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.

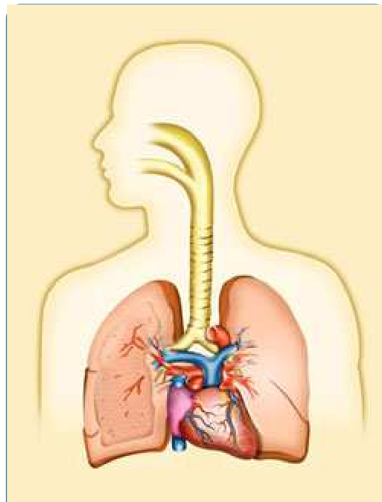
If you're a health care provider, visit AIRNow's Health Care Provider page for educational materials and trainings.

For more information on how EPA works to reduce ground level ozone, visit the Ozone Standards page.

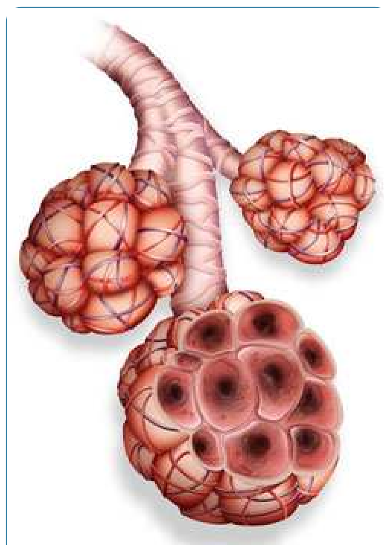
For more information on ground level ozone, health and the environment, visit:

- 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 Thursday, November 01, 2012

EPA 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.

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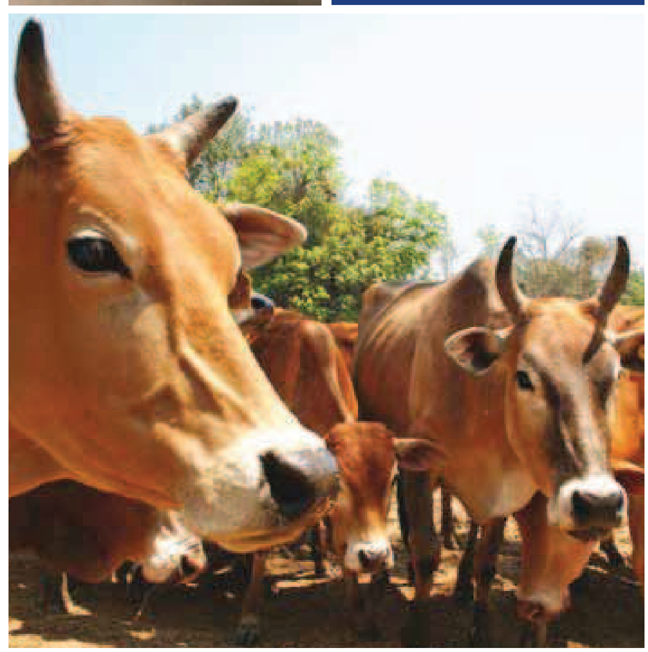
UNEP

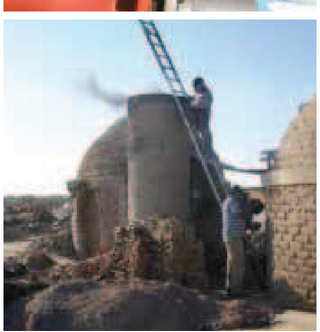
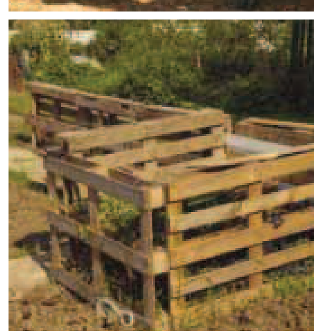
World Meteorological Organization

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.

UNEP/GC/26/INF/20

Disclaimers

Writing team: Coordinators – Drew Shindell (National Aeronautics and Space Administration, Goddard Institute for Space Studies, USA) and Johan C. I. Kuylenstierna (Stockholm Environment Institute, University of York, UK); Writers – Kevin Hicks (Stockholm Environment Institute, University of York, UK), Frank Raes (Joint Research Centre, European Commission, Italy), Veerabhadran Ramanathan (Scripps Institution of Oceanography, USA), Erika Rosenthal (Earth Justice, USA), Sara Terry (US Environmental Protection Agency), Martin Williams (King's College London, UK).

With inputs from: Markus Amann (International Institute for Applied Systems Analysis, Austria), Susan Anenberg (US Environmental Protection Agency), Volodymyr Demkine (UNEP, Kenya), Lisa Emberson (Stockholm Environment Institute, University of York, UK), David Fowler (The Centre for Ecology and Hydrology, UK), Liisa Jalkanen (WMO, Switzerland), Zbigniew Klimont (International Institute for Applied Systems Analysis, Austria), N. T. Kim Oahn, (Asian Institute of Technology, Thailand), Joel Schwartz (Harvard University, USA), David Streets (Argonne National Laboratory, USA), Rita van Dingenen (Joint Research Centre, European Commission, Italy), Harry Vallack (Stockholm Environment Institute, University of York, UK), Elisabetta Vignati (Joint Research Centre, European Commission, Italy).

With advice from the High-level Consultative Group especially: Ivar Baste (UNEP, Switzerland), Adrián Fernández Bremauntz (National Institute of Ecology, Mexico), Harald Dovland (Ministry of Environment, Norway), Dale Evarts (US Environmental Protection Agency), Rob Maas (The National Institute for Public Health and the Environment, Netherlands), Pam Pearson (International Cryosphere Climate Initiative, Sweden/USA), Sophie Punte (Clean Air Initiative for Asian Cities, Philippines), Andreas Schild (International Centre for Integrated Mountain Development, Nepal), Surya Sethi (Former Principal Adviser Energy and Core Climate Negotiator, Government of India), George Varughese (Development Alternatives Group, India), Robert Watson (Department for Environment, Food and Rural Affairs, UK).

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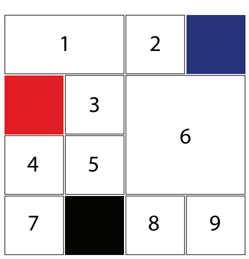

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Integrated Assessment of Black Carbon and Tropospheric Ozone

Summary for Decision Makers

Table of Contents

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.

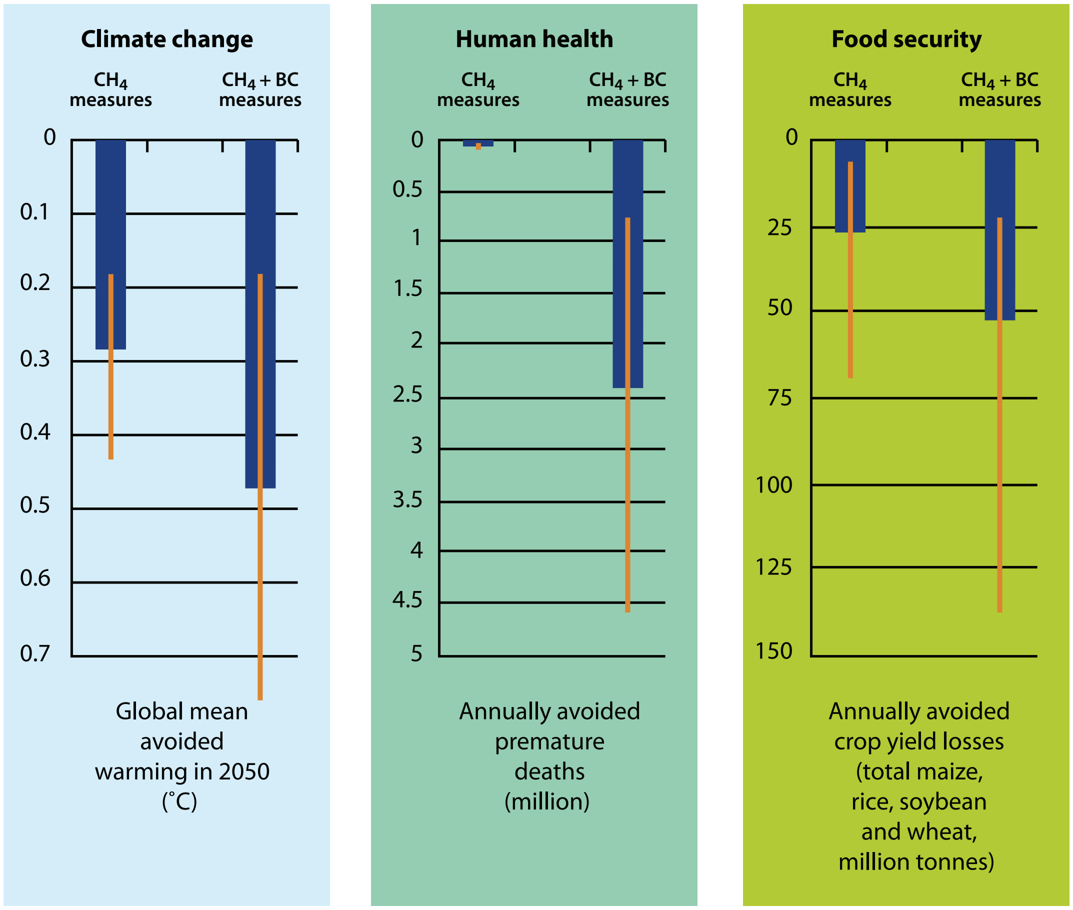


Figure 1. Global benefits from full implementation of the identified measures in 2030 compared to the reference scenario. The climate change benefit is estimated for a given year (2050) and human health and crop benefits are for 2030 and beyond.

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.

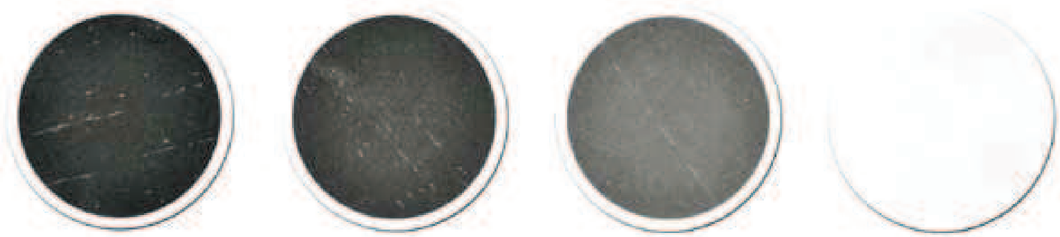
The black in BC refers to the fact that these particles absorb visible light. This absorption leads to a disturbance of the planetary radiation balance and eventually to warming. The contribution to warming of 1 gramme of BC seen over a period of 100 years has been estimated to be anything from 100 to 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 **Uncontrolled Diesel Exhaust** (Level 1)	Retrofitted with **Diesel Oxidation Catalyst (DOC)** (Level 1)	Retrofitted with **Partial Filter** (Level 2)	Retrofitted with **Diesel Particulate Filter (DPF)** (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	Extraction and transport of fossil fuel
Reduced gas leakage from long-distance transmission pipelines	Extraction and transport of fossil fuel
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	Waste management
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	Agriculture
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	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	Residential
Introduction of clean-burning biomass stoves for cooking and heating in developing countries[2, 3]	Residential
Substitution of clean-burning cookstoves using modern fuels for traditional biomass cookstoves in developing countries[2, 3]	Residential
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	Industry
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.

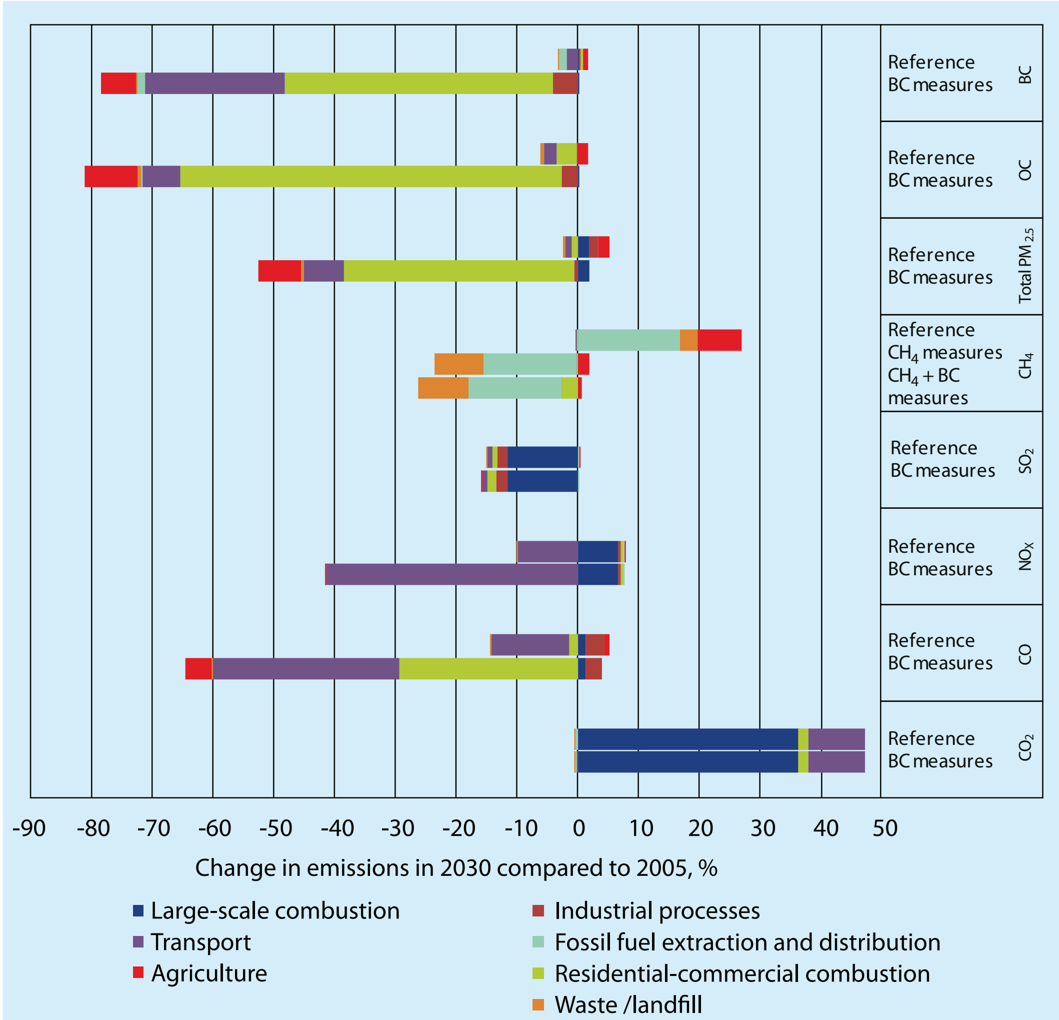


Figure 2. Percentage change in anthropogenic emissions of the indicated pollutants in 2030 relative to 2005 for the reference, CH_4, BC and CH_4 + BC measures scenarios. The CH_4 measures have minimal effect on emissions of anything other than CH_4. The identified BC measures reduce a large proportion 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

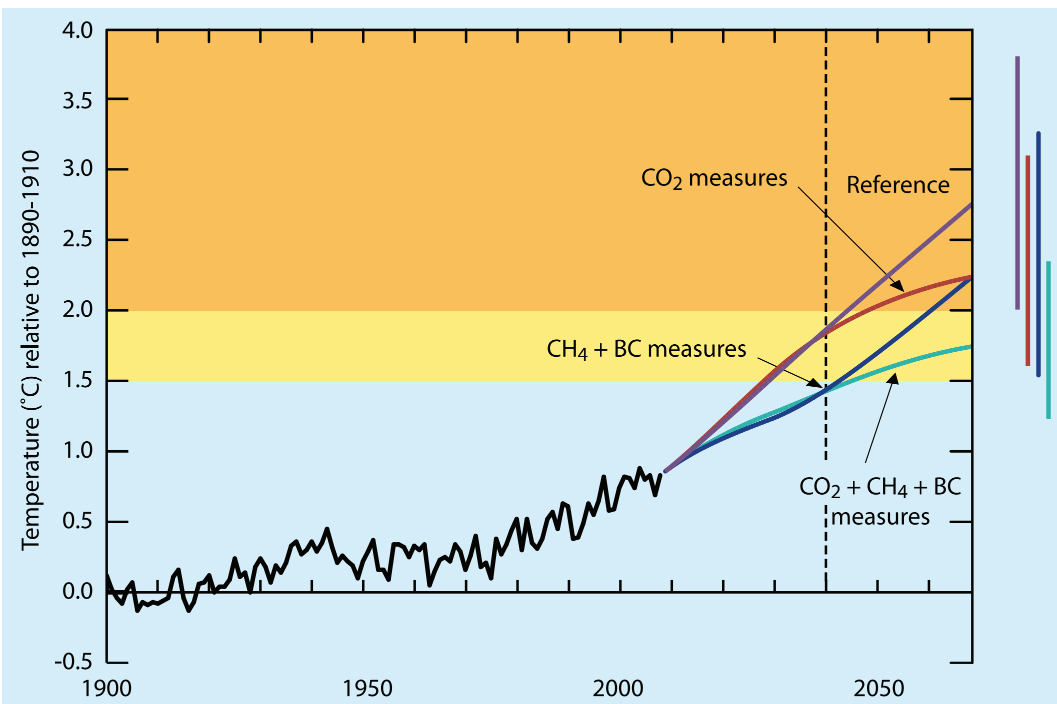


Figure 3. Observed deviation of temperature to 2009 and projections under various scenarios. Immediate implementation of the identified BC and CH_4 measures, together with measures to reduce CO_2 emissions, would greatly improve the chances of keeping Earth's temperature increase to less than 2˚C relative 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

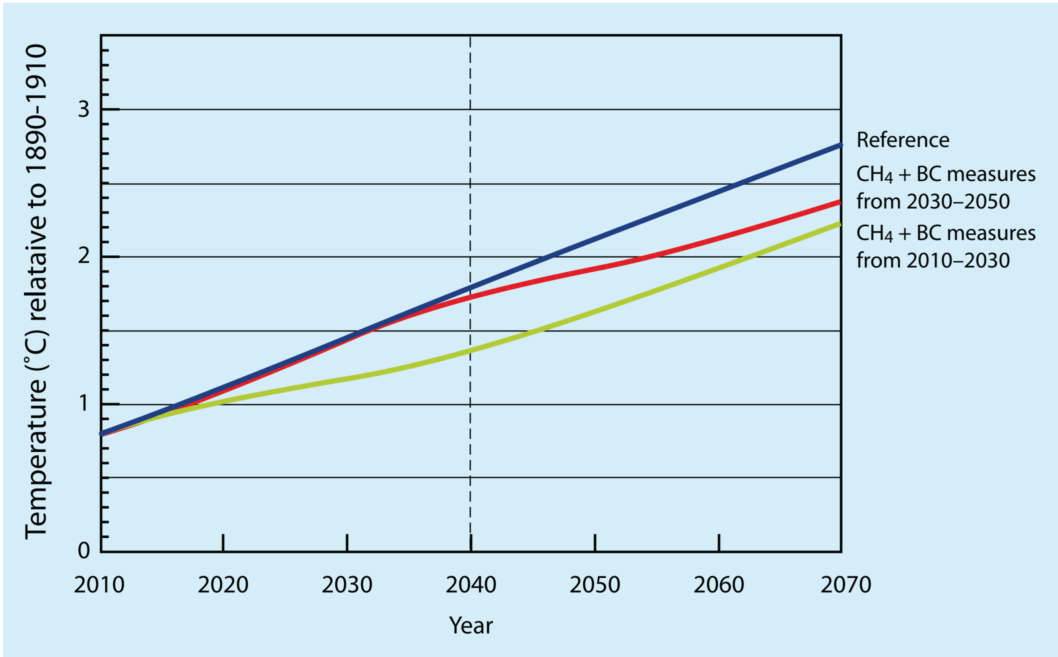


Figure 4. Projected global mean temperature changes for the reference scenario and for the CH_4 and BC measures scenario with emission reductions starting immediately or delayed by 20 years.

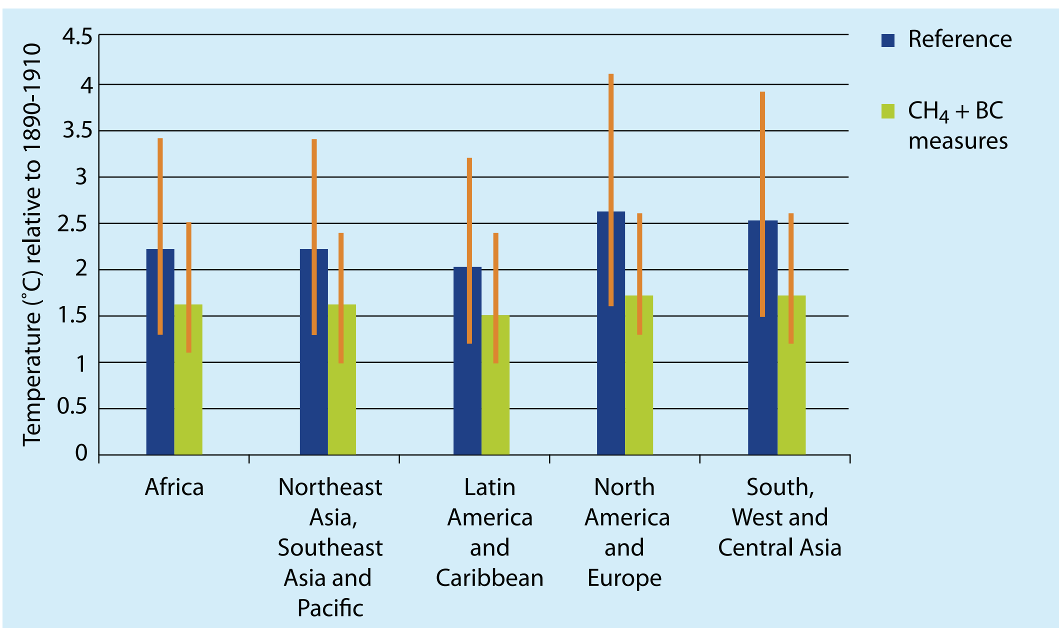


Figure 5. Comparison of regional mean warming over land (°C) showing the change in 2070 compared with 2005 for the reference scenario (Table 2) and the CH_4 + BC measures scenario. The lines on each bar show the range of estimates.

