TECHNICAL MEMORANDUM

September 30, 2012

Prepared by:

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Re: Assessment of Groundwater Sampling Results Completed by the U.S. Geological Survey

Summary

The organic chemistry at MW01 has not changed substantially since the EPA sampled the well; some constituents have increased and some have decreased, as would be expected with organic contaminants discharging from a series of event, the hydraulic fracturing of natural gas wells. Because the water chemistry data at MW01 has essentially been replicated, the evidence supporting the hypothesis that natural gas drilling activities, including fracking, have contaminated the Wind River aquifer near Pavillion WY has been strengthened. The conclusions based on that analysis should be more widely accepted now that the water quality has been replicated.

The concentrations of gas, including methane and ethane, have increased and that of propane has remained relatively constant. The ratio of ethane and propane to methane and the isotopic signature of methane all indicate that the gas source is thermogenic, meaning a deep formation. An increasing concentration indicates the formation is likely the source because the concentration will increase as more of the formation contributes to gas at the monitoring well.

EPA monitoring well 2 was not sampled because it did not yield sufficient water. The EPA had been able to purge over a borehole's volume of water, therefore they were clearly sampling formation water. There is no reason to consider that the current condition of MW02 negates the results of the EPA in 2011.

The problems with MW02 however indicate other problems with the sampling of these wells. The USGS used standard purge techniques, not techniques designed to minimize losses of volatile organics to the atmosphere. Purging too fast or drawing the water level too low could cause the measurement to be biased too low.

Introduction

The U.S. Environmental Protection Agency (EPA) published in late 2011 a study assessing the association of various organic compounds, which could be associated with the presence of

natural gas development, or hydraulic fracturing (fracking), in water wells and monitoring wells near Pavillion WY. This study was one of the first to document fracking fluid chemicals in water wells and monitor wells away from the actual natural gas wells. The U.S. Geological Survey (USGS) recently published a data-series report (Wright et al 2012) that reports groundwater quality sampling completed in one of EPA's monitoring wells that had been constructed and sampled for the EPA study.

Wright et al (2012) do not make any conclusions regarding the data presented nor do they compare it to the original EPA report (EPA 2011). They present sampling and quality control data in detail. This memorandum takes the USGS study an additional step by comparing the results released in the new study with the original EPA report (EPA 2011). It considers whether the new data refutes the original EPA study, either with the actual chemistry data collected or by showing problems with EPA monitoring well 2.

Sampling and Chemistry of EPA Monitoring Well 1

USGS sampled EPA monitoring well # 1 (MW01) in late April 2012. The USGS collected four types of blank samples and two replicates from the well after purging more than a borehole's volume of water. Spike samples were also created to assess the accuracy of the testing equipment at the labs. EPA monitoring well # 2 (MW02) was not similarly sampled for reasons discussed in a following section.

Sampling commenced by purging groundwater from the well to remove the static water from the borehole. Their goal had been to remove at least one borehole volume, or 429 gallons, or to the point where several parameters including pH and EC stabilized. The USGS began pumping about 6 gpm which lowered the water level about 135 feet within the time that 300 gallons were removed from the well bore. At that point, the pumping rate dropped to about 2.5 gpm and the water level quickly recovered about 60 feet. Sampling commenced at about 670 cumulative gallons. Purging continued, and the second environmental sample commenced after about 1300 cumulative gallons. Thus the samples were taken after about one and half and three bore holes volume, respectively. The purge rate was commensurate with that used by the EPA for MW01 in that they started at 7.3 gpm and reduced it to about 6 gpm as the water level quickly dropped (EPA 2011).

The USGS did not sample exactly the same constituents as did the EPA. The USGS sampled many constituents and their Table 7 lists many that had below detect (ND) levels, as did the EPA. Table 1 compares constituents found by either the EPA (2011) or the USGS (Wright et al 2012), or by both.

Table 1: Comparison of water chemistry for EPA Monitoring Well # 1 for EPA phase 3 and 4 sampling (EPA 2011) with environmental samples 1 and 2 as reported by Wright et al (2012). The table includes only constituents for which there were detectable values at least once. Nd means no detect. Blank table cells under Phase 3 or 4 mean no sample. P means preservative added.

Name	Units	Phase 3	Phase 4	Env Sample 1	Env Sample 2
pH		11.9	11.2	11.4	10.7
K	mg/l	54.9	24.7	15	13
Cl	mg/l	23.3	23.1	26	27
Diesel-range organics [C10–C28]	µg/L	634	924	180	85
Gasoline-range organics [C6–C10]	µg/L	389	592	700	730
Gasoline-range organics [C6–C10]	µg/L			1100p	700p
3 & 4 Methylphenol	µg/L	included in phenol		0.95	0.47
Benzoic acid	µg/L	212	457	340	190
Benzyl alcohol	µg/L			0.59	nd
Phenol	µg/L	11.1	20.9	10	6.1
1-Methylnaphthalene	µg/L			0.0096	nd
2-Methylnaphthalene	µg/L			0.0110	0.0072
Benzo[*a*]anthracene	µg/L			nd	0.0042
Benzo[*a*]pyrene	µg/L			nd	0.0410
Benzo[*b*]fluoranthene	µg/L			nd	0.0310
Benzo[*g,h,i*]perylene	µg/L			0.0410	0.0740
Benzo[*k*]fluoranthene	µg/L			nd	0.0290
Chrysene	µg/L			nd	0.0037
Dibenz(*a,h*)anthracene	µg/L			nd	0.0510
Fluoranthene	µg/L			nd	0.0063
Indeno[1,2,3-*cd*]pyrene	µg/L			0.0160	0.0570
Pyrene	µg/L			0.0089	0.0130
Methylene blue active substances	mg/L			0.14	0.15
Methane	µg/L	15950	17930	27,500	25,500
Methane	µg/L			27,000p	20,000p
Ethane	µg/L	2230	2950	3,600	3,200
Ethane	µg/L			3,800p	2,600p
Ethylene	µg/L			7.2	7.2
Ethylene	µg/L			7.2p	7.2p

Propane	µg/L	790	1250	1,400	1,100
Propane	µg/L			1,300p	1,000p
Toluene	µg/L	0.75	0.56	nd	nd
xylenes (total)	µg/L		0.89	nd	nd
isopropanol	µg/L		212	nd	nd
diethylene glycol	µg/L		226	nd	nd
triethylene glycol	µg/L		46	nd	nd
tetraethylene glycol	µg/L		7.3	nd	nd
2-butoxyethanol	µg/L		12.7	not tested	
acetate	µg/L		8050	not tested	
formate	µg/L		112	not tested	
lactate	µg/L		69	not tested	
propionate	µg/L		309	not tested	

The concentrations of potassium (K) and the pH level are still much higher than the background levels in the formation, although K has decreased since the EPA sampling. EPA linked the presence of potassium to its use as a crosslinker and solvent during fracking, according to the Material Data Safety Sheets provided by the industry. Most of the fracking occurred several years ago, therefore the source is not a continuous release. A relatively conservative element such as potassium could move through the aquifer much more quickly than some of the organics.

Gasoline range organics and the various carbon-chain gases were found at concentrations that have increased significantly since the EPA study. Benzoic acid was found at concentrations similar to the EPA (2011). Diesel range organics and phenol remained present but at lower concentrations. The USGS found at least nine organic constituents that the EPA had either not found or not tested for. USGS found acrylonitrile at 21 ug/l in one of the replicate samples, not presented in Table 1[1]. At least six constituents that had been detected by the EPA (2011) were not detected by the USGS. At least six constituents that EPA has found at various concentrations were not tested for by the USGS.

The concentration of organics at Pavillion should vary for several reasons. Changes from one sampling event to the next do not represent a trend. A non-detect does not prove the constituent does not exist.

Organics are measured at very low concentrations, parts per billion, so a relatively small change proportionally seems much larger. An acceptable spike sample is one for which the measured

[1] According to Dr. Glenn Miller, acrylonitrile is "perhaps the single best indicator of fracing, and should be considered presumptive evidence that fracing fluids have contaminated the groundwater", although he also acknowledged that one observation, in a replicated sample, is not proof. Email communication, 9/27/2012.

concentration varies from 70 t 130% of the known concentration which indicates just how variable the test methods are. Even 70% recovery could cause a sample which otherwise should have had a detectable concentration to be missed; a 130% recovery means however that a concentration can be overestimated, although it will not find a constituent in a sample in which it does not exist.

Organics attenuate by interactions with clay and silt sized particles so seasonal changes could be expected. This sampling occurred during late April, a time period during which recharge should be highest, since there is a mound in the shallow groundwater suggesting downward movement of water. Such vertical flow could dilute the formation water and cause seasonal changes not accounted for in spot samples as collected by the USGS.

The concentration of methane and ethane increased substantially and that of propane remained relatively constant. The stable isotope ratios of carbon vs. hydrogen in methane are also almost exactly as found by the EPA. The gas in MW01 is thermogenic, and its concentration is increasing. An increasing concentration of thermogenic gas suggests its source is the formation rather than a leaky gas well. The continued increase in concentration reflects that gas flow from more of the formation has reached the monitoring well, a process which will continue until it reaches equilibrium; in other words, the flow of gas through the formations, released by fracking, could reach equilibrium at the current or a higher concentration. If the formation is the source, the gas contamination will continue as long as the source releases gas.

In summary, the organic chemistry at MW01 has not changed substantially since the EPA sampled the well. The chemistry of MW01 found by the USGS is similar to that found by the EPA (2011). The new data does not disprove the hypothesis made by the EPA that natural gas drilling activities, including fracking, have contaminated the Wind River aquifer near Pavillion WY. The conclusions based on that analysis should be more widely accepted because the water quality has been replicated.

Monitoring Well 2

The USGS did not sample MW02 because the well reportedly yielded only about 1 gallon per hour (Wright et al 2012). This differs from the EPA's purging which for Phase IV reportedly removed 1249 liters (330 gallons) of water prior to sampling; EPA did find that the water level lowered more quickly than they could measure it. The USGS redeveloped the well but this did not improve the yield sufficiently for sampling, therefore they did not obtain a sample.

MW02 had been completed in a layer of sandstone approximately 20 feet thick with a shale confining layer both above and below. The resistivity logs also suggest this should be a productive zone. There is no good explanation for the well's failure to produce sufficient water for sampling, but its failure does not obviate the results found by the EPA for that well. The fact

that the well produced substantial water from the sandstone twice indicates that the formation contained the constituents.

Bias Due to Volatilization

Most of the organic chemicals sampled for at the EPA monitoring wells will volatilize, meaning be lost to the air from the sample, under the correct conditions. In general those conditions are due to exposure to air which can be enhanced due to turbulence (Nielsen and Nielsen 2006). Sampling a well just after purging without allowing the well to recover without pumping can cause more volatilization and decrease the amount of constituent recovered in the sample (Herzog et al 1988). Too much purging or purging that causes too much drawdown can also increase volatilization because of the speed with which groundwater flows back into the well (McAlary and Barker 1987). Purging too rapidly or not sampling at the correct time after recovery can cause a bias in the resulting sample concentration. This could have occurred at both the USGS sampling of MW01 and in the EPA's sampling of MW01 and MW02. Concentrations of organics, particularly VOCs, should be considered as potentially low compared to the background groundwater.

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NATURE | NEWS: EXPLAINER

Is fracking behind contamination in Wyoming groundwater?

Questions about whether hydraulic 'fracking' is to blame remain as the US EPA prepares for peer review.

Jeff Tollefson

04 October 2012 Clarified: 10 October 2012

Natural gas extraction via hydraulic fracturing has been linked to contamination in groundwater.

GETTY IMAGES

The US Environmental Protection Agency (EPA) sparked a firestorm in December last year when it released a draft report[1] suggesting that the use of hydraulic fracturing — or 'fracking' — to extract natural gas had contaminated groundwater near Pavillion, Wyoming. Industry officials have long denied that fracking affects groundwater, and Pavillion has become the first high-profile test of this claim. On 26 September, the US Geological Survey (USGS) released data showing the presence of groundwater contamination in the region[2]. Although the data would seem to support the EPA's assessment — as does an independent analysis released by environmental groups this week[3] — the survey did not seek to determine the source of the contamination. *Nature* examines the on-going debate and how it relates to broader questions about groundwater contamination from fracking across the United States.

How did this investigation begin?

After local landowners complained about the smell and taste of their water, the EPA began in 2009 to analyse the groundwater outside Pavillion. The agency tested the water in the shallow wells that tap the groundwater above the 169 gas-producing wells in the field; in two municipal wells in the town; and in several surface and deep wells that it drilled for monitoring purposes. It found evidence of contamination in both the shallow and deep wells, and attributed the shallow contamination to the 33 or so nearby surface pits used to store drilling wastes[1]. The pits could not, however, explain the contamination in the deeper groundwater.

What is the evidence that fracking contaminated the deep groundwater?

A range of hydrocarbons showed up in the deep wells, as did some synthetic organic chemicals associated with fracking fluids and drilling activities. The EPA also found high pH levels that could be explained by

potassium hydroxide, which was used in a solvent at the site. The agency also analyzed the evolution of the pollution plume to determine that groundwater seems to be migrating upward, suggesting that the source of contamination came from the gas production zone rather than the surface pits.

Officials with both industry and the state of Wyoming questioned the EPA's data as well as its interpretation, arguing that some hydrocarbons are to be expected through natural migration from the gas field. The state then asked the USGS to conduct a new analysis and provide the data to the state. The USGS provided those data last week[2]; it also sent samples to the EPA, which is conducting its own analysis.

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What do the latest results suggest?

The USGS provided only the raw data and no interpretation. An analysis released this week by two environmental groups found that the data support the EPA's original conclusion. A scientist who has investigated possible contamination at other sites, Rob Jackson of Duke University in Durham, North Carolina, says that multiple lines of evidence are certainly "suggestive" of fracking as a source of contamination.

Does this settle the debate?

No. Encana Corporation, an energy producer based in Calgary, Canada, that has wells in the field near Pavillion, maintains that neither the EPA draft report nor the USGS results provide any proof that drilling operations are to blame.

Is this case unique?

There have been allegations of groundwater contamination at other locations where fracking has taken place, but it is not yet clear how common the problem might be. It is less likely, for instance, in regions where the gas is very deep in the ground, such as in Pennsylvania, where production takes place at depths of 1,500 meters or more. In Pavillion, the gas wells are as shallow as 372 metres, while wells tapping groundwater are up to 244 metres deep; this makes communication between the two zones much easier.

A report in February by the University of Texas at Austin's Energy Institute found no evidence of contamination from fracking near wells in Texas, Pennsylvania or New York, but the university is currently reviewing that report after the lead scientist, Charles Groat, was accused of having a conflict of interest (see 'Unfortunate oversight').

A 2011 study in the *Proceedings of the National Academy of Sciences* by Jackson and his colleagues[4] documented high concentrations of methane and other hydrocarbons in groundwater close to fracking operations in Pennsylvania and New York. But Jackson says that the contamination may have come not from the fracking but from the wells themselves, which can serve as a conduit between geological formations if

not properly sealed.

What comes next?

The EPA plans to complete its analysis of the water samples and then turn over all of the data for an independent peer review later this year. In a press conference on Tuesday, Wyoming Governor Matt Mead said that the state would analyse the USGS data and then determine whether it needs to change its rules on fracking operations.

In parallel, the EPA is conducting a national assessment of environmental and public-health issues associated with fracking and expects to produce an initial report later this year.

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Clarifications

Clarified: An earlier version of this story did not make clear that an analysis of USGS data by environmental groups found that the data are consistent with but do not confirm - with EPA conclusions about water contamination due to fracking. This has been clarified.

References

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Comments

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Sherif Hindi said: Induced hydraulic fracturing is a technique used to increase the released petroleum and/or natural gas. This type of fracturing creates fractures from a wellbore drilled into reservoir rock formations. Potential environmental impacts, including contamination of ground water, risks to air quality, the migration of gases and hydraulic fracturing chemicals to the surface, surface contamination from spills and flowback and the health effects of these factors. For these reasons, hydraulic fracturing has come under scrutiny internationally, with some countries suspending or even banning it. Hydraulic fracturing has raised environmental concerns and is challenging the adequacy of existing regulatory regimes. These concerns have included ground water contamination, risks to air quality, migration of gases and hydraulic fracturing chemicals to the surface, mishandling of waste, and the health effects of all these. Accordingly, a fair decision must be regarded for selecting either profit or human health, especially when the petroleum projects approaches to residential communities. However, accurate fracturing monitoring must be regarded by measuring of the pressure and rate during the growth of a hydraulic fracture, the fluid properties along with geology information that provide the simplest monitoring method. In addition, injection of radioactive tracers is sometimes used for this monitoring task. Furthermore, microseismic monitoring is sometimes used to estimate the size and orientation of hydraulically induced fractures by placing an array of geophones in a nearby wellbore. Tiltmeter arrays, deployed on the surface or down a well, provide another technology for monitoring the strains produced by hydraulic fracturing. Dr. Sherif Shawki Zaki Hindi King Abdull-Aziz Univ. Saudi Arabia

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TECHNICAL MEMORANDUM

April 30, 2012

Review of DRAFT: Investigation of Ground Water Contamination near Pavillion Wyoming
Prepared by the Environmental Protection Agency, Ada OK

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SUMMARY AND RECOMMENDATIONS

After consideration of the evidence presented in the EPA report and in URS (2009 and 2010), it is clear that hydraulic fracturing (fracking (Kramer 2011)) has caused pollution of the Wind River formation and aquifer. The EPA documents that pollution with up to four sample events in the domestic water wells and two sample events in two monitoring well constructed by the EPA between the level of the domestic water wells and the gas production zone. The EPA's conclusion is sound.

Three factors combine to make Pavillion-area aquifers especially vulnerable to vertical contaminant transport from the gas production zone or the gas wells – the geology, the well design, and the well construction. Natural flow barriers are not prevalent in this area, so there are likely many pathways for gas and contaminants to move to the surface, regardless of the source. There is also a vertical gradient, evidenced by flowing water wells, although its magnitude and extend are undefined, to drive advective vertical transport. The entire formation is considered an underground source of drinking water, but 169 gas wells have been constructed into it; this is fracking fluid injection directly into an underground source of drinking water.

The well design is poor because the surface casing does not extend below the level of the water wells, as is required in many other states, and because the wells contain substantial borehole lengths without surface casing or cement between the production casing and the edge of the borehole. This allows vertical transport of gas and fluids and decreases the protection against leakage during fracking or gas production. Third, the EPA documented many instances of sporadic bonding, which simply means the cement does not completely seal the annulus between the production casing and the edge of the borehole. This provides pathways which could allow gas and contaminant transport along the well bore.

The EPA also appropriately accounted for the potential that their monitoring well construction could have explained the contamination. "Since inorganic and organic concentration patterns measured in the drilling additives do not match patterns observed in the deep monitoring wells and because large volumes of ground water were extracted from the wells during development and prior to sampling, it is unlikely that ground-water chemistry was at all impacted by drilling additives."(EPA, 2011, p 7).

The EPA also demonstrated that the inorganic geochemistry in the monitoring wells is substantially different than that which would occur naturally in the area, and that the enrichment of numerous constituents is most likely due to the interaction of fracking fluid with the groundwater near the sampled well. This is particularly true for the elevated levels of potassium, chloride, and pH.

Any of the three contaminant transport pathways suggested by the EPA could be responsible for the contamination moving from the fracking zone to the drinking water wells. The EPA has also presented evidence that contamination in surface ponds has not caused the contamination in the water wells or their monitoring wells.

The situation at Pavillion is not an analogue for other gas plays because the geology and regulatory framework may be different. The vertical distance between water wells and fracking wells is much less at Pavillion than in other areas, so the transport time through the pathways may also be low compared to other gas plays. It is important, however, to consider that the pathways identified at Pavillion could be applicable elsewhere (Myers, 2012; Osborn et al, 2011). In addition to improving and enforcing the relevant regulations, monitoring the pathways between the target formation and aquifers should be standard at all gas plays with fracking.

The following recommendations would improve the analysis and continue the study into the future made throughout this review.

1. The EPA should continue data collection to better verify the sources and map the potential contaminant plumes.
2. EPA should map the gas production wells according to their construction date. The EPA should also compare the locations of observed contamination with the nearby well construction dates to estimate the travel times from the sources to the well receptors.
3. The EPA should map the depth to water prior to sampling in the water wells. Using this, they should map vertical gradients and correlate these gradients to areas with contaminants most likely sourced to deep aquifers.
4. The EPA should install deeper monitoring wells near the shallow pits to better map the depth of the plume emanating from those pits.
5. Data collection should continue so the results can be replicated. An additional, deeper monitoring well should be constructed in the gas production zone between the existing monitoring wells to determine the vertical gradient and estimate the rate of vertical flow.
6. The EPA presents no evidence regarding the extent that fracturing extends above targeted formations. It may not be possible to prove whether this occurred at this site, but the EPA should at least discuss the possibility. It would be useful to perform some simple testing to map the extent of fractures, as described by Fisher and Warpinski (2010).

INTRODUCTION

The Environmental Protection Agency (EPA) has released a study of groundwater contamination in the Pavillion gas play in west-central Wyoming. Their preliminary conclusion is that gas well development and hydraulic fracturing (fracking (Kramer, 2011)) has caused the contamination. The EPA report is in draft form and is open for comment until March 12, 2012. This technical memorandum reviews the EPA report. This review was prepared with support from the Natural Resources Defense Council, Wyoming Outdoor Council, Earthworks, Oil and Gas Accountability Project and Sierra Club.

This review discusses in detail the appropriateness of the study design, methodology, execution, results, and interpretation and the reasonableness of the conclusions. It specifically follows and considers the EPA's "lines of reasoning" approach used to reach its conclusion.

STUDY AREA

The study area is in the Pavillion gas field in west-central Wyoming. It lies northeast of the Wind River Range. The general geology for uppermost 1000 meters (m) is the Eocene-aged ((56 to 34 million years before present) Wind River Formation, which is interbedded sandstone and shale with coarse-grained meandering stream channel deposits. The presence of stream channel deposits indicates that the formation has been carved by river beds which left fluvial deposits interspersed among formation layers These fluvial deposits often provide connectivity among formation layers and can fragment otherwise continuous sedimentary layers.

The area has experienced gas development since the 1960s, with 169 gas wells constructed in the study area. EPA Figure 2 shows the gas well construction chronology. There were three main periods of construction – 1963-65, 1975-83, and 1998 – 2006, with each subsequent period having more new wells constructed than the previous period. EPA does not specify when fracking first occurred, however.

Recommendation: Add a map of gas production wells coded for the year or time period during which the well was completed (or fracking occurred if substantially different). This would allow an assessment of travel time for contaminants to flow from production zones to the monitoring wells and domestic wells.

The US Geological Survey studied the water resources on the Wind River Reservation (Daddow 1996), which surround this study area (but does not include it). The Wind River Formation is the primary source of drinking water on the reservation. Daddow's (1996) description of the formation indicates that the formation consists of interbedded shale and sandstone with extremely variable permeability that could lead to highly variable contaminant loads throughout the formation (Osiensky et al 1984).

Recommendation: A more detailed description of the geology and hydrogeology of the area, perhaps based on the relevant Geological Survey reports would provide more insight regarding geochemical trends as found by the USGS.

STUDY LAYOUT AND DESIGN

EPA started this study in response to citizen complaints regarding contamination in their water wells. EPA established dedicated monitoring wells after two rounds of sampling various water wells rather than prior to construction of the gas wells. For much of their study data, the EPA had to use sample data collected from existing water wells. Water wells are not the best tool for monitoring groundwater quality because, even if the well construction is of similar quality to a dedicated monitoring well, water wells have much longer screens, or open intervals, than do monitoring wells. They screen the most productive formation layers, usually based on observations made during drilling, to maximize the pumping rate while minimizing the drawdown. Wells drilled specifically for monitoring wells also screen productive zones, but target the screen to a specific zone, usually 20 feet or less thick, so that the sample represents a given aquifer level.

Samples from water wells are therefore a mixture of water from all productive zones of the entire open interval, weighted according to the transmissivity of each zone. A domestic water well sample is useful for determining whether a contaminant exists at some point in the aquifer, but a dedicated monitoring well is necessary to determine which layer is contaminated.

EPA established two dedicated monitoring wells to supplement the data obtained from the water wells. The new monitoring wells were primarily screened below the level of the water wells (Figure 1) and above the gas production wells to "differentiate potential deep (e.g., gas production related) versus shallow (e.g., pits) sources of groundwater contamination" (EPA p 5). The EPA established just two monitoring wells due to a limited budget (Id.). EPA placed the monitoring wells' screened interval along the conceptualized vertical pathway between the potential contaminant source (i.e. the production wells and/or zone) and the water wells. The monitoring wells were designed appropriately to detect and monitor contaminant movement upward from the production zone to the water wells; if the monitoring wells had been constructed at the same depth as the water wells, they would not have added substantial useful information.

Figure 1 (EPA Figure 3) shows that domestic water wells in the regions are screened at all levels down to about 250 m, or more than 800 feet, with half of the wells being deeper than 300 feet, similar to the depths found by Daddow (1996) in other areas of the aquifer. However, the EPA states the information source was from the State Engineer *and* homeowner interviews (EPA p 2). It is unclear whether both were used for each well. It is my experience that homeowners have a poor concept of the depth of their well unless they have paperwork that documents it.

Recommendation: The EPA should provide more information about the source of its water well construction data, showing it in EPA Table A1.

The following table summarizes in general terms the wells that were sampled during each sampling phase (other media were also sampled but not included in this table). It is apparent that the wells sampled in phases subsequent to the first phase depended in part on the results of the prior phases.

