurry injection system*: Both the slaked lime slurry and recycled ash slurry preparation and delivery systems were redesigned to improve overall performance and reliability. The improved system allows for slurry pressure control at both the individual reactor level and for each slurry injection header level on each reactor. Tri-State notes that consistent control of slurry parameters (pressure, flow, composition) promotes consistent and reliable SO2 removal performance. The Division concurs that with the recent redesign of the slurry injection system and expansion to two trains of recycled ash slurry preparation, no further redesigns are possible at this time.

Therefore, there are no technically feasible upgrade options for Craig Station Unit 3. However, the state evaluated the option of tightening the emission limit for Craig Unit 3 and determined that a more stringent 30-day rolling SO_2 limit of 0.15 lbs/MMBtu represents an appropriate and reasonable level of emissions control for this dry FGD control technology. Upon review of 2009 emissions data from EPA's Clean Air Markets

Division website, the state has determined that this emissions rate is achievable without additional capital investment.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Craig – Unit 3	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.33	
Dry FGD	0.15	0.26
Dry FGD	0.07	0.38

The current SO2 emission limits for Craig 3 are:

- 0.20 lb/MMBtu averaged over a calendar day, to be exceeded no more than once during any calendar month;
- 80% reduction of the potential combustion concentration of SO2, determined on a 30-day rolling average basis
- 2,125 tons/year annual emission limit

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 3: 0.15 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of existing dry FGD controls. An SO2 limit lower than 0.15 lbs/MMBtu would not result in significant visibility improvement (less than 0.2 delta deciview) and would likely result in frequent non-compliance events and, thus, is not reasonable.

PM10 RP Determination for Craig – Unit 3

The State has determined that the existing Unit 3 regulatory emissions limits of 0.013 (filterable PM) and 0.012 lb/MMBtu (PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for Craig – Unit 3

Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Unit 3.

The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 3 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	853	$4,173,000	$4,887
SCR	4,281	$29,762,387	$6,952

SCR was eliminated from consideration due to the excessive cost/benefit ratio.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	NOx Annual Emission Rate (lb/MMBtu)	98^{th} Percentile Impact (Δdv)
Daily Maximum (2^{nd} half 2009)	0.365	
SNCR	0.240	0.32
SCR	0.070	0.79

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.
Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Craig Unit 3 is the following NOx emission rates:

Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of SNCR. To the extent practicable, any technological application Tri-State utilizes to achieve this RP emission limit shall be installed, maintained, and operated in a manner consistent with good air pollution control practice for minimizing emissions. For SNCR-based emission rates at Unit 3, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls with guidance cost criteria discussed in section 8.4 above.

- Unit 3: \$4,887 per ton NOx removed; 0.32 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs.

A complete analysis that supports the RP determination for the Craig facility can be found in Appendix D.

8.5.2.8 RP Determination for Public Service Company's Cameo Station

Public Service Company informed the state that the Cameo Station east of Grand Junction, Colorado will be shutdown 12/31/2011, resulting in SO2, NOx and PM reductions of approximately 2,618, 1,140, and 225 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

Chapter 9 Long Term Strategy

The Long-Term Strategy (LTS) is required by both Phase 1 (Reasonably Attributable Visibility Impairment) and Phase 2 (Regional Haze) regulations. The LTS' of both phases are to be coordinated.

This chapter contains:

- LTS requirements;
- An overview of the current Reasonably Attributable Visibility Impairment Long Term Strategies (RAVI LTS), adopted by the Commission in 2004 and subsequently approved by EPA;
- A review of the 2004 RAVI LTS and a SIP revision;
- A Regional Haze LTS; and
- Reasonable Progress Goals for each of the state's 12 mandatory federal Class I areas.

9.1 LTS Requirements

The LTS requirements for reasonably attributable visibility impairment, as described in 40 CFR 51.306, are as follows:

- Submittal of an initial RAVI LTS and 3-year periodic review and revision (since revised to 5-year updates per 40 CFR 51.306(g)) for addressing RAVI;
- Submittal of revised LTS within three years of state receipt of any certification of impairment from a federal land manager;
- Review of the impacts from any new or modified stationary source;
- Consultation with federal land managers; and
- A report to the public and EPA on progress toward the national goal.

The LTS requirements for Regional Haze (RH), as described in 40 CFR 51.308(d)(3), are as follows:

- Submittal of an initial LTS and 5-year progress review per 40 CFR 51.308(g) that addresses regional haze visibility impairment;
- Consult with other states to develop coordinated emission management strategies for Class I areas outside Colorado where Colorado emissions cause or contribute to visibility impairment, or for Class I areas in Colorado where emissions from other states cause or contribute to visibility impairment;
- Document the technical basis on which the state is relying to determine its' apportionment of emission reduction obligations necessary for achieving reasonable progress in each Class I area it affects;
- Identify all anthropogenic sources of visibility impairing emissions;
- Consider the following factors when developing the LTS:
  (1) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
  (2) Emission limitations and schedules for compliance to achieve the RP goal;
  (3) Measures to mitigate the impacts of construction activities;

(4) Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for this purpose;
(5) Source retirement and replacement schedules;
(6) Enforceability of emission limitations and control measures; and
(7) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

The following sections 9.2 and 9.3 address these LTS requirements.

9.2 2004 RAVI Long-Term Strategy

The RAVI LTS was adopted by the Commission in November 2004. It was subsequently approved by EPA in December 2006 and is summarized below.

9.2.1 Existing Impairment

The LTS must have the capability of addressing current and future existing impairment situations as they face the state. Colorado considers that Commission Regulation No. 3, Part B, 5XIV.D ("Existing Impairment") meets this LTS requirement regarding existing major stationary facilities and provides Federal Land Managers (FLMs) the opportunity to certify whether an existing stationary source(s) is likely reasonably attributable to existing visibility impairment and potentially subject to BART. The state believes existing regulations along with strategies and activities outlined below have together provided for reasonable progress toward the national visibility goal under Phase 1 of the visibility protection program. However, a specific requirement associated with the RH rule is found in 40 CFR § 51.306(c) and is intended to bring into harmony the reasonable attribution requirement in place since 1980 and the RH rule. As such, to meet one part of that requirement, the State of Colorado commits to review the long-term strategy as it applies to reasonably attributable impairment, and make revisions, as appropriate, within three years of state receipt of any certification of reasonably attributable impairment from a Federal Land Manager. This is consistent with the current LTS and State Regulation No. 3 noted above. In addition, Regulation 3, Part D, is amended as part of this SIP action to change the current 3 year review cycle to a 5 year cycle to coordinate the RAVI and RH elements together as intended by the RH rule. Elsewhere in this SIP the state has documented measures to be adopted to address the RH element of the rule including BART determinations and strategies identified in Chapter 8- Reasonable Progress.

In a related action, this 5-year update will satisfy Colorado's requirement for developing emissions estimates from activities on federal lands (Colorado Revised Statute 25-7-105(1)). The state commits to consult with Federal Land Managers to develop a consolidated emissions inventory, which will be brought to the Air Quality Control Commission as part of the 5-year LTS update and then submitted to EPA. After the 2008 emission inventory data submittal, the Consolidated Emission Reporting Rule will be completely replaced by the Air Emissions Reporting Requirements Rule.

Following is a review of the elements contained in the LTS in a chronological order. During the five-year review required by the RH rule, the State of Colorado will add to or revise this section as needed based on any new findings or actions taken related to RAVI notifications delivered to the state by a FLM.

9.2.1.1 Mt. Zirkel Wilderness

The U.S.D.A. Forest Service (USFS) concluded in its July 1993 certification letter to the State of Colorado that visibility impairment existed in the Mt. Zirkel Wilderness Area (MZWA) and local existing stationary sources, namely the Craig and Hayden power stations, contributed to the problem. In 1996 and again in 2001, settlement agreements between various parties and the Hayden and Craig (Units 1 and 2) Generating Stations, respectively, were completed. The state believes significant emission reductions of SO2 and PM effectively address the RAVI in the MZWA associated with the Hayden and Craig (Units 1 & 2) Generating Stations. The state further believes the Hayden and Craig Consent Decrees effectively resolve the certification of impairment brought by the U.S.D.A. Forest Service. The Forest Service indicated its complaint against Hayden and Craig had been satisfied.

9.2.1.2 BART and Emission Limitations

Although RAVI BART determinations were not made by the state regarding Hayden and Units 1 and 2 of Craig generating stations, emission limitations for the two power plants were incorporated into the LTS SIP in August 1996 (Hayden) and April 2001 (Craig Units 1 and 2) and these SIP revisions remain incorporated into the Colorado SIP. The contents of the August 1996 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for Hayden generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference. EPA originally approved this SIP amendment on January 16, 1997. The contents of the April 2001 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for the Craig generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference.

This RH SIP amendment establishes new limits on Hayden Units 1 and 2, and Craig Units 1 and 2, based on a full BART analysis under the current EPA guidelines. Chapter 6 of this SIP (and Appendix C as well as supporting technical support documents) and changes to Regulation No. 3 result in new control requirements for these units to meet BART.

9.2.1.3 Monitoring

It is important to track the effects of the emission changes on visibility and other Air Quality Related Values in and near Mt. Zirkel Wilderness Area and other Class I areas in Colorado. The Division committed in the 2004 LTS SIP amendment to coordinating a monitoring strategy with other agencies and to provide periodic assessments of various monitored parameters in "before" compared to "after" emission reductions periods. Colorado commits to maintain a monitoring strategy and periodically report to the public and the EPA on an annual basis to include trends, current levels and emission changes. In addition periodic emission inventory updates required by the national emissions reporting rule establish a 3-year reporting cycle for emissions updates. Finally, this RH SIP commits to a five year review process established by the RH rule. Through this, the state believes a demonstration of ‘before and after emission reductions’ will be met.

9.2.1.4 Other Stationary Sources and Colorado Class I Areas and Additional Emission Limitations and Schedules for Compliance

There are no outstanding certifications of Phase I visibility impairment in Colorado. For Regional Haze, Chapters 6 and 8 specifically delineate the comprehensive BART analysis and Reasonable Progress analysis of other sources. In these sections specific additional controls of selected stationary sources are detailed and emission reductions from these are reflected in the Appendices and technical support documents. The state believes the coordination of these added control measures meets the requirements of the LTS showing both emission limitations and schedules for compliance. In regard to any future certification of any RAVI, the state is prepared to respond to any future certifications as per AQCC Regulation No. 3 X1V.D in accordance with the five year limit established in 40 CFR § 51.306(c).

9.2.1.5 Ongoing Air Pollution Programs

In the 2004 LTS SIP revision, the state committed to:

- Continue to attain and maintain the PM10 and PM2.5 standards which will have some effect on improving visibility in pristine and scenic areas;
- Continue to provide technical support to efforts to understand and reduce the Brown Cloud in the Front Range of Colorado. Analysis of Brown Cloud data indicates it improved approximately 28% between 1991 and 2006, and data through 2009 indicates this trend continues as demonstrated in the APCD Annual Air Quality Data reports;
- Continue to stay involved and inform the Colorado Air Quality Control Commission about emissions growth in the Four Corners area;
- Continue to participate in any future work of the Rocky Mountain National Park research effort; and,
- Continue to administer and follow existing regulations of point, area and mobile sources as specified in AQCC regulations.

9.2.2 Prevention of Future Impairment

The LTS must establish mechanisms to address the prevention of future impairment and outline strategies to ensure progress toward the national goal. The 2004 LTS summarized programs and activities providing reasonable progress toward the national goal under the Phase 1 RAVI program. Generally, Colorado considers its NSR and PSD programs meet the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities.

9.2.3 Smoke Management Practices

The LTS requires smoke management practices of prescribed burning be addressed. The 2004 LTS described Colorado’s Regulation No. 9 regarding open burning and wildland fire smoke management. As the level and complexity of burning increases the Division committed to continually evaluate its regulatory program for this source of air pollution and surveyed its current activities in the 2004 LTS review. The addition of the Fire Emissions Tracking System (FETS) by the WRAP, FLMs and states allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation 9 to maintain a database of fire related permits and actions - the basis for data entered into the FETS.

9.2.4 Federal Land Manager Consultation and Communication

The state committed to providing for the plans, goals, and comments of the Federal Land Managers during SIP and LTS revisions. The state will provide, at a minimum, the opportunity for consultation with the FLMs at least 60 days prior to any public hearing on any element of the Class I Visibility SIP including LTS revisions and review. In addition the state will publish as part of the SIP process any formal comments received by the FLMs as a result of their review along with a listing of responses the state made in regard to such comments.

9.3 Review of the 2004 RAVI LTS and Revisions

A July 2007 review of the 2004 RAVI LTS concluded that "The Division does not believe extensive and substantive revisions are necessary at this time to ensure reasonable progress toward the national goal under Phase I of the Class I Visibility Protection Program. However, small updates and edits are proposed so this part of the SIP does not become outdated." Appendix A of this SIP document contains this review. The only other changes to this LTS relate to the change in the update period in Regulation 3, as described above in section 9.2.1, and a commitment to utilize the FETS to track fire data as described above in section 9.2.3. The state commits to work with the FLMs to coordinate any changes to the RH/RAVI LTS on the five year cycle required by the regulation. This will include responding to any notification of impairment by the FLMs, providing an opportunity to comment 60 days prior to any public hearing on proposed changes to the RH/RAVI LTS, and to publish the FLM comments and state responses as part of that review process. Appendix B of this document contains the SIP revision for the RAVI LTS.

9.4 Regional Haze Long Term Strategy

The following presents Colorado's Long Term Strategy (LTS) for Regional Haze.

9.4.1 Impacts on Other States

Where the state has emissions reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another state or states, the state must consult with the other state(s) in order to develop coordinated emission management strategies. Colorado has analyzed the output of the initial 2006 PSAT product from the WRAP and determined that emissions from the state do not significantly impact other states' Class I areas. The two largest Colorado visibility impacts are at Canyonlands National Park in Utah and Bandelier National Monument in New Mexico, where Colorado's total nitrate and sulfate contribution are only 1.0% and 0.5%, respectively, of total haze at these Class I areas. This is not a meaningful level of contribution, and all other modeled contributions at other Class I areas are of a smaller magnitude.

Table 9-1 Colorado's Nitrate and Sulfate Impacts at Bandelier and Canyonlands

Mandatory Class I Area	Modeled Visibility Improvement by 2018 [deciviews]	Colorado's Contribution to 2018 Nitrate	2018 Total Nitrate Impacts at CIA	Colorado's Nitrate Contribution to 2018 Haze at CIA	Colorado's Contribution to 2018 Sulfate	2018 Total Sulfate Impacts at CIA	Colorado's Total Sulfate Contribution to 2018 Haze at CIA	Colorado's Total Nitrate & Sulfate Contribution to 2018 Haze at CIA
Bandelier National Monument	0.3	5.1%	6.6%	0.3%	1.2%	15.5%	0.2%	0.5%
Canyonlands National Park	0.5	6.9%	9.5%	0.7%	2.3%	14.8%	0.3%	1.0%

All Colorado Impacts to nearby Class I Areas that exceed 5.0% are shaded in purple. No Colorado 2018 Sulfate Contributions exceeding 5% were indentified.

9.4.2 Impacts from Other States

Where other states cause or contribute to impairment in a mandatory Class I Federal area, the state must demonstrate it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area. Chapter 7 presents modeling information that describes the contribution to visibility impairment in Colorado's Class I areas from other states. Colorado is establishing reasonable progress goals later in this chapter utilizing modeling results presented in Chapter 7, with supporting information in the technical support documents. This demonstration reflects the emission reductions achieved by the controls committed to by other states.

9.4.3 Document Technical Basis for RPGs

The state must document the technical basis (e.g., modeling) on which the state is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area. This is addressed in the Technical Support Document, Chapter 7, and later in this Chapter 9.

9.4.4 Identify Anthropogenic Sources

The state must identify all anthropogenic sources of visibility impairment considered by the state in developing its LTS. Colorado presents comprehensive emission inventories in Chapter 5 and the TSD, and presents emissions control evaluations in Chapters 6 and 8. Chapter 7 and the Technical Support Documents present information about source apportionment for each Class I area in Colorado.

9.4.5 Emission Reductions Due to Ongoing Air Pollution Control Programs

Below is a discussion of ongoing air pollution control programs that reduce visibility impairing emissions throughout Colorado.

Numerous emission reduction programs exist for major and minor industrial sources of NOx, SO2 and particulates throughout the state, as well as in the Denver Metro Area/Northern Front Range region for VOCs, NOx, and particulates from mobile, area, stationary and oil/gas sources, and are contained in the following Colorado Air Quality

Control Commission Regulations:

- Regulation Number 1: Emission Controls for Particulates, Smoke, Carbon Monoxide and Sulfur Oxides
    - In the SIP (includes specific fugitive dust and open burning regulations)
- Regulation Number 3: Stationary Source Permitting and Air Pollutant Emission Notice Requirements
    - Parts A, B,D, F in the SIP or Submitted to EPA for inclusion in the SIP
    - Part C is the Title V program and is delegated by EPA to the state
- Regulation Number 4: New Wood Stoves and the Use of Certain Woodburning Appliances on High Pollution Days
    - Regulation Number 4 is in the SIP. One provision, the Masonry Heater Test Method, is state only. Colorado is waiting for EPA to develop their own test method – the state will adopt it when EPA goes final
- Regulation Number 6: Standards of Performance for New Stationary Sources
    - Part A – Federal NSPS's adopted by the state – EPA has delegated authority to the state to implement; Colorado has requested delegation for the most recent adoptions
    - Part B – state-only NSPS regulations
- Regulation Number 7: Control of Ozone Precursors
    - The majority of Regulation Number 7 for VOC and NOx control is in the SIP or has been submitted for approval into the SIP – these provisions relate to VOC and NOx control measures for the Denver Metro Area/North Front Range 8-hour ozone nonattainment area and are summarized below
- Regulation Number 9: Open Burning, Prescribed Fire and Permitting – state-only
- Regulation Number 11: Motor Vehicle Emission Inspection Program – Parts A-F in the SIP
- Regulation Number 16: Street Sanding Emissions – In the SIP

Some examples of these programs and the visibility-improving emission reductions they achieve are as follows. It is noted as to whether the program is federally enforceable, submitted by the state in an unrelated submittal for inclusion into the SIP, or state-only enforceable.

- Early reductions from BART sources include approximately 24,000 tpy of SO2 from metro Denver power plants, approximately 6,500 tpy of SO2 from the Comanche power plant, and approximately 18,000 tpy of SO2 from the Craig and Hayden power plants – state-only
- Oil and gas condensate tank control regulations for the Front Range region that have achieved approximately 52,000 tpy of volatile organic compounds (VOC) emission reductions by 2007 - in the SIP - with additional projected reductions of 18,000 tpy by 2010 – Submitted for inclusion in the SIP
- Existing industrial engine control regulations for the Front Range region that have achieved NOx and VOC emissions reductions of approximately 8,900 tpy – In the SIP
- Oil and gas pneumatic actuated device control regulations for the Front Range

region that have achieved VOC emission reductions of approximately 8,400 tpy – state-only

- Mobile source emissions controls for VOCs and NOx through vehicle inspection/maintenance and lower volatility gasoline programs for the Front Range region is estimated to reduce emissions by approximately 8,000 tpy by 2011 – Submitted for inclusion in the SIP
- Statewide condensate tank control regulations that have achieved approximately 5,600 tpy of VOCs emission reductions – state-only
- Statewide existing industrial engine control regulations that are estimated to achieve NOx and VOC emissions reductions of approximately 7,100 tpy by 2010 – state-only
- PM10 emission reduction programs in PM10 maintenance areas throughout the state – In the SIP
- Fugitive dust control programs for construction, mining, vehicular traffic, and industrial sources state-wide – In the SIP
- Smoke management programs for open burning and prescribed fire activities statewide – state-only
- Renewable energy requirements that are driving current and future NOx, SO2 and PM emission reductions from coal-fired power plants - Ballot Initiative 37 – by requiring electricity to be obtained from renewable resources – state-only
- Attaining and maintaining the PM10 and PM2.5 standards throughout the state
- Reducing Colorado Front Range Urban Visibility Impairment (Denver's Brown Cloud) by 28% between 1991 and 2006) – state-only
- Reducing Colorado emissions in the Four Corners area (which is upwind of numerous Class I areas in three states) through oil and gas control measures administered by the CDPHE and the Colorado Oil and Gas Conservation Commission, and by working with the Southern Ute Indian Tribe to develop a Title V permitting program and a minor source permitting program – state-only
- Federal mobile source tailpipe exhaust reductions of approximately 55,000 tpy of VOC and NOx emissions by 2020 – gained through fleet turn-over

(Discussion of state-only measures in this Regional Haze SIP is informational only and not intended to make such measures federally enforceable. However, such measures could be included in future SIP revisions if found necessary to meet National Ambient Air Quality Standards or visibility requirements.)

Another comprehensive review of existing and ongoing programs as well as monitoring data and trends is contained in the Colorado Air Quality Control Commission's 2008-2009 Report to the Public available at the following website:

http://www.cdphe.state.co.us/ap/rttplinks.html

As recently as 1995 Colorado had 12 "non-attainment" areas within the state for carbon monoxide, ozone, and/or PM10 health standards. Generally, all of these areas now maintain good air quality. This progress reflects the effects of local, statewide, regional, and national emission control strategies. This clean-up of Colorado's non-attainment areas also benefited Class I visibility conditions to some unknown degree.

In the summer of 2003, the Denver metropolitan area violated the 8-hour ozone standard. EPA designated all or parts of 9 counties in northeastern Colorado as nonattainment for the 1997 8-hour ozone standard, though the nonattainment designation was deferred with the adoption of the Ozone Action Plan by the Colorado Air Quality Control Commission in March 2004 under EPA's Early Action Compact provisions. High concentrations of ground-level ozone during the 2005-2007 period put the nine-county Denver region in violation of the 1997 standard, and the deferred nonattainment designation became effective in November 2007. A detailed plan to reduce ozone was adopted by the Colorado Air Quality Control Commission in December 2008 and submitted to EPA for approval in 2009. This new plan contains additional VOC and NOx emission reduction measures to support achievement of compliance with the 1997 ozone standard by the end of 2010.

The table below shows the designation status for all current and former non-attainment areas.

Table 9-1 REDESIGNATION and PLAN AMENDMENT STATUS REPORT

PM10	**Redesignations**	**Plan Amendments**
Aspen	AQCC approved 1/11/01; EPA approved 5/15/03, effective 7/14/03	10-year update: AQCC approved 12/16/10
Canon City	AQCC approved 10/17/96; EPA approved 5/30/00, effective 7/31/00	10-year update: AQCC approved 11/20/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009
Denver	AQCC approved 4/19/01; EPA approved 9/16/02, effective 10/16/02	Plan amendment developed with MOBILE6 to remove I/M from SIP; AQCC approved 12/15/05; EPA approved 11/6/07, effective 1/7/08
Lamar	AQCC approved 11/15/01; EPA approved 10/25/05, effective 11/25/05	None
Pagosa Springs	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Steamboat Springs	AQCC approved 11/15/01; EPA approved 10/25/04, effective 11/24/04	
Telluride	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010

Carbon Monoxide	Redesignations	Plan Amendments
Colorado Springs	AQCC approved 1/15/98; EPA approved 8/25/99, effective 9/24/99	- Amendment to drop oxyfuels approved by AQCC 2/17/00; EPA approved 12/22/00, effective 2/20/01 - Amendment using MOBILE6 to eliminate I/M from SIP and revise emission budget approved by AQCC 12/18/03; EPA approved 9/07/04, effective 11/08/04 - 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Denver	AQCC approved 1/10/00; EPA approved 12/14/01, effective 1/14/02	- Amendment using MOBILE6 to revise emission budgets approved by AQCC 6/19/03; EPA approved 9/16/04, effective 11/15/04 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08
Ft. Collins	AQCC approved 7/18/02; EPA approved 7/22/03, effective 9/22/03	10-year update: AQCC approved 12/16/10
Greeley	AQCC approved 9/19/96; EPA approved 3/10/99, effective 5/10/99	- Amendment using MOBILE6 to revise emission budget & to eliminate oxyfuels from the regulation/SIP & I/M from the SIP approved by AQCC 12/19/02; EPA approved 8/19/05, effective 9/19/05 - 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Longmont	AQCC approved 12/19/97; EPA approved 9/24/99, effective 11/23/99	- Amendment using MOBILE6 to revise emission budget approved by AQCC 12/18/03; EPA approved 9/30/04, effective 11/29/04 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08

Ozone	Redesignations	Plan Amendments
Denver/Northern Front Range	AQCC approved 1-hour redesignation request and maintenance plan 1/11/01; EPA approved 9/11/01, effective 10/11/01 Early Action Compact 8-hour Ozone Action Plan approved by AQCC 3/12/04; EPA approved 8/19/05, effective 9/19/05	- 8-hour OAP updated to include periodic assessments; AQCC approved 12/15/05; EPA approved //0, effective //0 - 8-hour OAP updated 12/17/06 by AQCC to incorporate Reg. 7's 75% oil and gas condensate tank requirements. EPA approved 2/13/08, effective 4/14/08 - Due to 2005-2007 ozone values, Front Range has violated the ozone standard and the nonattainment designation became effective 11/20/07; revised attainment plan approved by AQCC 12/11/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009
Lead	**Redesignations**	**Plan Amendments**
Denver	EPA redesignated Denver attainment in 1984	
Nitrogen Dioxide	**Redesignations**	**Plan Amendments**
Denver	EPA redesignated Denver attainment in 1984	

For larger stationary sources, the state of Colorado considers its New Source Review and Prevention of Significant Deterioration (PSD) programs as being protective of visibility impairment from proposed major stationary sources or major modifications to existing facilities.

9.4.6 Measures to Mitigate the Impacts of Construction Activities

Regulations 1 and 3 are currently part of Colorado's EPA-approved SIP and apply statewide. In part, provisions of Regulation 1 address emissions of particulate matter, from construction activities. Provisions of Regulation 3 cover issuance of permits applicable to sources defined in these regulations and air pollution emission notices required of specified sources. Provisions of Regulation 1, sections III.D.2.b apply to new and existing point and area sources. This section of the regulation addresses fugitive particulate emissions from construction activities. As such the state believes these regulations address common construction activities including storage and handling of materials, mining, haul roads and trucks, tailings piles and ponds, demolition and blasting activities, sandblasting, and animal confinement operations.

Colorado believes point and area sources of emissions from these regulated sources are in part contributing to regional haze in Colorado. Colorado relies on the particulate emission controls specified in Regulation 1 to most directly address these sources of fine and course particles known to have a minor, but measured, impact on visibility in Class I areas of the state. Based on Coarse Mass Emissions Trace Analysis, described in Section 8 of the Technical Support Document for each Mandatory Class I Federal Area in Colorado included in this SIP, the greatest impact from coarse mass related construction in the state is expected in Rocky Mountain National Park. In RMNP slightly over 6% of the total impact on visibility on the 20% worst days is attributed to coarse mass particulate matter from construction activities. All other Class I areas have impacts from construction in the 2 to 3 percent range.

This regulatory provision requires applicable new and existing sources to limit emissions and implement a fugitive emission control plan. Various factors are specified in the regulation under which consideration in the control plan encompasses economic and technological reasonability of the control.

9.4.7 Smoke Management

For open burning and prescribed fire, Colorado believes its smoke management program reduces smoke emissions through emission reduction techniques and is protective of public health and welfare as well as Class I visibility.

Regulation No. 9 (Open Burning, Prescribed Fire, and Permitting) is the main vehicle in Colorado for addressing smoke management and preventing unacceptable smoke impacts. The rule applies to all open burning activity within Colorado, with certain exceptions. Section III specifically exempts agricultural open burning from the permit requirement[45]. Section III.A of the regulation requires anyone seeking to conduct open burning to obtain a permit from the Division. Regulation No. 9 also contains a number of factors the Division must consider in determining whether and, if so, under what conditions, a permit may be granted. Many of these factors relate to potential visibility impacts in Class I areas. A permit is granted only if the Division is reasonably certain that under the permit's conditions that include the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. Colorado's program also maintains an active compliance assistance and enforcement component. In 2005, the Division certified its smoke management program as consistent with EPA's *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998.

Factors considered under Regulation No. 9, include, for example,

- the potential contribution of such burning to air pollution in the area;
- the meteorological conditions on the day or days of the proposed burning;
- the location of the proposed burn and smoke-sensitive areas and Class I areas that might be impacted by the smoke and emissions from the burn;

[45] The Division has determined that agricultural burning is not a significant source of emissions related to regional haze impairment. For example, 2004 estimates from the Division are that only 503 tpy of PM10 were generated from agricultural burning in the entire State of Colorado. See TSD "Agricultural Burning in Colorado, 2003 and 2004 Inventories".

- whether the applicant will conduct the burn in accordance with a smoke management plan or narrative that requires:
    - that best smoke management methods will be used to minimize or eliminate smoke impacts at smoke-sensitive receptors (including Class I areas);
    - that the burn will be scheduled outside times of significant visitor use in smoke-sensitive receptor areas that may be impacted by smoke and emissions from the fire; and
- a monitoring plan to allow appropriate evaluation of smoke impacts at smoke-sensitive receptors.

The regulation requires all prescribed fire permitees to submit an application to the Division. A permit is granted only if the Division's assessment demonstrates that under the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. The Division reviews each permit application and determines if the burn can be conducted without causing unacceptable visibility impacts within Class I areas, as well as other smoke sensitive sites. In addition, the regulation provides for the Division to impose "permit conditions necessary to ensure that the burn will be conducted so as to minimize the impacts of the fire on visibility and on public health and welfare."

Permitted sources are also required to report actual activity to the Division. Depending on the size and type of fire, reporting may be a daily requirement. At a minimum, each year all permitted sources must return their permit forms with information indicating whether or not there was any activity in the area covered by the permit and, if so, how many acres were burned. The Division annually prepares a report on prescribed burning activity and estimated emissions. Reports from 1990 through 2009 are available by contacting the Division.

The regulation requires the draft permit for any proposed prescribed fire rated as having a "high" smoke risk rating be subject to a 30-day public comment period. The notice for the public comment period must contain information relating to the potential air quality and visibility impacts at smoke sensitive receptors, including Class I areas.

The Division's web site contains information about various aspects of Colorado's Smoke Management Program, downloadable forms and instructions, and links. It is also used to contain the notices for public comment periods for the draft permits subject to public comment. It is located at: http://www.cdphe.state.co.us/ap/smoke/

The addition of the Fire Emissions Tracking System (FETS) allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation 9 to maintain a data base of fire related permits and actions - the basis for data entered into the FETS.

9.4.8 Emission Limitations and Schedules for Compliance to Achieve the Reasonable Progress Goal, and Enforceability of Emission Limitations and Control Measures

The emission limitations and compliance schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and Regulation Nos. 3 and 7. Enforceability of the requirements is ensured by codifying these requirements in regulation, inspecting the sources for compliance and initiating enforcement action under EPA-approved compliance regimes, and requiring monitoring, recordkeeping and reporting.

9.4.9 Source Retirement and Replacement Schedules

Source retirement and replacement schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and in Regulation No. 3. Unless otherwise indicated in those chapters or in Regulation No. 3, the state assumes that all other stationary sources will remain in operation through the end of this planning period. For mobile sources, the turnover of the fleet from older, higher-emitting vehicles to newer, lower-emitting vehicles is captured in the emission inventory presented in Chapter 5 – the fleet turn-over rate was developed utilizing EPA-approved methodologies.

9.4.10 Anticipated Net Effect on Visibility

The WRAP has produced extensive analytical results from air quality monitoring, emissions inventories and air quality modeling. These data demonstrate that causes of regional haze in the West are due to emissions from a wide variety of anthropogenic and natural sources, some of which are controllable, some of which are natural, and some of which originate outside the jurisdiction of any state or the federal government and are uncontrollable. Analyses to date consistently show that anthropogenic emissions of haze causing pollutants will decline significantly across the West through 2018, but overall visibility benefits of these reductions will be tempered by emissions from natural, international, and uncontrollable sources.

Colorado in this RH SIP addresses projections to 2018 anticipating growth and all committed to or reasonably expected controls at the time of modeling (emission inventories for Colorado are presented in Chapter 5). Note that at the time of this 2009 WRAP modeling, Colorado had made BART determinations for each subject to BART unit in 2007 and 2008, and the associated emission reductions were included in the modeling. The inventories indicate a total SO2 emission reduction of 58,907 tons per year and a total NOx emission reduction of 123,497 tons per year by 2018. (SO2 and NOx are the primary emissions addressed by Colorado in this Regional Haze SIP.)

For the uniform rate of progress analysis and to establish Reasonable Progress Goal (RPGs), the modeling results from Chapter 7 are utilized. The modeled Uniform Rate of Progress and the progress made towards URP are presented below. Depending on the Class I area, the state has achieved 36 to 76 percent of the visibility improvement necessary to achieve URP. Note that this analysis does not include emission reductions that result from the BART and RP determinations presented in Chapters 6 and 8.

Figure 9-2 Summary of CMAQ Modeling Progress Towards 2018 URP

Colorado Mandatory Class I Federal Areas

Uniform Progress Summary in Haze Index Metric

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	*20% Worst Days*					*20% Best Days*		
	Worst Days Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2018 URP delta from Baseline [dv]	2018 Modeling Projection [dv]	CMAQ Modeling % Towards 2018 URP	Best Days Baseline Condition [dv]	2018 CMAQ Modeling Results [dv]	2018 CMAQ Modeling Below Baseline?
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

Uniform Rate of Progress for 2018

Projected Amount of Progress by 2018 Towards URP

The total tons of visibility impairing pollutants reduced by 2018 due to the BART and RP measures adopted in 2010 are summarized below in Figures 9-4, 9-5 and 9-6.

- 2010 BART: 20,734 tons/year
- 2010 BART alternative: 37,488 tons/year
- 2010 RP: 12,624 tons/year

Total: 70,846 tons/year

The following figures also present "CALPUFF" modeling results that show the visibility benefits of each BART and RP determination. Though not additive to the visibility improvement values presented in Figure 9-2 above because different modeling platforms were used, the CALPUFF modeling illustrates that additional visibility improvement can be anticipated from the BART and RP controls.

Figure 9-3 Emission Reductions Achieved by 2010 BART Determinations

BART Emission Control Analysis

NOx BART - SCR

Source	SCR Capital Costs	Annualized SCR Costs	SCR NOx Reduced [tpy]	SCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Hayden - Unit 2	$ 71,780,853	$ 12,321,491	3,032	$ 4,064	0.82	23 (Zirkel)
Hayden - Unit 1	$ 61,938,167	$ 10,560,612	3,120	$ 3,385	1.12	48 (Zirkel)
Craig - Unit 2 (SCR @ 74% Reduction)	$ 209,552,000	$ 25,036,709	3,975	$ 6,299	0.98	41 (Mt. Zirkel)

NOx BART - SNCR

Source	SNCR Capital Costs	Annualized SNCR Costs	SNCR NOx Reduced [tpy]	SNCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Craig - Unit 1 (SNCR @ 14% reduction)	$ 13,118,000	$ 3,797,000	727	$ 5,226	0.31	15 (Mt. Zirkel)
CEMEX - Kiln	$ 600,000	$ 1,636,636	846	$ 1,934	0.40	14 (RMNP)

NOx BART - Other

Source	Capital Costs	Annualized Costs	NOx Reduced [tpy]	NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Drake - Unit 5 (ULNB w/OFA)	$ 2,895,672	$ 288,844	215	$ 1,342	0.08	> 0 (RMNP)
Drake - Unit 6 (ULNB w/OFA)	$ 3,340,318	$ 337,751	509	$ 664	0.20	> 3 (RMNP)
Drake - Unit 7 (ULNB w/OFA)	$ 4,500,232	$ 461,217	749	$ 616	0.26	> 3 (RMNP)
CENC (TriGen) - Unit 4 LNB, w/SOFA	$ 4,284,900	$ 678,305	214	$ 3,170	0.08	3 (RMNP)
CENC (TriGen) - Unit 5 LNB, w/SOFA and SNCR	$ 6,556,888	$ 1,739,825	354	$ 4,919	0.26	14 (RMNP)
CEMEX - Dryer T5 Permit Limits	$ -	$ -	0	$ -	0.00	none

SO2 BART

Source	Capital or O&M Costs	Annualized Costs	SO2 Reduced [tpy]	SO2 Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Drake - Unit 5: (DSI w/0.26 Emission Limit 30-day)	$ 6,000,000	$ 1,340,663	762	$ 1,761	0.12	2 (RMNP)
Drake - Unit 6: (FGD w/0.13 Emission Limit 30-day)	$ 38,000,000	$ 6,665,771	2,368	$ 2,816	0.24	3 (RMNP)
Drake - Unit 7: (FGD w/0.13 Emission Limit 30-day)	$ 44,166,000	$ 9,577,538	3,764	$ 2,544	0.39	6 (RMNP)
Hayden - Unit 1 Tighten Emission Limit to 0.13	$165,000 parts & $110,000 O&M	$ 141,150	61	$ 2,318	0.01	>12 (Mt. Zirkel)
Hayden - Unit 2 Tighten Emission Limit to 0.13	$165,000 parts & $110,000 O&M	$ 141,150	39	$ 3,629	0.05	>8 (Mt. Zirkel)

TOTAL CAPITAL COST	$ 467,283,031
TOTAL ANNUALIZED COST	$ 74,724,662

TOTAL NOX REDUCED	**13,741**	*tons/year*
TOTAL SO2 REDUCED	**6,993**	*tons/year*
TOTAL COMBINED POLLUTANTS REDUCED	**20,734**	*tons/year*

Figure 9-4 Emission Reductions Achieved by 2010 BART Alternative Determinations

Facility	NOx Emissions Average 2006-2008 (tpy)	NOx Emissions from Alternative (TPY)	Total NOx Emissions Reduced (TPY)	SO2 Emissions Average 2006 -2008 (tpy)	SO2 Emissions from Alternative (TPY)	Total SO2 Emissions Reduced (TPY)
Arapahoe						
Unit 3	1,770	0		925	0	
Unit 4	1,148	900[46]		1,765	1.28	
Cherokee						
Unit 1	1,556	0		2,221	0	
Unit 2	2,895	0		1,888	0	
Unit 3	1,866	0		743	0	
Unit 4	4,274	2,063[47]		2,135	7.81[48]	
Valmont	2,314	0		758	0	
Pawnee	4,538	1,403[49]		13,472	2,406[50]	
Totals	20,361	4,366	15,995	23,908	2,415	21,493

Total Emission Reductions Achieved: 37,488 tons per year

[46] Includes 300 tpy NOx for offset or netting purposes and 600 tpy NOx from firing Arapahoe 4 on natural gas as a peaking unit.

[47] Includes 500 NOx tpy for offset or netting purposes and emissions at 0.12 lb NOx/MMBtu

[48] Emissions at 0.0006 lb SO2/MMBtu

[49] Emissions at 0.07 lb NOx/MMBtu

[50] Emissions at 0.12 lb SO2/MMBtu

Figure 9-5 Emission Reductions Achieved by 2010 RP Determinations

RP Emission Control Analysis

NOx RP - SCR						
Source	SCR Capital Costs	Annualized SCR Costs	SCR NOx Reduced [tpy]	SCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement

NOx RP - SNCR						
Source	SNCR Capital Costs	Annualized SNCR Costs	SNCR NOx Reduced [tpy]	SNCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Craig - Unit 3 (SNCR @ 15% Reduction)	$ 13,139,000	$ 4,173,000	854	$ 4,886	0.32	6 (Mt. Zirkel)
Holcim Cement (establish limit)	not estimated	$ 2,520,000	1,028	$ 2,451	0.23	5 (GSDNP)

NOx RP- Other						
Source	Capital Costs	Annualized Costs	NOx Reduced [tpy]	NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	861	n/a	n/a	n/a
Cameo - Unit 1 (Shutdown)	n/a	n/a	516	n/a	n/a	n/a
Cameo - Unit 2 (Shutdown)	n/a	n/a	624	n/a	n/a	n/a
CENC - Boiler 3 (none)	n/a	n/a	n/a	n/a	n/a	n/a
Nixon - Unit 1 (ULNB w/Overfire Air)	$ 3,822,000	$ 970,000	707	$ 1,372	0.15	2 (RMNP)
Nucla (none)	n/a	n/a	n/a	n/a	not modeled	not modeled
Rawhide - Unit 1 (enchanced combustion control)	$ 1,180,000	$ 288,450	448	$ 644	0.35	18 (RMNP)

SO2 RP						
Source	Capital Costs	Annualized Costs	SO2 Reduced [tpy]	SO2 Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	1,457	n/a	n/a	n/a
Cameo - Unit 1 (Shutdown)	n/a	n/a	849	n/a	n/a	n/a
Cameo - Unit 2 (Shutdown)	n/a	n/a	1,769	n/a	n/a	n/a
CENC - Boiler 3 (none)	n/a	n/a	n/a	n/a	n/a	n/a
Craig - Unit 3 (tighten existing emission limit)	none	none	0	n/a	0.26	6 (RMNP)
Holcim Cement (establish limit)	not estimated	not estimated	0	n/a	-	n/a
Nixon - Unit 1 LSD @ 0.10 lb/MMBtu (0.11 lb/MMBtu 30-day rolling)	$ 96,160,000	$ 12,036,604	3,215	$ 3,744	0.46	11 (RMNP)
Nucla (none)	n/a	n/a	n/a	n/a	not modeled	not modeled
Rawhide - Unit 1 (no technically feasible options)	n/a	n/a	n/a	n/a	n/a	n/a

PM RP						
Source	Capital or O&M Costs	Annualized Costs	PM Reduced [tpy]	PM Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	72	n/a	n/a	n/a
Cameo - Units 1 & 2 (Shutdown)	n/a	n/a	225	n/a	n/a	n/a

TOTAL CAPITAL COST	$ 114,301,000
TOTAL ANNUALIZED COST	$ 19,988,054

TOTAL NOX REDUCED	5,038	*tons/year*
TOTAL SO2 REDUCED	7,290	*tons/year*
TOTAL PM REDUCED	297	*tons/year*
TOTAL COMBINED POLLUTANTS REDUCED	12,624	*tons/year*

Of these 70,800 tons of SO2 and NOx reduced due to 2010 BART and RP, approximately 44,500 tons per year were not included in the WRAP's 2009 "CMAQ" modeling. Figure 9-6 below presents this analysis for each of the BART and RP sources.

Figure 9-6 Difference Between the WRAP and Final BART/RP Emissions for NOx and SO2

Additional NOx and SO2 Reductions

Difference between PRP2018b and Proposed BART/RP

PLANT	PRP 2018b NOx [tpy]	2018 BART/RP NOx [tpy]	Difference [tpy]	PRP 2018b SO2 [tpy]	2018 BART/RP SO2 [tpy]	Difference [tpy]
AQUILA, INC. - W.N. CLARK STATION	1,090	-	(1,090)	1,322	-	(1,322)
CEMEX, INC. - LYONS CEMENT PLANT	901	901	-	97	95	(2)
COLORADO SPRINGS UTILITIES - NIXON PLT	2,331	1,650	(681)	4,073	907	(3,166)
COLORADO SPRINGS UTILITIES - DRAKE PLT	3,669	2,789	(880)	2,701	1,590	(1,111)
HOLCIM (US) INC. PORTLAND PLANT	1,859	2,087	228	393	721	328
PLATTE RIVER POWER AUTHORITY - RAWHIDE	3,912	1,418	(2,494)	927	913	(14)
PUBLIC SERVICE CO - CAMEO (shutdown)	-	-		-	-	-
PUBLIC SERVICE CO - ARAPAHOE (Unit 3-Shutdown, Unit 4 NG only)	-	900	900	-	1	1
PUBLIC SERVICE CO - VALMONT	2,279	-	(2,279)	879	-	(879)
PUBLIC SERVICE CO CHEROKEE PLT (Units 3 & 4)	5,998	1,813	(4,185)	5,214	8	(5,206)
PUBLIC SERVICE CO CHEROKEE PLT (Units 1 & 2)	4,317	250	(4,067)	1,750	-	(1,750)
PUBLIC SERVICE CO COMANCHE PLT (Units 1 & 2)	6,143	4,602	(1,541)	3,686	2,953	(733)
PUBLIC SERVICE CO COMANCHE PLT (Unit 3)	2,600	2,600	-	3,250	3,250	-
PUBLIC SERVICE CO HAYDEN PLT	7,307	1,341	(5,966)	2,898	2,541	(357)
PUBLIC SERVICE CO PAWNEE PLT	3,942	1,403	(2,539)	2,225	2,406	181
TRI STATE GENERATION CRAIG (Units 1 & 2)	10,974	5,861	(5,113)	2,117	1,952	(165)
TRI STATE GENERATION CRAIG (Unit 3)	5,825	4,839	(986)	1,823	1,863	40
TRI STATE GENERATION NUCLA	1,753	2,167	414	1,325	1,325	0
TRIGEN - COLORADO ENERGY CORPORATION (Units 4 & 5)	1,185	722	(463)	2,624	2,762	138
TRIGEN - COLORADO ENERGY CORPORATION (Unit 3)	159	222	63	170	379	209
	66,243	**35,565**	**(30,678)**	**37,473**	**23,666**	**(13,807)**

Combined Reductions from NOx and SO2 Controls [tpy]: (44,486)

These substantial additional emission reductions will further the amount of progress achieved by 2018.

Colorado believes the combination of WRAP's CMAQ modeling and the Division's BART and RP modeling adequately demonstrate the anticipated net positive visibility benefit or improvement for this SIP. Although the state of Colorado makes no commitment to produce comprehensive RH modeling unless resources are available and there is a need for such analysis (e.g., through the WRAP), it is anticipated in the five year review required by the RH rule and committed to in this SIP that additional regional CMAQ modeling will be done to evaluate compliance with the Reasonable Progress Goals for all the western states.

9.5 Reasonable Progress Goals

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals, for each Class I area in Colorado (expressed in deciviews) that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. The reasonable progress goals (RPGs) must provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

Colorado is relying on the Western Regional Air Partnership's (WRAP's) CMAQ regional modeling performed in 2009 to establish these goals. As stated throughout this chapter, all western states' reasonably foreseeable control measures at the time of modeling were included in the projections of 2018 visibility levels. Colorado determines that the 2018 projections represent significant visibility improvement and reasonable progress upon the state's consideration of the statutory factors, and are the RPGs for each Class I area. Figure 9-7 presents these RPGs.

Figure 9-7 Reasonable Progress Goals for Each Class I Area

Colorado Mandatory Class I Federal Areas

Uniform Progress Summary in Haze Index Metric

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	20% Worst Days					20% Best Days		
	Worst Days Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2018 URP delta from Baseline [dv]	2018 Modeling Projection [dv]	CMAQ Modeling % Towards 2018 URP	Best Days Baseline Condition [dv]	2018 CMAQ Modeling Results [dv]	2018 CMAQ Modeling Below Baseline?
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

Reasonable Progress Goals for 2018

No Degradation of Visibility for the Best Days

As required, each Class I area must 1) make improvement in visibility for the most-impaired (20% worst) days over the period ending in 2018, and 2) allow no degradation in visibility for the least-impaired (20% best) days. This is demonstrated in Figure 9-5. As stated above in section 9.4.10, these goals reflect the emissions reductions achieved throughout Colorado (as reflected in the Chapter 5 inventories) and the nation. The additional emissions reductions from the BART and RP determinations will increase the amount of progress achieved by 2018.

In establishing the RPGs, the state considered the required four factors as per EPA regulations: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. Colorado describes in Chapter 8 how the four factors were used to select significant sources/source categories not already covered by BART or federal measures for control evaluation. The evaluations resulted in substantial emission reductions that build on the reductions already achieved by other measures.

Although the state used the four factors to determine reasonable and appropriate emission controls for subject facilities, Figure 9-7 illustrates that the RPGs do not achieve URP. The state realizes additional emissions reductions from both within and outside of the state are necessary to achieve URP. The state finds that the RPGs established in this SIP are reasonable for this planning period and that achieving URP in this planning period is not reasonable. In this SIP, Colorado has described, based upon its consideration of the statutory factors, why certain controls for specified BART and RP sources are reasonable, and why additional controls during this planning period are not reasonable. Similarly, the state has described why additional controls for certain area sources (such as oil and gas heater treaters and lean burn RICE engines) are not reasonable in this planning period. The emission reductions needed to achieve URP at each Class I area for this planning period cannot be determined with precision, due to limitations in calculating and modeling all of the visibility-impairing emissions. In the first 5-year assessment, the state commits to begin evaluating this shortfall, first accounting for the degree of additional emission reductions achieved in Colorado and in other states that are not included in the modeling, and then assessing the inventory and modeling technical issues.

Because RPGs are not achieving URP by 2018 and natural conditions by 2064, Colorado is required by the Regional Haze rule to re-calculate and state the length of time necessary to achieve natural conditions, as shown below and presented in Figure 9-8. Instead of achieving natural conditions in 2064 (60 years) at all Class I areas, the year and the length of time is re-calculated as follows:

- Sand Dunes: 2152 (148 years)
- Mesa Verde: 2168 (164 years)
- Zirkel & Rawah: 2106 (102 years)
- Rocky Mountain: 2098 (94 years)
- Black Canyon, Weminuche, & La Garita: 2119 (115 years)
- Eagles Nest, Flat Tops, Maroon Bells & West Elk: 2083 (79 years)

The recalculated natural conditions timeline is based upon progress through 2018, though, as described above, the calculations do not consider the emission control requirements adopted by the state in 2010 and presented in Chapters 6 and 8. The four factors were used to evaluate significant sources of SO2, NOx (and PM from stationary sources) only as the state also determined that it was not reasonable to evaluate sources organic carbon, elemental carbon and particulate matter for control during this planning period. Thus, all reasonable control measures are presented in this SIP and it is acceptable under the Regional Haze rule that natural conditions are projected to be achieved beyond 2064.

Figure 9-8 Re-Calculation of the Length of Time Necessary to Achieve Natural Conditions

Colorado Mandatory Class I Federal Areas

Number of Years to Attain Natural Conditions

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	20% Worst Days										
	Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2064 Natural Conditions [dv]	Total Haze Delta (Baseline-2064 NC) [dv]	Haze Program Period [yrs]	Haze Program Reduction Rate [dv/yr]	2018 Modeling Projection [dv]	2018 Modeling <= 2018 UPG?	Recast Reduction Rate [dv/yr]	Number of years to NC [yrs]	New NC Goal [year]
Great Sand Dunes National Park & Preserve	12.78	11.35	6.66	6.12	60	0.102	12.20	No	0.041	148	2152
Mesa Verde National Park	13.03	11.58	6.81	6.22	60	0.104	12.50	No	0.038	164	2168
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	6.08	4.44	60	0.074	9.91	No	0.044	102	2106
Rocky Mountain National Park	13.83	12.27	7.15	6.68	60	0.111	12.83	No	0.071	94	2098
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	6.21	4.12	60	0.069	9.83	No	0.036	115	2119
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	6.06	3.55	60	0.059	8.98	No	0.045	79	2083

The following figures for Mesa Verde National Park illustrate the re-calculations.