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

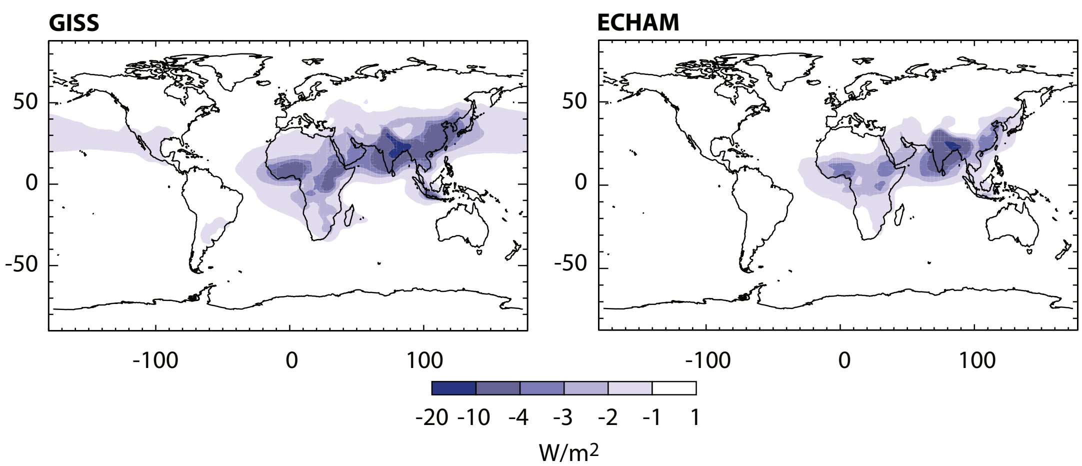


Figure 6. Change in atmospheric energy absorption (Watts per square metre, W/m² as annual mean), an important factor driving tropical rainfall and the monsoons resulting from implementation of BC measures. The changes in absorption of energy by the atmosphere are linked with changes in regional circulation 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

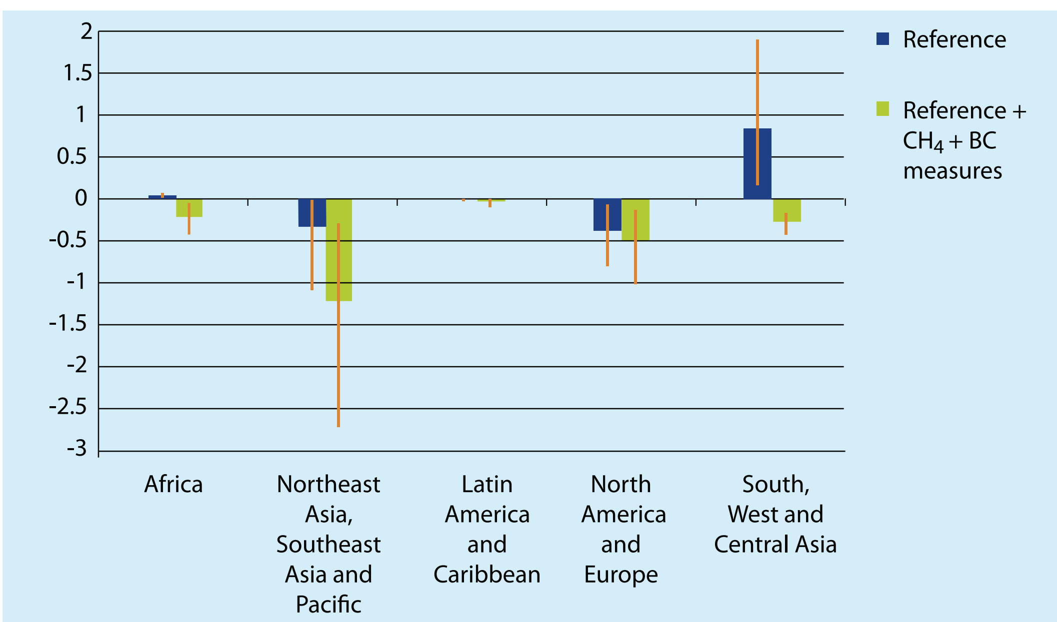


Figure 7. Comparison of premature mortality (millions of premature deaths annually) by region, showing the change in 2030 in comparison with 2005 for the reference scenario emission trends and the reference plus CH_4 + BC measures. The lines on each bar show the range of estimates.

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

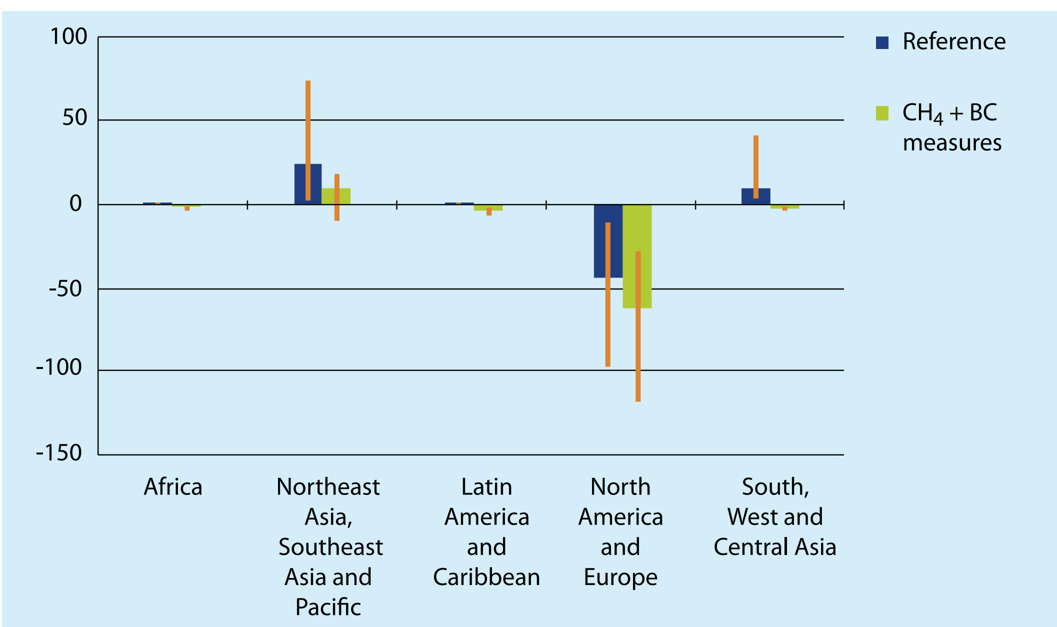
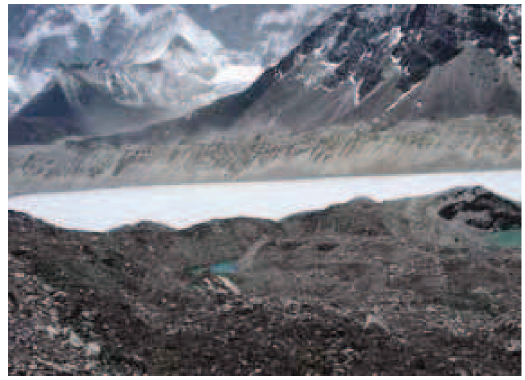


Figure 8. Comparison of crop yield losses (million tonnes annually of four key crops – wheat, rice, maize and soy combined) by region, showing the change in 2030 compared with 2005 for the reference emission trends and the reference with CH_4 + BC measures. The lines on each bar show the range of estimates.

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

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.

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.


Credit: Alba Corral Avitia


Credit: Robert Marquez

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.

Concluding Remarks

Credit: John Ogren, NOAA

Aerosol measurement instruments

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.

Credit: Christian Lagerek

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.
Trans-boundary 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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The following individuals have provided input to the Assessment. Authors, reviewers and review editors have contributed to this report in their individual capacity and their organizations are mentioned for identification purposes only.

Chair: Drew Shindell (National Aeronautics and Space Administration Goddard Institute for Space Studies, USA).

Vice-chairs: Veerabhadran Ramanathan (Scripps Institution of Oceanography, USA), Frank Raes, (Joint Research Centre, European Commission, Italy), Luis Cifuentes (The Catholic University of Chile, Chile) and N. T. Kim Oanh (Asian Institute of Technology, Thailand).

High-level Consultative Group: Ivar Baste (UNEP, Switzerland), Harald Dovland (Ministry of Environment, Norway), Dale Evarts (US Environmental Protection Agency), Adrián Fernández Bremauntz (National Institute of Ecology, Mexico), Rob Maas (The National Institute for Public Health and the Environment, Netherlands), Pam Pearson (International Cryosphere Climate Initiative, Sweden/USA), Sophie Punte (Clean Air Initiative for Asian Cities, Philippines), Andreas Schild (International Centre for Integrated Mountain Development, Nepal), Surya Sethi (Former Principal Adviser Energy and Core Climate Negotiator, Government of India), George Varughese (Development Alternatives Group, India), Robert Watson (Department for Environment, Food and Rural Affairs, UK).

Scientific Coordinator: Johan C. I. Kuylenstierna (Stockholm Environment Institute, University of York, UK).

Coordinating Lead Authors: Frank Raes (Joint Research Centre, European Commission, Italy), David Streets (Argonne National Laboratory, USA), David Fowler (The Centre for Ecology and Hydrology, UK), Lisa Emberson (Stockholm Environment Institute, University of York, UK), Martin Williams (King's College London, UK).

Lead Authors: Hajime Akimoto (Asia Center for Air Pollution Research, Japan), Markus Amann (International Institute for Applied Systems Analysis, Austria), Susan Anenberg (US Environmental Protection Agency), Paulo Artaxo (University of Sao Paulo, Brazil), Greg Carmichael (University of Iowa, USA), William Collins (UK Meteorological Office, UK), Mark Flanner (University of Michigan, USA), Greet Janssens-Maenhout (Joint Research Centre, European Commission, Italy), Kevin Hicks (Stockholm Environment Institute, University of York, UK), Zbigniew Klimont (International Institute for Applied Systems Analysis, Austria), Kaarle Kupiainen (International Institute for Applied Systems Analysis, Austria), Johan C. I. Kuylenstierna (Stockholm Environment Institute, University of York, UK), Nicholas Muller (Middlebury College, USA), Veerabhadran Ramanathan (Scripps Institution of Oceanography, USA), Erika Rosenthal (Earth Justice, USA), Joel Schwartz (Harvard University, USA), Sara Terry (US Environmental Protection Agency), Harry Vallack (Stockholm Environment Institute, University of York, UK), Rita Van Dingenen (Joint Research Centre, European Commission, Italy), Elisabetta Vignati (Joint Research Centre, European Commission, Italy), Chien Wang (Massachusetts Institute of Technology, USA).

Contributing Authors: Madhoolika Agrawal (Banares Hindu University, India), Kirstin Aunan (Centre for International Climate and Environmental Research, Norway), Gufran Beig (Indian Institute of Tropical Meteorology, India), Luis Cifuentes (The Catholic University of Chile, Chile), Devaraj de Condappa (Stockholm Environment Institute, USA), Sarath Guttikunda (Urban Emissions, India/Desert Research Institute, USA), Syed Iqbal Hasnain (Calicut University, India), Christopher Heyes (International Institute for Applied Systems Analysis, Austria), Lena Höglund Isaksson (International Institute for Applied Systems Analysis, Austria), Jean-François Lamarque (National Center for Atmospheric Research, USA), Hong Liao (Institute of Atmospheric Physics, Chinese Academy of Sciences, China), Zifeng Lu (Argonne National Laboratory, USA), Vishal Mehta (Stockholm Environment Institute, USA), Lina Mercado (The Centre for Ecology and Hydrology, UK), N. T. Kim Oanh (Asian Institute of Technology, Thailand), T. S. Panwar (The Energy and Resources Institute, India), David Purkey (Stockholm Environment Institute, USA), Maheswar Rupakheti (Asian Institute of Technology-UNEP Regional Resource Center for Asia and the Pacific, Thailand), Michael Schulz (Norwegian Meteorological Institute, Norway), Stephen Sitch (University of Leeds, UK), Michael Walsh (International Council for Clean Transportation, USA), Yuxuan Wang (Tsinghua University, China), Jason West (University of North Carolina, USA), Eric Zusman (Institute for Global Environmental Studies, Japan).

External Reviewers: John Van Aardenne (European Environment Agency, Denmark), John Bachmann (Vision Air Consulting, USA), Angela Bandemehr (US Environmental Protection Agency), Ellen Baum (Clean Air Task Force, USA), Livia Bizikova (International Institute for Sustainable Development, Canada), Elizabeth Bush (Environment Canada), Zoë Chafe (University of California, Berkeley (Energy and Resources Group and School of Public Health), USA), Linda Chappell (US Environmental Protection Agency), Dennis Clare (Institute of Governance and Sustainable Development, USA), Hugh Coe (University of Manchester, UK), Benjamin DeAngelo (US Environmental Protection Agency), Pat Dolwick (US Environmental Protection Agency), Neil Frank (US Environmental Protection Agency), Sandro Fuzzi (Istituto di Scienze dell'Atmosfera e del Clima – CNR, Italy), Nathan Gillett (Environment Canada), Michael Geller (US Environmental Protection Agency), Elisabeth Gilmore (US Environmental Protection Agency), Peringe Grennfelt (Swedish Environmental Research Institute, Sweden), Andrew Grieshop (University of British Columbia, Canada), Paul Gunning (US Environmental Protection Agency), Rakesh Hooda (The Energy and Resources Institute, India), Bryan Hubbell (US Environmental Protection Agency), Mark Jacobson (Stanford University, USA), Yutaka Kondo (University of Tokyo, Japan), David Lavoué (Environment Canada), Richard Leaitch (Environment Canada), Peter Louie (Hong Kong Environmental Protection Department, Government of the Hong Kong Special Administrative Region, China), Gunnar Luderer (Potsdam Institute for Climate Impact Research, Germany), Andy Miller (US Environmental Protection Agency), Ray Minjares (International Council on Clean Transportation, USA), Jacob Moss (US Environmental Protection Agency), Brian Muehling (US Environmental Protection Agency), Venkatesh Rao (US Environmental Protection Agency), Jessica Seddon (Wallach) (US Environmental Protection Agency), Marcus Sarofim (US Environmental Protection Agency), Erika Sasser (US Environmental Protection Agency), Sangeeta Sharma (Environment Canada), Kirk Smith (University of California, USA), Joseph Somers (US Environmental Protection Agency), Darrell Sonntag (US Environmental Protection Agency), Robert Stone (The Cooperative Institute for Research in Environmental Sciences, National Oceanic and Atmospheric Administration, USA), Jessica Strefler (Potsdam Institute for Climate Impact Research, Germany).

Review Editors: Umesh Kulshrestha (Jawaharlal Nehru University, India), Hiromasa Ueda (Kyoto University, Japan), Piers Forster (University of Leeds, UK), Henning Rodhe (Stockholm University, Sweden), Madhav Karki (International Centre for Integrated Mountain Development, Nepal), Ben Armstrong (London School of Hygiene and Tropical Medicine, UK), Luisa Molina (Massachusetts Institute of Technology and the Molina Center for Energy and the Environment, USA), May Ajero (Clean Air Initiative for Asian Cities, Philippines).

Coordination team: Volodymyr Demkine (UNEP, Kenya), Salif Diop (UNEP, Kenya), Peter Gilruth (UNEP, Kenya), Len Barrie (WMO, Switzerland), Liisa Jalkanen (WMO, Switzerland), Johan C. I. Kuylenstierna (Stockholm Environment Institute, University of York, UK), Kevin Hicks (Stockholm Environment Institute, University of York, UK).

Administrative support: Nyokabi Mwangi (UNEP, Kenya), Chantal Renaudot (WMO, Switzerland), Emma Wright (Stockholm Environment Institute, University of York, UK), Tim Morrissey (Stockholm Environment Institute, University of York, UK).

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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.

www.unep.org

United Nations Environment Programme
P.O. Box 30552 - 00100 Nairobi, Kenya
Tel.: +254 20 762 1234
Fax: +254 20 762 3927
e-mail: uneppub@unep.org
www.unep.org

UNEP

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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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 Thursday, August 09, 2012

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
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

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CONTACT INFORMATION

This document has been prepared by staff from the Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. Questions related to this document should be addressed to Alexander Macpherson, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, C445-B, Research Triangle Park, North Carolina 27711 (email: macpherson.alex@epa.gov).

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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.

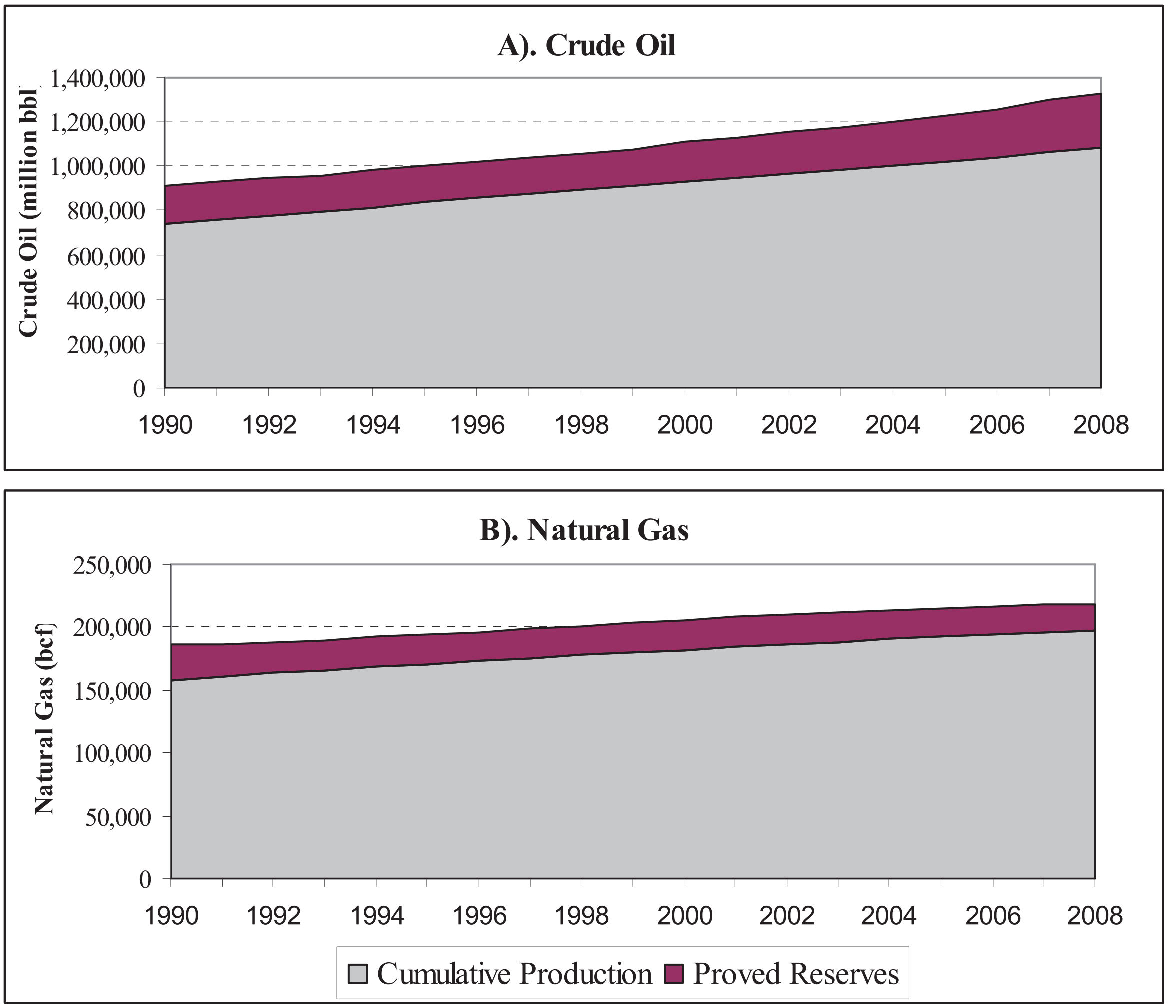

Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2008. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2008

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.