Phase	Date	Domestic and Stock Wells	Municipal Wells	Stock Wells	Monitoring Wells	Comments
I	3/09	35	2	0	0	
II	1/10	17 (10 previously sampled)	2	4	0	This phase came about because EPA had detected methane and dissolved hydrocarbons during Phase I.
III	10/10	3 (2 previously sampled)	0	0	2	Gas samples also collected from the well casing of EPA's two deep monitoring wells.
IV	4/11	8 previously sampled	0	3 previously sampled	2	Added glycols, alcohols, low molecular weight acids

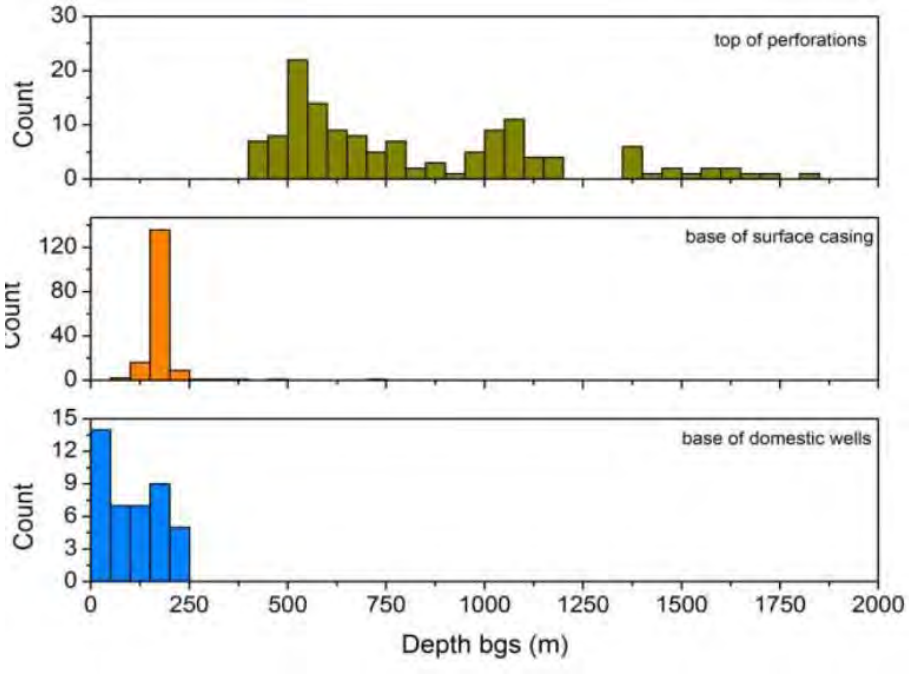

Figure 1: Snapshot from EPA (2011) Figure 3 showing frequency of depth for gas wells (top), surface casing for gas wells, and base of domestic wells.

EPA Table A1 lists the wells and the phase during which they were sampled, broken into eight data types.

1. anions and alkalinity
2. metals
3. alcohols and VOCs
4. low molecular weight acids and glycols
5. semi-volatile organic compounds (SVOCs), pesticides, PCBs, and tentatively identified compounds (TICs);

6. gas/diesel related compounds, and hydrocarbons
7. bacteria
8. fixed gases, heavy hydrocarbons, dissolved carbon, and gas and water isotopic ratios

EPA Table A2a presents the geochemical results – anions, cations, and alkalinity. Unfortunately, this table does not consistently state in which phase the initial sample was taken. Additional samples are identified with a suffix on the sample number. The other data tables in Appendix A provide results by phase, but some results are found only in other reports, including URS (2009 and 2010).

URS (2009) reports the Phase 1 sampling (water wells only) in their Table 9, which shows concentration of SVOC contaminants, including caprolactam at 1.4 ug/l at PGDW20, dimethylphthalate detected at nine wells, and Bis (2-ethylhexyl)phthata at 9.8, 6.4 and 12 ug/l in PGDW25, -20 and -14[1], respectively, and detect levels at ten other wells. Total purgeable hydrocarbons were 26 and 25 ug/l in wells PGDW05 and PGDW30, respectively. Measurable methane concentrations were found in 8 wells. Total purgeable organics are generally gasoline and diesel range organics. PGDW25 is one of the deeper wells at 243.8 m below ground surface (bgs) and PGDW05 and -30 are at 64.0 and 79.2 m bgs, respectively. URS (2010) reports the Phase 2 sampling in more detail. It shows more than 20 wells with detectable levels of a variety of semi-volatile organics (URS 2010, Table 9). The report does not assess these detects with the depth of the well, but a quick glance suggests that most of them are on the deeper half of the domestic wells. An exception is PGDW39, reported to be just 6.1 m deep, although the EPA should consider whether "6.1" is correct because if so it would be tens of meters shallower than any other water well in the aquifer.

Recommendation: The EPA should present and discuss the correlation of contaminant detects in the domestic wells with depth.

EPA based this study on four sample events including various subsets of domestic, municipal, and stock wells and two sample events in the monitoring wells. A reasonable question is whether the number of samples is sufficient for developing an opinion? A time series would help to identify a trend, but is not necessary to establish presence/absence. Objections to this data on the basis of there being just two samples are without merit – simple presence of a substance that would not naturally occur in the aquifer, if other causes can be eliminated, is sufficient to reach a preliminary conclusion that fracking fluid has affected the aquifer. However, the EPA should continue the sampling to determine whether the concentrations are trending higher, or not, and determine how or whether the plume expands.

TRANSPORT PATHWAYS

The EPA identifies three potential pathways for contaminants to reach the water wells from the fracking (EPA, p 32).

- Fluid and gas movement up compromised gas wells.

[1] The table did not highlight the values at PGDW14 and -20 as being exceedences.

- Fluid excursion from thin discontinuous tight sandstone units into sandstone units of greater permeability.
- Out-of-formation fracking, whereby new fractures are created or existing fractures are enlarged above the target formation, increasing the connectivity of the fracture system.

The EPA does not conclude which or whether any of these pathways actually facilitated the contamination at Pavillion, although arguments throughout the document (and reviewed in this report) support the potential for any of them. EPA correctly notes that for all three pathways there would be a correlation between the concentration of gas in the water wells and the proximity to gas well, as found by Osborn et al (2011) in the Marcellus shale in Pennsylvania. They also note that for all three pathways, "advective/dispersive transport would be accompanied by degradation causing a vertical chemical gradient" (EPA, p 32) as discussed in other portions of the report. In other words, with increasing distance from the source, both vertical and horizontal, the contaminant concentration would decrease. This would be due in part to chemical degradation, dispersion of a finite mass over a larger volume, attenuation due to chemicals adsorbing to soil particles, and dilution by mixing with groundwater..

The following sections consider evidence from various aspects of the EPA report in context of the pathways.

Lithologic Barriers

Very low permeability layers can prevent or impede the upward movement of fluid or gas from depth to the water well zone, which in the Wind River Formation is the upper 250 meters (based on the reported water well depth). Extensive layers of shale are often sources of gas and/or capstones, which prevent gas in underlying sandstone from escaping to the surface. However, the shale must be horizontally extensive and not fractured to be an effective seal, which is not the situation in the Pavillion field as quoted above. The formation is most productive (for gas) at its base with gas trapping occurring in "localized stratigraphic sandstone pinchouts on the crest and along flanks of a broad dome" (EPA p 2).

Hypothesis: The lithology in the Pavillion area does not prevent the vertical movement of gas or contaminants to the surface because it is either not sufficiently extensive or impervious. EPA claims there is no "lithologic barrier … to stop upward vertical migration" (EPA p viii) and also that "there is little lateral and vertical continuity of hydraulically fractured tight sandstones" (Id.).

Evidence: EPA presented a lithologic cross-section (Figure 20) showing mapped shale layers, production, water, and monitoring wells and the points where the production wells had been fracked. EPA found that the lithology is "highly variable and difficult to correlate from borehole to borehole" (EPA p 15). "Sandstone and shale layers appeared thin and of limited lateral extent" (Id.). Pathways could go around the intermittent shale so that contaminants in a given monitoring well may not result from the nearest production well. Pathways for movement through sandstone could be tortuous (EPA p 37); vertical pathways through sandstone could be more tortuous than horizontal pathways because the particles in sandstone tend to be elongated with the longer side being horizontal.

Fracking has occurred for up to 45 years, so there is potential for many pathways from various sources to a receptor well. The travel time to a given point could be any time period up to 45 years. Additionally, out-of-formation fracking occurring at any time could have shortened the pathway.

Conclusion: The lithology in most areas would not prevent the vertical movement of contaminants to the water wells because of the lateral variation.

Vertical flow and gradient

In order for contaminants to move from the fracked zones or from deep well bores to surface aquifers, there should be a vertical hydraulic gradient. Lacking such a gradient, movement could still be possible due to lateral dispersion and upward concentration gradients, but it would be much slower.

Hypothesis: There is upward flow in the Pavillion gas field that would support advection of contaminants associated with fracking fluids to the monitoring and water wells.

Evidence: In the Pavillion area, there are flowing wells, which would indicate an upward gradient, at least at depth, which could drive vertical advection, or contaminant transport with the groundwater flow . Daddow (1996) also documented flowing wells in other areas of the Wind River Range, with the depth range from 225 to 450 feet bgs. EPA uses PGDW44 as an example (p 36). This water well lies near the middle of the field near MW01. MW01 showed a depth to water equal to 61.2 m at the beginning of a purge for sampling (p 11 and Figure 8). MW02 had depth to water of 80.5 m (p 12). The depth to water in the monitoring wells does not support the idea of an upward gradient, but being the only wells at that depth, the data is not conclusive. Table A1 reports the PGDW44 well depth is 228.6 m; PGDW25 is deeper, at 243.8 m bgs. MW01 is just 10 m deeper. There is apparently an upward gradient at that point because the well is flowing, but the analysis could be improved, as follows.

EPA documents that the shallower monitoring well has more natural breakdown products of the organic contaminant like BTEX or glycol that are found in the deeper monitoring well and in fracking fluids (p 36). It suggests that the contaminants in the shallow well are derived from the natural breakdown of the contaminants found in the deeper well. This could only occur if the wells represent a vertical flow path, which they do and therefore these findings support the hypothesis of upward movement.

The gas found in the deep Wind River Formation is chemically similar to gas in the underlying Fort Union Formation suggesting that gas in the Wind River Formation has naturally moved upward until captured in localized capstones, or “localized stratigraphic sandstone pinchouts” (EPA, p 2). EPA concludes that differences in gas composition and isotopes support the hypothesis of upward migration through the various layers in the Wind River formation (p 29). The fraction of ethane and propane in the gas from domestic wells is mostly less than in the produced gas, but the isotopic composition is clearly thermogenic, which suggest there is an ongoing “preferential loss of ethane and propane relative to methane” (p 29, 38). This evidence supports the hypothesis of upward fluid and gas movement.

Vertical movement could occur in the absence of a vertical gradient, if the pressurization caused by the fracking is sufficient and there is a poorly developed well bore nearby. Contaminants can migrate

quickly upward through a leaky borehole due to the transient pressure gradient across an aquitard created by the fracking pressure (Lacombe et al, 1995).

Conclusion: There is evidence to support the concept of upward movement in the area, but it is not conclusive. The EPA should complete more studies documenting the vertical hydraulic gradient throughout the area.

Recommendation: The EPA report should document the depth to water in the domestic wells prior to sampling so that they could map water levels for different well depths and determine the zones of upward gradient.

Contamination from shallow pits

The presence of shallow disposal pits is an alternative source of contamination. EPA notes that there are 33 shallow pits that had been used for the "storage/disposal of drilling wastes, produced water, and flowback fluids in the area of investigation" (EPA p 17). As part of this study, the EPA communicated with stakeholders to further determine the location of pits. Shallow monitoring wells have found very high concentrations of several contaminants that were also found in deeper water wells and the EPA monitoring wells. These pits could have received the detritus of fracking operations in the past.

Hypothesis: Contaminated water seeping from these pits could be responsible for the observed contamination.

Evidence: Shallow monitoring wells that had been installed previously for reasons not associated with this project (EPA, p 11) are reported to have very high contaminant concentrations, although this data is not well summarized in the report. The shallow monitoring wells are only 4.6 m bgs (EPA p 17), so there is little information about how deep the contamination extends beneath the pits. Assuming the pits are some distance away from homes and people avoided them when constructing their water wells, it is possible the shallow disposal pits are sources of contamination beyond the level the EPA considers shallow, or 31 m bgs (Id.).

Irrigation could help to contain the contamination near the shallow pits because they would be located in low recharge areas, either by design or in comparison with irrigated fields. It would be unlikely that the pits would have been constructed within irrigated fields, so the seepage from the pits may be much less than the seepage beneath irrigated fields because of the continuous application of water to the field, and for a much shorter time period. Irrigation water would have seeped deeper and faster due to the likely higher rate of application and effectively diluted or prevented the deeper circulation of seepage from the pit.

Conclusion: The EPA concludes that these shallow pits are not the source of contaminants found in deeper water wells. Because there is little contamination in intermediate-depth wells, their conclusion is sound, but the document would benefit from more analysis and discussion.

Recommendation: The EPA should document more fully the contaminant plumes near the pits. Specifically, deeper monitoring wells near the pits should be constructed to construct a contamination

profile beneath the pits. Better investigation of the pits as a source would also facilitate the remediation of the groundwater near those pits.

LINES OF REASONING

The EPA used a line of reasoning analysis regarding the presence of fracking fluid constituents and gas in monitoring wells in support of their preliminary conclusion that fracking has contaminated aquifers in Pavillion Wyoming. This is critical because the conclusion is not just that leakage from the wells or spills caused contamination, but that the fracking process itself caused the contamination. EPA deemed the multiple lines of reasoning approach necessary due to the complexity in detecting contaminants in groundwater from deep sources. This section critically reviews each of the EPA's lines of reasoning.

High pH Values

The EPA monitoring wells both have very high pH, ranging from 11.2 to 12.0, which is much higher than the level seen in the domestic water wells in the Wind River formation. EPA concluded the high pH was due to hydroxide (OH) which indicated the addition of a strong base to the background water (EPA p xii). EPA's reaction path modeling suggested that the addition of just a small amount of potassium hydroxide to the sodium-sulfate waters typical of deep portions of the Wind River formation would cause such a pH change; EPA concludes from the modeling that the typical groundwater in the Pavillion aquifer "is especially vulnerable to the addition of a strong base" (EPA p 20).

Potassium hydroxide was used as a crosslinker and solvent for fracking the production wells in the area (EPA p 33), which could be a source of the OH to increase the pH of the water in the area of the production wells.

The use of soda ash as a drilling additive when drilling the monitoring wells, often to control the pH, is a possible alternate explanation for the elevated pH[2]. Soda ash is 100% Na_2CO_3. At a 1:100 mixing ratio with water, the pH of dense soda ash was 11.2 (EPA Table 2). The recommended ratio for use in fracking fluid is 1:100 to 1:50 (EPA Table 1). The pH of drilling mud varied between 8 and 9. The concentrations of neither sodium nor carbonate are abnormal in the monitoring wells. If the soda ash did separate from the drilling mud, mixing with background groundwater would further dilute it so that the pH would be less than observed at the 1:100 mixing ratio.

EPA Figure 12 verifies these pH values are higher than in the domestic wells, but also shows they fall on the general trend of pH with elevation of the well open interval. Based on this information, it is not possible to conclude that the high pH is not natural, but the EPA's conclusion appears to be justified based cumulatively on all of the facts concerning pH. EPA should consider geophysical logging completed by the industry if it includes pH logs to improve their analysis; such logs could provide pH values for deeper areas that could be compared with the pH values for their monitoring wells.

[2] http://www.halliburton.com/ps/default.aspx?navid=125&pageid=60&prodgrpid=MSE%3a%3a1053024648177449, visited 1/13/12

Chemistry in the shallow wells has been affected by irrigation with Wind River water. This irrigation water has very low total dissolved solids (TDS) and neutral pH (<8) (EPA Figure 11) but the other shallow groundwater wells show that the irrigation water picks up contaminants as it seeps.

The methods used to collect samples probably minimized contamination causing high pH in the monitoring wells. EPA purged the monitor wells until pH stabilized, a process which would minimize the potential that any residual contamination from well development would have been sampled.

EPA's analysis associated with Figures 11 and 12, explaining the shallow water geochemistry, is accurate and useful. It utilizes data from all of the wells in the area and surface waters to show water chemistry trends through the study area. It also shows how EPA's monitoring wells differ substantially from the general trends, supporting the conclusion that elevated pH in water samples from EPA's deep monitoring wells was likely caused by contamination with hydraulic fracturing chemicals.

Elevated potassium and chloride

The monitoring wells both have concentrations of K and Cl much higher, 14 to 18 times, than the domestic water wells (EPA p 34). Potassium concentration ranged from 43.6 to 53.9 mg/l and Cl concentration averaged 466 mg/l (Id.). The drilling additives reported by EPA to have been used at Pavillion had a much lower concentration for both anions. The fracking fluid contained several compounds with high concentrations of both ions (Id.). Therefore, the high concentrations of K and Cl suggest contamination with fracking fluid.

The chloride concentration data plotted in EPA Figure 12 shows clearly that Cl concentration in two of the three samples from EPA's deep monitoring wells are much higher than those in domestic wells, and EPA correctly assesses there must be a cause other than natural variation for the high concentrations. However, in this case I disagree with EPA's assessment that "regional anion trends tend to show decreasing Cl concentrations with depth" (EPA p 19) because EPA Figure 12 shows little variation with depth although there are a couple of high concentration outliers near the surface. Regardless of the interpretation of trend, concentrations from the EPA monitoring wells plot far higher than the Cl data from domestic wells.

The chloride concentrations reported from the EPA monitoring wells are also much higher than reported by the USGS in their Wind River study (Daddow 1996). He describes the formation water as having TDS concentration as high as 5000 mg/l, but Cl is a small proportion of that. He also reported that the highest Cl concentration on surface water sites was less than about 30 mg/l, so assuming the river recharges the alluvial aquifer, the source of the groundwater is relatively clean with respect to chloride. Cl concentrations at EPA's monitoring wells are much higher than the regional values reported by USGS in either ground or surface water on the Wind River Reservation, and are unlikely to be properly considered "naturally occurring".

For potassium, it is much clearer that the monitoring well concentrations exceed the domestic water well concentrations by many times (EPA Figure 12, p 20).

There is too little of either K or Cl in drilling mud or additives for it to have been the source or cause of the enrichment in the monitoring wells. Also, purging prior to sampling occurred until the specific conductivity (SC) of the purged water reached a relative steady state (EPA Figure 9). K and Cl both contribute to the SC of the water being sampled. Any potential contamination due to well construction or development has most likely been purged from the system.

The high K and Cl concentrations are clearly present in the formation water near the monitoring wells. Without a natural source as explanation, the mostly likely source is the fracking fluid which used compounds that have high concentrations of both anions. EPA has reasonably concluded the most likely source of elevated K and Cl is fracking fluid.

Detection of synthetic organic compounds

The EPA found in the monitoring wells significant concentrations of isopropanol, diethylene glycol, triethylene glycol, and tert-butyl alcohol (TBA) (in MW02). TBA was not directly used as a fracking fluid, but "is a known breakdown product of methyl tert-butyl ether and tert-butyl hydroperoxide". The first three products are found in fracking fluid based on the material safety data sheets (MSDSs) analyzed by EPA, but the parent compounds of TBA have not been reported as such; importantly, MSDSs, which are the source of the fracking fluid additives lists in the report, do not list all chemicals because the formulas are proprietary. That a chemical is missing from the list of additives is not evidence they were never in fracking fluid.

Isopropanol was found in "concentrated solutions of drilling additives" at concentrations much lower than detected in the monitoring wells (EPA p 35) and the others, glycols and alcohols, were not used for drilling.

None of these compounds naturally occur in groundwater. The EPA is correct in its conclusion that there is no acceptable alternative explanation and the most likely source of these contaminants is fracking fluid.

Detection of petroleum hydrocarbons

EPA detected benzene, toluene, ethylbenzene, and xylenes (BTEX), trimethylbenzenes, and naphthalene at MW02 (EPA, p 35). They detected gasoline and diesel range organics at both monitoring wells (Id.). These are not found in drilling additives, but the MSDSs showed a long list of additives in the fracking fluid that could be the source of the contamination just cited (EPA p 35, 36). For example, a BTEX mixture had been used in the fracking fluid as a breaker and a diesel oil mixture was used in guar polymer slurry (Id.).

EPA rejects alternative explanations that claim that substances, used on the well or pump, caused these contaminant detections. Specifically, the agency points out that the contact time for water with the well or pump during purging and sampling would be so low that contamination would be unlikely, especially after purging. This would be especially true for the Phase 4 sampling which would have occurred after

the well had been purged for sampling twice and had several months of natural groundwater flow through it.

An alternate explanation considered by EPA is that the constituents are due to the groundwater being above a natural gas field. In fact, the EPA has noted that historically some wells encountered gas at levels shallower than the monitoring wells. EPA encountered methane while logging MW01 (EPA p 11). EPA notes that the gas from the Wind River formation is "dry and unlikely to yield liquid condensates" (EPA p 36). They also argue that the monitoring wells have substantially different compositions of liquid condensates, which would not result if they came from a common source of gas. The explanation is reasonable, unless there is a variation with depth. Because these contaminants occur only at low concentrations in the deepest domestic wells, the data does not rule out a natural gradient from the gas sources at depth to the shallower zones of the formation. However, the EPA explanation is supported by the fact that the monitoring wells are far enough apart, more than a mile, that they must have different gas well sources and represent different pathways..

Recommendation: To further decrease the uncertainty, the EPA should complete an additional sampling event with more domestic wells sampled. It would also be desirable to have another monitor well screened at the level of the gas wells. The EPA could then develop a concentration profile as a function of depth and formation layer.

Breakdown products of organic compounds

EPA verified a vertical pathway by showing that organic compounds in the shallower monitoring wells are daughter products of the organic compounds found in the deeper monitoring wells. This supports the concept of upward migration with ongoing biologic transformation or natural degradation. It supports the concept of an upward flow gradient. It cannot be asserted that the EPA monitoring wells are on the same flow pathway, as they are more than a mile apart, therefore, the presence of contaminants in the monitoring wells is evidence that there are multiple sources of contaminants at the level of the gas production wells.

As part of this line of reasoning, the EPA presents the "hypothetical conceptual model" that "highly concentrated contaminant plumes exist within the zone of injection with dispersed lower concentration areas vertically and laterally distant from the injection points". This refers to how the fracking fluids, once injected, simply disperse in all directions because there are no confinements, similar to how they disperse from coal seam fracking. It is consistent with the lower concentrations found further from the source.

EPA's hypothesis is reasonable and explains the vertical movement of contaminants from a broad zone of production wells. Its simplicity indicates that fracking in such a formation will eventually lead to contamination moving vertically from the gas wells – it is only a matter of time (Myers, 2012).

Sporadic bonding outside of production casing and hydraulic fracturing in thin discontinuous sandstone

The last two lines of reasoning are considered together because they describe two pathways for fracking fluid to get into the aquifer. The fracking that occurs in the Pavillion gas field directly injects fracking fluid into an underground source of drinking water. Fracking occurs as little as 150 m below the bottom of the deeper water wells. The sandstone and intervening shale zones are discontinuous, which suggests there are no significant continuous barriers to a vertical component of flow and contaminant movement. Fracking has also occurred for up to 40 years, so the pathways could have required up to 40 years for transport. Sporadic bonding above the zone being fracked basically means the annulus between the production zone and surface casing may not be fully sealed with cement which may allow gas or fluids to move vertically among formation layers. During fracking, the high pressure could force some of the fracking fluid through improperly sealed well bores to contaminate formations nearer the water wells.

Both of these lines of reasoning correctly describe potential pathways and sources of fluids in the aquifer. The EPA's conclusions in this regard are reasonable and appropriate and conform to the available facts and data.

Gas in Monitoring and Shallow Wells

Many shallow water wells have gas concentrations that exceed expected background levels. EPA also uses several lines of reasoning to conclude that gas has migrated to domestic wells from the fracked zones, in addition to or instead of it occurring naturally in those wells.

Isotopic composition of gas samples from shallow wells, deeper monitoring wells and produced gas are all similar in that all have a thermogenic origin. However, the shallower domestic water wells have very little higher chain carbon-based gas, which suggests some dispersion and decomposition with vertical movement (ethane and propane degrade faster). The isotopic composition of most wells is thermogenic and indicative of a deep source; URS (2010) noted that methane in one domestic well of eight sampled with measurable methane had biogenic origins.

EPA also found that the concentration of methane in domestic water wells was generally higher in areas of higher gas production, as counted by the number of gas wells. Although it could be coincidental because more gas wells are constructed where more gas naturally occurs, this seems unlikely because the presence of gas in domestic water wells shows that gas is occurring outside of the production zones deep in the Wind River Formation or high in the underlying Fort Union Formation. Gas would only move naturally from depth to areas near the surface if there is a lack of containment which would have depleted the gas source at some point in the last 40,000,000 years. Thus, the gas wells have apparently provided a migration pathway for gas released by fracking into overlying formations; this migration occurred at a rate sufficient to allow gas to accumulate to a concentration capable of causing a blowout at 159 m bgs near well PDGW05.

The area also generally has gas well designs that are below current industry standards in some states, with surface casing not extending below the maximum depth of water wells and with a "lack of cement or sporadic bonding of cement outside of production casing" (EPA p 38). This would provide a pathway from depth to at least the bottom of the surface casing, and allow gas leakage to higher levels in the

aquifer. Many states and areas require surface casing to extend below the maximum depth of USDWs (a USDW must generally have TDS less than10,000 mg/l). The gas well design in Pavillion appears to be below industry standards because the surface casing does not extend even below the bottom of the zone of domestic wells. The pathways discussed above for fluid movement would also facilitate gas movement (Id.).

The EPA acknowledges that poorly sealed domestic wells could also be a pathway (EPA p 38-39). This is true but not a relevant argument because the gas wells are much deeper and actually tap formation layers with gas. Once gas reaches a domestic well, it is possible that the well provides an additional pathway, but it is not the source of the contamination or the primary pathway from the gas source zone to the aquifers.

The EPA also references the fact of citizen's complaints (EPA p 39) as an indicator that gas contamination started after fracking. Citizens do not complain until a problem occurs. Assuming their water well was initially acceptable, they would complain when they noticed a change.

DISCUSSION OF CONTAMINANT TRANSPORT PATHWAYS

The general dispersion of contaminants upward from the fracking zone would result from either well bore transport or transport through overlying higher permeability sandstone. Transport through wellbores that cross multiple aquifer layers, as the gas wells do near Pavillion, would allow contaminants to reach the different levels. However, the concentration reaching shallower formations would be much less because the contaminants bleed off to the deeper aquifer zones (Nordbotten et al 2004). Fracking could also create the vertical gradient to temporarily cause contaminants to move vertically upward through wellbores to contaminate shallower aquifer layers (Lacombe et al 1995).