Figure 9-9 Current Uniform Rate of Progress Glidepath for Mesa Verde and the Reasonable Progress Goal for 2018

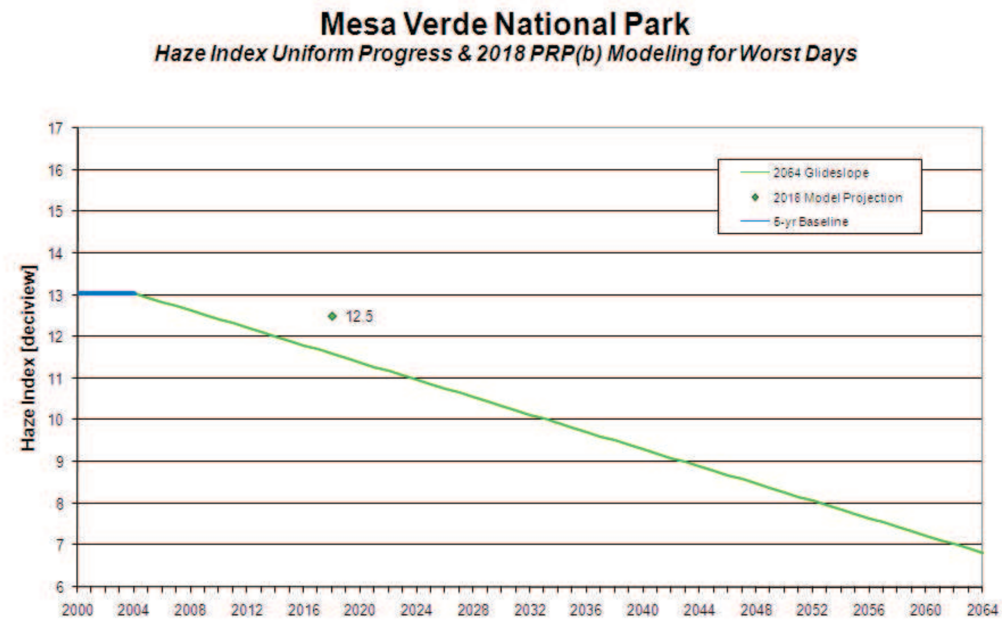
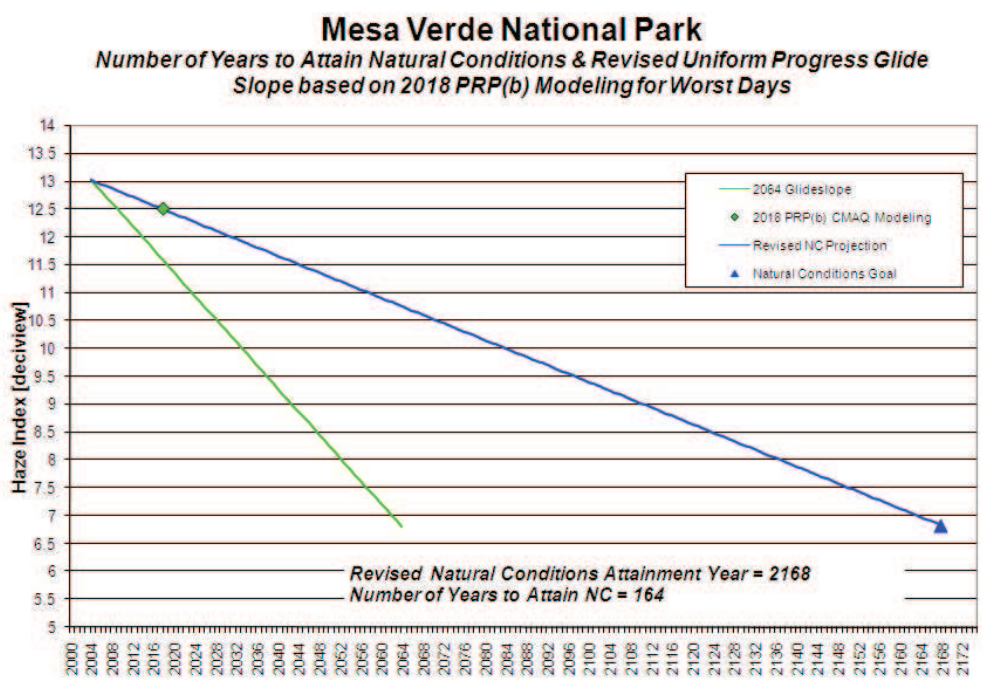


Figure 9-10 Revised Glidepath for Mesa Verde Illustrating the Number of Years to Achieve Natural Conditions



Chapter 10 Commitment to Consultation, Progress Reports, Periodic Evaluations of Plan Adequacy, and Future SIP Revisions

10.1 Future Consultation Commitments

10.1.1 FLM Consultation

As required by 40 CFR 51.308(i)(4), Colorado will continue to consult with the FLM on the implementation of the visibility protection program: and the following items

1. Colorado will provide the FLM an opportunity to review and comment on SIP revisions, the five-year progress reports, and other developing programs that may contribute to Class I visibility impairment. This report will include:
    a. Implementation of emission reduction strategies identified in the SIP as contributing to achieving improvement of worst-day visibility;
    b. Summary of major new source permits issued;
    c. Any changes to the monitoring strategy or monitoring stations that may affect tracking reasonable progress;
    d. Work underway in preparing the five and ten year reviews
2. Colorado will afford the FLM with an opportunity for consultation in person and at least 60 days prior to holding any public hearing on a SIP revision. The FLM consultation must include the opportunity to discuss their assessment of visibility impairment in each federal Class I area; and to provide recommendations on the reasonable progress goals and on the development and implementation of the visibility control strategies. Colorado will include a summary of how it addressed the FLM comments in the revised RH SIP.

10.1.2 Tribal Consultation

Colorado will continue to remain in contact with those Tribes which may reasonably be anticipated to cause or contribute to visibility impairment in Colorado mandatory Class I Federal area(s). For those Tribes that adopted a RH TIP, Colorado will consult with them directly. For those Tribes without a RH TIP, Colorado will consult with both the Tribe and EPA. Documentation of the consultation will be maintained.

10.1.3 Inter-state Consultation/Coordination

In accordance with 40 CFR 51.308(d)(1)(iv) and 51.308(d)(3)(i), Colorado commits to continue consultation with Arizona, Nebraska, Kansas, Wyoming, New Mexico, Utah, and California, and any other state which may reasonably be anticipated to cause or contribute to visibility impairment in federal Class I areas located within Colorado. Colorado will also continue consultation with any state for which Colorado’s emissions may reasonable be anticipated to cause or contribute to visibility impairment in those state’s federal Class I areas.

With regards to the established or updated goal for reasonable progress, should disagreement arise between another state or group of states, Colorado will describe the actions taken to resolve the disagreement in future RH SIP revisions for EPA's consideration. With regards to assessing or updating long-term strategies, Colorado commits to coordinate its emission management strategies with affected states and will continue to include in its future RH SIP revisions all measures necessary to obtain its share of emissions reductions for meeting progress goals.

10.1.4 Regional Planning Coordination

As per the requirements of [51.308(c)(1)(i)],Colorado commits to continued participation with one or more other States in a planning process for the development of future RH SIP revisions. Future plans will include:

1. Showing of inter-state visibility impairment in federal Class I areas based on available inventory, monitoring, or modeling information as per the requirements of [51.308(c)(1)(ii)].
2. Description of the regional planning process, including the list of states, which have agreed to work with Colorado to address regional haze, the goals, objectives, management, decision making structure for the regional planning group, deadlines for completing significant technical analyses and developing emission management strategies, and a schedule for State review and adoption of regulations implementing the recommendations of the regional group as per the requirements of ; [51.308(c)(1)(iii)].
4. Address fully the recommendations of WRAP, including Colorado's apportionment of emission reduction obligations as agreed upon through WRAP and the resulting control measures required [51.308(c)(1)(iv) and 51.308(d)(3)(ii)].

10.2 Commitment to Progress Reports

40 CFR 51.308(g), requires a State/Tribe to submit a progress report to EPA every five years evaluating progress towards the reasonable progress goal(s). The first progress report is due five years from the submittal of the initial implementation plan and must be in the form of an implementation plan revision that complies with Sections 51.102 and 51.103. At a minimum, the progress reports must contain the elements in paragraphs 51.308(g)(1) through (7) for each Class I area as summarized below.

1. Status of implementation of the RFP SIP measures for CIAs in Colorado and those outside the State identified as being impacted by emissions from within the state
2. Summary of emissions reductions in Colorado adopted or identified as part of the RFP strategy

3. A five year annual average assessment of the most and least impaired days for each CIA in Colorado including the current visibility conditions, difference between current conditions and baseline and change in visibility impairment over the five year period
4. Analysis, by type of source or activity of pollutant emission changes or activities over the five year period from all sources contributing to visibility impairment in Colorado, based on the most recent EI with estimates projected forward as necessary to account for changes in the applicable five year period
5. Assessment of significant changes in anthropogenic emissions in or out of Colorado in the applicable five years which limited or impeded RFP;
6. Assessment of the current SIP sufficiency to meet reasonable progress goals both in Colorado and other States CIA identified as being significantly impacted by Colorado emissions
7. Assessment of Colorado's visibility monitoring strategy and modifications of the strategy as necessary.

In accordance with the requirements listed in Section 51.308(g) of the federal regional haze rule, Colorado commits to submitting a report on reasonable progress to EPA every five years following the initial submittal of the SIP. That report will be in the form of an implementation plan revision. The reasonable progress report will evaluate the progress made towards the reasonable progress goal for each mandatory Class I area located within Colorado and in each mandatory Class I area located outside Colorado, which have been identified as being affected by emissions from Colorado.

The State will also evaluate the monitoring strategy adequacy in assessing reasonable progress goals.

10.3 Determination of Current Plan Adequacy

Based on the findings of the five-year progress report, 40 CFR 51.308(h) requires a State to make a determination of adequacy of the current implementation plan. The State must take one or more of the actions listed in 40 CFR 51. 308(h)(1) through (4) that are applicable. These actions are described below and must be taken at the same time the State is required to submit a five-year progress report.

1. If the State finds that no substantive SIP revisions are required to meet established visibility goals and emissions reductions, the State will provide a negative declaration that no implementation plan revision is needed.
2. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from outside the State, the State shall notify EPA and the other contributing state(s) or tribe(s). The plan deficiency shall be addressed through a regional planning process in developing additional strategies with the planning efforts described in the progress report(s).
3. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from another country, the State shall notify EPA and provide the available supporting information.

4. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from within the State, the State shall revise the plan to address the deficiency within a year.

Colorado commits, in accordance with 40 CFR 51.308(h), to make an adequacy determination of the current SIP at the same time a five-year progress report is due.

10.4 Commitment to Comprehensive SIP Revisions

In addition to SIP revisions made for plan adequacy as specified in Section 10.3 of this plan, 40 CFR 51.308(f)(1-3)requires a State to revise and submit its regional haze implementation plan to EPA by July 31, 2018, and every ten years thereafter. Colorado commits to providing this revision and to evaluate and reassess elements under 40 CFR 51.308(d) taking into account improvements in monitoring data collection and analysis, and control technologies. Elements of the future plans are summarized below.

10.4.1 Current Visibility Conditions

Colorado commits to determine and report current visibility conditions for the most and least impaired days using themost recent five year period for which data is available and to determine the actual progress made towards natural conditions. Current visibility conditions will be calculated based on the annual average level of visibility impairment.

10.4.2 Long Term Strategy Effectiveness

Colorado commits to determine the effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period(s) and to affirm or revise the RPG and monitoring strategy as specified in 10.4.3 and 10.4.4 of this section.

10.4.3 Affirmation of or Revisions to Reasonable Progress Goals

As part of this comprehensive SIP update and future ten year revisions, Colorado commits to affirm or revise the reasonable progress goals in accordance with the procedures set forth in 40 CFR 51.308(d)(1). For any goal which provided a slower rate of progress than needed to attain natural conditions by the year 2064, Colorado will perform the analysis of additional measures that could be adopted to achieve the degree of visibility improvement projected by the analysis contained in the initial implementation plan. This analysis of additional measures will be performed in accordance with the procedures set forth in 40 CFR 51.308(d)(1)(A) to include a consideration of the costs of compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and a demonstration showing how these factors were taken into consideration in selecting the goal.

1. Colorado commits, in accordance with 40 CFR 51.308(d)(1)(B), to analyze and determine the rate of progress needed to attain natural conditions by the year 2064 comparing baseline visibility to natural visibility conditions in each CIA considering the uniform rate of improvement and emission reduction measures needed to achieve RFP.

2. As per 40 CFR 51.308(d)(1)(B)(ii) if Colorado establishes a RPG with a slower rate of progress than needed to attain natural conditions by 2064, Colorado will demonstrate, based on the factors listed in this section 10.4.3, the rate of progress is unreasonable and the established goal is reasonable. Colorado will provide for a public review, as part of the implementation plan revision in 2018, an assessment of the number of years it will take to attain natural conditions based on the RPG.
3. As per 40 CFR 51.308(d)(1(B)(iv) Colorado will consult with States reasonably anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal areas and where Colorado or another State cannot agree a RPG is appropriate, Colorado will describe, in the SIP submittal of 2018, actions taken to resolve disagreements.

Chapter 11 Resource and Reference Documents

There are a substantial number of documents that are referenced in this SIP and form the detailed technical basis for the proceeding Chapters. This Chapter is not the full Technical Support Document. It is a catalog of references used in the preparation of this SIP revision. The full Technical Support Document will be on the Air Pollution Control Division web site at http://www.cdphe.state.co.us/ap/regionalhaze.html

11.1 Class I Area Technical Support Documents (TSDs) TSDs are a comprehensive technical summary for each Class I area in Colorado. The individual Class I area TSDs includes sections describing the Class I area; visibility monitoring; visibility conditions; haze impacting particles; emission source characterization; regional modeling; and PM source apportionment. Included in each TSD is the PSAT Modeling showing estimated source category impacts on Class I areas. Titles include:

Colorado State Implementation Plan for Regional Haze Technical Support Document – Black Canyon of the Gunnison National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Eagles Nest Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Flat Tops Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –La Garita Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document – Maroon Bells Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Mesa Verde National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Mount Zirkel Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Rocky Mountain National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Rawah Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Sand Dunes National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document – Weminuche Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –West Elk Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

11.2 Other Technical Support Documents In addition to the Class I area-specific TSDs, two other technical support documents have been developed. One for the IMPROVE look-alike monitors at Douglas Pass and Ripple Creek and another for agricultural burning in Colorado. Titles are:

Colorado State Implementation Plan for Regional Haze Technical Support Document –Douglas Pass and Ripple Creek Pass Sites, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, June 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Agricultural Burning in Colorado 2003-4 Inventory, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, July 2007

Colorado State Implementation Plan for Regional Haze. Technical Support Document, Analysis of Colorado Visibility Impacts on Nearby Class I Areas, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, March 2007

11.3 Long-Term Strategy Review Update In 2004, the State adopted this SIP revision in order to update the LTS. This SIP revision is intended to amend the 2002 LTS portion of the Class I Visibility SIP. This document is titled:

Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part II Revision of the Long-Term Strategy, Colorado Department of Public Health and Environment, Air Pollution Control Division, November 2004

List of Appendices –

Appendix A – Periodic Review of Colorado RAVI Long Term Strategy

Appendix B – SIP Revision for RAVI Long Term Strategy

Appendix C – Technical Support for the BART Determinations

Appendix D – Technical Support for the Reasonable Progress Determinations

<u>Newark, East (Barnett Shale) Field</u>
<u>Discovery Date – 10-15-1981</u>

- **As of September 28, 2011 there are a total of gas wells 15,306 entered on RRC records.**

In addition, there are 3,212 permitted locations (represents pending oil or gas wells, where either the operator has not yet filed completion paperwork with the Commission, or the completed well has not yet been set up with a Commission identification number)**.**

- Currently, there are 180 commercial disposal wells in the 23-county area. So far in 2011, there have been no new commercial disposal well permits issued.

- This field produces in twenty five (25) counties: Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackelford, Somervell, Stephens, Tarrant, and Wise. In addition, drilling permits have been issued for wells in Hamilton and Young counties.

- Gas Well Gas Production –
  January 2004 through December 2004 = 380 Bcf
  January 2005 through December 2005 = 505 Bcf
  January 2006 through December 2006 = 717 Bcf
  January 2007 through December 2007 = 1,104 Bcf
  January 2008 through December 2008 = 1,612Bcf
  January 2009 through December 2009 = 1,775 Bcf
  January 2010 through December 2010 = 1,847 Bcf
  January 2011 through July 2011 = 1,092 Bcf

- For January through July 2011 production accounts for 31% of Texas Production

- Drilling Permits Issued –
  January 2004 through December 2004 = 1,112
  January 2005 through December 2005 = 1,629
  January 2006 through December 2006 = 2,503
  January 2007 through December 2007 = 3,643
  January 2008 through December 2008 = 4,145
  January 2009 through December 2009 = 1,755
  January 2010 through December 2010 = 2,157
  January 2011 through August 2011 = 1,414

- There are a total of 231 operators in the Newark, East (Barnett Shale) Field.

Top Ten Gas Operators for January through July 2011 as follows:

	Operator Name	Operator No.	Casinghead (MCF)	GW Gas (MCF)	Total Natural Gas (MCF)
1	DEVON ENERGY PRODUCTION CO, L.P.	216378	199,246	264,612,260	264,811,506
2	CHESAPEAKE OPERATING, INC.	147715	0	246,283,399	246,283,399
3	XTO ENERGY INC.	945936	322,942	180,301,876	180,624,818
4	EOG RESOURCES, INC.	253162	18,424,587	104,123,235	122,547,822
5	QUICKSILVER RESOURCES INC.	684830	0	84,432,820	84,432,820
6	CARRIZO OIL & GAS, INC.	135401	0	30,976,622	30,976,622
7	ENCANA OIL & GAS(USA) INC.	251691	28,431	29,876,339	29,904,770
8	RANGE PRODUCTION COMPANY	691703	5,447	19,787,015	19,792,462
9	WILLIAMS PROD. GULF COAST, L.P.	924558	0	19,001,118	19,001,118
10	ENERVEST OPERATING, L.L.C.	252131	0	15,912,812	15,912,812

Rapid photochemical Production of A Ozone at High Concentrations in a Rural Site During Winter

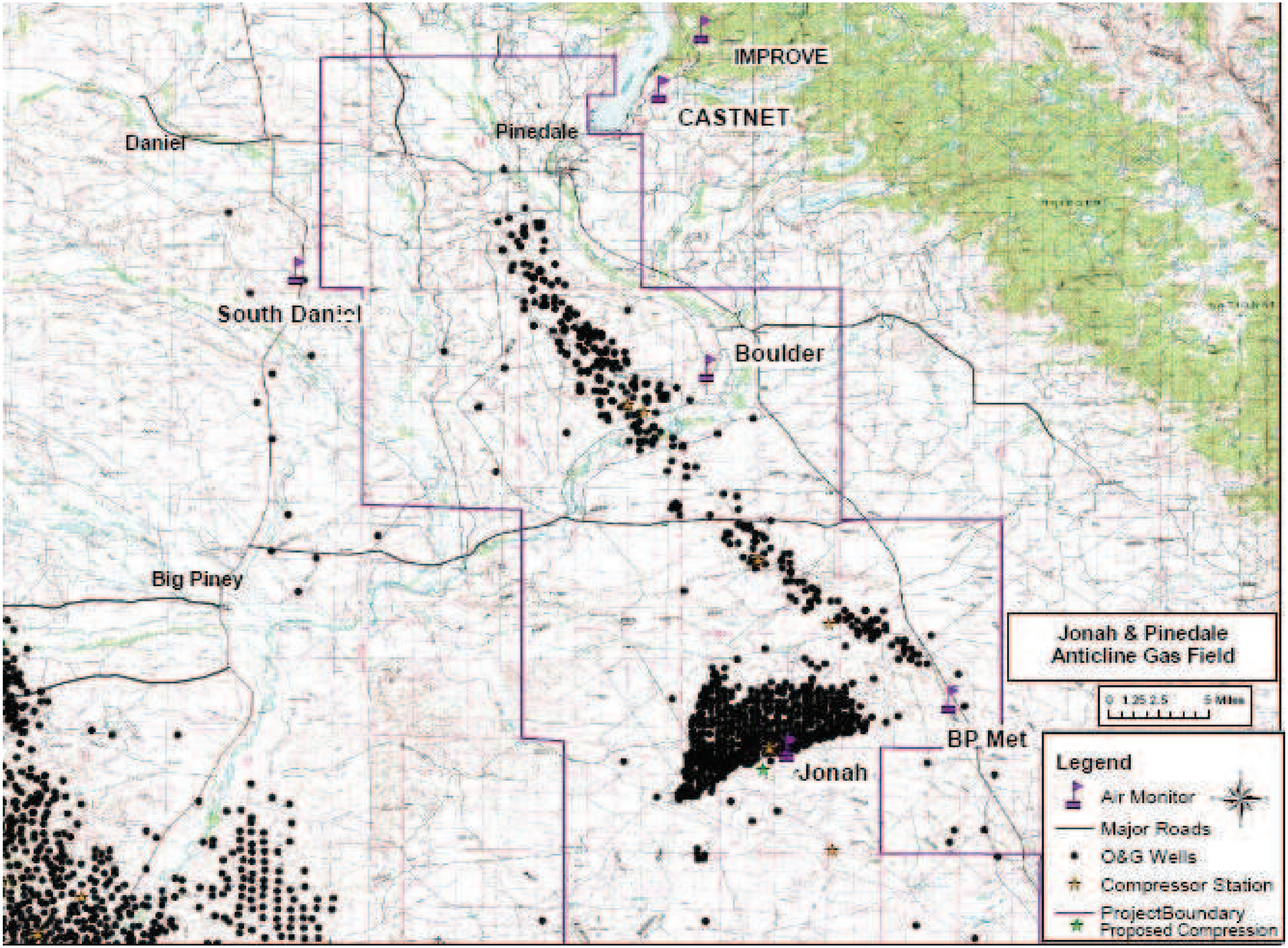
Russ Schnell, Sam Oltmans, and Ryan Neely[1] , Maggie Endres[2], John Molenar[3] and Allen White[1]

[1]NOAA, Earth System Research Laboratory, Boulder, CO 80305

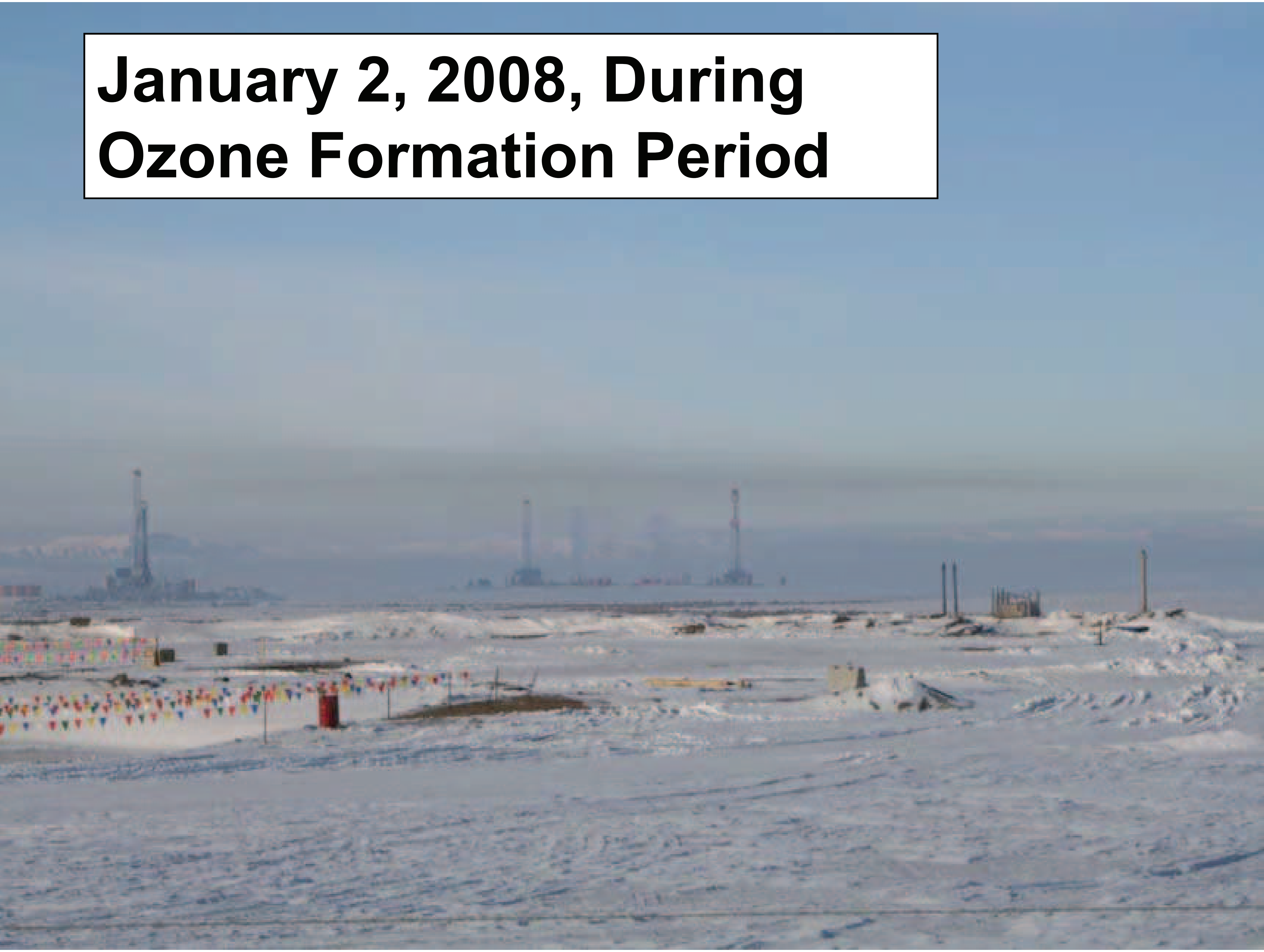
[2]Wyoming Department of Air Quality, Cheyenne, WY

[3]Air Resource Specialists, Fort Collins. CO

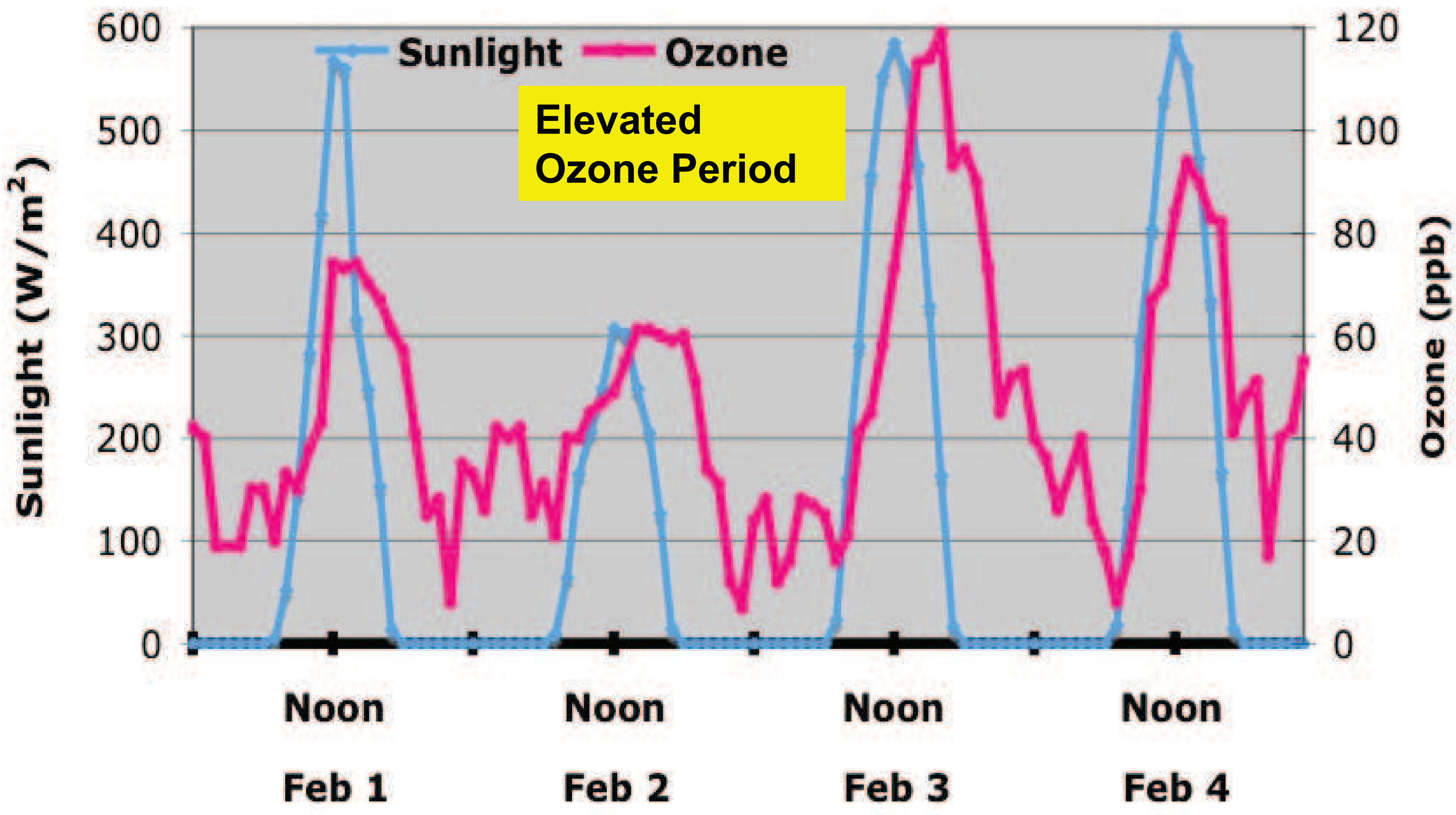
Pinedale Anticline, Jonah, Wyoming



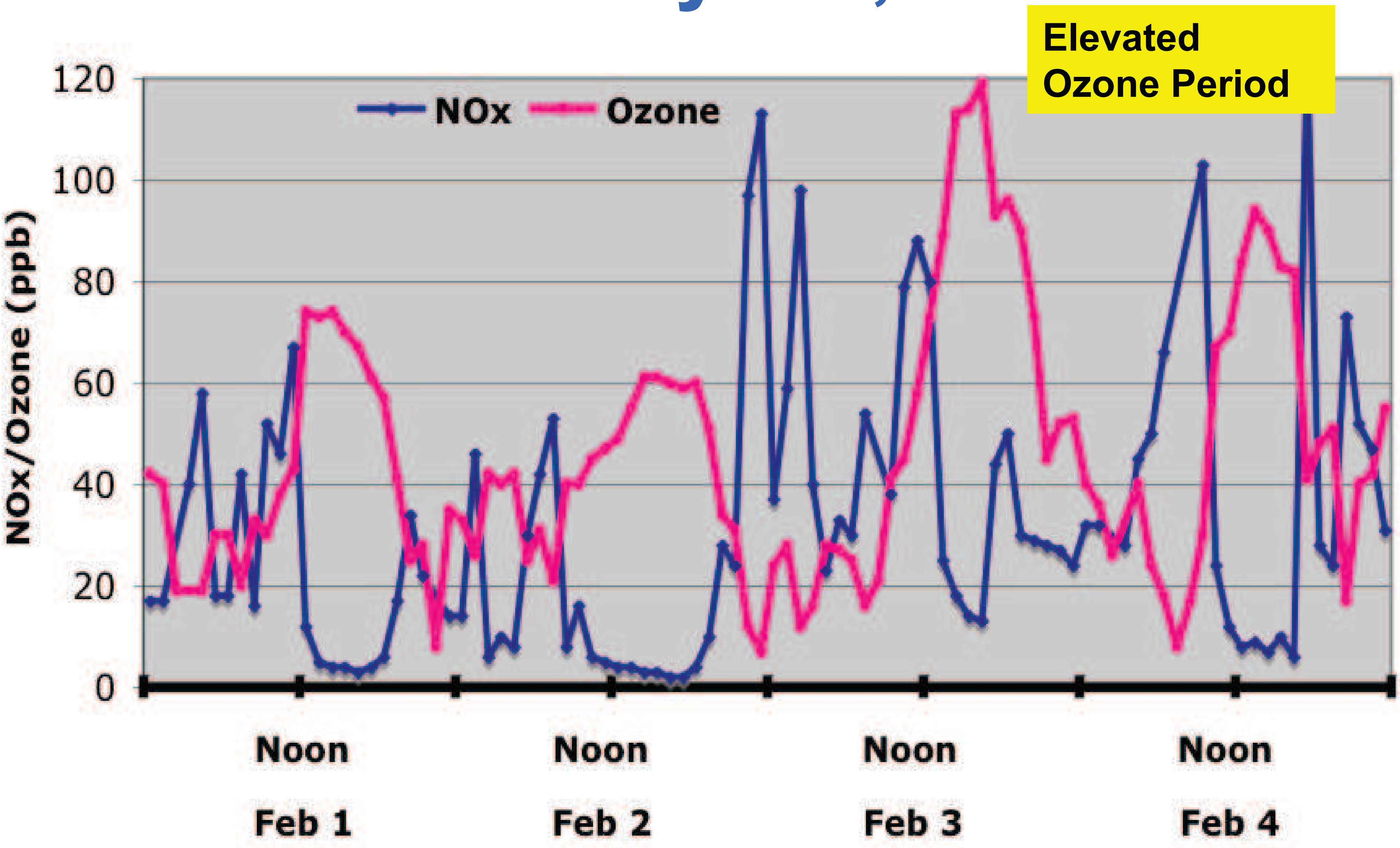

Well Density
will increase
300% in 3-5
Years
Blm-5409
Blm-5410
© 2006 Navteq
Image © 2006 DigitalGlobe
Google
Pointer 42°27'04.65" N 109°42'12.14" W elev 7237 ft
Streaming |||||||||| 100%
Eye alt 15726 ft


January 2, 2008, During
Ozone Formation Period

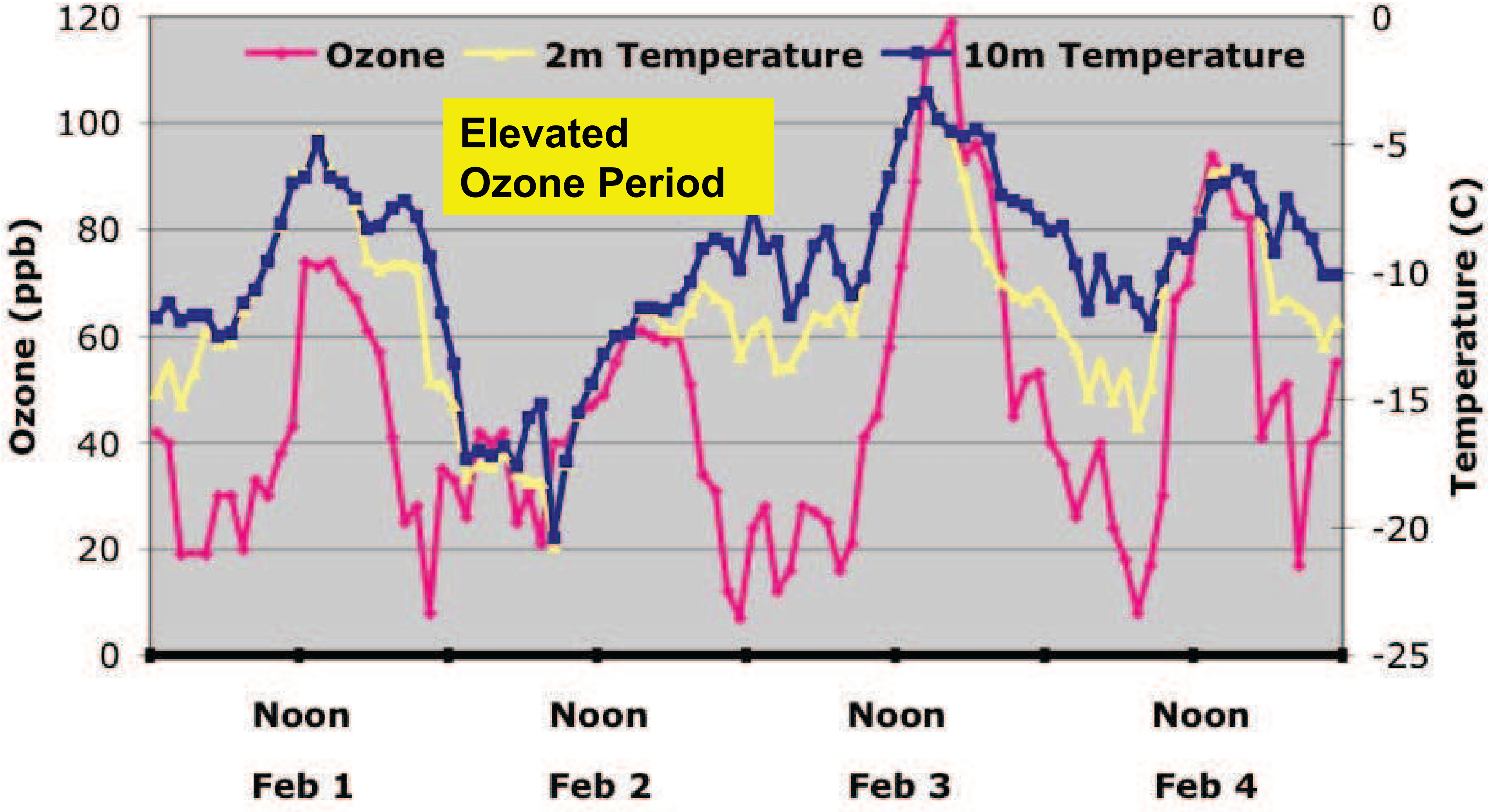
Solar Radiation and Ozone, Jonah, February 1-4, 2005



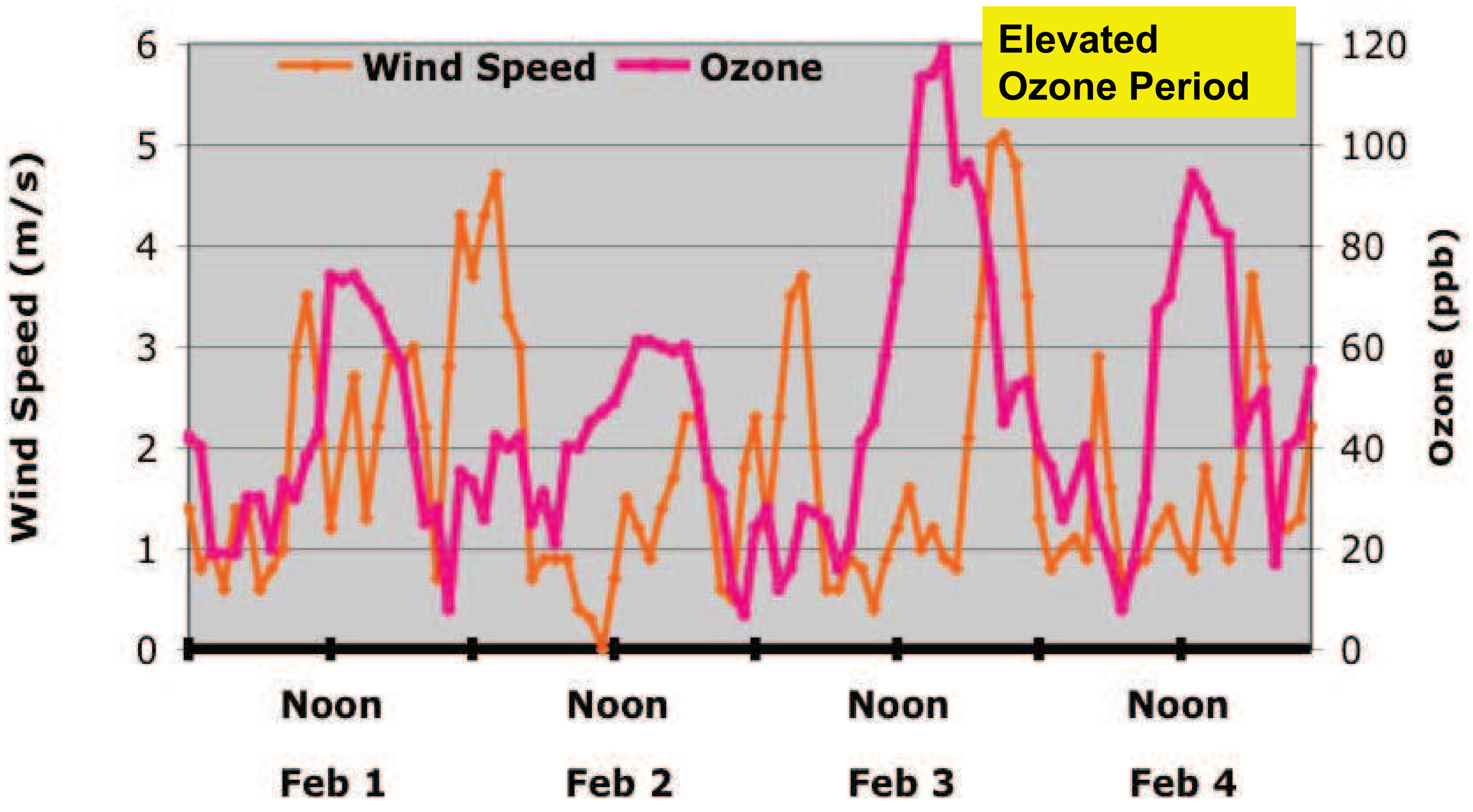
Ozone and NOx, Jonah, February 1-4, 2005



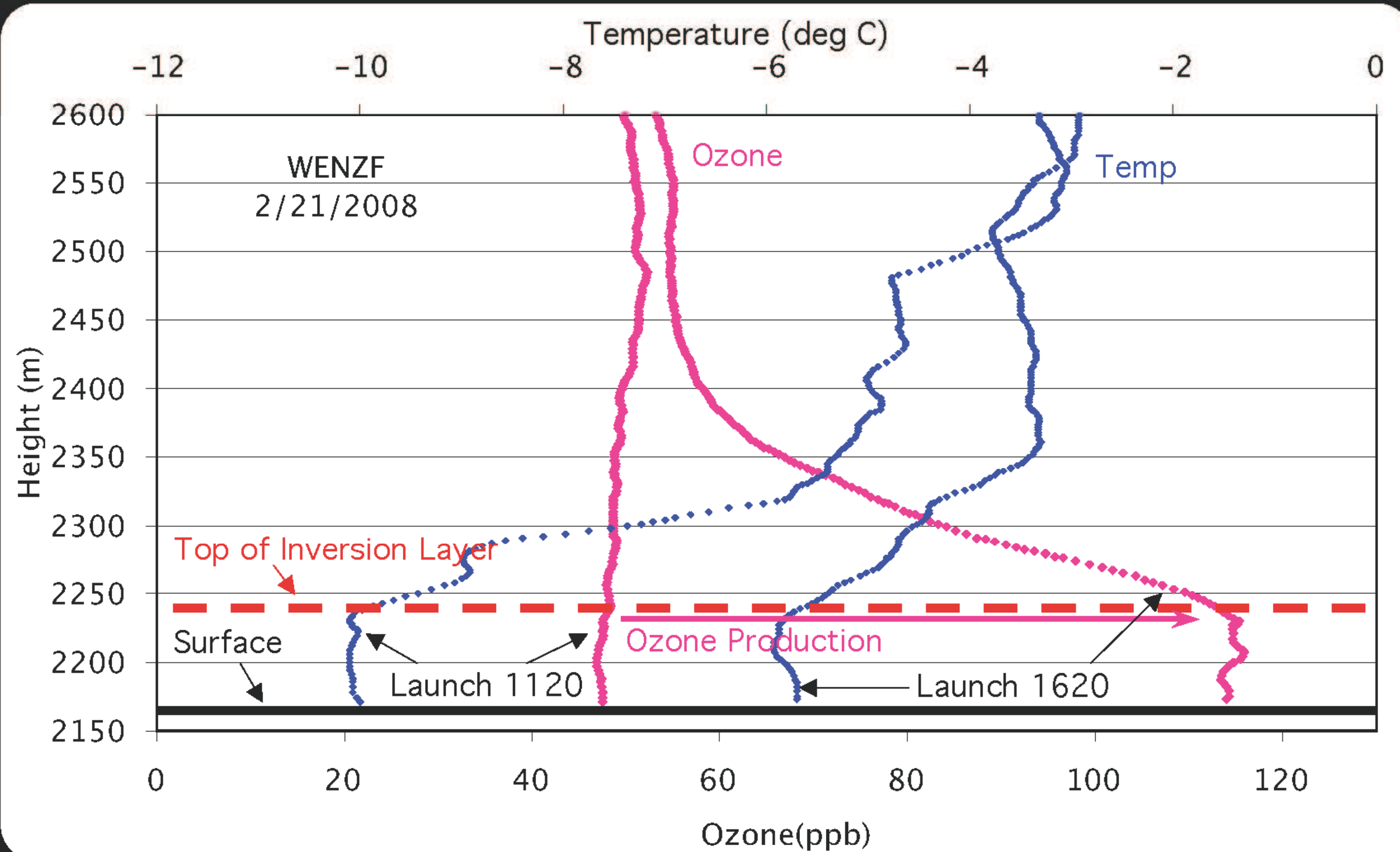
Ozone and Temperature, Jonah, February 1-4, 2005

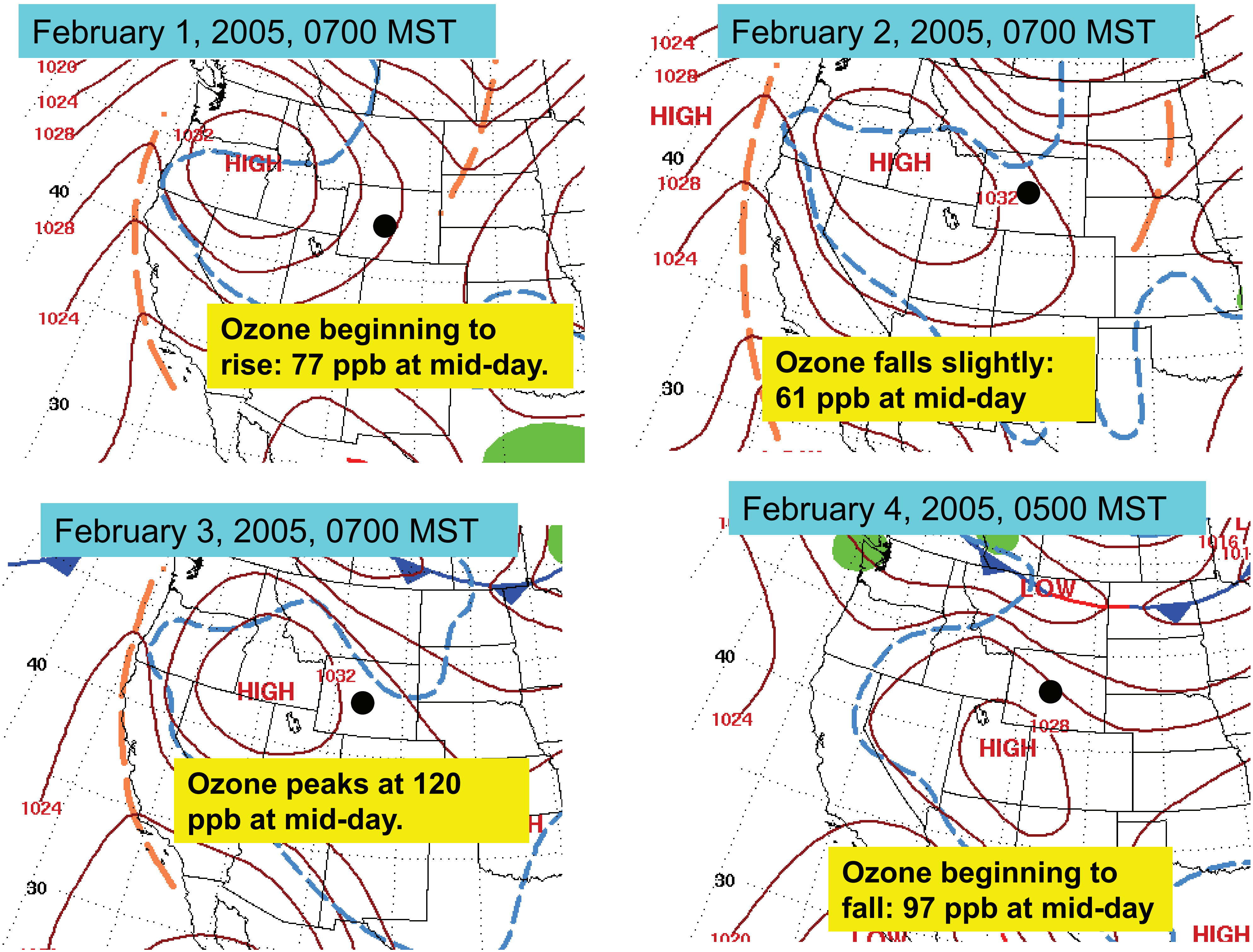


Ozone and Wind Speeds, Jonah, WY, Feb 1-4, 2005



Ozonesondes




February 1, 2005, 0700 MST
1020
1024
1028
1032
HIGH
40
1028
1024
30
Ozone beginning to rise: 77 ppb at mid-day.
February 2, 2005, 0700 MST
1024
1028
HIGH
40
1028
HIGH
1032
1024
30
Ozone falls slightly: 61 ppb at mid-day
February 3, 2005, 0700 MST
40
HIGH
1032
1024
30
Ozone peaks at 120 ppb at mid-day.
February 4, 2005, 0500 MST
1016
LOW
40
1024
1028
HIGH
30
Ozone beginning to fall: 97 ppb at mid-day
HIGH

Economics Of The Jonah Gas Field

- The 30,000 acre Jonah gas field, 30 miles south of Pinedale, Wyoming, is estimated to hold 10 trillion cubic feet of natural gas.
- The field presently produces enough gas to serve 3,000,000 U.S. homes per year.
- In 2007, the Jonah Field produced natural gas revenues in excess of $8 billion.
- The value of the gas to be extracted from the field over 40 years is calculated to be in excess of $60 billion (2005 prices).

Thank You for Hanging In Until the END!

DAVE FREUDENTHAL
GOVERNOR

THE STATE OF WYOMING

STATE CAPITOL
CHEYENNE, WY 82002

Office of the Governor

March 12, 2009

Ms. Carol Rushin
Acting Regional Administrator
USEPA Region 8
Mail Code: 8P-AR
1595 Wynkoop Street
Denver, CO 80202-1129

RE: Wyoming 8-Hour Ozone Designation Recommendation

Dear Ms. Rushin:

This letter transmits my recommendations, as allowed for under Section 107(d)(1) of the Clean Air Act, for Wyoming area designations and nonattainment area boundaries for the new eight-hour ozone National Ambient Air Quality Standards. These recommendations are based on a Wyoming Department of Environmental Quality (WDEQ) staff analysis which follows EPA's guidance dated December 4, 2008, "Area Designations for the 2008 Revised Ozone National Ambient Air Quality Standards."

At this time, I am recommending that all areas of the State of Wyoming be designated as attainment/unclassifiable with respect to the 8-hour ozone standard except for Sublette County and partial sections of Sweetwater and Lincoln counties. Enclosed with this letter is a table listing all specific areas of the state with their corresponding recommended designations, along with a figure showing the boundary of the nonattainment area, and ozone monitoring data collected through 2008.[1] The technical support document, which includes a 9-Factor Analysis, is being sent by the Director of the Department of Environmental Quality under separate cover.

Elevated ozone in a truly rural environment when temperatures are well below freezing is an uncommon event. As we move forward to solve this problem, we are uniquely challenged by the lack of tools available to understand and predict ozone formation in the winter in a valley flanked by the Wind River Mountains.