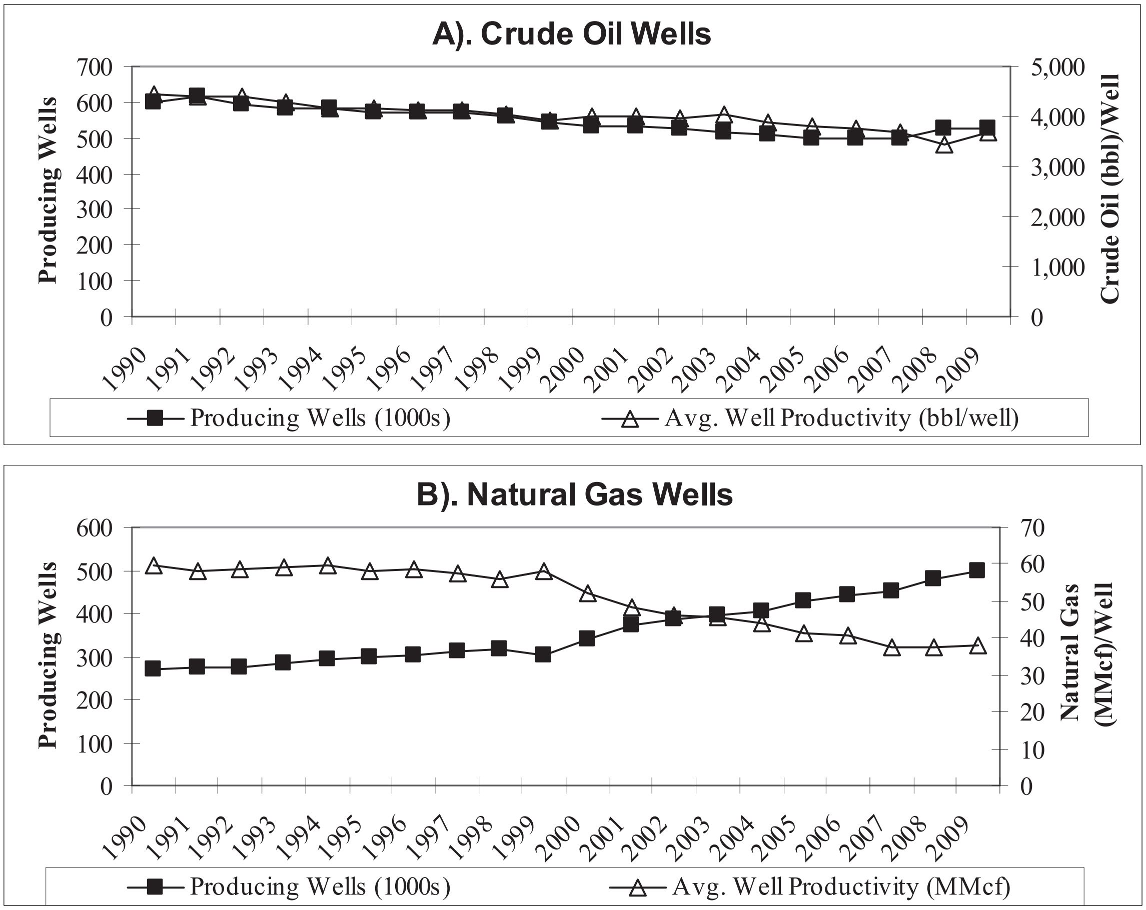

Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2009. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2009.

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.

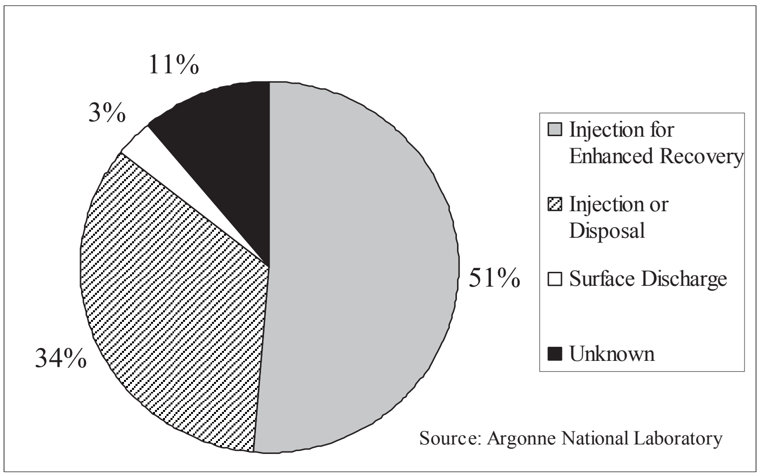

Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

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.

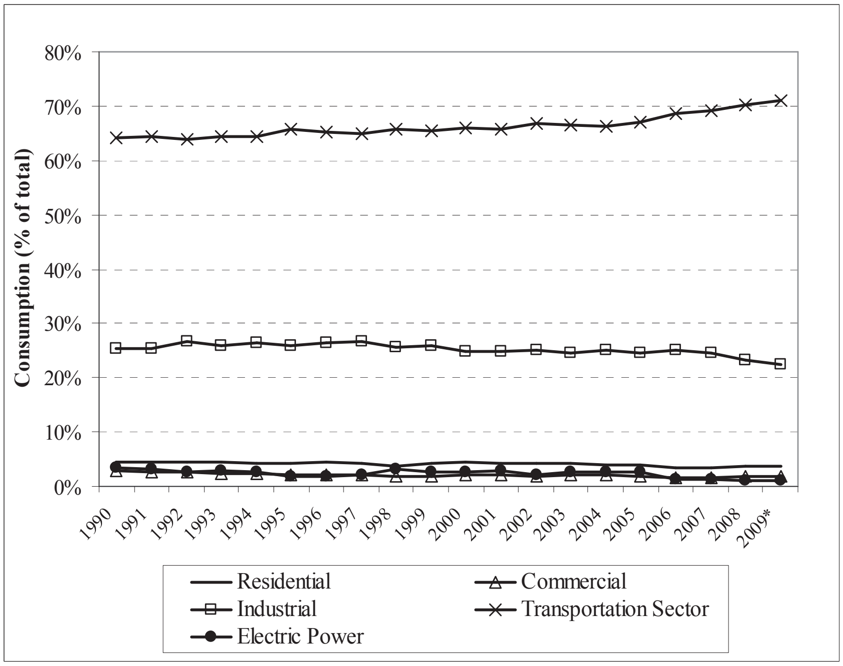

Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2009

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

		Percent of Total				
Year	Total (bcf)	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.

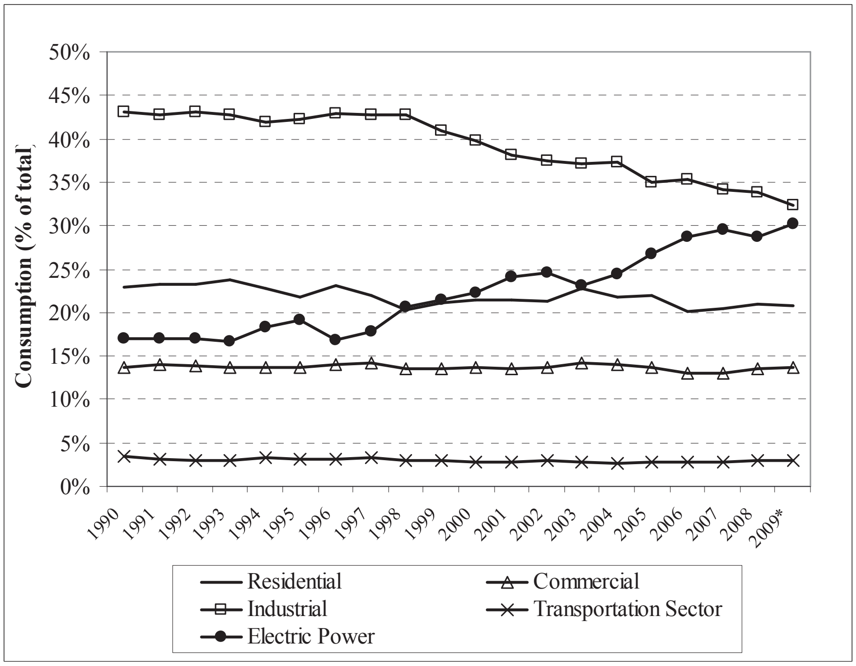

Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2009

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.

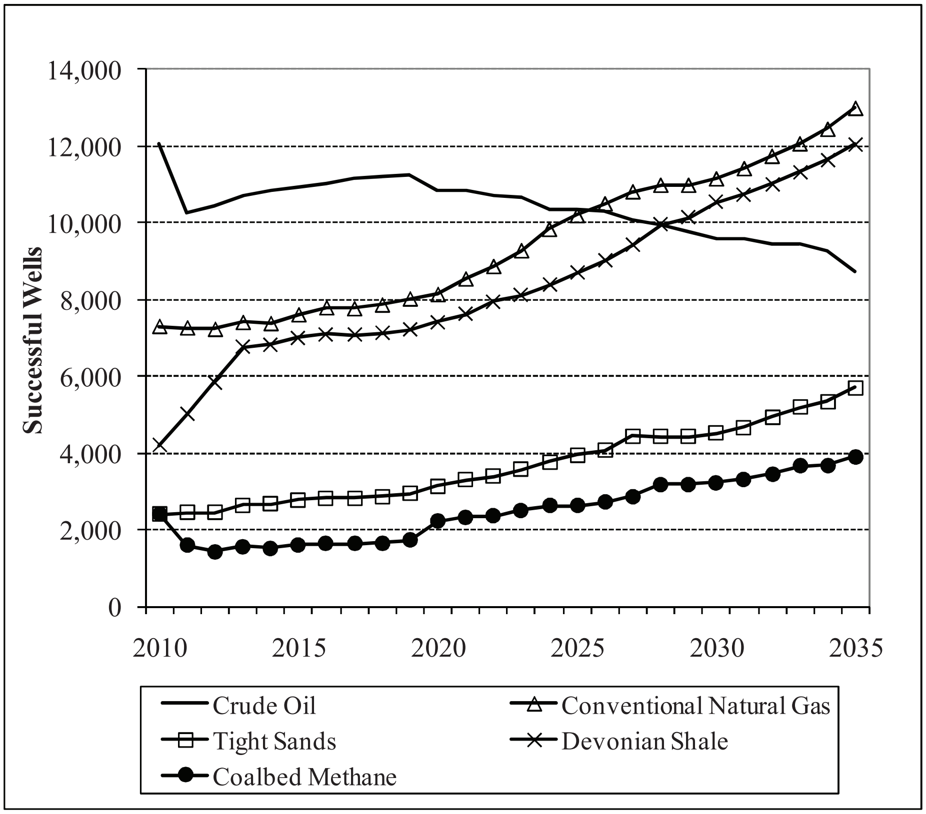

Figure 2-6 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

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.

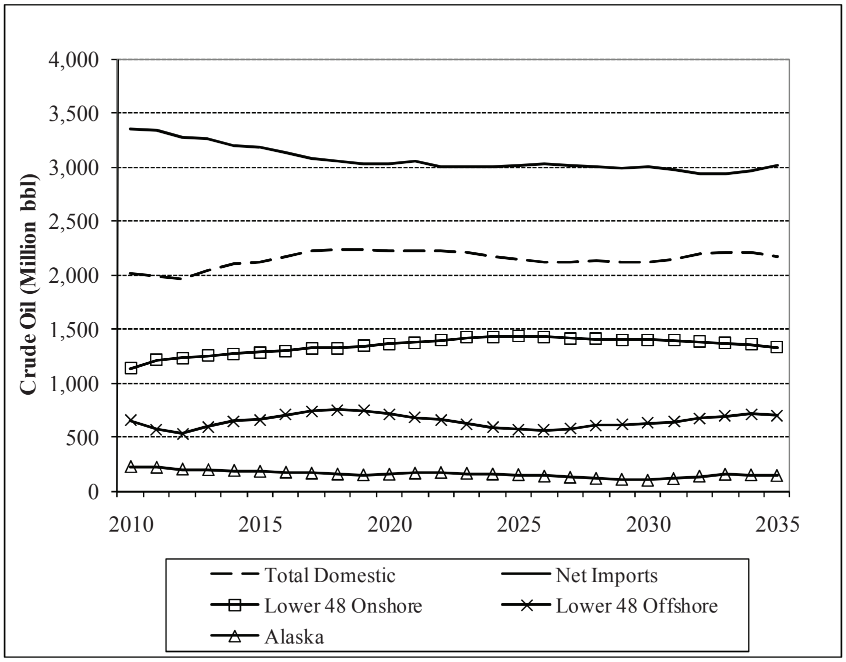

Figure 2-7 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2035

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).

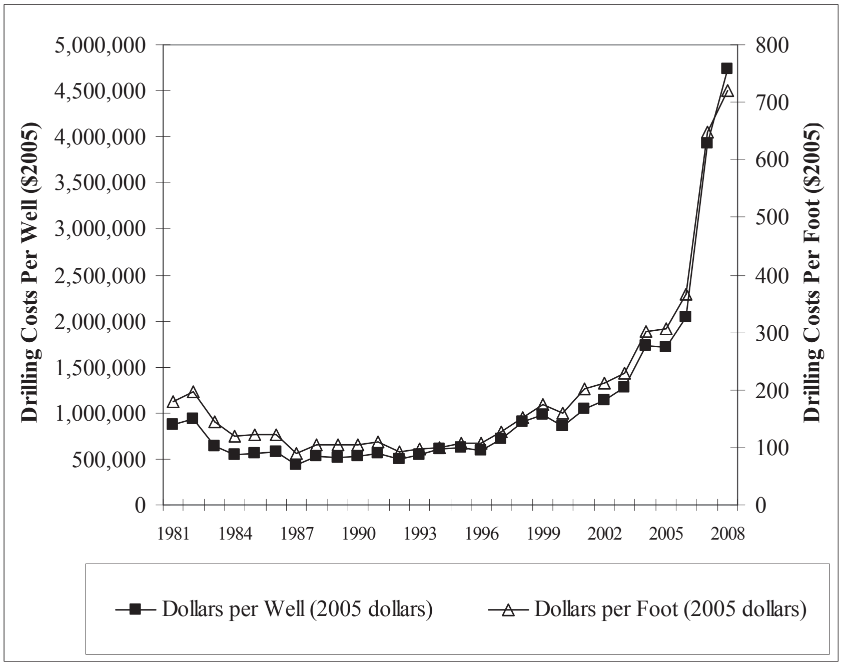

Figure 2-8 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

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.

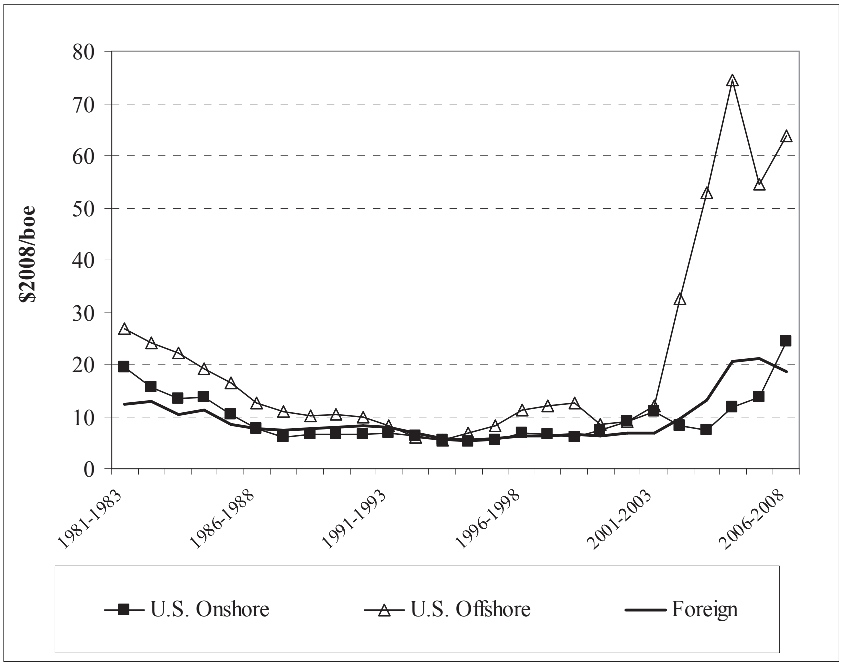

Figure 2-9 Finding Costs for FRS Companies, 1981-2008

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.

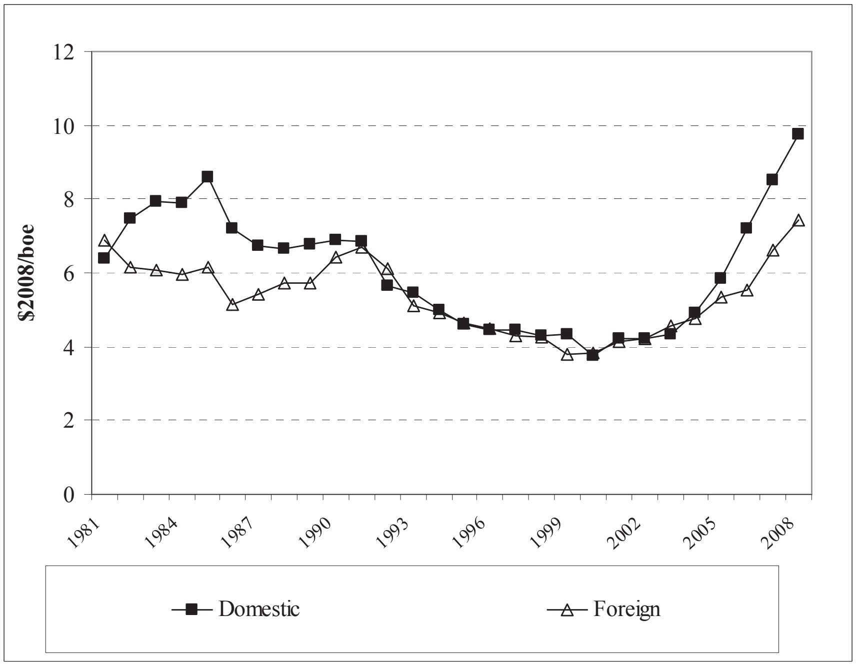

Figure 2-10 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2008 (3-year Running Average)

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.

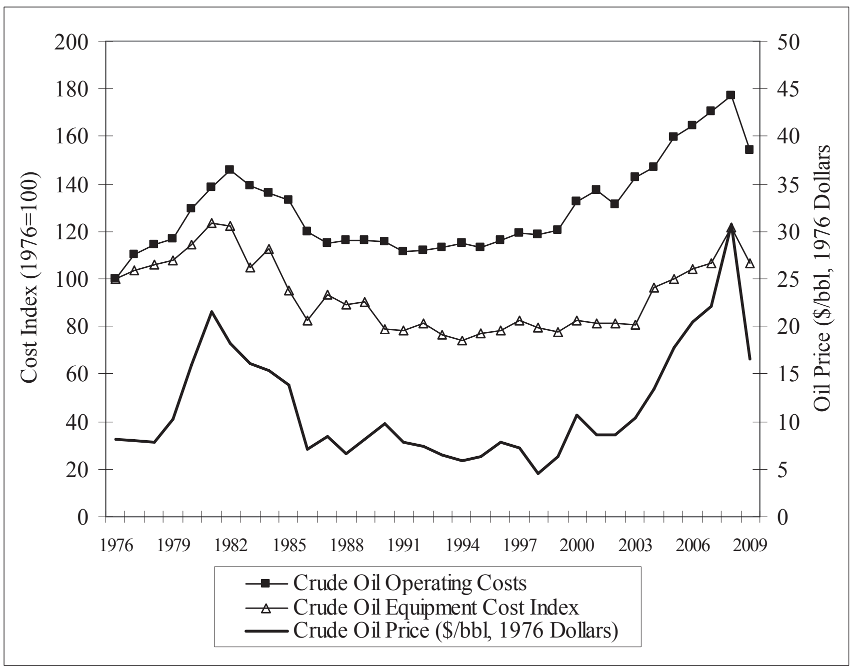

Figure 2-11 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009

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.