Because there are not any significant horizontal confining units within the Pavillion Field, the upward vertical contaminant transport is partially due to dispersion through relatively porous media. In areas with extensive horizontal confining layers, such as the Marcellus shale areas, transport through vertical fractures, similar to that through wellbores, could transport substantial contaminant mass through the impervious zones (Myers, 2012). If the bulk media bounding the fractures have conductivity less than one hundredth that in the fracture, the contaminants will transport with little dispersion, or loss, into the bulk media (Zheng and Gorelick, 2003).

This appears to be the case in the Pavillion Field, given the existing geology. Thus, unless fracking is very carefully done, and well bores are solidly (not intermittently) bonded, this result is to be expected. In the case of the Pavillion Field, sporadic bonding is revealed and reported for 9 of the wells that EPA examined well bore data made available to them. To the extent that this is indicative of the entire field, it would greatly increase the likelihood that transport of contaminants from the gas wells to the water wells of the rural Pavillion residents would occur.

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

Subject: Action Memorandum - Request for Funding for a Removal Action at the Dimock Residential Groundwater Site, Intersection of PA Routes 29 & 2024 Dimock Township, Susquehanna County, Pennsylvania

From: Richard M. Fetzer, On-Scene Coordinator
Eastern Response Branch (3HS31)

To: Dennis P. Carney, Associate Division Director
Hazardous Site Cleanup Division (3HS30)

JAN 19 2012

I. PURPOSE

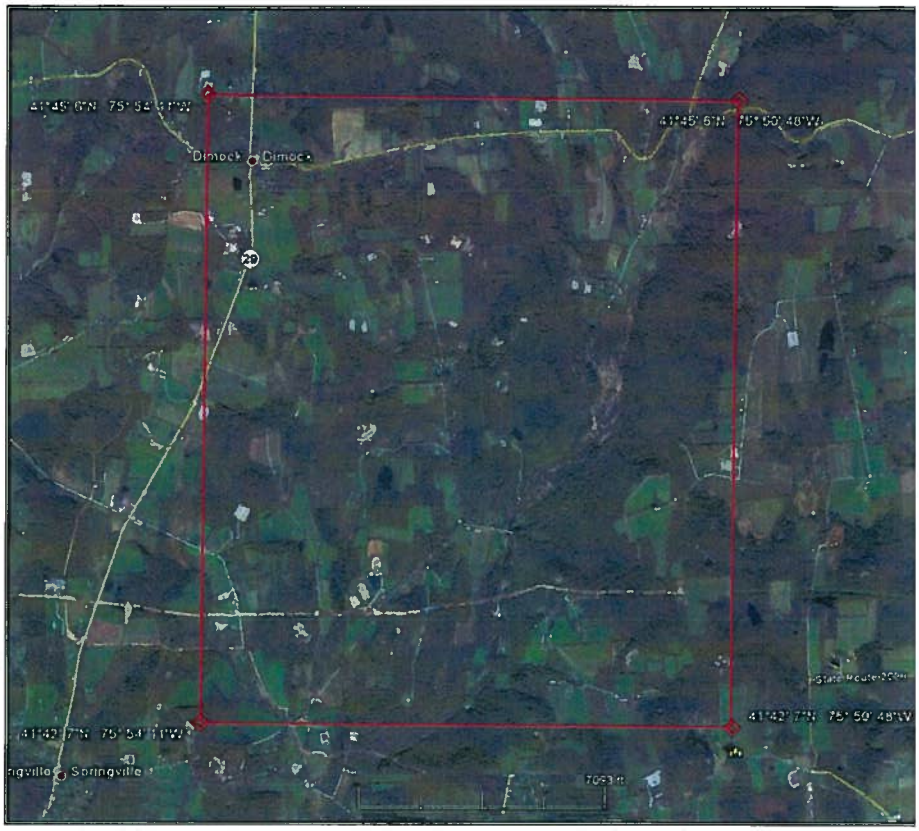
The purpose of this Action Memorandum is to request and document approval of an emergency removal action to prevent, limit, or mitigate the threats posed by the presence of hazardous substances at the Dimock Residential Groundwater Site (the "Site"), pursuant to Section 104(a) of the Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. § 9604(a) (CERCLA). The Site is located in Dimock Township, Susquehanna County, Pennsylvania. The OSC has initiated a removal site evaluation in accordance with the National Oil and Hazardous Substances Pollution Contingency Plan (NCP), 40 C.F.R. Part 300. The OSC has determined, based on Pennsylvania Department of Environmental Protection (PADEP) and Cabot Oil and Gas Corporation (Cabot) sampling information, consultation with an EPA toxicologist, the Agency for Toxic Substances and Disease Registry (ATSDR) Record Of Activity (AROA), issued 12/28/11, and the recent EPA well survey effort, that a number of home wells in the Dimock area contain hazardous substances, some of which are not naturally found in the environment. Inorganic hazardous substances are present in four home wells at levels that present a public health concern. These four specific homes have been dependent upon donated water for drinking and/or household use and the reliability of the sources for donated water is at this point uncertain.

Historic drilling activities in the Dimock area may have used materials containing hazardous substances. Spills and other releases have been documented by PADEP from these drilling activities. There is reason to believe that a release of hazardous substances has occurred. The presence of hazardous substances in the four home wells constitutes a release or substantial threat of a release and the situation meets the criteria for conducting a removal action under Section 300.415 of the NCP. The OSC has determined that funds in the amount of $100,000 are needed to mitigate the human health concern initially at four homes and therefore proposes the actions included in this Action Memorandum. This action includes provision of alternate water to four homes and home well sampling at approximately 61 homes within the Site area.

II. SITE CONDITIONS AND BACKGROUND

A. Background

1. Site Description - The Site area is located in Dimock, a rural area of northeastern Pennsylvania in Susquehanna County. A map of the area is included below.



2. History - Cabot began drilling for natural gas in the Dimock area in 2008. Methane contamination was detected in private wells thereafter in concentrations exceeding those previously found. PADEP had the lead in investigating the environmental complaints in Dimock. PADEP entered into a Consent Order and Agreement (CO&A) with Cabot which required permanent restoration or replacement of the affected water supply. A public water line was initially considered. PADEP later modified the CO&A to require installation of "gas mitigation" systems for 19 homes served by 18 private wells in the Site area.[1] Until the gas mitigation systems were installed, Cabot was to provide a temporary water source. Some well owners, within the scope of the PADEP CO&A, have gas mitigation systems installed, but others do not. While the gas mitigation systems were designed to remove methane, a potential exists that they may remove some hazardous substances as a by-product of their operation. Regardless, EPA does not know what, if any, hazardous substances these "gas mitigation" systems, originally designed to address methane, are removing. Therefore, EPA is including both pre- and post-treatment sampling in the scope of this action. Furthermore, there are

[1] It had originally been reported that 19 homes were served by the 18 wells included within the scope of the CO&A but the door-to-door home well survey conducted to date by EPA has identified that there are currently 21 homes served by 20 wells on those same properties.

other homes served by private wells that were not covered by the scope of the PADEP CO&A, but are within this Site area.

III. Quantities/Types of Substances Present

1. Arsenic* – Arsenic is a naturally occurring element widely distributed in the earth's crust. Arsenic may also be present at elevated concentrations in the groundwater due to the use and effects of drilling fluids. Arsenic is classified as a known human carcinogen. This classification is based on animal and human studies, which indicate an increased risk for developing cancers of the skin, lung, bladder, kidney, liver, and prostate from consuming arsenic containing water. Non-cancer health effects associated with ingestion of arsenic include circulatory problems and skin damage.
2. Barium – Barium is a silvery-white metal that exists in nature only in ores containing mixtures of elements. It combines with other chemicals such as sulfur or carbon and oxygen to form barium compounds. Barium sulfate is sometimes used by doctors to perform medical tests and to take x-rays of the gastrointestinal tract. Ingesting drinking water containing levels of barium above the EPA drinking water guidelines for relatively short periods of time can cause gastrointestinal disturbances and muscle weakness. Ingesting high levels for a long time can damage the kidneys. Barium is known to be a common constituent of drilling fluids.
3. Bis(2-ethylhexyl)phthalate (DEHP)* - DEHP is a manufactured chemical that is commonly added to plastics to make them flexible. The phthalates are generally considered to be of slight to moderate toxicity. DEHP may be irritating to the eyes, skin, and mucous membranes. Mild gastric disturbances and diarrhea may occur following ingestion of larger doses. Central nervous system (CNS) depression may occur if large amounts of phthalate acid esters are absorbed. EPA has determined that DEHP is a probable human carcinogen. These determinations were based entirely on liver cancer in rats and mice. DEHP is known to be associated with drilling activities.
4. Glycol Compounds (including Ethylene Glycol* and 2-Methoxyethanol) – Glycol compounds are a class of organic compounds belonging to the alcohol family. Exposure to large amounts of ethylene glycol can damage the kidneys, nervous system, lungs, and heart. Exposure to high concentrations of 2-methoxyethanol is associated with testicular damage, impaired nervous system, and anemia. Glycols are known to be common in drilling fluids.
5. Manganese* – Manganese is a naturally occurring substance found in many types of rock and soil. Manganese is also known to be a constituent of some specialized drilling fluids. Eating a small amount of manganese from food or water is needed to stay healthy. At high levels, it can cause damage to the nervous system.

6. Phenol* - Phenol is both a manufactured chemical and a natural substance. Phenol is used as a disinfectant and is found in a number of consumer products. Skin exposure to high amounts can produce skin burns, liver damage, dark urine, and irregular heart beat. Various phenols are commonly associated with drilling fluids.
7. Sodium* – Sodium is an essential nutrient and occurs naturally in most foods. Excessive sodium intake is associated with high blood pressure. Various sodium containing compounds are associated with drilling fluids.

*A hazardous substance, as defined under CERCLA Section 101(14) and designated in Section 302.4 of the National Contingency Plan (NCP), 40 C.F.R. Section 302.4.

B. National Priorities List

The Dimock Residential Groundwater Site is not on the CERCLA National Priorities List (NPL).

C. State and Local Authorities' Roles

Cabot had been sampling the home wells and providing bottled drinking water and alternate water for non-potable use, through a Consent Order and Agreement (CO&A) with PADEP. The CO&A applies only to a specific list of homes, and does not include other homes, also located within the same geographic area. Some of these additional homes have had limited sampling conducted by Cabot and/or PADEP. PADEP determined that Cabot has complied with the terms of the CO&A, as it applies to the provision of temporary water, and subsequently approved Cabot's request to stop the delivery of alternate water.

IV. THREATS TO PUBLIC HEALTH OR WELFARE OR THE ENVIRONMENT

Section 300.415 of the NCP lists the factors to be considered in determining the appropriateness of a Removal Action. Paragraphs (b)(2)(i), (ii), and (vii) of Section 300.415 directly apply to the conditions found at the Dimock Residential Groundwater Site.

In evaluating the situation, the OSC first considered whether hazardous substances were present in a home well. The levels of those hazardous substances were then considered against primary Maximum Contaminant Levels (MCLs). They were also considered for non-cancer risk to determine if the levels generate a hazard quotient greater than 2. The presence of inorganic and organic chemicals in a number of wells supports the need for this action.

300.415 (b)(2)(i) "Actual or potential exposure to nearby human populations, animals or the food chain from hazardous substances or pollutants or contaminants"

The hazardous substances listed above, present in water from home wells at this Site based on sampling data described below, could cause adverse health impacts when chronic exposure through drinking water or other uses of water in the home occurs. There are other contaminants discussed in the Agency for Toxic Substances and Disease Registry's (ATSDR) Record of Activity (AROA) issued on December 28, 2011, which could also cause adverse health impacts. ATSDR has concluded for the area originally included with the PADEP/Cabot CO&A, which includes the four homes being considered here for alternate water, that a chronic health risk exists for most wells and that the situation supports a "Do Not Use the Water" action including the consideration of alternative home water supplies until further characterization is completed. An EPA Region III toxicologist's opinion is that, of the homes evaluated to date in an on-going effort, that four home wells contain contaminants at levels that present a public health concern. In one home, manganese was detected at 628 ug/L. Exposure to this concentration would yield a Hazard Quotient of approximately 2. In another home, manganese (1360 ug/L) was detected at a level that generates a Hazard Quotient of approximately 4. Note that children reside at this location. In the third home, arsenic was observed at a concentration (37 ug/L) that exceeds its MCL of (10 ug/L) and would pose a long-term cancer risk of 8E-04. Note that children reside at this location. In the fourth home, manganese was detected at 669 ug/L. Exposure to this concentration would yield a Hazard Quotient of approximately 2.3. Available data also indicate that hazardous substances may be present in a number of other homes. Because the available data is not complete and is of uncertain quality, additional sampling is needed to facilitate a further evaluation of any potential health concerns from the drinking water at home wells in the Site area.

EPA is providing water based upon a risk of exposure to hazardous substances above health-based levels. Furthermore, the OSC notes that for those homes where the EPA toxicologist has not identified contaminants that present a public health concern, that the limited data available does identify the existence of hazardous substances. In addition, PADEP's CO&A determined that 18 home wells were impacted by drilling activities; such impact may be evidence of the migration of hazardous substances.

Again, it is noted that this determination is based upon data which was collected by parties other than EPA (Cabot and PADEP). The quality assurance/quality control (QA/QC) information has not been verified. However, what is clear is that this data strongly suggests that hazardous substances have been released and are present in some home wells at levels that may present a public health concern. Current data does show arsenic and manganese at higher levels than may be typically found, in post drilling samples. Since arsenic and manganese are naturally occurring substances, EPA's assessment will include comparisons of background concentrations and post drilling concentrations present. EPA routinely acts under CERCLA to protect public health first while it acts to further define contamination. Thus, within this action, EPA will complete an assessment of the water quality of the home wells in the Site area to close information gaps as soon as possible. This sampling will be focused initially on evaluating those homes in the Site area that have been sampled in the past. Beyond that, sampling at homes will be based upon a sampling rationale using information regarding alleged health impacts and

data gaps. In addition, EPA will continue to evaluate the updated data, and may revise its actions to provide water to any of the additional homes, or to cease provision of water, as warranted by the data.

300.415 (b)(2)(ii) "Actual or potential contamination of drinking water supplies or sensitive ecosystems"

The discussion of 300.415 (b) (2) (i) above applies to this factor. Both organic and inorganic contaminants have been detected in home wells. Although this action is predominantly based upon inorganic data at the four homes, it should be noted that organic compounds have been detected at other homes as detailed in the ATSDR AROA. Glycol detections included ethylene glycol, triethylene glycol, and 2,2'oxybisethanol (diethylene glycol). Some wells had all three reported glycols present in their wells but no exceedances of risk based screening criteria (note: the analytical detection level used appeared to be higher than screening levels). Bis(2-ethylhexyl) phthalate (DEHP) was detected in five samples and ranged from 0.14 µg/L to 22 ug/L. 2-methoxyethanol concentrations (ranging from 880 ug/L to 1,300 ug/L) were detected in each of six wells.

300.415 (b) (2) (vii) "The availability of other appropriate federal or state response mechanisms to respond to the release"

The four homes being considered for alternate water under this action were all dependent upon donated water, either bottled, water buffaloes (temporary storage tanks) or both. It is the OSC's understanding that the last delivery of bulk water from those organizations ceased on January 3, 2012. In any case the reliability of sources for donated water is at best uncertain.

V. PROPOSED ACTIONS AND ESTIMATED COSTS

A. Proposed Action

1. Proposed Action Description

Throughout the duration of Site activities, all personnel involved with execution of this proposed action will comply with the requirements of CERCLA and with all other applicable Federal and State regulations to the extent practicable considering the exigencies of the situation in accordance with 40 CFR § 300.415(j). Available data indicate that a number of homes in the area have hazardous substances present in the home wells, but only four indicate concentrations identified by the EPA toxicologist at a level of concern. Thus, those four homes will be immediately supplied with water. At the same time, approximately 61 home wells will be sampled by EPA to obtain data of known quality assurance to support future evaluations and response decisions. EPA will continue to evaluate the updated data, and may revise its actions to provide water to any of the additional homes, or to cease provision of water, as warranted by the data. The Removal activities at the Site will include the following:

1. Mobilize and demobilize personnel and equipment to conduct the action;
2. Delivery of a temporary source of clean water for household use to the four (4) homes with wells that contain contaminants at levels of public health concern. This provision of temporary water will continue until potential exposures are further understood and mitigated as needed.
3. The sampling program will include analysis for a broad range of parameters with a special priority being placed on quick turnaround for those parameters which are most frequently observed in the data available to EPA at this time. The Agency will also do some limited sampling for methane and bacteriological constituents. Home well water sampling will be performed by EPA in the Site area using the following assigned priority:

    i. The four (4) homes considered for provision of alternate water, to assess the potential exposure to hazardous substances and to determine whether continued temporary provision of clean water for household use is required.
    ii. The seventeen (17) remaining homes located on properties included in the PADEP/Cabot CO&A[2], which were identified as being impacted by drilling activities.
    iii. Approximately thirty (30) additional homes in the immediate area that have been sampled in the past.
    iv. Additional homes in the Site area where one or more of the factors below supports sampling.
        1. Direct observation or other evidence (home well surveys) of adverse health effects potentially attributable to contaminated groundwater use.
        2. Where data gaps in groundwater measurement or sampling need to be filled to gain an adequate understanding of Site conditions.

    Approximately ten (10) homes are currently identified from well surveys, but more could be added based upon data review.
4. Maintain necessary documentation of Site activities.
5. Develop and implement appropriate health and safety protocols for the removal activity.

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[2] It had originally been reported that 19 homes were served by the 18 wells included within the scope of the CO&A but the door-to-door home well survey conducted to date by EPA has identified that there are currently 21 homes served by 20 wells on those same properties.

2. Contribution to Remedial Performance

A remedial action is not anticipated and therefore this removal action is not inconsistent with any proposed remedial action.

3. Applicable or Relevant and Appropriate Requirements ("ARARs")

Actions will be conducted in compliance with Applicable or Relevant and Appropriate Regulations (ARARs) to the extent practicable considering the exigencies of the situation, in accordance with 40 CFR 300.415(j).

B. Estimated Costs

Extramural Costs	Total
Regional Allowance Costs: (ERRs Contractors and Subcontractors)	$ 50,000
Other Extramural Costs Not Funded From the Regional Allowance: START Contractor	$ 25,000
Subtotal, Extramural	$ 75,000
Extramural Costs Contingency	$ 25,000
Total Removal Action Project Ceiling	**$100,000**

VI. EXPECTED CHANGE IN SITUATION SHOULD ACTION BE DELAYED OR NOT TAKEN

If no action is taken, the residents may utilize well water which poses a potential public health concern.

VII. OUTSTANDING POLICY ISSUES

Because this response action could be considered nationally significant or precedent setting, it requires the prior concurrence of the Assistant Administrator, Office of Solid Waste and Emergency Response (AA-OSWER). Furthermore, because the action appears to be nationally significant and/or precedent-setting, the Region will continue to coordinate closely with Headquarters. EPA also will maintain coordination and communications with PADEP. In taking this action, EPA is aware of and has considered the potential applicability of the natural gas exclusion under CERCLA, the Bentsen Amendment under the Resource Conservation and Recovery Act (RCRA), and the exclusions to the definition of 'underground injection' under the Safe Drinking Water Act (SDWA). EPA has concluded that this action is appropriate under CERCLA at this time.

VIII. ENFORCEMENT

The total EPA costs for this removal action based upon full-cost accounting practices that will be eligible for cost recovery are estimated below as follows:[3]

Direct Extramural Costs	$100,000
Direct Intramural Costs	$ 25,000
Total Direct Costs	$125,000
Indirect Cost (67.13% x Direct Costs)	$ 83,912
Total Costs (Direct and Indirect)	$208,912

IX. RECOMMENDATION

This Action Memorandum represents the selected Removal Action for the Dimock Residential Groundwater Site in Dimock Township, Susquehanna County, Pennsylvania, developed in accordance with CERCLA, as amended, and is consistent with the NCP. This decision is based on the administrative record for the Site. The administrative record consists of the following documents

1. 1/13/12 "Dimock Home Well Data" memo from EPA Toxicologist Dawn Ioven.
2. ATSDR AROA Issued 12/28/11.
3. Summary of Portions of data received by EPA and reviewed by the OSC.
4. PADEP Consent Order and Agreement, dated December 15, 2010.
5. EPA Data Review Memo, January 13, 2012.
6. EPA 104e request to Cabot, January 6, 2012

Conditions at the Site meet the Removal Action requirements of Section 300.415(b) of the NCP and I recommend your approval of the proposed removal action and exemption from the statutory limits. The total project ceiling, if approved, will be $100,000. Of this, as much as, $50,000 comes from the Regional removal allowance. Please indicate your approval or disapproval below.

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[3] Direct Costs include direct extramural costs and direct intramural costs. Indirect costs are calculated based on an estimated indirect cost rate expressed as a percentage of site-specific direct costs, consistent with the full cost accounting methodology effective October 2, 2000. These estimates do not include pre-judgment interest, do not take into account other enforcement costs, including Department of Justice costs, and may be adjusted during the course of a removal action. The estimates are for illustrative purposes only and their use in not intended to create any rights for responsible parties. Neither the lack of a total cost estimate nor deviation of actual total costs from this estimate will affect the United States' right to cost recovery.

Action by the Approving Official:

I have reviewed the above-stated facts and, based upon those facts and the information compiled in the documents described above, I hereby approve/disapprove the selected removal action.

APPROVED: Dennis P Carney **DATE** 1/19/2012

Dennis P. Carney, Associate Division Director
Hazardous Site Cleanup Division
EPA Region 3

DISAPPROVED: _____ **DATE** _____

Dennis P. Carney, Associate Division Director
Hazardous Site Cleanup Division
EPA Region 3

Newsroom
News Releases By Date

EPA Completes Drinking Water Sampling in Dimock, Pa.

Release Date: 07/25/2012
Contact Information: Terri White white.terri-a@epa.gov (215) 814-5567

PHILADELPHIA (July 25, 2012) – The U.S. Environmental Protection Agency announced today that it has completed its sampling of private drinking water wells in Dimock, Pa. Data previously supplied to the agency by residents, the Pennsylvania Department of Environmental Protection and Cabot Oil and Gas Exploration had indicated the potential for elevated levels of water contaminants in wells, and following requests by residents EPA took steps to sample water in the area to ensure there were not elevated levels of contaminants. Based on the outcome of that sampling, EPA has determined that there are not levels of contaminants present that would require additional action by the Agency.

“Our goal was to provide the Dimock community with complete and reliable information about the presence of contaminants in their drinking water and to determine whether further action was warranted to protect public health,” said EPA Regional Administrator Shawn M. Garvin. “The sampling and an evaluation of the particular circumstances at each home did not indicate levels of contaminants that would give EPA reason to take further action. Throughout EPA's work in Dimock, the Agency has used the best available scientific data to provide clarity to Dimock residents and address their concerns about the safety of their drinking water.”

EPA visited Dimock, Pa. in late 2011, surveyed residents regarding their private wells and reviewed hundreds of pages of drinking water data supplied to the agency by Dimock residents, the Pennsylvania Department of Environmental Protection and Cabot. Because data for some homes showed elevated contaminant levels and several residents expressed concern about their drinking water, EPA determined that well sampling was necessary to gather additional data and evaluate whether residents had access to safe drinking water.

Between January and June 2012, EPA sampled private drinking water wells serving 64 homes, including two rounds of sampling at four wells where EPA was delivering temporary water supplies as a precautionary step in response to prior data indicating the well water contained levels of contaminants that pose a health concern. At one of those wells EPA did find an elevated level of manganese in untreated well water. The two residences serviced by the well each have water treatment systems that can reduce manganese to levels that do not present a health concern.

As a result of the two rounds of sampling at these four wells, EPA has determined that it is no longer necessary to provide residents with alternative water. EPA is working with residents on the schedule to disconnect the alternate water sources provided by EPA.

Overall during the sampling in Dimock, EPA found hazardous substances, specifically arsenic, barium or manganese, all of which are also naturally occurring substances, in well water at five homes at levels that could present a health concern. In all cases the residents have now or will have their own treatment systems that can reduce concentrations of those hazardous substances to acceptable levels at the tap. EPA has provided the residents with all of their sampling results and has no further plans to conduct additional drinking water sampling in Dimock.

For more information on the results of sampling, visit: http://www.epa.gov/aboutepa/states/pa.html .

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NATURAL RESOURCES DEFENSE COUNCIL

September 8, 2010

By FedEx and e-mail

The Honorable Lisa Jackson
Administrator
United States Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Rulemaking Pursuant to Section 6974(a) of the Resource Conservation and Recovery Act Concerning the Regulation of Wastes Associated with the Exploration, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy.

Dear Administrator Jackson:

To best protect human health, food sources, and our environment from the toxicity of contaminants found in wastes associated with the exploration, development and production of oil, gas, and geothermal energy, we believe it is appropriate for the Environmental Protection Agency (EPA) to reconsider its 1988 Regulatory Determination and regulate these wastes under Subtitle C of the Resource Conservation and Recovery Act (RCRA). The Natural Resources Defense Council (Petitioner) is submitting the attached rulemaking petition pursuant to Section 6974(a) of RCRA, 42 U.S.C. § 6974(a). In support of this petition, we identify numerous reports and data produced since the EPA's Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development, and Production Wastes (July 6, 1988) which quantify the waste's toxicity, threats to human health and the environment, inadequate state regulatory programs, and readily available solutions.

The Natural Resources Defense Council (NRDC) is a nonprofit environmental action group established in 1970 by a group of law students and attorneys at the forefront of the environmental movement. The Natural Resources Defense Council's purpose is to safeguard the Earth: its people, its plants and animals and the natural systems on which all life depends. NRDC uses law, science and the support of 1.2 million members and online activists to protect the planet's wildlife and wild places and

to ensure a safe and healthy environment for all living things. NRDC has worked for many years to ensure the proper regulation of oil and gas exploration and production operations.