The State of Wyoming is also challenged by the need to reduce emissions from the natural gas industry which has not traditionally been regulated for ozone nonattainment problems. While the EPA has a long list of control strategies to apply in nonattainment areas, very few of them will

[1] The recommendation does not extend to lands under the jurisdiction of Tribal Authority.

help to reduce ozone in Sublette County. Lowest Achievable Emissions Rate (LAER), Reasonably Available Control Technology (RACT), major source offsets, transportation control measures, and clean fuels programs are designed to reduce emissions from very large industrial sources and urban traffic which are not present in rural Wyoming. Therefore, the WDEQ has already identified the sources that require controls such as drill rigs, pneumatic pumps, dehydration units, and small heaters.

The State is not waiting for the nonattainment process to unfold to tackle the problem, but is addressing the issue on several fronts:

- Several significant field studies have been initiated to understand the processes leading to the occurrence of high ozone levels and to precisely define meteorological conditions that exist when these ozone events occur. These field operations began in 2007 and have continued through the winter of 2009.

- The AQD has deployed more Federal Reference Monitors in southwest Wyoming.

- DEQ is working with contractors to develop models to replicate the high wintertime ozone concentrations observed in the Upper Green.

- The University of Wyoming is conducting an ozone and precursor sampling program in 2009 to provide an independent perspective and further information on spatial variability of ozone in the Basin.

- The DEQ, the Wyoming Department of Health and the Sublette County Commissioners are working together to assess public health risks posed by air toxics associated with natural gas development. A study is now underway.

- The Air Quality Division has moved aggressively to reduce air pollution by applying BACT to all well sites in the Jonah and Pinedale Anticline gas fields, as well as a minor source offset permitting program. To my knowledge, there isn't another place in the world with this much attention given to permitting natural gas emission points.

I share the outline of our aggressive program for two reasons. First, we believe that the area designations should be based on the technical information painstakingly developed by the DEQ for a unique ozone nonattainment problem. If the EPA uses standard analytic tools appropriate for summertime ozone formation in large metropolitan areas, EPA will reach the wrong conclusions about what causes ozone in Sublette County and how to fix it.

Secondly, I understand that a nonattainment designation includes requirements to reduce air pollution from existing sources. Many local gas producers, working in cooperation with our DEQ, have aggressively reduced air emissions and those reductions will continue even as our natural gas resources continue to be developed. These air emission reductions have occurred because of the application of Wyoming's stringent air pollution permitting requirements; because of industry response to our calls for voluntary emission reductions; and because of Wyoming's insistence on stringent air pollution mitigation requirements in the Jonah Infill and Pinedale Anticline Records of Decision. We have not waited for the federal declaration of nonattainment to solve our air pollution problems, and I do not want a nonattainment designation by EPA to penalize the State for instituting early emission reductions.

While we have submitted recommendations as required under the Act, I envision that much work remains. I would like to propose that my staff at DEQ work with US EPA Region 8 to formalize an approach to share technical information and consult over choices of the baseline EI, the size of the nonattainment area and the resulting classification. Should you have any questions or concerns regarding this matter, please contact Mr. John Corra (307-777-7192) or Mr. Dave Finley (307-777-3746).

Best regards,

Dave Freudenthal
Governor

Enclosures: Attachment 1 - Designation Areas
Attachment 2 - Boundary of Designation Area (Figure)
Attachment 3 - Ozone Monitoring Data

cc: John Corra, DEQ Director
David Finley, AQD Administrator
Lori Bocchino, AQD
Christine Anderson, AQD
Callie Videtich, Director, Air and Radiation Program, EPA Region 8 w/ Enclosures
Monica Morales, EPA Region 8 w/ Enclosures
Kerri Fiedler, EPA Region 8 w/ Enclosures

Attachment 1

2008 Primary and Secondary NAAQS 8-hour Primary and Secondary Ozone Standard
Wyoming Recommendations for Ozone Designations
For areas not under the jurisdiction of Tribal Authority

Region	8-hour Ozone Designation
Casper, WY: Natrona County (part).. The portion within the City of Casper	Attainment/Unclassifiable
Cheyenne, WY: Laramie County (part) .... The portion within the City of Cheyenne	Attainment/Unclassifiable
Evanston, WY: Uinta County (part).. The portion within the City of Evanston	Attainment/Unclassifiable
Gillette, WY: Campbell County (part) .... The portion within the City of Gillette	Attainment/Unclassifiable
Jackson, WY: Teton County (part) .... The portion within the City of Jackson	Attainment/Unclassifiable
Lander, WY: Fremont County (part) .... The portion within the City of Lander	Attainment/Unclassifiable
Laramie, WY: Albany County (part).. The portion within the City of Laramie	Attainment/Unclassifiable
Riverton, WY: Fremont County (part) .... The portion within the City of Riverton	Attainment/Unclassifiable
Rock Springs, WY Sweetwater County (part) .... The portion within the City of Rock Springs	Attainment/Unclassifiable
Sheridan, WY Sheridan County (part) .... The portion within the City of Sheridan	Attainment/Unclassifiable
Albany County (remainder)	Attainment/Unclassifiable
Big Horn County	Attainment/Unclassifiable
Campbell County (remainder)	Attainment/Unclassifiable
Carbon County	Attainment/Unclassifiable
Converse County	Attainment/Unclassifiable
Crook County	Attainment/Unclassifiable
Fremont County (remainder)	Attainment/Unclassifiable
Goshen County	Attainment/Unclassifiable
Hot Springs County	Attainment/Unclassifiable
Johnson County	Attainment/Unclassifiable
Laramie County (remainder)	Attainment/Unclassifiable
Lincoln County (remainder)	Attainment/Unclassifiable
Natrona County (remainder)	Attainment/Unclassifiable
Niobrara County	Attainment/Unclassifiable
Park County	Attainment/Unclassifiable
Platte County	Attainment/Unclassifiable
Sheridan County (remainder)	Attainment/Unclassifiable
Sweetwater County (remainder)	Attainment/Unclassifiable
Teton County (remainder)	Attainment/Unclassifiable
Uinta County (remainder)	Attainment/Unclassifiable

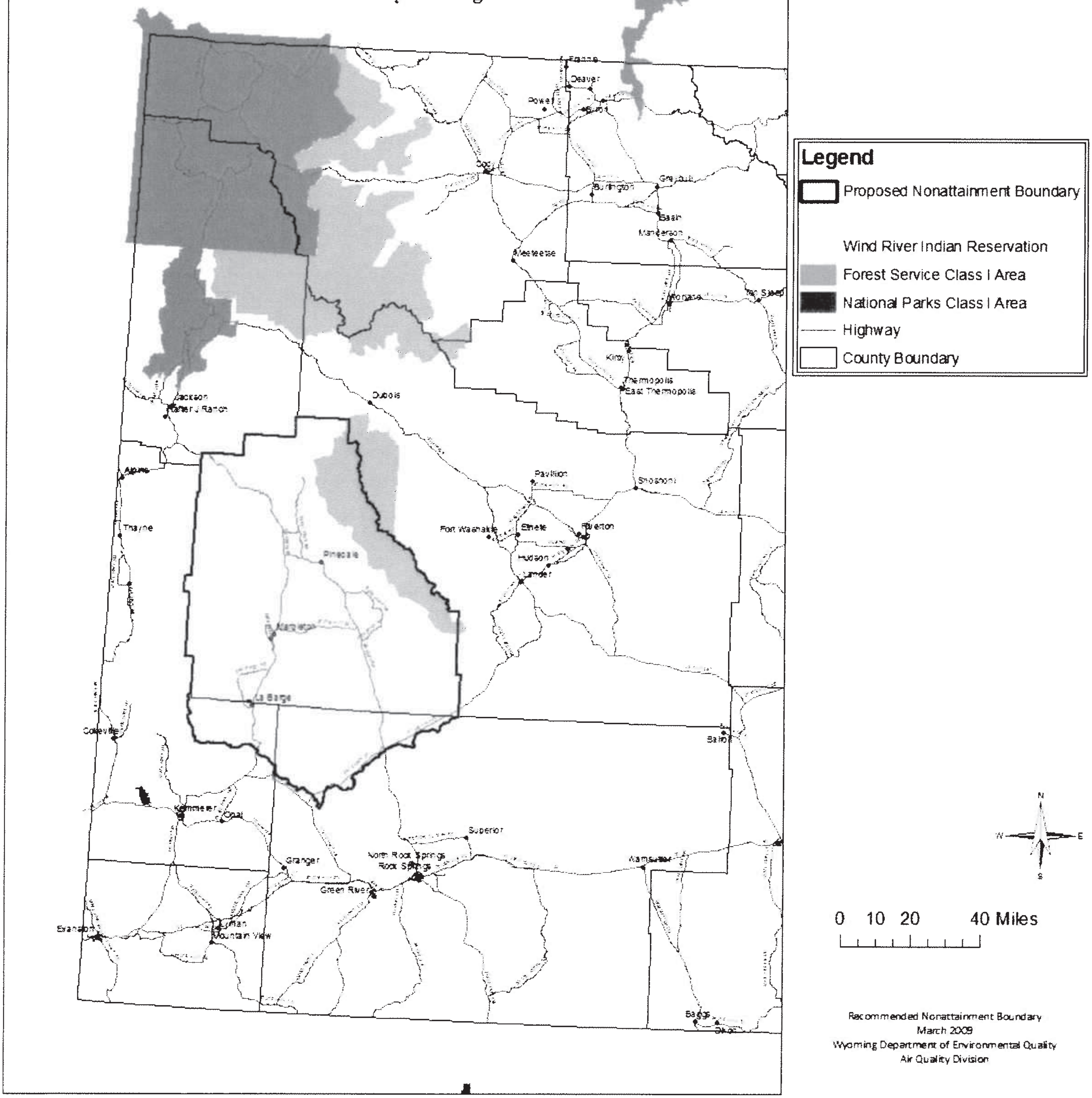
Attachment 1

2008 Primary and Secondary NAAQS 8-hour Primary and Secondary Ozone Standard
Wyoming Recommendations for Ozone Designations
For areas not under the jurisdiction of Tribal Authority
Page 2

Region	8-hour Ozone Designation
Washakie County	Attainment/Unclassifiable
Weston County	Attainment/Unclassifiable
Upper Green River Basin Area: Sublette County: (all) Lincoln County: (part) The area of the county north and east of the boundary defined by a line starting at the point defined by the intersection of the southwest corner Section 30 Range (R) 115 West Township (T) 27N and the northwest corner of Section 31 R 115 West T 27N of Sublette County at Sublette County's border with Lincoln County. From this point the boundary moves to the west 500 feet to the Aspen Creek. The boundary follows the centerline of Aspen Creek downstream to the confluence of Aspen Creek and Fontenelle Creek (in R 116 W T26N, Section 1). From this point the boundary moves generally to the south along the centerline of Fontenelle Creek to the confluence of Fontenelle Creek and Roney Creek (in R115W T24N Section 6). From the confluence, the boundary moves generally to the east along the centerline of Fontenelle Creek and into the Fontenelle Reservoir (in R112W T24N Section 6). The boundary moves east southeast along the centerline of the Fontenelle Reservoir and then toward the south along the centerline of the Green River to where the Green River in R111W T24 N Section 31 crosses into Sweetwater County. Sweetwater County: (part) The area of the county west and north of the boundary which begins at the midpoint of the Green River, where the Green River enters Sweetwater County from Lincoln County in R111W T24N Section 31. From this point, the boundary follows the center of the channel of the Green River generally to the south and east to the confluence of the Green River and the Big Sandy River (in R109W R22 N Section 28). From this point, the boundary moves generally north and east along the centerline of the Big Sandy River to the confluence of the Big Sandy River with Little Sandy Creek (in R106W T25N Section 33). The boundary continues generally toward the northeast long the centerline of Little Sandy Creek to the confluence of Little Sandy Creek and Pacific Creek (in R106W T25N Section 24). From this point, the boundary moves generally to the east and north along the centerline of Pacific Creek to the confluence of Pacific Creek and Whitehorse Creek (in R103W T26N Section 10). From this point the boundary follows the centerline of Whitehorse Creek generally to the northeast until it reaches the eastern boundary of Section 1 R103W T 26North. From the point where Whitehorse Creek crosses the eastern section line of Section 1 R103W T 26North, the boundary moves straight north along the section line to the southeast corner of Section 36 R103W T27N in Sublette County where the boundary ends.	Non-attainment

R Range, T - Township, N - North, W - West

Attachment 2 - Boundary of Designation Area



Attachment 3

Design Values for Wyoming Ambient Ozone Monitors							
Site Name	AQS ID	Year				3-Year Average 2005-2007 (ppm)	3-Year Average 2006-2008[1] (ppm)
		2005 (ppm)	2006 (ppm)	2007 (ppm)	2008 Q1-Q3[1] (ppm)		
Daniel South	56-035-0100	0.067[2]	0.075	0.067	0.074	N/A	0.072[1]
Boulder	56-035-0099	0.080[3]	0.073	0.067	0.101	0.073[3]	0.080[1]
Jonah	56-035-0098	0.076	0.070	0.069	0.082	0.072	0.074[1]
Yellowstone (NPS)	56-039-1011	0.060	0.069	0.064	0.065	0.064	0.066[1]
Thunder Basin	56-005-0123	0.063	0.072	0.072	0.074	0.069	0.073[1]
Campbell County	56-005-0456	0.063[4]	0.065	0.072	0.060	0.067[4]	0.066[1]

[1] Data collected and validated through 3rd quarter 2008
[2] Incomplete year; began operation in July 2005
[3] Incomplete year; began operation in February 2005
[4] One quarter with less than 75% data completeness

4th Maximum 8-Hour Ozone Values for Ambient Monitors without 3 years of data					
Site Name	AQS ID	Year			
		2005 (ppm)	2006 (ppm)	2007 (ppm)	2008 Q1-Q3[1] (ppm)
Murphy Ridge	56-041-0101	---	---	0.070	0.061
South Pass	56-013-0099	---	---	0.071[2]	0.065
OCI[3]	56-037-0898	---	0.071[3]	0.066	0.072
Wamsutter	56-005-0123	---	0.067[4]	0.064	0.064
Atlantic Rim	56-007-0099	---	---	0.047[5]	0.064

[1] Data collected and validated through 3rd quarter 2008
[2] Incomplete year; began operation in March 2007
[3] Site operated by industry. Incomplete year; began operation in May 2006
[4] Incomplete year; began operation in March 2006
[5] Incomplete year; began operation in October 2007

STATE OF WYOMING

Technical Support Document I
For Recommended 8-Hour Ozone Designation
For the Upper Green River Basin, WY

March 26, 2009

The Wyoming Department of Environmental Quality
Air Quality Division
Herschler Building, 122 West 25th Street
Cheyenne, Wyoming 82002

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EXECUTIVE SUMMARY

In March 2008 the US EPA promulgated a new National Ambient Air Quality Standard (NAAQS) for ozone. The new standard was lowered from 0.08 ppm to 0.075 ppm based on the fourth highest 8-hour average value per year at a site, averaged over three years. Based on monitoring results from 2006 through 2008, the entire state of Wyoming is in compliance with this standard except for at a single monitor, the Boulder monitor, in Sublette County.

The Wyoming Department of Environmental Quality, Air Quality Division (AQD) evaluated whether a nonattainment area should be designated due to the monitored results at the Boulder monitor. Using EPA's guidance in the Robert J. Meyers December 4, 2008 memo, the AQD performed a nine-factor analysis, which is the basis of this document. This analysis supports AQD's recommendation that the Upper Green River Basin (UGRB), as defined in the introduction to this document, be designated as nonattainment for the 2008 ozone NAAQS.

The AQD bases this recommendation on a careful review of the circumstances surrounding the incidence of elevated ozone events. Elevated ozone in the UGRB is associated with distinct meteorological conditions. These conditions have occurred in February and March in some (but not all) of the years since monitoring stations began operation in the UGRB in 2005. Our determination of an appropriate nonattainment area boundary is focused on an evaluation of EPA's nine factors, applied to the first quarter of the year. It is important to evaluate conditions during the first quarter of the year in order to focus on the very specific set of circumstances that lead to high ozone.

The most compelling reasons for the boundary recommendation are based on the meteorological conditions in place during and just prior to elevated ozone events. Elevated ozone episodes occurred in 2005, 2006 and 2008; they were associated with very light low-level winds, sunshine, and snow cover, in conjunction with a strong low-level surface-based temperature or "capping" inversion. The longest such event (February 19-23, 2008), which also resulted in the highest measured ozone of 122 ppb as an 8-hour average at the Boulder station, has been reviewed in detail and summarized in Section 7 of this document. Section 7 demonstrates that sources outside the recommended nonattainment area would not have a significant impact on the Boulder monitor due to the presence of an inversion and very low wind speeds, which significantly limit precursor and ozone transport from sources located outside of the UGRB.

The AQD carefully examined sources of ozone and ozone precursors within Sublette and surrounding counties. When evaluating sources, AQD considered these five of EPA's factors: population density, traffic and commuting patterns, growth rates and patterns, emission data, and level of control of air emissions. Sublette County is a rural county with a population density of two people per square mile; the most densely populated nearby county (Uinta) is also largely rural with a population density of ten people per square mile. As would be expected, the number of commuters into or out of the UGRB is small and does not represent a significant source of precursor emissions. While there is an interstate highway 80 miles south of the Boulder monitor, the attached analysis demonstrates that I-80 traffic is not considered to be a significant contributor of emissions that impact the Boulder monitor during ozone events.

Although population and population growth was not a significant factor, growth in the oil and gas (O&G) industry in Sublette County was considered pertinent. The volume of natural gas produced doubled between 2000 and 2008 in the county; the number of wells completed doubled between 2004 and 2008. Approximately 1,500 well completions were recorded in Sublette County in the last four years. Growth in the oil and gas industry in nearby areas is much slower.

AQD prepared an estimated inventory of emissions for the recommended nonattainment area and the surrounding counties. The inventory showed that approximately 94% of VOC emissions in the UGRB and 60% of NOx emissions are attributable to oil and gas production and development. Of the eleven major sources in the UGRB, all are O&G related. To the north, east and west there are few major sources in counties adjacent to the UGRB. In addition to the major sources, there are numerous minor sources in the UGRB including several concentrated areas of O&G development. Just to the south of the UGRB, there are a few major sources, several minor sources and again, a concentrated area of O&G wells. AQD then used other factors, meteorology, topography, and level of control of emissions, to determine which of the sources to the south of Sublette County should be included in the proposed nonattainment boundary.

The level of control of emissions in the Jonah and Pinedale Anticline Development is very stringent and new oil and gas production units in Sublette County and surrounding counties require permits including Best Available Control Technology (BACT). An interim policy for Sublette County which took effect in 2008 results in a net decrease in emissions of ozone precursors with every permit that is issued. Since stricter controls for O&G are already in place in Sublette County, if O&G sources outside of Sublette County might contribute ozone or ozone precursors to the Boulder monitor, including these O&G sources in the proposed nonattainment area would provide motivation to control these sources.

In evaluating topography, the east, north and west county boundaries are natural boundaries of high mountains. These geographical and jurisdictional boundaries also coincide with population boundaries and emission source boundaries. To the south, the topographical boundaries are less dramatic, but there are rivers, valleys, and buttes that form geographic boundaries near the southern border of Sublette County. Therefore, the AQD considered the county boundary to the north, east and west to be a reasonable boundary based on geography, jurisdictions, emission sources, population and growth.

However, meteorology provided the strongest basis for setting the southern boundary of the proposed nonattainment area. Elevated ozone in the UGRB is associated with distinct meteorological conditions. These conditions have occurred in February and March in some (but not all) of the years since monitoring stations began operation in the UGRB in 2005.

Meteorological conditions in place during and just prior to elevated ozone events provide the most specific data for setting the south boundary. Elevated ozone episodes are associated with very light low-level winds, cold temperatures, sunshine, and snow cover, in conjunction with strong low-level surface-based temperature inversions. Sources outside the recommended nonattainment area would not have a significant impact on the Boulder monitor due to the presence of an inversion and the very low wind speeds, which influence the transport of emissions. Detailed meteorological data collected during intensive field studies shows that emissions from sources south of the recommended nonattainment area are generally carried toward the east and not into the UGRB during or just prior to an ozone episode. Speciated VOC data collected in the UGRB during elevated ozone episodes also has a dominant oil and gas signature, indicating the VOC concentrations are largely due to O&G development activities.

Meteorology and topography indicate that sources outside a southern boundary defined by the Little Sand Creek and Pacific Creek to the east and the Green River and Fontenelle Creek to the west do not contribute to ozone and ozone precursors which could affect the Boulder monitor.

The analysis conclusively shows that elevated ozone at the Boulder monitor is primarily due to local emissions from oil and gas (O&G) development activities: drilling, production, storage, transport, and treating. The ozone exceedances only occur when winds are low indicating that there is no transport of ozone or precursors from distances outside the proposed nonattainment area. The ozone exceedances only occur in the winter when the following conditions are present: strong temperature inversions, low winds, cold temperatures, clear skies and snow cover. If transport from outside the proposed nonattainment area was contributing to the exceedances, then elevated ozone would be expected at other times of the year. Mountain ranges with peaks over 10,000 feet border the area to the west, north and east influence the local wind patterns. Emission sources in nearby counties are not upwind of the Boulder monitor during episodes which exceed the 8-hour ozone standard in Sublette County.

The proposed nonattainment area boundary includes the violating monitor and the sources which are most likely to contribute ozone and ozone precursors to the monitored area. Using this as a boundary will allow the State to focus its resources on the emission sources that contribute to the ozone issue and will allow the State to control the ozone problem in a timely manner.

INTRODUCTION

BACKGROUND AND REGULATORY HISTORY

The U.S. Environmental Protection Agency (EPA) is charged with developing air quality standards for the protection of human health and welfare. EPA is also required to periodically evaluate those standards and revise them if scientific analyses indicate different standards would be more protective of public health and welfare. In March of 2008, EPA promulgated a new National Ambient Air Quality Standard (NAAQS) for ozone. This new standard lowered the 8-hour level of ozone from 0.08 parts per million (ppm) to 0.075 ppm, based on the fourth maximum 8-hour value at a site averaged over three years. Each state must recommend ozone designations no later than March 12, 2009 and final designations must be complete by March 12, 2010.

BASIS FOR TECHNICAL SUPPORT

This technical support document considers nine criteria, or "factors" to make a recommendation for the appropriate location and boundary of a nonattainment area. Those factors are derived from EPA's memorandum issued December 4, 2008, "Area Designations for the 2008 Revised Ozone National Ambient Air Quality Standards." States must submit an analysis of these nine factors, along with a proposed nonattainment boundary, for any areas that are not meeting the federal standard. The nine factors that must be addressed are:

- Air quality data
- Emissions data (location of sources and contribution to ozone concentrations)
- Population density and degree of urbanization (including commercial development)
- Traffic and commuting patterns
- Growth rates and patterns
- Meteorology (weather/transport patterns)
- Geography/topography (mountain ranges or other air basin boundaries)
- Jurisdictional boundaries (e.g., counties, air districts, existing nonattainment areas, Reservations, metropolitan planning organizations (MPOs))
- Level of control of air emissions

RECOMMENDED NONATTAINMENT AREA BOUNDARY

The State of Wyoming recommends that the UGRB, with boundaries described as follows, be designated as a nonattainment area for the 2008 8-hour ozone standard:

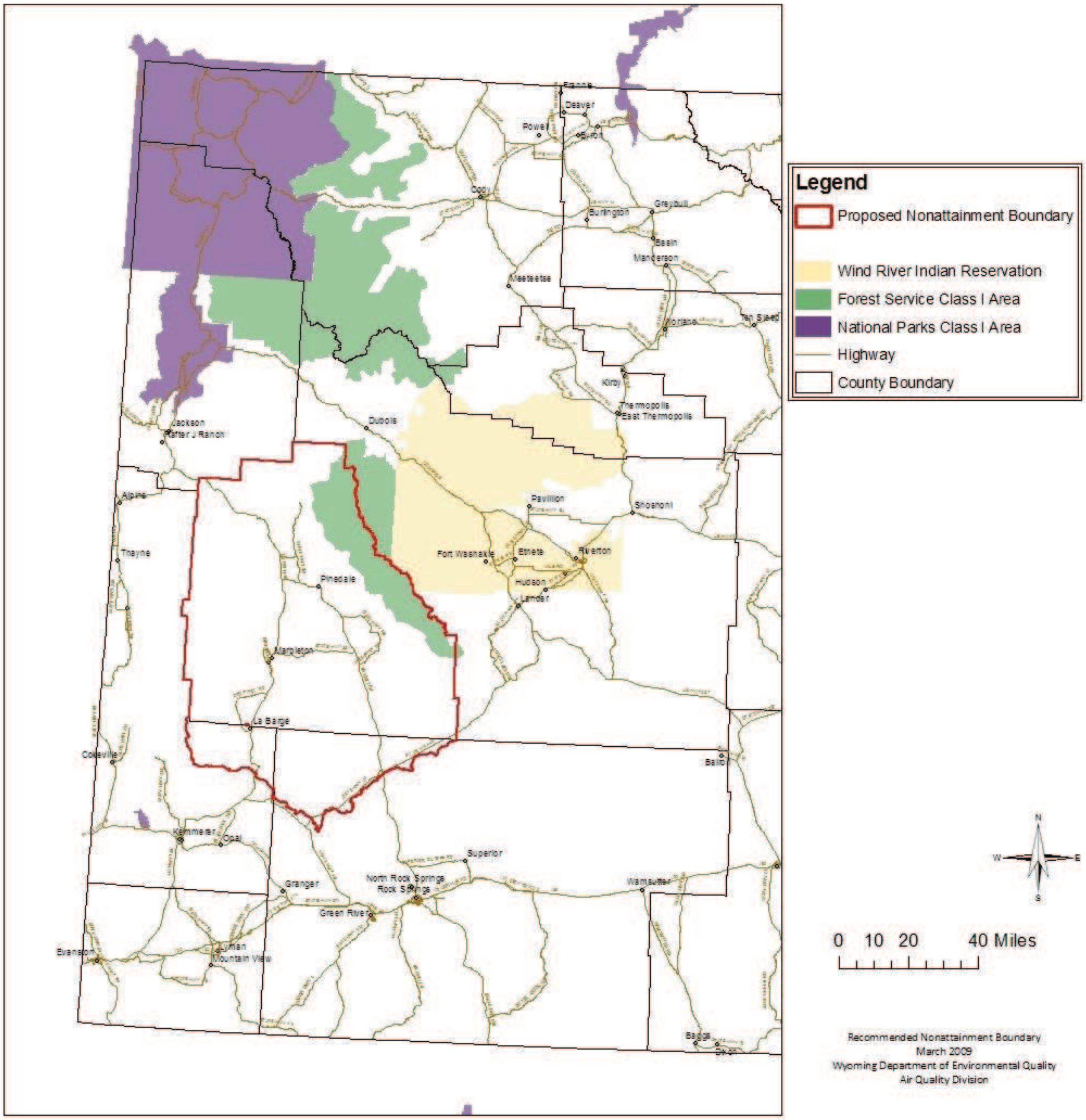
Sublette County: (all)

Lincoln County: (part) The area of the county north and east of the boundary defined by a line starting at the point defined by the intersection of the southwest corner Section 30 Range

(R) 115 West Township (T) 27N and the northwest corner of Section 31 R 115 West T 27N of Sublette County at Sublette County's border with Lincoln County. From this point the boundary moves to the west 500 feet to Aspen Creek. The boundary follows the centerline of Aspen Creek downstream to the confluence of Aspen Creek and Fontenelle Creek (in R 116 W T26N, Section 1). From this point the boundary moves generally to the south along the centerline of Fontenelle Creek to the confluence of Fontenelle Creek and Roney Creek (in R115W T24N Section 6). From the confluence, the boundary moves generally to the east along the centerline of Fontenelle Creek and into the Fontenelle Reservoir (in R112W T24N Section 6). The boundary moves east southeast along the centerline of the Fontenelle Reservoir and then toward the south along the centerline of the Green River to where the Green River in R111W T24 N Section 31 crosses into Sweetwater County.

Sweetwater County: (part) The area of the county west and north of the boundary which begins at the midpoint of the Green River, where the Green River enters Sweetwater County from Lincoln County in R111W T24N Section 31. From this point, the boundary follows the center of the channel of the Green River generally to the south and east to the confluence of the Green River and the Big Sandy River (in R109W R22 N Section 28). From this point, the boundary moves generally north and east along the centerline of the Big Sandy River to the confluence of the Big Sandy River with Little Sandy Creek (in R106W T25N Section 33). The boundary continues generally toward the northeast along the centerline of Little Sandy Creek to the confluence of Little Sandy Creek and Pacific Creek (in R106W T25N Section 24). From this point, the boundary moves generally to the east and north along the centerline of Pacific Creek to the confluence of Pacific Creek and Whitehorse Creek (in R103W T26N Section 10). From this point the boundary follows the centerline of Whitehorse Creek generally to the northeast until it reaches the eastern boundary of Section 1 R103W T 26North. From the point where Whitehorse Creek crosses the eastern section line of Section 1 R103W T 26North, the boundary moves straight north along the section line to the southeast corner of Section 36 R103W T27N in Sublette County where the boundary ends.

A picture of this area follows.



KEY ISSUES

Elevated ozone concentrations in most areas occur during the warm summer months, when there is abundant solar radiation and high temperatures. The elevated ozone concentrations at the Boulder monitor in Sublette County occur in late winter and early spring when sun angles are low so there is less solar radiation and temperatures are below freezing. Ozone formation at the Boulder monitor in Sublette County does not follow the pattern of ozone formation found in urban areas in the summer.

Moderately elevated ozone was first detected in Sublette County in February of 2005 and 2006. The Wyoming Air Quality Division (AQD) conducted intensive meteorological and ambient data collection and analyses in 2007 and 2008 in order to understand this phenomenon. AQD is continuing this effort in 2009. Although analysis of all the data is not complete, AQD has already determined that:

- Local meteorological conditions are the single most important factor contributing to the formation of ozone and the definition of the nonattainment boundary.
- Meteorological models that utilize only regional data will not correctly attribute ozone and ozone precursors to the sources which affect the UGRB.
- Trajectory analyses using detailed observation-based wind field data show that local scale transport of ozone and ozone precursors is dominant during periods of elevated ozone.
- Trajectory analyses using the wind field data show that regional transport of ozone and ozone precursors appears to be insignificant during periods of elevated ozone.

SECTION 1
AIR QUALITY DATA

SYNOPSIS

Ozone at levels exceeding the standard has been monitored at one of three stations in the UGRB – specifically, the Boulder monitor.

Measured ozone levels have not exceeded the standard in the counties adjacent to the UGRB.

Elevated ozone within the UGRB typically only occurs in January, February, or March.

VOCs detected in ambient air in the UGRB have a strong oil and gas signature.

ANALYSIS

The Wyoming Air Quality Division (AQD) operated three monitoring stations in the proposed nonattainment area in 2005-2008. Monitor locations are shown on the map in Figure S.1-1. This map also shows the location of monitors in adjacent counties.

FIGURE S.1-1: Map Showing Monitoring Stations In and Near the Upper Green River Basin

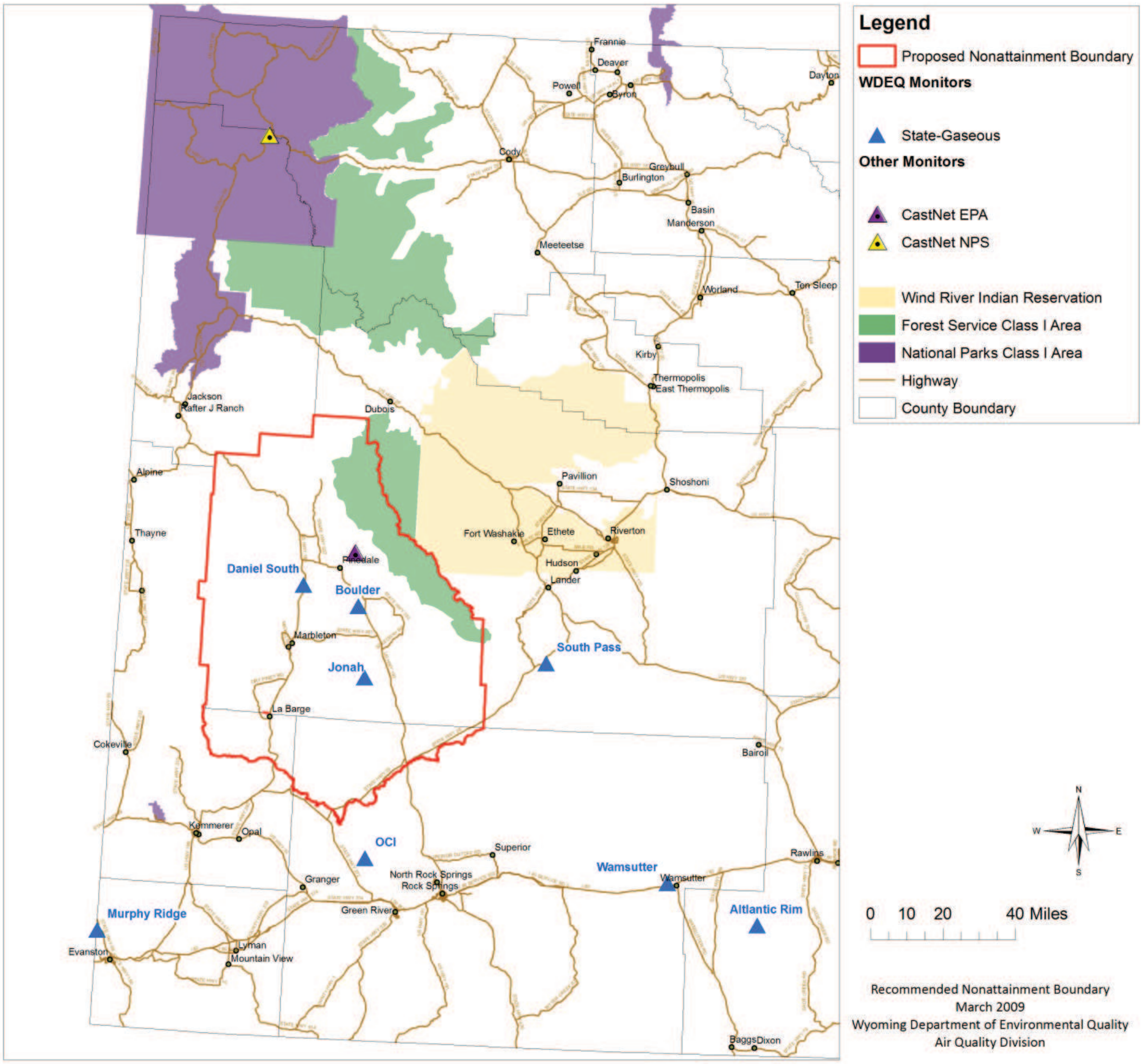


Table S.1-1 shows the ozone design values for the 8-hour standard for the Reference or Equivalent Method monitoring stations shown in Figure S.1-1. All data are collected by Reference or Equivalent Method monitors and meet EPA's criteria for quality and completeness unless otherwise noted. Please note, Pinedale CASTNet data are not included in the design values because this station was not operated in accordance with Part 58 QA requirements until 2007. The design value is the three-year average of the annual fourth highest daily maximum 8-hour ozone concentration (a calculated value less than or equal to 0.075 ppm indicates attainment of the standard; a calculated value of greater than 0.075 ppm is a violation of the standard). Table S.1-2 shows monitored data from other Federal Reference Method (FRM) or Federal Equivalent Method (FEM) ozone monitors in the counties surrounding the UGRB. These monitors have been running for less than 3 years and therefore do not have a design value calculated.

Table S.1-1: Design Values for Monitors In or Near the Upper Green River Basin

Site Name	AQS ID	Year				3-Year Average 2005-2007 (ppm)	3-Year Average 2006-2008[1] (ppm)
		2005 (ppm)	2006 (ppm)	2007 (ppm)	2008 Q1 – Q3 (ppm)		
Daniel South	56-035-0100	0.067[2]	0.075	0.067	0.074	N/A	0.072[1]
Boulder	56-035-0099	0.080[3]	0.073	0.067	0.101	0.073[3]	0.080[1]
Jonah	56-035-0098	0.076	0.070	0.069	0.082	0.072	0.074[1]
Yellowstone (NPS)	56-039-1011	0.060	0.069	0.064	0.065	0.064	0.066

[1] Data collected and validated through 3rd quarter 2008
[2] Incomplete year; began operation in July 2005
[3] Incomplete year; began operation in February 2005

Table S.1-2: 4th Maximum 8-Hour Ozone Values for Monitoring in Surrounding Counties					
Site Name	AQS ID	Year			
		2005 (ppm)	2006 (ppm)	2007 (ppm)	2008 Q1 – Q3 (ppm)
Murphy Ridge	56-041-0101	---	---	0.070	0.061[1]
South Pass	56-013-0099	---	---	0.071[2]	0.065[1]
OCI[3]	56-037-0898	---	0.071[3]	0.066	0.072[1]
Wamsutter	56-005-0123	---	0.067[4]	0.064	0.064[1]
Atlantic Rim	56-007-0099	---	---	0.047[5]	0.064[1]

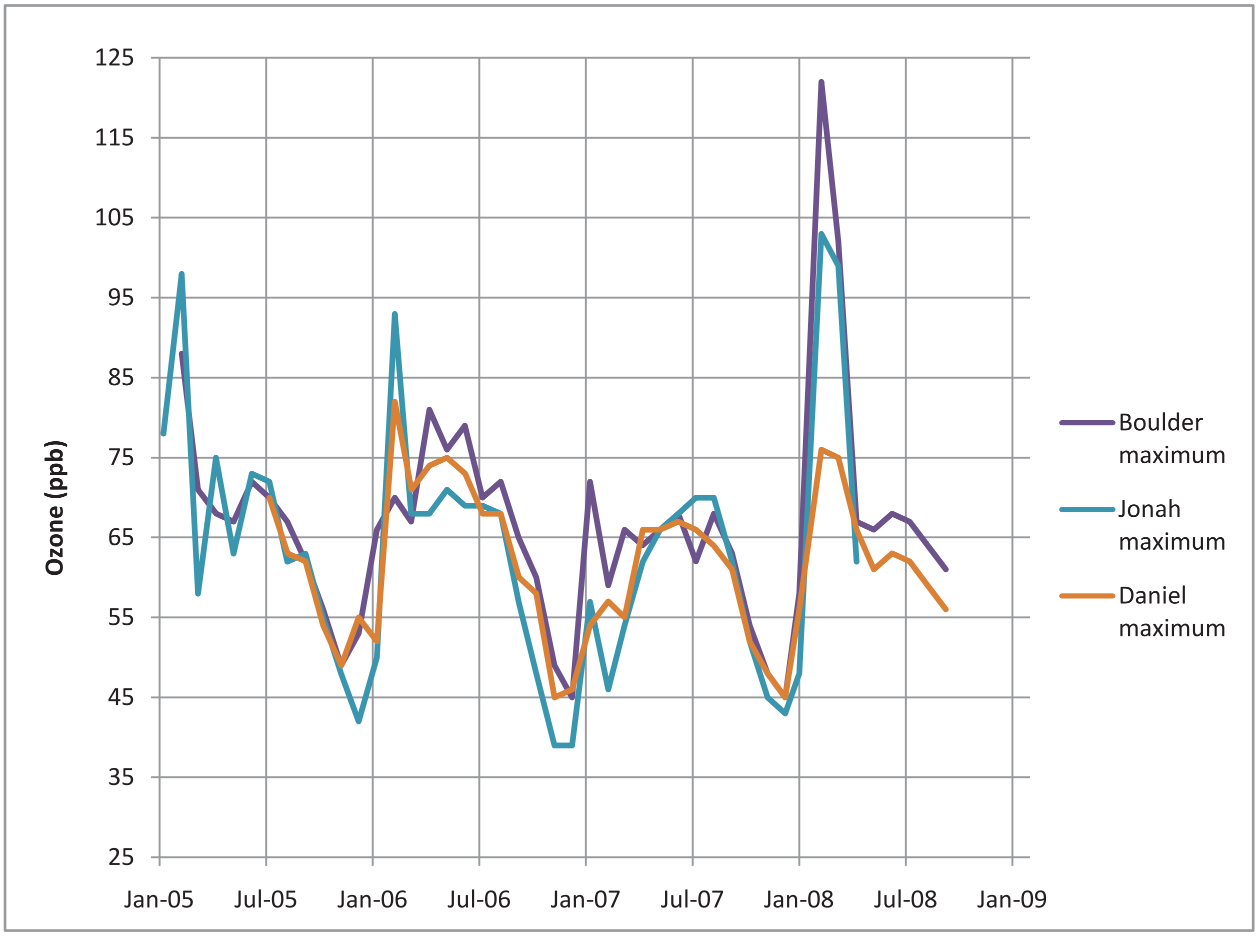
[1] Data collected and validated through 3rd quarter 2008
[2] Incomplete year; began operation in March 2007
[3] Site operated by industry. Incomplete year; began operation in May 2006
[4] Incomplete year; began operation in March 2006
[5] Incomplete year; began operation in October 2007

Using only data from 2005 through 2007, the monitors for which a design value can be calculated indicate compliance with the ozone NAAQS. Year-to-date data from 2008, however, bring the 2006 - 2008 design value for the Boulder monitor to 0.080 ppm (compared to the standard of 0.075).

While monitors in counties adjacent to the UGRB have not been in operation for a full three-year period (with the exception of the Yellowstone NPS monitor), none of them have 4th-high maximum 8-hour ozone values above 0.075 ppm for any year. This would indicate that, based on ambient monitoring data, ozone levels have not been measured that exceed the standard outside of the UGRB (within Wyoming).

When the data from the Boulder monitoring station, the only monitor showing ozone levels in excess of the standard, is reviewed closely, it shows that elevated ozone typically occurs in the winter. This trend is also evident at the two stations nearby (South Daniel and Jonah). Figure S.1-2 shows the daily 8-hour maximum for these stations on a monthly basis over the last four years. This is an unprecedented phenomenon, as ozone was thought to be a summertime problem. The Wyoming DEQ, with the help of industry, has dedicated significant resources to better understand this situation. The studies indicate that elevated ozone occurs in the UGRB under very specific meteorological conditions, described in greater detail in Section 7 of this document. Briefly, these conditions are the presence of a strong temperature inversion in conjunction with low wind speeds, snow cover and clear skies. These conditions have occurred in January, February, and March.

Figure S.1-2: Monthly 8-Hour Maximum Ozone Within the UGRB



AQD performed Winter Ozone Studies in 2007, 2008 and 2009 in the UGRB. The purpose of these studies is to investigate and monitor the mechanisms of ozone formation during the winter months. These data will in turn be used to develop a conceptual model of ozone formation in the UGRB. As the study has progressed, the scope of the study has been refined as AQD has learned about the unique issue of winter ozone formation. In general terms, the scope of the winter ozone studies include:

1. Placing additional FEM and non-FEM (2B ozone analyzers) monitors throughout the UGRB to characterize spatial and temporal distribution of ground-level ozone.
2. Placing additional three-meter meteorological towers (mesonet) throughout the UGRB to characterize local micro-scale meteorology.
3. Placing additional precursor monitoring (e.g., VOC, NOx and CO) in a few sites around the UGRB to characterize precursor concentrations.
4. Flying a plane equipped with continuous ozone and $PM_{2.5}$ around the UGRB to characterize spatial distribution of ozone (above, in, and below the boundary layer).
5. Launching ozone and rawinsondes to characterize vertical meteorology and ozone distribution.

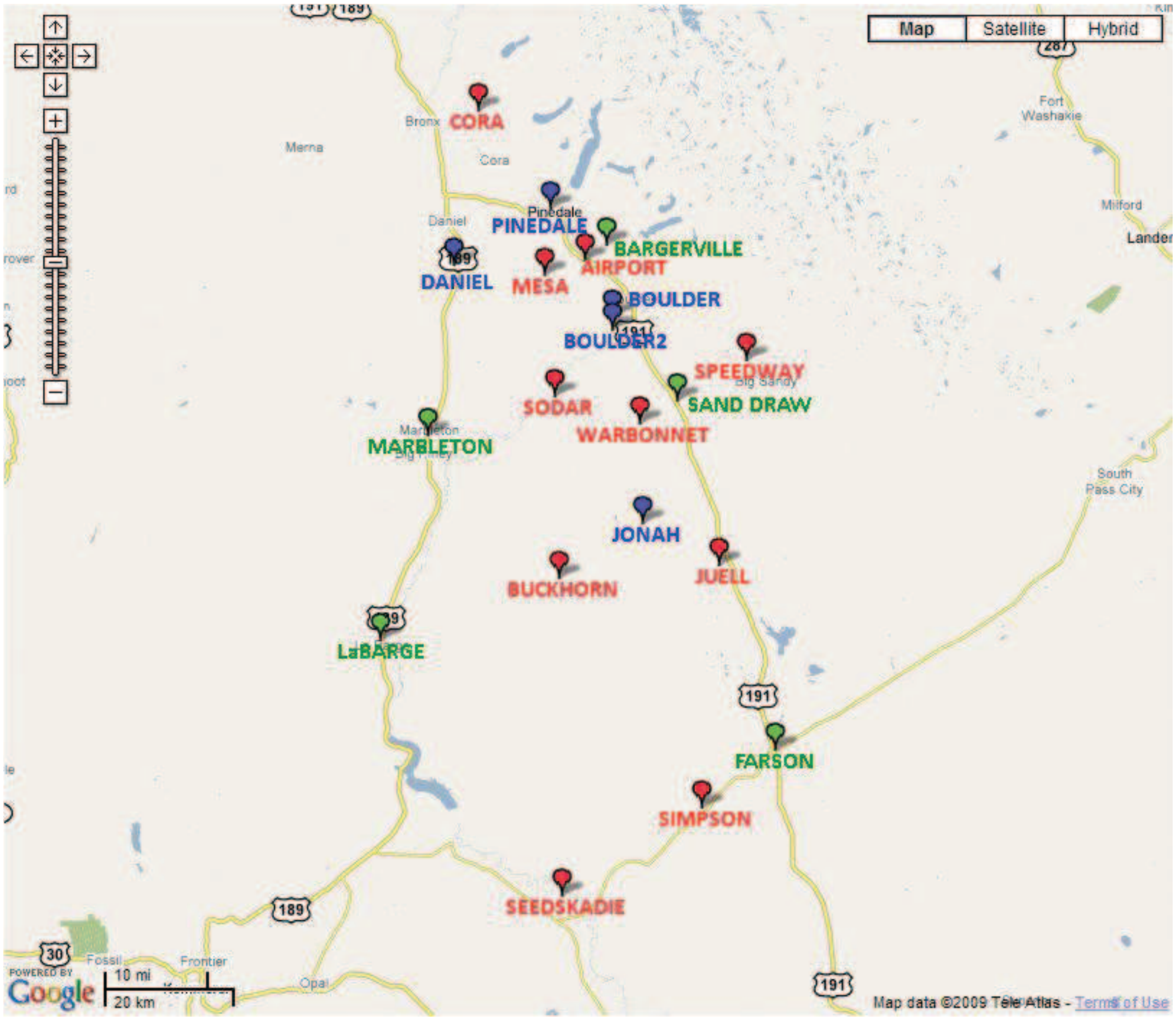
6. Operating ground based upper-air meteorological instruments (e.g., Mini-SODAR, RASS, Wind Profiler) to characterize mixing levels and inversion heights.

In 2007, meteorological conditions did not set up as they had in 2005 and 2006 and elevated ozone did not form in February and March. However, AQD collected data that helped to draw some conclusions about winter ozone formation. The speciated VOC samples collected had a strong oil and gas signature. AQD was able to investigate which detected VOC species were having a greater effect on ozone formation. UV radiation measurements showed that when fresh snow is available, greater than 80% of the ultra-violet light can be reflected.

During the 2008 winter study, several multi-day episodes of elevated ozone were studied. Six additional ozone monitoring locations were added and the plane was flown to provide more information on the spatial and temporal variability around the UGRB. AQD continued to collect speciated VOC samples which confirmed the strong oil and gas signature. These data also allowed us to identify species of interest with respect to elevated ozone formation. AQD also used a mini-SODAR and rawinsondes to characterize the mixing heights and inversion strength on elevated ozone days. It was found that on days with elevated ozone, mixing heights could be as shallow as 50-200 meters above ground level.

For the 2009 winter study, AQD has placed eleven FEM and non-FEM continuous ozone monitors around the UGRB. Additionally, AQD has placed five FEM ozone monitors in communities around the UGRB as part of an Air Toxics study. These monitors compliment the three long-term FEM ozone monitors currently operating. AQD has also added precursor monitoring at the Boulder, Jonah and SODAR stations. Figure S.1-3 shows the current configuration of ozone monitoring in the UGRB.

Figure S.1-3: Winter 2009 Ozone Monitoring in the Upper Green River Basin



While ozone data from these studies cannot be used directly for designation, AQD has used these data to support our recommendation on a nonattainment area boundary for the UGRB. Specifically, VOC data are referenced in Section 2 and mesonet data are used to develop a localized wind field referenced in Section 7. Final reports, quality assurance project plans, and databases from the 2007 and 2008 studies are available on the WDEQ/AQD website: (http://deq.state.wy.us/aqd/Monitoring%20Data.asp). Data from the 2009 study will be posted to the AQD Monitoring page after it has been fully quality assured.

SECTION 2
EMISSIONS DATA

SYNOPSIS

The primary sources of ozone-forming precursors in the recommended nonattainment area are associated with the oil and gas development and production industry in the UGRB.

ANALYSIS

Ground-level ozone is primarily formed from reactions of volatile organic compounds (VOCs) and oxides of nitrogen (NOx) in the presence of sunlight. VOCs and NOx are considered "ozone precursors." As part of the nine-factor analysis, the Air Quality Division compiled emission estimates for VOCs and NOx for ten source categories in the proposed nonattainment area as well as counties or portions of counties surrounding the area. This information is summarized in Table S.2-1 and represents preliminary estimated first quarter 2007 emission inventory data for all potential sources. Emissions information for 2007 is used because it is the most recently available data for all source sectors. Only the first quarter is shown because elevated ozone in the UGRB occurs during limited episodes in the first three months of the calendar year. In general, quarterly emissions for the second through fourth quarters of the year are the same as for the first quarter, with the exception that biogenic VOC emissions are expected to be greater in the spring and summer months.

When comparing the raw precursor emission totals in Table S.2-1, AQD is aware that the total for the area defined as "Sweetwater Outside of Upper Green River Basin" is the largest for both VOCs and NOx. However, after carefully reviewing the other eight factors to determine an appropriate boundary, AQD has concluded that there are no violations occurring in Sweetwater County, nor are the emissions sources in most of Sweetwater County contributing meaningfully to the observed violations in Sublette County. AQD will demonstrate in this document that the emissions identified in the UGRB, along with other key factors such as site-specific air quality data (Section 1), unique meteorological and geographical conditions (Sections 6 and 7), as well as extraordinary industrial growth rates (Section 5), will explain the exceedances of the ozone standard at the Boulder monitor in Sublette County.

AQD has taken the next step to focus in on the particular emission sources believed to be contributing to high ozone levels. Figure S.2-1 shows emission inventory data for the UGRB. These emission estimates indicate that the most significant sources of ozone precursors in the UGRB are biogenics and the oil and gas industry.

<u>Biogenics</u>

During the first quarter of the year, biogenic emissions are lower than emissions from the other months of the year. The 2007 and 2008 Upper Green Winter Ozone Study (described in Section 1) analyzed canister samples for four biogenic species: isoprene, a-pinene, b-pinene, and d-limonene. Of particular interest is that isoprene, which is a common and highly reactive species of overwhelmingly biogenic origin, was not detected in any of the samples collected at the Jonah monitor and found only at levels just above the method detection limit in one sample at the Daniel monitor and two samples at the Boulder monitor. A-pinene, b-pinene and a-limonene were detected in 3% or less of the samples at each site. These results are consistent with the expected absence of biogenic VOCs in the study area during the winter months.