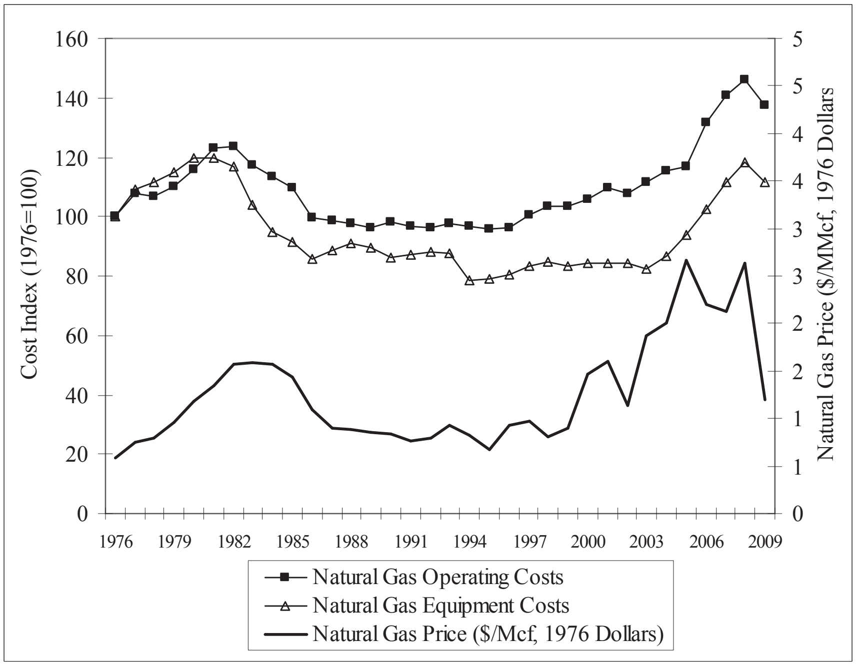

Figure 2-12 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

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/>

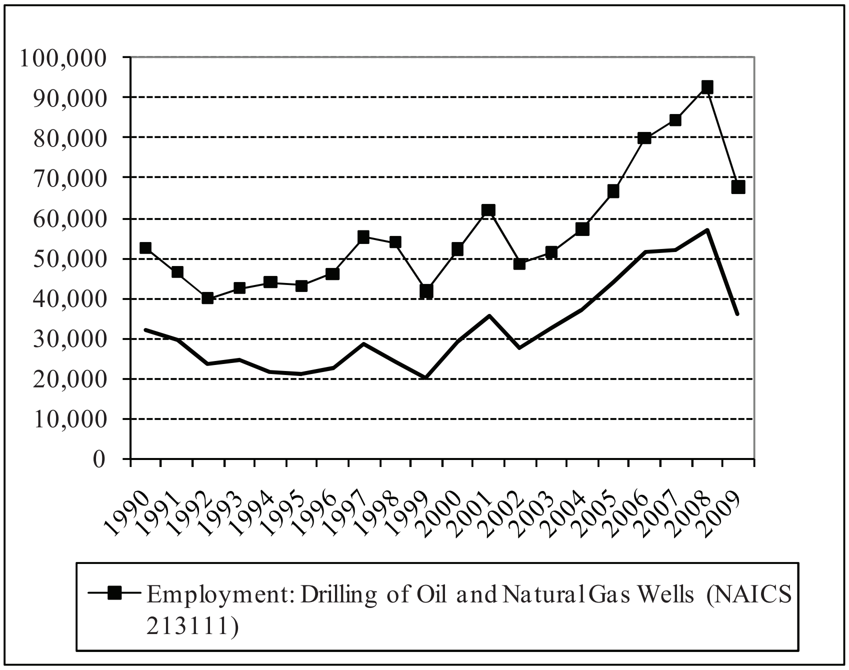

Figure 2-13 Employment in Drilling of Oil and Natural Gas Wells (NAICS 213111), and Total Oil and Natural Gas Wells Drilled, 1990-2009

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.

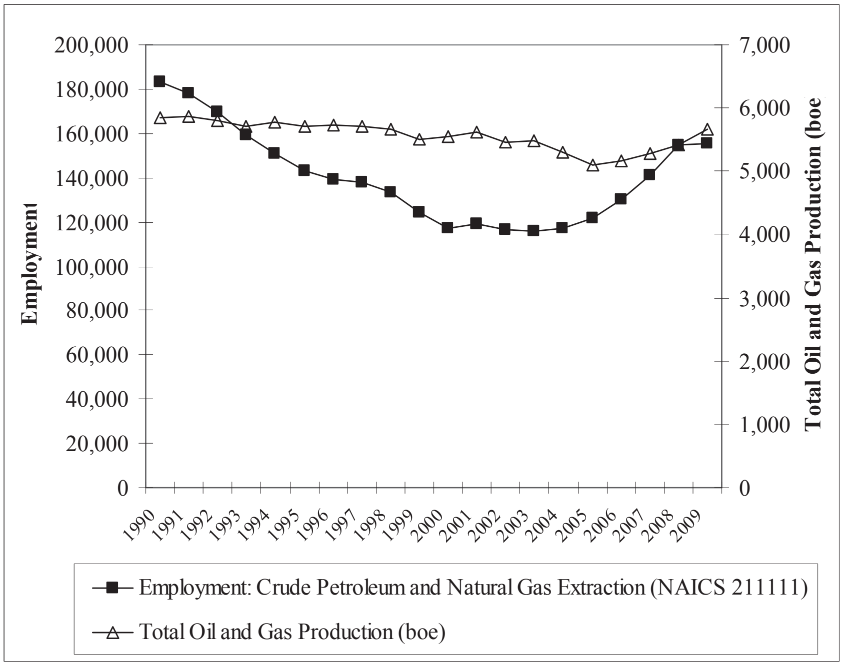

Figure 2-14 Employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Total Crude Oil and Natural Gas Production (boe), 1990-2009

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.

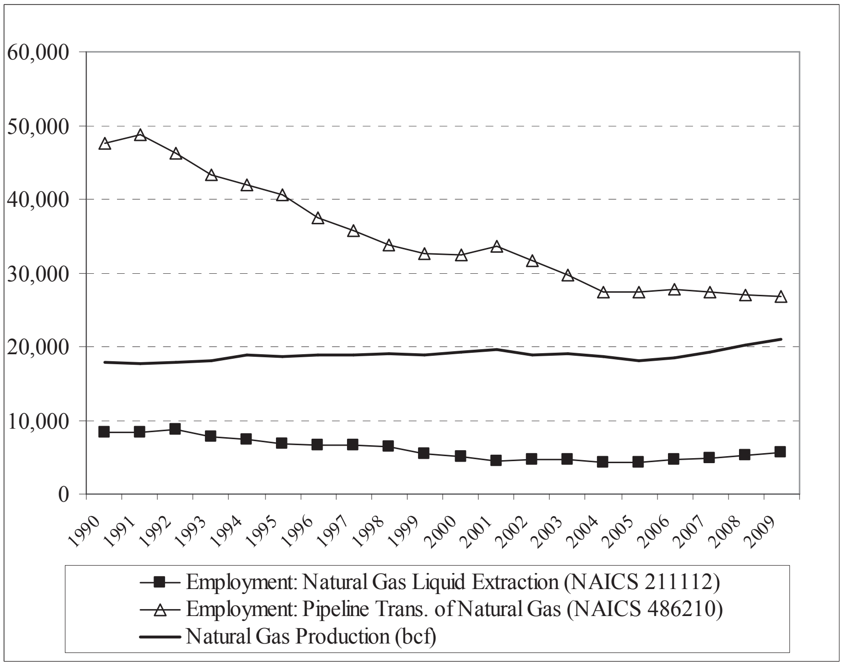

Figure 2-15 Employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009

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.

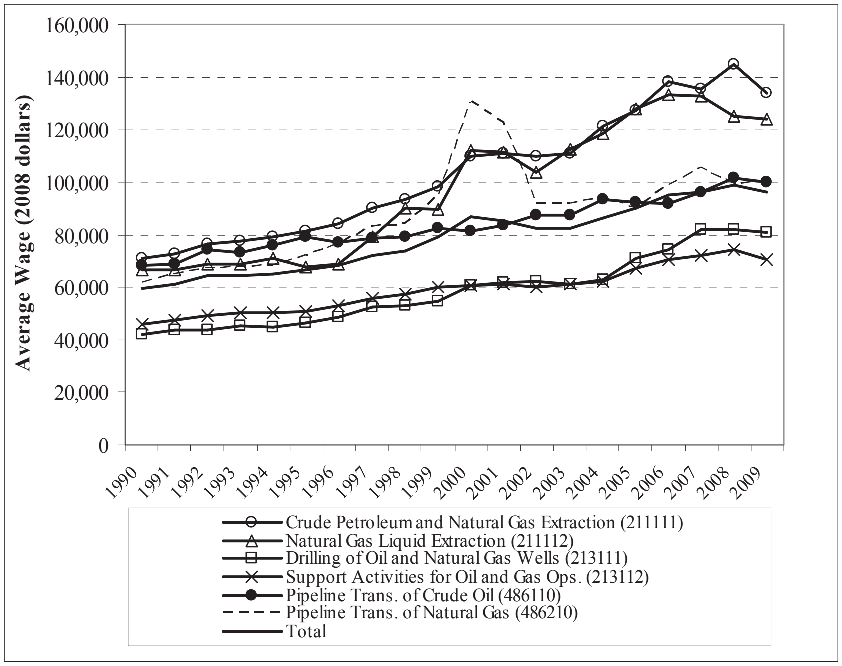

Figure 2-16 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 ($2008)

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

Rank by Total Assets	Company	Employees	Total Assets ($ millions)	Total Rev. ($ millions)	Net Inc. ($ millions)	Worldwide Production: Liquids (Million bbl)	Worldwide Production: Natural Gas (Bcf)	U.S. Production: Liquids (Million bbl)	U.S. Production: 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.

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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

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[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	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

		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
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.

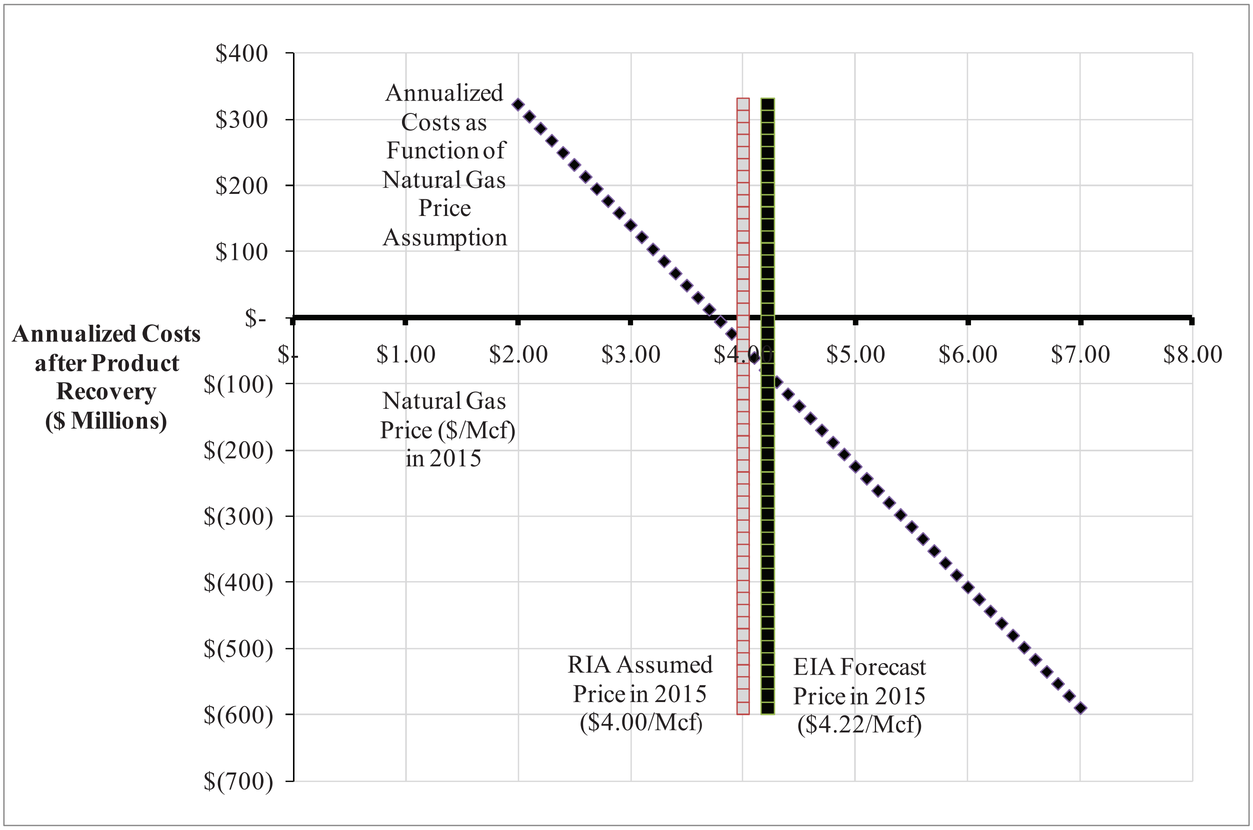

Figure 3-1 Sensitivity Analysis of Proposed NSPS Annualized Costs after Revenues from Additional Product Recovery are Included

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: Natural Gas Savings (Mcf/unit)	Unit-level Product Recovery: Condensate (bbl/unit)	Total Product Recovery: Natural Gas Savings (Mcf)	Total Product Recovery: 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

Oil and Gas Journal. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

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.

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.

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[9] In previous RIAs, we have also referred to these impacts as energy disbenefits.

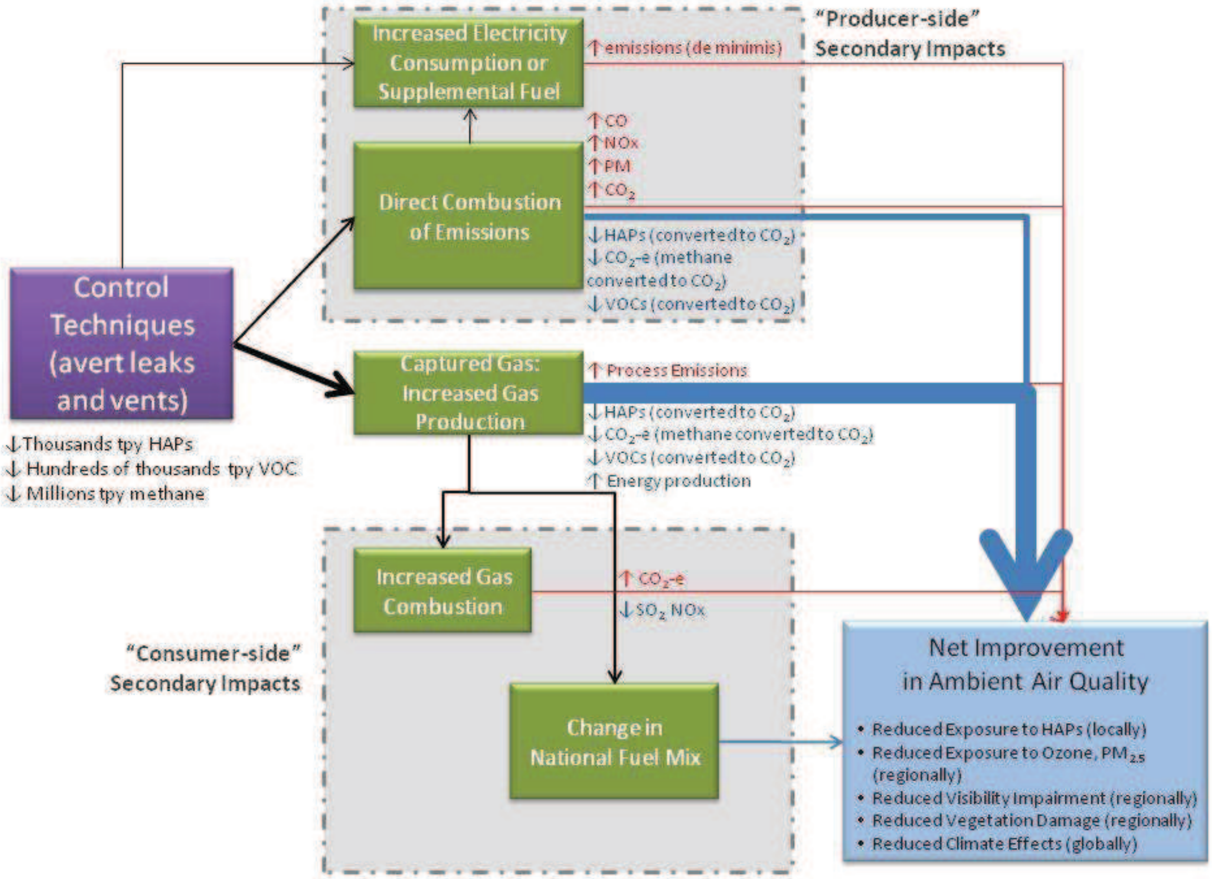

Figure 4-1 Conceptual Diagram of Secondary Impacts from Oil and Gas NSPS and NESHAP Amendments

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.

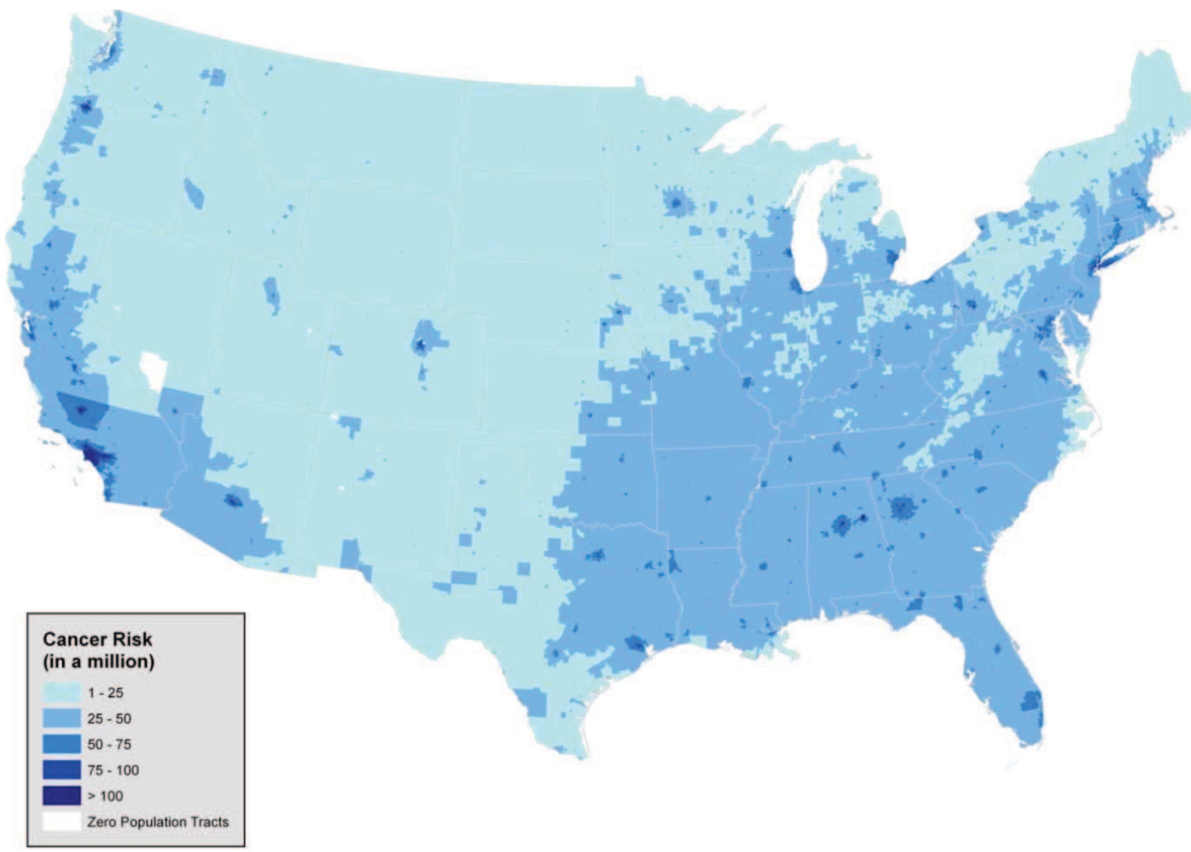

Figure 4-2 Estimated Chronic Census Tract Carcinogenic Risk from HAP exposure from outdoor sources (2005 NATA)

[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.

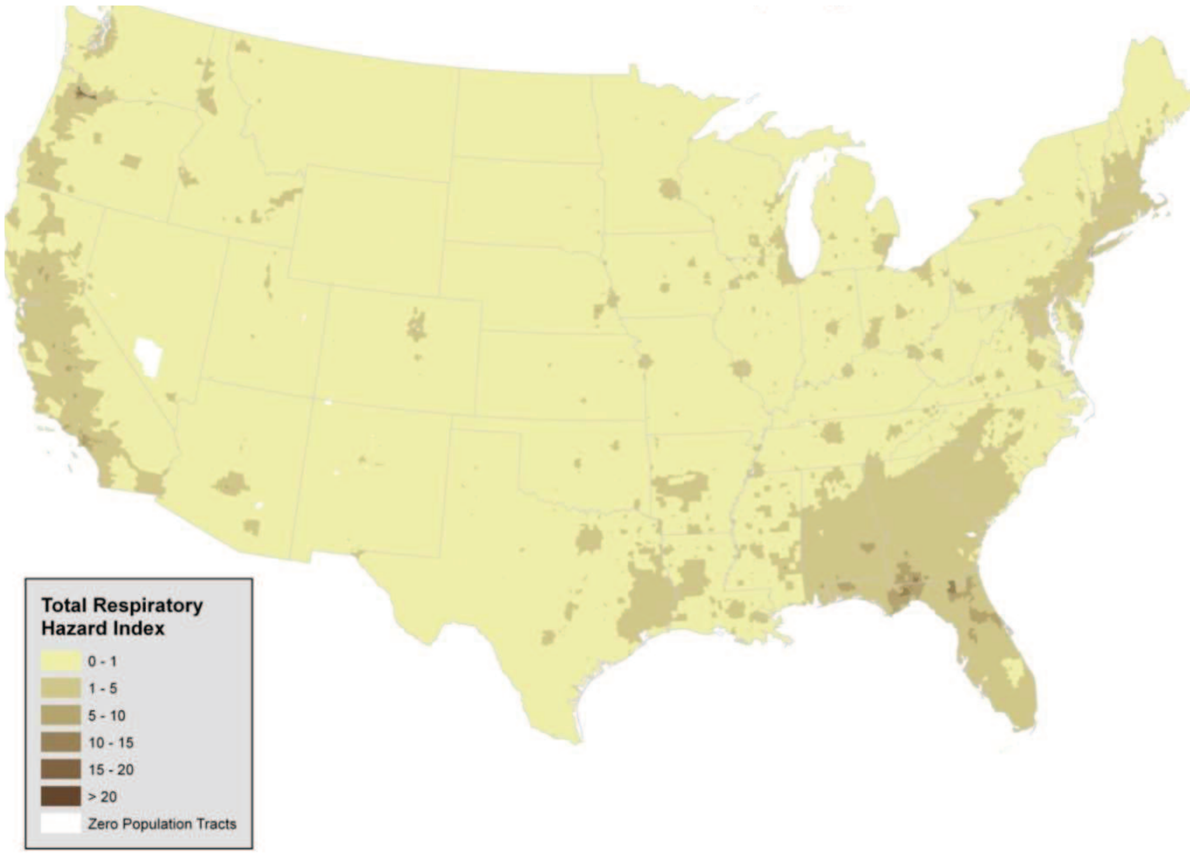

Figure 4-3 Estimated Chronic Census Tract Noncancer (Respiratory) Risk from HAP exposure from outdoor sources (2005 NATA)

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.