Section 6974(a) of RCRA allows any person to petition the Administrator of the EPA to promulgate an environmental regulation. Within a reasonable time following receipt of such petition, the Administrator shall take action with respect to such petition and shall publish notice of such action in the Federal Register, together with the reasons therefor. This petition asks the EPA to take specific actions and directs the EPA's attention to the ample documentation in the record, which provides full support for the designation of wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy as hazardous waste under RCRA and provides a firm and compelling basis for the reconsideration of the EPA's July 1998 Regulatory Determination.

Thank you in advance for your consideration of this petition.

Respectfully submitted by:

Amy Mall
Senior Policy Analyst

Diane Donnelly
Legal Intern

Natural Resources Defense Council
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I. THE EPA SHOULD REGULATE WASTE FROM THE EXPLORATION, DEVELOPMENT AND PRODUCTION OF CRUDE OIL AND NATURAL GAS UNDER SUBTITLE C OF RCRA.

We request that the U.S. Environmental Protection Agency (EPA) promulgate regulations that subject wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy to the hazardous waste provisions of Subtitle C of the Resource Conservation and Recovery Act (RCRA). We submit this petition pursuant to 42 U.S.C. § 6974(a), seeking that EPA ensure safe management of these wastes throughout their life cycle from cradle to grave, including generation, transportation, treatment, storage and disposal. Reports concerning the toxicity of exploration, development and production wastes, their release into the environment, threats to human health, the increasing amount of these types of wastes being generated, the inadequacy of existing state regulations, enforcement and oversight, and the feasibility and economic benefits of using disposal techniques that are less harmful to the environment all support regulation under Subtitle C, as described in detail below.

A. The EPA Has Authority to Reconsider Its 1988 Regulatory Determination.

Congress gave EPA the authority to prescribe necessary regulations to carry out its functions under RCRA.[1] Congress charged EPA with the task of "assuring that hazardous waste management practices are conducted in a manner which protects human health and the environment."[2] Congress ensured that the public had a way to seek additional protections from hazardous wastes by allowing "[a]ny person . . . [to] petition the Administrator for the promulgation, amendment, or repeal of any regulation under" RCRA, and by requiring that "[w]ithin a reasonable time following receipt of such petition, the Administrator shall take action with respect to such petition and shall publish notice of such action in the Federal Register, together with the reasons therefor."[3]

With these provisions, Congress expressed its intent that RCRA would adapt to changing hazardous waste management needs. Foreseeing the need to update regulations promulgated under RCRA to account for changing circumstances,[4] Congress provided the public a way to bring about EPA review of its regulations.[5] These provisions authorize EPA to reconsider its current treatment of wastes associated with the exploration, development, or production of oil and gas (E&P wastes).

[1] 42 U.S.C. § 6912(a)(1).
[2] 42 U.S.C. § 6902(a)(4).
[3] 42 U.S.C. § 6912(a)(1).
[4] 42 U.S.C. § 6912(b).
[5] 42 U.S.C. § 6912(a)(1).

Congress passed RCRA in 1976 as an amendment to the Solid Waste Disposal Act of 1965 in an effort to enact more comprehensive waste disposal standards nationwide.[6] Through RCRA, Congress declared that the "disposal of solid waste . . . without careful planning and management [was] a danger to human health and the environment."[7] Congress later amended RCRA with the Solid Waste Disposal Act Amendments of 1980.[8] One of the 1980 amendments, the so-called Bentsen Amendment, temporarily exempted "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas" from regulation under RCRA.[9]

Under the Bentsen Amendment, Congress directed EPA to conduct a study to determine whether or not E&P wastes should be regulated as hazardous wastes under RCRA.[10] EPA completed the required study and submitted a Report to Congress on the Management of Waste from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy.[11] Shortly after submitting its report to Congress, EPA issued its Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development, and Production Wastes, in which it decided that regulation of E&P wastes under Subtitle C of RCRA was unwarranted.[12]

In the more than twenty years that have passed since EPA issued its Regulatory Determination on E&P wastes, both the oil and gas industry and the risks associated with E&P wastes have expanded dramatically, making EPA's 1988 Regulatory Determination unjustified. While E&P wastes have always been hazardous to human health and the environment, the recent expansion of drilling operations to more densely populated areas places even more people at risk. EPA's reconsideration of its 1988 Regulatory Determination is especially necessary now that the basis for its Regulatory Determination no longer reflects current conditions. In its 1988 Regulatory Determination, EPA identified three factors as the basis for its decision not to regulate E&P wastes under Subtitle C. These factors included: (1) the infeasibility of implementing alternative regulations, (2) the adequacy of state regulations, and (3) the economic harm that would befall the oil and gas industry if additional regulatory controls were imposed.[13]

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[6] Joseph F. Scavetta, *RCRA 101: A Course in Compliance for Colleges and Universities*, 72 NOTRE DAME L. REV. 1647 (1997).
[7] Natasha Ernst, Note, *Flow Control Ordinances in a Post*-Carbone *World*, 13 PENN ST. ENVTL. L. REV. 53 (2004) (citing 42 U.S.C §§ 6901–6992k (2003)).
[8] Pub. L. 96-482; *see also* James R. Cox, *Revisiting RCRA'S Oilfield Waste Exemption as to Certain Hazardous Oilfield Exploration and Production Wastes*, 14 VILL. ENVTL. L.J. 1, 3 (2003).
[9] 42 U.S.C. § 6921(b)(2)(A).
[10] 42 U.S.C. § 6921(b)(2)(B).
[11] EPA, REPORT TO CONGRESS, MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY, Vols. 1–3 EPA530-SW-88-003 (1987) [hereinafter REPORT TO CONGRESS].
[12] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. 25446, 25447 (July 6, 1988).
[13] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25446.

As will be discussed at greater length below, new evidence clearly demonstrates that alternative disposal practices are feasible, state regulations remain inadequate, and the oil and gas industry is unlikely to be severely harmed by the imposition of more stringent waste disposal requirements. Because this evidence shows that the assumptions on which EPA's 1988 Regulatory Determination was based are no longer correct, EPA must revisit its decision.[14]

Nothing in RCRA prevents the EPA from reconsidering its 1988 Regulatory Determination. In *American Portland Cement Alliance*,[15] the court upheld EPA's authority to reconsider regulatory determinations made pursuant to the 1980 amendments to RCRA.[16] Moreover, statements made by EPA in its 1988 Regulatory Determination indicate that EPA never intended the Regulatory Determination to be its final word on E&P waste. Instead, EPA established a three-pronged plan and intended to take further action to fill in existing gaps in the regulations governing the disposal of E&P wastes.[17] To date this three-pronged plan has not been fulfilled. Gaps in the regulatory system governing E&P wastes have grown even wider and evidence of the substantial harm E&P wastes can cause to human health and the environment has continued to accumulate. EPA must revisit its 1988 Regulatory Determination to fulfill its obligations under the 1988 Regulatory Determination and protect human health and the environment from the significant risks posed by E&P wastes.

Unless EPA revisits its 1988 Regulatory Determination and recommends that E&P wastes be regulated under Subtitle C of RCRA, E&P wastes will continue to present substantial hazards to human health and the environment.[18]

B. EPA Should Regulate E&P Wastes Under Subtitle C of RCRA.

In light of the documented toxicity of contaminants found in E&P waste, the failure of states to adequately regulate the disposal of E&P wastes, the dramatic increase in oil and gas production that has occurred since 1988, and the availability of safer cost-effective disposal alternatives, EPA must take action in order to prevent further harm to human health and the

[14] EPA Region 8 itself stated that "EPA may need to revisit the continued validity of the exemption in light of the advancements in practices." EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY 3-14 (Working Draft 2008).
[15] 101 F.3d 772 (D.C. Cir. 1996).
[16] *Id.*
[17] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25,447.
[18] [This footnote intentionally deleted in corrected copy.]

environment. EPA should reconsider its 1988 Regulatory Determination and regulate E&P wastes under Subtitle C of RCRA. Regulation under Subtitle C is not only appropriate, given that E&P wastes fall within the regulatory criteria for characteristic hazardous waste,[19] but necessary because, without such action, the oil and gas industry will lack the incentives to implement safer techniques as quickly as is necessary.[20]

1. E&P Waste Is Toxic.

E&P waste that is exempt from regulation under Subtitle C includes: drilling fluids and cuttings, produced water, used hydraulic fracturing fluids, rigwash, workover wastes, tank bottom sludge, glycol-based dehydration wastes, amine-containing sweetening wastes, hydrocarbon-bearing soil, and many other individual waste products.[21] In its 1988 Regulatory Determination, EPA admitted that E&P wastes contain toxic substances that endanger both human health and the environment.[22] Despite noting that benzene, phenanthrene, lead, arsenic, barium, antimony, fluoride, and uranium found in E&P wastes were of major concern and present at "levels that exceed 100 times EPA's health based standards,"[23] EPA declined to regulate these toxic substances under Subtitle C of RCRA. But EPA can no longer refuse to act: an ever-increasing amount of evidence demonstrates that E&P wastes are toxic, have had substantial negative effects on human health and the environment, and should be a major concern for EPA. Since 1988, numerous reports, studies, and cases have demonstrated that E&P wastes contain toxic substances that threaten both human health and the environment.

a. Contaminants Found in Different Types of E&P Wastes

E&P wastes are generally divided into three categories: produced water, drilling fluids and cuttings, and associated wastes.[24] All of these wastes contain a variety of toxic substances that present substantial risks to human health and the environment. Despite these risks, these E&P wastes are currently exempt from regulation under Subtitle C.

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[19] *See* notes 282–313 *infra* and accompanying text.
[20] Closing Argument of the New Mexico Citizens for Clean Air and Water, Dec. 2007, OCD Document Image No. 14015_648_CF[1] at 9-10; *see also* AMY MALL, DRILLING DOWN: PROTECTING WESTERN COMMUNITIES FROM THE HEALTH AND ENVIRONMENTAL EFFECTS OF OIL AND GAS PRODUCTION vi (2007) [hereinafter "DRILLING DOWN"].
[21] *See* RAILROAD COMMISSION OF TEXAS, *Hazardous and Nonhazardous Oil and Gas Waste* 3–6, *in* WASTE MINIMIZATION IN THE OIL FIELD (2001).
[22] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25448.
[23] *Id.*; *see also* Cox, *supra* note 8, at 9.
[24] CLAUDIA ZAGREAN NAGY, CALIFORNIA DEP'T OF TOXIC SUBSTANCES CONTROL, OIL EXPLORATION AND PRODUCTION WASTES INITIATIVE 6 (2002).

i. Produced Water & Hydraulic Fracturing Wastewater

Produced water, also known as brine, is generally—but erroneously—considered to be "relatively clean" and contain less contaminants than other E&P waste.[25] Despite this common misconception, a study sponsored by the U.S. Department of Energy demonstrated that oil production yields "environmentally hazardous" produced water.[26] The West Virginia Department of Environmental Protection (WVDEP) found many contaminants of concern present in oil and gas wastewaters,[27] including arsenic, lead, and hexavalent chromium, while EPA Region 8 identified the presence of barium, chloride, sodium, sulfates, and other minerals,[28] and the Oklahoma Corporation Commission Oil and Gas Conservation Division stated that produced water can contain high levels of boron.[29] In 2009, the Colorado Oil and Gas Conservation Commission (COCG) documented multiple spills of produced water containing benzene levels exceeding the state's water quality standards, at least one of which was confirmed to have impacted groundwater.[30]

Knowledge of the hazardous nature of produced water is not new. In 1972, Chevron Oil Field Research Company found that "oil field produced waters contain dissolved organic compounds that are toxic to marine life."[31] More than a decade later, the U.S. General Accounting Office (GAO) acknowledged that "[b]rines associated with oil and gas production contain very high levels of chlorides . . . . Brines may also contain . . . petroleum hydrocarbons and additives, such as corrosion inhibitors, . . . and other radioactive materials."[32] EPA was aware of these hazardous constituents when it issued its 1988 Regulatory Determination. In its 1987 Report to Congress, EPA knew that "PAHs [polycyclic aromatic hydrocarbons] are a typical component of some produced waters," that "very low concentrations . . . of PAH are lethal to some forms of aquatic wildlife," and that the practice of disposing of "produced water in

[25] KELLY CORCORAN, KATHERINE JOSEPH, ELIZABETH LAPOSATA, & ERIC SCOT, UC HASTINGS COLLEGE OF THE LAW'S PUBLIC LAW RESEARCH INSTITUTE, SELECTED TOPICS IN STATE AND LOCAL REGULATION OF OIL AND GAS EXPLORATION AND PRODUCTION 31–32.
[26] C. TSOURIS, OAK RIDGE NATIONAL LABORATORY, EMERGING APPLICATIONS OF GAS HYDRATES 7.
[27] The contaminants of concern included: "sulfate, chloride, arsenic, titanium, cobalt, nickel, silver, zinc, vanadium, tin, cadmium, lead, chromium, hexavalent chromium, copper, fluoranthene, cyanide, mercury, selenium, antimony, beryllium, barium, ammonia nitrogen, fluoride, nitrite nitrogen, nitrate nitrogen, oil and grease, total suspended solids, iron, aluminum, chloroform, benzene, phthalate esters, strontium, strontium-90, boron, lithium, gross alpha radiation, gross beta radiation, radium 226+ [and] radium 228." Letter from West Virginia Department of Environmental Protection to William Goodwin, Superintendent Clarksburg Sanitary Board, July 23, 2009.
[28] EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY, WORKING DRAFT 3-11 (2008).
[29] OKLAHOMA CORPORATION COMMISSION OIL AND GAS CONSERVATION DIVISION, GUIDELINES FOR RESPONDING TO AND REMEDIATING NEW OR HISTORIC BRINE SPILLS 2 (2009).
[30] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631502, 1631508 (groundwater impact confirmed).
[31] A.H. BEYER, CHEVRON OIL FIELD RESEARCH CO., TECHNICAL MEMORANDUM, PURIFICATION OF PRODUCED WATER, PART 1—REMOVAL OF VOLATILE DISSOLVED OIL BY STRIPPING 1 (1972).
[32] U.S. GENERAL ACCOUNTING OFFICE, RCED-89-97, SAFEGUARDS ARE NOT PREVENTING CONTAMINATION FROM INJECTED OIL AND GAS WELLS 11 (1989).

unlined percolation pits [allows] PAHs and other constituents to migrate into and accumulate in soils."[33]

In addition to containing dangerous contaminants, produced water can also be radioactive. This problem first attracted national attention 1988 in southern and Gulf Coast states.[34] Shortly thereafter, GAO's 1989 report openly acknowledged the hazard.[35] A more recent analysis of normally occurring radioactive materials (NORM) levels in produced waters from the Marcellus Shale indicates that the dangers may be greater than initially thought.[36] Samples of produced water in the Marcellus Shale analyzed by the New York State Department of Environmental Conservation (NYSDEC) were reported to contain "levels of radium 226, a derivative of uranium, as high as 267 times the limit safe for people to drink."[37]

Despite knowledge of these risks, the data currently available may underestimate the actual radiation levels in produced water. A common method used by industry and EPA to measure radiation levels in produced water has been criticized because of its tendency to underestimate actual radiation levels. In the late 1980s, Exxon Mobil, along with Rogers and Associates Engineers (RAE) and the American Petroleum Institute (API), formulated correlations that could be used to estimate NORM in levels of equipment used to hold produced water.[38] The external measurement process chosen by RAE to measure the NORM levels has since been challenged as "seriously flawed" and has resulted in the reporting of a "greatly reduced radioactivity concentration of 480 pCi/gm."[39] Accurate testing could reveal that the NORM levels in produced water are even higher than currently being reported.

Wastewaters from hydraulic fracturing, largely composed of used fracturing fluids, are also toxic. Common substances found in these wastewaters include: surfactants, friction reducing chemicals, biocides, scale inhibitors, polymers, cross linkers, pH control agents, gel breakers, clay control agents and propping agents.[40] Many of these substances are possible and probable carcinogens.[41] Analysis of fracturing fluid flowback waters from Pennsylvania and West Virginia found the known carcinogen benzene present in nearly half of all fracturing fluid flowback waters at average concentrations nearly one hundred times the maximum acceptable

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[33] EPA, REPORT TO CONGRESS, *supra* note 11, at II-44.
[34] Keith Schneider, *Radiation Danger Found in Oilfields Across the Nation*, N.Y. TIMES, Dec. 3, 1990, at A1.
[35] GAO, RCED-89-97, *supra* note 32.
[36] N.Y. DEP'T OF ENVTL. CONSERVATION, DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM 6-130 (2009) [hereinafter DRAFT SGEIS].
[37] Abrahm Lustgarten, ProPublica, *Natural Gas Drilling Produces Radioactive Wastewater*, SCIENTIFIC AMERICAN, Nov. 9, 2009; *see also* DRAFT SGEIS, *supra* note 36, at app. 13.
[38] Motion in Limine to Exclude Rogers and Associates Engineering Reports, Lester v. Exxon Mobil Corp., No. 630-402 (La. 24th Jud. Dist. Ct. 2009), at 6–7.
[39] *Id.* at 7-8.
[40] Wilma Subra, Louisiana Environmental Action Network, Comments on Hydraulic Fracturing to the Louisiana Senate Environmental Quality Committee, Mar. 11, 2010.
[41] *Id.*

contaminant levels established by EPA.[42] While this information demonstrates that these wastes contain toxic compounds, the true extent of the risks associated with hydraulic fracturing wastewaters is currently unknown as many of the compounds used in fracturing fluids and returned in the wastewaters are not publically disclosed.[43]

ii. Drilling Fluids and Drill Cuttings

Drilling fluids and cuttings make up two to four percent of oil and gas wastes.[44] They include rock removed during drilling (drill cuttings) and drilling muds, also known as drilling fluids, which can be either water or oil-based and often contain various additives.[45] A joint EPA/API survey found drilling fluids in reserve pits to contain "chromium, lead and pentachlorophenol at hazardous levels."[46] The survey also found that "oil-based fluids may contain benzene"[47] and that when oil-based fluids are used, "potentially toxic hydrocarbons" will be present in greater quantities.[48] Drilling muds may also contain other "potentially hazardous substances including . . . cadmium, arsenic . . . mercury, copper . . . diesel oil; grease; and various other hydrocarbons and organic compounds (e.g., methanol, chlorinated phenols, formaldehyde, benzene, toluene, ethyl benzene, xylene, and acrylamide)," as well as additives including acids and caustics, corrosion inhibitors, bactericides and biocides, surfactants, defoamers, emulsifiers, filtrater

[42] Susan Riha et al, *Comments on the Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program*, Jan. 2010, at 5; *see also* N.Y. DEP'T OF ENVTL. CONSERVATION, DRAFT SGEIS 5-104 (2009).

[43] Wilma Subra, Comments on Hydraulic Fracturing, *supra* note 40. *See also* DRAFT SGEIS, *supra* note 36, at 5-51 (stating that the fracturing fluid additives list "[c]hemical constituents are not linked to product names in Table 5.6 because a significant number of product composition and formulas have been justified as trade secrets as defined [under New York law] . . . .").

[44] U.S. CONGRESS, OFFICE OF TECHNOLOGY ASSESSMENT, MANAGING INDUSTRIAL SOLID WASTES FROM MANUFACTURING, MINING, OIL AND GAS PRODUCTION, AND UTILITY COAL COMBUSTION—BACKGROUND PAPER 67 (1992).

[45] *Id; see also* U.S. FISH & WILDLIFE SERV., REGION 6, ENVTL. CONTAMINANTS PROGRAM, RESERVE PIT MANAGEMENT: RISKS TO MIGRATORY BIRDS 4–5 (2009).

> "Water-based drilling muds can contain glycols, chromium, zinc, polypropylene glycol, and acrylamide copolymers. Synthetic-based muds contain mineral oil and oil-based muds can contain diesel oil, although diesel oil is being replaced by a palm oil derivative or hydrated caster [*sic*] oil. Other additives typically used in drilling fluids include: polymers (partially hydrolyzed polyacrylamide (PHPA) and polyanionic cellulose (PAC)); drilling detergents; and sodium carbonate (soda ash). PHPA is used to increase viscosity of fluid and inhibit clay and shale from swelling and sticking. PAC is used to increase the stability of the borehole in unconsolidated formations. Drilling detergents or surfactants are used with bentonite drilling fluids to decrease the surface tension of the drill cuttings. Soda ash is used to raise the pH of the water and precipitate calcium out of the water." *Id.* (internal citations omitted).

[46] U.S. CONGRESS, OFFICE OF TECHNOLOGY ASSESSMENT, MANAGING INDUSTRIAL SOLID WASTES FROM MANUFACTURING, MINING, OIL AND GAS PRODUCTION, AND UTILITY COAL COMBUSTION—BACKGROUND PAPER 5 (1992).

[47] *Id.*

[48] OIL & GAS ACCOUNTABILITY PROJECT, PIT POLLUTION—BACKGROUNDER ON THE ISSUES, WITH A NEW MEXICO CASE STUDY 6 (2004).

reducers, shale control inhibitors, thinners and dispersants, weighing materials, bentonite clay, and acrylamide.[49]

The use of these additives increases the risks associated with E&P waste, as many are hazardous compounds themselves.[50] EPA has already classified at least one additive, flocculant acrylamide, as a probable carcinogen.[51] Another frequently used additive, barite weighting agent, can contain cadmium and mercury.[52] When Greenpeace analyzed the heavy metal contents of one drilling fluid additive, SOLTEX® (a scale inhibitor used in both on- and off-shore drilling muds), it identified the presence of antimony, arsenic, barium, cadmium, chromium, cobalt, copper, fluoride, lead, mercury, nickel, vanadium, and zinc.[53] These reports alone create cause for concern; yet, the full extent of the risk these chemicals present is unknown, as the additives' formulas, and thus the concentrations of the various chemicals, are proprietary information and undisclosed by oil and gas companies.[54]

iii. Associated Wastes

Associated wastes include oily sludges, workover wastes, well completion and abandonment wastes and other small volume wastes associated with oil or gas production.[55] Oily sludges consist of "oily sands and untreatable emulsions segregated from the production stream, and sediment accumulated on the bottom of crude oil and water storage tanks."[56] Workover wastes include foam treatment wastes and stimulation fluids.[57] Of all the E&P wastes, associated wastes are generated in the lowest volume;[58] however, this does not mean that they are safe or that current regulations ensure they are disposed of properly. Indeed, "[a]lthough associated wastes constitute a relatively small proportion of total wastes, they are most likely to contain a range of chemicals and naturally occurring materials that are of concern to health and safety."[59] Several associated wastes identified in Colorado have the "potential to be ignitable" while others "can exhibit toxicity for heavy metals such as lead."[60]

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[49] *Id.*
[50] *Id.*
[51] U.S. EPA, *Technology Transfer Air Toxics: Acrylamide*.
[52] T.A. Kassim, *Waste Minimization and Molecular Nanotechnology: Toward Total Environmental Sustainability*, *in* 3 ENVIRONMENTAL IMPACT ASSESSMENT OF RECYCLED WASTES ON SURFACE AND GROUND WATERS: ENGINEERING MODELING AND SUSTAINABILITY 191, 204 (Tarek A. Kassim ed., 2005); Texas Railroad Commission, Waste Minimization in Drilling Operations.
[53] JONATHAN WILLS, MUDDIED WATERS, A SURVEY OF OFFSHORE OILFIELD DRILLING WASTES AND DISPOSAL TECHNIQUES TO REDUCE THE ECOLOGICAL IMPACT OF SEA DUMPING (2000).
[54] OIL & GAS ACCOUNTABILITY PROJECT, *supra* note 48, at 6–7.
[55] NAGY, *supra* note 24, at 6.
[56] *Id. at* 13.
[57] *Id.* at 14.
[58] *Id. at* 6; American Petroleum Institute, Waste Management.
[59] Dara O'Rourke & Sarah Connolly, *Just Oil? The Distribution of Environmental and Social Impacts of Oil Production and Consumption*, 28 ANNUAL REV. ENVTL. RESOURCES 587, 595 (2003).
[60] Testimony of Margaret A. Ash, OGCC Envtl. Supervisor, *In the Matter of Changes to the Rules and Regulations of the Oil and Gas Conservation Commission of the State of Colorado*, at 15.

b. Contaminants Found in Specific E&P Waste Disposal Sites

The hazardous contaminants used in oil and gas exploration and production and whose presence has been identified in E&P wastes end up being disposed of in a variety of methods. Pits, burial, land application, and injection wells are the methods most frequently used to dispose of E&P wastes. Wastewater treatment facilities are also increasing in use. Studies of some of these different types of common E&P waste disposal sites provide further evidence of the toxicity of E&P wastes.