Biogenic emissions may be overestimated in the standard models used to prepare Table S.2-1, as typical biogenic species have not been detected in significant quantities in canister samples. Alternatively, they may be attributed to forested areas on the east and west flanks of the recommended nonattainment area, which may not influence air composition at Boulder, Daniel, and Jonah during the episodic ozone conditions when canister samples have been taken.

Oil and Gas Production and Development

Oil and gas production and development is the only significant industry emission source within the UGRB. We have divided the emissions from this industry further into those associated with construction, drilling, and completion of wells; well site production; and major sources. Oil and gas production is the largest source of VOCs, with the second largest being biogenic sources. The largest NOx emission sources are from rigs drilling the natural gas wells, natural gas compressor stations (O&G Major Sources) and gas-fired production equipment.

Figure S.2-2 shows the nonattainment boundary and the location of emission sources within and around the boundary. There are 11 major sources within the proposed boundary. Ten of these are compressor stations and one is a liquids gathering system. The figure also shows the distribution of oil and gas wells in the nonattainment and surrounding area.

The boundary encompasses areas of oil and gas development and their respective emissions sources, defined by topography (Section 6) and meteorology (Section 7), which are the most likely sources of ozone-forming precursors influencing the Boulder monitor during elevated ozone episodes.

While the Air Quality Division has been studying the emissions from oil and gas production and development for a number of years, it is an extremely complex industry to understand from an air quality perspective. AQD has made a concerted effort to estimate the emissions impacting the monitors during very unusual circumstances. These efforts will continue and AQD has plans to refine these estimates over time.

Table S.2-1: 1st Quarter, 2007 Estimated Emissions Summary (tons)

	Upper Green River Basin		Lincoln Outside of Upper Green River Basin		Sweetwater Outside of Upper Green River Basin		Uinta		Fremont		Teton	
Emissions Sources	NOx	VOCs	NOx	VOCs	NOx	VOCs	NOx	VOCs	NOx	VOCs	NOx	VOCs
On-Road Mobile Emissions	136	79	155	89	1,727	308	655	122	242	138	157	90
Non-Road Mobile Emissions	36	473	593	208	2,000	174	604	157	101	104	34	256
O&G Well Construction, Drilling & Completion	915	166	243	227	747	870	12	13	102	254	0	0
O&G Production Emissions	327	20,550	148	7,074	460	21,232	133	4,095	281	10,005	0	0
O&G Major Sources	481	198	488	63	9,631	2,200	174	196	111	20	0	0
EGUs Major Sources	0	0	3,151	24	6,335	75	0	0	0	0	0	0
Other Major Sources	0	0	0	0	2,445	1,929	0	0	0	0	0	0
Non-O&G Minor Sources	17	86	346	31	171	56	22	60	10	33	3	0
Biogenic Emissions	0	2,957	0	2,376	0	2,184	0	816	0	5,354	0	3,268
Fire Emissions	5	4	0	0	0	0	0	0	317	232	0	0
Total Emissions	**1,917**	**24,514**	**5,124**	**10,092**	**23,516**	**29,027**	**1,600**	**5,458**	**1,163**	**16,142**	**194**	**3,614**

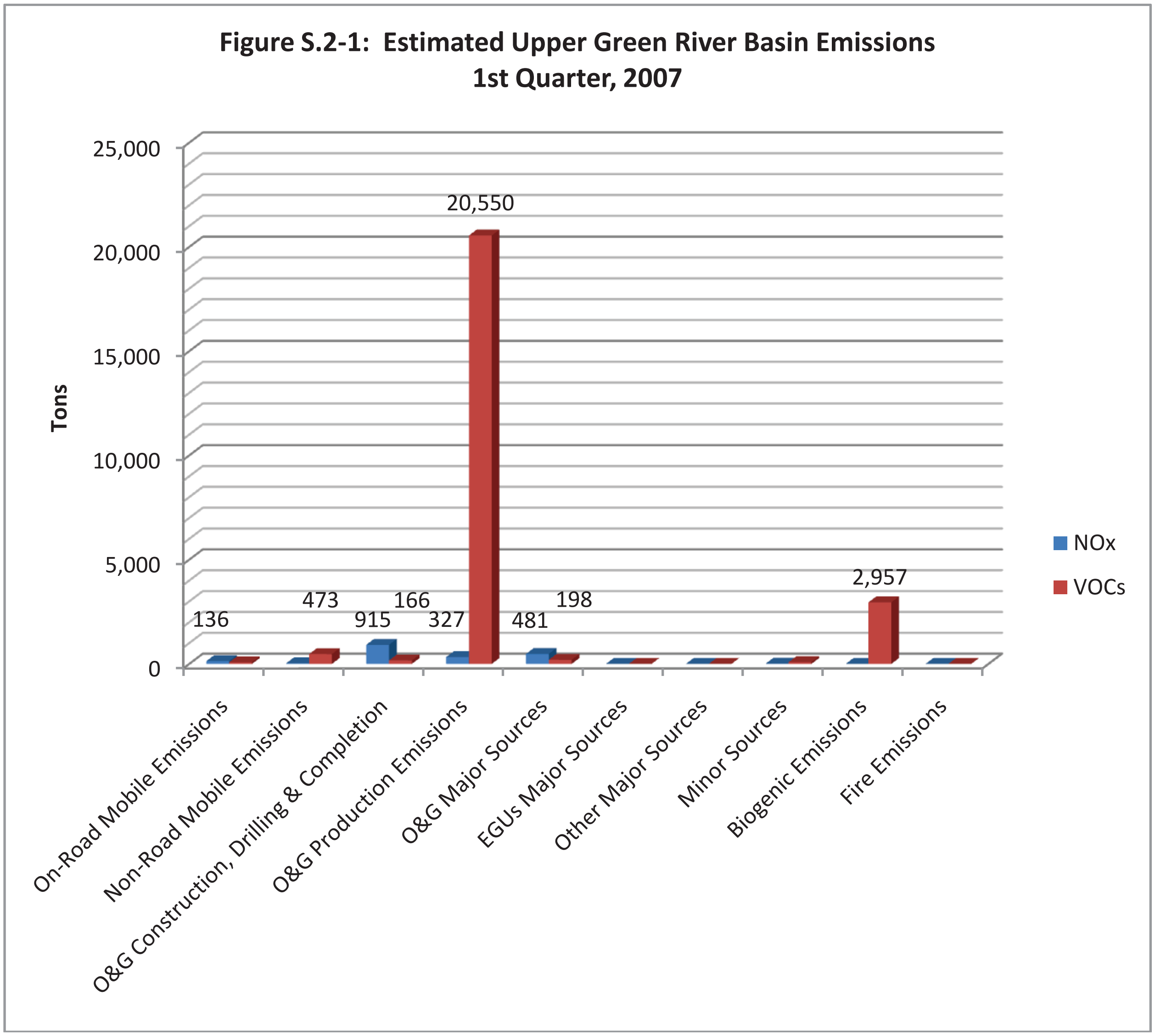


Figure S.2-1: Estimated Upper Green River Basin Emissions
1st Quarter, 2007
Tons
25,000
20,000
15,000
10,000
5,000
0
136
473
915
166
327
20,550
481
198
2,957
NOx
VOCs
On-Road Mobile Emissions
Non-Road Mobile Emissions
O&G Construction, Drilling & Completion
O&G Production Emissions
O&G Major Sources
EGUs Major Sources
Other Major Sources
Minor Sources
Biogenic Emissions
Fire Emissions

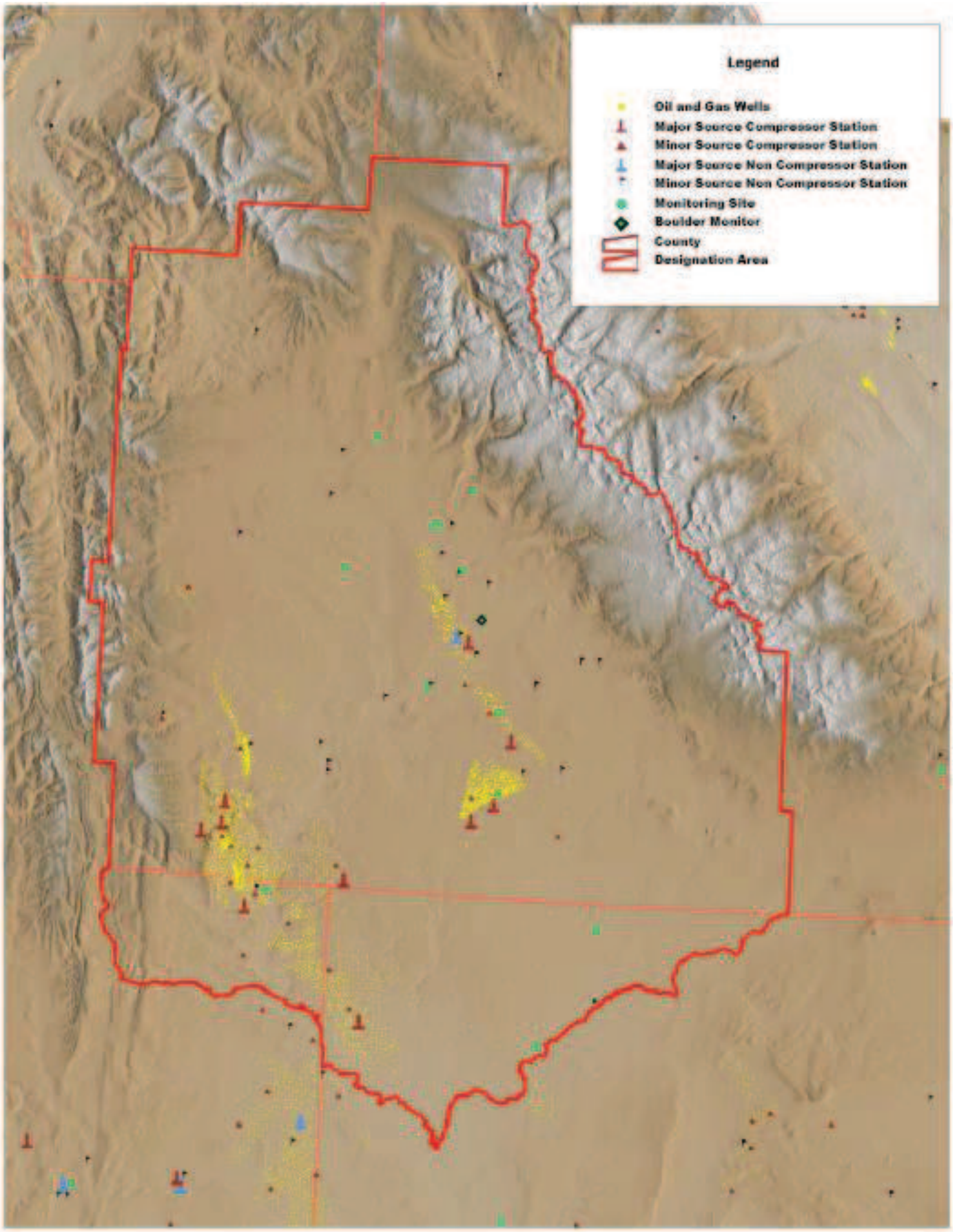


Figure 2.2-2: Designation Area Boundary

SECTION 3
POPULATION DENSITY AND DEGREE OF URBANIZATION

SYNOPSIS

Urbanized areas in surrounding counties do not affect ozone formation or precursors in the proposed nonattainment area just prior to and during elevated ozone episodes, because the urbanized areas are distant and in some cases separated by geographical features such as mountains.

The past and anticipated future rapid population growth is expected to be limited to the proposed nonattainment area, which would suggest that neighboring counties should not be included in the proposed nonattainment area.

Factors which are associated with ozone formation in urban areas have a lower significance for selecting the boundary for this nonattainment area since Southwest Wyoming is mostly rural with a low population density.

ANALYSIS

Sublette County and the surrounding counties (Table S.3-1) are rural with a low overall population density. There are no metropolitan areas with a population of 50,000 or more in this six-county area.

Table S.3-1: Population Density

	Sublette	Sweetwater	Lincoln	Uinta	Fremont	Teton
Estimated 2007 Population	7,925	39,305	16,171	20,195	37,479	20,002
Area (square mile)	4,882	10,426	4,069	2,082	9,183	4,008
Population/square mile	2	4	4	10	4	5
Percent in Urbanized Area*	0	89	20	59	48	56
Percent in Rural Area*	100	11	80	41	52	44

* Based on 2000 Census

The largest community in Sublette County is Pinedale. The estimated population in 2007 was 2,043. The largest communities in the counties surrounding Sublette are Rock Springs (population 19,659), Green River (population 12,072) and Evanston (population 11,483). Rock Springs, Evanston, Riverton and Jackson are classified by the U.S. Census Bureau as Micropolitan Statistical Areas. Table S.3-2 shows population estimates and projections from the Wyoming State Department of Administration and Information.

Table S.3-2: Population Estimates and Projections

County and Cities	2007 Estimate	2008 Forecast	2010 Forecast	2015 Forecast	2020 Forecast	2025 Forecast	2030 Forecast
Sublette	**7,925**	**8,340**	**9,170**	**11,200**	**13,370**	**15,010**	**16,930**
Big Piney	476	501	551	673	803	902	1,017
Marbleton	919	967	1,063	1,299	1,550	1,741	1,963
Pinedale	2,043	2,150	2,364	2,887	3,447	3,869	4,364
Fremont	**37,479**	**37,870**	**38,390**	**39,320**	**40,110**	**41,130**	**42,370**
Dubois	1,033	1,044	1,058	1,084	1,106	1,134	1,168
Lander	7,131	7,205	7,304	7,481	7,632	7,826	8,062
Riverton	9,833	9,936	10,072	10,316	10,523	10,791	11,116
Lincoln	**16,171**	**16,560**	**17,240**	**18,710**	**20,100**	**21,190**	**22,430**
Afton	1,782	1,825	1,900	2,062	2,215	2,335	2,472
Alpine	764	782	815	884	950	1,001	1,060
Kemmerer	2,427	2,485	2,587	2,808	3,017	3,180	3,366
Star Valley Ranch	1,567	1,605	1,671	1,813	1,948	2,053	2,174
Sweetwater	**39,305**	**40,180**	**41,700**	**44,430**	**46,530**	**47,220**	**48,130**
Green River	12,072	12,341	12,808	13,646	14,291	14,503	14,782
Rock Springs	19,659	20,097	20,857	22,222	23,273	23,618	24,073
Teton	**20,002**	**20,240**	**20,570**	**21,340**	**22,140**	**23,470**	**24,990**
Jackson	9,631	9,746	9,904	10,275	10,660	11,301	12,033
Uinta	**20,195**	**20,420**	**20,730**	**21,210**	**21,550**	**21,950**	**22,440**
Evanston	11,483	11,611	11,787	12,060	12,253	12,481	12,760
Lyman	1,990	2,012	2,043	2,090	2,124	2,163	2,211
Mountain View	1,176	1,189	1,207	1,235	1,255	1,278	1,307

Population in Sublette County and Sublette County communities is expected to increase at a rate of approximately 5% over the next 23 years. Population in surrounding counties is expected to increase more slowly at rates of 2% or less.

The population in Sublette County has increased at a greater pace than surrounding counties (Table S.3-3). In the period 2006 to 2007, Sublette County continued to see faster growth than surrounding counties.

Table S.3-3: Population Growth

Population	Sublette	Sweetwater	Lincoln	Uinta	Fremont	Teton
Estimated 2007	7,925	39,305	16,171	20,195	37,479	20,002
Estimated 2006	7,359	38,763	16,383	20,213	37,163	19,288
Estimated 2004	6,879	38,380	15,780	20,056	36,710	18,942
2000	5,920	37,613	14,573	19,742	35,804	18,251
Percent Population Increase						
2000 to 2007	34%	4%	11%	2%	5%	10%
2004 to 2007	15%	2%	2%	1%	2%	6%
2006 to 2007	8%	1%	-1%	0%	1%	4%

Sublette County does not have any urbanized areas. Urbanized areas in surrounding counties are geographically distant from the monitor with the ozone exceedance in Sublette County (the Boulder monitor). As is described in Section 7 of this document, meteorological conditions associated with elevated ozone episodes greatly limit the possibility of emissions transport. Table S.3-4 shows the approximate distance to the Boulder monitor from communities with a population greater than 9,000 in 2007. Additionally, Riverton is separated from the UGRB by the Wind River Range. (Appendix S3 - **Figure -** Wyoming Population Density by Census Tract)

Table S.3-4: Distance to Boulder Monitor
(Miles, approximate)

Riverton	Green River	Rock Springs	Jackson	Evanston
73	82	80	75	118

The analysis in Section 7 of this document will demonstrate that emissions from sources outside of the UGRB do not significantly influence ozone levels at the Boulder monitor during elevated ozone episodes.

References:

1. http://www.census.gov/main/www/cen2000.html, U.S. Census Data.
2. http://eadiv.state.wy.us/pop/CO-07EST.htm, State of Wyoming populations statistics and projections by county and city.
3. Appendix S.3., Population Density by Census Tract

SECTION 4
TRAFFIC AND COMMUTING PATTERNS

SYNOPSIS

The number of commuters into or out of Sublette County (and the UGRB) is small and does not support adding other counties or parts of counties into the nonattainment area based on contribution of emissions from commuters from other counties.

The percent of emissions from on-road mobile sources is small within the proposed nonattainment area: 7% of NOx and 0.3% of VOCs. Even if this source increases, it will remain a small percentage of total emissions.

Interstate 80, the interstate highway that is nearest to the Boulder monitor, is approximately 80 miles south of the Boulder monitor. Ozone monitors in closer vicinity to the interstate have not shown ozone exceedances. I-80 traffic is not considered to be a significant contributor of emissions that impact the Boulder monitor during ozone events.

ANALYSIS

Consistent with the rural character of the counties in southwest Wyoming including Sublette County, traffic volumes are low. The Wyoming Department of Transportation's (WYDOT)[1] inventory shows traffic volume at 447,953 daily vehicle miles traveled (DVMT) for Sublette County in 2007. WYDOT inventories are based on travel on paved roads. Table S.4-1 shows traffic volumes for Sublette County and surrounding counties for 1994, 2004 and 2007.

Emissions from mobile sources within the UGRB are very low, as would be expected from such low DVMTs. As shown in Table S.2-1, NOx emissions for the first quarter of 2007 are approximately 136 tons (7% of total NOx) and VOC emissions are 79 tons (0.3%). This makes emissions from this sector of much lower significance than is typically seen in urban nonattainment areas.

Approximately 90% of the traffic volume in Sweetwater and Uinta Counties is interstate traffic. Interstate 80 is located approximately 80 miles south of the Boulder monitor, the ozone monitor that showed the exceedance. There are five ozone monitors located closer to the Interstate: Wamsutter (~1 mile), OCI (~12 miles), South Pass (~45 miles), Murphy Ridge (~5 miles), and Jonah (~60 miles) (See Figure S.1-1). None of the monitors located closer to the Interstate have shown an ozone exceedance.

Table S.4-1: WYDOT - 2007 Traffic Surveys

	Sublette	Sweetwater	Lincoln	Uinta	Fremont	Teton
DVMT-2007	447,953	2,667,117	615,113	1,013,595	979,546	622,356
DVMT - interstate-2007		2,421,684		911,916		
DVMT-2004	342,034	2,473,882	564,771	944,416	892,814	600,836
DVMT-1994	229,553	1,917,738	466,753	761,626	737,863	504,904
Increase 1994 to 2007	95%	39%	32%	33%	33%	23%
Miles of roads	229.2	568.7	337.2	218.4	507.2	144.2
DVMT/mile of road	1954	4689	1824	4641	1931	4315

The Wyoming Department of Employment (DOE)[2] surveys commuting trends between counties. Table S.4-2 summarizes the average number of commuters for the years 2000 through 2005 that commute between Sublette County (the county with the Boulder monitor) and surrounding counties. Although commuting has increased for some neighboring counties, such as Sweetwater County, the volume of commuters is low.

Table S.4-2: Wyoming DOE Commuter Surveys 2000 Through 2005

Commuters driving to Sublette from:	2000	2001	2002	2003	2004	2005
Fremont	20	29	17	26	41	47
Lincoln	112	117	106	84	100	128
Sweetwater	62	86	79	77	111	185
Teton	49	52	45	35	38	49
Uinta	14	12	22	31	38	53
Total						462
Commuters driving from Sublette to:						
Fremont	81	67	70	37	48	44
Lincoln	77	59	76	114	97	93
Sweetwater	126	129	109	121	152	209
Teton	171	148	150	135	142	130
Uinta	33	66	55	31	20	26
Total						502

North Carolina's Economic Development Intelligence System (EDIS)[3] compiled 2000 Census data to determine the number of commuters in Wyoming counties. Extrapolating this data to 2008, to account for only population growth, the estimated number of commuters in Sublette County and surrounding counties is shown in Table S.4-3. Since rapid population growth in Sublette County is biased toward the working age population, the straight extrapolation from 2000 data is likely to underestimate the number of commuters. The EDIS data indicate the majority of commuters commute within their county of residence. The number of commuters leaving Sublette County calculated by the Wyoming DOE correlates well with the EDIS generated estimates of commuters leaving Sublette County.

Table S.4-3: Number of Commuters in Sublette and Surrounding Counties

	Sublette	Sweetwater	Lincoln	Uinta	Fremont	Teton
Estimated number of commuters in 2000*	2767	18,012	6069	8921	15,074	10,527
Estimated number of commuters in 2008	3357	18,726	7084	9114	15,761	11,811
Estimated number of 2008 commuters that stay in their county	2921	17,977	5596	7565	14,973	11,338

* 2000 Census data

Commuting patterns in Sublette County and in surrounding counties show that commuting to or from the adjacent counties is not a major source of VMT in Sublette County. Therefore, commuters from adjacent counties are not a significant factor in ozone generation in the proposed nonattainment area.

Reference:

1. Appendix S.4.A, 2007 Vehicle Miles on State Highways By County
2. Appendix S.4.B, Commuting Patterns in Sublette County
3. North Carolina Department of Commerce web site. https://edis.commerce.state.nc.us/docs/countyProfile/WY/

SECTION 5
GROWTH RATES AND PATTERNS

SYNOPSIS

The pace of growth in the oil and gas industry in Sublette County is significantly greater than in surrounding counties. While population is growing in Sublette County, the county and surrounding area is rural with a low population density. Population growth does not influence determination of a designation area boundary in this case.

ANALYSIS

Statistical data available is broken down on a county basis. The following analysis compares Sublette County to surrounding counties. While the recommended nonattainment area includes a portion of Sweetwater and Lincoln counties in addition to Sublette, the trends described for Sublette County also hold true, in general, to the recommended nonattainment area.

Population growth is described in Section 3. Sublette County population has grown at an annual rate of approximately five percent over the last seven to ten years. Sublette County is forecast to continue to grow at this rate for the foreseeable future. Counties surrounding Sublette have grown at rates of less than two percent during this time period and are forecast to continue to grow at this slower pace.

Industrial growth in Sublette County is driven by the oil and gas (O&G) industry. Table S.5-1 shows the increase in O&G production for Sublette County as shown by the number of well completions for years 2000 through 2008. Table S.5-2 shows total well completions for 2005 through 2008 for Sublette, Sweetwater, Uinta and Lincoln counties. Sweetwater and Lincoln counties also show an increasing trend in well completions, though to a lesser extent than in Sublette. Teton County is not listed because it has no oil and gas production. Fremont County is not shown because O&G production areas in Fremont County are separated from the other counties by the Wind River Mountain Range.

Table S.5-1: Completion Report Sublette County*

(Confidential Records Are Not Listed)

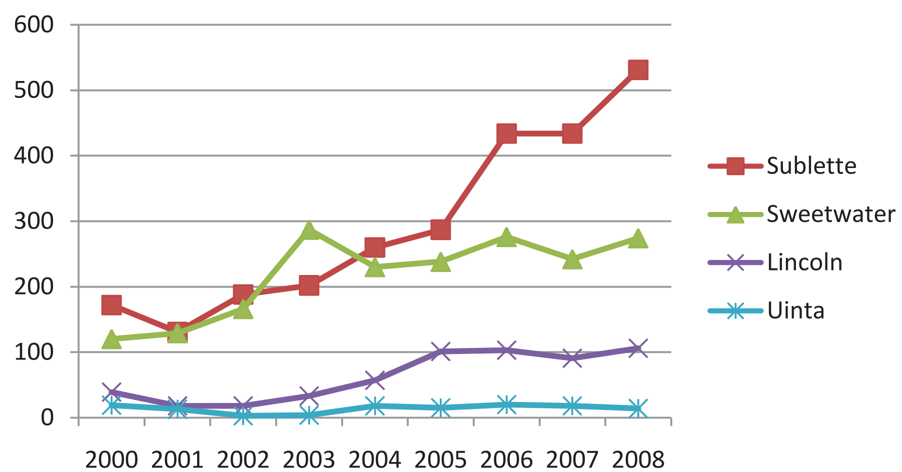
	2000	2001	2002	2003	2004	2005	2006	2007	2008
Distinct Gas Well Completion Count	126	110	150	185	252	281	428	420	517
Distinct Oil Well Completion Count	45	20	32	15	5	0	3	5	4
Total Distinct Well Completion Count	172	131	188	202	260	287	434	434	531

*Wyoming Oil and Gas Conservation Commission (WOGCC)

Table S.5-2: Total Well Completions/Oil, Gas, and CBM* (Confidential Records Are Not Listed)									
	2000	2001	2002	2003	2004	2005	2006	2007	2008
Sublette	172	131	188	202	260	287	434	434	531
Sweetwater	120	129	166	287	230	238	276	242	274
Lincoln	39	18	18	33	57	101	103	91	106
Uinta	19	13	3	4	18	15	20	18	14

*Wyoming Oil and Gas Conservation Commission (WOGCC)

Figure S.5-1: Well Completions Per County



As Figure S.5-1 shows, there have been more O&G well completions in Sublette than for the surrounding counties. Table S.5-3 and Figure S.5-2 show the steady growth in Sublette County O&G production since 2000.

Table: S.5-3 Sublette County Production Levels			
	Oil Bbls	**Gas Mcf**	**Water Bbls**
2008	7,666,396	1,143,614,170	22,921,983
2007	7,096,499	1,008,001,400	18,251,807
2006	5,769,581	880,855,575	13,203,000
2005	5,102,164	814,748,425	11,641,926
2004	4,705,836	731,276,509	11,812,077
2003	4,539,385	655,573,062	10,526,328
2002	4,380,011	571,000,866	13,950,895
2001	3,840,436	493,577,283	7,785,291
2000	3,345,063	448,281,668	7,364,792

Figure S.5-2: Sublette County Gas Production Mcf

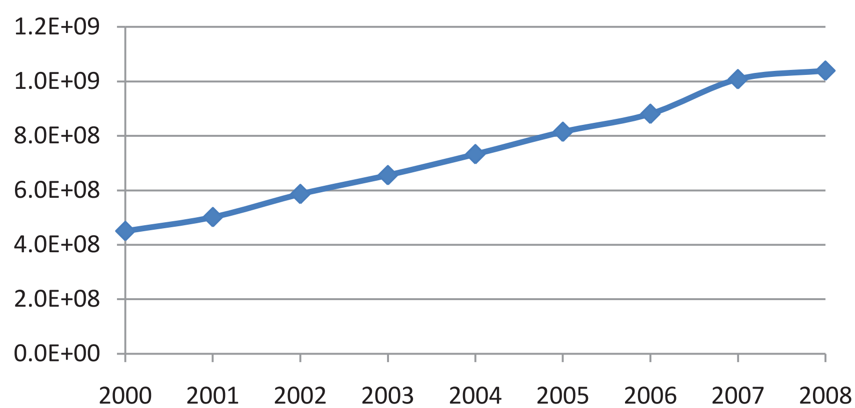


Table S.5-4 shows growth in the oil and gas industry by county through the following three measures: oil production (in barrels), gas production (in thousand cubic feet), and produced water generation (in barrels). Growth in production of gas and water is increasing in Sublette County and is either static or decreasing in the surrounding counties.

Table S.5-4: Four County Production				
	Oil Bbls			
	Sublette	Lincoln	Sweetwater	Uinta
2008	7,666,396	819,751	5,392,316	1,341,993
2007	7,096,499	801,807	5,738,262	1,506,562
2006	5,769,581	782,165	5,295,610	1,914,262
2005	5,102,164	762,801	4,872,531	2,246,896
	Gas Mcf			
2008	1,143,614,170	89,516,900	240,214,449	130,282,928
2007	1,008,001,400	89,189,164	235,687,851	128,068,870
2006	880,855,575	85,753,007	238,339,251	139,700,716
2005	814,748,425	83,579,467	222,772,057	141,490,407
	Water Bbls			
2008	22,921,983	1,228,058	42,026,953	3,011,981
2007	18,251,807	1,300,854	47,522,714	2,843,082
2006	13,203,000	1,375,969	49,928,115	2,641,554
2005	11,641,926	1,065,943	45,110,120	2,950,473

References:

Wyoming Oil and Gas Conservation Commission (http://wogccms.state.wy.us/)

SECTION 6
GEOGRAPHY/TOPOGRAPHY

SYNOPSIS

The Wind River Range, with peaks up to 13,800 feet, bounds the UGRB to the east and north; the Wyoming Range, with peaks up to 11,300 feet, bounds the UGRB to the west.

Significant terrain influences the weather patterns throughout Southwest Wyoming. Other terrain features such as river and stream valleys also influence local wind patterns.

Mountain-valley weather patterns in the UGRB tend to produce limited atmospheric mixing during periods when a high pressure system is in place, setting up conditions for temperature inversions, which are enhanced by the effect of snow cover.

ANALYSIS

Southwest Wyoming and the UGRB are within the Wyoming Basin Physiographic Province. Topography in the UGRB is characterized by low, gently rolling hills interspersed with buttes. Elevations range from approximately 7,000 to 7,400 feet above mean sea level (AMSL) in the lowest portions of the UGRB. The Wind River Range, with peaks up to 13,800 feet, bounds the UGRB to the east and north and the Wyoming Range, with peaks up to 11,300 feet, bounds the UGRB to the west. There are also important low terrain features such as the Green River Basin and the Great Divide Basin.

Mountain elevations decrease moving south along both the Wyoming and Wind River ranges. Along the western boundary of the Green River Basin, in the southern part of the Wyoming Range, the elevation decreases to about 6,900 feet above mean sea level (AMSL) with some peaks in the 7,500 to 8,000-foot range. Moving south along the Wind River Range, the elevation decreases to 7,800 feet at South Pass.

Figure S.6-1: Nonattainment area shown (blue outline) against an aerial view of the topography in the Upper Green River Basin and adjacent areas.

The surrounding significant terrain features effectively create a bowl-like basin in the northern portion of the Green River Basin, which greatly influences localized meteorological and climatological patterns relative to geographical areas located outside of the UGRB. Although difficult to quantify over the entire UGRB valley, the UGRB is roughly 900 to 1,300 meters (3,000 to 4,300 feet) lower than the terrain features bounding the UGRB to the east and west. Typical elevation profiles within the UGRB are illustrated in two different cut-planes (transects) across the UGRB, as shown in Figure S.6-2.

The southern boundary of the area is defined by river and stream channels. To the east the Big Sandy, Little Sandy and Pacific Creek drainages define the boundary and to the west the Green River and Fontenelle Creek drainages define the boundary.

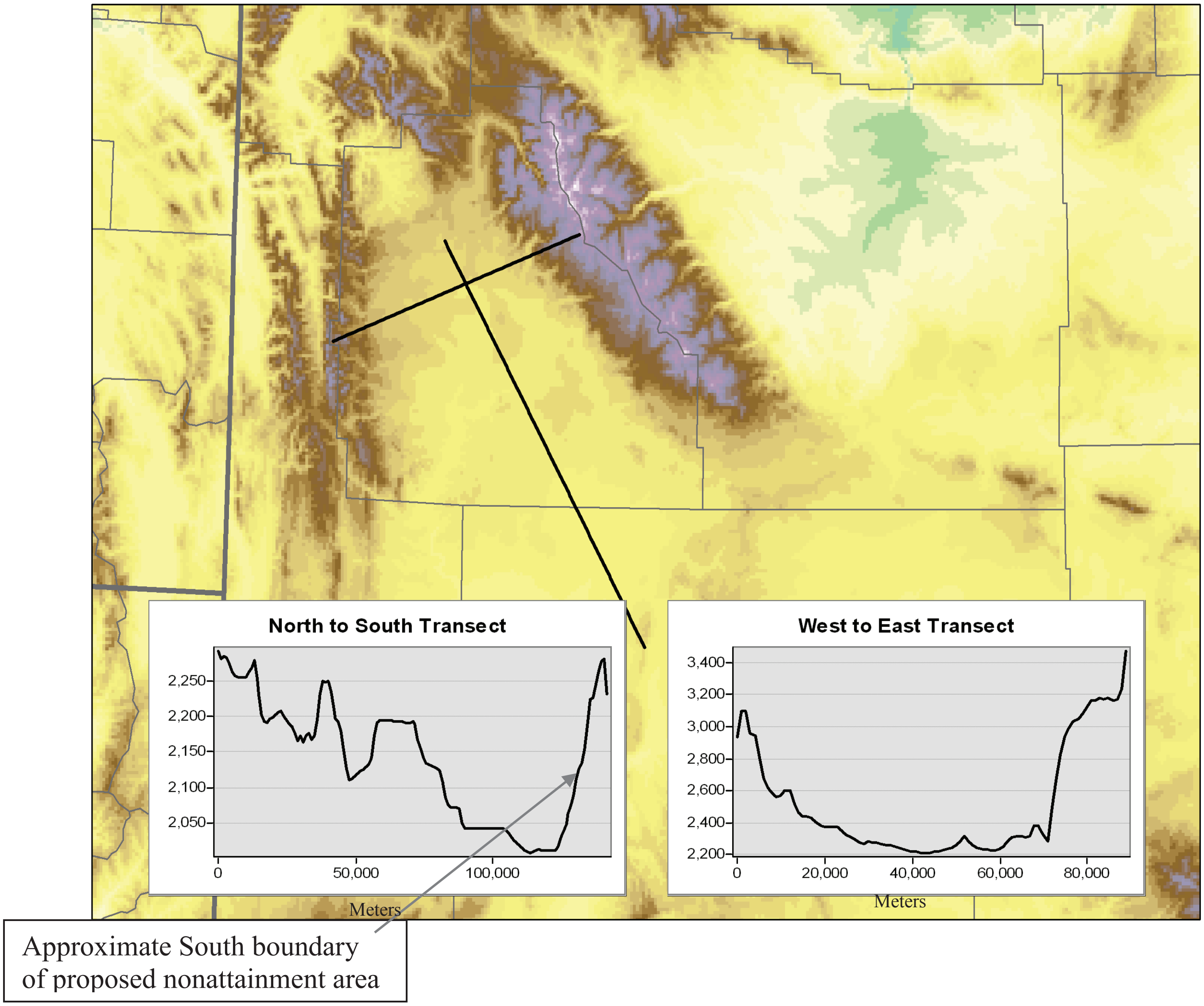


Figure S.6-2: Transects across the Upper Green River Basin (running north-south and west-east) showing cross sections of the terrain; terrain elevations and distance units shown in the transects are in meters.

Significant terrain in the UGRB has an impact on the local meteorology (wind speed, wind direction, and atmospheric stability). In mountain-valley areas – such as the UGRB – during the night cold air will accelerate down the valley sides (downslope winds), while during the day warmer air will flow up the valley sides (upslope winds). At night, this can create a cold pool of air within the UGRB that stratifies the atmosphere (inhibits mixing) since colder, denser air exists at the surface with warmer air above. Further, at the valley floor, the wind speed is likely to be lower than in an open plain as the roughness of the surrounding terrain tends to decrease wind speeds at the surface. The terrain obstacles surrounding the UGRB also tend to cut-off, block, or redirect air that might normally flow through the valley. This effect is exacerbated during times of calm weather, such as the passage of a high pressure system that tends to set up conditions for strong surface-based temperature inversions.

The Wind River Range on the east and the Wyoming Range on the west provide significant barriers to movement of ozone and ozone precursors into the area proposed for a nonattainment area designation. Although the recommended southern boundary is not bordered by a mountain range, the southern boundary lies along two significant drainage divides: the Fontenelle/Green River and the Pacific/Big Sandy River. These geographic features influence air flow, although they do not provide an absolute barrier to migration. The influence of these geographic features on wind flows, especially during periods of low winds which are needed for ozone formation is illustrated in Figure S.7-17. This figure shows winds generally conforming to the drainages which establish the southern boundary of the proposed nonattainment area. The conclusions about the southern boundary are further supported by the meteorological analyses presented in Section 7.

SECTION 7
METEOROLOGY

SYNOPSIS

The unique meteorology in the UGRB of Wyoming creates conditions favorable to wintertime ozone formation.

The meteorology within the UGRB during winter ozone episodes is much different than on non-high ozone days in the winter, and is also much different than the regional meteorology that exists outside of the UGRB during these wintertime high ozone episodes.

The 2008 field study data reveal that, for the days leading up to the February 19-23, 2008 ozone episode, sustained low wind speeds measured throughout the monitoring network were dominated by local terrain and strong surface-based inversions, which significantly limited the opportunity for long-range transport of precursor emissions and ozone to reach the Boulder monitor.

Minimal emissions transport and dispersion, due to the influence of localized winds (light winds) in the UGRB characterize the February 19-23, 2008 ozone episode.

An ozone-event specific wind field was developed to more accurately simulate meteorological conditions in the UGRB and surrounding areas, and was used to drive a trajectory model for air parcel movement into and out of the UGRB.

Trajectory analyses were used to develop a reasonable southern boundary for the nonattainment area.

The unique meteorological conditions in the UGRB are one of the most significant factors for assigning this nonattainment boundary.

ANALYSIS

General

There is significant topographic relief in Wyoming which affects climate and daily temperature variations. This is a semiarid, dry, cold, mid-continental climate regime. The area is typified by dry windy conditions, with limited rainfall and long, cold winters. July and August are generally the hottest months of the year, while December and January are the coldest. Pinedale's mean temperature in January is 12.5°F with a mean of 60°F in July (Western Regional Climate Center, 2009). The high elevation and dry air contribute to a wide variation between daily minimum and maximum temperatures. At Pinedale, the total annual average precipitation is about 10.9 inches, and an average of 61 inches of snow falls during the year.

Strong winds are common in Wyoming, especially in the south. Wind velocity can be attributable, in part, to the prevailing westerly winds being funneled through the Rock Mountains at a low point in the Continental Divide.

The meteorological conditions conducive to the formation of high ozone levels in the UGRB during the winter and early spring are characterized by:

- A stable atmosphere, characterized by light low-level winds

- Clear or mostly sunny skies
- Low mixing heights or capping inversions
- Extensive snow cover
- Low temperatures

The above conditions take some time to develop (at least 48 hours after a storm frontal passage), and occur during periods when the synoptic weather is dominated by high pressure over the western Rockies.

Looking at the meteorological conditions in the UGRB, elevated ozone episodes in 2005, 2006 and 2008 were associated with strong temperature inversions and light low-level winds. This was the case during the February 19-23, 2008 ozone episode, in which the highest ozone concentrations monitored to date in the UGRB were recorded at the Boulder monitor. Because these meteorological conditions are common to all of the high ozone episodes in the UGRB observed to date, the ozone episode of February 19-23, 2008, a 5-day period marking the longest consecutive ozone episode observed, is considered to be representative of other ozone episodes. This particular 5-day ozone episode is the primary focus of this section on meteorological influences and wintertime high ozone.

Winter Ozone Field Studies

After elevated ozone levels were monitored in the winter of 2005 and 2006; the AQD initiated intensive field studies to collect meteorological and ambient data in the first quarter of 2007, 2008, and 2009 throughout the Green River Basin to better understand the relationships between winter meteorological conditions and high ozone levels versus low ozone levels. In spite of careful planning to record data, the winter of 2007 did not produce conditions conducive to the formation of ozone. In contrast, the winter of 2008 provided a significant amount of data on ozone formation since there were several high ozone episodes. A map showing the monitoring sites employed in the 2008 field study and regional terrain features in the 2008 study area is shown in Figure S.7-1. The entire data set and reports on the winter studies completed to date are available on the WDEQ/AQD website (http://deq.state.wy.us/aqd/Monitoring%20Data.asp). AQD has continued field studies into 2009, but those results will not be available until later in 2009.

During January and the beginning of February 2008, the study area was under the influence of a series of weak to moderately strong synoptic disturbances that migrated from the Gulf of Alaska, across the Pacific Northwest and southern British Columbia and the northern Great Basin and into the Northern Rockies. These weather features generally moved rapidly through southwest Wyoming as they migrated along a belt of strong westerly to northwesterly winds aloft that were associated with a persistent high pressure ridge located over the eastern Pacific, off California. In addition, a number of deep Pacific troughs moved across the area earlier in the winter and into the first half of January. The end result of all this activity was the deposit of substantial snow cover in southwestern Wyoming, including the UGRB, which was to remain in place through the rest of the winter. After mid-February, the eastern Pacific ridge exhibited a tendency to extend or migrate into the interior west until it finally moved directly over southwest Wyoming by February 20, 2008.

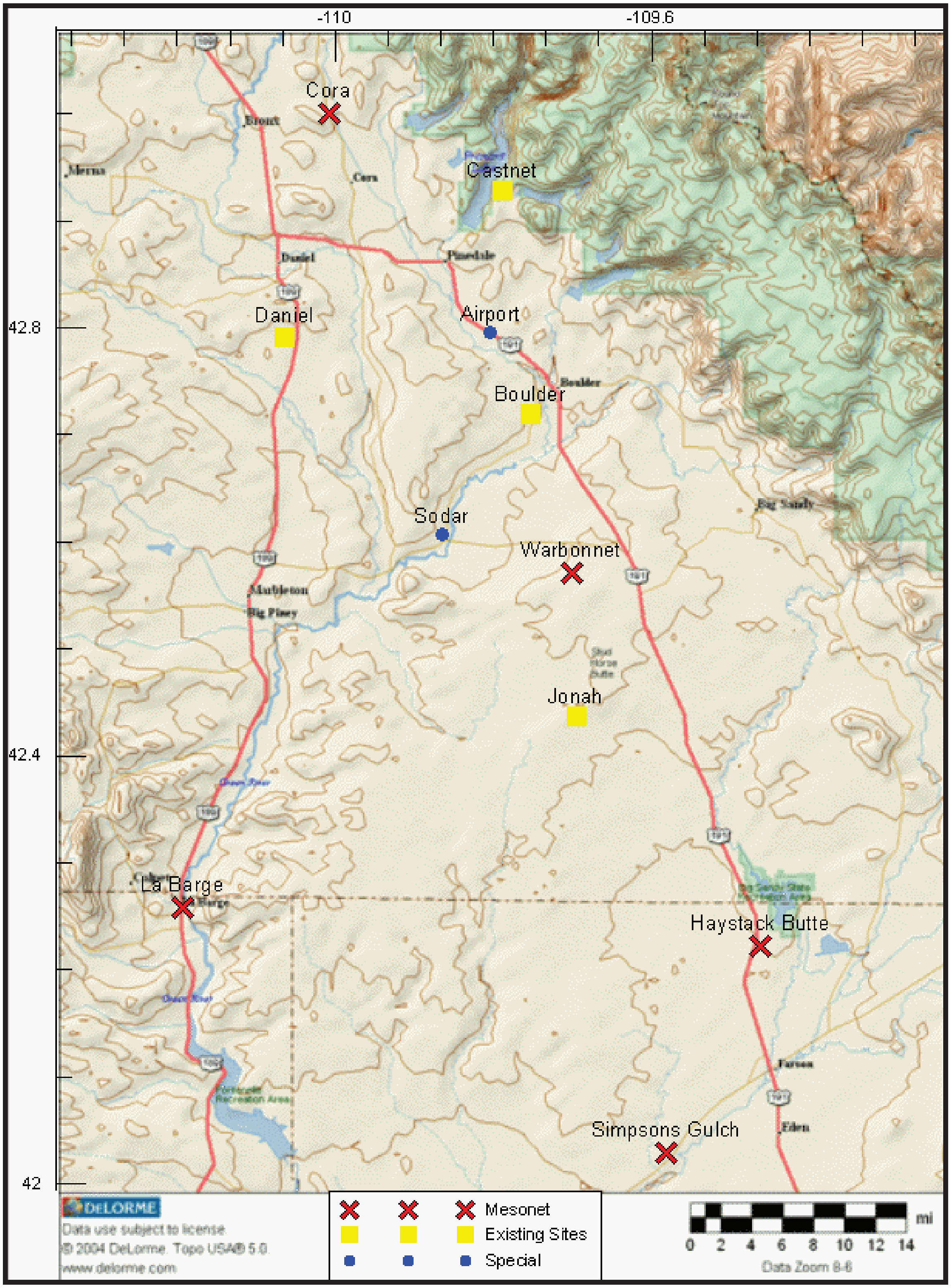


Figure S.7-1. Surface and upper air monitoring sites employed in the 2008 field study.

Comparison of 2007 and 2008 Field Study Observations

Snow Cover and Sunlight

Comparison of meteorological conditions in 2008 with those prevailing during the 2007 field study revealed that one of the key differences was the extensive snow cover in 2008 which was not present during 2007. Snow cover appears to be a key ingredient in winter ozone development, specifically, fresh snow, which results in higher surface albedo, perhaps as great as 0.9. The increased surface albedo results in greater actinic flux and therefore elevated NO_2 photolysis rates. The elevated photolysis rate due to the high (snow cover driven) albedo is likely greater than the photolysis rate in the UGRB in the summer months.

During the 2007 field study, although there were extended periods when synoptic-scale meteorological conditions were conducive to poor horizontal dispersion, the lack of snow cover and subsequent lower UV albedo reduced the amount of UV radiation available for photolysis and associated ozone production. In addition, the 2007 and 2008 field studies suggest that the sensible and radiative heat flux impacts of the snow cover enhance low-level atmospheric stability, substantially reducing vertical mixing during most or all of the daylight hours.

Low Wind Speeds

Stable, stagnant weather conditions occurred in southwest Wyoming during the period from February 18 through 22, 2008. The main synoptic feature responsible for this was a strong Pacific high pressure ridge that slowly migrated across the western United States. This period was dominated by low wind speeds in the boundary layer, which reduced pollutant transport and dispersion. This effect is shown in Figure S.7-2 where ozone concentrations and wind speeds are plotted for the Boulder monitor for February and March of 2008.

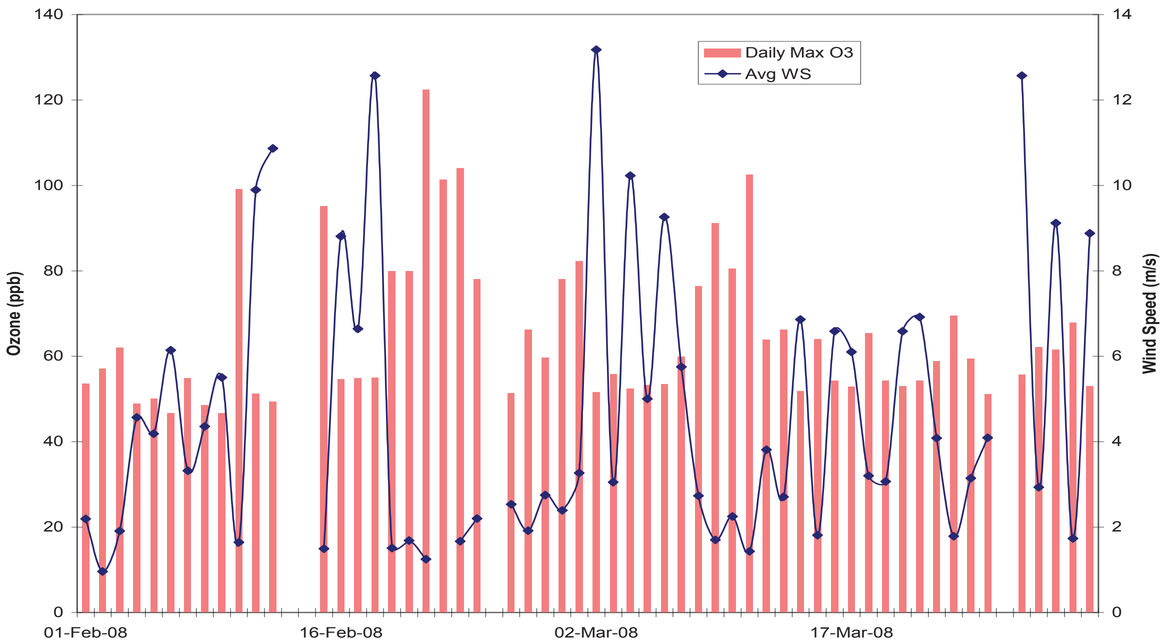


Figure S.7-2. Wind speed and ozone concentrations plotted for the Boulder monitor in February and March 2008.

The 2008 field study data reveal that the sustained low wind speeds measured throughout the monitoring network were dominated by local terrain and strong surface-based inversions, which significantly limited the opportunity for long-range transport of precursor emissions and ozone on the days leading up to the February 19-23, 2008 ozone episode.

Ozone Carryover

When the favorable synoptic conditions described above develop late in the day or during the night hours, the first high ozone concentrations typically develop the following day between approximately 11:00 and 13:00 so long as favorable conditions for high ozone formation persist. During a day of elevated ozone, such as February 20, 2008, the high readings at the monitors in the UGRB peak in the afternoon. As the day progresses, lower but still elevated concentrations continue, in some cases lasting well into the evening hours and, in a few cases, past midnight before lowering. When the following day continues to have these favorable weather conditions, the ozone levels begin to rise earlier than the previous day and frequently to much higher levels, indicative of some carryover of ozone and precursors from one day to the next. Once high ozone concentrations have formed, ozone levels were observed to remain elevated even with increasing cloud cover ahead of an approaching storm system. Additionally, wind reversals, which were most apparent at the Jonah and Boulder monitors, were observed at many of the monitoring sites during the field study; which further assisted in the carryover and build-up of ozone and ozone precursors from emission sources in close proximity to the monitors. Ozone concentrations do not return to near background conditions until brisk (usually west or northwesterly) winds have arrived and scoured out the surface inversion.

Atmospheric Mixing

The observed weather patterns in the 2007 field study showed that the winter storm systems generally did not provide a strong push of cold air and did not produce much precipitation in the project area, but did allow strong wind speeds aloft with considerable mixing of the atmosphere. Specifically, the weather conditions over the study area during February and March of 2007 were characterized by less precipitation (including less snow depth), stronger winds aloft and much warmer surface temperatures compared to the previous two winters. High pressure systems in 2007 tended to keep the air mass over the study area relatively well mixed and mild, which in turn did not allow for snow accumulation and strong inversion development.

Feb. 19 – 23, 2008 Case Study Illustrating the Specific Weather Conditions Which Produce Elevated Ozone in the Upper Green River Basin

This ozone episode is of particular interest for study, as it: 1) occurred over five days, marking the highest 1-hour and 8-hour ozone concentrations recorded at the Boulder monitor to date, 2) occurred during a field study Intensive Operating Period (IOP) that was in place to measure detailed actual ambient and meteorological conditions leading up to and during this multi-day winter ozone episode, 3) provides a high quality database of observations for several meteorological parameters, both during IOPs and regular hourly observations during this ozone episode, and 4) provides information which clearly shows how the topography in the Upper Green River Basin creates different meteorological conditions within the UGRB. A summary of the daily maximum 8-hour averaged ozone concentrations monitored at the Jonah, Boulder, and Daniel FRM monitors during this ozone episode, as well as the day immediately preceding it, are provided in Table S.7-1.