[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

[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.

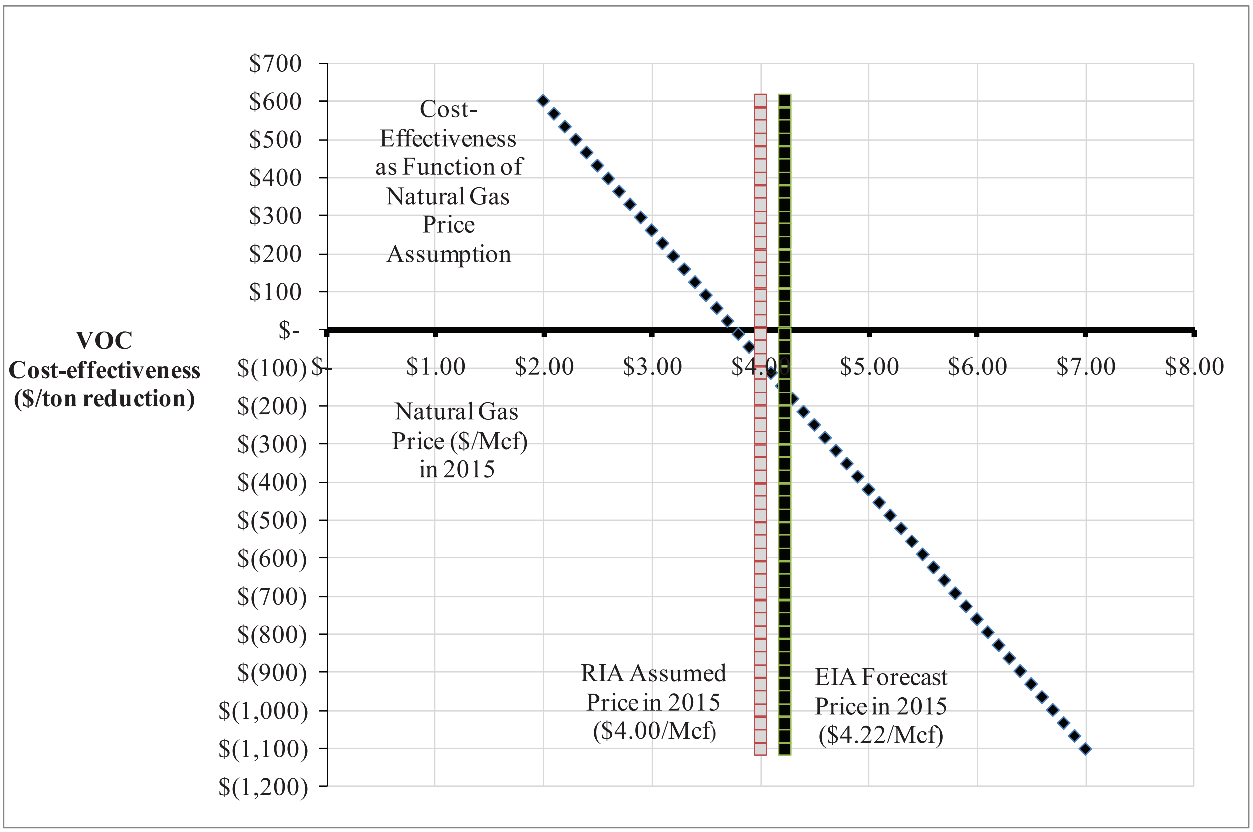

Figure 6-1 Illustrative Break-Even Diagram for Alternate Natural Gas Prices for the NSPS

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.

[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>.

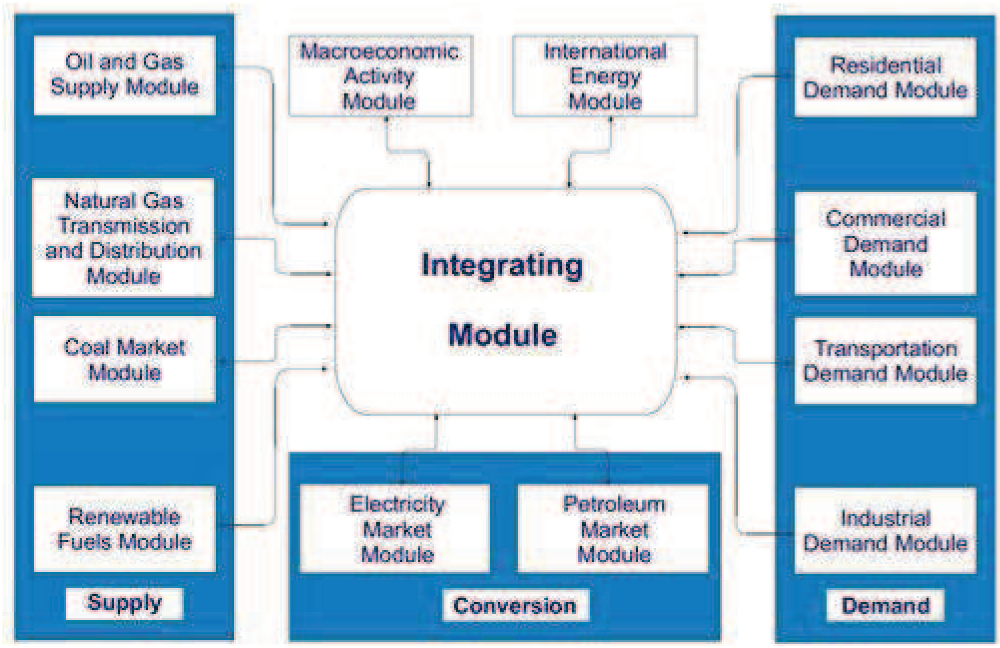

Figure 7-1 Organization of NEMS Modules (source: U.S. Energy Information Administration)

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

		Future NSPS Scenario, 2015			
	2011	**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

	2011	Future NSPS Scenario, 2015 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

	2011	Future NSPS Scenario, 2015 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

	2011	Future NSPS Scenario, 2015 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 environment while promoting economic growth, innovation, competitiveness, and job creation" (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.

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[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:

- *Establishment*: 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

			Owned by Firms with:					
NAICS	NAICS Description	SBA Size Standard (effective Nov. 5, 2010)	< 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

NAICS	NAICS Description	Total Firms	Percent of Firms: Small Businesses	Percent of Firms: Large Businesses	Percent of Firms: 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

Firm Type/Size	Number of Firms	Estimated Revenues (millions, 2008 dollars) 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.

7.5 References

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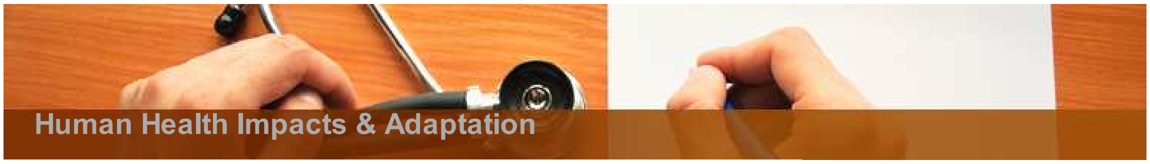
EPA United States Environmental Protection Agency

Climate Change

Human Health Impacts & Adaptation

climatechange/impacts-adaptation/health.html#adapt



[Climate Impacts on Human Health](#) [Adaptation Examples in Human Health](#)

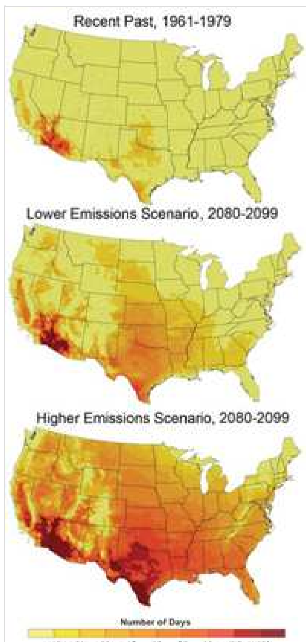
Weather and climate play a significant role in people's health. Changes in climate affect the average weather conditions that we are accustomed to. Warmer average temperatures will likely lead to hotter days and more frequent and longer heat waves. This could increase the number of heat-related illnesses 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

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

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.

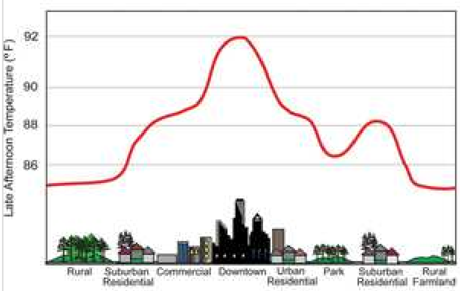
Related Links

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)

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]

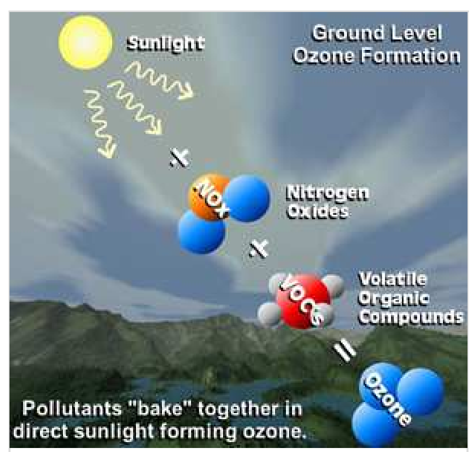
- Ground-level ozone can damage lung tissue and can reduce lung function and inflame airways. This can increase respiratory symptoms and aggravate asthma or other lung diseases. It is especially harmful to children, older adults, outdoor workers, and those with asthma and other chronic lung diseases. [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)

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]



Ozone chemistry. Source: NASA (2012)

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]

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)

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 Thursday, June 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 Thursday, July 12, 2012

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.

You will 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.

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 Friday, June 15, 2012

United States Environmental Protection Agency

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

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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.

Detailed questions concerning the National Energy Modeling System and the *Annual Energy Outlook 2009* may be addressed to the following analysts:

AEO2009	Paul D. Holtberg (paul.holtberg@eia.doe.gov, 202/586-1284)
Integrating Module/Carbon Emissions. . .	Daniel H. Skelly (daniel.skelly@eia.doe.gov, 202-586-1722)
Macroeconomic Activity Module	Kay A. Smith (kay.smith@eia.doe.gov, 202/586-1132)
International Energy Module.	Adrian Geagla (adrian.geagla@eia.doe.gov, 202/586-2873)
Residential Demand	John H. Cymbalsky (john.cymbalsky@eia.doe.gov, 202/586-4815)
Commercial Demand	Erin E. Boedecker (erin.boedecker@eia.doe.gov, 202/586-4791)
Industrial Demand	Amelia L. Elson (amelia.elson@eia.doe.gov, 202/586-1420)
Transportation Demand	John D. Maples (john.maples@eia.doe.gov, 202/586-1757)
Electricity Demand Module	Jeffrey S. Jones (jeffrey.jones@eia.doe.gov, 202/586-2038)
Renewable Fuels Module	Chris R. Namovicz (chris.namovicz@eia.doe.gov, 202/586-7120)
Oil and Gas Supply Module	Eddie L. Thomas, Jr. (eddie.thomas@eia.doe.gov, 202/586-5877)
Natural Gas Transmission and Distribution Module	Joseph G. Benneche (joseph.benneche@eia.doe.gov, 202/586-6132)
Petroleum Market Module	William S. Brown (william.brown@eia.doe.gov, 202/586-8181)
Coal Market Module	Diane R. Kearney (diane.kearney@eia.doe.gov, 202/586-2415)

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.

National Energy Information Center, EI-30
Energy Information Administration, Forrestal Building
Washington, DC 20585, Telephone: 202/586-8800
FAX: 202/586-0727, TTY: 202/586-1181
9 a.m. to 5 p.m., eastern time, M-F
E-mail: infoctr@eia.doe.gov
World Wide Web Site: http://www.eia.doe.gov, FTP Site: ftp://ftp.eia.doe.gov

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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.

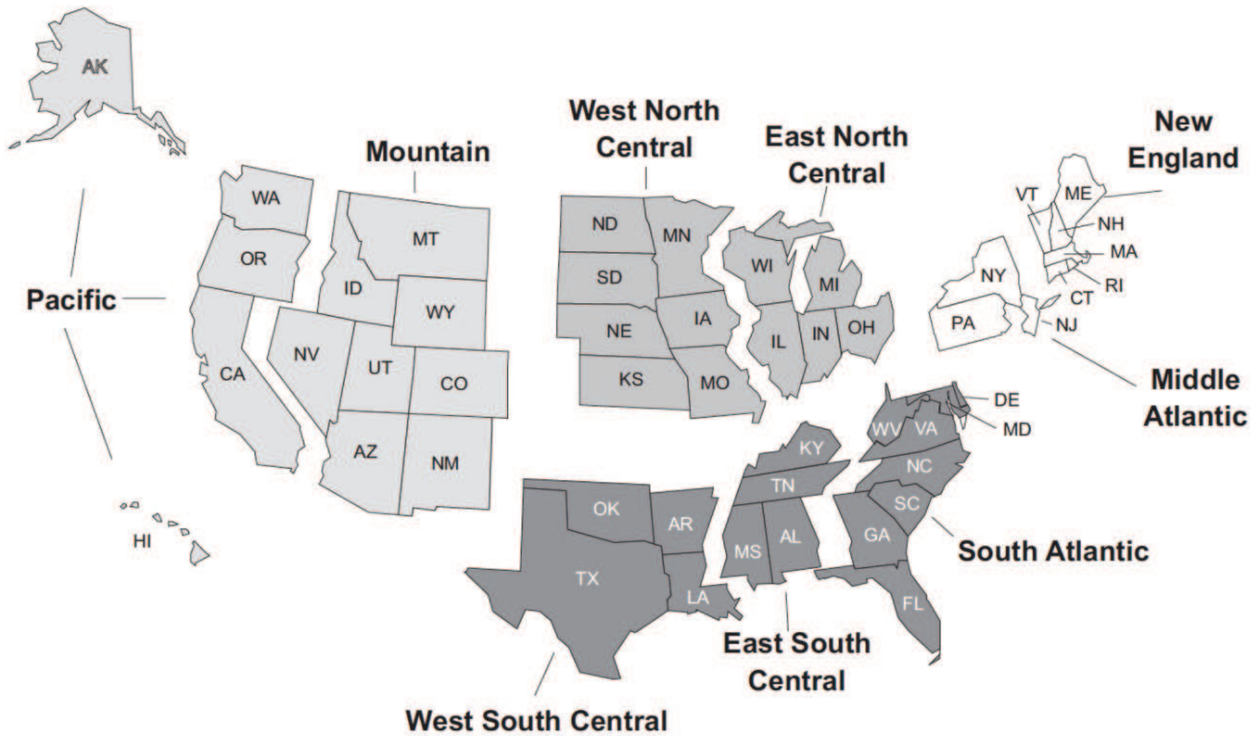
Because energy markets are heterogeneous, a single methodology does not adequately represent all supply, conversion, and end-use demand sectors. The modularity of the NEMS design provides the flexibility for each component of the U.S. energy system to use the methodology and coverage that is most appropriate. 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.

Overview of NEMS

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

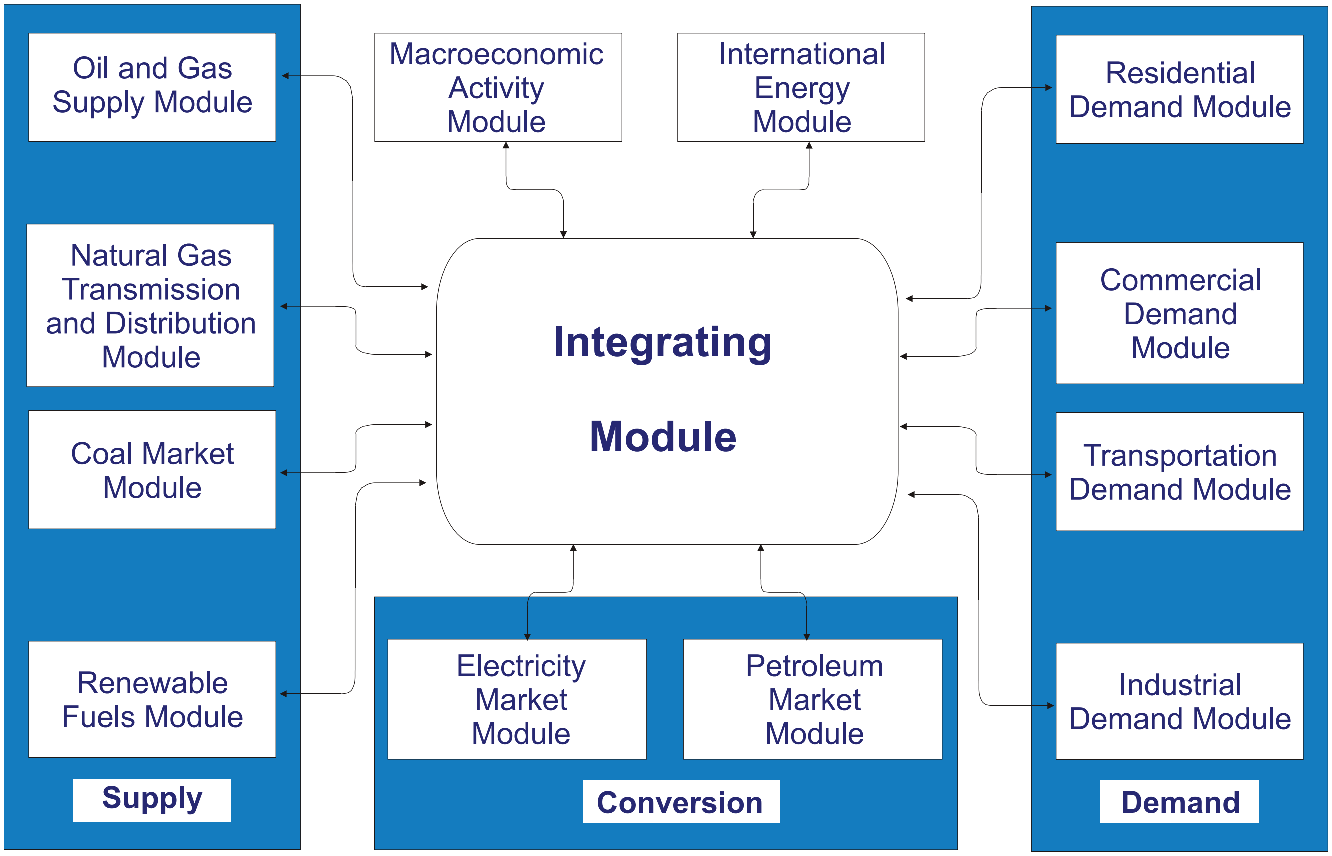
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

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.