Pits are a common E&P waste disposal method used both to store drilling muds and cuttings brought to the surface in drilling operations and to hold produced water, production fluids, used hydraulic fracturing fluid, and other wastes.[61] Numerous studies have found pits to contain toxic levels of many hazardous compounds. In 2007, an industry committee of oil and gas companies in New Mexico sponsored a sampling and analysis program of waste pits in the San Juan Basin.[62] Forty-two substances, including the "BTEX" chemicals[63] (benzene, toluene, ethylbenzene, and xylene), acetone, arsenic, barium, mercury, and radium were found in the samples.[64] Eleven of the chemicals were present at concentration levels above state limits.[65] A more recent sampling of an oilfield pit in Texas identified the presence of high levels of mercury and chromium.[66] Dirt removed from a pit in Oklahoma was contaminated with "high levels of arsenic, dioxins and total petroleum hydrocarbons."[67]

Analysis of land application sites, another method for disposing of E&P wastes, provides further evidence illustrating the hazards of E&P wastes. A study of landfarms conducted by the Arkansas Department of Environmental Quality (ADEQ) found that the substances in E&P wastes that were being land applied exceeded Arkansas' acceptable limits for chloride concentrations in most of the facilities it tested.[68] In addition, "[n]ine out of eleven facilities had

[61] CORCORAN ET AL., *supra* note 25, at 20–21.
[62] The Endocrine Disruption Exchange, Potential Health Effects of Residues in 6 New Mexico Oil and Gas Drilling Reserve Pits Based on Compounds Detected in at Least One Sample, Nov. 15, 2007.
[63] SHANNON D. WILLIAMS, DAVID E. LADD & JAMES J. FARMER, U.S. GEOLOGICAL SURVEY, FATE AND TRANSPORT OF PETROLEUM HYDROCARBONS IN SOIL AND GROUND WATER AT BIG SOUTH FORK NATIONAL RIVER AND RECREATION AREA, TENNESSEE AND KENTUCKY, 2002–2003 10 (2006) ("The BTEX compounds . . . appear on The Clean Water Act Priority Pollutant list of 126 chemical substances (Office of the Federal Register, 2002)."). Testing obtained by individuals residing near the pits has also confirmed the presence of dangerous contaminants. DRILLING DOWN, *supra* note 20, at 26 n.156.
[64] The Endocrine Disruption Exchange, *supra* note 62.
[65] The Endocrine Disruption Exchange, Number of Chemicals Detected in Reserve Pits for 6 Wells in New Mexico That Appear on National Toxic Chemicals Lists: Amended Document, Nov. 15, 2007.
[66] Letter from Roy Staiger, District Office Cleanup Coordinator, Texas Railroad Commission, to Exxon Mobil Corporation, Dec. 31, 2009.
[67] OIL & GAS ACCOUNTABILITY PROJECT, SPRING/SUMMER 2006 REPORT (2006).
[68] Arkansas Dep't of Envtl. Quality, Report on Landfarms ("Four facilities had pond chlorides greater than 3,000 mg/L and the ponds were full . . . . Eight out of eleven facilities had soil concentrations greater than 1,000 mg/Kg on at least one application area. Most were several times higher than 1,000 mg/Kg . . . .").

TPH concentrations that would indicate the application of [oil-based drilling fluids] had taken place."[69] Analysis of soil samples taken from a residential property in Texas, where pit sludge had been land applied less than 300 feet from a residence, "confirmed the presence of numerous hydrocarbons identified as Recognized and Suspected human carcinogens and neurotoxins (1, 2, 4 Trimethylbenzene, 1, 3, 5 Trimethylbenzene, 4-Isopropyltoluene, Acetone, Benzene, Carbon disulfide, Ethylbenzene, Isopropylbenzene, m&m Xylene, n-Butylbenzene, n-Propylbenzene, o-Xylene, sec-Butylbenzene, tert-Butylbenzene, Toluene)."[70] The residents of this property all reported skin rashes after the waste was applied to their land.[71]

c. The risks associated with these contaminants

i. Substances in E&P Wastes Endanger Human Health.

Many of these substances identified in E&P wastes are known carcinogens.[72] The most prevalent contaminants found in E&P wastes are the "BTEX" chemicals:[73] benzene,[74] toluene,[75] ethylbenzene,[76] and xylene.[77] Exposure to benzene has been "associated with an increased risk of leukemia in industrial workers"[78] and other serious health conditions, exposure to toluene can cause nervous system damage,[79] while xylenes can "cause dizziness, headaches and loss of balance among other problems."[80]Many of the other chemicals found in E&P waste, including

[69] *Id.*
[70] WOLF EAGLE ENVIRONMENTAL, ENVIRONMENTAL STUDIES: FUGITIVE AIR EMISSIONS TESTING, IMPACTED SOIL TESTING, MR. AND MRS. TIMOTHY RUGGIERO (2010).
[71] Eric Griffey, *Toxic drilling waste is getting spread all over Texas farmland*, FORT WORTH WEEKLY, May 12, 2010.
[72] *See* Cox, *supra* note 8, at 4.
[73] CORCORAN ET AL., *supra* note 25, at 21.; *see also* WILLIAMS ET AL., *supra* note 63, at 10 ("The BTEX compounds . . . appear on The Clean Water Act Priority Pollutant list of 126 chemical substances (Office of the Federal Register, 2002)."); U.S.G.S., TOXIC SUBSTANCE HYDROLOGY PROGRAM: BTEX.
[74] "Benzene is a known human carcinogen and causes leukemia." DRILLING DOWN, *supra* note 20, at vi; *see also* WILLIAMS ET AL., *supra* note 63, at 26. ("Because of the high degree of toxicity and mobility of benzene (compared to other petroleum hydrocarbons), it is commonly the main ground-water contaminant of concern at petroleum release sites.").
[75] "Toluene can cause fatigue, confusion, weakness, memory loss, nausea, hearing loss, central nervous system damage, and may cause kidney damage. It is also known to cause birth defects and reproductive harm." DRILLING DOWN, *supra* note 20, at vi (footnotes omitted).
[76] "Ethylbenzene can cause dizziness, throat and eye irritation, respiratory problems, fatigue, and headaches. It has been linked to tumors and birth defects in animals, as well as to damage in the nervous system, liver, and kidneys." *Id.* (footnote omitted).
[77] "Xylene can cause headaches; dizziness; confusion; balance changes; irritation of the skin, eyes, nose and throat; breathing difficulty; memory difficulties; stomach discomfort; and possibly changes in the liver and kidneys." *Id.* (footnote omitted).
[78] N.Y. DEP'T OF ENVTL. CONSERVATION, *supra* note 36, at 5-62 (2009).
[79] CORCORAN ET AL., *supra* note 25, at 21.
[80] *Id.*

acetone,[81] arsenic,[82] barium,[83] mercury,[84] and radium,[85] all found in E&P waste samples, also raise serious concerns for human health.

The impacts of these contaminants have been documented. In a 1997 Louisiana case against U.S. Liquids & Exxon, plaintiffs reported that shortly after the dumping of more than fifty million gallons of E&P waste containing benzene, toluene, and lead occurred at a facility located less than 500 feet from the nearest resident's home, "[a] strange smell blew over the community and . . . . [m]any people in the area felt sick . . . . For nearly three weeks, most residents, including children, suffered from stomach pains, sinus problems and other ailments."[86] Other evidence demonstrates that exposure to contaminants in E&P wastes can result in delayed and long-term health effects. One study conducted in the Amazon Basin of Ecuador found that pregnant women who resided in areas where there was discharge of untreated oilfield wastes into the environment experienced higher levels of spontaneous abortion.[87] Another epidemiological study in the same area showed "significantly higher incidence of cancer for all sites combined in both men and women living in proximity to oil fields . . . . [specifically,] [s]ignificantly higher incidences were observed for cancers of the stomach, rectum skin melanoma, soft tissue and

[81] Acetone can cause nose, throat, lung and eye irritation, respiratory problems, fatigue and headaches. *See* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR ACETONE (1995); DRILLING DOWN, *supra* note 20, at vi (footnote omitted).

[82] "Chronic arsenic exposure can cause damage to blood vessels, a sensation of 'pins and needles' in hands and feet, darkening and thickening of the skin, and skin redness. It is a known human carcinogen and can cause cancer of the skin, lung, bladder, liver, kidney, and prostate." DRILLING DOWN, *supra* note 20, at vi (footnote omitted); *see also* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR ARSENIC (2007) ("Exposure to lower levels can cause nausea and vomiting, decreased production of red and white blood cells, abnormal heart rhythm . . . ."); SCIENCELAB.COM, CHEMICALS & LABORATORY EQUIPMENT, MATERIAL SAFETY DATA SHEET: ARSENIC MSDS 1 (2008), ("[Arsenic is] toxic to kidneys, lungs, the nervous system, mucous membranes.")

[83] "Ingesting drinking water containing levels of barium above the EPA drinking water guidelines for relatively short periods of time can cause gastrointestinal disturbances and muscle weakness. Ingesting high levels for a long time can damage the kidneys . . . . Some people who eat or drink amounts of barium above background levels found in food and water for a short period may experience vomiting, abdominal cramps, diarrhea, difficulties in breathing, increased or decreased blood pressure, numbness around the face, and muscle weakness. Eating or drinking very large amounts of barium compounds that easily dissolve can cause changes in heart rhythm or paralysis and possibly death. Animals that drank barium over long periods had damage to the kidneys, decreases in body weight, and some died." AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR BARIUM (2007).

[84] "Mercury can permanently damage the brain, kidneys, and developing fetus and may result in tremors, changes in vision or hearing, and memory problems. Even in low does, mercury may affect an infant's development, delaying walking and talking, shortening attention 'span,' and causing learning disabilities." DRILLING DOWN, *supra* note 20, at vi (footnote omitted).

[85] "Radium is a known human carcinogen, causing bone, liver, and breast cancer." *Id.* (footnote omitted); *see also* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR RADIUM (1999).

[86] Chris Gray, *Pits Cause Stink in Lafourche*, TIMES-PICAYUNE, July 14, 1997, at A1.

[87] Miguel San Sebastian, Ben Armstrong, & Carolyn Stephens, *Outcomes of Pregnancy among Women Living in the Proximity of Oil Fields in the Amazon Basin of Ecuador*, 8 INTL. J. OF OCCUPATIONAL AND ECON. HEALTH 312 (2002).

kidney in men and for cancers of the cervix and lymph nodes in women.[88] As reports and first-hand accounts indicate, the risks posed by the contaminants found in E&P waste are not merely speculative. And the risks will not decrease anytime soon. As many pits containing E&P wastes are buried and forgotten, the buried E&P wastes have the potential to threaten future generations who will be unaware of the hazards just below the surface.

Human health can also be harmed by exposure to radiation in NORM-contaminated E&P wastes. Exposure can occur through inhalation of radium-bearing particles, through direct contact with NORM-contaminated soils and water, or through ingestion of radium-barium particles found in plants or animals exposed to NORM-contaminated soils or water.[89] Exposure to radium can result "in an increased risk of bone, liver, and breast cancer . . . . [it] has been shown to cause effects on the blood (anemia) and eyes (cataracts). It also has been shown to affect the teeth, causing an increase in broken teeth and cavities."[90] And the risks associated with NORM-contaminated soils and waters can persist for decades. In particular, land contaminated by radium 226, such as that found in produced water from the Marcellus Shale,[91] can pose a threat to "many generations of individuals living or working on NORM-contaminated land for a period covering nearing 20,000 years."[92]

ii. Substances in E&P Wastes Endanger Wildlife and Livestock.

In addition to harming human health, exposure to contaminants in E&P waste can sicken and kill wildlife. A recent report prepared by the U.S. Fish and Wildlife Service (USFWS) indicates that pits present significant risks to wildlife. Pits can "entrap and kill migratory birds and other wildlife . . . . Birds are attracted to reserve pits by mistaking them for bodies of water. . . . The sticky nature of oil entraps birds in the pits and they die from exposure and exhaustion."[93] In 2009, ExxonMobil pled guilty to violating the Migratory Bird Treaty Act,[94] after numerous birds (including mallard ducks, grebes, white-faced ibis, gadwell ducks, owls, Wilson pharalopes, Northern Shoveler ducks, avocets, curlew, a green-winged teal, a Cassin's sparrow, a purple

[88] Anna-Karin Hurtig & Miguel San Sebastian, *Geographical Differences in Cancer Incidence in the Amazon Basin of Ecuador in Relation to Residence near Oil Fields*, 31 INT'L. J. OF EPIDEMIOLOGY 1021, 1025 (2002).
[89] Henry Spitz, Kennith Lovins & Christopher Becker, *Evaluation of Residual Soil Contamination From Commercial Oil Well Drilling Activities and Its Impact on the Naturally Occurring Background Radiation Environment*, 6 SOIL & SEDIMENT CONTAMINATION: AN INT'L J. 37, 43 (1997).
[90] AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, *supra* note 85.
[91] *See supra* note 37.
[92] Henry Spitz, Kennith Lovins & Christopher Becker, *Evaluation of Residual Soil Contamination From Commercial Oil Well Drilling Activities and Its Impact on the Naturally Occurring Background Radiation Environment*, 6 SOIL & SEDIMENT CONTAMINATION: AN INT'L J. 37, 41 (1997).
[93] U.S. FISH & WILDLIFE SERV., REGION 6, ENVTL. CONTAMINANTS PROGRAM, RESERVE PIT MANAGEMENT: RISKS TO MIGRATORY BIRDS i (2009).
[94] 16 U.S.C. §§ 703-708.

martin, and a hawk) were found sick and dead after being exposed to pit contents, including hydrocarbons, in multiple states.[95]

E&P wastes have the potential to destroy lands upon which wildlife depend, disrupt food chains, and prevent wildlife from reproducing.[96] The New Mexico Department of Game & Fish has expressed concern about the hazards of hydrocarbon toxicity to wildlife including "acute and chronic ingestion or absorption toxicity, loss of thermal stability from oiling of fur or feathers, and reproductive failure due to absorption of chemicals from the maternal bird body through the shell of eggs."[97] Other researchers are concerned about the bioaccumulation of E&P wastes in wildlife, a process that would cause their harmful effects to magnify as they progress up the food chain.[98] Wildlife habitat may also be harmed by E&P waste. The New Mexico Department of Game and Fish has stated that it "is concerned that chloride contamination of the soil vadose zone may permanently impact the ability of a closed pit location to support vegetation necessary for productive wildlife habitat."[99] Just as E&P wastes can harm humans in ways that are not immediately apparent but can cause harm to future generations, so too can they harm successive generations of wildlife.

Domesticated animals are also harmed by E&P wastes. The Pennsylvania Department of Agriculture quarantined cattle after they came into contact with hydraulic fracturing wastewater being stored in a pit that leaked into an adjacent field. The owners of the property where the pit was located noticed seepage from the pit for as long as two months prior to the leak. The Department stated that wastewater "contains dangerous chemicals and metals." Tests of the wastewater found that it contained strontium as well as other substances.[100] E&P waste is sometimes disposed of on land used for cattle grazing.[101] Residents of the Barnett Shale have reported seeing cattle drinking from sludge pits.[102] Cattle have been lost due to exposure to E&P waste in New Mexico[103] and 54 out of 56 hair samples from sick cattle analyzed by the Texas Veterinary Medical Diagnostic Laboratory contained petroleum.[104]

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[95] Joint Factual Statement, U.S. v. Exxon Mobil Corp., ¶¶ 10–27 (D.Col. 2009).
[96] BRYAN M. CLARK, DIRTY DRILLING: THE THREAT OF OIL AND GAS DRILLING IN LAKE ERIE 25 (2002).
[97] Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to Florene Davidson, Commission Secretary, EMNRD Oil Conservation Division (Jan. 20, 2006); *see also* Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to Florene Davidson, Commission Secretary, EMNRD Oil Conservation Division (Mar. 7, 2006).
[98] BRYAN M. CLARK, *supra* note 96, at 25.
[99] Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to EMNRD Oil Conservation Division (Feb. 2, 2007).
[100] Press Release, Pa. Dep't of Envtl. Prot., *Cattle from Tioga County Farm Quarantined after Coming in Contact with Natural Gas Drilling Wastewater* (July 1, 2010).
[101] *See e.g.*, Amended Complaint, Sweet Lake Land and Oil Co. v. Exxon Mobil Corp., No. 209CV01100, at ¶ 32 (W.D. La. filed Sept. 14, 2009), 2009 WL 4701364.
[102] Bluedaze: Drilling Reform for Texas blog (July 25, 2008).
[103] DRILLING DOWN, *supra* note 20, at 26.
[104] Test results from Veterinary Medical Diagnostic Laboratory on July 26, 2005, August 18, 2005, and September 6, 2005; DRILLING DOWN, *supra* note 20, at 26.

In response to occurrences like these, cattle ranchers and others whose animals are at risk have sought to prevent E&P waste disposal facilities from opening near their properties.[105] Protecting cattle and other domesticated animals from exposure to E&P wastes is particularly important as the hazardous contaminants of E&P wastes have the potential to bioaccumulate in these animals and potentially make their way into the human food chain.[106]

2. Current State Regulations and Enforcement Are Inadequate and Allow E&P Waste to Be Released into the Environment.

Waste produced in E&P operations is disposed of in a variety of ways, with underground injection and burial of waste historically being the most widely used methods.[107] Wastewater treatment facilities are another growing disposal method. Even before EPA made its 1988 Regulatory Determination, data indicated that commonly used disposal practices failed to prevent E&P wastes from contaminating soil and groundwater.[108] A 1987 report documented "the migration of leachate 400 feet from reserve pits buried in . . . North Dakota and reported groundwater contamination 50 feet below the buried reserve pits."[109] Incidences of soil and groundwater contamination have continued to occur since then.

E&P wastes may leak, spill, or evaporate into the air, allowing the chemicals used in oil and gas operations to be released into the environment. These releases occur in large part because many states' regulations do not adequately account for all of these potential modes of contamination, despite the fact that releases are occurring with alarming regularity, or are not vigorously enforced. The regulations of the Railroad Commission (RRC) of Texas have been described as providing only weak assurance that the "quality of waters (and land) will not be impacted by a gas operator's activity."[110] Assurances are similarly minimal in other states where regulations provide virtually useless oversight of E&P waste disposal because they fail to "clearly indicate acceptable disposal practices for all drilling wastes."[111]

An Ohio resident with 23 years of experience in drilling oil and gas wells testified before the state legislature that existing regulations are inadequate and cannot be appropriately enforced: "… the [Ohio Department of Natural Resources] has a serious lack of ability to enforce their own regulations due to the way the current law and this bill are written."[112] A review of Tennessee oil

[105] Susan Hylton, *Drilling Waste Feud, Neighbors of Maverick Energy Services Think Water is Being Polluted*, TULSA WORLD, Mar. 21, 2010, at A11
[106] DRILLING DOWN, *supra* note 20, at 26.
[107] *See* E&P FORUM, EXPLORATION AND PRODUCTION (E&P) WASTE MANAGEMENT GUIDELINES 5 (Report No. 2.58/196, 1993).
[108] U.S. FISH & WILDLIFE SERV., *supra* note 93, at 4.
[109] *Id.*
[110] League of Women Voters of Tarrant County, Gas Drilling Waste-Water Disposal (2008).
[111] BRYAN M. CLARK, *supra* note 96, at 35.
[112] Testimony of James E. McCartney to the 128th General Assembly, Ohio Senate Environmental and Natural Resources Committee. Opponent Testimony on Senate Bill 165, Oct. 28, 2009.

and gas regulations found that the state does not have technical criteria for E&P waste management practices or any certification for E&P haulers.[113] Although all pits must be lined in Tennessee, pits are not considered or tracked through the permitting process and there are no security or wildlife protection measures.[114]

A 2009 letter from the EPA to the RRC of Texas states that the Commission should have "more rigorous evaluation" of conditions for waste disposal wells.[115] Texas also "allows companies to hire their own environmental consultants to check for contamination."[116] These regulatory failures existed when EPA issued its 1988 Regulatory Determination, and have been exacerbated in the wake of EPA's decision not to regulate E&P wastes under Subtitle C of RCRA.

a. Pits

Pit construction requirements vary greatly across the country. While a few states, such as New Mexico and Colorado, have recently adopted stricter rules governing the disposal of E&P wastes in pits, other states have minimal regulations and often do not even require the use of pit liners.[117]

The open design of pits, combined with the often minimal regulatory requirements governing their construction and use, present greater opportunities for their dangerous contents to be released into the environment. Reports indicate that the release of E&P wastes from pits is far too common.

In September 2008, New Mexico compiled its data on cases where pit substances contaminated New Mexico's groundwater.[118] The numbers were staggering: More than 700 incidents of groundwater contamination by oilfield wastes or products were documented.[119] Elsewhere, in 2001, E&P wastes from the Black Mountain disposal facility in Colorado contaminated nearby soil and groundwater when its clay lined pits began to leak.[120] Since then, many more releases of E&P wastes have occurred in Colorado. The Colorado Oil and Gas Conservation Commission (COGCC) documented several pits at the same pad site in Garfield

[113] TENNESSEE DEP'T OF ENV'T & CONSERVATION, STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., TENNESSEE STATE REVIEW 13, 19, 22, 24 (2007).
[114] *Id.* at 30.
[115] FY2008 EPA Region 6 End-of-year Evaluation of the Railroad Commission of Texas Underground Injection Control Program, with transmittal letter from Bill Luthans, Acting Director, Water Quality Protection Division, Region 6 to Tommie Seitz, Director, Oil and Gas Division (June 19, 2009).
[116] Joe Carroll, *Exxon's Oozing Texas Oil Pits Haunt Residents as XTO Deal Nears*, Bloomberg Businessweek, April 16, 2010.
[117] *See infra* notes 146–160 and accompanying text; *see also* OKLA. ADMIN. CODE § 165:10-7-16(b)(1)(B)(iii), (2)(b).
[118] NEW MEXICO ENERGY, MINERALS AND NATURAL RES. DEP'T, OIL CONSERVATION DIV., CASES WHERE PIT SUBSTANCES CONTAMINATED NEW MEXICO'S GROUND WATER (2008).
[119] Oil & Gas Accountability Project, Groundwater Contamination.
[120] Kim Weber, Regarding Support of HB 1414—Evaporative Waste Facilities Regulations.

County whose liners had torn and allowed wastes to be released on multiple occasions between April and August 2008.[121] The reports indicated that the pits were located on rocky terrain and that some of the liners had been torn by rocks on the site.[122] In total, more than 6,000 barrels of pit contents escaped the pits because of the tears.[123] In La Plata County, a landowner reported the possible contamination of his well by an unlined reserve pit located a mere 350 feet uphill from his well.[124] The COGCC eventually concluded that "it appear[ed] that fluids from the unlined reserve pit infiltrated into the shallow groundwater, flowed downhill and impacted the Thomson water well."[125] The COGCC has documented numerous other incidents where pits have leaked,[126] overflowed, [127] or been unlined,[128] thereby allowing their contents to be absorbed by unprotected ground.

In May, 2008, a Colorado citizen drank water from his spring and fell ill. The COGCC found benzene in the groundwater that exceeded standards by 32 times and benzene in faucet water that exceeded standards by 13 times, as well as elevated levels of toluene and xylenes. Although the COGCC began investigating this complaint in June, 2008, it wasn't until October, 2008, that the operator stated that it became aware that the production pit was never permitted. The state appears to have been unaware that the pit was never permitted even though it was investigating the pit as a possible source of groundwater contamination. In July, 2010, the COGCC found that the operator failed to properly permit, construct, maintain, and repair the pit, leading to a release or releases of E&P waste that impacted groundwater. The agency found that the liner had been stretched over rocks and had improperly sealed seams.[129]

In addition to the reports from New Mexico and Colorado, there have been many complaints by citizens of contamination reportedly caused by E&P wastes in other states. NYSDEC has received numerous reports of E&P waste releases, many of which have contaminated soil and

[121] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630424, 1630426, 1630427, 1630428, 1630429, 1630430.
[122] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NO. 1630428.
[123] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630424 (714 bbls), 1630426 (2000 bbls), 1630427 (500 bbls), 1630428 (1250 bbls), 1630429 (204 bbls), 1630430 (2017 bbls).
[124] Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development, Maralex Drilling Fluids in Drinking Water; COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORT, DOC. NO. 1953000.
[125] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, NOAV REPORT, DOC. NO. 200085988; *see also* Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development, Maralex Drilling Fluids in Drinking Water.
[126] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631518, 1631599, 2605176, 2605847.
[127] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 200225543, 200225547, 200225546.
[128] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NO.1632846.
[129] Colorado Oil and Gas Conservation Commission, Cause No. 1V, Order No. 1V, Docket No. 1008-OV-06

groundwater.[130] In June 1987, in West Seneca, N.Y., product from an open pit containing oil and other solvents was found running from the pit towards a nearby creek.[131] In November 1996, in Reading, N.Y., a produced water pit overflowed and spilled approximately two hundred gallons of produced water into a creek feeding into Seneca Lake.[132] NYSDEC determined that no cleanup was possible.[133] When a property owner in Bolivar, N.Y., called in June 2002 to report leaking oil wells, NYSDEC inspectors also found unlined leaking containment ponds.[134]

E&P wastes in pits have been released into the environment in other states as well. Pennsylvania's Department of Environmental Protection (PADEP) has documented several incidents of dangerous E&P waste releases into the environment. Notably, at two of Atlas Resources LLC's well sites in Pennsylvania, "compromised" pit liners allowed fracturing flowback fluids to escape.[135] In Ohio, a fracturing flowback pit was cut with a track hoe in 2010, causing more than 1.5 million gallons of fluid were spilled into the environment.[136] In 2008, the back wall of a pit in Ohio gave way, causing pit contents to spill and flow towards a creek.[137]

In addition to releases caused by torn liners and overflows, pits allow the hazardous contaminants in E&P wastes to be released into the environment through evaporation into the air. E&P wastes such as produced water stored in open pits can "release methane, toxic volatile organic chemicals and sulfur based compounds into the air."[138] Rocky Mountain Clean Air Action collected data showing that wastewater evaporation pits in Garfield County, Colorado are "major sources of air pollution and pose greater threats to human health than previously reported."[139] The data indicated that high levels of hydrocarbons and other hazardous air pollutants were being released into the air. [140] Also in Garfield County, beginning in October 2005, a resident repeatedly notified the COGCC that severe odors were emanating from an E&P waste pit located close to her home.[141] In early December 2005, the resident reported smelling "a different sort of stench . . . the 'Benzene smell'" to the COGCC and requested that the agency

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[130] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST (2009).
[131] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 37 (2009) (Spill Number: 8702469).
[132] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 53 (2009) (Spill Number: 9610217).
[133] *Id.*
[134] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 124-25 (2009) (Spill Number: 0275147).
[135]Consent Assessment of Civil Penalty, In re Atlas Resources LLC, Dancho-Brown 4, ¶¶ AV–AZ, Groves 8, ¶¶ BA–BE.
[136] Ohio Department of Natural Resources, Notice of Violation No. 1278508985, June 21, 2010.
[137] Ohio Department of Natural Resources, Notice of Violation No. 2016754140, May 16, 2008.
[138] Subra, *supra* note 43.
[139] Phillip Yates, *Clean Air Group Contends Evaporation Ponds in Garfield County More Dangerous than Previously Believed*, POST INDEPENDENT, Jan. 9, 2008.
[140] *Id.*
[141] Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development.

install full-time air monitoring equipment.[142] At the end of the month, the resident learned that sampling of the air fairly close to the pit "showed that benzene and xylenes exceeded the [EPA's] 'non-cancer risk levels' for these compounds – at 67 µg/m3, benzene was present at more than double the risk level. Other detectable compounds included acetone, toluene and ethylbenzene."[143]