Date	Jonah (ppb)	Boulder (ppb)	Daniel (ppb)
2/18/09	45	55	54
2/19/08	80	79	74
2/20/08	75	79	76
2/21/08	84	122	62
2/22/08	102	101	76
2/23/08	76	104	74

Table S.7-1. Summary of daily maximum 8-hour averaged ozone concentrations monitored at the Jonah, Boulder, and Daniel monitors during February 18-23.

A synopsis of the particular meteorological conditions associated with the February 19-23, 2008 winter high ozone episode is provided below, describing the evolution of the meteorological conditions that were in place during the February 19-23, 2008 ozone episode.

Synopsis of 19 – 23 February 2008 Ozone Episode

Figure S.7-3 shows the 700 millibar (mb) chart for the morning of February 19, 2008, which shows the axis of the Pacific ridge extending north and south from the Four Corners area, through northwestern Idaho and up into eastern British Columbia. At that time, the ridge axis was still west of Wyoming, resulting in fairly strong northwesterly gradient flow (winds blowing from the northwest along the isobars) just above ground level in southwest Wyoming. With clear skies accompanying the approaching ridge, and a good snow cover at the surface, a capping inversion formed overnight and persisted throughout the next day in the UGRB. However, the strong winds above the stable layer, along with mixing heights on the order of several hundred meters, transferred sufficient momentum downward, allowing these northwest winds to mix down to the surface during the day resulting in predominant northwesterly wind patterns within the UGRB.

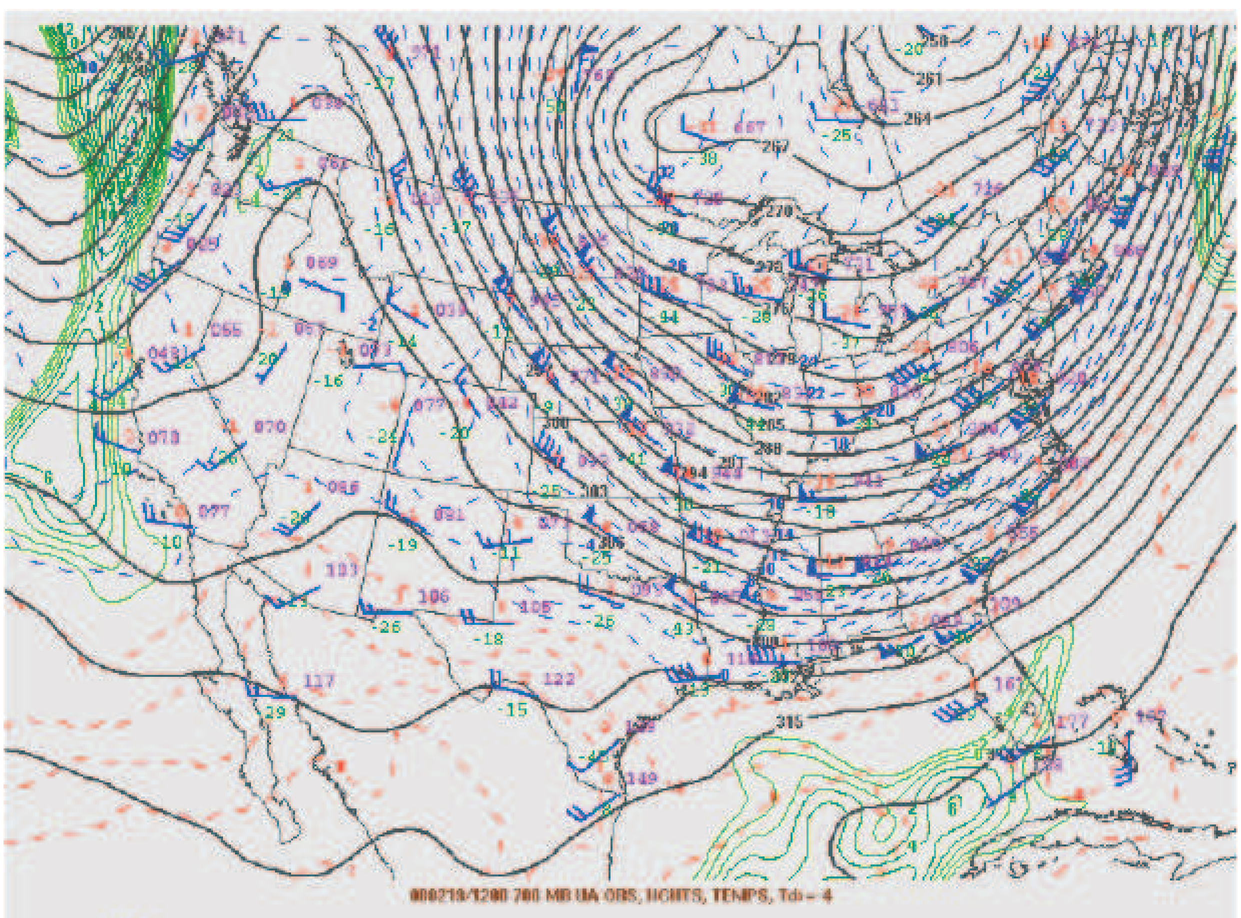


Figure S.7-3. Constant pressure map for 700 mb, 02/19/08 (1200 UTC) [(5 am LST)].

The high pressure ridge continued to progress slowly eastward during February 20th resulting in the central axis pushing into southwestern Wyoming by the middle of the day. As a result, a capping low-level inversion was observed throughout the day, and a weakened northwest gradient wind flow allowed the establishment of local valley flow patterns in the area. Local valley flow patterns are characterized by light variable winds with pronounced down slope winds at night. A weak storm system that moved out of California and across the southern Great Basin during February 20th forced some broken high cloudiness over southwestern Wyoming during the afternoon, but the clouds failed to curtail ozone production in the area, based on monitored data.

Figure S.7-4 shows the 700 mb chart for the evening of February 21, 2008. Although the high pressure ridge had weakened by the afternoon of February 21st, it had also flattened and the central ridge axis was over southwestern Wyoming through the entire day. The resulting light wind situation, characterized by low wind speeds and significantly reduced air flow movement within the UGRB, enabled the strongest ozone production seen to date in Sublette County.

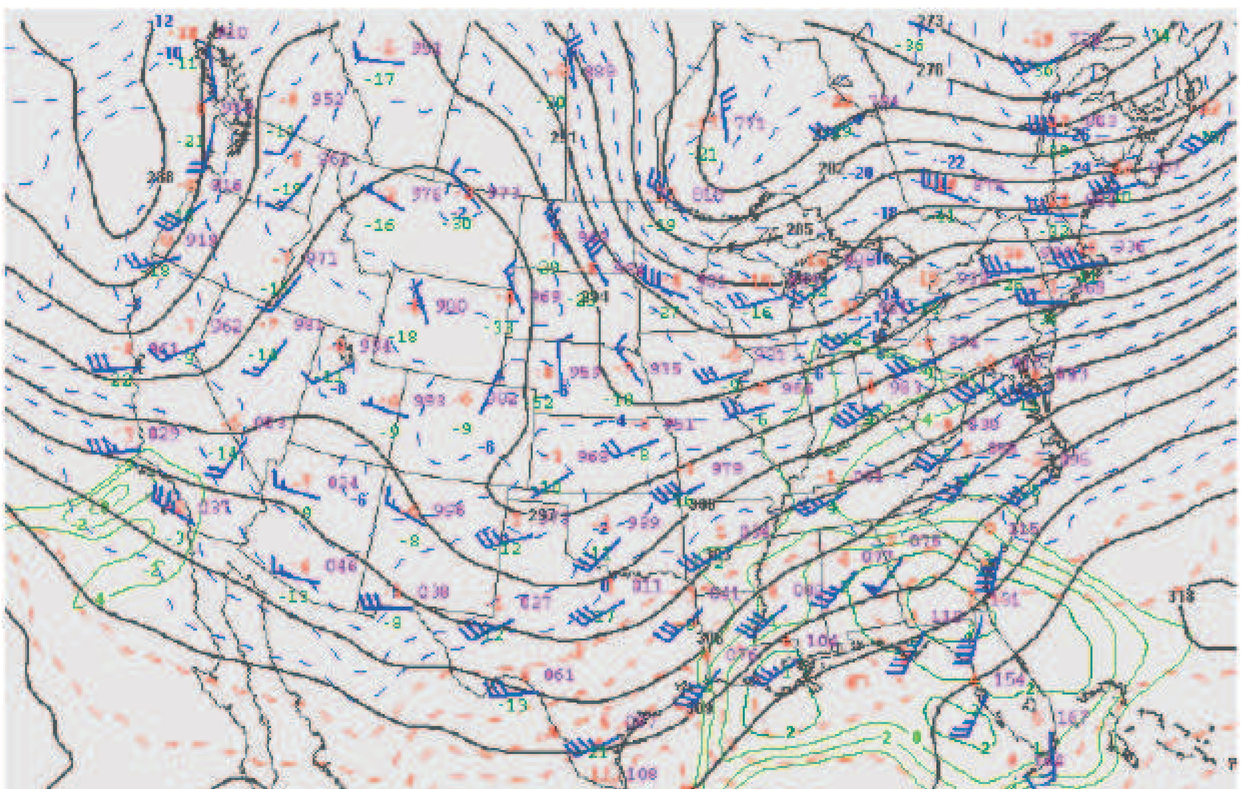


Figure S.7-4. Constant pressure map - 700 mb, 02/22/08 (0000 UTC) [02/21/08 (5 pmLST)].

On February 21, 2008, the low level inversion stayed intact through the entire daylight period, keeping ground level emissions trapped near the surface. With the very light and variable winds above the inversion (see Figure S.7-10) localized wind flow patterns near the ground level developed during the day allowing emissions to transport along those pathways (see Figure S.7-6 and Figure S.7-7). The height of the 700 mb pressure surface during the day was around 3,020 meters (MSL), the temperature averaged about -6° C, and the wind speeds were less than 5 knots. The height of the 500 mb pressure surface averaged around 5,550 meters (MSL) and the wind speeds at that height were around 15 knots.

The high pressure ridge continued to weaken during February 22, 2008, while a shortwave low pressure trough approached southwestern Wyoming from the northwest. Skies became mostly cloudy during the morning hours and light precipitation spread over the area later in the afternoon; the low level inversion stayed intact well into the afternoon, and ozone concentrations remained high during most of the day. It was anticipated that the stable layer would be mixed-out by the trough by early morning the next day and trapped emissions would be dispersed. Instead, the late arrival of the trough allowed one more day of high ozone concentrations.

Description of Surface Wind Data

With the addition of the temporary mesonet monitoring sites to the existing permanent meteorological monitoring stations in the 2007 and 2008 field studies, a fairly detailed picture of wind flow patterns within the UGRB was obtained, revealing that the wind flow patterns were distinctly different throughout the northern and southern portions of southwest Wyoming. A composite map of wind rose plots generated from meteorological data collected throughout southwest Wyoming during the time period 18 – 22, February 2008 is provided in Figure S.7-5.

As can be seen in Figure S.7-5, the wind patterns in the northern portion of Sublette County reflect the prevailing northwest winds typical of this area during most of the year. However, this moderately strong, organized northwest flow does not extend to the southern monitoring sites (Haystack Butte and Simpsons Gulch). Monitoring sites located in Sweetwater, Lincoln and Uinta Counties experienced a generally westerly wind flow, which was also a characteristic of the prevailing flows noted during the 2007 field study at those monitoring sites. Additionally, during the afternoon, winds reversed at some monitoring sites in the UGRB, shifting from the northwest to the southeast; this mid-day flow reversal is typical of high ozone days in the UGRB, and is thought to be causing recirculation of pollutants within the UGRB.

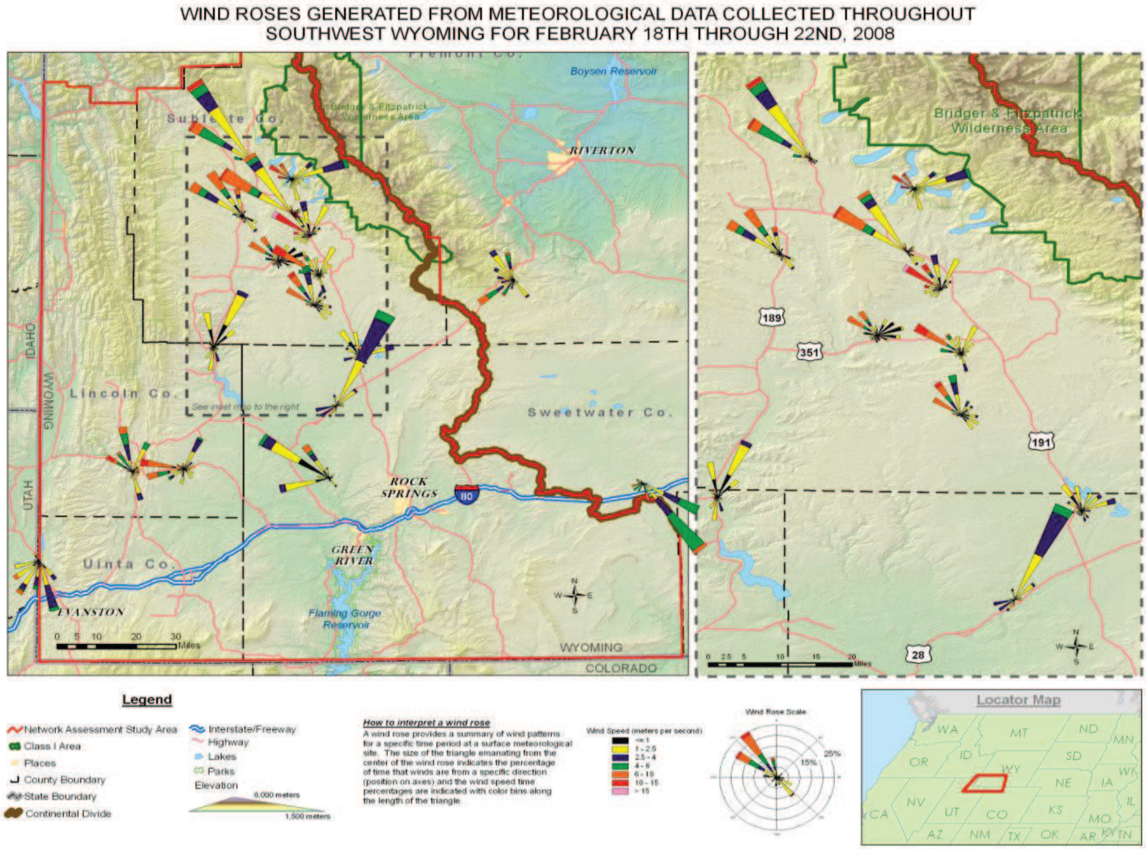


Figure S.7-5. Composite wind rose map for February 18 – 22, 2008 at monitoring sites located throughout Southwest Wyoming.

Wind vector fields were also examined spatially to gain an understanding of flow patterns in the field study area. Winds on a typical ozone episode day (February 20th), and on the day with the highest 8-hour ozone concentration recorded at the Boulder monitoring site (February 21st) are shown in Figure S.7-6 and Figure S.7-7.

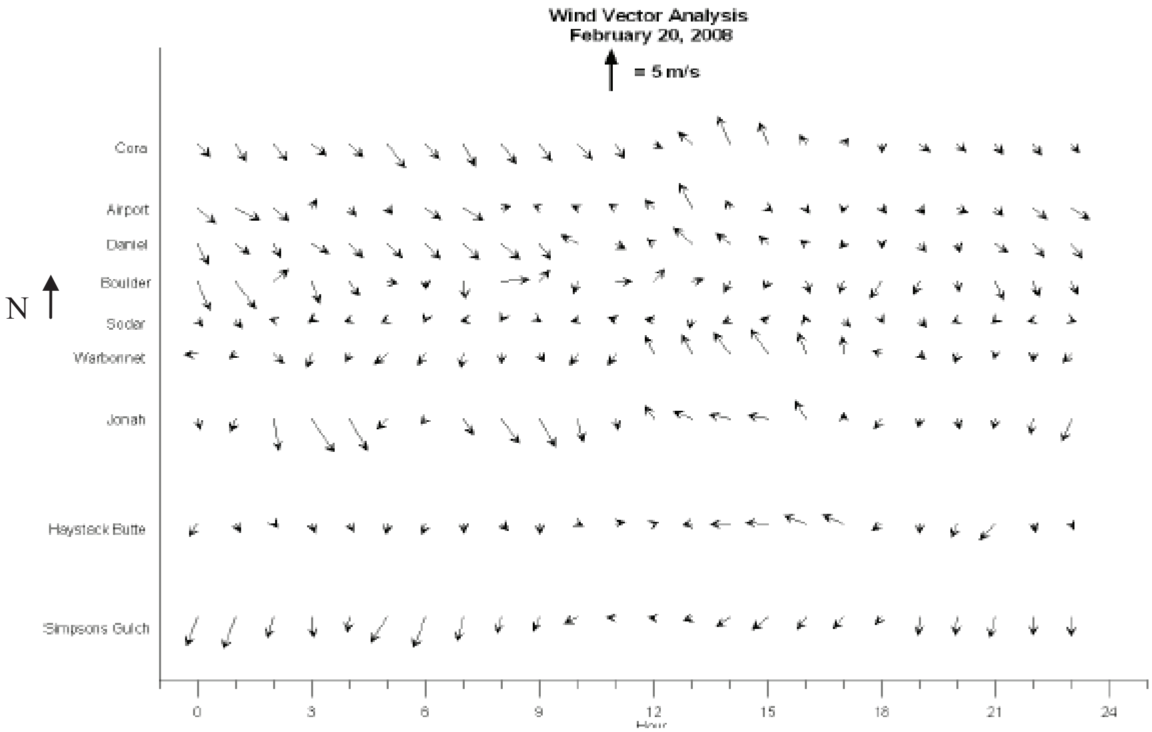


Figure S.7-6. Time-series showing February 20, 2008 hourly wind vectors for monitors used in 2008 field study monitoring network.

As shown in Figure S.7-6, winds in the UGRB are generally out of the northwest in the morning until about mid-day, at which point the flow has reversed with southeasterly winds, or at least southerly component winds are observed at most sites. This continues through the afternoon until 18:00 MST at which time the flow begins to switch back to the northwest, and by 6:00 MST the following morning, winds are northwest or northeast at nearly all of the monitoring sites. The switch from an overnight flow consisting of generally northwesterly or down slope winds, which last until approximately mid-day before reversing to a generally southeasterly wind flow pattern during the afternoon, was repeated on many of the 2008 ozone episode days.

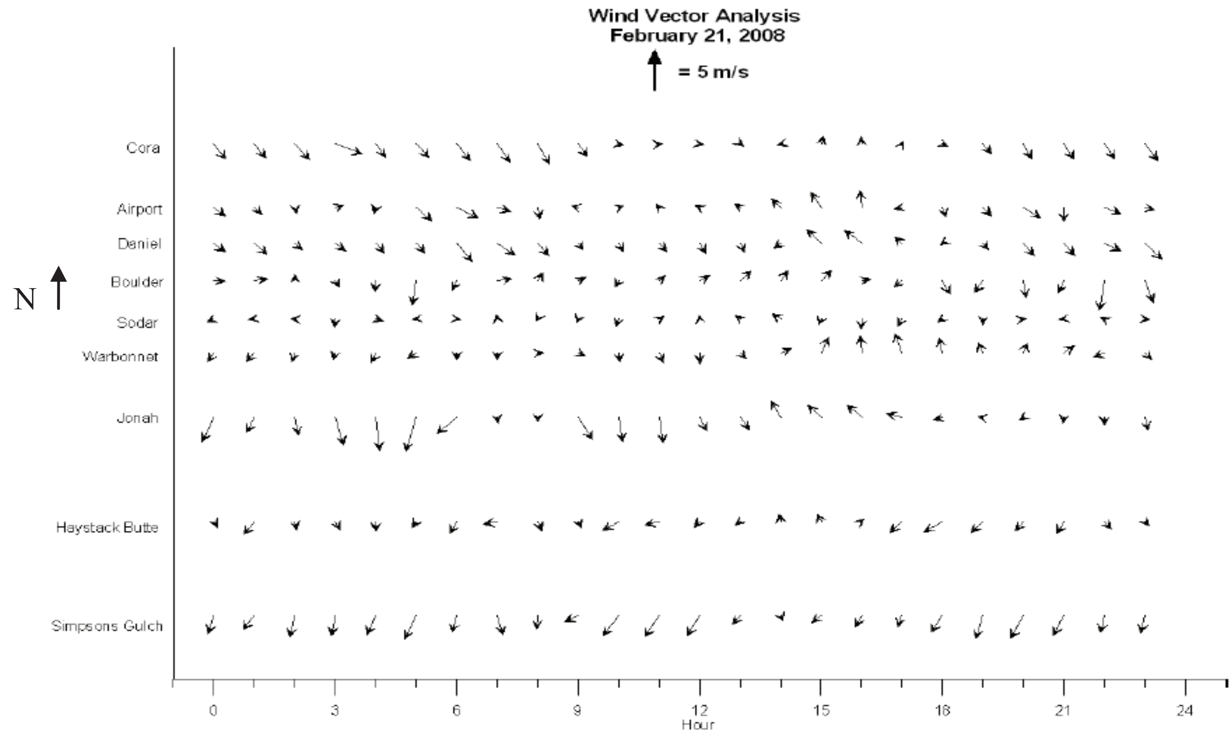


Figure S.7-7. Time-series showing February 21, 2008 hourly wind vectors for monitors used in 2008 field study monitoring network.

As shown in Figure S.7-7, winds on February 20th and 21st were generally light with variable directions throughout the monitoring network. There were two notable exceptions. After midnight, there was a general light northwest flow suggestive of a regional drainage pattern as colder, heavier air from the higher elevations flows downhill.

Generally stronger winds were measured at Jonah in the forenoon hours relative to the other sites in the network; this effect is also sometimes seen at Daniel and is likely due at least in part to the fact that winds at these two sites are measured on a standard 10 meter tower whereas the other sites made use of 3 meter high tripod mounted anemometers. During the afternoon, winds reversed at some sites, shifting to the southeast. This mid-day flow reversal is typical of high ozone days in the UGRB. On February 20, 2008, peak 8-hr ozone concentrations in the 70-85 ppb range were measured at sites throughout the study area; on February 21, 2008, the Boulder monitor recorded a 122 ppb 8-hr average ozone concentration. High ozone continued on February 22, 2008 with the Jonah monitor recording a daily maximum 8-hour average ozone concentration of 102 ppb. Minimal emissions transport and dispersion, due to the light winds in the UGRB, were characteristic throughout the February 19-23, 2008 ozone episode.

The South Daniel FRM monitor which is in the northwest portion of the recommended nonattainment area is typically upwind of local precursor sources and the Boulder monitor. On February 20 ambient nitrogen dioxide (NO_2) concentrations at the Daniel monitor were essentially equal to zero (0) ppb for all 24 hours; very low concentrations of VOCs were also measured in the VOC canister samples collected at Daniel on this day. Nearly identical values were observed at the Daniel monitor and in the Daniel VOC canister samples obtained throughout the ozone episode (February 19-23, 2008); this was also the case during all three IOPs. The canister samples collected at the Daniel monitor in the 2007 field study also showed consistently low VOC concentrations. Additionally, monitored NOx concentrations recorded at Daniel have been very low since this site began operation nearly four years ago; the VOC canister data and the NOx monitoring conducted at Daniel clearly indicate the air coming into this area has low ozone precursor concentrations. Additionally, based on the 2008 field study data at the Daniel monitor, background ozone concentrations during the winter are typically in the 50 - 60 ppb range. Daily maximum 8-hour ozone concentrations at the Daniel monitoring site during the February 19-23, 2008 ozone episode ranged between 62-76 ppb.

One view of the surface wind direction-ozone relationship is shown on Figure S.7-8, which presents a wind rose using measurements from the Boulder monitoring site. This diagram is constructed using the daily peak 8-hr ozone level and 15:00 MST hourly averaged winds. These results show that high ozone levels were associated with afternoon winds from a variety of directions, reflecting the "light and variable" nature of the surface layer winds when the monitored 8-hour ozone levels were above 75 ppb, as opposed to 8-hour ozone concentrations that were less than 75 ppb, which tend to be associated with persistent higher wind speeds and the predominant northwest flow direction along the valley axis.

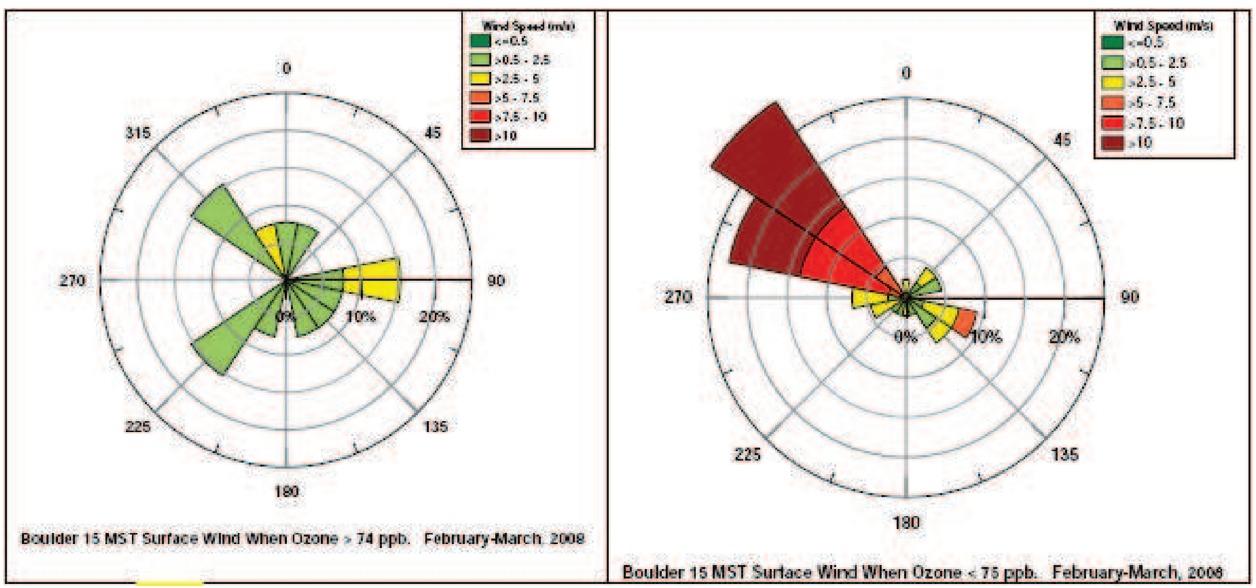


Figure S.7-8. Wind roses based on 15:00 (MST) data from the Boulder site for days with maximum 8-hour average ozone a) greater than 74 ppb (left) and b) less than 75 ppb (right).

Description of Conditions Aloft

A multi-level SODAR was operated continuously at a location approximately 3 miles southwest of the Boulder monitoring site during the 2008 field study. The SODAR provided two types of data: 1) vertical profiles of wind speed and wind direction at 10-meter increments up to 250 meters above ground level, and 2) information which allows an estimation of mixing height (mixed layer depth). The regular hourly observations during the 2008 field study were supplemented with high resolution measurements of vertical wind speed, wind direction, and temperatures during the IOPs. The hourly meteorological data capture rate was excellent. Comparing the measured wind data with peak 8-hour ozone concentrations at Boulder, a strong correlation between ozone concentrations and low mixed layer average wind speeds is evident. Looking at SODAR data on the afternoon of February 21, 2008, a day when 8-hour ozone concentrations above 75 ppb were noted throughout the field study area, reveals a top to the mixing layer at about 100 meters above ground level (AGL) representing a very shallow layer trapping ozone precursors and other pollutants in high concentrations near the surface.

Similar vertical profiles (soundings) and boundary layer development were measured by balloon-borne observations (ozone measurements, temperature, relative humidity and winds) on each of the high ozone days. Stable atmospheric conditions prevailed, and were characterized by strong low-level temperature inversions with very shallow mixing heights and light boundary-layer winds**.** Peak ozone concentrations were often observed somewhat above the surface but still within the stable inversion layer. As shown in Figure S.7-9, at low mixing heights (below 100 meters), the highest values of ozone were observed. Table S.7-2 provides a summary of the days with low-level capping inversions, and the measurements obtained, including the date and time of each balloon launch, the ground temperature and maximum inversion temperature (temperature at top of inversion layer), the difference between the maximum inversion temperature and the ground temperature (inversion layer Delta T), which reflects the strength of the temperature inversion. Note the highest inversion layer temperature measured is 14.5 (^{o}C) and occurs on February 19th.

Launch Date	Launch Time (MST)	Ground Temp (^oC)	Max Inversion Temp (^oC)	Inversion Layer ΔT (^oC)	Inversion Height (meters AGL)
2/18/08	11:00	-3.8	-3.2	0.6	150
2/18/08	16:00	-1.8	-1.7	0.1	47
2/19/08	7:00	-14.8	-0.3	14.5	489
2/19/08	1100	-8.1	1.3	9.4	442
2/19/08	13:00	-5.3	2.2	7.5	403
2/19/08	16:00	-4.5	1.8	6.3	445
2/20/08	7:00	-13.6	-2.4	11.2	398
2/20/08	1100	-13.9	-2.0	11.9	342
2/20/08	13:00	-7.7	-3.2	4.5	449
2/20/08	16:00	-5.4	-2.3	3.1	543
2/21/08	7:00	-17.4	-4.0	13.4	500
2/21/08	1100	-7.9	-3.0	4.9	405
2/21/08	13:00	-3.4	-2.6	0.8	373
2/21/08	16:00	-5.7	-2.9	2.8	494
2/27/08	8:00	-9.7	-1.4	8.3	670
2/27/08	1100	-5.4	0.1	5.5	711
2/27/08	13:00	-2.3	1.0	3.3	608
2/27/08	16:00	-1.2	0.7	1.9	527
2/28/08	8:00	-8.6	-2.3	6.3	149
2/28/08	1100	-1.4	-2.4	-1.0	265
2/28/08	13:00	1.8	0.0	-1.8	91
2/28/08	17:00	0.5	1.0	0.5	190
2/29/08	8:47	-6.2	-2.5	3.7	460
2/29/08	1100	-8.9	-0.3	8.6	396
2/29/08	13:00	-1.4	0.3	1.7	314
2/29/08	16:00	-0.3	1.5	1.8	470
3/10/08	8:00	-12.2	-5.8	6.4	470
3/10/08	1100	-7.6	-5.0	2.6	480
3/10/08	14:00	-1.6	-2.1	-0.5	312
3/10/08	17:00	-1.3	-2.0	-0.7	705
3/11/08	8:00	-13.1	1.3	14.4	373
3/11/08	1100	-2.4	1.5	3.9	312
3/11/08	13:00	2.1	2.0	-0.1	252
3/11/08	17:00	0.5	1.2	0.7	236
3/12/08	8:00	-9.3	-2.1	7.2	142
3/12/08	1100	2.3	2.5	0.2	90
3/12/08	15:00	3.5	-0.3	-3.8	261

Table S.7-2. Summary of low-level temperature measurements, and related data on inversion strength.

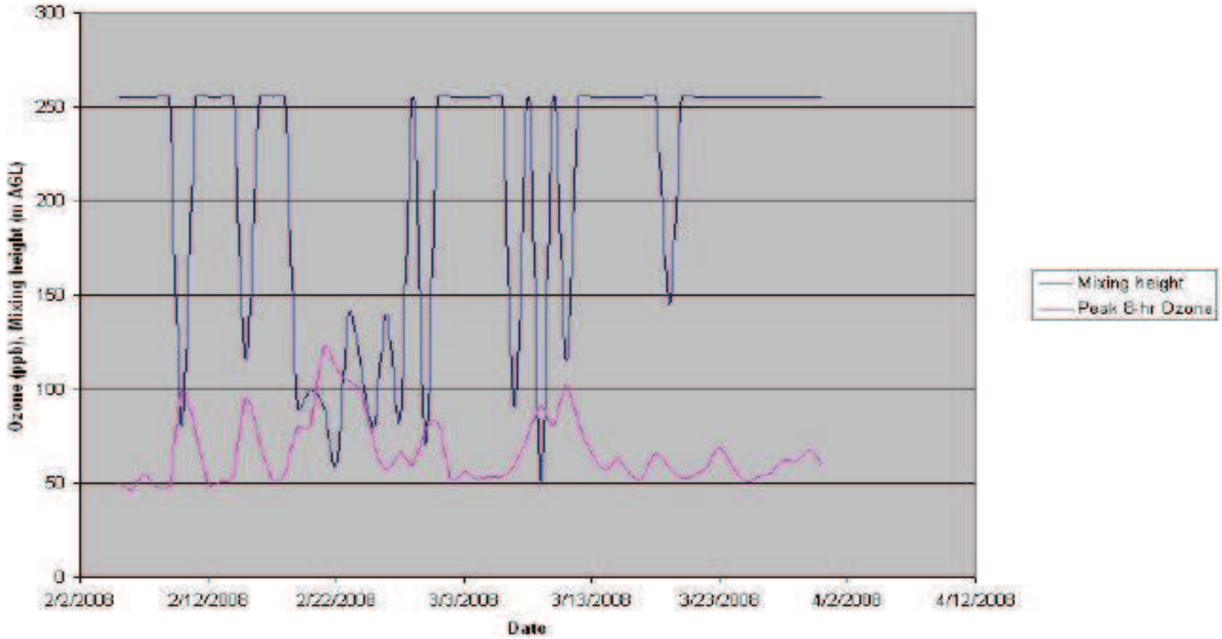


Figure S.7-9. SODAR-reported mixing height versus peak daily 8-hour ozone concentrations at Boulder. Measurements limited to below approximately 250 meters above ground level (AGL).

Soundings taken in the forenoon and afternoon of February 21, 2008 are shown in Figure S.7-10. Profiles for ozone (black line), temperature (red line), dew point temperature (dashed blue line) and winds (vectors) are plotted as functions of height above the ground elevation of the balloon launch site. A strong low-level inversion was present up to 2,500 meters-msl (~ 400 meters-agl) with a maximum temperature at the top of the inversion of -2.9 ^{o}C, several degrees warmer than the temperature at the surface. Boundary-layer winds in the forenoon were light from the west when ozone levels were ~50 ppb, before becoming southeast in the afternoon.

Figure S.7-10 shows the inversion is setting up in the morning of February 21, 2008, and that the inversion persisted through daylight hours, resulting in high ozone concentrations beneath the inversion. Figure S.7-10 also shows that at 11:00 (MST) ozone concentrations were ~ 50 ppb below the inversion height of 2,500 meters (MSL) which is shown by the green circle (left pane) towards the bottom of Figure S.7-10; measured ozone levels above the inversion layer were also generally ~ 50 ppb.

Normally, some vertical mixing of the air would exist, as the temperature aloft begins to fall off with increasing height above ground; however, the strong surface-based inversion persists to 4:00 pm, effectively inhibiting vertical mixing. A shallow layer of high ozone (> 110 ppb) was present in the afternoon (16:00 MST) sounding, which is shown by the green oval (right pane) towards the bottom of Figure S.7-10. Ozone concentrations decrease rapidly with height below the inversion; ozone levels above the inversion are about 50 ppb. Note that the vertical wind shear measured at the top of the inversion layer height above ground (wind arrows on the right side of graphs) attest to the complete decoupling of the boundary layer air from layers aloft.

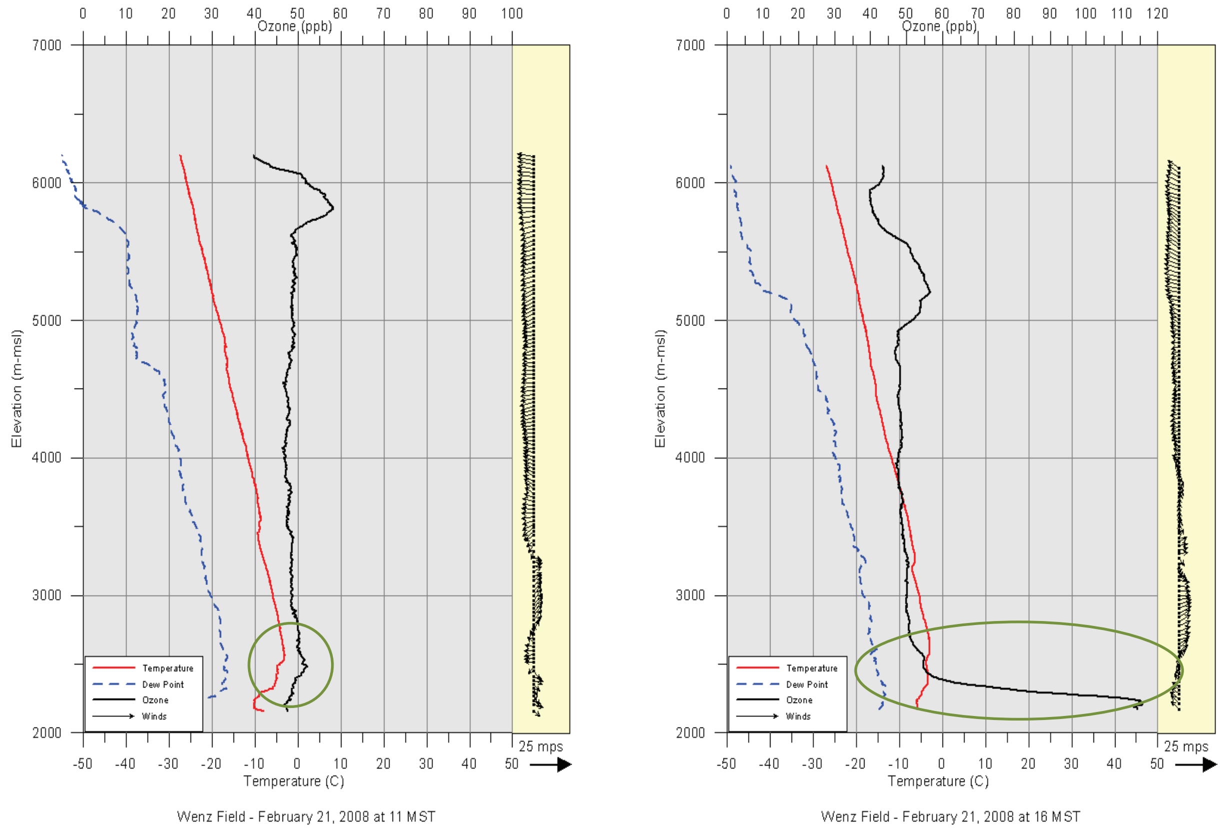


Figure S.7-10. February 21, 2008 balloon-borne soundings; Sounding at 11:00 (MST) (left); Sounding at 16:00 (MST) (right).

<u>Tools to Evaluate Air Parcel Transport: HYSPLIT vs. AQplot Back Trajectory Analyses</u>

Trajectory analyses were used to determine possible air parcel transport into the UGRB during February 20, 2008, as a means of evaluating possible precursor emissions and ozone transport in the UGRB and at the Boulder and Jonah monitors.

The HYSPLIT (<u>HY</u>brid <u>S</u>ingle-<u>P</u>article <u>L</u>aGrangian <u>I</u>ntegrated <u>T</u>rajectory) model is a trajectory model that is used for computing simple air parcel trajectories. HYSPLIT can use meteorological data from several archived meteorological modeling databases, including the NCEP Eta Data Assimilation System (EDAS), which is based on a 40 kilometer resolution data (2004-present). However, 40 kilometer (km) data may not provide sufficient resolution to resolve the significant terrain features that influence the wind flow patterns in the UGRB. The result of using such low resolution data to represent the terrain features in and surrounding the UGRB will be that the modeled terrain will be much smoother, and will not match the actual terrain (see Figure S.7-11). This will affect the wind trajectory analysis because the roughness of the terrain as well as terrain blocking and channeling effects may not be well represented, which would otherwise influence the wind speeds and the trajectory path lengths. In very complex terrain, such as in the UGRB, the HYSPLIT model trajectories may not be very accurate unless the local wind flow patterns are being driven by the large-scale synoptic conditions (e.g., strong winds).

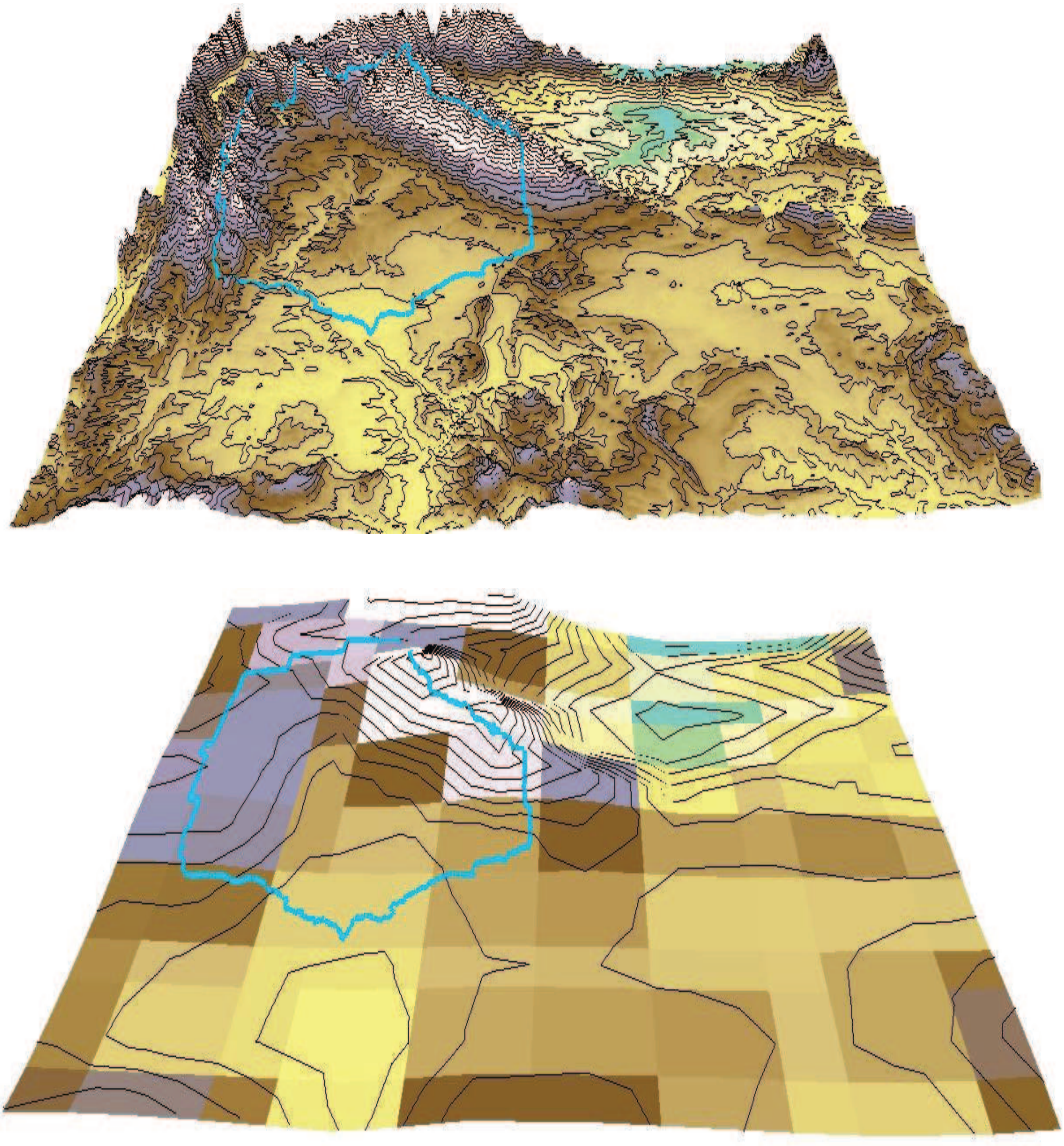


Figure S.7-11. A comparison of the local terrain features at 1 km and 40 km resolution, respectively, and the resulting "smoothed" terrain as shown in the 40 km 3-D topographic plot.

Figure S.7-12 shows a similar comparison of the local terrain features at 1 km and 40 km resolution as depicted in the 2-dimensional contour plots. Note the terrain features in the bottom pane are much less resolved (less terrain detail and decreased roughness) than those terrain features as shown in the top pane.

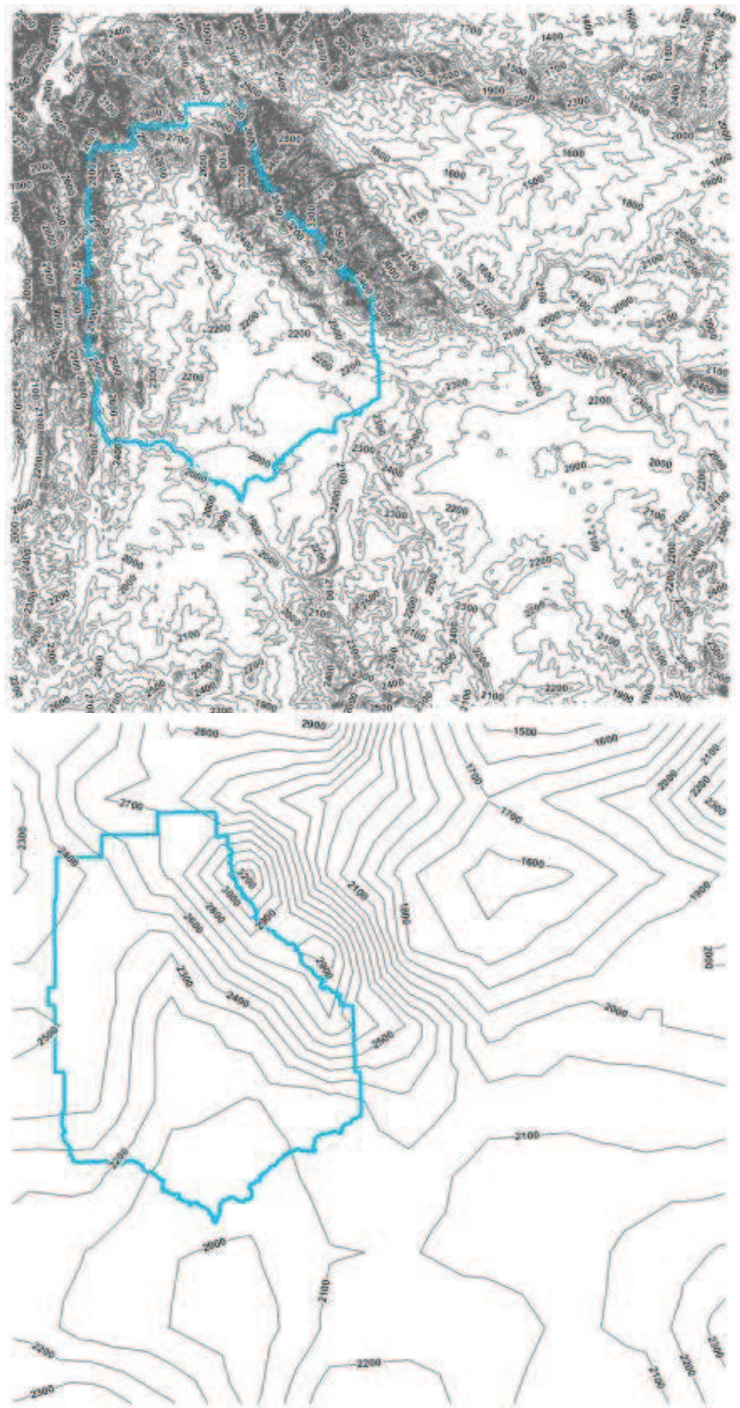


Figure S.7-12. A comparison of the local terrain features at 1 km and 40 km resolution, respectively, as depicted in the 2-D contour plots.

While the trajectory model is a useful tool in assessing approximate air parcel movement, and can be used to better understand potential pathways for pollutants moving within and into and out of the UGRB, trajectories are a highly simplified representation of the complex, two- and three-dimensional transport and turbulent diffusion processes that move pollutants from place to place. Thus, a particular trajectory path is subject to uncertainty and should not be interpreted as an exact representation of actual pollutant transport. Generally, the longer an air mass is tracked forward or backward in time, the more uncertain is its position (Kuo et al., 1985; Rolph and Draxler, 1990; Kahl and Samson, 1986).

Additionally, the trajectory model error is a function of the complexity of the meteorological scenario under study. In this analysis, the strong surface-based inversion layer in place on February 19-22, 2008 results in a decoupling of the upper air layers (above the inversion layer) and the lower air layers (below the inversion) and winds in the upper and lower layers will at times blow in different directions at different speeds. Winds are light and variable in the lower layer, adding to the complexity of the situation. This very complex meteorological scenario is difficult to represent accurately in a trajectory model.

AQD ran a comparison of 12-hour back trajectories from the Jonah and Boulder monitoring sites, using the HYSPLIT model with the EDAS 40 kilometer meteorological data, and AQplot, (a 2-dimensional trajectory model) using actual meteorological data from the Jonah and Boulder monitoring sites, respectively. This comparison shows that much different back trajectories are produced by these two models, as shown in Figures S.7-13 and S.7-14. The 2-dimensional trajectory model (AQplot), used in these analyses, was developed by the Texas Commission on Environmental Quality.

Additional trajectory analyses using a 3-D trajectory model are discussed in the next section. However, for this particular comparison, a 2-D trajectory model is an acceptable model to assess trajectories near the monitoring sites because the surface winds in the UGRB under these episodic winter conditions have been effectively decoupled from the upper air layers. The amount of vertical air movement is limited due to the capping inversion in place – in other words, the movement of air parcels below the inversion is not influenced by winds above the inversion, and there is little vertical mixing of air near the ground. Monitoring data of the localized meteorological patterns in the proposed nonattainment area boundary show that under these episodic conditions, the wind patterns are 2-dimensional, and the use of the 2-D AQplot trajectory model for this particular application is reasonable under these winter meteorological conditions (inversion, low mixing height, and stable atmosphere) as the air parcel trajectories start off and tend to stay close to the ground.

As shown in Figures S.7-13 and S.7-14, the resulting short trajectories never get very far away from the monitor site; considering the short duration of the trajectory analysis, less interpolation error would be expected. The HYSPLIT model does not consider the wind influences as measured in the 2008 field study surface monitoring network; the AQplot local-scale back trajectories are a more accurate depiction of what is going on because of the input of local data.

- Trajectories ending 14:00 MST at Boulder on 20 February 2008
- Markers at 1-hour intervals; 12 hours total
- Very light, meandering surface winds at Boulder not reproduced by EDAS 40 km data set

Figure S.7-13. Comparison of HYSPLIT (red) and AQplot (pink) 12-hour back trajectories from the Boulder monitoring site on February 20, 2008.

- Regional-scale model: HY-SPLIT back trajectories using 40 km resolution EDAS
- Local scale: UGWOS '08 surface wind data (markers at 1-hour intervals)

- 20 February 2008: 14:00 MST surface back trajectory from Jonah
- Markers at 1-hour intervals; 12 hours total

Figure S.7-14. Comparison of HYSPLIT (red) and AQplot (green) 12-hour back trajectories from the Jonah monitoring site on February 20, 2008.