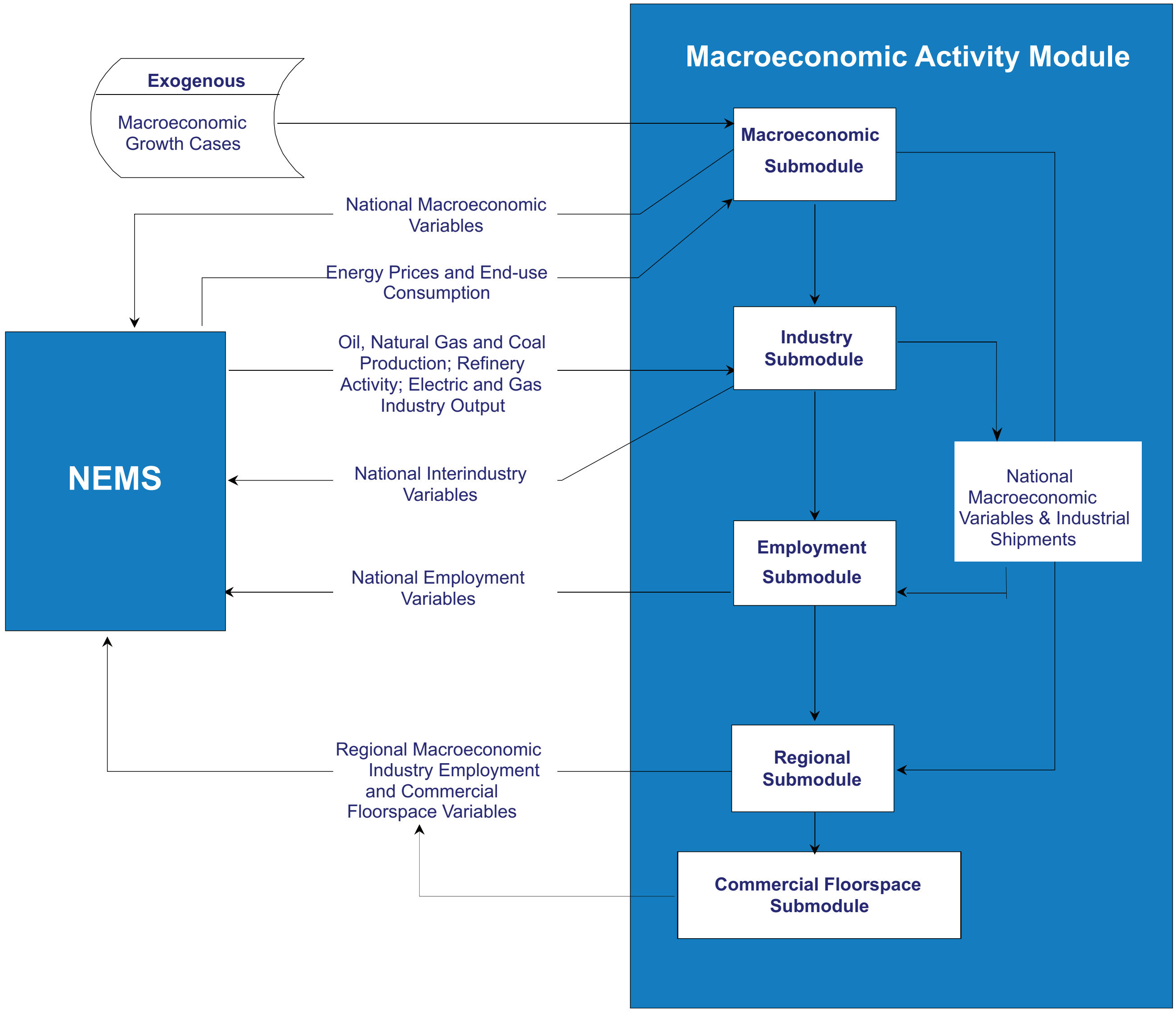
The Industry Submodule takes the final demand projections from the Macroeconomic Submodule as inputs to provide projections of output and other key indicators for 61 sectors, covering the entire economy. This is later aggregated to 41 sectors to provide information to NEMS. The Industry Submodule insures 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.

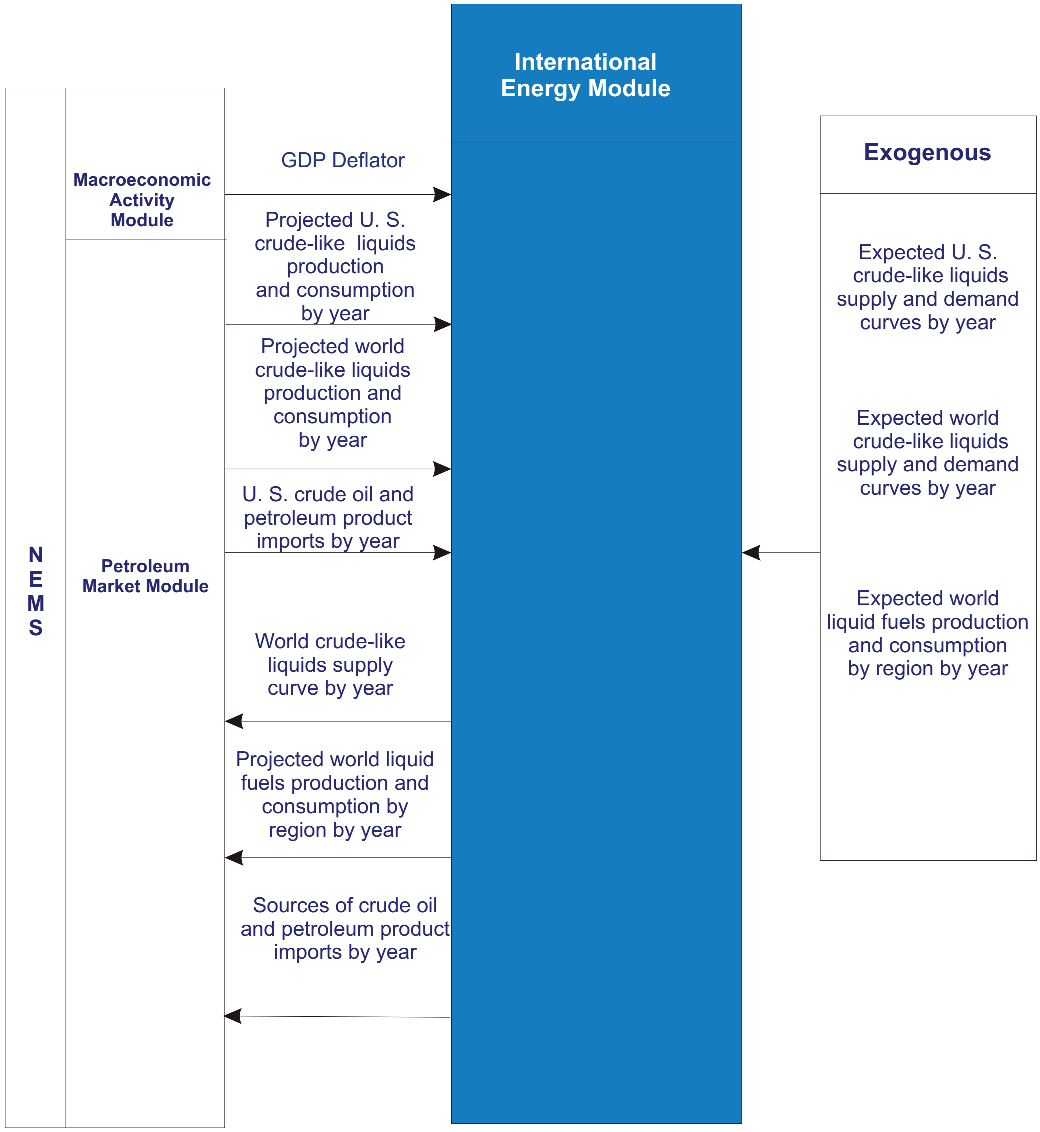
Because U.S. production and consumption of conventional liquids are dynamic values (output from NEMS), all other world regions have been proportionally updated such that the world liquids production and consumption reflect the corresponding value as in the *International Energy Outlook* (*IEO*).

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

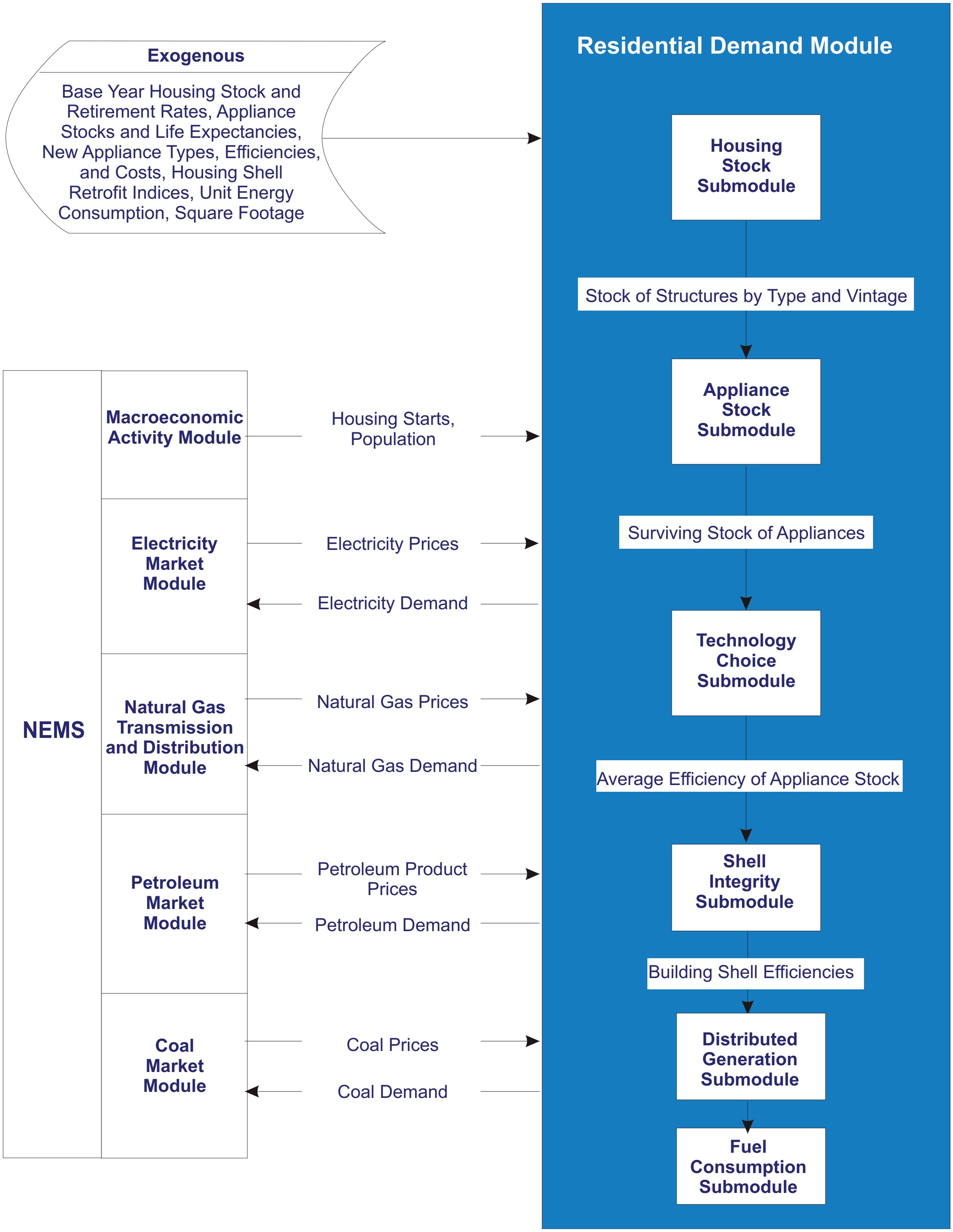


Table 2. NEMS Residential Module Equipment Summary

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

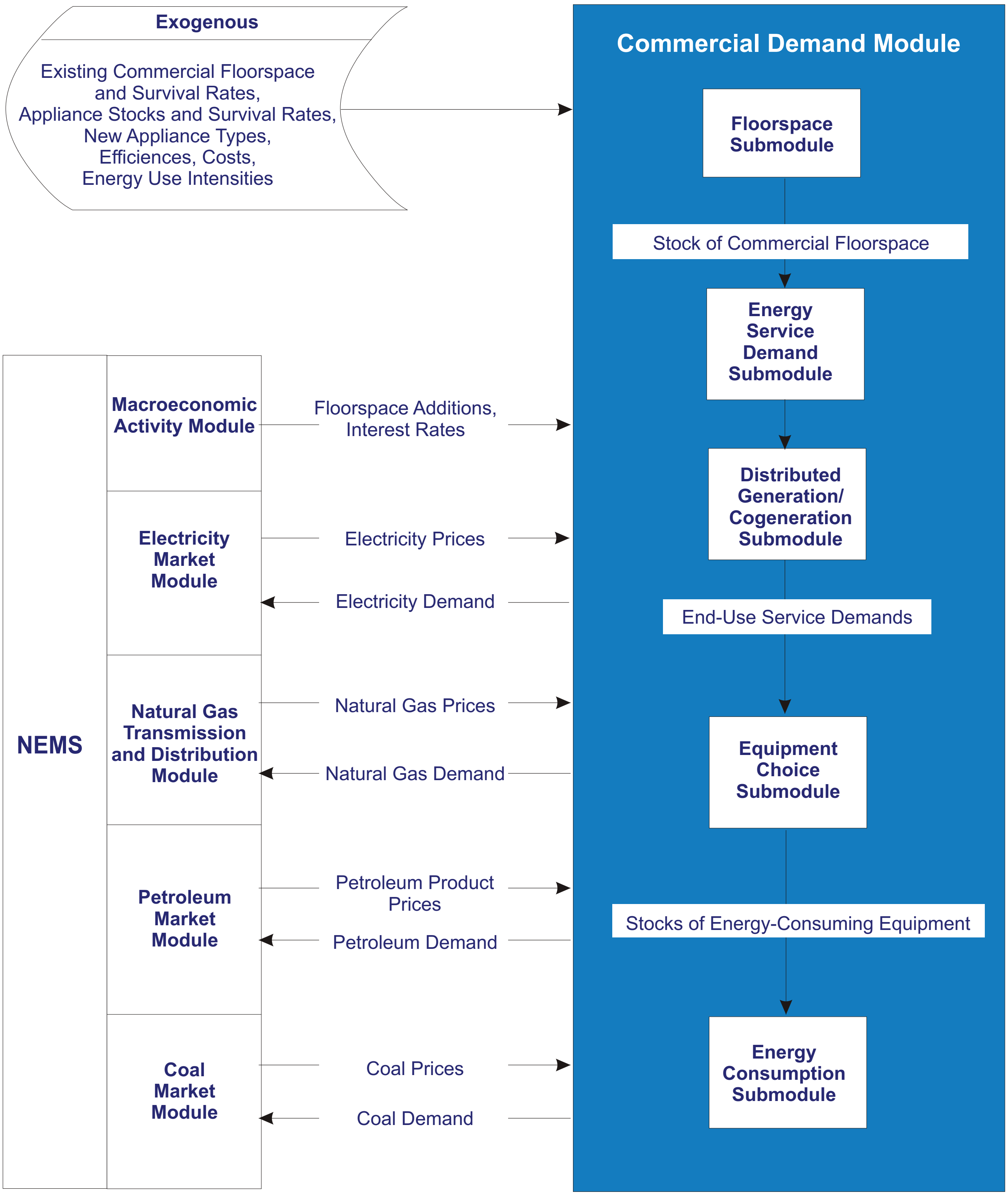
The base stock of commercial floorspace by Census division and building type is derived from EIA's 2003 Commercial Buildings Energy Consumption Survey (CBECS). CDM receives projections of total floorspace by building type and Census division from the macroeconomic activity module (MAM) based on IHS Global 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).

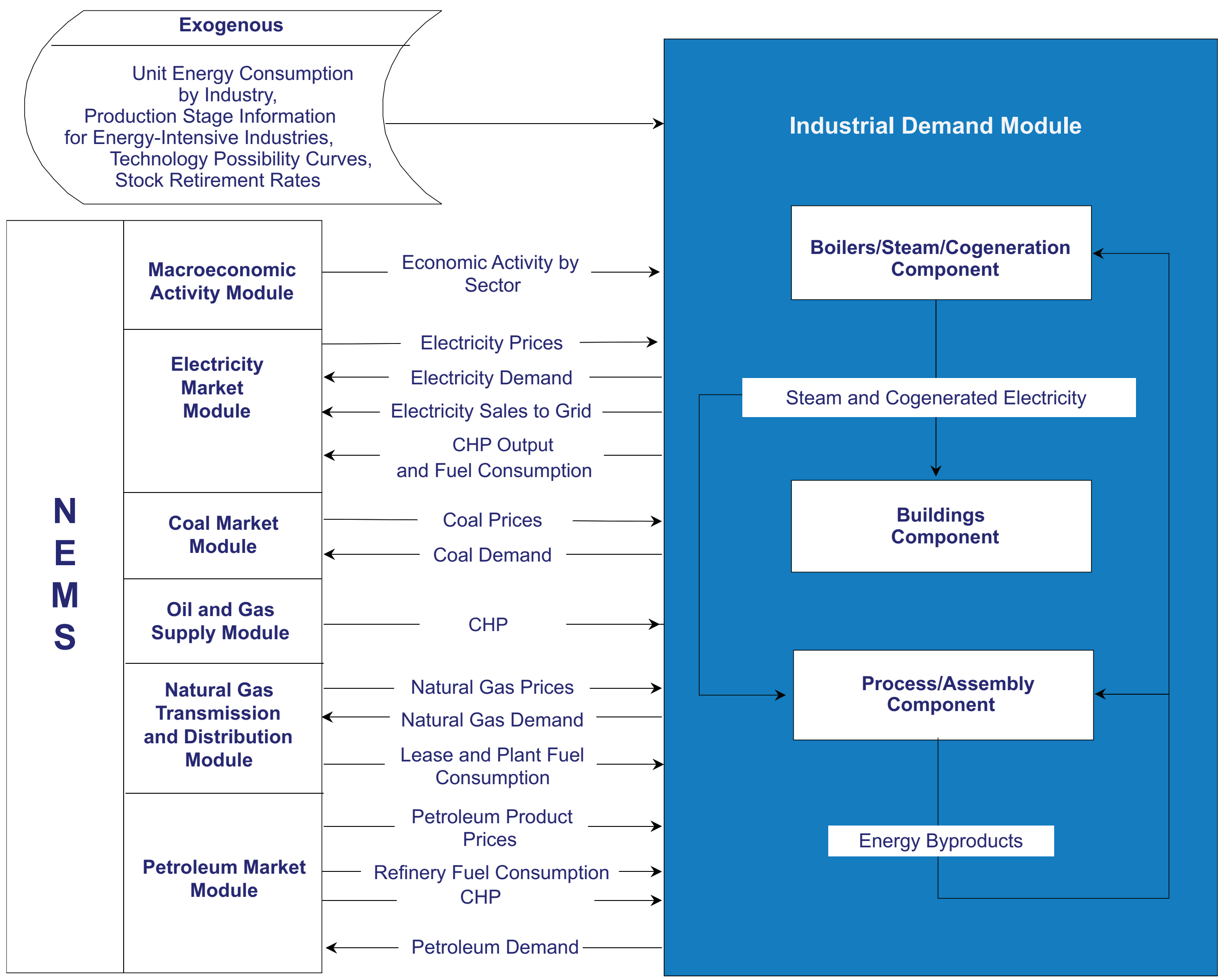
Table 6. Economic Subsectors Within the IDM

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

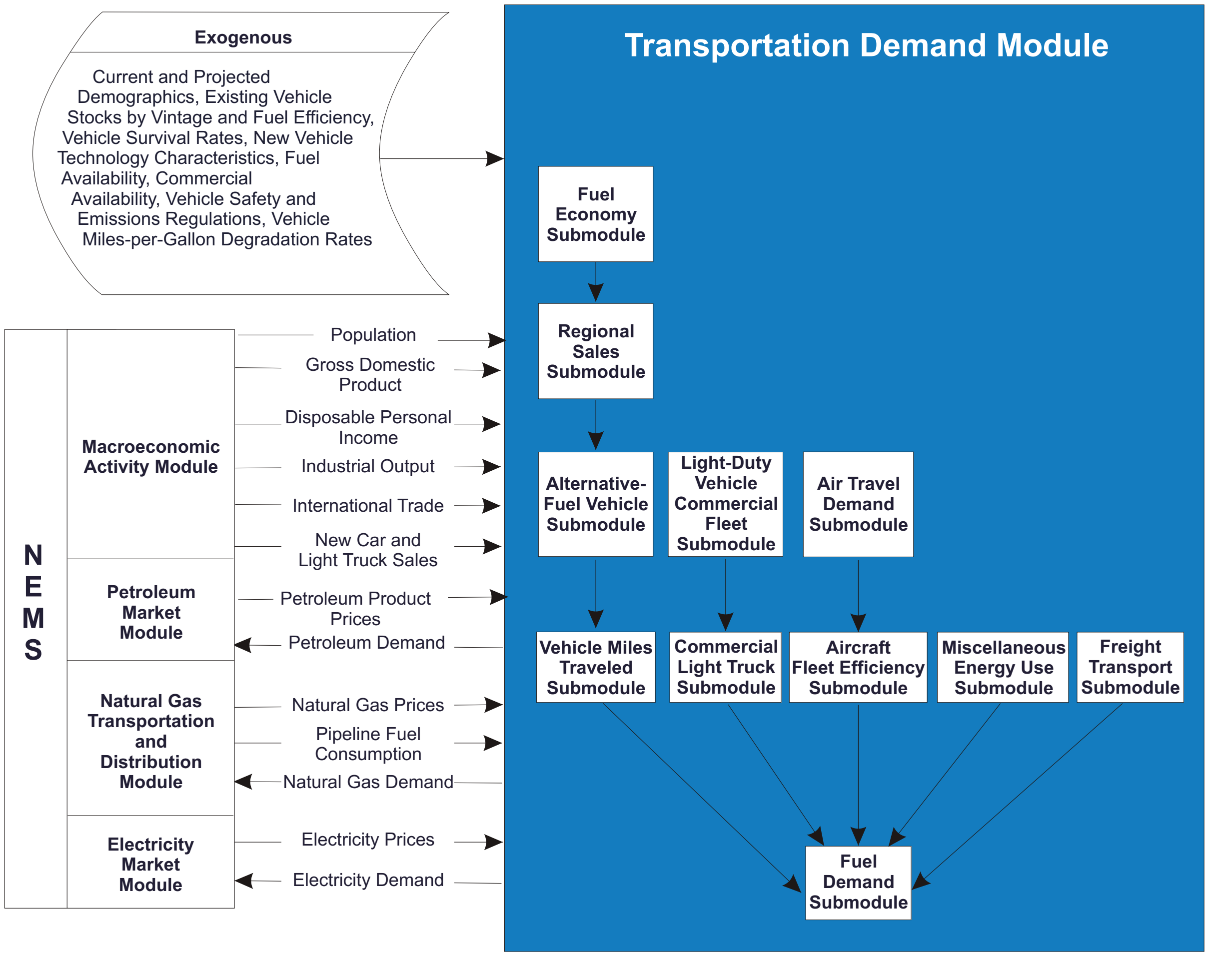
Table 9. Examples of Midsize Automobile Attributes

	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.