While some incidents are effectively reported and prosecuted by state authorities, many more incidents occur that are not addressed adequately by state officials. In these cases, the citizens affected by such releases into the environment have instead turned to the judicial system in order to hold the oil and gas companies accountable. John Preston Stephenson, Jr. sued Chevron U.S.A alleging that waste from Chevron oil pits contaminated his property with "hazardous toxic and carcinogenic chemicals."[144] Similarly, the Sweet Lake Land and Oil Company sued multiple defendants, including Exxon, Noble Energy, Inc., and Texas Eastern Skyline Oil Company, for contamination of "the soil and groundwater with produced water, oil, drilling muds, technologically enhanced naturally occurring radioactive materials (sometimes referred to as 'TENORM'), hydrocarbons, metals, and other toxic and/or hazardous substances, wastes and pollutants," claiming that the defendants knew the pits contents would contaminate the plaintiff's surface and subsurface soil and water.[145] Sweet Lake Land and Oil Company further alleged that "[t]he presence of the pits, substances and scrap on and under the Property constitutes a nuisance."[146] These claims are only a handful of many more by citizens who have been harmed by E&P wastes released from pits.[147]

These reports of contamination are at least partially attributable to inadequate state efforts to regulate E&P waste disposal in pits. Despite the fact that pit contents have been found to contain hazardous contaminants,[148] many states fail to require operators to use the most basic of precautions. Tennessee, for example, does not even take pits into account in its permitting process, thereby "making their management and disposal difficult to track" and increasing the

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[142] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, COMPLAINT REPORT, DOC. NO. 200081602.
[143] Oil &Gas Accountability Project, *supra* note 141.
[144] Amended Complaint at ¶ 9, Stephenson v. Chevron U.S.A, Inc., No. 209CV01454, (W.D. La. filed Sept. 11, 2009), 2009 WL 4701406.
[145] Sweet Lake Land and Oil Co. v. Exxon Mobil Corp., *supra* note 101, at ¶ 10.
[146] *Id.* at ¶ 27.
[147] *See also* Petition for Damages, Brownell Land Corp., LLC v. Honey Well Int'l., No. 08CV04988, ¶¶ 11-12 (E.D. La. filed Nov. 21, 2008), 2008 WL 5366168; Rice Agricult. Corp., Inc., v. HEC Petroleum Inc., 2006 WL 2032688 (E.D. La); Petition for Damages, Tensas Poppadoc, Inc. v. Chevron U.S.A., Inc., No. 040769, ¶ 8 (7th Judicial Court La. filed Sept. 21, 2005), 2005 WL 6289654; Petition for Damages to School Lands, Louisiana v. Shell Oil Co., No. CV04-2224 L-O, (W.D. La. filed Oct. 29, 2004), 2004 WL 2891505 (where the State of Louisiana and the Vermilion Parish School Board made similar allegations against Shell Oil, claiming they had contaminated school property. In July 2006, the case was remanded to state court).
[148] *See* notes 62–67 *supra*.

likelihood that the locations of the wastes will be forgotten in the future.[149] In addition, Tennessee has no freeboard or liner integrity requirements,[150] does not require testing or tracking of pit wastes,[151] and fails to require oil to be removed from pits.[152] Kentucky similarly turns a blind eye to the risks E&P wastes present to the public through its failure to require testing of E&P waste characteristics and its treatment of all E&P wastes except production brines and drilling muds as solid wastes, subject to less stringent disposal requirements "irrespective of the risk posed to human health or the environment from the waste."[153]

States also fail to take other simple steps that would dramatically decrease the likelihood of E&P wastes being released into the environment, for example, requiring pits to be lined with impermeable barriers. In Oklahoma, neither emergency pits nor pits holding water-based drilling fluids are required to have any lining.[154] This failure to require the use of a liner in pits holding water-based drilling fluids increases the risk that the "barite, clays, lignosulfonate, lignite, caustic soda and other specialty additives" found in water-based muds will contaminate the environment.[155] Kentucky's liner requirements are also inadequate. Kentucky does not require the use of liners in drilling pits that are used for less than thirty day storage and has "minimal liner requirements for holding pits" for storage over thirty days.[156]

Wildlife protection devices are another important and too often underused safety measure. Tennessee,[157] Louisiana,[158] and Kentucky all fail to require any "fencing, flagging or netting of pits," thereby increasing the risks the pits present to wildlife and domestic animals.[159] And according to a recent report prepared by Region 6 of the U.S. Fish & Wildlife Service, these three states are not alone.[160] As reported by Region 6, only thirteen states require pits or open tanks to be screened or netted to prevent wildlife from coming into contact with E&P wastes.[161] The failure to require pit operators to use even the most basic protection devices such as fencing or netting greatly increases the likelihood that wildlife will come into contact with E&P waste and suffer significant harm.

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[149] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 30.
[150] *Id.*
[151] *Id.* at 32.
[152] *Id.* at 31.
[153] STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., KENTUCKY STATE REVIEW 50–51 (2006).
[154] OKLA. ADMIN. CODE § 165:10-7-16(b)(1)(B)(iii), (2)(b).
[155] CORCORAN ET AL., *supra* note 25, at 20; *see also* U.S. FISH & WILDLIFE SERV., *supra* note 93, at 4–5 ("Water-based drilling muds can contain glycols, chromium, zinc, polypropylene glycol, and acrylamide copolymers.").
[156] KENTUCKY STATE REVIEW, *supra* note 153, at 54.
[157] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 30.
[158] STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., LOUISIANA STATE REVIEW 29 (2004).
[159] *Id.*
[160] U.S. FISH & WILDLIFE SERVICE, *supra* note 93, at 13 fig. 15.
[161] *Id.*

States also fail to regulate where pits may be located, allowing them to be placed near residences, schools, and other areas frequently used by the public. In some cases, homes are located so close to pits that residents have been forced indoors because of the foul odors and health symptoms emanating from the pits. One Pennsylvania family reported severe headaches caused by fumes from a pit less than 200 feet from their home.[162] As of 2005, when STRONGER, Inc. conducted a review of Indiana's E&P waste disposal practices and regulations, Indiana regulations had no requirements regarding "specifications for the location, orientation and construction of drilling pits. There [were] no required setbacks of minimum distances from buildings, homes or other structures for drilling pits." Since then, although Indiana has adopted a new rule requiring pits to be located at least one hundred feet from streams, rivers, lakes and drainage ways, it still does not specifically require pits to be setback from other structures.[163] By allowing pits to be sited close to where people live and children attend school, state regulators are bringing health risks literally closer to the citizens across the country.

b. Land application

EPA has stated that hazards also exist with land application of E&P wastes, finding that hydrocarbons, salts, and metals can all cause contamination when E&P wastes are land applied.[164] The Oil Industry International Exploration and Production Forum (E&P Forum), an international industry association, has also issued warnings, stating that land application may result in contaminants accumulating "in the soil [at] a level that renders the land unfit for further use."[165] New York State allows waste to be disposed of in municipal landfills.[166] Land where only oil and gas waste is applied is often called a "landfarm." Studies of landfarm conditions confirm that these hazards are real. When the Arkansas Department of Environmental Quality conducted a study of landfarms in Arkansas, it found that "all 11 sites that land applied fluids at some point had improperly discharged the fluids so as to cause runoff into the waters of the state."[167]

Land application sites outside of Arkansas are sources of similar concerns. Near Holdenville, Oklahoma, residents protested the opening of a landfarm because they were worried about

[162] Christie Campbell, *Foul Odor from Impoundment Upsets Hopewell Woman*, OBSERVER-REPORTER, Apr. 14, 2010. June Chappel, who lives near a pit, stated that the odor "reminded her of a hair perm. It smelled like ammonia . . . [and] 'took your breath away.'" *Id*. Other times the fumes have smelled like gasoline, diesel fuel, and sewage. *Id*.
[163] 312 IND. ADMIN. CODE 16-5-13 (2010).
[164] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 49 (2000).
[165] E&P FORUM, *supra* note 107, at 17.
[166] Letter from Gary M. Maslanka, New York State Division of Solid & Hazardous Materials, to Joseph Boyles, Casella (April 27, 2010).
[167] Press Release, Arkansas Dep't of Envtl. Quality, ADEQ Releases Landfarm Study Report (Apr. 20, 2009).

potential "water contamination and land spoilage."[168] After the residents lost two appeals in which they tried to prevent its opening, the landfarm finally began operations and made the residents' fears a reality. Claudia Olivo, who owns a cattle ranch adjacent to the landfarm, filed a complaint with EPA after she noticed "strange glistening spots in the water" on her property.[169] In response, EPA issued a cease-and-desist order against the landfarm after finding that it had made unauthorized discharges of drilling mud into a creek that ran through Olivo's property, in violation of the Clean Water Act.[170] The Crouch Mesa landfarm in Aztec, New Mexico, is located directly across the street from a residential area and is the source of considerable visible dust observed blowing toward homes.[171]

Despite these risks, many states inadequately regulate land application. In Oklahoma, one-time land applications may occur as close as one hundred feet from any perennial stream, freshwater pond, lake or wetland.[172] Tennessee regulations fail to provide any explicit guidance regarding the use of land applications.[173] Meanwhile, Kentucky has no siting criteria for land application specific to E&P wastes.[174]

These lax regulations result in E&P wastes being land applied near, and in some cases, on residential property, increasing the likelihood that humans will be exposed to E&P waste's toxic compounds.[175] In Martha, Kentucky, produced water and tank bottoms were land applied on farmland near where a family of two adults and two children lived.[176] The family grew the majority of the vegetables and meat they consumed on the farm,[177] and the portion of the family's land used for storing E&P waste disposal was located a mere 100 feet from a small creek which "drains into a marsh, which then drains into a larger creek" from which the farm's cattle drank.[178] The family no longer drinks from its well, which has been contaminated with benzene.[179] Lead and arsenic were found in soil samples.[180] In addition, areas of the farm where E&P wastes had been disposed were found to be NORM-contaminated sites which "will remain radioactive for many thousands of years," "creating many opportunities for radium to enter the soil and be taken up by plants or cattle grazing on the land," and threatening "[f]uture inhabitants or workers on the NORM-contaminated land [who] may also be directly exposed to ionizing

[168] Susan Hylton, *supra* note 105, at A11.
[169] *Id*.
[170] *Id*.
[171] DRILLING DOWN, *supra* note 20, at 22.
[172] OKLA. ADMIN. CODE § 165:10-7-26(c)(6) (2009).
[173] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 32.
[174] KENTUCKY STATE REVIEW, *supra* note 153, at 50.
[175] *See* WOLF EAGLE ENVIRONMENTAL, *supra* note 70.
[176] Spitz et al., *supra* note 92, at, 45.
[177] *Id.* at 46.
[178] *Id.* at 45.
[179] *Id*.
[180] *Id.* at 55.

radiation or inhale radium-bearing particles."[181] As demonstrated by the contamination that occurred in Martha, Kentucky, inadequate state regulations too frequently fail to protect the public and the environment from the hazards associated with land application of E&P wastes.

A Texas resident lives fifty feet away from a 100-acre land farm, where the Texas Railroad Commission issued 22 minor permits for 22 different operations that are all located on one property. A second land farm is located just down the road.[182]

c. Injection Wells

Underground injection, the most widely used disposal method,[183] also poses concerns. If the formation into which E&P wastes are injected does not meet certain levels of permeability, porosity, and low reservoir pressure, the formations can form a poor seal around the E&P wastes and threaten nearby aquifers.[184] Under the Underground Injection Control (UIC) Program, E&P wastes may be injected in Class II wells, while wastes designated as hazardous under RCRA can only be disposed of in the more strictly regulated Class I wells.[185]

The lower standards applicable to Class II wells have proven inadequate to prevent E&P wastes from contaminating groundwater. In 1988, GAO released a report, *Safeguards Are Not Preventing Contamination from Injected Oil and Gas Wells,* which examined the effectiveness of EPA's UIC program.[186] Although GAO speculated that it was likely that more incidents had occurred, it reported that the EPA was aware of at least 23 cases across the country where Class II injection wells had contaminated drinking water supplies.[187] Since then more incidences of concern have occurred.

In September 2007, a state inspector in Texas inspected an underground injection disposal well site outside of Fort Worth and found no problems. Yet a resident complained of "spilled oil, overflowing dikes and green-colored fluid in standing puddles." Inspectors returned and found that "oil-stained soil" had seeped several inches into the ground, that the "containment dike will not hold estimated capacity," and that standing water had oil in it. State records showed that the well site was not being used, when in fact it was actively being injected with oil and gas waste.[188]

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[181] *Id.* at 57.
[182] *See* Griffey, *supra* note 71
[183] M.G. PUDER & J.A. VEIL, ARGONNE NATIONAL LABORATORY, OFFSITE COMMERCIAL DISPOSAL OF OIL AND GAS EXPLORATION AND PRODUCTION WASTE: AVAILABILITY, OPTIONS, AND COSTS, S-2 (2006) ("By far, the most common commercial disposal method for produced water is injection.").
[184] *See* E&P FORUM, *supra* note 107, at 15.
[185] DRILLING DOWN, *supra* note 20, at 17; *see also* 42 U.S.C § 300h-4; 42 U.S.C § 300h(b); 42 U.S.C. § 300(h)-1(c).
[186] U.S. GENERAL ACCOUNTING OFFICE, *supra* note 32, at 2.
[187] *Id.* at 3.
[188] Abrahm Lustgarten, *State Oil and Gas Regulators Are Spread Too Thin to Do Their Jobs,* ProPublica, December 30, 2009.

Residents in DeBerry, Panola County, Texas, first began complaining that their groundwater was contaminated in 1996.[189] An underground injection disposal facility began operations one-eighth of a mile away from the community in 1987, injecting produced water into the ground at depths between 1,080 and 1,110 feet.[190] In 1996, while the well was still in operation, DeBerry residents told an EPA Region 6 employee that their water was discolored, was staining their kitchen and bath fixtures, and that they were experiencing gastrointestinal problems.[191] The residents of DeBerry ultimately stopped using their drinking water and instead began to obtain water from other sources.[192] No government agency tested DeBerry's drinking water for several years after residents first complained. Not until 2002 did the site operator of the injection wells in DeBerry, Basic Energy, sample the drinking water.[193] When it did, the residents' suspicions were confirmed. The results showed the presence of contaminants above the EPA's maximum contaminant levels.[194] In 2003, the Texas RRC found benzene, barium, arsenic, cadmium, lead and mercury in wells at levels exceeding the state's drinking water standards.[195] Because the Texas RRC never completed a full assessment of the contamination, the source of the contamination is not definitively known; however, residents strongly believe the injection wells were the cause of the contamination, and EPA has been unable to rule this possibility out conclusively.[196]

Also in Texas, an underground injection disposal facility in Daisetta is linked to contamination of a fresh water aquifer. The EPA found a lack of compliance reviews, inappropriate monitoring, and incomplete record-keeping, as well as a lack of evidence that all problems were ever remedied. This problematic facility led to a surface collapse and a large sinkhole.[197]

The likelihood that similar incidents will continue to occur exists as long as underground injection associated with oil and gas exploration, production, and development only has to meet the requirements for Class II wells and states fail to require better monitoring.

In addition, a vast amount of E&P waste is being injected underground without any UIC regulation whatsoever. Used hydraulic fracturing fluid—perhaps millions of gallons per each

[189] EPA OFFICE OF THE INSPECTOR GENERAL, COMPLETE ASSESSMENT NEEDED TO ENSURE RURAL TEXAS COMMUNITY HAS SAFE DRINKING WATER, NO. 2007-P-00034 2 (2007).
[190] *Id.* at 3.
[191] *Id.* at 2.
[192] *Id.*
[193] *Id.*
[194] *Id.*
[195] *Hearing Before the Subcomm. on Superfund and Environmental Health of the S. Comm. on Environment and Public Works* 12–13 (2007) (statement of Robert D. Bullard, Dir. Environmental Justice Resource Center).
[196] EPA, OFFICE OF THE INSPECTOR GENERAL, *supra* note 189, at 3.
[197] EPA, *supra* note 115.

well—remain underground permanently. It has been estimated that up to 90% of hydraulic fracturing fluids used in the Marcellus shale formation remain underground.[198] Yet this waste disposal and storage activity is not subject to any federal underground injection regulations.

d. Wastewater Treatment Facilities

In regions where underground injection is not readily available, hydraulic fracturing wastewater and produced water may be sent to wastewater treatment plants prior to release to surface water. The plants may be publicly owned treatment works (POTWs) that typically process municipal sewage or centralized wastewater treatment (CWT) facilities that process industrial wastes. None of the POTWs and few of the CWT plants currently in operation have the capacity to reduce to safe levels all of the chemical contaminants commonly found in E&P waste. As a result, toxins are released to surface water, with adverse impacts on drinking water quality. The very high concentrations of total dissolved solids (TDS)—principally salts—that are common in hydraulic fracturing wastewater and produced water present a particular problem for wastewater treatment facilities.

Without adequate pretreatment, pollutants in oil and gas waste will pass through a POTW into the receiving stream, and they may interfere with ordinary sewage treatment systems.[199] Even with pretreatment, POTWs are not effective in removing salts from those wastes.[200] The use of POTWs for treatment of E&P waste in western Pennsylvania produced TDS levels in the Monongahela River in excess of drinking water standards, forcing the Commonwealth to limit the waste to one percent of influent at nine plants along the river.[201] Unauthorized discharges of pollutants, including fecal matter, from a POTW into the Susquehanna River were attributed to the plant's acceptance of oil and gas wastes.[202] Even CWT plants rarely have the evaporation and crystallization technologies needed to reduce extremely high levels of TDS in hydraulic fracturing wastewater and produced water (up to 300,000 mg/l) to levels consistent with water quality standards (500 mg/l). There is not a single CWT facility with that capacity in all of New York or Pennsylvania.[203]

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[198] PROCHEMTECH INTERNATIONAL, INC., MARCELLUS GAS WELL HYDROFRACTURE WASTEWATER DISPOSAL BY RECYCLE TREATMENT PROCESS.
[199] N.Y. State Water Res. Inst., *Waste Management of Cuttings, Drilling Fluids, Hydrofrack Water and Produced Water*; Oh. Envtl. Prot. Agency, *Marcellus Shale Gas Well Production Wastewater*.
[200] *Id*.
[201] Joaquin Sapien, *With Natural Gas Drilling Boom, Pennsylvania Faces an Onslaught of Wastewater*, ProPublica, Oct. 4, 2009; *Municipal Authorities' Perspective: Marcellus Shale Natural Gas Wastewater Treatment, Hearing Before the S. Comm. on Envtl. Res. & Energy* (Pa. 2010) (statement of Peter Slack, Pennsylvania Municipal Authorities Ass'n).
[202] Press Release, Pa. Dep't Envtl. Prot., DEP Says Jersey Shore Borough Exceeds Wastewater Permit Limits (June 23, 2009).
[203] N.Y. State Water Res. Inst., *supra* note 199; Joaquin Sapien, *supra* note 201.

e. Other spills, leaks, and intentional dumping

In addition to those releases that commonly occur when these common E&P waste disposal methods are being used properly, many other spills and releases occur before E&P wastes reach these storage or disposal sites. These other releases can be the result of equipment failure, accidents, negligence, or intentional dumping. Consistent federal regulations for waste management, storage and disposal would help prevent them in the future.

For example, in Pennsylvania, Atlas Resources LLC "discharged residual and industrial waste, including diesel and production fluids, onto the ground at seven of the 13 well sites."[204] At three of the wells Atlas allowed produced water to be released into the environment.[205] Pennsylvania records also show that pipes used to transport waste, sometimes for miles, have leaked. In October, 2009, a pipe carrying diluted wastewater spilled about 10,500 gallons into a high-quality stream, killing about 170 small fish and salamanders. In December, 2009, a pipe failed in five places, spilling an estimated 67,000 total gallons of fluid, tests of which found elevated levels of salts, barium and strontium.[206]

NYSDEC has documented numerous other examples of releases. In October 1997, a produced water tank in Willing, New York, containing produced water from natural gas extraction overflowed and contaminated the surrounding soil and a nearby creek from which cows drank with fifteen thousand gallons of produced water.[207] The produced water killed vegetation in its path.[208] More recently, in September 2005, eight hundred gallons of production brine from another tank in Pine City, New York, overflowed when it was not emptied on schedule, causing an impact on nearby streams.[209] In July 1996, crude oil tank bottoms were dumped into a pit and set on fire.[210] In March 2003, a property owner in Ithaca, New York, called to report that a driller was dumping mud on his property.[211] In May 2007, NYSDEC received an anonymous tip indicating that produced water from a natural gas well was being

[204] Press Release, Pa. Dep't Envtl. Prot., DEP Fines Atlas $85,000 for Violations at 13 Well Sites, Jan. 7, 2010.
[205] Consent Assessment of Civil Penalty, *In re Atlas Resources LLC*, Pevarnik 8, ¶¶ Z–AD, Willis 18, ¶¶ AE–AI, Thompson 33 ¶¶ AP–AU.
[206] Laura Legere, *Massive Use of Water in Gas Drilling Presents Myriad Chances for Pollution*, SCRANTON TIMES-TRIBUNE, June 22, 2010.
[207] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 3 (2009) (Spill Number: 9707892).
[208] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 4 (2009) (Spill Number: 9707892).
[209] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 8 (2009) (Spill Number: 0507041).
[210] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 23 (2009) (Spill Number: 9604701).
[211] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 68 (2009) (Spill Number: 0212276).

dumped on the ground near Cayuga Creek in Sheldon, New York.[212] In May 2009, eight hundred gallons of produced water contaminated soils in Westfield, New York, after equipment failed and allowed the fluids to be released into the environment a mere 1200 yards away from nearby homes.[213]

The COGCC has also documented incidents where tanks have been improperly sealed[214] or allowed to overflow,[215] where corroded equipment allowed produced water to contaminate the ground,[216] and where equipment failure has allowed produced water to escape from underground injection wells.[217] Between June 2002 and June 2006, 555 produced water spills were reported to the COGCC.[218]

In Texas, between 2001 and 2006, thirty percent of spill complaints were inspected "either late or not at all."[219] Most recently in the Texas town of Flower Mound, the Texas RRC sent out a notification stating that approximately 3,000 gallons of "flowback water containing fracturing fluid and associated additives" spilled out of gas well pad site.[220] To date, the RRC has not publically released either the cause of the spill or the exact contents of the flowback water.[221]

The mayor of West Union, West Virginia, wrote a letter to the WVDEP in October 2009 to express his concern over WVDEP's failure to notify the town until two months after a spill occurred.[222] The mayor was even more concerned about WVDEP's failure to have any emergency notification system in place, stating that the continued failure to establish such a system "will only result in less time for the water system to react [to future spills] and [result in] a greater chance of catastrophe."[223] Elsewhere in West Virginia, Luanne McConnell Fatora reported a release of between fifty and seventy barrels of some type of oil and gas waste in a

[212] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 159 (2009) (Spill Number: 0750225).
[213] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 143 (2009) (Spill Number: 0902327).
[214] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORT, DOC. NO. 1630697.
[215] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631155, 1631831, 1631794, 1632853.
[216] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630885, 1631496, 1631519, 1632057, 2605191, 1632995.
[217] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 200226284, 200225725, 2605709.
[218] OIL & GAS ACCOUNTABILITY PROJECT, COLORADO OIL AND GAS INDUSTRY SPILLS: A REVIEW OF COGCC DATA (JUNE 2002-JUNE 2006) 1-2 (2006).
[219] Lustgarten, *supra* note 188.
[220] *Frac Fluid Spill Reported in Flower Mound*, CROSS TIMBERS GAZETTE, Mar. 17, 2010.
[221] *Id.*
[222] Letter from Robert F. Fetty, Mayor, Town of West Union, to Barbara Taylor, Director, WVBPH/Office of Environmental Health Services, Oct. 28, 2009.
[223] *Id.*

stream in Doddridge County.[224] Fatora's son discovered the spill when he tried to go fishing in the stream in late August 2009 and found the water to be "acrid" and covered with a "red/orange gel" that had an oily smell which got on his hands and did not "go away for some time despite repeated washing."[225] Although the Chief of the West Virginia Oil and Gas Office stated that the fluids were consistent with oil and gas waste, more than a month after the spill the WVDEP remained uncertain about what caused the release.[226]

These releases, and the undoubtedly numerous other unreported incidents, demonstrate that current regulations and regulatory enforcement is inadequate to prevent E&P wastes from being released into the environment.

3. Oil & Gas Production Has Increased Dramatically Since 1988.

When EPA released its 1988 Regulatory Determination, the domestic oil and natural gas industry was struggling. Since then, oil and natural gas production in the United States has increased dramatically. Tens of thousands of new oil wells have been drilled. According to the U.S. Energy Information Administration (US EIA), between 1989 and 2008 the number of producing gas wells nationwide almost doubled, increasing from roughly 262,000 to 479,000 wells.[227]

Bureau of Land Management (BLM) statistics also demonstrate the growth in oil and gas operations under its jurisdiction. In most years during the 1990s, there were less than four thousand applications for permits to drill (APDs) filed with the BLM.[228] BLM has stated that "[s]ince 1996, the number of new APDs has risen dramatically."[229] BLM received more than ten thousand APDs in 2006.[230] Although BLM projects that the number of APDs will decline by 2010,[231] BLM still expects to receive a staggering number, approximately 7,000, of APDs in 2010. Furthermore, BLM attributes this projected decrease to the fact that a larger percentage of proposed drilling is expected to occur on existing leases and not to a decrease in drilling.[232]

State agency statistics also demonstrate an increase in the amount of domestic drilling: one example is Texas, where the number of permits issued by the RRC for drilling in the Barnett

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[224] Ken Ward Jr., *What Caused Big Fracking Fluid Spill in Doddridge County?*, SUSTAINED OUTRAGE: A GAZETTE WATCHDOG BLOG (Oct. 2, 2009); *see also* Letter from Louanne McConnell Fatora to Gov. Manchin, West Highlands Conservancy (Aug. 30, 2009).
[225] Letter from Louanne McConnell Fatora to Gov. Manchin, (Aug. 30, 2009).
[226] Ward Jr., *supra* note 224.
[227] U.S. ENERGY INFO. ADMIN., NUMBER OF PRODUCING GAS WELLS (2009).
[228] BUREAU OF LAND MGT., BLM FY 2010 BUDGET JUSTIFICATIONS III-120 (2010).
[229] *Id.* at III-119.
[230] *Id.* at III-120.
[231] *Id.*
[232] *Id.* at III-122.