This comparison demonstrates that the HYSPLIT model overestimates the back trajectory path length because the localized low wind speed conditions and the wind flow reversal are not reproduced in 40 kilometer EDAS meteorological analysis fields. Additionally, the HYSPLIT model trajectory shows a less dramatic shift in wind direction and much higher wind speeds leading to a completely different result. A trajectory model that accurately reflects the terrain influence, sustained low wind speeds, and local-scale observed wind flow patterns was needed to effectively evaluate air parcel transport throughout the UGRB under these episodic conditions.

AQplot Back Trajectory Analysis

Back trajectories using the AQplot model and the meteorological data collected during the field study on February 20, 2008 are shown in Figure S.7-15; the trajectories were used to evaluate air parcel movement near the monitors during the 12 hours leading up to the February 20, 2008 monitored high ozone concentrations. These back trajectories start at 2:00 pm (MST), and show that the wind patterns leading up to the afternoon high monitored ozone concentrations at the Boulder monitoring site (and other monitors in close proximity to the Boulder monitor) produce short trajectories, with the air parcels remaining in close proximity to these monitors during this 12-hour period, due to the observed low wind speeds and recirculation patterns (wind reversals).

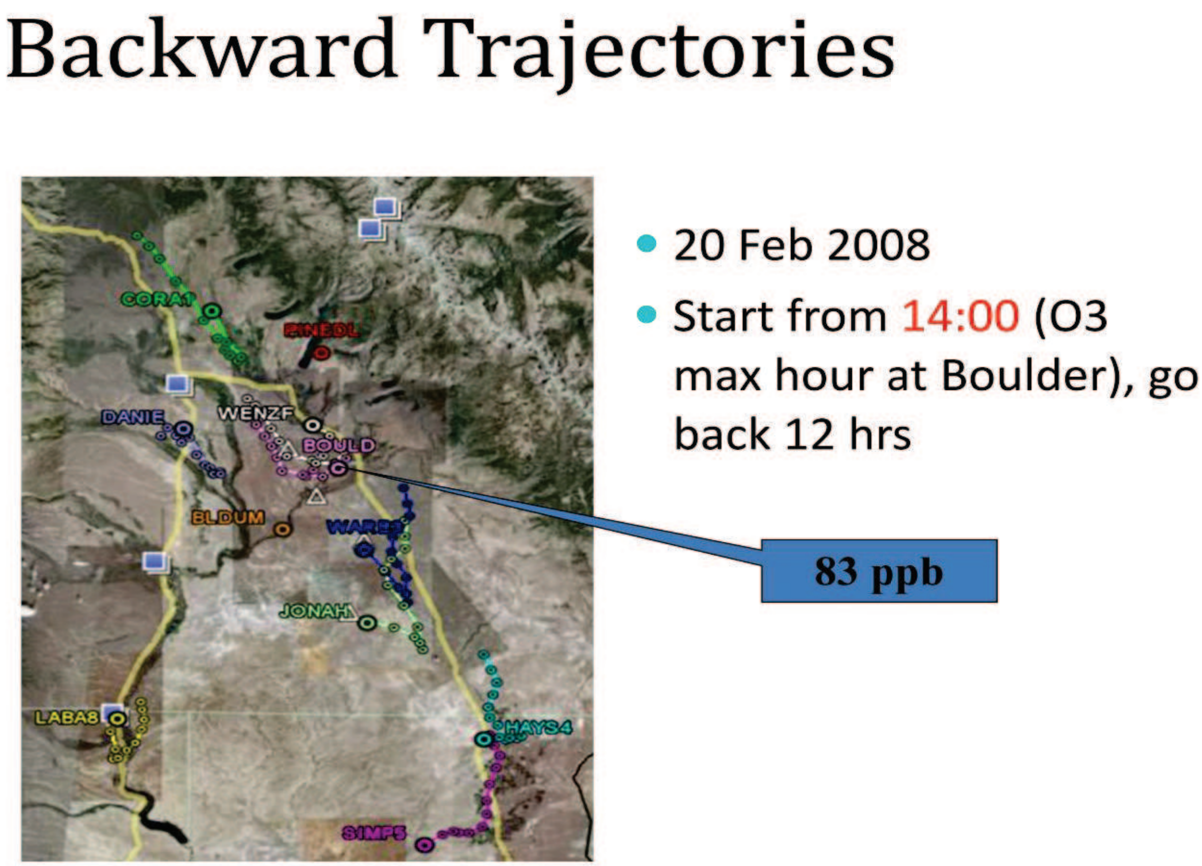


Figure S.7-15. 12-hour back trajectories near field study monitors on February 20, 2008.

Due to the complexity of the winds in the UGRB during February 19-23, 2008, including the significant terrain-dominated effects on localized winds, stable conditions, and wind flow reversals, as discussed, and the terrain-dominated regional meteorology outside of the UGRB, a high resolution 3-dimensional (3-D) wind field was needed that could correctly reproduce:

1) Shallow inversions and near-field wind flow patterns as measured at the SODAR, which is near the Boulder monitor; and
2) Regional-scale wind flow patterns.

This particular wind field would be utilized in conjunction with a full 3-D trajectory model to evaluate:

1) Air parcel movement in the study area;
2) Influences from the surrounding regional terrain on air parcel movement;
3) Air parcel inflow (ozone or precursor emissions transport) into Sublette County on the days leading up to and during the February 19-23, 2008 ozone episode.

AQD contracted out the development of a 3-D CALMET wind field to evaluate the above, which is discussed in the following section.

CalDESK Trajectory Analysis

AQD developed a high resolution (spatial and temporal) 3-dimensional wind field that uses the National Center for Environmental Prediction (NCEP) Rapid Update Cycle (RUC) model at 20 kilometer resolution, coupled with the high resolution observational database of surface and upper air meteorological data measurements obtained during the 2008 field study. It should be noted that the terrain elevation data used in this wind field is based on much higher terrain resolution than is currently used in the HYSPLIT model. The RUC and field meteorological data were processed through the CALMET diagnostic wind model to generate a 1 kilometer gridded wind field, using high resolution terrain and land use/land cover data, and actual observations of daily snow cover to account for actual snow cover (and albedo effects) within the CALMET domain. The complexity of the terrain, as represented in this 3-dimensional (3-D) CALMET wind field in shown in Figure S.7-16.

This CALMET wind field was developed to evaluate the ozone episode-specific meteorology associated with the February 18-23, 2008 ozone episode. The CALMET domain was set up using the same meteorological modeling domain (464 km x 400 km) developed for the Southwest Wyoming Technical Air Forum (SWWYTAF) modeling analyses (1999), with increased vertical resolution to total 14 vertical layers; the lower layers having small vertical depths in order to better resolve complex flow patterns and temperature inversions near the surface.

Figure S.7-17 provides a snapshot of the wind field based on the winds at 4:00 am (MST) on February 20, 2008, and shows the complexity of the terrain surrounding the UGRB is very well represented in the CALMET wind field. The wind field captures the strong terrain-dominated down slope winds during the early morning hours, and the strong channeling and drainage effects which are exhibited throughout the UGRB – CALMET "sees" the influence of the terrain.

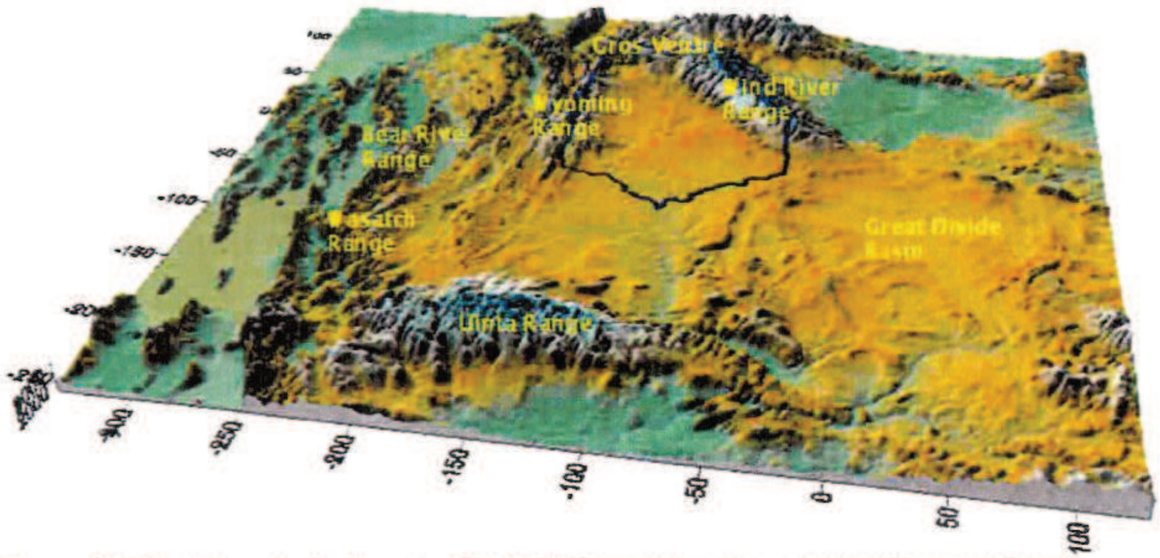


Figure S.7-16. Terrain features in CALMET modeling domain (464 km x 400 km).

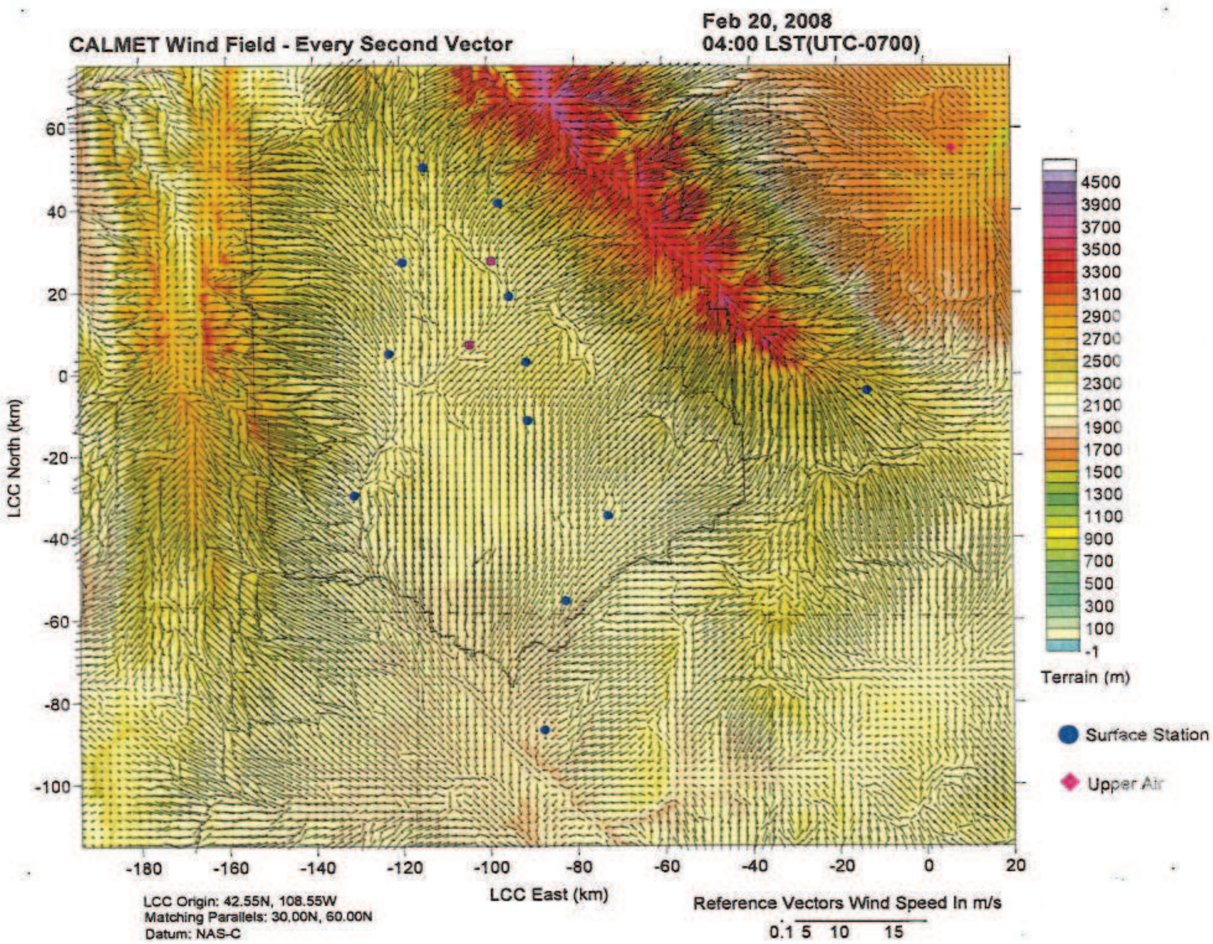


Figure S.7-17. CALMET wind field at 4:00 am (MST) on February 20, 2008. The 2008 field study meteorological monitoring sites are shown for reference.

The 3-D CALMET wind field accurately depicts meteorological conditions in the UGRB and surrounding area. A detailed report discussing the development of the CALMET wind field and the validation of the wind field compared to observations, entitled, "Upper Green River Winter Ozone Study: CALMET Database Development Phase I" will be posted on the DEQ web site and will be sent under separate cover to EPA shortly. Validation of this wind field has shown that the local-scale observed meteorological conditions are being reproduced:

- Temperature lapse rates associated with inversion conditions and low mixing heights
- Wind speeds and wind reversals
- Duration of down slope winds, which last until approximately mid-day before reversing to a generally southeasterly wind flow pattern

The trajectory analyses using this wind field lead to the conclusion that regional transport is insignificant, and local-scale precursor emissions transport is the dominant means of precursor transport during the high ozone periods. The trajectory analyses that follow were a key factor in selection of an appropriate southern boundary of the nonattainment area. The trajectory analyses demonstrate that the proposed southern boundary of the nonattainment area is reasonable, and that there is no significant contribution of ozone or ozone precursors from areas or sources outside the proposed nonattainment area during elevated ozone events.

Specific Examples of Trajectory Analyses Using CalDESK

Based on this wind field, AQD used the CalDESK visualization software to run forward trajectory analyses to evaluate air parcel transport into and out of the UGRB, specifically with respect to air parcels from large stationary sources (power plants and Trona plants) located to the south of the UGRB, and to evaluate the southern extent of air parcel inflow into the UGRB. A series of CalDESK forward trajectory analyses follow, along with a brief discussion of the resulting trajectories generated by CalDESK during February 18-23, 2008. CalDESK Forward Trajectory Analyses (FTA) for February 18, 2008 are shown in Figures S.7-18 through S.7-22.

NOTE: Trajectory figures (Figures S.7-18 through S.7- 49) are being updated to show the proposed nonattainment area boundary. Those figures will be available shortly. AQD will send those figure to EPA as replacement pages.

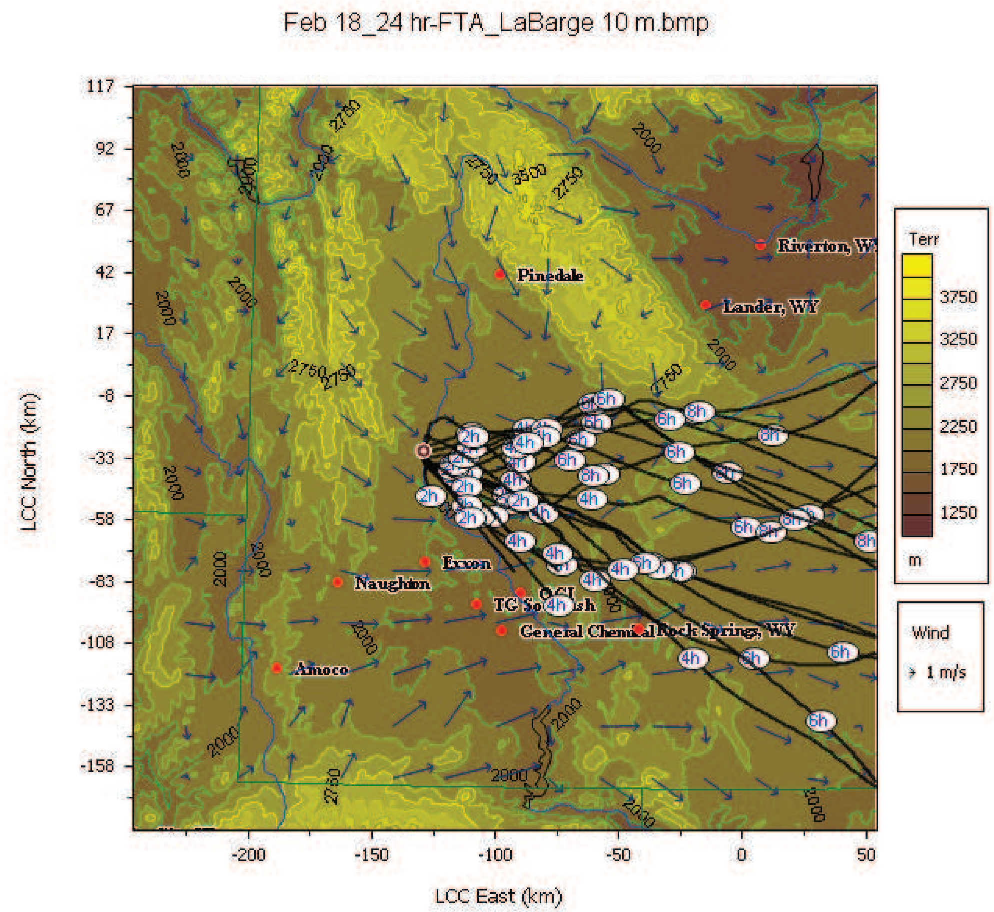


Figure S.7-18. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 18, 2008.

As shown in Figures S.7-18 through S.7-22, the prevailing northwest winds within the UGRB on this day limit air parcel transport into the UGRB from sources located south of Sublette County, which is reflected in the trajectory analysis for the LaBarge and Moxa Arch areas, the Naughton power plant, the OCI Trona processing facility, and the Bridger power plant. Additionally, the wind speeds at the monitoring sites on the Pinedale Anticline were also generally high and reflect the prevailing northwest winds typical of the study area during most of the year. This moderately strong, organized northwest flow does not extend to the field study southern monitoring sites (Haystack Butte and Simpsons Gulch); these southern monitoring sites experienced a generally westerly wind. The 2008 field study monitoring sites are shown in Figure S.7-1.

Wind speeds were generally high throughout the monitoring network on February 18th. These conditions continued throughout the night until the early morning of February 19th. Winds decreased significantly thereafter becoming light and variable for the remainder of the day, setting the stage for the next several days. Ozone levels were relatively low, in the 50 ppb range on February 18th; increasing on February 19th, with both the Boulder and Jonah monitoring sites experiencing 8-hr peaks of 80 ppb.

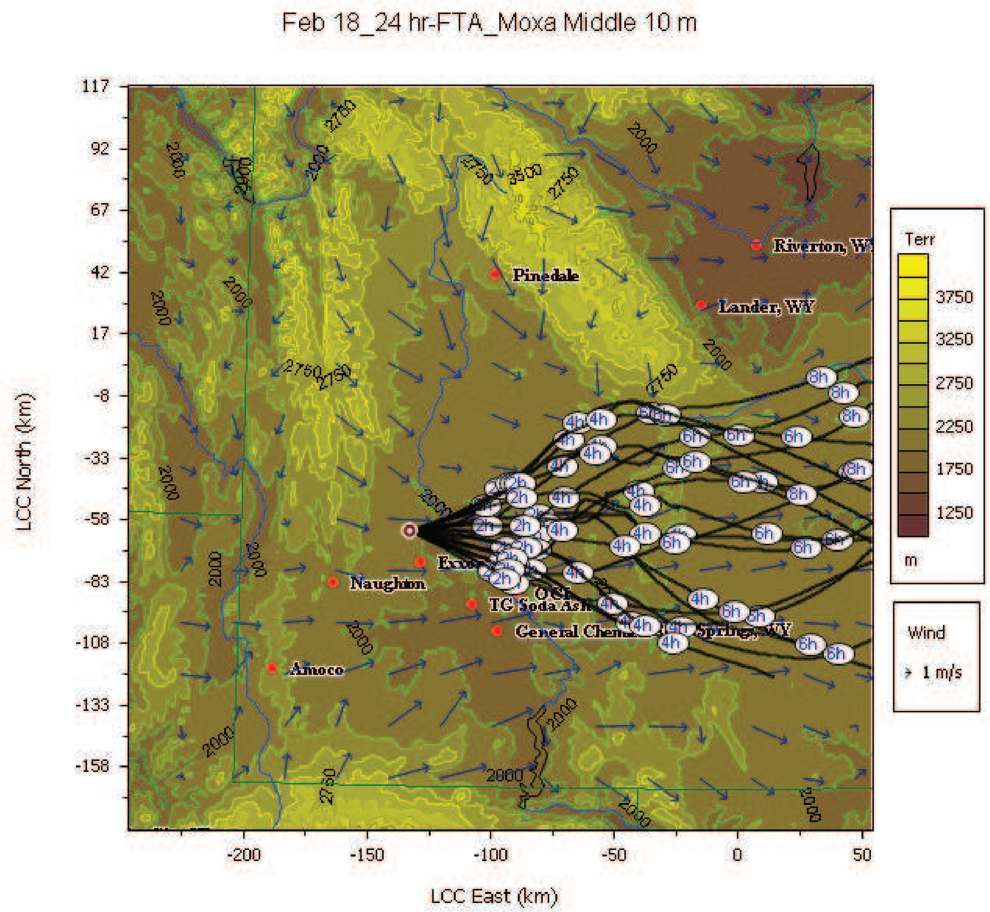


Figure S.7-19. 24-hour forward trajectory analysis in the Moxa Arch area on February 18, 2008.

The trajectory analysis shown in Figure S.7-19 places the initial air parcel release point in the northern part of the Moxa Arch field. The predominant paths shown trend to the east, and there is a slight northerly component to several of the modeled trajectories. These trajectories generally parallel the southern boundary of the proposed nonattainment area along Pacific Creek. While some of the trajectory paths lie within the proposed nonattainment area, none of the paths indicate that sources within the Moxa Arch cause or contribute to elevated ozone levels within the proposed nonattainment area.

Feb 18_24 hr-FTA_Naughton 10 m.bmp

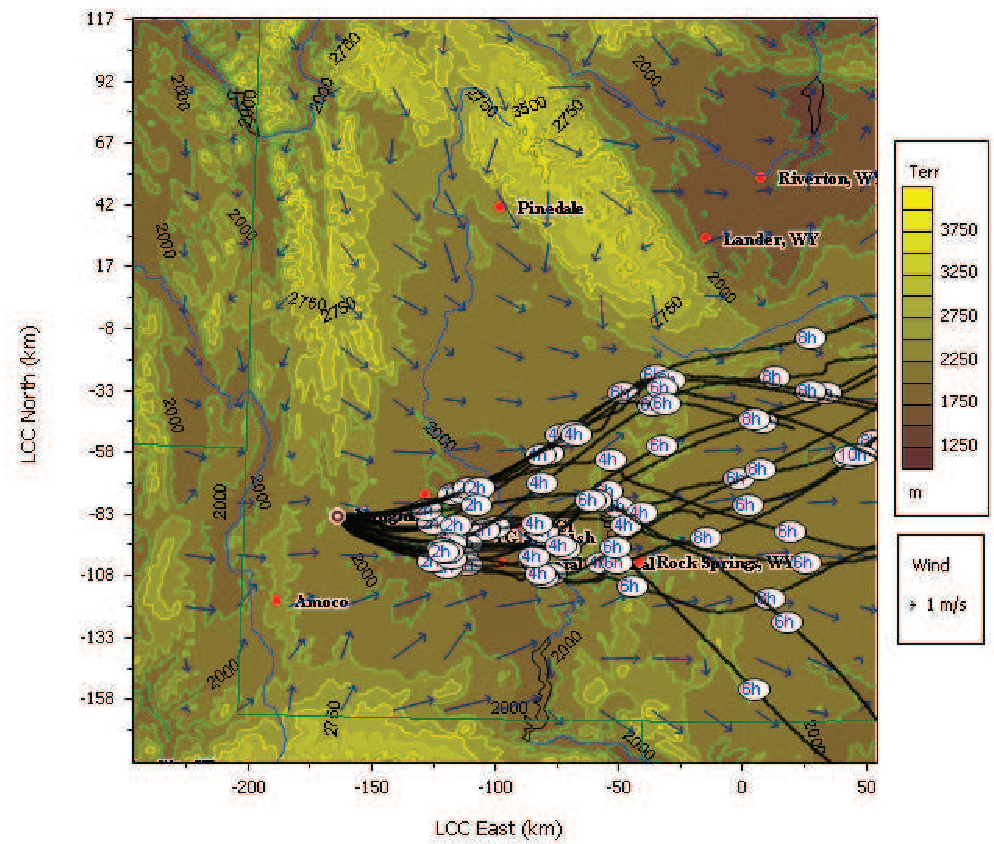


Figure S.7-20. 24-hour forward trajectory analysis at Naughton power plant on February 18, 2008.

The trajectory analysis in Figure S.7-20 shows all modeled trajectories from Naughton not entering the proposed nonattainment area.

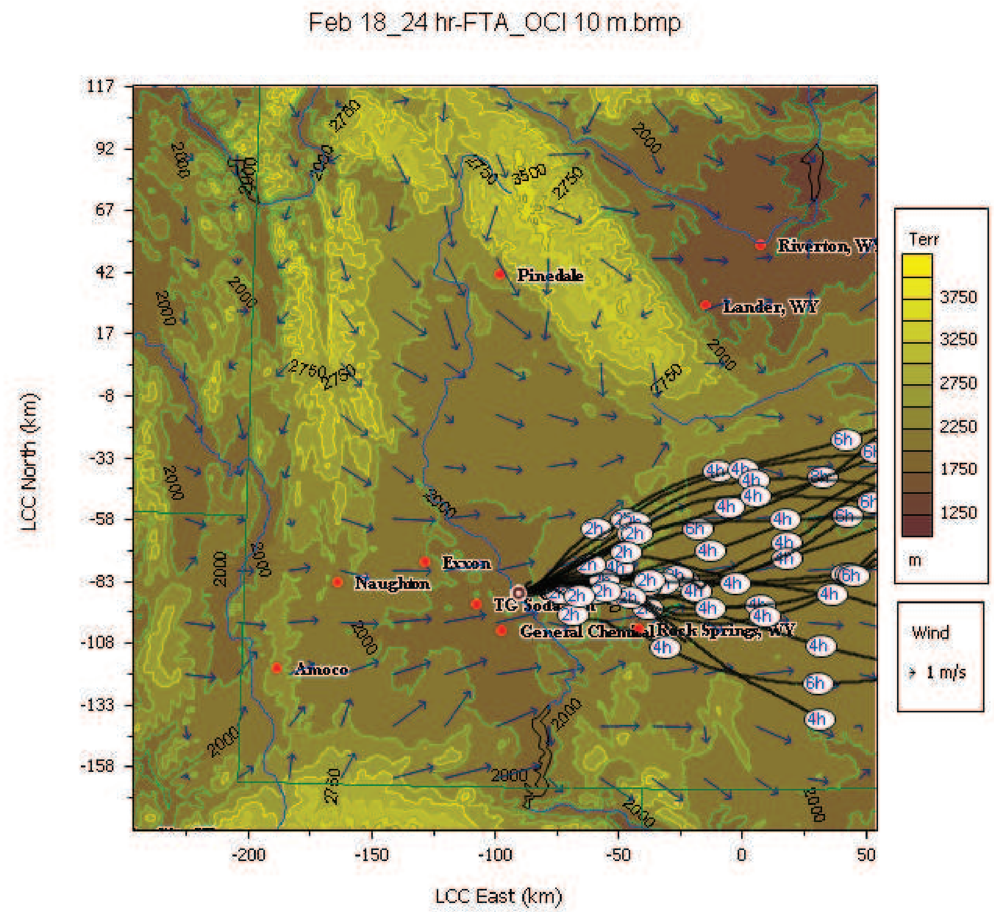


Figure S.7-21. 24-hour forward trajectory analysis at OCI Trona plant on February 18, 2008.

The trajectory analysis in Figure S.7-21 shows all modeled trajectories from OCI not entering the proposed nonattainment area.

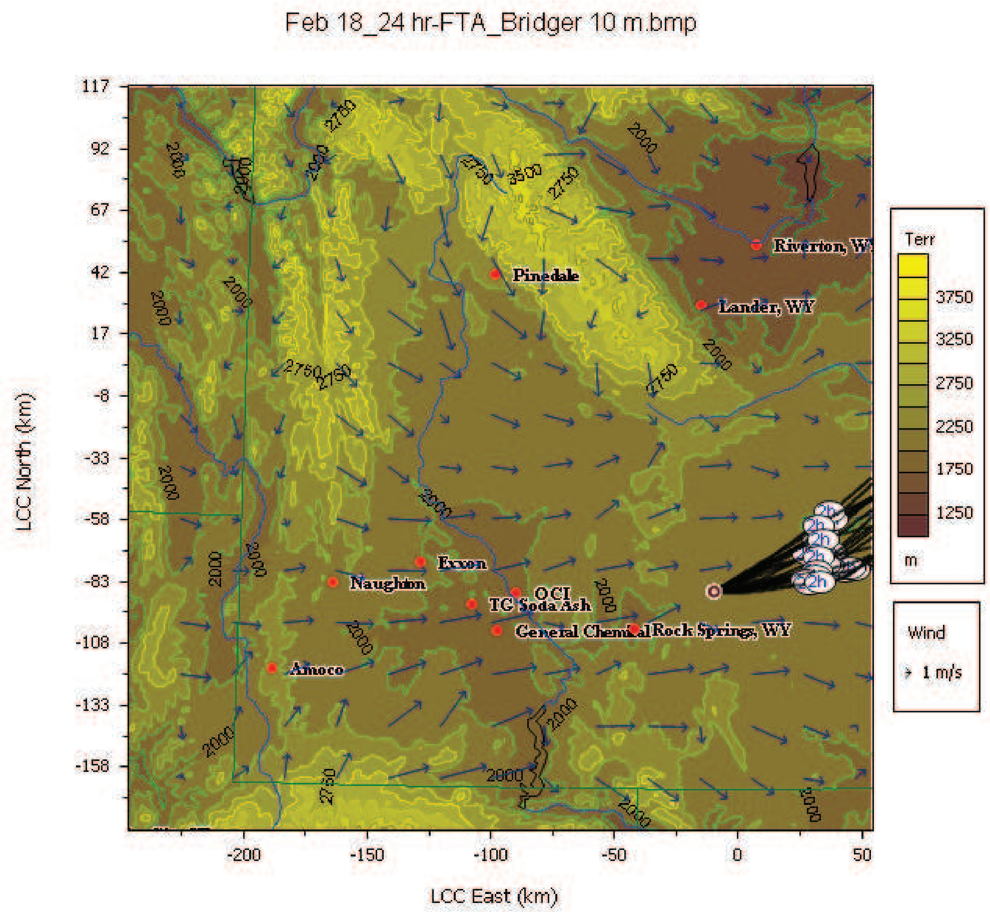


Figure S.7-22. 24-hour forward trajectory analysis at Bridger power plant on February 18, 2008.

The trajectory analysis in Figure S.7-22 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

CalDESK Forward Trajectory Analyses for February 19, 2008 are shown in Figures S.7-23 through S.7-29.

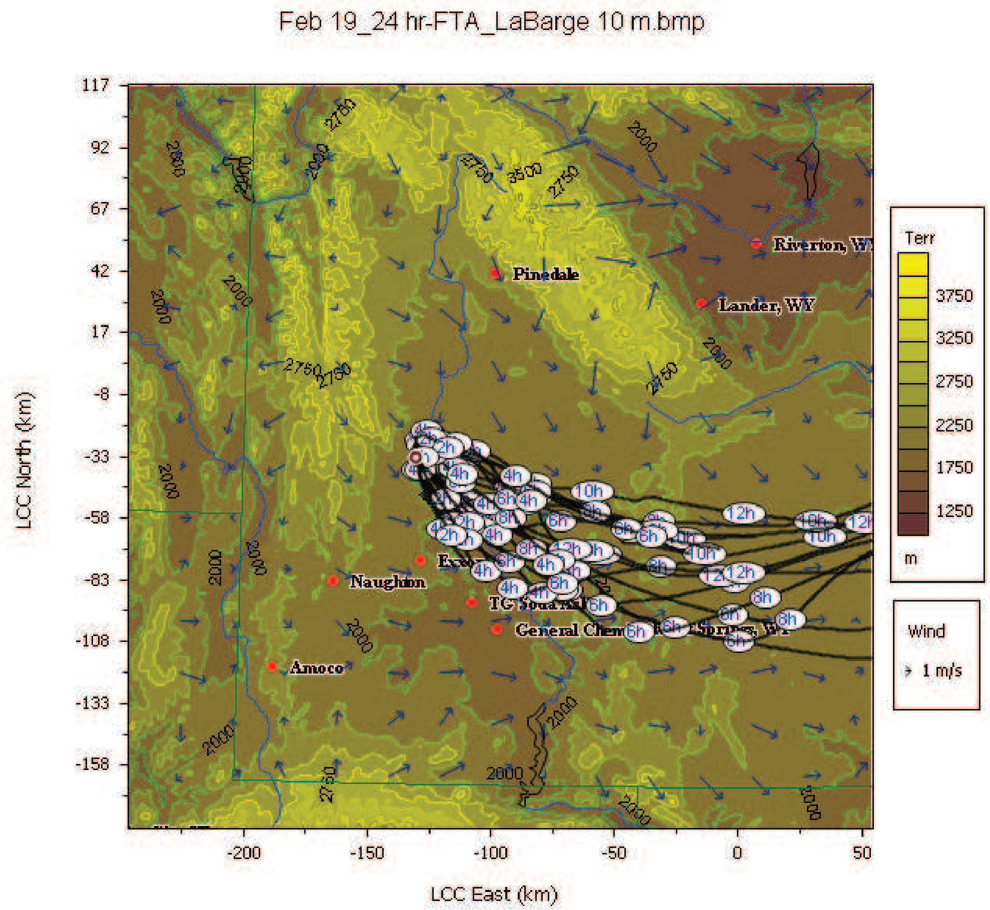


Figure S.7-23. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 19, 2008.

As shown in Figures S.7-23 through S.7-27, the prevailing northwest winds on February 19th continue to limit air parcel transport into the UGRB from the south, which is reflected in the trajectory analysis for the LaBarge and Moxa Arch areas, the Naughton power plant, the OCI Trona processing facility, and the Bridger power plant.

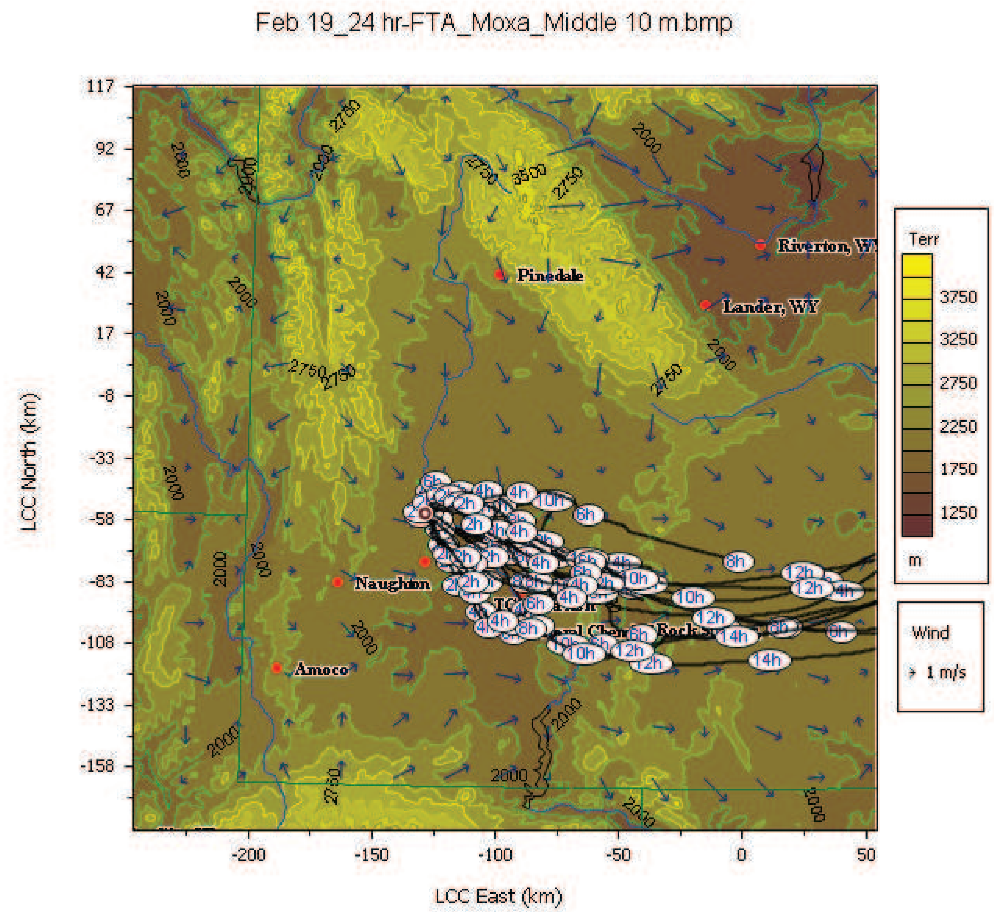


Figure S.7-24. 24-hour forward trajectory analysis in the Moxa Arch area on February 19, 2008.

The trajectory analysis in Figure S.7-24 shows all modeled trajectories from Moxa Arch not entering the proposed nonattainment area.

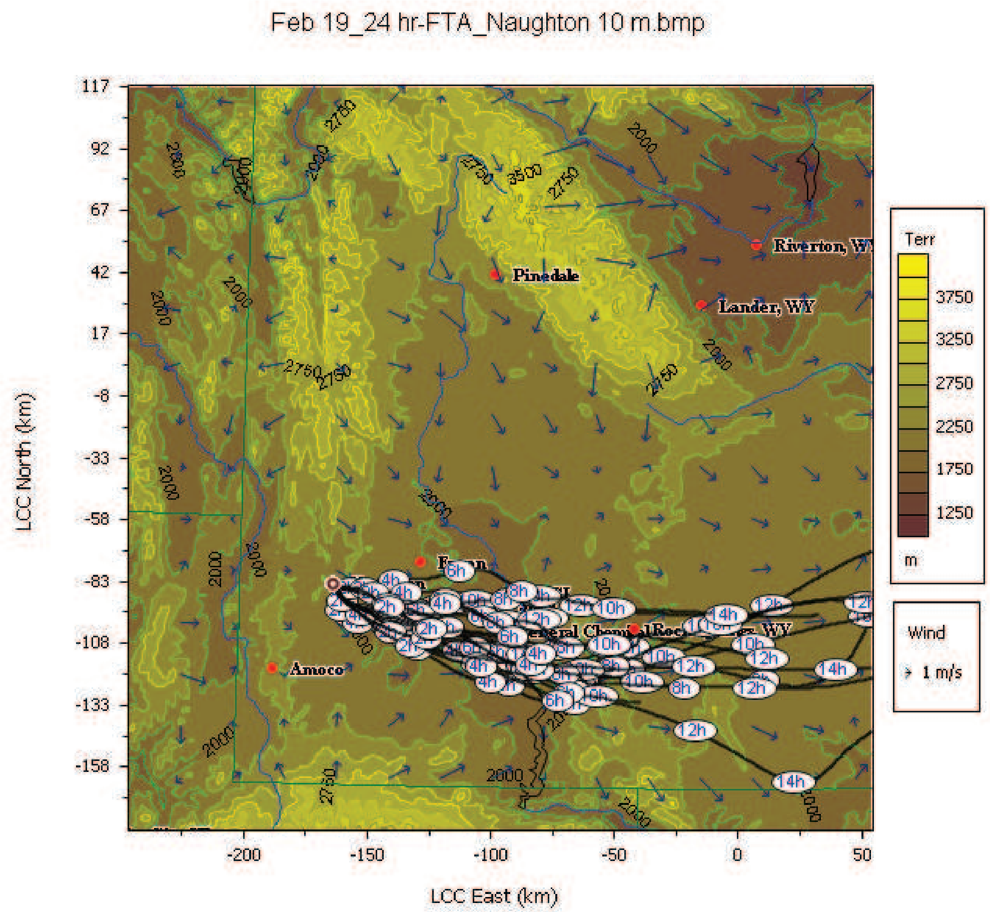


Figure S.7-25. 24-hour forward trajectory analysis at Naughton power plant on February 19, 2008.

The trajectory analysis in Figure S.7-25 shows all modeled trajectories from Naughton not entering the proposed nonattainment area.

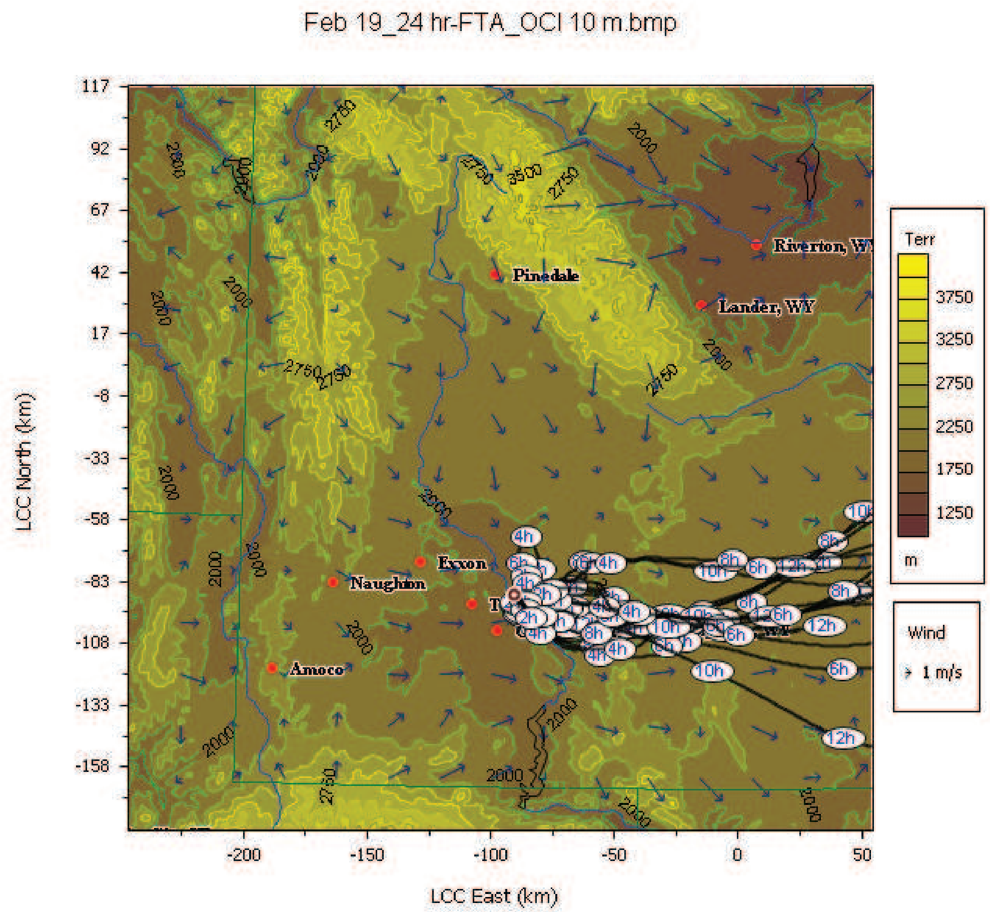


Figure S.7-26. 24-hour forward trajectory analysis at OCI Trona plant on February 19, 2008.

The trajectory analysis in Figure S.7-26 shows all modeled trajectories from OCI not entering the proposed nonattainment area.

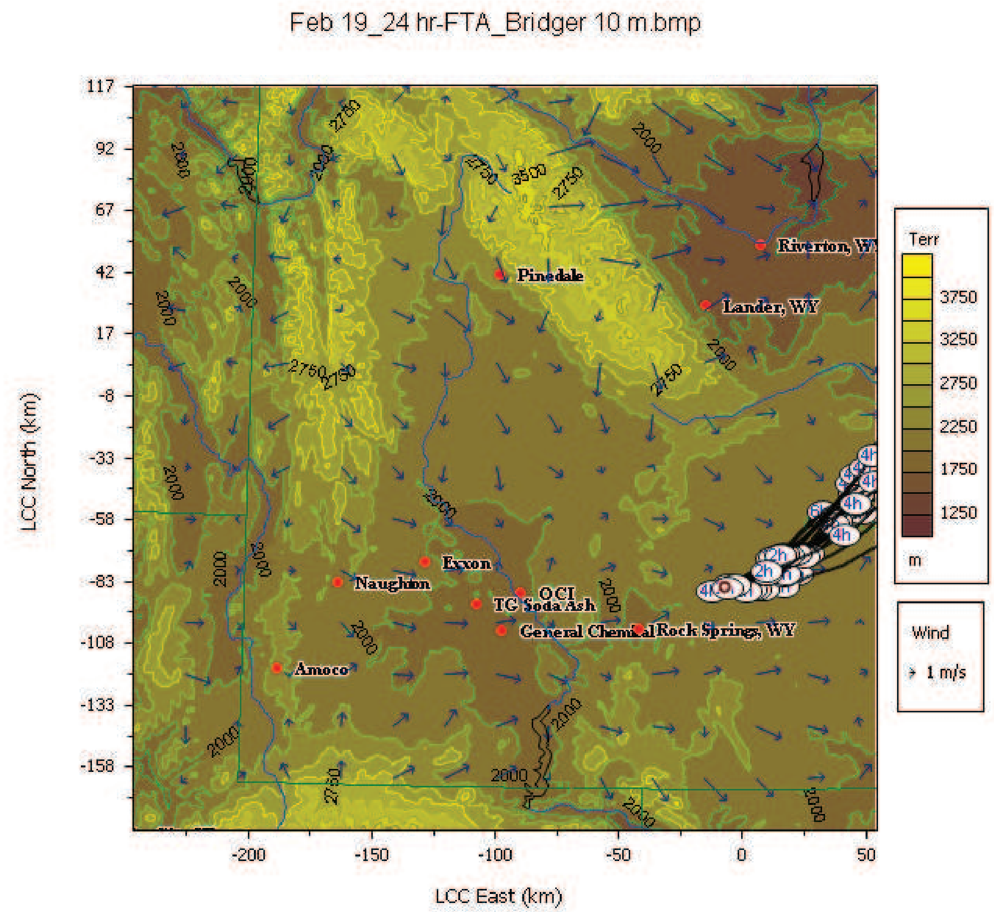


Figure S.7-27. 24-hour forward trajectory analysis at Bridger power plant on February 19, 2008.

The trajectory analysis in Figure S.7-27 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

CalDESK Forward Trajectory Analyses for February 20, 2008 are shown in Figures S.7-28 through S.7-32.

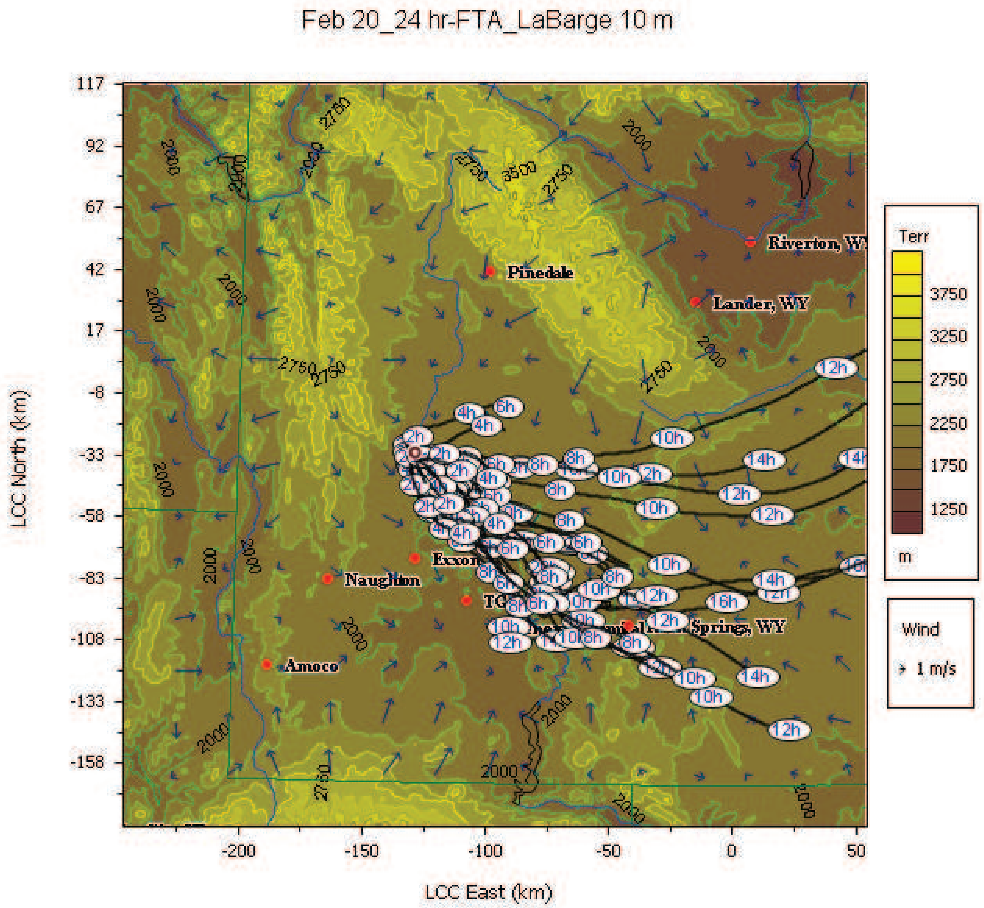


Figure S.7-28. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 20, 2008.

As shown in Figure S.7-28, on February 20, 2008, the trajectory analysis for the LaBarge area begins to exhibit a few possible trajectory paths into the area west of the Jonah oil and gas field, indicating some potential for upwind emissions transport at the Jonah monitor. Figures S.7-29 through S.7-32 show the prevailing northwest winds continue to limit southerly transport of emissions into the UGRB, along with the prevailing southwesterly winds along the Interstate-80 corridor, which are reflected in the trajectory analysis for the Moxa Arch area, the Naughton power plant, the OCI Trona processing facility, and the Bridger power plant.

It is important to note that as the trajectory start point is located further south, and out of the UGRB, the dominant northwest winds taper off, and the airflow at the south end of the UGRB mixes with the prevailing winds along the Interstate-80 corridor, which tend to dominate air parcel transport once the air parcel is out of the UGRB, south of the Wyoming Range terrain influence.