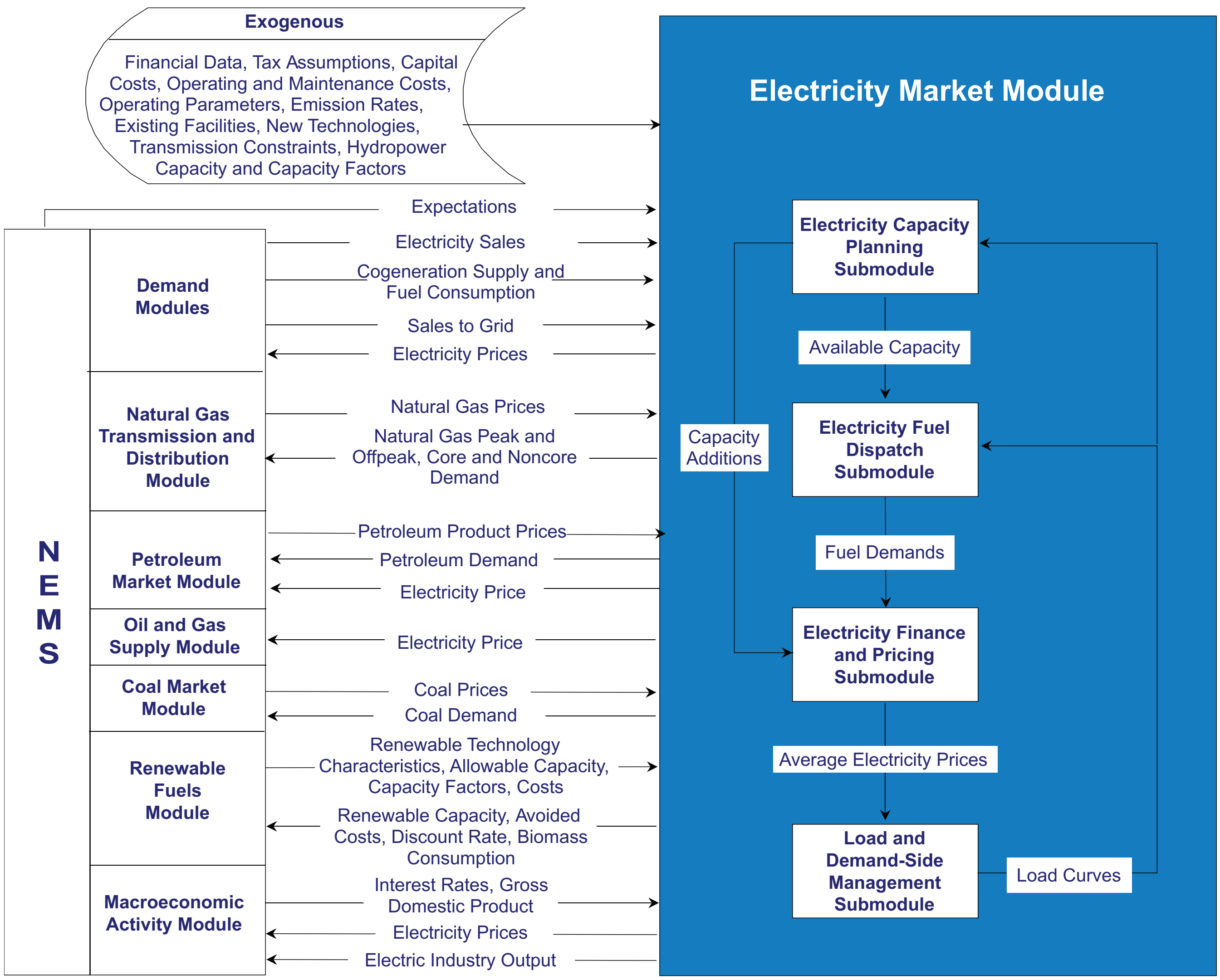
Electricity Capacity Planning Submodule

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.

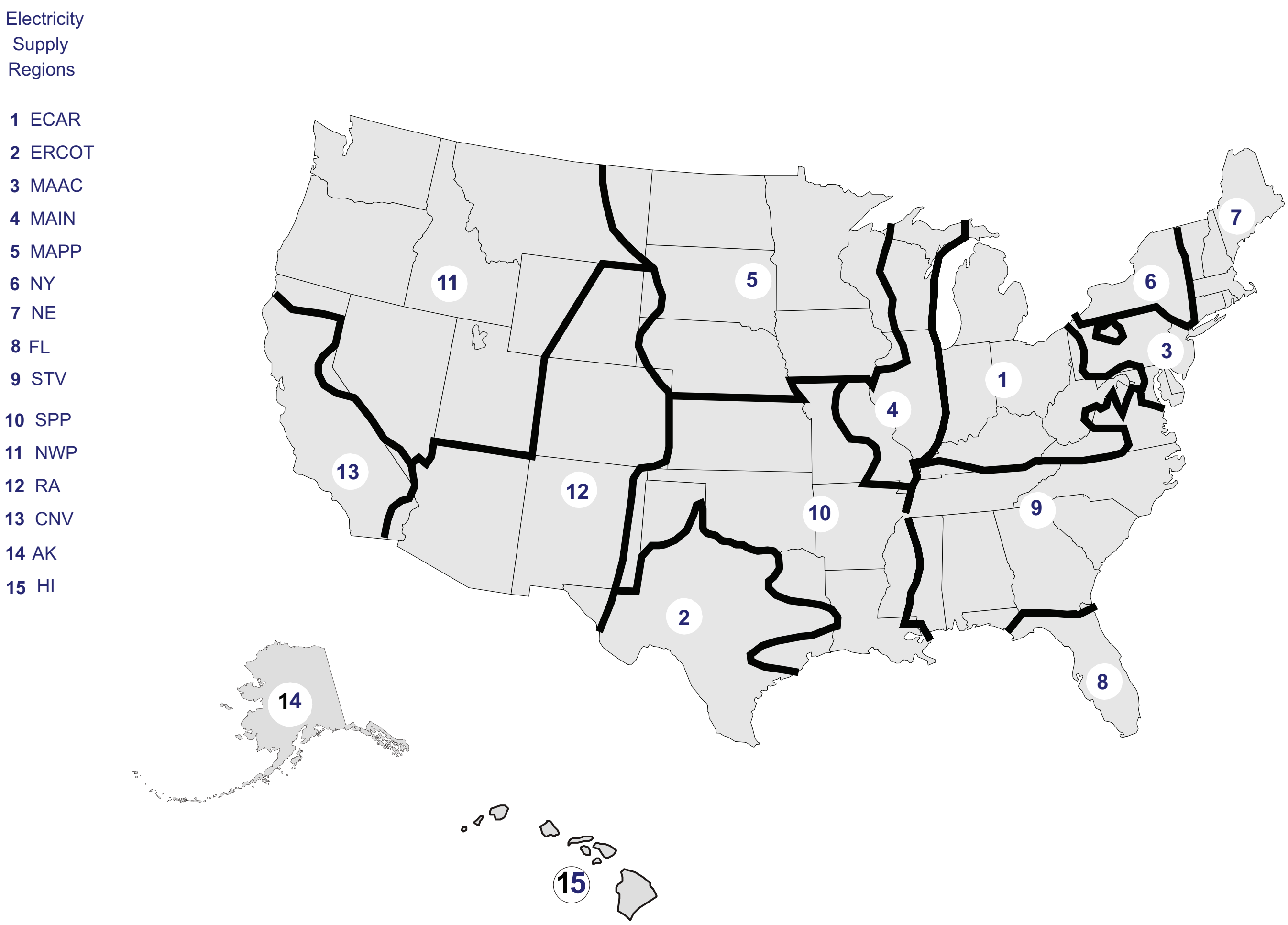
Technologies are compared on the basis of total capital and operating costs incurred over a 20-year period. As new technologies become available, they are competed against conventional plant types. Fossil-fuel, nuclear, and renewable central-station generating technologies are represented, as listed 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

Electricity Market Module

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.

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

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.

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

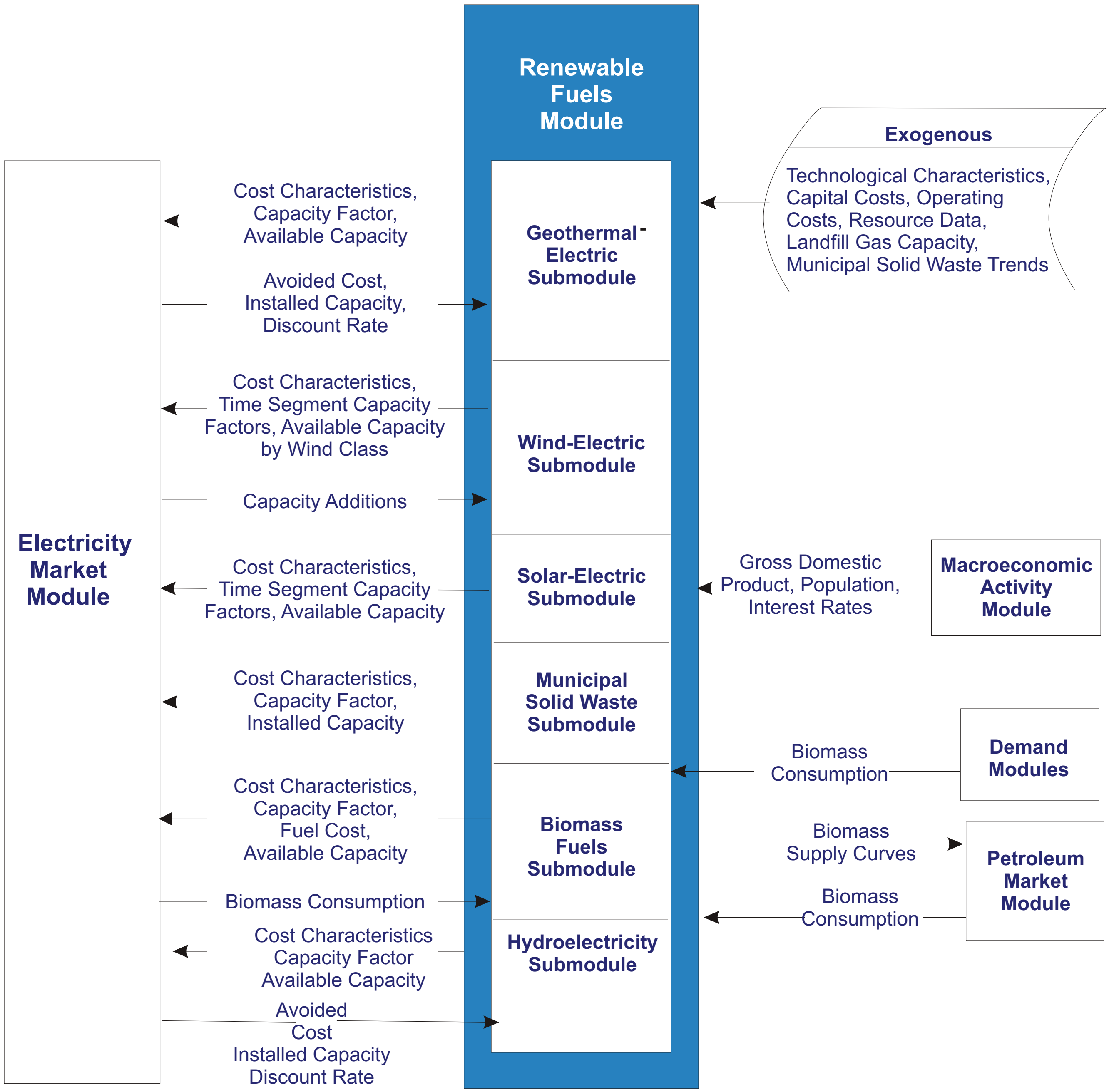
The wind-electric submodule projects the availability of wind resources as well as the cost and performance of wind turbine generators. This information is passed to EMM so that wind turbines can be built and dispatched in competition with other electricity generating technologies. The wind turbine data 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.

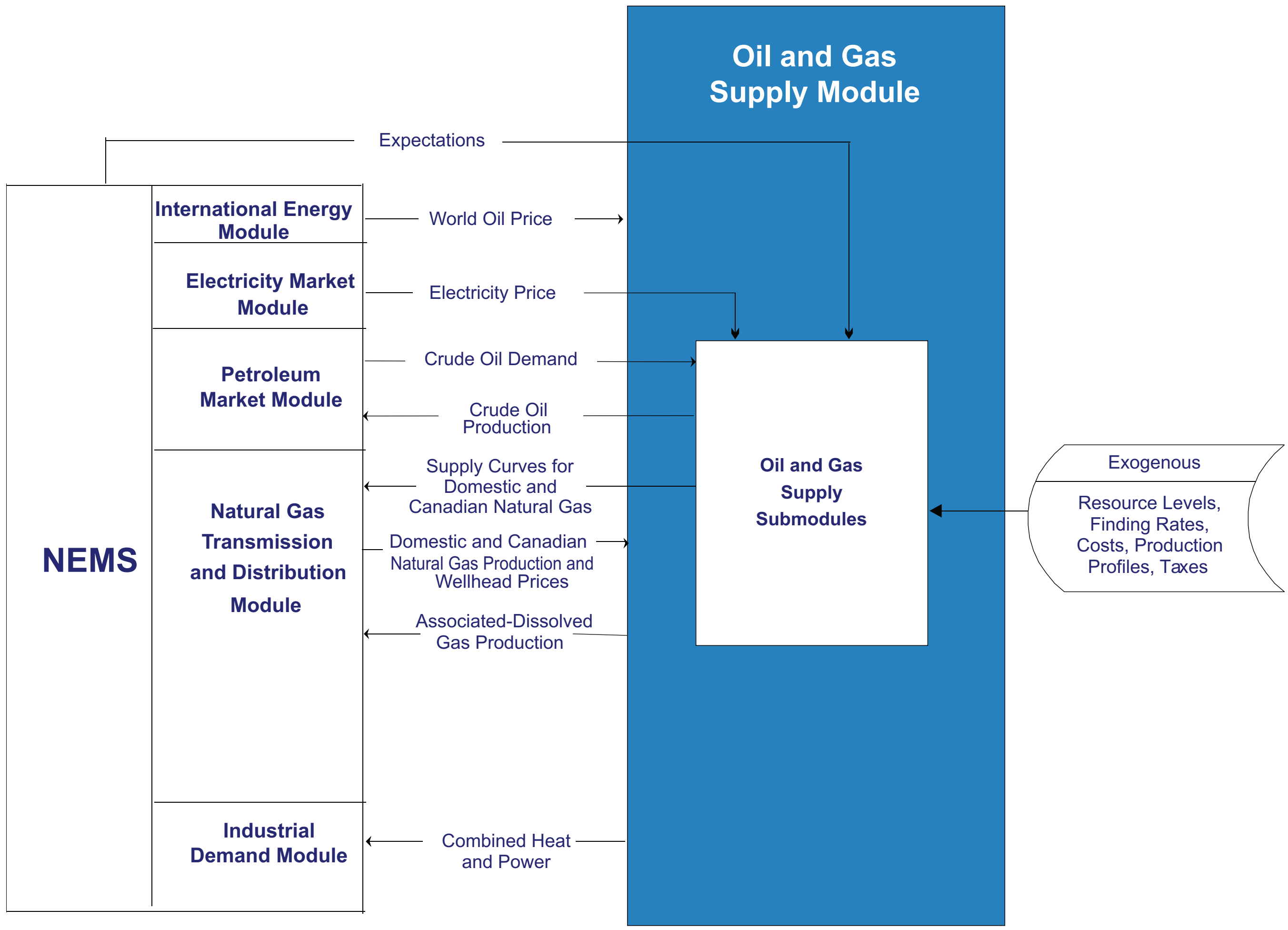
Unconventional Gas Recovery Supply Submodule

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.

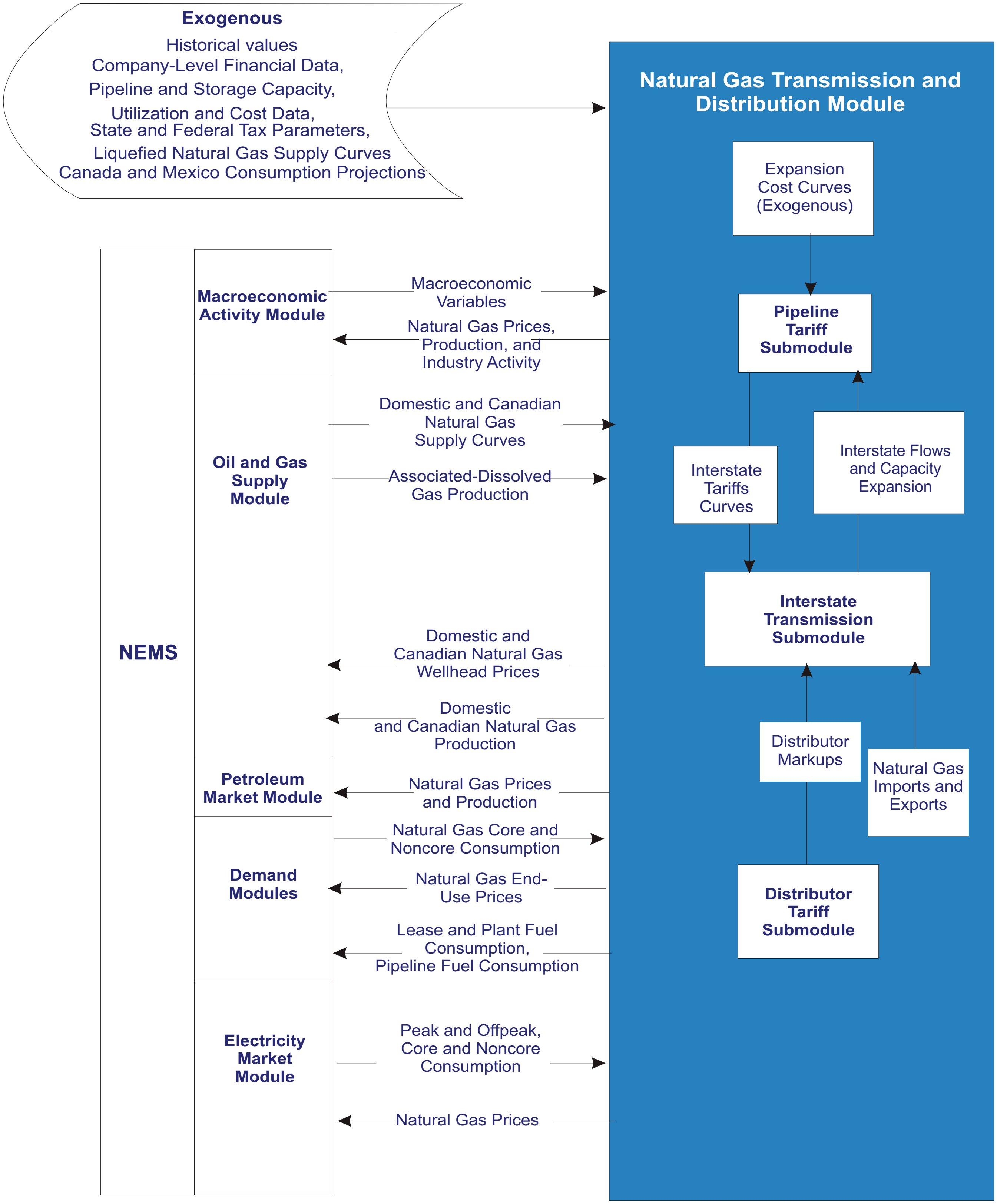
Interstate Transmission Submodule

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.