Shale increased from 273 in 2000 to 3,653 in 2007,[233] and 4,145 in 2008.[234] Industry-wide, API statistics confirm that these increases are not isolated incidents. The API reported that 2006 was a record year for gas drilling, in which more than 29,000 new wells were drilled.[235] The API expected that this trend would continue and it did: a new 21-year record was reached when 11,771 wells were drilled in the first-quarter of 2007.[236]

Along with this increase in drilling, there has been an associated increase in the amount of E&P waste produced. In Utah's Uintah County the amount of produced water generated from oil and gas operations increased from approximately 800,000 barrels per month in January 1999 to over 1,600,000 barrels per month in January 2007.[237] Even though some techniques have been implemented to reduce the amount of produced water generated from oil and gas extraction activities, EPA's Region 8 noted an overall two percent increase in the amount of produced water generated from 2002 to 2008.[238] The increases in both drilling and E&P waste that have occurred since 1988 indicate that the risks associated with E&P wastes have become even more substantial and that EPA must revisit its Regulatory Determination in light of these developments.

4. Regulation Under Subtitle C of RCRA Would Not Harm the Oil & Gas Industry.

In its 1988 Regulatory Determination, EPA placed significant weight on the potential harm that increased regulation of E&P waste could cause the oil and natural gas industry in making its determination not to regulate E&P wastes under Subtitle C of RCRA. EPA claimed that regulating E&P wastes under Subtitle C would be "extremely costly" for industry.[239] EPA also asserted that "[a]ny program to improve management of oil and gas wastes in the near term will be based largely on technologies and practices in current use."[240] While in 1988 EPA did not believe that the oil and gas industry would develop new waste management technologies, its belief has proved to be incorrect.

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[233] Hannah Wiseman, *Untested Waters: The Rise of Hydraulic Fracturing in Oil and Gas Production and the Need to Revisit Regulation*, 20 FORDHAM ENVTL. L. REV. 115, 124 (2009) (citing Texas Railroad Commission, Newark, East (Barnett Shale), Drilling Permits Issued (1993–2007)).
[234] Texas Railroad Commission, Newark, East (Barnett Shale) Field, Drilling Permits Issued (1993–2009).
[235] Daniel Cusick, *Industry Sets Record for Drilling, Well Completions*, LAND LETTER, Jan. 18, 2007.
[236] Am. Petroleum Inst., "U.S. Q1 drilling & completion estimates at 21-year high—API," Apr. 26, 2007.
[237] DIV. OF OIL, GAS AND MINING, UTAH DEP'T OF NATURAL RES., PRODUCED WATER DISPOSAL, graph slide 6 (2007).
[238] EPA REGION 8, *supra* note 28, at fig. 3-9.
[239] 53 FED. REG. at 25446-01, 25456.
[240] *Id.* at 25,451. EPA's Report to Congress indicates that EPA did not truly believe this assertion that it made in the 1988 Regulatory Determination: "Long-term improvements in waste management need not rely, however, purely on increasing the use of better existing technology. The Agency does foresee the possibility of significant technical improvements in future technologies and practices." EPA, REPORT TO CONGRESS, MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY III-2 (1987)

Evidence since 1988 demonstrates that new technologies and practices are available and that the use of these safer practices often results in significant cost savings. In 2008, EPA itself stated that "It has been 20 years since the RCRA exemption for oil and gas exploration and production was implemented, and many practices and chemicals used have changed during that time,"[241] and has noted that many safer drilling fluids have been developed[242] and the use of alternatives to pits has become increasingly practical.[243] In addition to the savings that can result from the use of these new disposal methods, companies using safer disposal practices also obtain cost benefits by preventing pollution in the first place, as opposed to being allowed to use "cheaper" practices and later required to clean up the damage they create.[244] The State of New Mexico found that drilling activity more than doubled in the year immediately following establishment of more protective rules for oil and gas waste pits.[245]

It is time for EPA to require oil and gas companies to use these new, safer technologies.

a. New Waste Disposal Technologies

Safer disposal methods for E&P wastes have been developed since 1988. Although EPA acknowledged that such developments were likely in its 1987 Report to Congress, it chose not to require the use of then-emerging safer technologies because it believed that requiring their use would be prohibitively expensive for the oil and gas industry. Recent cost analyses indicate that those fears were unfounded; in many instances, the use of more environmentally sound disposal practices actually saves oil and gas companies money. For example, a study conducted in New Mexico found that eliminating pits, traditionally considered the cheapest disposal method, is actually more cost-effective than their continued use.[246]

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[241] EPA REGION 8, *supra* note 28, at 3–13.
[242] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 29 (2000).
[243] EPA, REGION 8, OIL AND GAS ENVIRONMENTAL ASSESSMENT REPORT 1996–2002 13 (2003).
[244]

> [W]e've had testimony through here that the costs of remediation are, you know, in the hundreds of thousands to, typically millions of dollars. And there's a huge cost benefit to business to prevent pollution versus us allowing them to pollute water and then come back and require them to clean it up. I think that's really a disservice to industry, not to help them prevent that from occurring.

Statement of Commissioner William Olson before the New Mexico Oil Conservation Division, Apr. 16, 2008, OCD Document Image 14015_657_CF[1] at 30.
[245] Press Release, State of New Mexico, Governor Bill Richardson Announces Oil and Gas Drilling Activity in New Mexico Is Strong: Environmental regulations are not driving business away (May 19, 2010).
[246] DORSEY ROGERS, GARY FOUT & WILLIAM A. PIPER, NEW INNOVATIVE PROCESS ALLOWS DRILLING WITHOUT PITS IN NEW MEXICO (2006).

An Oil and Gas Accountability Project (OGAP) analysis demonstrates that closed-loop drilling systems, which use storage tanks and other equipment instead of pits, are cost-effective and can save money compared to conventional waste management with pits.[247] Mary Ellen Denomy, an expert in petroleum accounting, testified before the New Mexico Oil Conservation Division and reported her findings that the costs associated with a typical closed loop drilling system, also known as a pitless drilling system, are only 3.58% of total drilling costs, a significant reduction from the costs associated with typical on-site pit burial (6.58% of total drilling costs) and digging up and hauling wastes to a centralized facility (9.38% of total drilling costs).[248] While initial costs may be higher, closed-loop drilling systems create long-term savings because there is no need to construct pits, drilling waste can be dramatically reduced, water use can be reduced by as much as eighty percent, truck traffic is reduced by as much as seventy-five percent, and tanks can be reused.[249] Comparisons have found closed-loop drilling can result in a cost savings of up to $180,000 per pit,[250] and a project in New Mexico found that:

> [T]he average cost of using a pit and hauling the waste elsewhere for disposal is about 45% more compared to following the same process without a reserve pit. Moreover, the analysis showed that burying the waste on-site costs about 24% more when using a reserve pit as opposed to employing the closed-loop system.[251]

Individual case studies provide further support for these conclusions. A survey of Prima Energy Corporation's closed-loop system in Colorado indicated that closed-loop drilling could be more cost effective than conventional rotary drilling with reserve pits.[252] Prima Energy Corporation drilled over 68 wells in Colorado using closed-loop systems and compared their costs to the costs of using conventional rotary drilling with reserve pits.[253] The closed-loop drilling systems' average cost was $15,600 compared to conventional rotary drilling's cost of $17,020.[254] The study further demonstrated that closed-loop drilling systems result in significant waste minimization. Conventional rotary drilling was found to generate 5,200 barrels more barrels of produced water than closed-loop drilling.[255]

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[247] Oil & Gas Accountability Project, Alternatives to Pits.
[248] Oil & Gas Accountability Project, Closing Argument and Proposed Changes to Proposed Rule 50, *Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, Dec. 10, 2007, at 10.
[249] Oil & Gas Accountability Project, *supra* note 247.
[250] *Id; see also* ROGERS ET AL., *supra* note 246, at 4–5.
[251] Dorsey Rogers, Dee Smith, Gary Fout & Will Marchbanks, *Closed-loop drilling system: A Viable Alternative to Reserve Waste Pits*, WORLD OIL, Dec. 2008, at 46.
[252] *See* Oil & Gas Accountability Project, *supra* note 247.
[253] Exhibit 8, Closed-Loop Drilling Case Studies, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, OCD Document Image No. 14015_637_[CF]1.
[254] *Id.*
[255] *Id.*

Similarly a study of two wells drilled two hundred feet apart in Matagorda County, Texas provides further support for assertions that closed-loop drilling systems can provide cost savings.[256] In Matagorda County, two wells were drilled two hundred feet apart "through the same formations, using the same rig crew, mud company and bit program."[257] One well used a closed-loop system while the other used traditional solids-control equipment. The closed-loop system "resulted in some significant savings" including: a forty-three percent savings in drilling fluid costs, twenty-three percent fewer rotating hours, fewer days to drill the wells to comparable depths, a thirty-seven percent reduction in bits used, and up to thirty-nine percent improvement in penetration rates.[258]

EPA's own studies confirm that closed-loop drilling systems are a safer and cost-saving waste disposal process.[259] Because of these types of findings, EPA has promoted the use of closed-loop drilling systems in Region 8.[260] The RRC of Texas has confirmed that closed-loop systems can result in significant cost savings;[261] and many other government agencies also support the use of closed-loop drilling systems.[262] In addition to the already demonstrated economic advantages of closed-loop systems, there is a great likelihood that the costs of constructing closed-loop systems will decrease even more in the future "as economies of scale and innovations in operations" continue to occur.[263] If these systems are manufactured in the United States, they add the benefit of new job creation in addition to lower environmental risk.

Although safer and economical, even closed loop systems can leak or spill. Strong regulations are required to govern the storage and transport of toxic waste. In some cases, waste may be transported via pipeline to storage or disposal sites. Yet in Texas, State officials declared at a public meeting that the state has no "rule-making authority" over such pipelines.[264]

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[256] *Id.*
[257] *Id.*
[258] *Id.*
[259] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 69 (2000).
[260] EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY 4-4 (Working Draft 2008).
[261] Abrahm Lustgarten, *Underused Drilling Practices Could Avoid Pollution*, PROPUBLICA, Dec. 14, 2009.
[262] U.S. Fish & Wildlife Serv., *Wildlife Mortality Risk in Oil Field Waste Pits*, U.S. FWS CONTAMINANTS INFORMATION BULLETIN (2000) (recommending the use of closed loop containment systems and elimination of open pits and ponds); BUREAU OF LAND MGT, THE GOLD BOOK: SURFACE OPERATING STANDARDS AND GUIDELINES FOR OIL AND GAS EXPLORATION AND DEVELOPMENT (4th ed. 2007). "To prevent contamination of ground water and soils . . . it is recommended that operators use a closed-loop drilling system or line reserve pits with an impermeable liner." *Id.* at 17.
[263] Controlled Recovery Inc.'s Written Closing Argument, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc*., Dec. 10, 2007, at 3.
[264] Lowell Brown, *Officials Give Few Answers to Argyle*, DENTON RECORD-CHRONICLE, Jan. 30, 2010.

b. Waste Minimization, Reuse, and Recycling Techniques

Waste minimization, reuse and recycling techniques also can be economical for companies. According to the RRC of Texas, "[w]aste minimization has been proven to be an effective and beneficial operating procedure," while recycling "is becoming a big business and more recycling options are available every day." [265] Both serve to reduce the total amount of E&P wastes that must be disposed and thereby decrease the risks associated with E&P wastes. In its manual *Waste Minimization in the Oilfield*, the RRC of Texas offers oil and gas companies more than one hundred ways to minimize wastes.[266] This manual, along with reports from individual companies implementing various waste minimization and recycling techniques, demonstrates that improved practices are possible.

Studies by the E&P Forum attest to the benefits of waste recycling[267] and identify several ways industry can reduce waste, "through process and procedure modifications . . . [For example,] improved solids control equipment and new technology can reduce the volumes [of drilling fluids] discharged to the environment, . . . more effective drillbits can reduce the need for chemical additions, [and] gravel packs and screens may reduce the volume of formation solids/sludge produced."[268] An analysis by OGAP found that the use of closed-loop drilling systems, in addition to providing cost benefits, maximizes the ability to reuse and recycle drilling fluids.[269] And waste reduction is not just beneficial from an environmental perspective. It can provide further opportunities for the oil and gas industry to save money. A study on land owned by the U.S. Army Corps of Engineers in Oklahoma found that a reduction in "wastes by close to 1.5 million pounds" resulted in "[a] material and disposal cost savings of $12,700."[270]

Both the government and industry are aware of the cost saving opportunities associated with the use of waste minimizing technologies and recycling and reuse projects. For example, STW Resources has developed a technology for use in the Barnett Shale that can reclaim approximately seventy percent of the flowback water produced by hydraulic fracturing operations in the region and thereby reduce the total amount of waste associated with hydraulic fracturing while also enabling the wastes to be reused.[271] And in July of 2008, the RRC of Texas approved Devon Energy's "third pilot program to treat and reuse frac fluid . . . . As a result of its water recycling efforts, Devon is the industry leader in water recycling and now used recycled

[265] Railroad Commission of Texas, *supra* note 52.
[266] DRILLING DOWN, *supra* note 20, at 29.
[267] E&P FORUM, *supra* note 107, at14 ("There are potential benefits in the sale of recovered hydrocarbons. All hydrocarbon wastes should be returned to the production stream where possible.").
[268] UNEP E&P FORUM, ENVIRONMENTAL MANAGEMENT IN OIL AND GAS EXPLORATION AND PRODUCTION: AN OVERVIEW OF ISSUES AND MANAGEMENT APPROACHES 54 (1997).
[269] Oil & Gas Accountability Project, *supra* note 247.
[270] Exhibit 8, Closed-Loop Drilling Case Studies, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, OCD Document Image No. 14015_637_[CF]1.
[271] STW RES., INC., CONTAMINATED WASTE WATER RECLAMATION OPPORTUNITIES 2–3.

frac water at one out of every 10 frac jobs in its Barnett Shale operations."[272] Devon's wastewater recycling program "is projected to produce 75 percent reusable fracture fluid and 25 percent high concentrate and solids. The concentrate will be used as a drilling fluid or disposed of in an authorized facility."[273] Devon Energy Production Central Division's vice president estimated that "[a]t full treatment capacity, up to 85 percent of [the] water [Devon] recover[s] from fracture completions in the Barnett Shale could be reused." [274] And Devon Energy is not alone: Fountain Quail Water Management, DTE Gas Resources Inc., Burlington Resources, and Stroud Energy have all engaged in reuse and recycling efforts.[275]

New projects are underway at the national level: the U.S. Department of Energy's National Energy Technology Laboratory launched nine new projects in October 2009 focused on developing new technologies "to improve management of water resources, water usage, and water disposal."[276] These projects add to the fifteen already underway that are focused on "assess[ing] options and technologies for handling, cleaning, and reuse of produced and flowback water" in the Barnett and Appalachian shale plays.[277] When combined with pitless drilling through a closed-loop system, recycling of waste is clearly an effective, available, and economical way to manage E&P waste more safely and allow for compliance with stronger regulations.

c. New Substitutes for Toxic Materials

Studies indicate that the use of less toxic drilling and hydraulic fracturing fluids can both reduce the risks associated with E&P wastes and also reduce oil and gas companies' liability, thus potentially saving them money in the long run.[278] Other agencies confirm EPA's findings on the benefits of using safer cost effective alternatives. Numerous agencies encourage operators "to substitute less toxic, yet equally effective products for conventional drilling products."[279] And most recently, ExxonMobil announced that it "'supports the disclosure of the identity of the ingredients being used in fracturing fluids.'"[280] OGAP sees ExxonMobil's statement as a "significant step" and believes that "[o]nce the chemicals are widely known . . . companies will

[272] News Release, Railroad Commission of Texas, Commissioners Approve of Devon Water Recycling Project for the Barnett Shale, July 29, 2008.
[273] *Id.*
[274] *Energy Companies Strive to Reuse Water*, WEATHERFORD TELEGRAM, July 25, 2007, at 3C.
[275] *Id.*
[276] U.S. Dep't of Energy, National Energy Technology Lab, *Nine New Projects*, OIL & GAS PROGRAM NEWSLETTER (Dep't), Winter 2009, at 8.
[277] *Id.* at 6.
[278] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006 (2000).
[279] BUREAU OF LAND MGT, THE GOLD BOOK: SURFACE OPERATING STANDARDS AND GUIDELINES FOR OIL AND GAS EXPLORATION AND DEVELOPMENT, at 39 (4th ed. 2007).
[280] Katie Burford, *ExxonMobil Favors Fracing Disclosure, Environmental Group Welcomes Position from Oil Industry Giant*, DURANGO HERALD, Apr. 19, 2010.

be more likely to use green alternatives" which will result in "a lessening of the toxicity of the fluids" over time.[281]

In addition, the search for chemicals with lower potential environmental impacts has "result[ed] in the generation of less toxic wastes . . . . [For] example . . . mud and additives that do not contain significant levels of biologically available heavy metals or toxic compounds."[282] These types of new synthetic drilling fluids already have been developed and are less toxic, "free of polynuclear aromatic hydrocarbons and have . . . faster biodegradability and lower bioaccumulation potential."[283] Safer alternatives to current drilling fluids are available—all that remains is for the oil and gas industry to adopt widespread use of them.

Industry has already proven itself to be capable of switching to less hazardous compounds in the past. In the 1990s many drilling companies voluntarily phased out the use of benzene in their operations.[284] EnCana stopped using a chemical, 2-Butoxyethanol, linked with reproductive problems in animals, while BJ Services, "one of the largest fracturing service providers in the world, has discontinued the use of fluorocarbons, a family of compounds that are persistent environmental pollutants." [285] Schlumberger has developed "GreenSlurry," which the company claims is "earth-friendly."[286] Antero Resources Corporation pledged to use only "green frac" materials in the communities of Rifle, Silt and New Castle in western Colorado.[287] Yet these reported less toxic fluids are not used everywhere. While the oil and gas industry clearly has the capability to adapt its operations to safer technologies, most companies have been reluctant to make such changes. EPA should thus act and require the oil and gas industry to expand the use of the safer, less toxic drilling fluids that are currently available.

5. Oil and Gas Waste Meets the Statutory and Regulatory Criteria for Hazardous Waste.

Absent their special exclusion from RCRA, E&P wastes would properly be regulated under Subtitle C of RCRA. Congress defined hazardous wastes under RCRA as:

> [A] solid waste, or combination of solid wastes, which because of its quantity, concentration, or physical, chemical or infectious characteristic may—

[281] *Id.*
[282] E&P FORUM, *supra* note 107, at12-23.
[283] Drilling Waste Management Information System, Drilling Waste Management Fact Sheet: Using Muds and Additives with Lower Environmental Impacts.
[284] Susan Riha et al., *supra* note 42, at 6.
[285] Lustgarten, *supra* note 261.
[286] Schlumberger, "Earth-friendly GreenSlurry system for uniform marine performance," March, 2003.
[287] The Rifle, Silt, New Castle Community Development Plan, Jan. 1, 2006.

> (A) cause, or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness; or
> (B) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed.[288]

Under RCRA, Congress instructed EPA to "define hazardous waste using two different mechanisms: by listing certain specific solid wastes as hazardous . . . and by identifying characteristics . . . which, when exhibited by a solid waste, make it hazardous."[289] Under RCRA, "[c]haracteristic wastes are wastes that exhibit measurable properties which indicate that a waste poses enough of a threat to warrant regulation as a hazardous waste."[290] The four technical criteria EPA uses to determine if a waste is a characteristic waste include:[291] ignitability, corrosivity, reactivity, and toxicity.[292] Waste will be considered hazardous if it exhibits *any* of the four characteristics.[293] Because various types of E&P wastes exhibit several of these characteristics, E&P wastes should properly be regulated under Subtitle C of RCRA as characteristic hazardous wastes.

a. Ignitability

Ignitability is a criterion used to identify wastes that "can readily catch fire and sustain combustion."[294] A substance's flashpoint is indicative of its ignitability.[295] A waste's flash point is "the lowest temperature at which the fumes above a waste will ignite when exposed to flame."[296] Eleven percent of oily sludges sampled in California had a flash point exceeding the regulatory threshold.[297]

The risks associated with E&P wastes having hazardous flashpoints under RCRA's criteria have been demonstrated in the past decade. In January 2003, a fire occurred when hydrocarbon vapor from basic sediment and water, a type of E&P waste, ignited at a Texas open area collection pit.[298] Three people were killed in the fire and four others were severely burned.[299] In

[288] 42 U.S.C. § 6903(5).
[289] EPA, RCRA ORIENTATION MANUAL, CHAPTER III: RCRA SUBTITLE C—MANAGING HAZARDOUS WASTE, at III-17.
[290] *Id.* at III-22.
[291] Hazardous Waste Treatment Council v. U.S. EPA, 861 F.2d 277, 279 (D.C. Cir. 1988).
[292] *See* 40 CFR § 261.20 et seq.
[293] *Id.*
[294] EPA, *supra* note 2899, at III-22.
[295] NAGY, *supra* note 24, at 36.
[296] EPA, *supra* note 2899, at III-23.
[297] NAGY, *supra* note 24, at 31.
[298] U.S. Dep't. of Labor, Occupational Safety & Health Admin., Potential Flammability Hazard Associated with Bulk Transportation of Oilfield Exploration and Production (E&P) Waste Liquids, SHIB-03-24-2008.
[299] *Id.*

May 2006, a natural gas condensate tank and pit caught on fire in Colorado.[300] Nearby residents were described as "'terrified' by the 200-foot flames."[301] Residents were also concerned because they were not able to learn what potential health impacts they were exposed to from the burning waste "since neither the company nor local or state authorities bothered taking air quality samples during the blaze."[302]

More recently, a wastewater impoundment pond in Washington County, Pennsylvania caught fire.[303] George Zimmerman reported seeing "flames shooting 100 feet in the air" at the fire that occurred at the hydraulic fracturing site located on his property.[304] A state police fire marshal determined that the fire was an accident caused by "a malfunction [that] ignited fumes [most likely in the frac tank] and caused $375,000 in damages."[305] The fire also "badly damaged" the frac pit liner, causing a spokeswoman from the Pennsylvania DEP to be concerned that the pit's contents might escape.[306] Instances such as these fires and the sampling data from California indicate that E&P wastes are ignitable, and that this characteristic of E&P wastes has resulted in serious harm. E&P wastes with these flash points would appropriately be regulated as characteristic hazardous wastes under Subtitle C of RCRA. Such regulation is necessary to prevent future incidents similar to the January 2003 and March 2010 fires.

b. Corrosivity

Waste is corrosive if "it is acqueous and has a pH less than or equal to 2 or greater than or equal to 12.5" or if "[i]t is a liquid and corrodes steel . . . at a rate greater than 6.35 mm per year."[307] Drilling wastes sampled in California had elevated pH levels approaching the 12.5 regulatory limit.[308] In addition, corrosive chemicals are frequently found in E&P wastes. For example, hydrogen sulfide is a corrosive and "toxic gas occurring naturally in some oil and gas reservoirs."[309] The corrosive characteristics of E&P wastes have already been responsible for many incidents where E&P wastes have been improperly released. On numerous occasions, spills of E&P wastes have been reported as originating from corroded equipment that had begun to leak because of corrosion attributed to the substances the equipment contained.[310] Again, because a waste is properly regulated under Subtitle C of RCRA when it exhibits *any* of the four

[300] OIL & GAS ACCOUNTABILITY PROJECT, SPRING/SUMMER 2006 REPORT (2006).
[301] *Id.*
[302] *Id.*
[303] Janice Crompton, *Residents Reported Gas Odors Before Explosion*, PITTSBURGH POST-GAZETTE, Apr. 1, 2010, at B-1.
[304] Kathie O. Warco, *Fumes Ignite at Gas Well*, OBSERVER-REPORTER, Apr. 1, 2010.
[305] *Id.*
[306] *Id.*
[307] 40 CFR § 261.22.
[308] NAGY, *supra* note 24, at 37.
[309] E&P FORUM, *supra* note 107, at28.
[310] *See supra* note 216 and accompanying text.

criteria of characteristic hazardous wastes, corrosive E&P wastes should be regulated under Subtitle C.

c. Reactivity

A waste is reactive if "(1) it is normally unstable and readily undergoes violent change without detonating, (2) [i]t reacts violently with water, (3) [i]t forms potentially explosive mixtures with water, (4) [w]hen mixed with water, it generates toxic gases, vapors or fumes in a quantity sufficient to present a danger to human health or the environment, (5) [i]t is a cyanide or sulfide bearing waste which, when exposed to pH conditions between 2 and 12.5, can generate toxic gases, vapors or fumes in a quantity sufficient to present a danger to human health or the environment, (6) [i]t is capable of detonation or explosive reaction if it is subjected to a strong initiating source or if heated under confinement, (7) [i]t is readily capable of detonation or explosive decomposition or reaction at standard temperature and pressure, [or] (8) [i]t is a forbidden explosive . . . ."[311]

Out of the four criteria for determining characteristic hazardous wastes, reactivity is the most difficult to test: "In many cases, there is no reliable test method to evaluate a waste's potential to explode, react violently, or release toxic gas under common waste handling conditions."[312] In some cases, a waste's reactivity can be evaluated by a releasable sulfide test.[313] Although no regulatory threshold valuable for releasable sulfides has been established, EPA established an interim guidance value.[314] Testing of E&P wastes in California found samples of sludge and tank bottoms exceeding EPA's interim guidance value.[315]

d. Toxicity

The Code of Federal Regulations describes the specific levels/concentrations at which various chemicals will be considered toxic for the purposes of RCRA. To determine whether a chemical meets the required level, EPA uses the Toxicity Characteristic Leaching Procedure (TCLP). Many E&P wastes would be considered toxic under this test. The New Mexico Oil Conservation Division (OCD) found that several samples taken from E&P waste disposal pits in the state contained levels of chemicals that failed the TCLP test.[316] Specifically, the OCD found pits that contained levels of arsenic, lead, mercury, 2,4-Dinitrotoluene, and 2-Methylnaphthalene that exceeded TCLP levels.[317] Its report indicated that the levels of lead they found alone would have allowed the wastes to be considered characteristically hazardous if not for the RCRA

[311] 40 CFR § 261.23.
[312] EPA, *supra* note 2899, at III-23.
[313] NAGY, *supra* note 24, at 38.
[314] *Id.*
[315] *Id.* at 38–39.
[316] *See* Earthworks, OCD's 2007 Pit Sampling Program: What Is in that Pit?, at 31.
[317] *Id.* at 34.

exemption.[318] Analysis of E&P waste in California determined that both produced water and oily sludge met the federal toxicity characteristic and would be considered hazardous, again, if not for the RCRA exemption.[319] Because of this evidence, and the multitude of evidence discussed above indicating that E&P wastes have caused, and present substantial risk of continuing to cause, hazards to human health and the environment, EPA should reconsider its 1988 Regulatory Determination and regulate E&P wastes under Subtitle C of RCRA, as would be proper given the fact that they frequently exhibit the same traits as characteristic hazardous wastes.