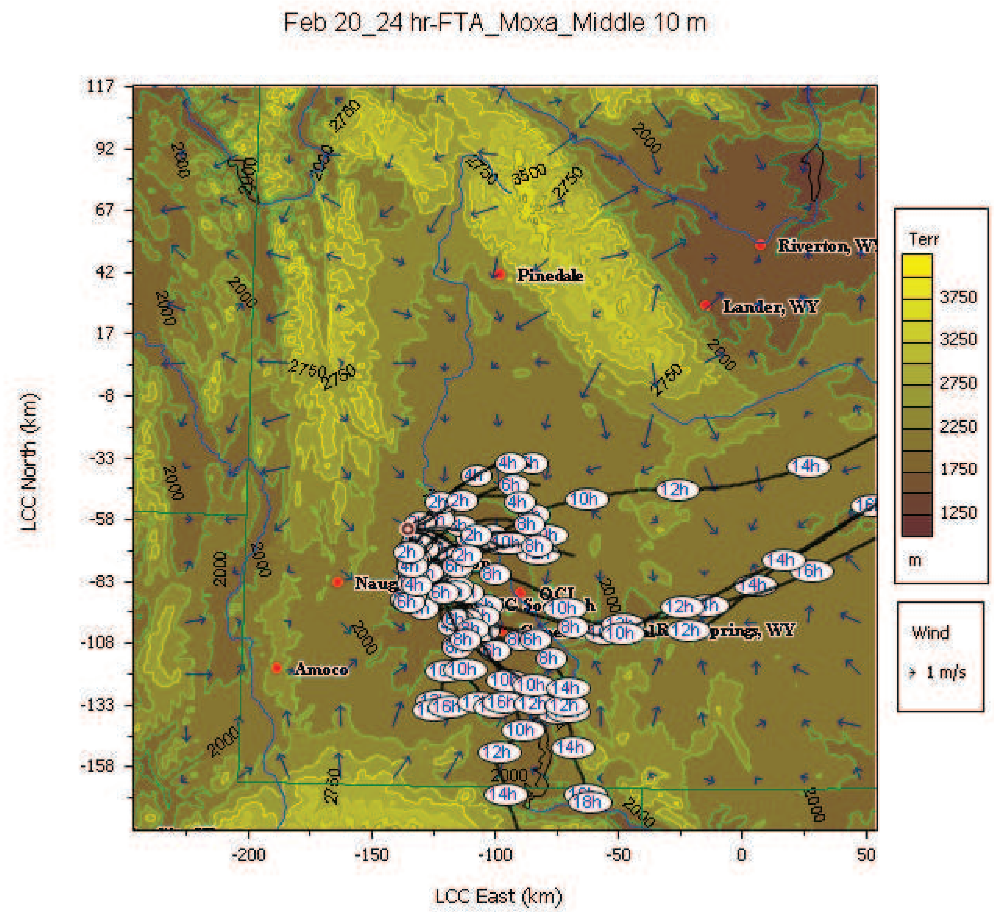


Figure S.7-29. 24-hour forward trajectory analysis in the Moxa Arch area on February 20, 2008.

The trajectory analysis in Figure S.7-29 shows all modeled trajectories from Moxa Arch not entering the proposed nonattainment area.

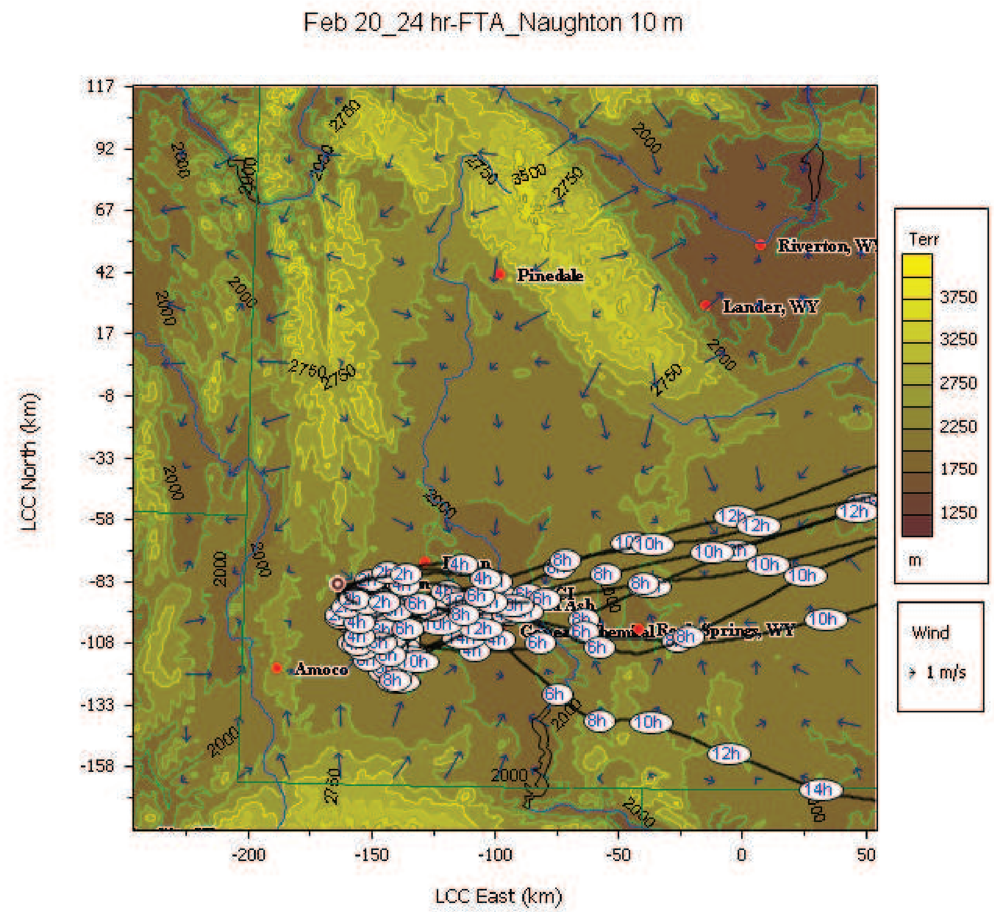


Figure S.7-30. 24-hour forward trajectory analysis at Naughton power plant on February 20, 2008.

The trajectory analysis in Figure S.7-30 shows all modeled trajectories from Naughton not entering the proposed nonattainment area.

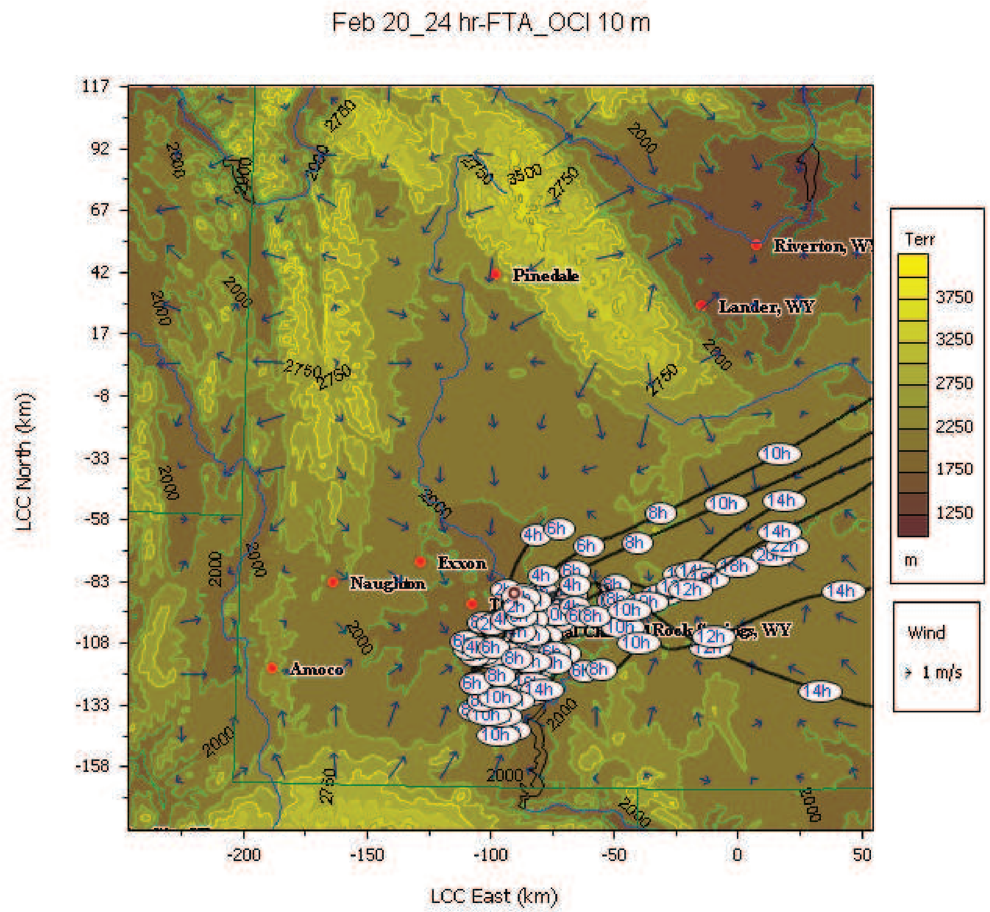


Figure S.7-31. 24-hour forward trajectory analysis at OCI Trona plant on February 20, 2008.

The trajectory analysis in Figure S.7-31 shows all modeled trajectories from OCI not entering the proposed nonattainment area.

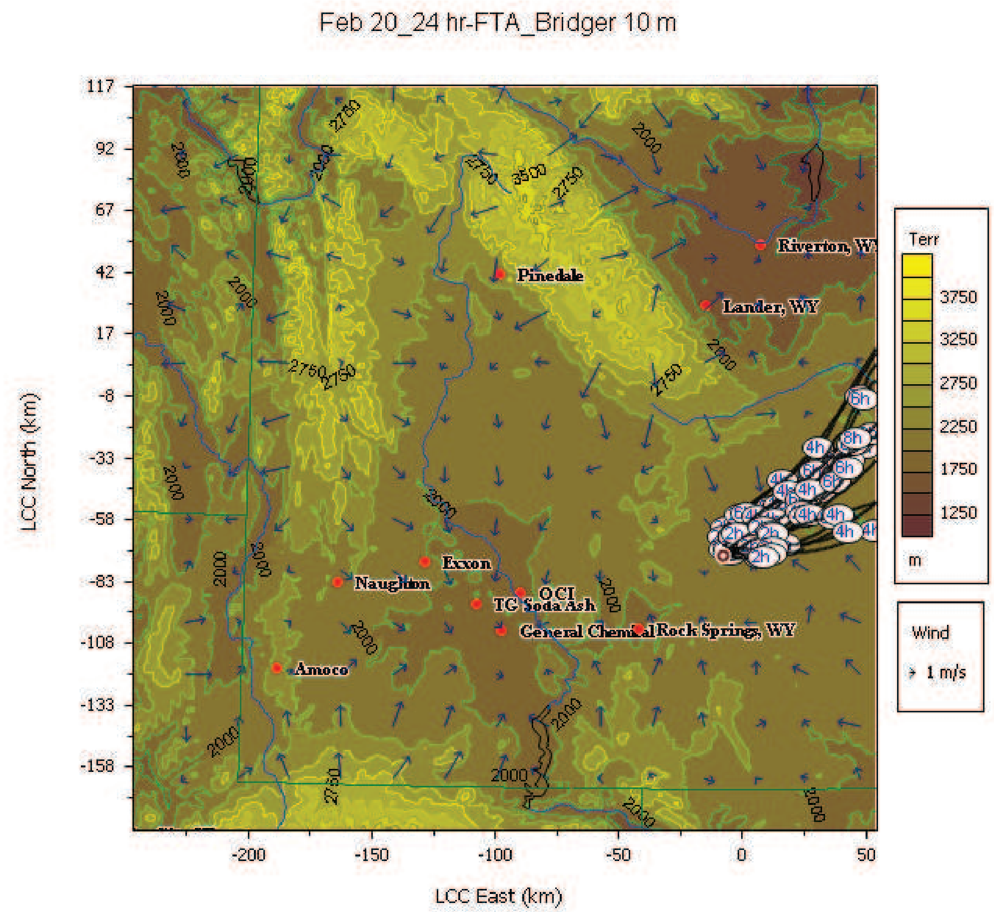


Figure S.7-32. 24-hour forward trajectory analysis at Bridger power plant on February 20, 2008.

The trajectory analysis in Figure S.7-32 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

CalDESK Forward Trajectory Analyses for February 21, 2008 are shown in Figures S.7-33 through S.7-37.

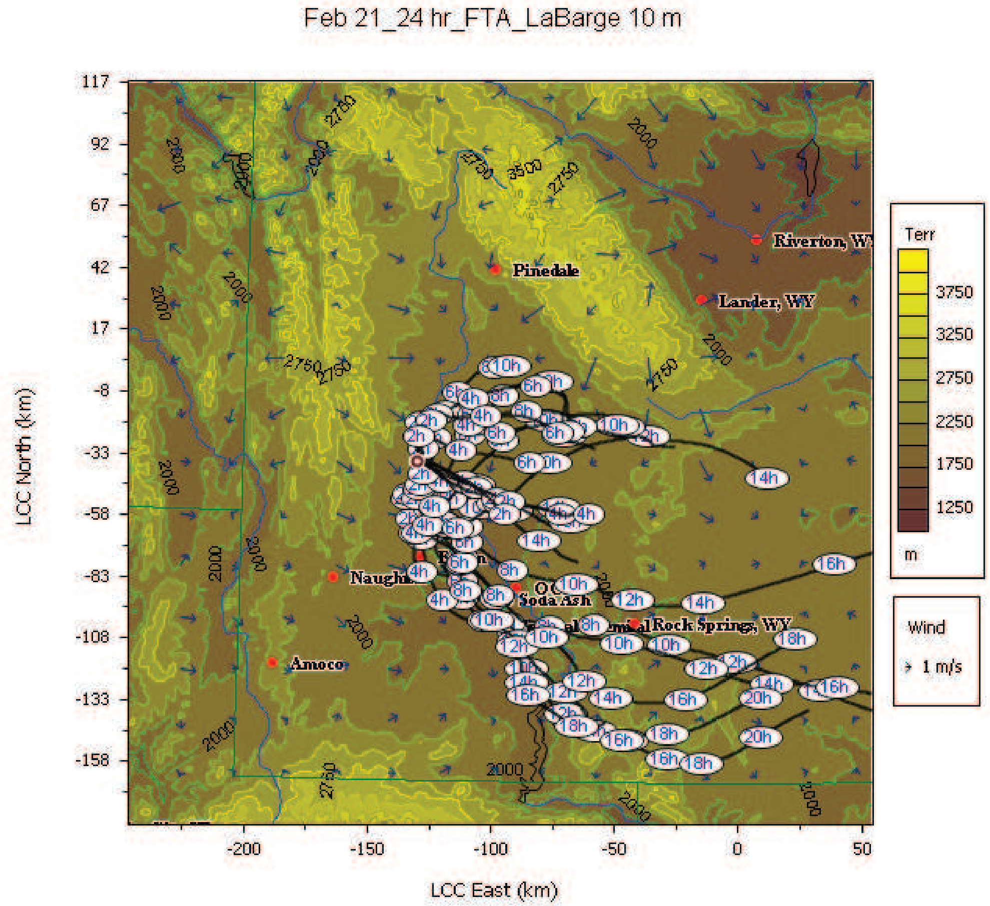


Figure S.7-33. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 21, 2008.

By the afternoon of February 21, 2008, the high pressure ridge had weakened, and had also flattened, and the central ridge axis was over or just east of southwestern Wyoming through the entire day; the resulting light wind stagnant situation also enabled the highest ozone production recorded at the Boulder monitoring site to date. These conditions were monitored during the first IOP, conducted February 18-21, 2008, in which a set of intensive meteorological and ambient measurements were collected when meteorological conditions similar to those associated with high ozone episodes during 2005 – 2006 had been forecast to occur during the 2008 field study.

The low level inversion was not quite as strong as on February 19, 2008, but it did stay intact through the entire daylight period, keeping ground level emissions trapped near the surface. With the very light and variable winds above the inversion, localized flow patterns near the ground level developed during the day allowing emissions to transport along those pathways.

As shown in Figure S.7-33, the trajectory analyses for the LaBarge area exhibit several possible air parcel paths to the northwest on February 21, 2008. Figure S.7-34 shows the trajectory analysis for the Moxa Arch area, which exhibits a few trajectories initially moving into the southernmost portion of the UGRB, but the strong northerly winds in the UGRB dominate the flow. This limits northward air parcel transport into the UGRB, and the vast majority of the trajectories continue to travel south out of the UGRB. The trajectory start point at Moxa Arch is approximately fourteen (14) miles south of the LaBarge trajectory start point, where the dominant northwest wind influence in the UGRB valley is tapering off, and mixes with prevailing westerly winds.

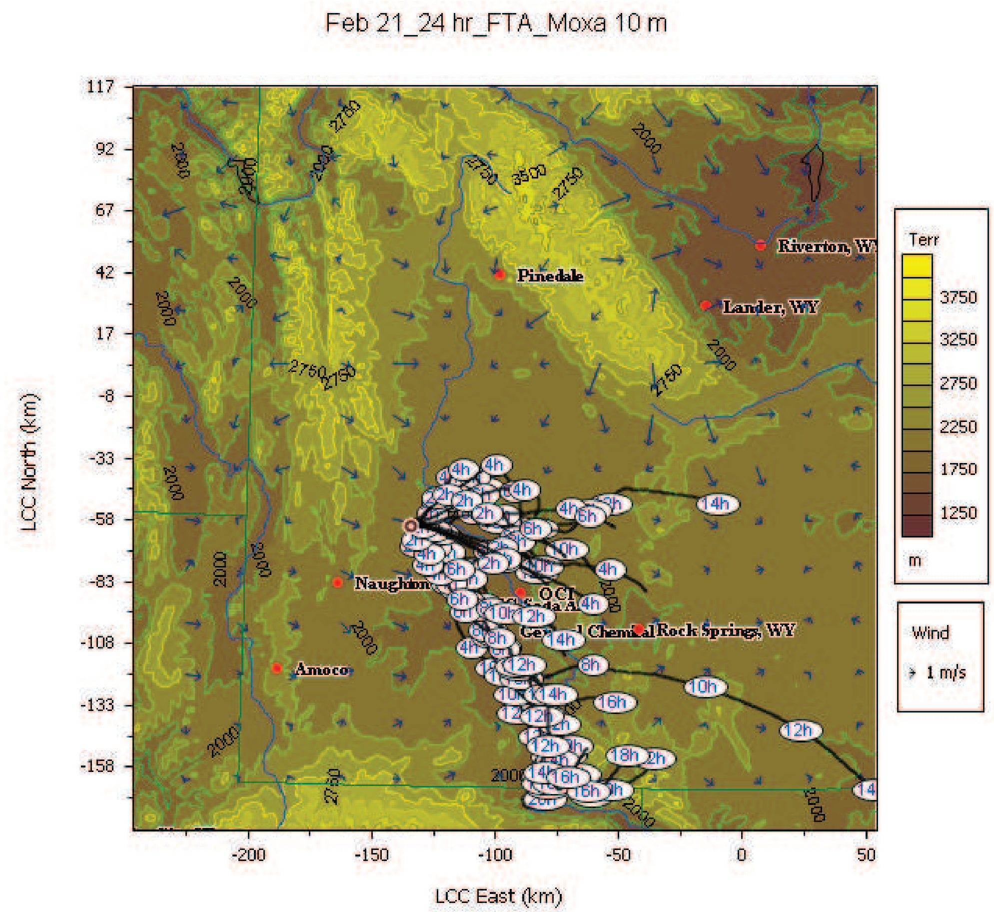


Figure S.7-34. 24-hour forward trajectory analysis in the Moxa Arch area on February 21, 2008.

Figure S.7-35 shows prevailing westerly winds at Naughton with air parcels moving eastward. The strong northwest winds in the UGRB and the terrain blocking effects of the Uinta Range to the south, collectively, influence the trajectory paths as they move from the Naughton power plant trajectory start point. The trajectory analysis in Figure S.7-35 shows all modeled trajectories from Naughton not entering the proposed nonattainment area

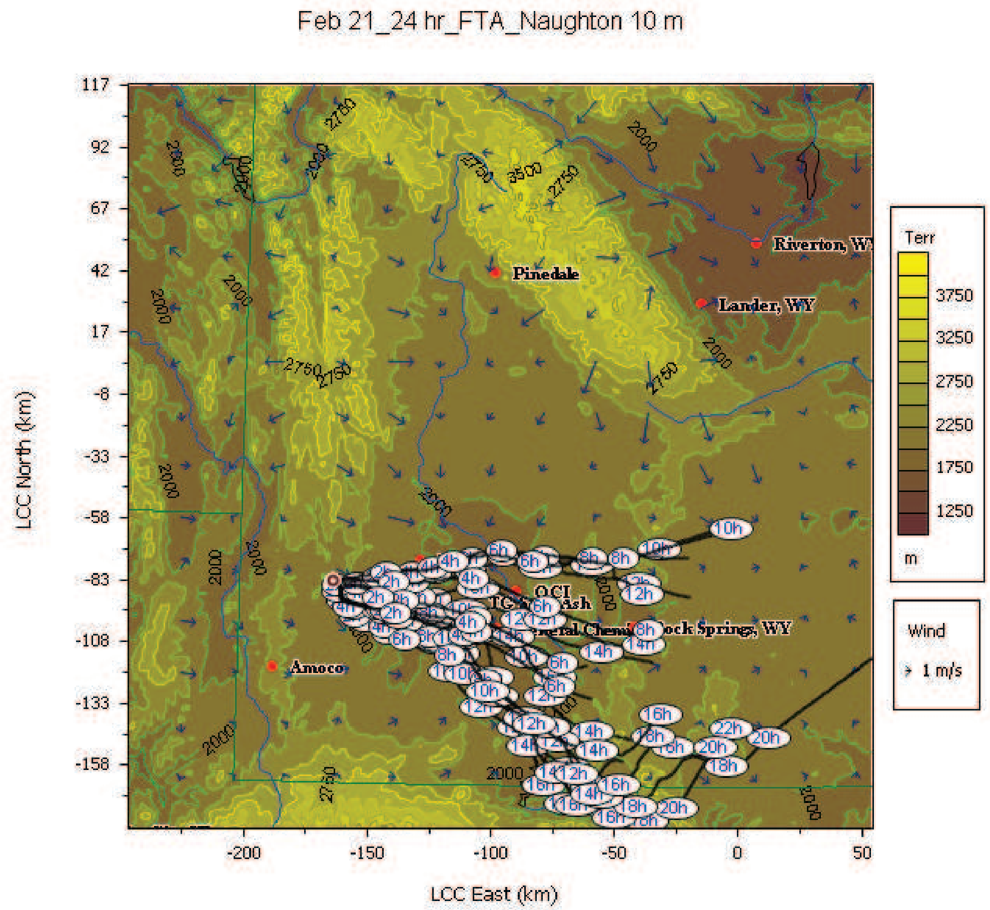


Figure S.7-35. 24-hour forward trajectory analysis at Naughton power plant on February 21, 2008.

Figures S.7-36 and S.7-37 show the prevailing westerly winds at the OCI Trona plant and the Bridger power plant, with the air parcels moving eastward and then northward. As noted with the forward trajectory paths from Naughton power plant, the strong northwest winds in the UGRB and the terrain blocking effects of the Uinta Range to the south continue to influence the trajectory paths as they move from the OCI and Bridger trajectory start points. The trajectory analysis in Figures S.7-36 and S.7-37 shows all modeled trajectories from OCI and Bridger not entering the proposed nonattainment area.

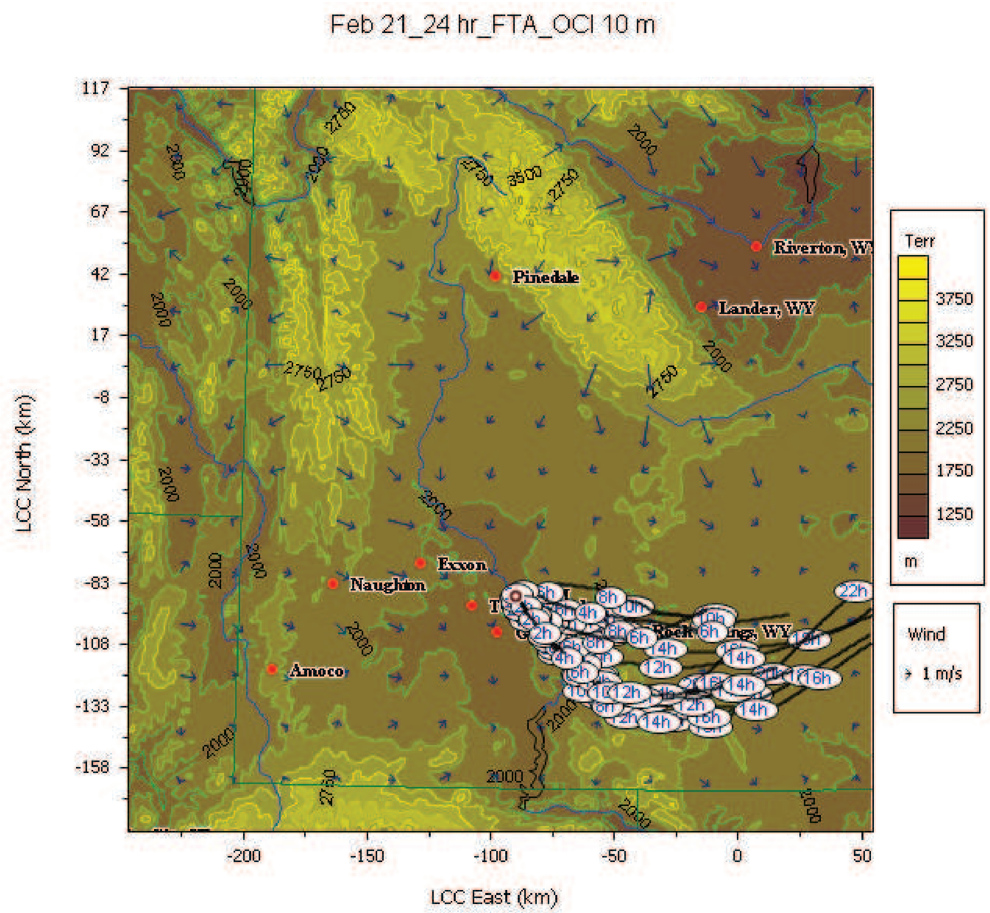


Figure S.7-36. 24-hour forward trajectory analysis at OCI Trona plant on February 21, 2008.

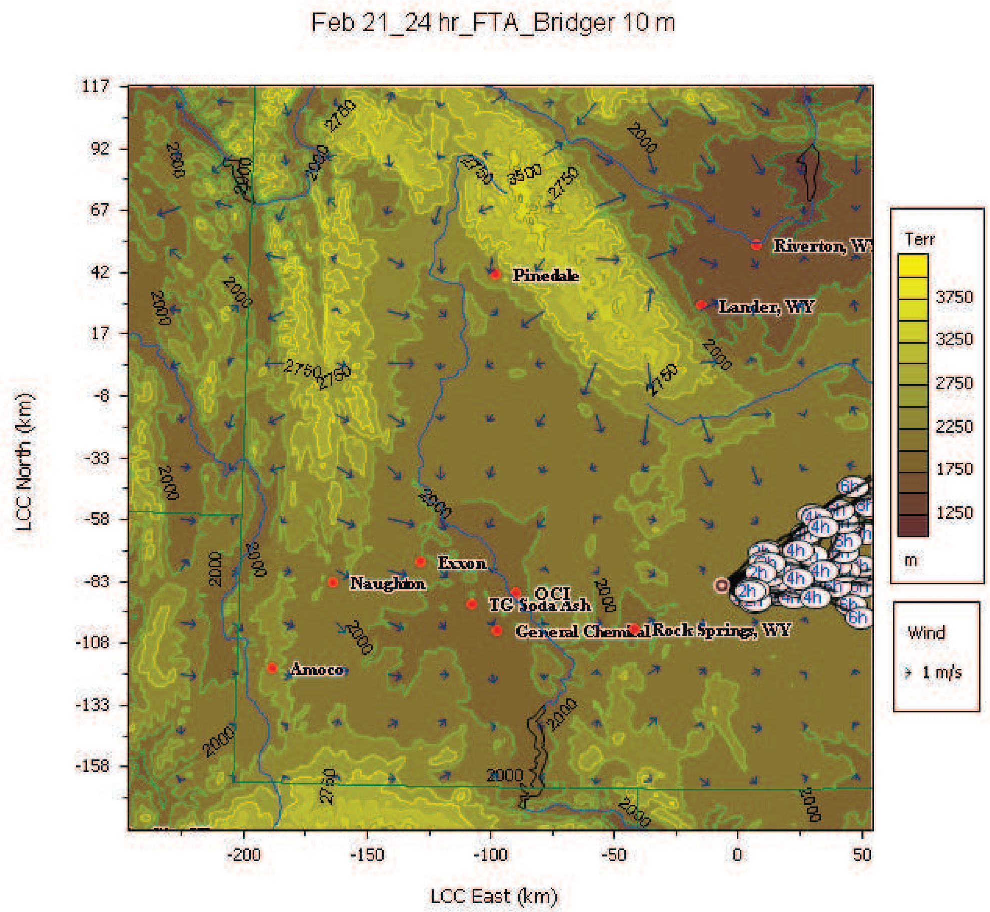


Figure S.7-37. 24-hour forward trajectory analysis at Bridger power plant on February 21, 2008.

As discussed previously, the localized meteorology within the UGRB during the ozone episodes influences air parcel movement within the UGRB, typically leading to shorter trajectory paths than if the trajectories were based on a start point located outside of the UGRB. CalDESK trajectory analyses that are initiated within the UGRB reflect the wind flow reversals and sustained low wind speeds; hence, shorter trajectory paths (and flow recirculation) are produced, which is consistent with the observed wind patterns.

During these wind reversals, the air flow changes direction. The winds are initially out of the northwest in the early morning, then out of the northeast, and then turn such that the winds flow out of the southeast later in the morning; the NW to SE wind flow reversal occurs approximately at 11:00 at the Boulder monitor on February 21, 2008.

CalDESK Forward Trajectory Analyses for February 22, 2008 are shown in Figures S.7-38 through S.7-42.

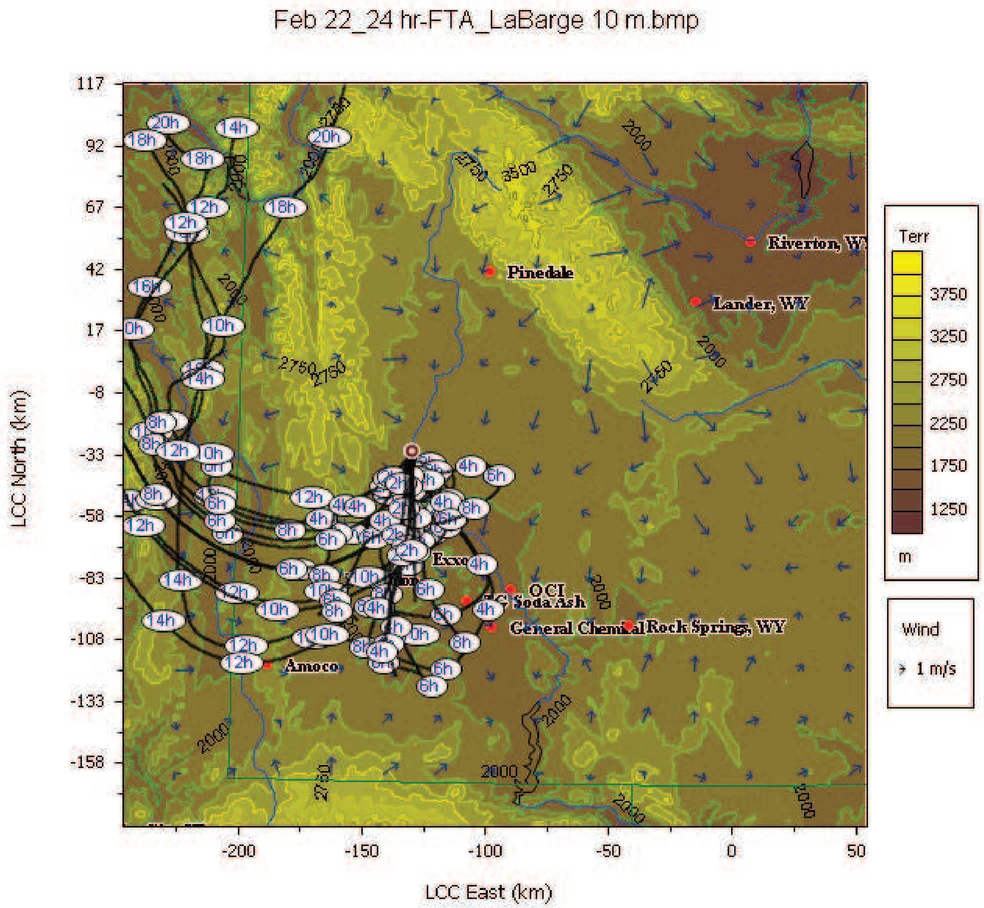


Figure S.7-38. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 22, 2008

The high pressure ridge continued to weaken during February 22, 2008, while a shortwave low pressure trough approached southwestern Wyoming from the northwest. Skies became mostly cloudy during the morning hours and light precipitation spread over the area later in the afternoon. However, the low level inversion stayed intact well into the afternoon, and ozone concentrations remained high during most of the day. No IOP operations were conducted this day because it was anticipated that the stable layer would be mixed-out by the trough by early morning and, therefore, trapped emission would be dispersed. Instead, the late arrival of the trough allowed one more day of high ozone concentrations.

As shown in Figure S.7-38, the trajectory analysis for the LaBarge area shows that most of the possible forward trajectory paths are now moving away from the UGRB during February 22nd. Figures S.7-38 through S.7-40 show air parcels tend to be blocked and channeled westward and then northward around the Wyoming Range, with limited air parcel movement into the UGRB. There are 1-2 trajectory paths showing air parcel movement from the Moxa Arch and Naughton areas into the UGRB, however, the vast majority of the air parcel trajectories do not enter the UGRB, due to the significant terrain blocking and channeling effects of the terrain that make up the Wyoming Range and the Wasatch Range. Terrain blocking and channeling effects can also be seen in Figure S.7-42 in the forward trajectories originating from the OCI Trona plant.

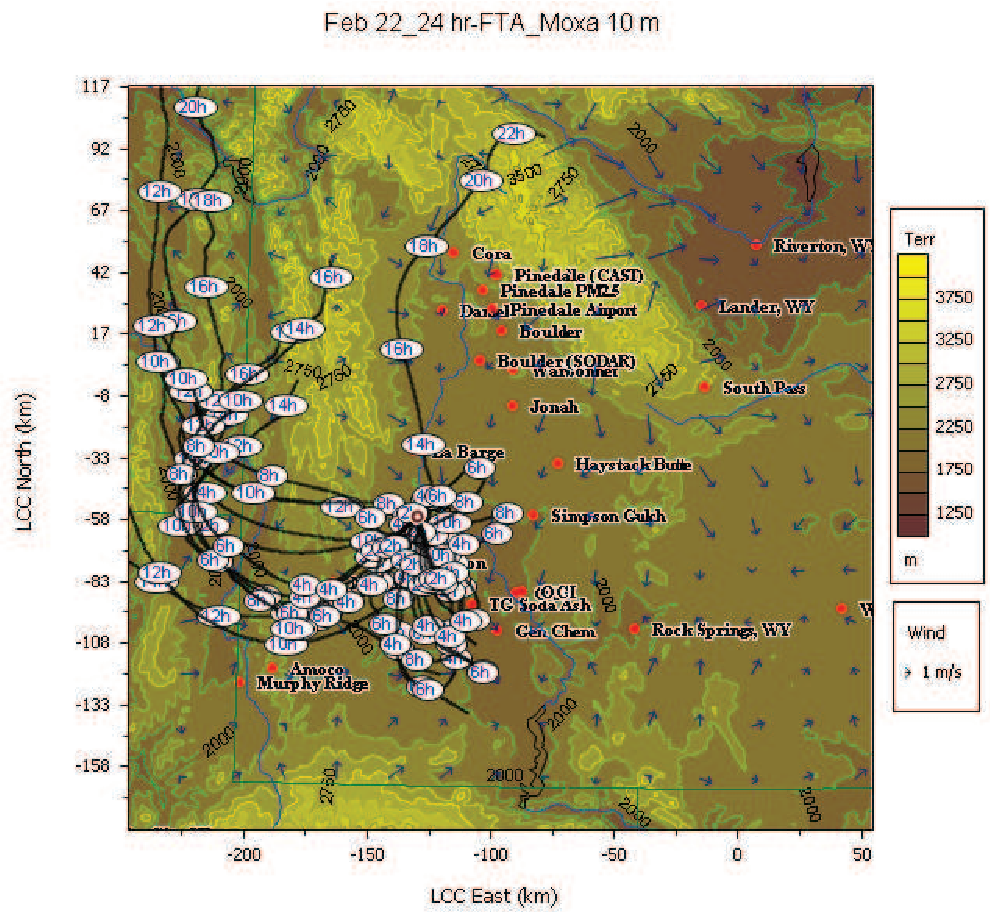


Figure S.7-39. 24-hour forward trajectory analysis in the Moxa Arch area on February 22, 2008.

Figure S.7-39 shows air parcels tend to be blocked and channeled westward and then northward around the Wyoming Range, with limited air parcel movement into the UGRB. There are 1-2 trajectory paths showing air parcel movement from the Moxa Arch into the UGRB, however, the vast majority of the air parcel trajectories do not enter the UGRB, due to the significant terrain blocking and channeling effects of the terrain that make up the Wyoming Range and the Wasatch Range.

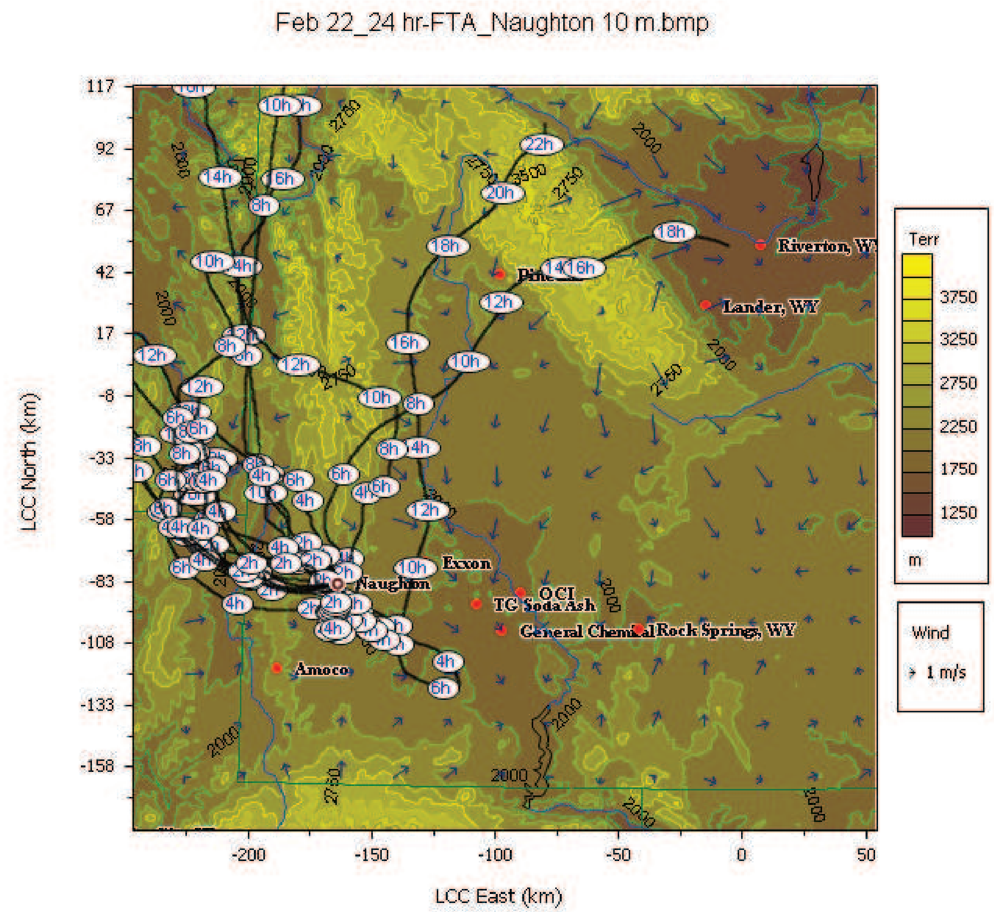


Figure S.7-40. 24-hour forward trajectory analysis at Naughton power plant on February 22, 2008.

There are two forward trajectory paths (2 am and 6 am) which show possible air parcel transport from the Naughton power plant into the UGRB. A 12-hour back trajectory analysis was performed at the Boulder monitor location (2 am – 2 pm) for February 22, 2008 to evaluate potential air parcel trajectories that could reach the Boulder monitor during this same time period (2 am and 6 am). The results of this back trajectory analysis are shown in Figure S.7-41.

Figure S.7-41 shows the calculated back trajectories of air parcels at the Boulder monitor tend to originate from within the UGRB, with very little air parcel movement occurring outside of the UGRB; the air parcels tend to stay within the UGRB during this 12 hour period (2 am – 2 pm) largely due to localized meteorological conditions in the UGRB. The back trajectory analysis in Figure S.7-41 shows a limited potential for sources outside the recommended nonattainment area to affect ozone measured at the Boulder monitor.

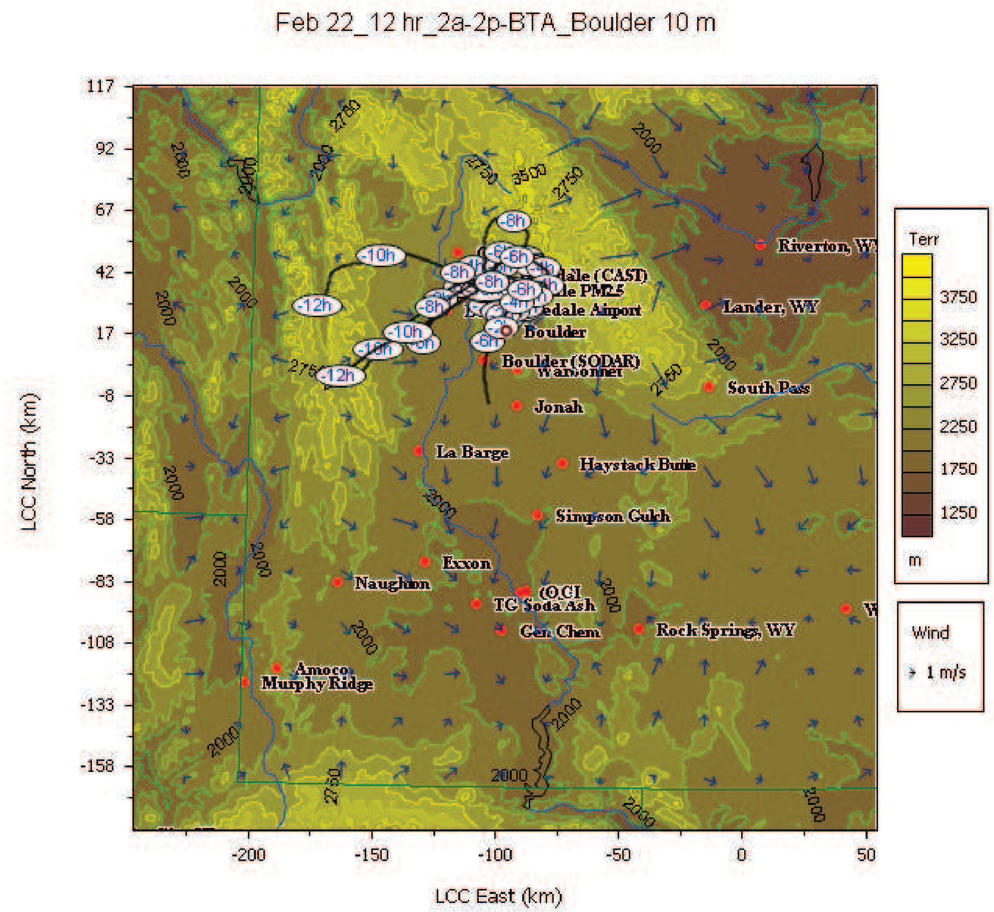


Figure S.7-41. 12-hour back trajectory analysis at Boulder monitor on February 22, 2008.

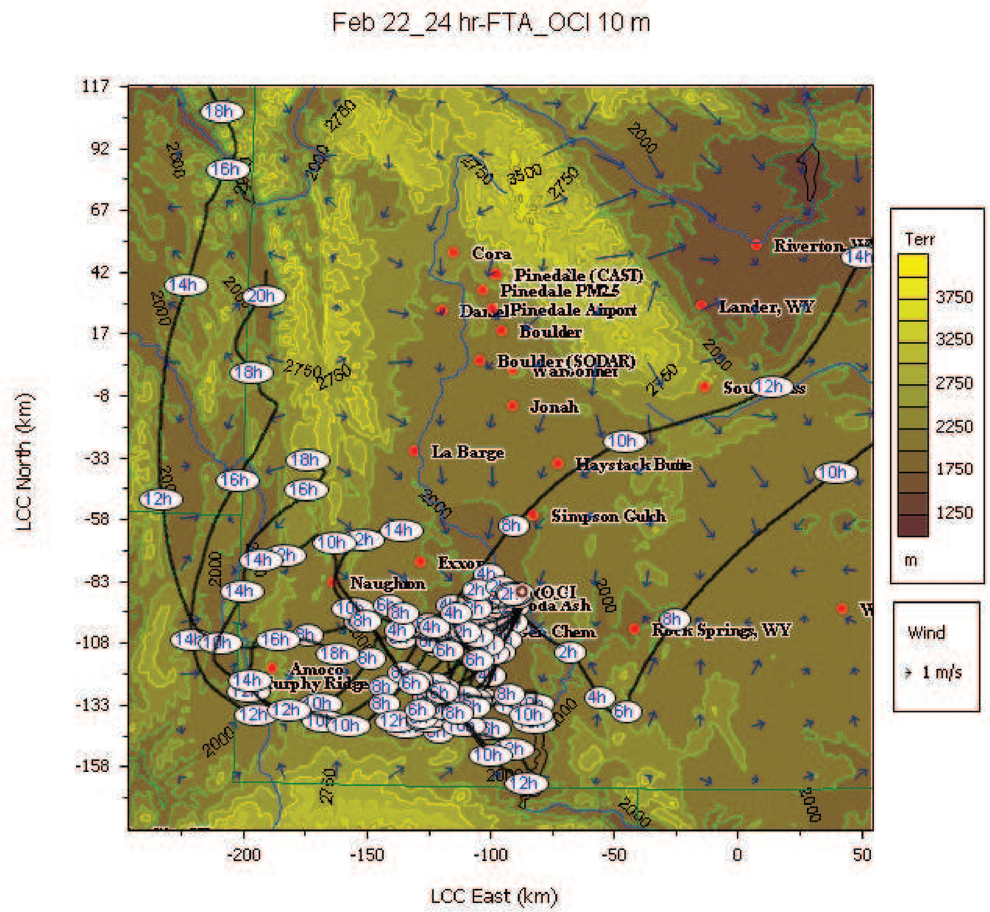


Figure S.7-42. 24-hour forward trajectory analysis at OCI Trona plant on February 22, 2008.

The predominant paths shown in the trajectory analysis shown in Figure S.7-42 trend to the south with northerly component to several of the modeled trajectories. Most of the possible forward trajectory paths are now moving away from the UGRB. Air parcels tend to be blocked and channeled westward and then northward around the Wyoming Range, with limited air parcel movement into the UGRB. There is one trajectory path showing air parcel movement from the OCI toward the UGRB. This trajectory generally parallels the southern boundary of the proposed nonattainment area along Pacific Creek. While some of the trajectory path may lie within the proposed nonattainment area, the path does not indicate that sources at OCI cause or contribute to elevated ozone levels within the proposed nonattainment area.

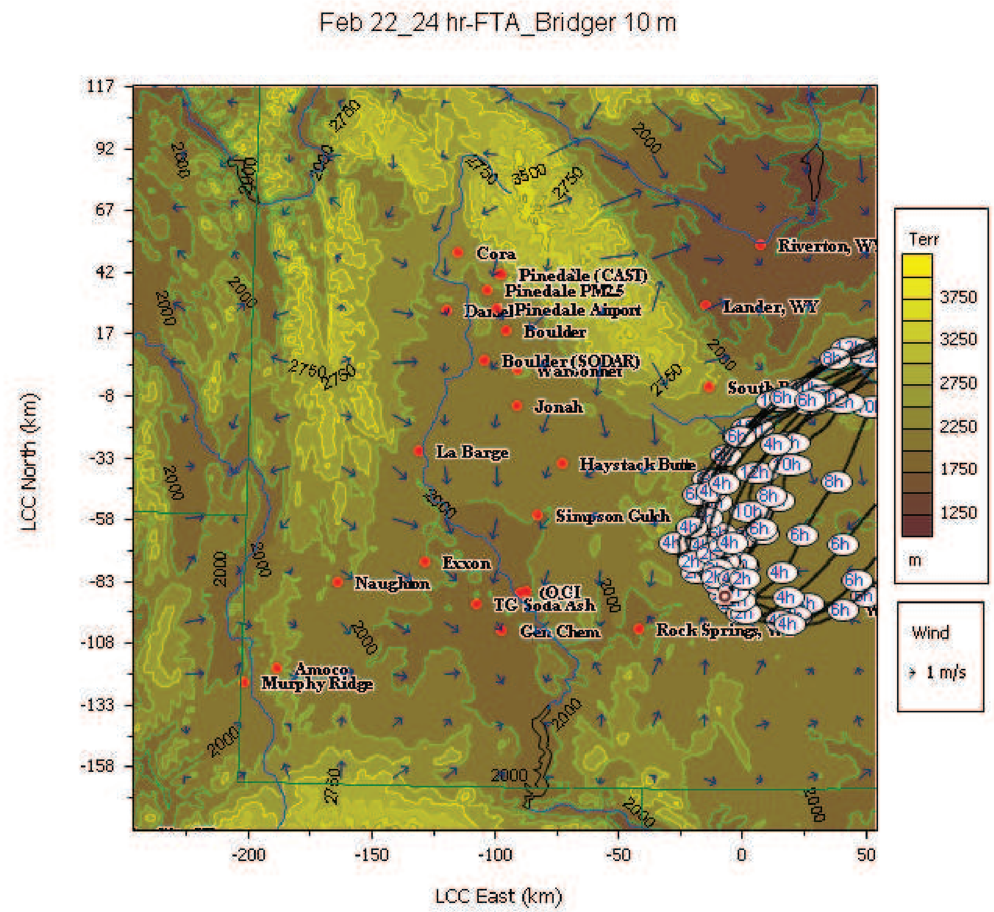


Figure S.7-43. 24-hour forward trajectory analysis at Bridger power plant on February 22, 2008.

The trajectory analysis in Figure S.7-43 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

CalDESK Forward Trajectory Analyses for February 23, 2008 are shown in Figures S.7-44 through S.7-48.