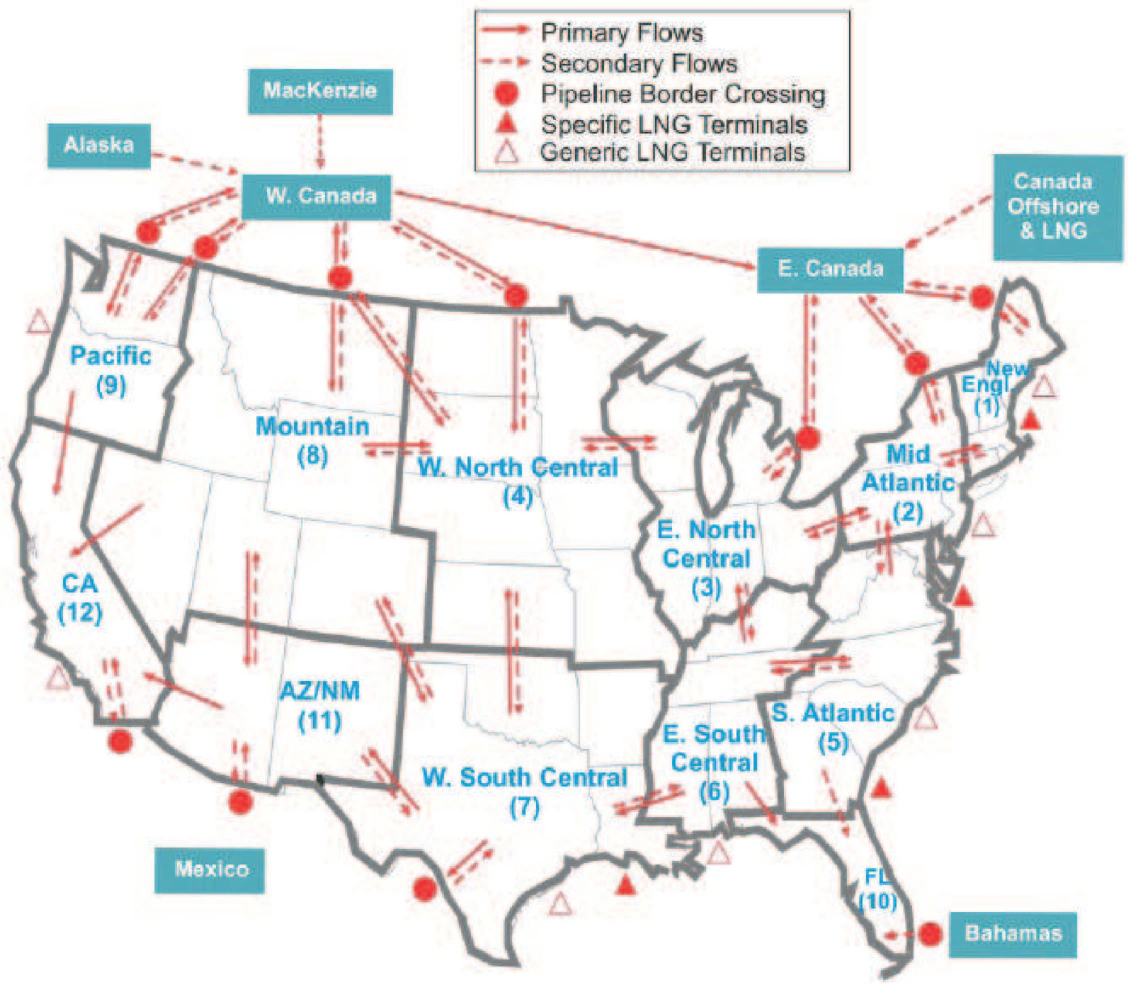
Natural Gas Imports and Exports

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

Natural Gas Transmission And Distribution Module

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 Crude oil imports and exports Crude oil demand Petroleum product imports and exports Refinery activity and fuel use Ethanol demand and price Combined heat and power (CHP) Natural gas plant liquids production Processing gain Capacity additions Capital expenditures Revenues	Petroleum product demand by sector Domestic crude oil production World oil price International crude oil supply curves International product supply curves International oxygenates supply curves Natural gas prices Electricity prices Natural glas production Macroeconomic variables Biomass supply curves Coal prices	Processing unit operating parameters Processing unit capacities Product specifications Operating costs Capital costs Transmission and distribution costs Federal and State taxes Agricultural feedstock quantities and costs CHP unit operating parameters CHP unit capacities

Figure 16. Petroleum Market Module Structure

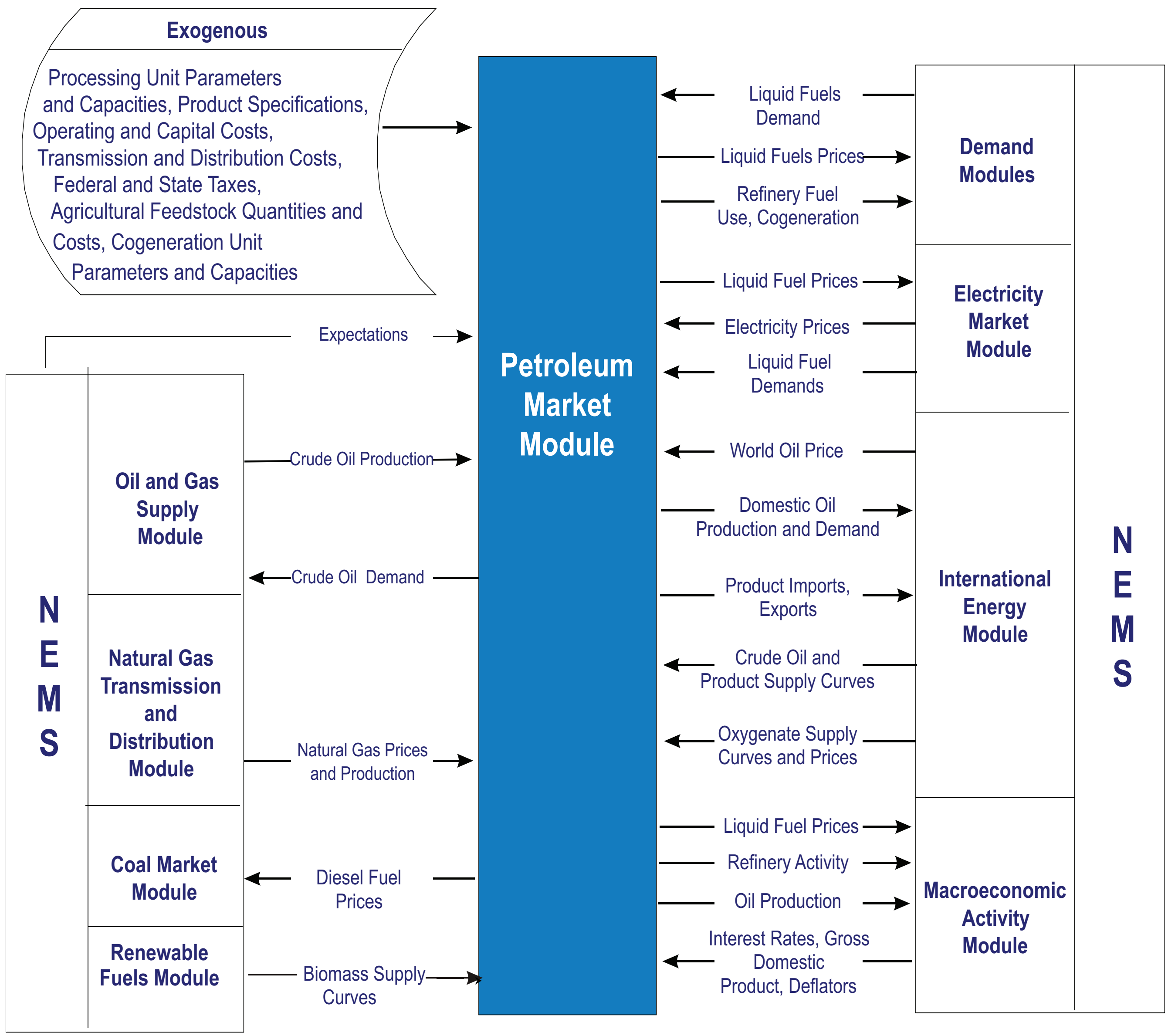
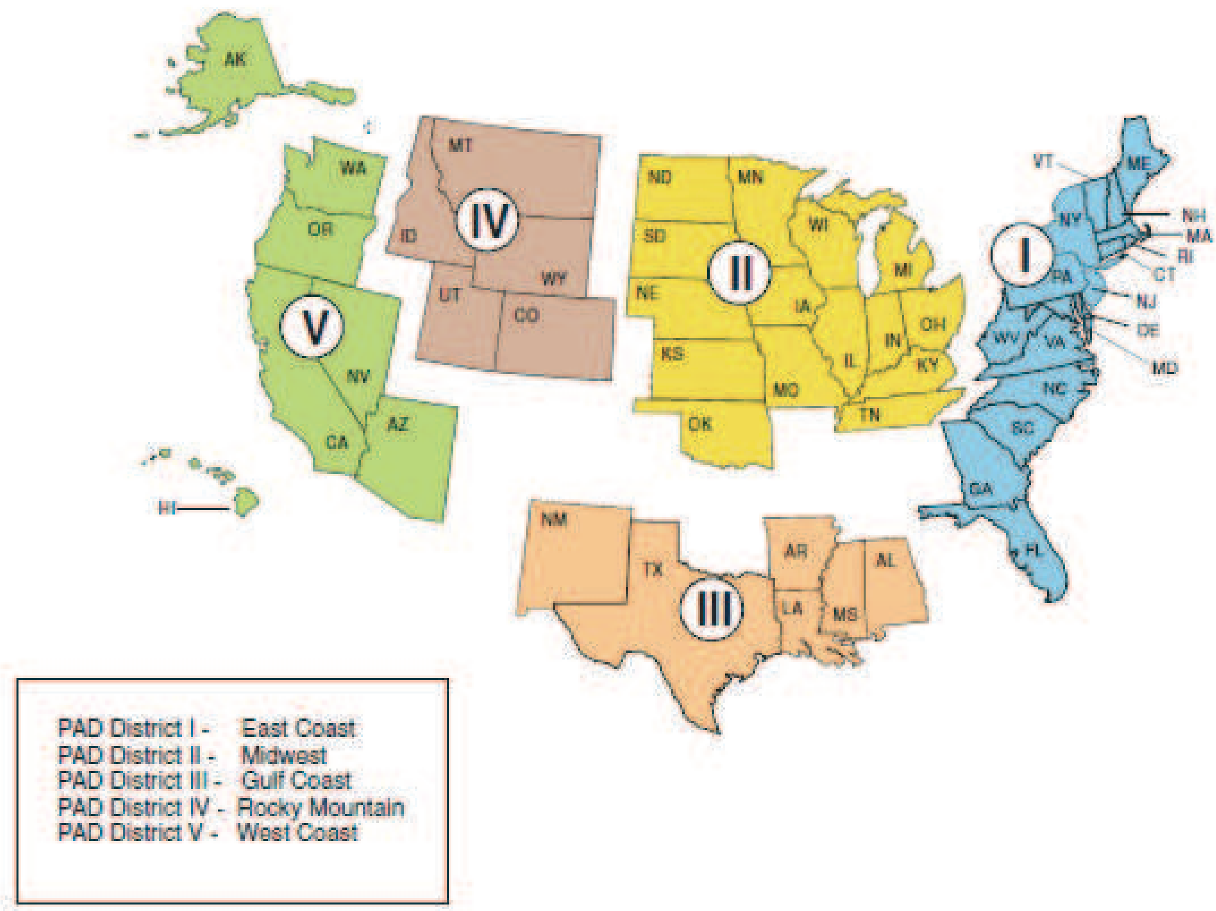


Figure 17. Petroleum Administration for Defense Districts



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.

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.

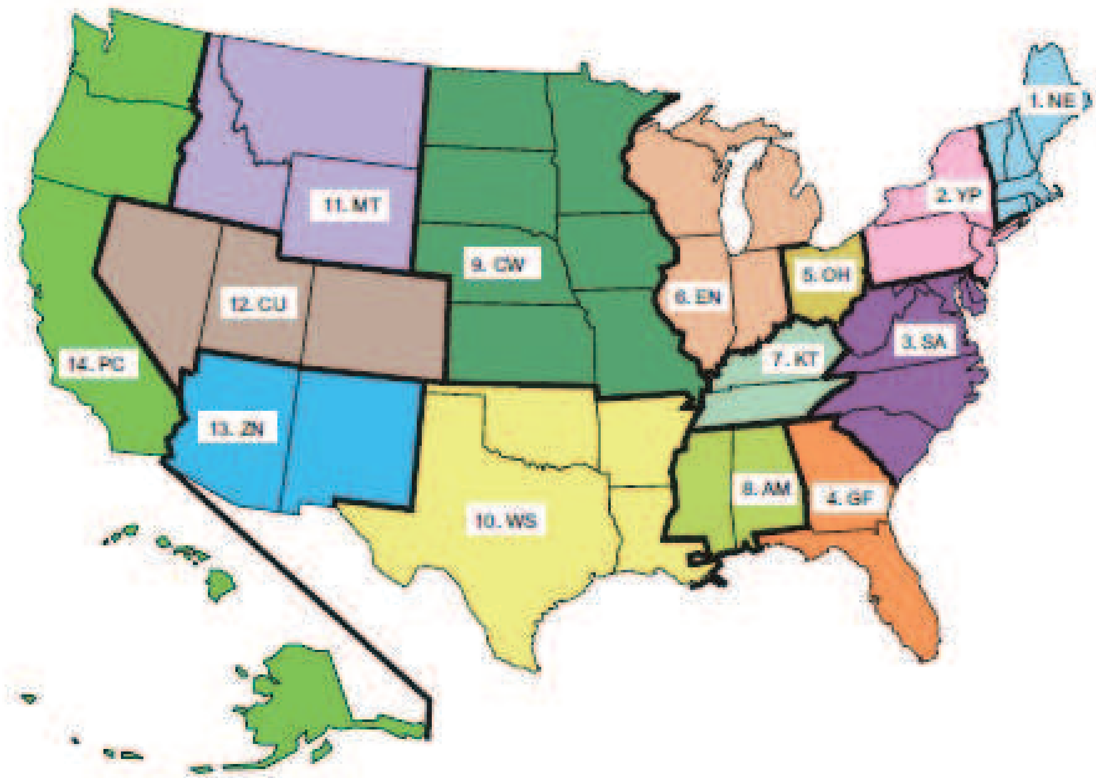
Coal transportation costs are simulated using interregional coal transportation costs derived by subtracting reported minemouth costs for each supply curve from reported delivered costs for each demand type in each demand region. For the electricity sector, higher transportation costs are assumed for 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

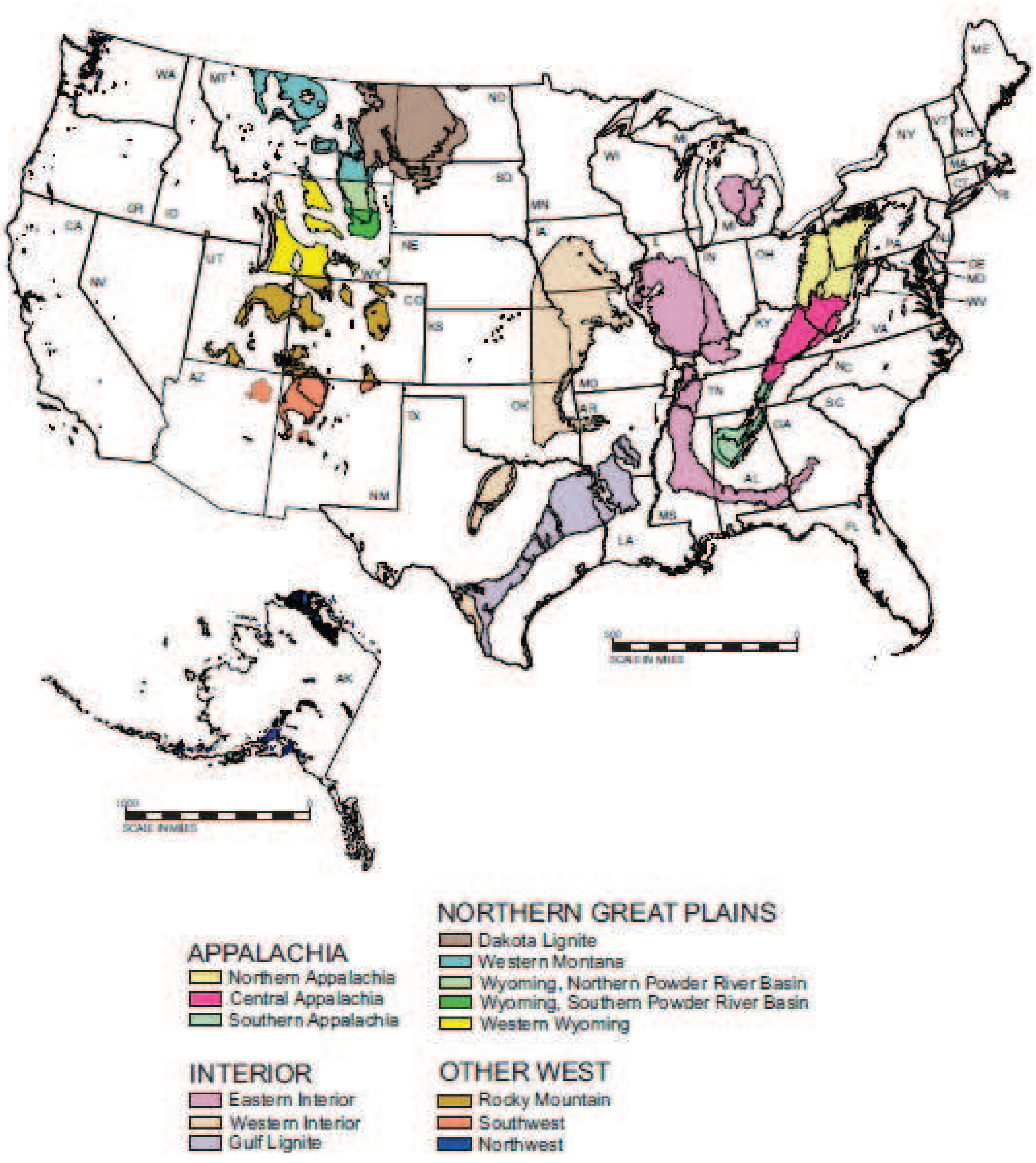
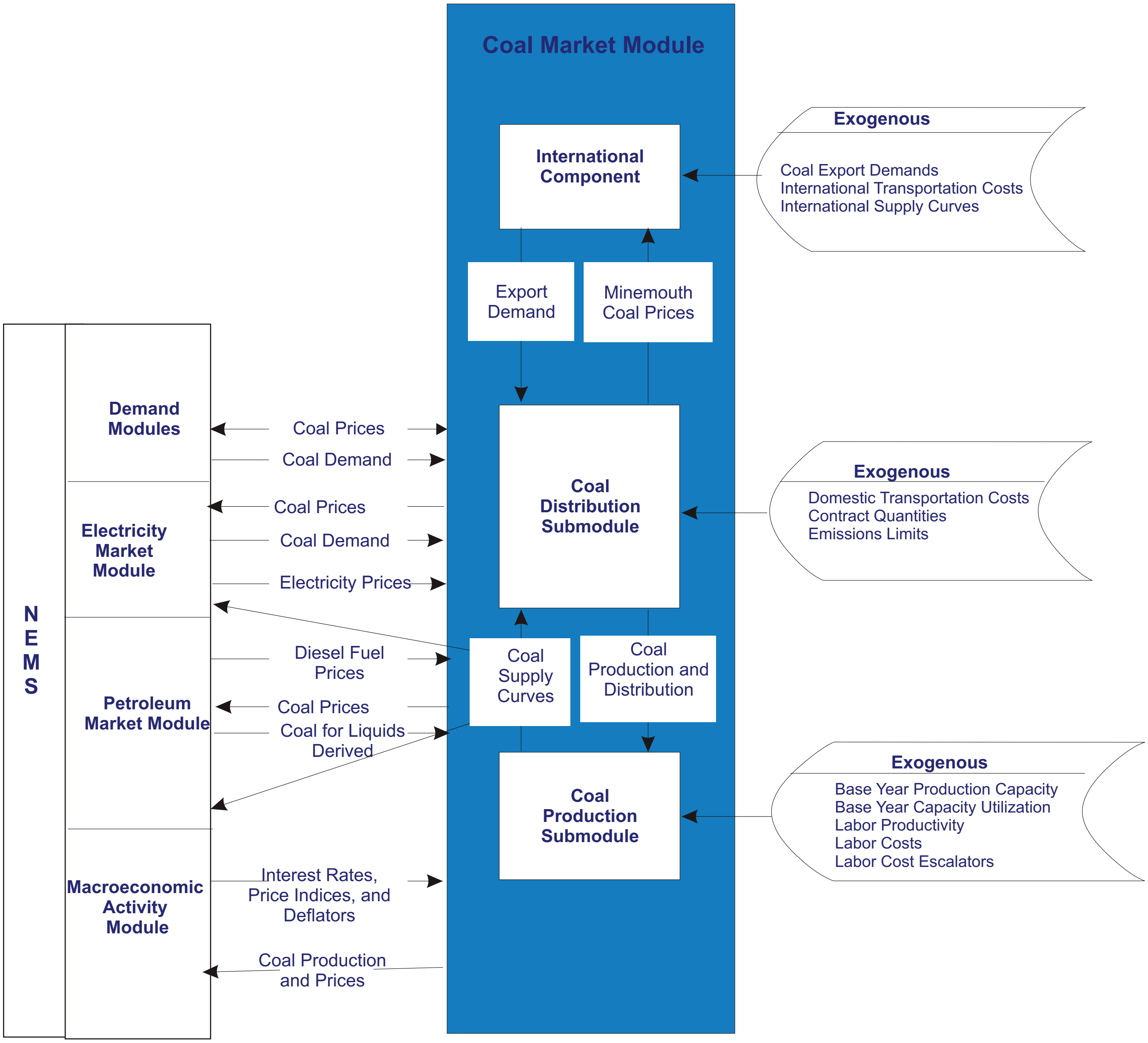


Table 13. Coal Export Component

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

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).

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