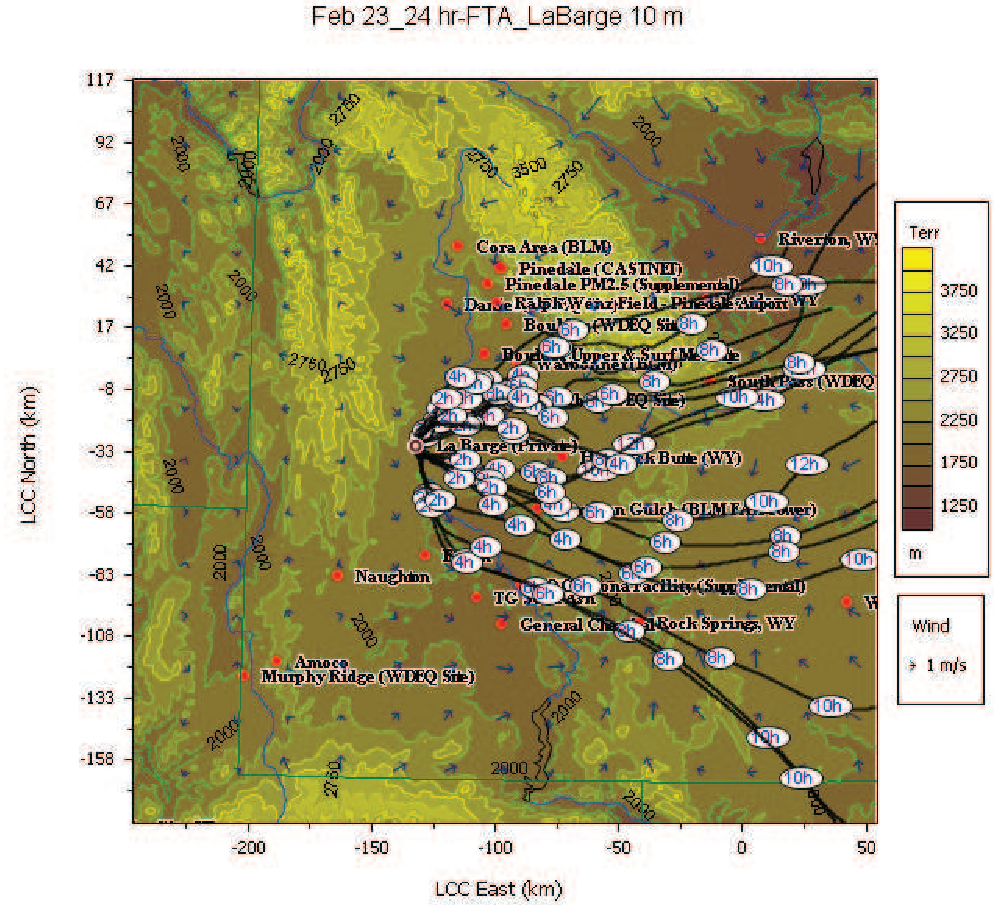


Figure S.7-44. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 23, 2008.

Figure S.7-44 shows the trajectory analysis for the LaBarge area; there are a few forward trajectory paths going northeast during Feb 23, 2008, but most are channeled around the rising terrain at the south end of the UGRB and the Wind River Range. As shown in Figures S.7-45 through S.7-48, the prevailing west and southwest winds generally move air parcels eastward and then northward, as reflected in the trajectory analysis for the Moxa Arch area, the Naughton power plant, the OCI Trona processing facility, and the Bridger power plant.

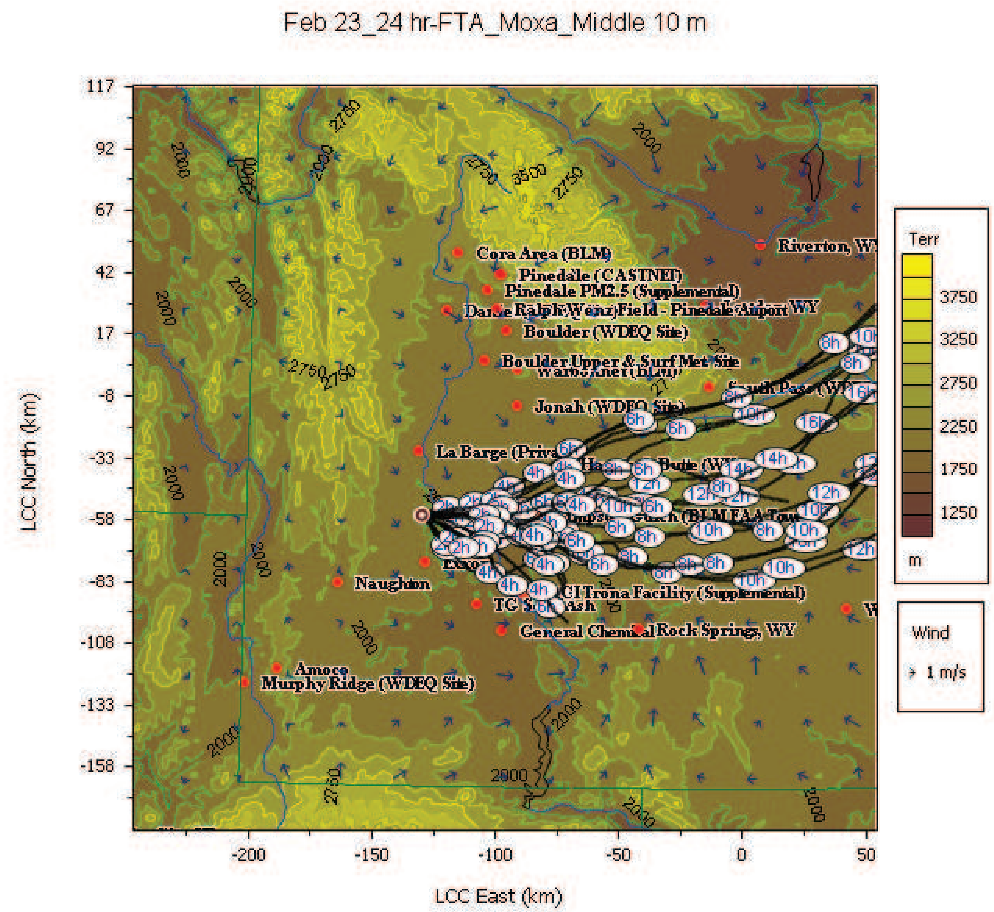


Figure S.7-45. 24-hour forward trajectory analysis in the Moxa Arch area on February 23, 2008.

The trajectory analysis shown in Figure S.7-45 places the initial air parcel release point in the northern part of the Moxa Arch field. The predominant paths shown trend to the east, and there is a slight northerly component to several of the modeled trajectories. These trajectories generally parallel the southern boundary of the proposed nonattainment area along Pacific Creek. While some of the trajectory paths lie within the proposed nonattainment area, none of the paths indicate that sources within the Moxa Arch cause or contribute to elevated ozone levels within the proposed nonattainment area.

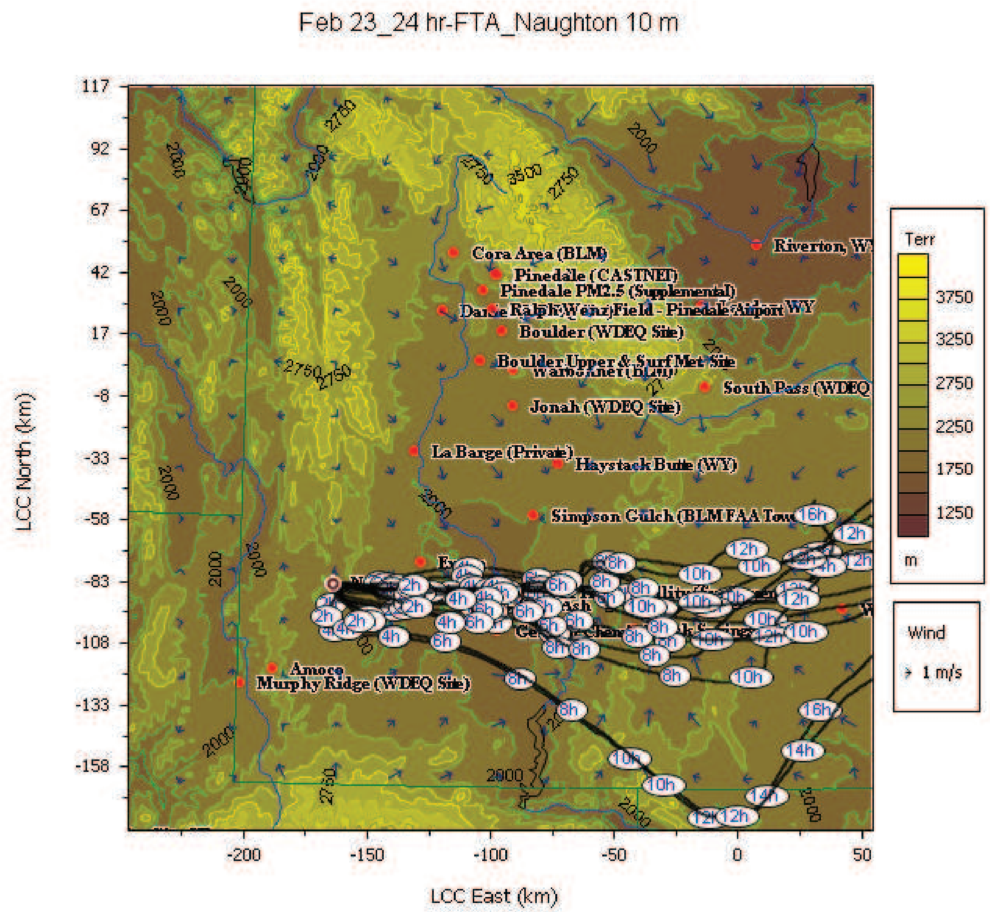


Figure S.7-46. 24-hour forward trajectory analysis at Naughton power plant on February 23, 2008.

The trajectory analysis in Figure S.7-46 shows all modeled trajectories from Naughton not entering the proposed nonattainment area.

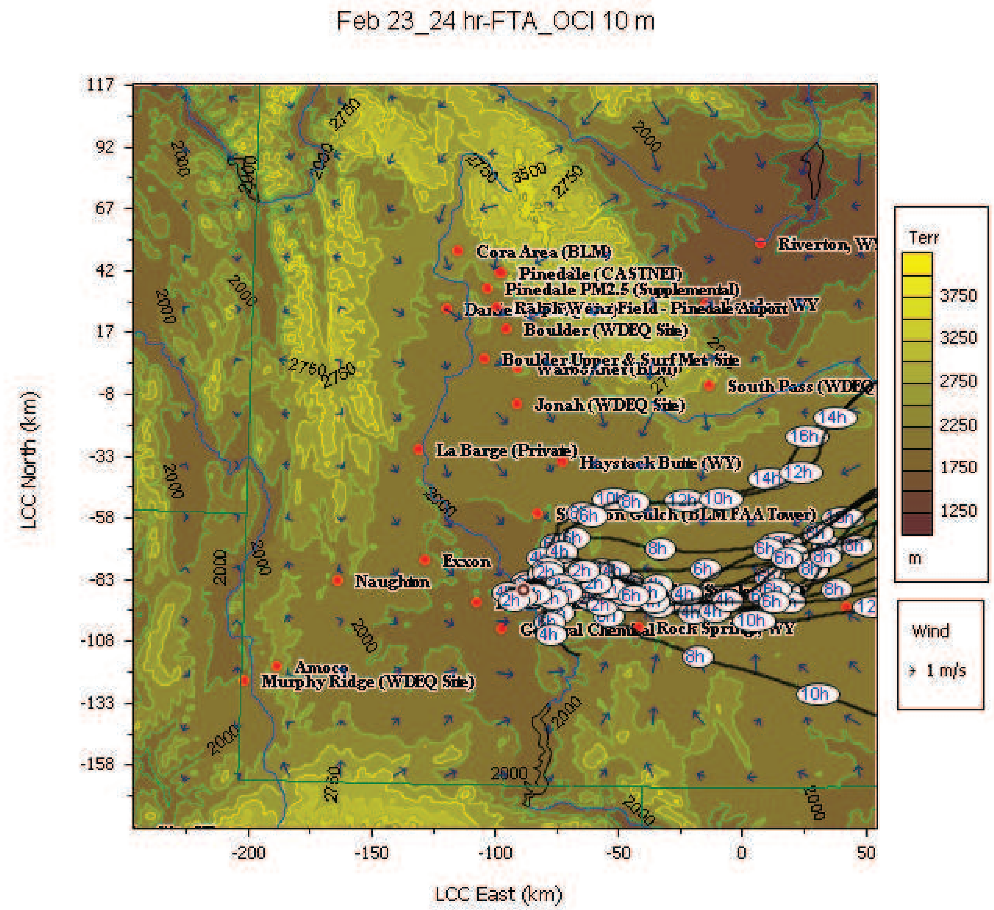


Figure S.7-47. 24-hour forward trajectory analysis at OCI Trona plant on February 23, 2008.

The trajectory analysis in Figure S.7-47 shows all modeled trajectories from OCI not entering the proposed nonattainment area.

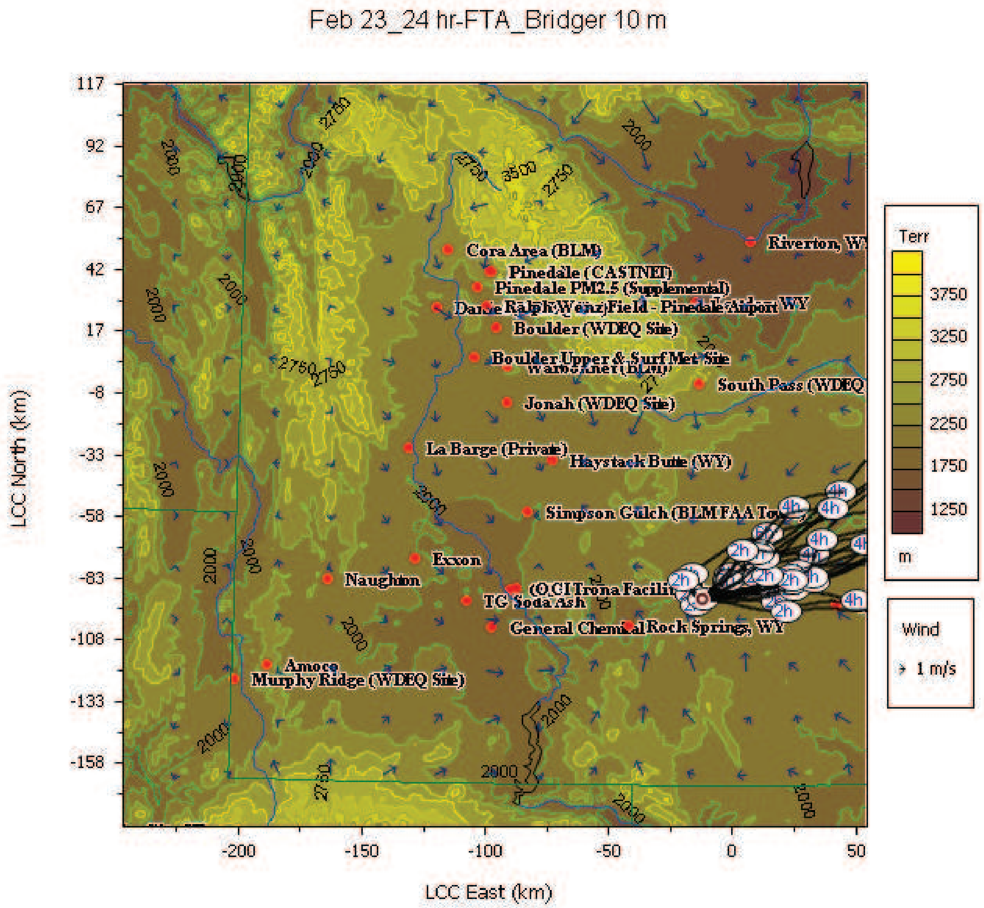


Figure S.7-48. 24-hour forward trajectory analysis at Bridger power plant on February 23, 2008.

The trajectory analysis in Figure S.7-48 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

<u>Summary of Trajectory Analyses</u>

The CalDESK trajectory analyses, based on a three dimensional wind field which incorporates the localized meteorological data collected during the 2008 field study have allowed AQD to evaluate air parcel movement as a means of evaluating precursor emissions and ozone transport into and out of the UGRB. These trajectories indicate that the southern boundary of the recommended nonattainment area defines an appropriate demarcation where emission sources within the nonattainment area may contribute ozone or ozone precursors to the Boulder monitor. Although the Fontenelle Creek, Little Sandy and Pacific drainages are not major topographic features, these drainage areas influence air movement into the UGRB from locations south of the recommended nonattainment area during the February 19-23, 2008 ozone episode and define a reasonable southern boundary for the nonattainment area. AQD has concluded that most, if not all, of the impact on the Boulder monitor just prior to and during these elevated ozone episodes is from emission sources located in the nonattainment area as described in this recommendation.

SECTION 8
JURISDICTIONAL BOUNDARIES

SYNOPSIS

The Sublette County jurisdictional boundary forms the northern and most of the western and eastern boundaries of the recommended nonattainment area. The remainder of the boundary is not jurisdictional but is based on topographical and meteorological considerations.

There is no existing local authority that transcends county boundaries, so the recommended nonattainment area has no single local administrative authority.

ANALYSIS

The Boulder monitor is located in Sublette County. Sublette County is governed by a three-person Commission. There are three incorporated towns in Sublette County: Pinedale, Big Piney and Marbleton. Approximately 80% of the land in Sublette County is owned by the government: BLM-40%; USFS-36%; State of Wyoming-4%. Federal and state land ownership in the surrounding counties follows a similar pattern.

The evaluation of the nonattainment area began with the Sublette County jurisdictional area as the presumptive boundary. This is consistent with EPA guidance in the December 4, 2008 memorandum which states: "Where a violating monitor is not located in a CBSA" (Core Based Statistical Area) "or CSA," (Combined Statistical Area) "we recommend that the boundary of the county containing the monitor serve as the presumptive boundary for the nonattainment area." The Boulder monitor is not in a CBSA or CSA.

The recommended nonattainment area includes all of Sublette County; the portion of Lincoln County northeast of the waterways of Aspen, Fontenelle, and Roney Creeks and northeast of Fontenelle Reservior and the Green River; and the portion of Sweetwater County northwest of the waterways of the Green River, the Big Sandy River, Little Sandy Creek, Pacific Creek, and Whitehorse Creek (see the detailed description in the introduction). This area includes the town of LaBarge in Lincoln County. The southern boundary of the recommended nonattainment area is defined based on topographical and meteorological considerations rather than jurisdictional boundaries. The Sublette County borders to the north, east, and west follow topographic features (mountain ranges) and are appropriate boundaries for the nonattainment area.

The six counties in Southwest Wyoming which were also included in the analysis are: Teton, Lincoln, Uinta, Sweetwater, and Fremont. Two Indian Tribal Nations are also located in the area, the Northern Arapahoe and Eastern Shoshone, at the Wind River Reservation in Fremont County. The reservation and the counties are shown in Figure S.1-1.

The recommended nonattainment area boundary does not fall under single authority, other than the State of Wyoming.

SECTION 9
LEVEL OF CONTROL OF EMISSION SOURCES

SYNOPSIS

Wyoming's NSR Program ensures that Best Available Control Technology (BACT) is utilized to reduce and eliminate air pollution emissions. Wyoming is fairly unique in that BACT is applied statewide to all new sources, both major sources and minor sources. Since 1995 all oil and gas production units that were constructed on or after May of 1974 require permits and BACT is utilized. In two of the gas fields in the proposed nonattainment area, more restrictive emission control requirements are already in effect. Wyoming has been focused on controlling emissions from oil and gas sources and has one of the most innovative and effective control programs in the nation.

While offset programs are traditionally limited to major source applications, the AQD issued an interim policy in August 2008 requiring offsets of ozone precursor emissions whenever a permit is issued for a new or modified source in Sublette County, regardless of major source applicability. This policy results in a net decrease in emissions of ozone precursors with every permit that is issued. This policy took effect after the ozone exceedances were recorded in the winter of 2008.

Data is not available for 2009, so it is too early to say with certainty whether this policy has contributed to reduced ozone concentrations at the Boulder monitor.

ANALYSIS

New Source Review Program

Wyoming's New Source Review (NSR) Program is a statewide permit program for the construction of new sources and modification of existing sources as established by Wyoming Air Quality Standards and Regulations (WAQSR) Chapter 6, Section 2, Permit requirements for construction, modification and operation and Chapter 6, Section 4, Prevention of significant deterioration. The primary purpose of the NSR Program is to assure compliance with ambient standards set to protect public health, assure that Best Available Control Technology is utilized to reduce and eliminate air pollution emissions, and to prevent deterioration of clean air areas. Any amount of air contaminant emissions from a facility subjects it to Wyoming's NSR Program.

Best Available Control Technology

Due to a desire to maintain and improve Wyoming's air quality, the Best Available Control Technology process is applied statewide to new sources, both major sources and minor sources, under the Wyoming NSR Program's permitting process. The BACT process is most appropriately defined as the elimination of pollutants from being emitted into the air whenever technically and economically feasible to do so. While the Air Quality Division takes the State and federally-required BACT review in the Prevention of Significant Deterioration (PSD) permitting actions seriously, AQD takes the State-required BACT review in minor source permitting actions equally as seriously, as the bulk of AQD's permit applications are for minor sources.

Control of Oil and Gas Production Sources

Within the recommended nonattainment area, the bulk of the NSR Program activity is due to oil and gas production and is permitted per the *Oil and Gas Production Facilities Chapter 6, Section 2, Permitting Guidance* discussed below. The remainder of the activity is attributed to facility types such as the compressor stations, asphalt plants and crushing and screening operations, which are permitted per Chapter 6, Section 2 and Chapter 6, Section 4 as described above.

In October 1995, AQD initiated a program to ensure that all oil and gas production units in southwest Wyoming, as well as the entire state, that were constructed since May of 1974 (the effective date of Wyoming's NSR Permit Program) were permitted and that BACT is utilized to control or eliminate emissions from both major and minor sources. To guide oil and gas producers through the NSR permitting process, AQD developed an oil and gas industry guidance document (Guidance) that was released in June of 1997. The Guidance has been revised several times since it was originally released in June of 1997. The most recent revision took effect in August of 2007 and includes requirements that apply statewide as well as specifically to the Jonah and Pinedale Anticline Development (JPAD) Area. The emphasis of the Guidance relies on a "Presumptive BACT" process, which results in more emissions being controlled earlier in the life of the production site. This is accomplished by allowing start up or modification of the production site to occur prior to obtaining a construction permit, provided the operators of such facilities meet certain emission control requirements, including timely installation of controls, which have been established through the Presumptive BACT process. Within the JPAD Area, emission control requirements are more restrictive and become effective upon start up or modification of the production site.

Under the WAQSR, applicants for permits are required to demonstrate to the Administrator of the Air Quality Division, that "[t]he proposed facility will not prevent the attainment or maintenance of any ambient air quality standard." [WAQSR Chapter 6, Section 2(c)(ii)] To allow applications for new or modified emission sources of VOC and/or NOx to be processed while the Division and industry initiatives are taken to reduce the overall emission levels for VOC and/or NOx in Sublette County, AQD adopted the *Interim Policy on Demonstration of Compliance with WAQSR Chapter 6, Section 2(c)(ii) for Sources in Sublette County* on July 21, 2008. The Interim Policy describes options that AQD will consider as an adequate WAQSR Chapter 6, Section 2(c)(ii) demonstration for permit applications (i.e., new as well as applications currently under AQD analysis) for new or modified emission sources in Sublette County.

Options for the Chapter 6, Section 2(c)(ii) demonstration include:

a. Ambient ozone modeling for any application requesting increases in VOCs and/or NOx emissions.
b. Emission reductions for VOCs and/or NOx emissions.

c. Applicants may propose alternate innovative demonstrations to the AQD.

To date, most applicants have chosen to offset VOC and/or NOx emissions and permit conditions have been established to make the commitments to control emissions federally enforceable.

During the implementation of the Interim Policy, other long-term approaches (e.g., development of a regional ozone model and implementation of additional control strategies) to deal with unacceptable ozone levels in the recommended nonattainment area, will continue to be pursued by AQD.

<u>Statewide and Industry-wide Control of Volatile Organic Compounds (VOC)</u>

WAQSR Chapter 13 establishes minimum requirements for motor vehicle emission control.

The following federal rules which are incorporated by reference in WAQSR Chapter 5 by reference contain performance or emission standards for VOCs that may apply to sources within the recommended nonattainment area and in adjacent areas:

40 CFR Part 60, Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971

40 CFR Part 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

40 CFR Part 60, Subpart Db - Standards of Performance for Industrial- Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart I - Standards of Performance for Hot Mix Asphalt Facilities

40 CFR Part 60, Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978

40 CFR Part 60, Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984

40 CFR Part 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines

40 CFR Part 60, Subpart WWW - Standards of Performance for Municipal Solid Waste Landfills

40 CFR Part 63, Subpart F - National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry

40 CFR Part 63, Subpart H - National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks

40 CFR Part 63, Subpart M - National Perchloroethylene Air Emission Standards for Dry Cleaning Facilities

40 CFR Part 63, Subpart R - National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

40 CFR Part 63, Subpart T - National Emission Standards for Halogenated Solvent Cleaning

40 CFR Part 63, Subpart HH - National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities

40 CFR Part 63, Subpart OO - National Emission Standards for Tanks - Level 1

40 CFR Part 63, Subpart PP - National Emission Standards for Containers

40 CFR Part 63, Subpart QQ - National Emission Standards for Surface Impoundments

40 CFR Part 63, Subpart RR - National Emission Standards for Individual Drain Systems

40 CFR Part 63, Subpart SS - National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process

40 CFR Part 63, Subpart TT - National Emission Standards for Equipment Leaks - Control Level 1

40 CFR Part 63, Subpart UU - National Emission Standards for Equipment Leaks - Control Level 2 Standards

40 CFR Part 63, Subpart VV - National Emission Standards for Oil-Water Separators and Organic-Water Separators

40 CFR Part 63, Subpart WW - National Emission Standards for Storage Vessels (Tanks) - Control Level 2

40 CFR Part 63, Subpart HHH - National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities

40 CFR Part 63, Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

40 CFR Part 63, Subpart VVV - National Emission Standards for Hazardous Air Pollutants: Publicly Owned Treatment Works

40 CFR Part 63, Subpart AAAA - National Emission Standards for Hazardous Air Pollutants: Municipal Solid Waste Landfills

40 CFR Part 63, Subpart EEEE - National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)

40 CFR Part 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

40 CFR Part 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

40 CFR Part 63, Subpart CCCCC - National Emission Standards for Hazardous Air Pollutants for Coke Ovens: Pushing, Quenching, and Battery Stacks

40 CFR Part 63, Subpart GGGGG - National Emission Standards for Hazardous Air Pollutants: Site Remediation

40 CFR Part 63, Subpart HHHHH - National Emission Standards for Hazardous Air Pollutants: Miscellaneous Coating Manufacturing

40 CFR Part 63, Subpart LLLLL - National Emission Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing Manufacturing

Statewide and Industry-wide Nitrogen Oxides (NOx)

WAQSR Chapter 2 establishes ambient air quality standards for those areas under WDEQ's jurisdiction. The standard for nitrogen oxides (NOx) is 100 ug/m^3 as an annual arithmetic mean. All facilities that are required to obtain a New Source Review (NSR) permit or a Title V permit under WAQSR Chapter 6 must demonstrate compliance with the State's ambient air quality standard before a permit can be issued.

WAQSR Chapter 3, Section 3 specifies nitrogen dioxide emission standards. Permitting rules require sources to meet NOx emission standards.

The following federal rules, which are incorporated by reference into Chapter 5, Sections 2 and 3 contain performance or emission standards for NOx that may apply to sources in the proposed nonattainment area and in the surrounding counties:

40 CFR Part 60, Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971

40 CFR Part 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

40 CFR Part 60, Subpart Db - Standards of performance for Industrial- Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines

The following federal New Source Performance Standards have not yet been adopted into State rules, but are scheduled for adoption. The federal standards will still apply.

NSPS Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

NSPS Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

NSPS Subpart KKKK - Standards of Performance for Stationary Combustion Turbines)

Contingency Plans

AQD requested that producers in parts of the proposed nonattainment area prepare emission reduction plans to be implemented when an ozone advisory is issued. The BLM adopted a contingency plan requirement in the Pinedale Anticline ROD. Producers, which cumulatively account for greater than 99% of production in the Pinedale Anticline, submitted contingency plans to the AQD. During the first quarter of 2009, the AQD issued ozone advisories on February 4th and 5th. The contingency plans were implemented and no 8-hour ozone values above 0.075 ppm were recorded at FRM monitors for those days.

CONCLUSIONS

The information presented in the preceding nine-factor analysis provides documentation and compelling evidence supporting a finding that the UGRB, as shown on the map in the Introduction, should be designated as nonattainment for the 2008 ozone NAAQS. It is important to note that only areas over which Wyoming has direct air quality jurisdiction are included in this nonattainment finding and recommendation. The Northern Arapahoe and Eastern Shoshone Indian Tribes are distinct nations or entities and consequently such Tribal lands (the Wind River Reservation) are specifically excluded from this designation recommendation.

The Wyoming AQD bases this recommendation on a careful review of the circumstances surrounding the incidence of elevated ozone events. Elevated ozone in the UGRB is associated with distinct meteorological conditions. These conditions have occurred in February and March in some (but not all) of the years since monitoring stations began operation in the UGRB in 2005. Our determination of an appropriate nonattainment area boundary is focused on an evaluation of EPA's recommended nine factors, applied to the first quarter of the year, during which winter ozone episodes occur. This timing does not change how the factors are reviewed, except for emissions inventory and meteorology. It is important to evaluate inventory and meteorology during the first quarter of the year in order to focus on the very specific conditions that lead to high ozone.

The most compelling reasons for the boundary recommendation are based on the meteorological conditions in place during and just prior to elevated ozone events. Elevated ozone episodes occurred in 2005, 2006 and 2008; they were associated with very light low-level winds, sunshine, and snow cover, in conjunction with a strong low-level surface-based temperature or "capping" inversion. The longest such event, which also resulted in the highest measured ozone of 122 ppb as an 8-hour average at the Boulder station, has been reviewed in detail and summarized in Section 7 of this document. Section 7 demonstrates that sources outside the recommended nonattainment area would not have a significant impact on the Boulder monitor due to the presence of the inversion and very low winds, which significantly limit emissions and ozone transport from sources located outside of the UGRB. Using detailed meteorological data collected during the February 19-23, 2008 ozone episode, a 1 kilometer high resolution (spatial and temporal) 3-dimensional gridded wind field was developed and used in trajectory analyses. The trajectory analyses show that air parcels originating at sources located south of the recommended nonattainment area – including power plants, Trona facilities, and the Moxa Arch gas field – are generally transported eastward and do not enter the UGRB just prior to and during the February 19-23, 2008 ozone episode. The meteorological conditions present during this multi-day ozone episode are representative of the meteorological conditions that were present during previous wintertime elevated ozone events that occurred in 2005 and 2006. From the trajectory analyses, it is concluded that emission sources located outside of the recommended nonattainment boundary could only have a very limited impact on the Boulder monitor, as the mountains to the west, north and east, along with the observed low wind speeds, would greatly limit the possibility of emissions transport.

The nine-factor analysis also concluded the following:

1. Ozone monitoring outside of the UGRB throughout Wyoming shows attainment of the 2008 NAAQS.
2. Emissions inventories of ozone precursors indicate that sources within the UGRB emit significant levels of precursors. Emissions from outside of the UGRB (while comparable to [for VOCs] or greater than [for NOx] emissions from within the UGRB) do not significantly influence the formation of ozone during and immediately preceding episodes of elevated ozone.
3. Population densities in Sublette and surrounding counties are very low and are not expected to be an important factor in ozone formation. This is also true of traffic and commuting patterns, which would be expected to be more important in urban areas rather than the rural communities and open spaces of southwest Wyoming.
4. The pace of growth in the oil and gas industry is significantly higher in the UGRB than in surrounding areas, which would correspond to a more rapid increase in emissions within the recommended nonattainment area in recent years.
5. Significant terrain features influence the meteorology throughout southwest Wyoming. Under a stagnating high pressure system, strong temperature inversions and low mixing heights tend to produce limited atmospheric mixing and precursor emissions can build up to high concentrations.

The elevated ozone episodes within the UGRB represent a unique situation which is quite different from other ozone nonattainment areas. The UGRB is rural with a very low population density; the only significant industry present is oil and gas. The significant terrain features surrounding the UGRB and the very low wind speeds associated with elevated ozone episodes may limit the ability of trajectory models, such as the HYSPLIT model, to accurately represent movement of air parcels within, into and out of the UGRB during these winter ozone events.

Due to the importance of meteorology to the formation of elevated ozone at the Boulder monitor – that is, ozone at levels that result in an exceedance of the NAAQS occurs during periods characterized by low mixing heights, temperature inversions and sustained low wind speeds – any emission reduction applied to sources outside of the UGRB will not result in any meaningful change in ozone levels at the Boulder monitor during these episodic conditions.

The information presented in this technical support document provides a strong weight-of-evidence basis for the recommended nonattainment boundary.

Appendix S.1.
Final Report 2008 Upper Green River Winter Ozone Study

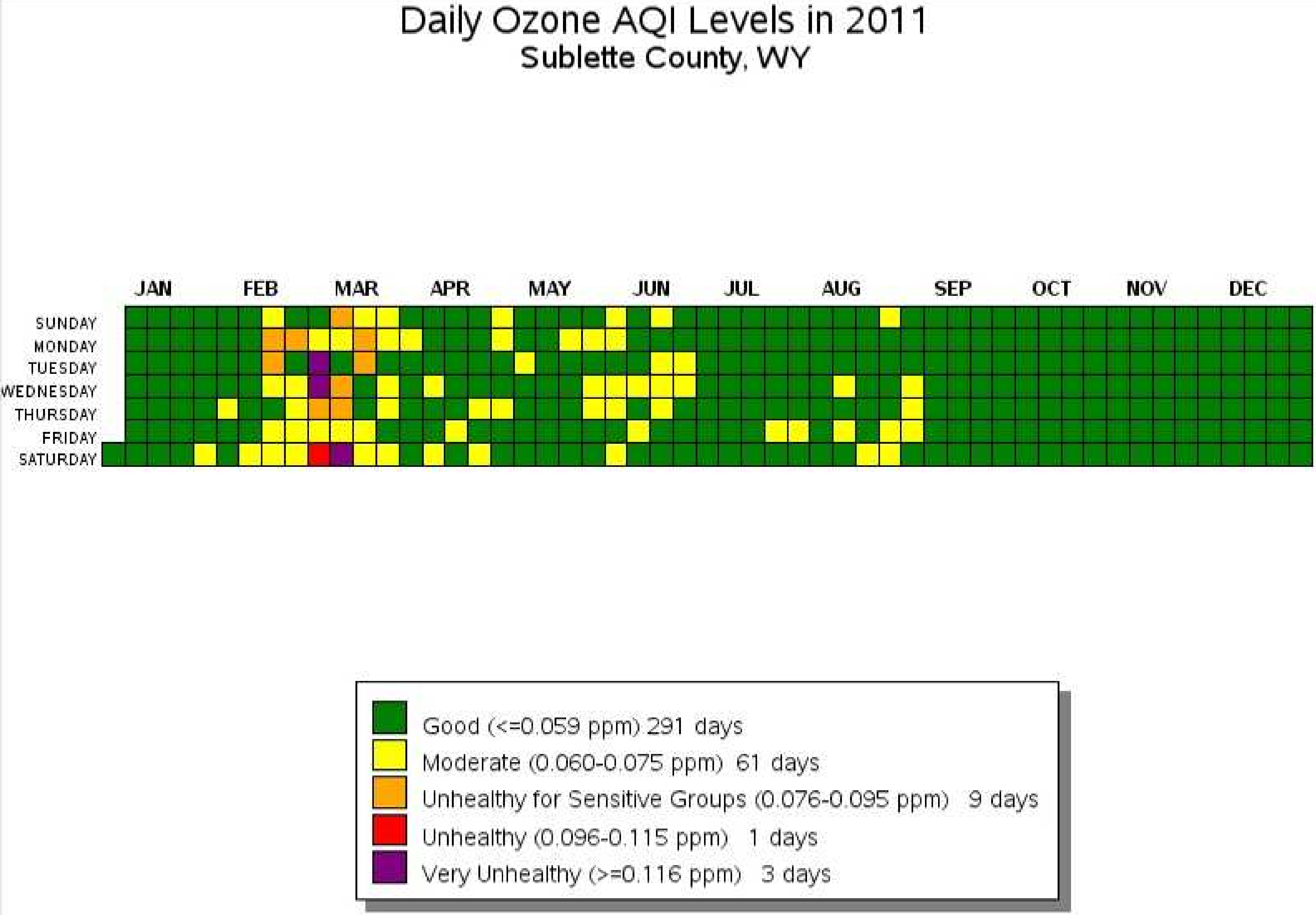
http://deq.state.wy.us/aqd/Monitoring%20Data.asp

Appendix S.3
Population Density by Census Tract

Appendix S.4.A.
2007 Vehicle Miles on State Highways By County

Appendix S.4.B.
Commuting Patterns in Sublette County

Appendix.
Glossary



Source: EPA's Air Explorer (http://www.epa.gov/airexplorer/)
Generated on: 06NOV12

Report: U.S. coal power plants emit toxic air pollutants

EPA: Energy Star TVs must use 40% less energy

Mar 09, 2011

Wyoming's smog exceeds Los Angeles' due to gas drilling

By Wendy Koch, USA TODAY

Updated 2011-03-09 11:52 AM

CAPTION By Mead Gruver, AP

Rural Wyoming, known for breathtaking vistas, now has worse smog than Los Angeles because of its boom in natural gas drilling.

Residents who live near the gas fields in the state's western corner are complaining of watery eyes, shortness of breath and bloody noses, reports the Associated Press. The cause is clearer than the air: local ozone levels recently exceeded the highest levels recorded in the biggest U.S. cities last year.

Preliminary data show the region's ozone levels last Wednesday got as high as 124 parts per billion, which is two-thirds higher than the Environmental Protection Agency's maximum healthy limit of 75 parts per billion and above the worst day in Los Angeles all last year, 114 parts per billion, AP reports. On March 1, the ozone levels hit 116 parts per billion.

Last year, too, Wyoming's gas-drilling area had days when its ozone levels exceeded Los Angeles' worst for 2009.

Yet, the Cowboy State is prospering. It has one of the nation's lowest unemployment rates, 6.4 percent, and is expected to run a budget surplus this year.

About Wendy Koch

Wendy Koch has been a reporter and editor at USA TODAY since 1998, covering politics and social issues. She's begun a quest to build the most eco-friendly home her budget allows. She'll share her experience and give you tips for greening your home. More about Wendy

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- Inhabitat
- Jetson Green
- Mother Earth News

"They're trading off health for profit. It's outrageous. We're not a Third World country," said Elaine Crumpley, a retired science teacher who lives just outside Pinedale, Wyo., told the AP.

In the Upper Green River Basin, at least one daycare center called off outdoor recess, and state officials urged the elderly, children and people with respiratory conditions to avoid strenuous or extended outdoor activity.

Gas industry officials say they're trying to curb smog by reducing truck traffic and switching to drilling rigs with pollution control equipment, and they report fewer emissions contributing to smog than in 2008, reports the AP. On Monday, Gov. Matt Mead discussed with state regulators and industry representatives what else companies can do.

See photos of: Los Angeles, Wyoming

TAGS: LOS ANGELES WYOMING ENVIRONMENTAL PROTECTION AGENCY PINEDALE OZONE SMOG COWBOY STATE UPPER GREEN RIVER BASIN

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25 comments Sort: Oldest to Newest

pencil-pusher
10:05 AM on March 9, 2011
Score: -3
Everybody in Wyoming should get an aerosol spray can and empty it in a day. Ozone will be depleted. Problem solved!
Report Abuse

smithy46 Score: -8
10:05 AM on March 9, 2011
If the poeple of Wyoming don't grin and bear it then they are America-hating, terrorist-loving, communist sympathizers!! If they're real Americans they'll take a hit for the team.
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mindstorms Score: 2
10:07 AM on March 9, 2011
Man polluting the environment they live in....I'm shocked?
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John Spencer Score: 0
10:08 AM on March 9, 2011
Now there's an idea pencil-pusher.
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rawn Score: 0
10:09 AM on March 9, 2011
Typical red state filled with oil and smog. Texas must be jealous.
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False_Paradigm Score: 1
10:10 AM on March 9, 2011
DRILL BABY DRILL!!! DERP AH-DERPITY DOO!!!
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foolsarerequired Score: 6
10:11 AM on March 9, 2011
The gas and oil executives wouldn't have a house no where near this drilling.
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Man the Middle Score: 0
10:13 AM on March 9, 2011
...and the smell is overwhelming!!!
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Independent01 Score: -1
10:15 AM on March 9, 2011
Oh well just send us your gas.
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WYVisNet website. Graphic by Pinedale Online.">

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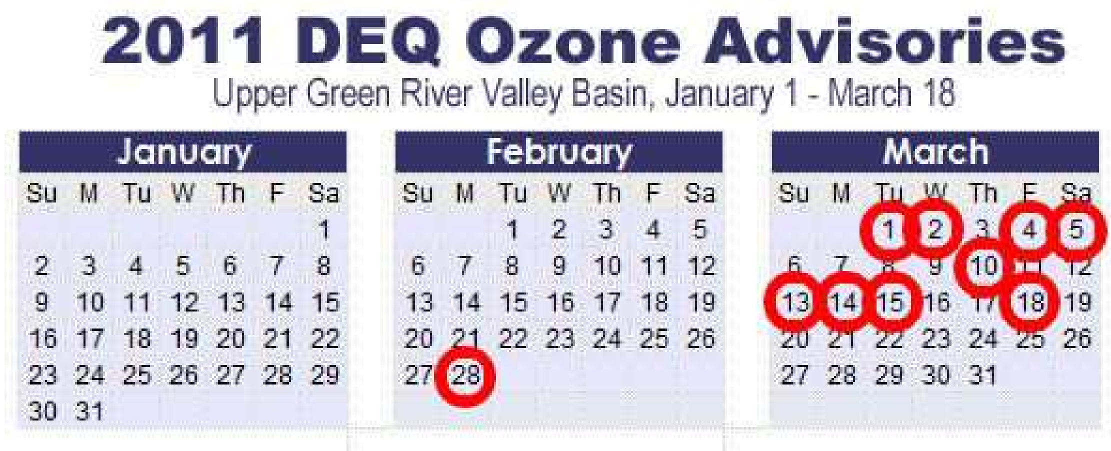
Back to Article



© Photo by Pinedale Online

Ozone Calendar

Wyoming DEQ has issued 10 Ozone Advisories for the Upper Green River Basin since February 28, 2011. Actual ozone levels may or may not have exceeded standards on any of those days. DEQ only issues prediction advisories, which are made based on weather predictions the day before they believe conditions may be condusive to creating high ozone levels in a given area. They do not issue a notice or advisory in real time to the public or media when high ozone levels are actually occuring. To see monitor readings in real time, visit the DEQ WYVisNet website. Graphic by Pinedale Online.

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Ozone Advisory for Monday, Feb. 28

by Wyoming Department of Environmental Quality
February 27, 2011

Upper Green River Basin, Wyo. - The Air Quality Division (AQD) of Wyoming's Department of Environmental Quality (DEQ), in conjunction with the Wyoming Department of Health (WDH), is issuing an ozone advisory for tomorrow, Monday February 28, 2011, for the Upper Green River Basin, in Sublette County.

The DEQ-AQD would like to communicate that this particular Ozone Advisory is anticipated to be a multi-day event. Weather forecasting for conditions conducive to elevated 8-hour ozone will continue on a daily basis and the AQD will continue to issue updated advisory status by noon each day such that, if the weather forecast changes, advisory status may also change. The DEQ-AQD will also be conducting intensive sampling of ozone and precursors during this period. These intensive measurements will focus on the vertical distributions of pollutants which will be accomplished by equipment attached to weather balloons.

Ozone is an air pollutant that can cause respiratory health effects especially to children, the elderly and people with existing respiratory conditions. People in these sensitive groups should limit strenuous or extended outdoor activities, especially in the afternoon and evening. More information on ozone and the health effects of ozone are available at the Wyoming Department of Health website, .http://www.health.wyo.gov.

An ozone advisory is issued when weather conditions appear to be favorable for the formation of ozone. Ozone appears to be elevated in the Basin when there is a presence of ozone-forming precursor emissions including oxides of nitrogen and volatile organic compounds coupled with strong temperature inversions, low winds, snow cover, and bright sunlight.

Current information on ozone levels at the Air Quality Division's monitoring stations at Daniel, Pinedale, Boulder, Juel Spring and the Wyoming Range can be found at www.wyvisnet.com.

Pinedale Online > News > February 2011 > Ozone Advisory for Monday, Feb. 28

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The New York Times

October 1, 2010

Air Quality Concerns May Dictate Uintah Basin's Natural Gas Drilling Future

By SCOTT STREATER of

An energy company's plan to drill more than 1,400 natural gas wells in northeast Utah's Uintah Basin could be tripped up by an emerging air pollution problem that has affected other densely developed oil and gas fields across the Rocky Mountain West.

The concern is wintertime ozone, a problem that federal regulators discovered for the first time in the basin just this year. If the phenomenon cannot be controlled, it could force Denver-based Gasco Energy Inc. to scale back plans to drill across 206,826 acres of mostly Bureau of Land Management property.

Ground-level ozone pollution, which is linked to respiratory diseases like asthma, is a well-known summer pollution problem, stemming from the mixing of auto and industrial emissions in sunlight and heat.

But federal regulators have discovered an unusual winter weather pattern in the Uintah Basin that causes ozone concentrations to reach potentially dangerous levels in January, February and March. The pattern is marked by stagnant air that allows emissions to collect in the lower atmosphere and then be converted into ozone by sunlight and heat reflecting off snow on the ground, said Stephanie Howard, a BLM environmental coordinator and the agency's project manager for the Gasco proposal.

Air pollution monitors recently installed in the Uintah Basin measured ozone concentrations exceeding federal health standards more than 68 times in the first three months of 2010, according to U.S. EPA data. On one day in January and two days in February, recorded ozone levels were nearly twice the federal health standard of 75 parts per billion.

“We think these ozone issues in the Uintah Basin call into question the justifica moving ahead to analyze or approve these sorts of projects,” said Steve Bloch, director of the Southern Utah Wilderness Alliance.

The winter ozone phenomenon surprised BLM, which this week issued a draft

impact statement (EIS) identifying hundreds of existing oil and gas wells in the basin as the primary cause of the ozone pollution.

The draft EIS is scheduled to be published tomorrow in the *Federal Register*, kicking off a 45-day public comment period through Nov. 15.

Gasco's project could still be permitted, though, since federal regulations require three consecutive years of monitoring data before a region can be deemed a violator of federal pollution standards, also known as National Ambient Air Quality Standards.

If the area were declared an ozone violator, EPA would mandate an emissions reduction plan to improve air quality by a certain deadline.

But BLM is not waiting for such a violation to occur. Rather, the agency's EIS includes measures to ensure the Gasco project does not exacerbate wintertime ozone, including possibly reducing or prohibiting drilling activity during the winter months.

"We're very anxious to see what the numbers are in January, February and March," Howard said. "We're holding our breath to see what happens."

Tougher standards

Further complicating the Gasco proposal is EPA's expected tightening of the ozone health standard by the end of the year.

EPA has proposed revising its "primary" health standard for ozone so that a region would violate the Clean Air Act if ozone concentrations reached between 60 and 70 parts per billion averaged over an eight-hour period. The agency has also proposed a "secondary" ozone standard aimed at protecting vegetation and sensitive ecosystems, including parks, wildlife refuges and wilderness areas (*Greenwire*, Jan. 7).

While a tougher ozone health standard would have its most immediate effect in urban areas, where motor vehicles contribute billions of tons of ozone-forming pollutants annually, the odorless gas has become a growing problem in remote areas as well, especially where oil and gas producers have sunk thousands of wells into the ground, resulting in releases of ozone precursors nitrogen oxide (NOx) and volatile organic compounds (VOCs).

The stakes could be especially high in Utah, one of the nation's fastest-growing states and a growing hub for oil and gas development, particularly within the Uintah Basin.

In fact, the Gasco Energy project is the smallest of four Uintah Basin drilling proposals currently under review by BLM. Collectively, these four projects could result in the drilling of more than 17,000 new natural gas wells across hundreds of thousands of acres of federal land over the next three years.

The largest is the Greater Chapita Wells Natural Gas Infill Project, which would place up to 7,028 wells across more than 40,000 acres of mostly BLM land. Next is the Greater Monument Butte plan, proposed by the Newfield Exploration Co. It calls for drilling 5,750 wells across 119,850 acres of mostly federal land. And finally, the Greater Natural Buttes Project, proposed by Kerr-McGee Oil & Gas Onshore LP, could result in drilling as many as 3,675 wells on 162,911 acres.

While drilling in the Uintah Basin has been going on in some form since the early 1900s, with some active federal leases dating back to the 1950s, Howard said better technologies and drilling techniques have attracted companies looking to access gas reserves at much greater depths than before.

"That's across the West. We are now able to develop more American oil and gas reserves that five, 10 years ago we didn't know how to," said Kathleen Sgamma, director of government affairs for the Denver-based Western Energy Alliance, an industry trade group.

Industry doubts readings

Sgamma, however, questioned the accuracy of the ozone readings in the Uintah Basin, saying the two monitors that registered high wintertime ozone were "faulty," and the readings did not pass EPA's quality assurance standards.

"That data cannot be used in determining the attainment status" of the region, Sgamma said.

Howard, however, disputed the assertion that the numbers were faulty, saying they had been vetted by EPA and posted on its website.

"I'm pretty sure that if the readings were faulty the EPA would not have published them," she said. "My understanding is those numbers are correct."

Faulty or not, Sgamma said the readings provide enough incentive for regulators and the industry to work together to ensure that emissions of ozone precursors stay low.

She also stressed that Uintah County, where the project would be located, currently is in compliance with federal health standards for ozone.

"Environmental groups are certainly trying to use the faulty readings in the basin as a means to stop oil and gas development and the associated jobs," Sgamma said. "But the bottom line is that economic activity does not need to be stopped in an area that remains in compliance for ozone."

Lessons from Wyoming

But the Uintah Basin is not the only place where oil and natural gas drilling activity is associated with high wintertime ozone.

In Sublette County, Wyo., wintertime ozone attributed largely to oil and gas production in the Jonah Infill and Pinedale Anticline gas fields could lead to Wyoming's first violations of EPA air quality standards, according to state officials. Federal maps also indicate that counties in the natural gas-rich Powder River Basin in northeast Wyoming could also violate federal air quality standards if EPA toughens its ozone health standard.

Wyoming Gov. Dave Freudenthal (D) asked EPA last year to designate Sublette County and portions of two other neighboring counties in the state's southwest corner as violating current ozone health standards (*Land Letter*, March 19, 2009). Wells in those two fields produced 7.6 million barrels of oil and 1.1 billion cubic feet of natural gas in 2008, according to state statistics.

Between 2000 and 2008, the number of annual new oil, gas and coalbed methane drilling wells in the region increased almost threefold, from 350 a year in 2000 to 925 a year in 2008, according to state figures. More than 2,600 new wells were drilled in Sublette County alone during that time.

An ozone monitor in southwest Wyoming began recording high ozone levels in 2005, and a technical analysis of air quality in the region conducted last year by the Wyoming Division of Air Quality found that 94 percent of VOCs and 60 percent of NOx emissions "are attributable to oil and gas production and development."

But last winter the region's ozone levels did not exceed federal ozone standards, in part because low wellhead prices significantly slowed production.

Industry officials attribute the drop in emissions to efforts by drillers to reduce emissions by up to 80 percent in the Pinedale Anticline region. Those measures include using cleaner-burning engines in machinery and piping oil and gas to reduce truck traffic in the field.

Meanwhile, BLM will continue to study wintertime ozone levels in Uintah Basin. Howard said the agency would likely allow Gasco to drill some wells before they have collected the three years of data needed to verify that the basin has an ozone problem.

Jeremy Nichols, climate and energy program director for WildEarth Guardians, said that would be a big mistake.

"BLM needs to understand they have a responsibility here, and they do need to start limiting operations and development activity when it looks like emission levels are going to rise," Nichols said. "The only way is to limit operations and limit development. They are going to have to stop rubberstamping all of these projects that are put in front of them."

Click here to read the draft EIS.

Streater writes from Colorado Springs, Colo.