II. REQUEST FOR PROMULGATION OF REGULATIONS

The Petitioner, the Natural Resources Defense Council, respectfully requests that the EPA promulgate regulations classifying wastes from the exploration, development and production of oil and natural gas as hazardous waste subject to provisions of Subtitle C of RCRA. This request is based on overwhelming evidence that waste from the exploration, development and production of oil and natural gas is hazardous, taking into account its toxicity, corrosivity, and ignitability, that it is released into the environment where it can cause harm, that state regulations are inadequate, and that there are numerous methods available to manage it as hazardous waste. As set forth in this Petition, evidence exists for EPA to document that, because of its quantity, concentration, and chemical characteristics, E&P waste may cause or significantly contribute to an increase in mortality and serious incapacitating illness and that it may pose a substantial present or potential hazard to wildlife and the environment when improperly treated, transported or disposed of, or otherwise managed, as is occurring throughout the U.S. in the absence of sufficient mandatory federal oversight. *See* 42 U.S.C. § 6902(4)-(5).

The Petitioner requests that the EPA consider the relevant statutory and regulatory factors, as well as the factors set forth in the July 1988 Regulatory Determination, and promulgate regulations applying to wastes from the exploration, development and production of oil and natural gas under Subtitle C of RCRA.

Respectfully submitted this 8th day of September, 2010.

[318] *Id.* at 35.
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Ohio Quakes Probably Triggered by Waste Disposal Well, Say Seismologists

January 6, 2012

Earthquakes that have shaken an area just outside Youngstown, Ohio in the last nine months—including a substantial one on New Year's Eve—are likely linked to a disposal well for injecting wastewater used in the hydraulic fracturing process, say seismologists at Columbia University's **Lamont-Doherty Earth Observatory** who were called in to study the quakes. Ohio Gov. John Kasich has shut down the injection well and put four other proposed wells on hold. In the meantime, steps have been taken to ease pressure in the well to avert further rumblings.

A tower for removing gas at the Marcellus Shale Formation in Pennsylvania. Credit: Ruhrfisch/Wikimedia Commons.

The concern comes as natural gas drilling in shale formations that underlie much of the Northeast grows. To extract the gas, a mix of water, sand and chemicals is pumped under high pressure into shale rocks, in a process called hydraulic fracturing, or fracking. Once the gas has been removed, wastewater is either recycled or trucked off-site and injected deep underground. As the pressurized water seeps through cracks deep below ground, it can sometimes cause earthquakes on ancient fault lines.

Ohio is home to 177 such disposal wells, including the Youngstown well, which lies in a seismically dormant region bordering Pennsylvania. The first rumblings surfaced in March, several months after injection of fracking waste from Pennsylvania began. Nine small temblors followed. In late November, Ohio authorities asked Lamont scientists to monitor the area with mobile instruments that could provide a more accurate location of subsequent earthquakes. On Dec. 24, the four instruments recorded a magnitude 2.7 quake 2.2 miles below the surface–a half-mile away and about 2,000 feet below the 1.7 mile deep well.

"The location of the earthquake was sufficient evidence that there could be a link," Lamont seismologist **John Armbruster** told **NPR's All Things Considered**. Later in the week, D&L Energy, which owns the site, agreed to shut down the well. Then, on Dec. 31, a magnitude 4.0 quake struck. The Lamont instruments located it at about 300 feet east, and some 500 feet under the previous event. A 4.0 is about 40 times more powerful than a 2.7. At that point, the state put a moratorium on activity on four other wells within a five-mile radius, all of them already inactive.

Hydrofracking by its nature causes tiny earthquakes, because it involves fracturing of rock—but these are largely imperceptible, as the process takes place in relatively weak, shallow shales that crack before building up much strain. Quakes triggered by waste injection wells can be potentially more powerful because more fluid is usually being pumped underground at a site for longer periods, said **Roger Anderson**, an energy geophysicist at Lamont-Doherty who is not involved in the study. Once fluid enters a preexisting fault, it can pressurize the rocks enough to move; the more stress placed on the rock formation, the more powerful the earthquake. The Lamont data suggests that the Dec. 31 movement near the Ohio well was a strike-slip motion, in which one rock face slides across the other horizontally.

The chance of triggering an ancient fault by injecting fluid underground is relatively slim—maybe one in 200, said Lamont seismologist **Won-Young Kim**, who heads the **Lamont-Doherty Cooperative Seismic Network**. But, he said, the potential damage and injuries from an earthquake could far outweigh the cost of closing the well. "Once you get one earthquake, it's better to stop then, because you may get another," he said. That point was echoed by Armbruster on NPR: "I would advocate monitoring of wells to know when triggering of earthquakes first begins," he said. "Then you can decide whether to continue using that well."

Seismologists have known about the potential for injection wells to trigger earthquakes since the 1960s, when injected wastewater from weapons production at the Rocky Mountain Arsenal in Colorado was tied to a **series of earthquakes** including several of magnitude 5.0 or greater that caused minor damage in Denver and other cities. Earthquakes in Arkansas, Texas, Oklahoma and the United Kingdom have been linked in recent years to disposal of fracking fluids. In 2001, scientists linked a magnitude 4.2 quake in Ashtabula, Ohio to a waste disposal well there, a "carbon copy" of the recent activity near Youngstown, said Kim.

After the New Year's quake, Kim said that the risk could continue for another year or two, as it could take that long for pressurized fluid to dissipate. To minimize that risk, Ohio officials announced Jan. 5 that they would start letting the injected fluids bubble back into storage tanks at the surface rather than capping the well under standard procedures.
The Lamont-Doherty scientists will continue to monitor the area with colleagues from Youngstown State University and Ohio Geological Survey. They are also talking with the university about upgrading its own seismic station.

More:
Watch how injected fluids trigger an earthquake in **this video** from Next media Animation.
For ongoing coverage of the scientific debate over hydrofracking see Scientific American's **Storify blog.**

Related Projects:
Lamont Cooperative Seismographic Network (LCSN)

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TAGS: EARTHQUAKES | HYDROFRACKING

THE WALL STREET JOURNAL.
WSJ.com

BUSINESS | November 3, 2011

Study Ties Fracking to Quakes in England

By ALEXIS FLYNN

LONDON—The company leading efforts to unlock the U.K.'s potentially vast shale-gas reserves suffered a setback Wednesday after a report found it was "highly probable" a controversial production technique caused two small earthquake tremors in the country earlier this year.

The report, which was financed by U.K. energy company Cuadrilla Resources Ltd., pointed to "strong evidence" that the two minor earthquakes and 48 weaker seismic events resulted from Cuadrilla's pumping drilling fluids used in hydraulic fracturing, or "fracking." At the same time, the report said the events were the result of a "rare combination of geological factors."

Bloomberg News

Cuadrilla Resouces' shale gas exploration site, in July.

The report could complicate efforts by privately held Cuadrilla to resume hydraulic-fracturing activity that was halted after the two seismic incidents.

The company said the report concluded that none of the events recorded, including one in April of 2.3 and one in May of 1.5 on the Richter scale, had any structural impact on the surface above.

The U.K. has become the latest venue in Europe to see shale gas spur major debate over fracking, which has been heavily criticized by environmental groups. In June, France became the first country to ban shale-gas exploration.

The Staffordshire, England-based company said the report vindicated its stance that its operations pose "no threat to people or property in the local area," but it pledged to implement an early-warning system and other recommendations to mitigate the risk.

Cuadrilla in September announced a big shale-gas discovery, but development is on hold after the company and government agreed in June to stop its shale-gas test drilling until its potential consequences were better understood.

More

Cuadrilla statement

Earlier: U.K. Gets Big Shale Find

EXPERIENCE WSJ PROFESSIONAL

Editors' Deep Dive: Shale Rush Hits Hurdles

PLATTS COMMODITY NEWS
US Interior To Issue Frack Fluid Disclosure Rule

ENERGY WASHINGTON WEEK
Gas Industry Criticizes EPA Fracking Well Air Rules

U.K. regulators said they would review the findings before shifting policy. Leading environmental groups and local-government officials also called for caution on fracking, which has been a key component in the rise of shale gas in the U.S. and other areas.

The U.K. Department of Energy and Climate Change will study the implications of the report, a department spokesman said. "The implications of this report will be reviewed very carefully—in consultation with the British Geological Survey, independent experts, and the other key regulators," said the spokesman.

The report found that the combination of geological factors that caused the quakes was rare and would be unlikely to occur together again at future well sites.

"If these factors were to combine again in the future, local geology limits seismic events to around magnitude 3 on the Richter scale as a worst-case scenario," the report said.

The Richter scale measures magnitude, which is expressed in whole numbers and decimal fractions, and not damage caused. Each whole number represents a tenfold increase in measured amplitude, so a 5.3 tremor might be rated moderate, while a strong earthquake could be recorded at 6.3.

Cuadrilla said the report was overseen by an independent team of seismic experts and was prepared in consultation with the Department of Energy and Climate Change. A department spokesman said the report was commissioned by the company and that it would comment on the substance of the conclusions after it studied the report's findings.

An earlier study by the British Geological Survey put the epicenter for each earthquake as being 500 meters (1,650 feet) away from the Preese Hall-1 well, at Weeton, near Blackpool, England.

British Geological Survey Earthquake Seismologist Dr. Brian Baptie said Wednesday's report confirmed his organization's own initial conclusion that fracking was responsible for the earthquakes. "It seems quite possible, given the same injection scheme in the same well, that there could be further earthquakes," he said.

Dr. Baptie said a way to minimize future risks could include the type of traffic-light monitoring system proposed by Cuadrilla but pointed out that even an "acceptable magnitude 2.6 earthquake might, at a depth of three kilometers (1.9 miles), result in an intensity of shaking that would not be expected to cause any damage but would be widely felt by people indoors and out, and may displace objects on shelves."

Spotting these types of seismic events could also be tricky, explained Dr. Baptie. "Earthquakes such as this result from very small movements on small faults that may be very difficult to identify," he said.

Nick Molho, head of energy policy at environmental group WWF-UK, said the findings "are worrying, and are likely to add to the very real concerns that people have about fracking and shale gas."

Local Liberal Democrat Councillor Sue McGuire, who also leads a residents' group opposed to fracking, said that if Cuadrilla drilled the 400 to 800 wells proposed than "we cou ld be looking at significant seismic activity in the area, which could have major impact on peoples' homes and

businesses in the area, not to mention the impact on the environment."

"A moratorium would give the government time to ensure that industry specific legislation can be put in place," she said.

Cuadrilla has said some 200 trillion cubic feet of shale gas may be contained in northwest England,enough to meet the country's gas demand for 64 years, although it has cautioned the actual recoverable figure may be much lower.

—Guy Chazan contributed to this article.

Write to Alexis Flynn at alexis.flynn@dowjones.com

Corrections & Amplifications

An earlier version of this story erroneously referred to a Cuadrilla estimate of 200 million feet of gas in northwest England; the estimate is for 200 trillion cubic feet of gas.

FINAL

RULE H-1 - CLASS II DISPOSAL AND CLASS II COMMERCIAL DISPOSAL WELL PERMIT APPLICATION PROCEDURES

a) Definitions:

1) "Class II Disposal Well"-- means:

A) A permitted Class II well in which Class II Fluids are injected into zones not productive of oil and gas, and brine used to produce bromine, within the field boundary established by an order of the Commission for the production of liquid hydrocarbons or brine used to produce bromine, where the well is located or will be located, for the purpose of disposal of those fluids; or

B) A permitted Class II well in which Class II Fluids are injected into a zone or zones~~,~~ which are not commercially productive of dry gas, within the same common source of supply, where the well is located or will be located, for the purpose of disposal of those fluids.

2) "Class II Commercial Disposal Well"-- means a permitted Class II well in which Class II Fluids are injected, for which the Permit Holder receives deliveries of Class II Fluids by tank truck from multiple oil and gas well operators, and either charges a fee at the disposal well facility or purchases the Class II Fluids at the source for subsequent transport to the disposal well facility for the specific purpose of disposal of the delivered Class II Fluids.

3) "Class II Fluids" means:

A) Produced water and/or other fluids brought to the surface in connection with drilling, completion, or fracture treatments, workover or recompletion and plugging of oil and natural gas wells~~,~~; Class II or wells that are required to be permitted as water supply wells by the Commission; enhanced recovery operations; or natural gas storage operations; or

B) Produced water and/or other fluids from (A) above, which prior to re-injection have been used on site for purposes integrally associated to oil and natural gas well drilling, completion, or fracture treatments, workover or recompletion and plugging of oil and natural gas wells; Class II or wells that are required to be permitted as water supply wells by the Commission; enhanced recovery operations; or natural gas storage operations, or chemically treated or altered to the extent necessary to make them usable for purposes integrally related to oil and natural gas well drilling, completion, workover and plugging, oil and gas production, enhanced recovery operations, or natural gas storage operations, or commingled with fluid wastes resulting from fluid treatments outlined above, and including any other exempted oil and gas related fluids under the Resource Conservation and Recovery Act, provided the commingled fluid wastes do not constitute a hazardous waste under the Resource Conservation and Recovery Act; or

C) Waste fluids from gas plants (including filter backwash, precipitated sludge, iron sponge, hydrogen sulfide and scrubber liquid) which are an integral part of oil and gas production operations; and waste fluids from gas dehydration plants (including glycol-based compounds and filter backwash), unless the gas plant or gas dehydration plant wastes are classified as hazardous under the federal Resource Conservation and Recovery Act.

4) "Confining layer" means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone. It is composed of rock layers that are impermeable or distinctly less permeable than the injection zone beneath it. There may be multiple confining layers above an injection zone.

5) "Permit Holder" means the entity or person to whom the permit is issued and who is responsible for all regulatory requirements relative to the Class II Disposal or Class II Commercial Disposal Well.

6) "USDW" means Underground Source of Drinking Water which is defined in Title 40, Code of Federal Regulations (40 CFR) Section 144.3, as an aquifer or its portion which:

A) Supplies any public water system (see 40 CFR); or

B) Contains a sufficient quantity of groundwater to supply a public water system (see 40 CFR) and currently supplies drinking water for human consumption; or

C) Contains fewer than 10,000 mg/l total dissolved solids (see 40 CFR); and

D) Which is not an exempted aquifer (see 40 CFR)

b) No person shall drill, deepen, re-enter, recomplete or operate any well for use as a Class II Disposal or Class II Commercial Disposal Well or inject into any well, without the applicable permits from the Commission, application for which shall be made on forms prescribed by the Director. Permits are valid only for the Permit Holder stated on the permit, and shall remain valid only with ongoing compliance with established operating requirements specified in General Rule H-2 or H-3, except that permits to drill, deepen, or re-enter shall automatically expire six (6) months from the date of issuance, unless commencement of the drilling, deepening or re-entry of plugged well operations authorized by the permit has occurred, which are to be continued with due diligence, but not to exceed one (1) year from the date of commencement of the drilling, deepening or re-entry of plugged well operations authorized by the permit, at which time the well shall be plugged, injection casing set, or a new permit application, along with a new permit fee and plat, must be filed. Failure to comply with the operating requirements in General Rule H-2 or H-3 may result in revocation of the Class II Disposal Well or Class II Commercial Disposal Well permit in accordance with subparagraph q) below.

1) Authority to conduct an injectivity test, step rate test or trial injection test prior to, or after the issuance of a permit may be approved as follows:

A) An injectivity test, step rate test or trial injection test of less than twelve (12) hours duration may be approved by the Director upon review of the well construction to determine well mechanical integrity for the protection of the USDW's and oil and gas resources during the test. The Director shall establish

the protective parameters of the test, require the submittal of any information or test data deemed necessary and may require the witnessing by Commission staff of the test.

B) An Applicant may request approval from the Commission, by filing an application in accordance with General A-2 and A-3 and other applicable hearing procedures, of an injectivity test, step rate test or trial injection test of twelve (12) hours or more in duration.

2) No Class II Disposal or Class II Commercial Disposal Well may be drilled at a surface location other than that specified on the permit, except that if a permit holder has commenced drilling operations and the Class II Disposal or Class II Commercial Disposal Well is lost due to adverse drilling conditions prior to surface casing being set, the permit holder may request an amendment of the permit without a fee for the new location, provided the Class II Disposal or Class II Commercial Disposal Well remains on the same surface owners property where the Class II Disposal or Class II Commercial Disposal Well was originally permitted and all other aspects of the permit request remain the same. Movement of the Class II Disposal or Class II Commercial Disposal Well location off the original surface owners' property, or after surface casing has been set, will require the filing of a new permit application, along with a new permit fee and plat. Drilling may not commence prior to the issuance of a new permit.

3) Permits to recomplete or operate shall automatically expire one year from the date of issuance, unless commencement of the operations authorized by the permit has occurred, or a new permit application, along with a new permit fee has been filed.

4) Upon issuance of a permit, a copy of the permit shall be displayed at the site where the Class II Disposal or Class II Commercial Disposal Well is being drilled for review by Commission staff.

5) Permits to drill, deepen, or re-enter a Class II Disposal or Class II Commercial Disposal Well may only be issued if the location complies with General Rule B-3.

c) The application to drill, deepen, re-enter, recomplete or operate a Class II Disposal or Class II Commercial Disposal Well shall include at a minimum:

1) The information required by subparagraph (h) below, for the existing or proposed well and any additional information deemed necessary by the Director for the protection of USDWs; and

2) Accompanied by a permit fee in the amount of $300.00 if the Class II Disposal or Class II Commercial Disposal Well is drilled, deepened, or re-entered; and

3) Accompanied by a non-refundable fee of $100.00 for a Class II Disposal Well or $500.00 for a Class II Commercial Disposal Well to recomplete or operate the Class II Disposal or Class II Commercial Disposal Well; and

4) Accompanied by the required financial assurance in accordance with General Rule B-2; and

5) Accompanied by a Form 1 Organizational Report in accordance with General Rule B-13; and

6 Be executed under penalties of perjury; and

7) If the applicant is a corporation, limited liability company, limited liability partnership or other business entity, it must be incorporated, organized, or authorized to do business in the State of Arkansas, and by filing an application, the applicant irrevocably waives, to the fullest extent permitted by law, any objection to a hearing before the Commission or in a court of competent jurisdiction in Arkansas; and

8) If the applicant is an individual, partnership, or other entity that is not a resident of Arkansas, the applicant must be authorized to do business in Arkansas, and by filing an application, the applicant irrevocably waives, to the fullest extent permitted by law, any objection to a hearing before the Commission or in a court of competent jurisdiction in Arkansas; and

9) Proof that the Class II Disposal or Class II Commercial Well location complies with General Rule B-3.

d) No person shall inject into USDWs or be issued a permit to inject into USDWs unless an aquifer exemption has been granted in accordance with US Environmental Protection Agency procedures.

e) Unless otherwise approved by the Commission, no person shall inject into a well which does not have at a minimum, five hundred (500) feet for a Class II Disposal Well or seven hundred-fifty (750) feet for a Class II Commercial Disposal Well, of confining layers between the base of the lowermost USDWs and the top of the injection interval, with no individual confining layer being less than 50 feet in thickness. A lesser amount of confining layer(s) may be approved, provided the Applicant provides substantial information as to the integrity of the confining layers to inhibit the upward migration of the injection fluids so as not to endanger the lowermost USDW in the area of the well.

f) If the application does not contain all of the required information or documents, the Director shall notify the Applicant in writing. The notification shall specify the additional information or documents necessary for an evaluation of the application and shall advise the Applicant that the application will be deemed denied unless the information or documents are submitted within sixty (60) days following the date of notification.

g) Applications for a Class II Disposal Well shall contain the names of all permit holders who are to utilize the proposed disposal well.

h) Contents of Application

1) A specification as to the type of Class II well being permitted as a Class II Disposal Well or a Class II Commercial Disposal Well.

2) The Applicant shall provide the name, address, phone, fax and e-mail (if available) of the local or on-site supervisory or field personnel responsible for the disposal well.

3) If the well is not located within the boundaries of an operating oil and gas leasehold or drilling unit, the Applicant shall provide documentation, in the form of a surface use agreement or an affidavit of a surface use agreement, indicating the Applicant's right to drill and to operate the proposed disposal well. If the well is located within the boundaries of an operating oil and gas leasehold or drilling unit, and the Applicant is someone other than the operator of the leasehold or drilling unit, the Applicant shall provide documentation, in the form of a surface use agreement, or an affidavit of a surface use agreement, indicating the Applicant's right to drill and to operate the proposed disposal well.

4) A survey plat of the location and ground elevation of the proposed disposal well or if the application is for an existing well, the well name and permit number of the existing well. A new survey is not required for a well to be converted or deepened well or a plugged well to be re-entered, if the original well location was surveyed, a copy of which shall be submitted with the application.

5) The name, geologic description and the approximate top and bottom elevation, from sub-sea, of the formation (indicating the perforated or open hole interval) into which fluid will be injected and the geologic description and top and bottom elevation, from sub-sea, of the above confining layers, in the proposed or existing disposal well. If an existing well is to be converted, a geophysical log of the well shall be submitted showing the above information. For a proposed well, an induction log from a well in the immediate vicinity of the proposed disposal well shall be submitted. If the geologic name of the interval is unclear include any additional geological evidence such as a cross section, structure or isopach map that may be necessary to adequately define the proposed injection interval.

6) A well bore diagram of the proposed or existing well showing casing for the injection well, indicating from the well head to total depth of the well, all casings and cementing of casings, any obstructions within well, all plugs set, tubing and packer setting depth, and all perforations and or open hole intervals. If application is for an existing well, a cement bond log (CBL) shall be submitted with the application, or if submitted after the application is filed, the CBL shall be submitted prior to commencement of operations as a condition of the permit.

7) The proposed daily amounts to be injected, the source and the type of fluid to be injected, and standard laboratory report from an accredited laboratory reporting the laboratory results of a representative sample of the proposed disposal fluids for the following parameters: chloride, pH, specific gravity, total dissolved solids (TDS) and total percent hydrocarbon (TPH). The sample shall be obtained and analyzed no earlier than one hundred-eighty (180) days prior to the date of filing of the application and analyzed in a timely fashion after collection.

8) The maximum injection pressure.

A) The Director shall determine the maximum permitted injected pressure, measured at the wellhead, by multiplying the results of the formula below by ninety percent (90%):

i) A maximum fracture gradient not to exceed 1.1 psi/ft (x) depth to injection formation (-)weight of fluid column (specific gravity of

injection fluid) (+) injection tubing friction loss in Ashley, Bradley, Calhoun, Columbia, Hempstead, Lafayette Miller, Nevada, Ouachita, and Union counties for injection into formations below the Midway Shale Formation; or

ii) A maximum fracture gradient not to exceed 1.0 psi/ft**(**x**)** depth to injection formation (-)weight of fluid column (specific gravity of injection fluid) (+) injection tubing friction loss in all other counties for injection into formations below the Fayetteville Shale Formation in the areas covered by General Rule B-43 (c) and (d), General Rule B-44, and the portions of Franklin, Logan, Scott, Sebastian, and Yell Counties not covered by General Rule B-44; or

iii) A maximum fracture gradient not to exceed 0.73 psi/ft**(x)** depth to injection formation (-)weight of fluid column (specific gravity of injection fluid) (+) injection tubing friction loss for all other formations and/or counties.

The following calculation is included only as an example, and for informational and demonstrative purposes only. For purposes of this example, assume the well is in ColumbiaCounty, the total depth to the injection formation is 2,500 feet, the specific gravity is 1.085, and the injection tubing friction loss is 250 psi. Using the formula provided above, the maximum permitted injection pressure for the well would be 1,642 psig, calculated as follows:

Step 1: 0.9 x [(1.1 psi/ft x 2500 ft) – [0.433psi/ft x 2500 ft) x 1.085 (specific gravity)] + 250 tubing friction loss]

Step 2: 0.9 x [2750 psi – 1175 + 250 tubing friction loss]

Step 3: 0.9 x [1825]

Step 4: Result = 1642 psig

B) An Applicant may request an increase in the maximum injection pressure specified in subparagraph h) 8) A) above, or appeal a Director's decision to issue a permit utilizing a fracture gradient less than the maximum fracture gradient specified in subparagraph h) 8) A) above, by filing an application in accordance with General A-2, A-3 and other applicable hearing procedures. Any increase in the maximum injection pressure may be granted if the Applicant presents sufficient evidence to justify the requested increased injection pressure will not initiate or propagate fractures in the overlying confining layer(s) that could enable the injection fluid or the fluid in the injection interval to leave the permitted injection intervals or cause movement of the injection fluid or formation fluids into USDWs.

9) A map showing:

A) The surveyed location of the well proposed to be drilled, deepened or converted, showing distances to the nearest property or lease lines; and

B) The location of all known plugged and unplugged wells, which penetrate the proposed injection interval, within the 1/2 mile radius from the proposed disposal well, and showing the status of each well as producing, shut-in, disposal, enhanced recovery, plugged and abandoned, or other status.

10) The Applicant shall submit evidence, where available, that all plugged and unplugged wells which penetrate the injection formation, within the ½ mile radius shown on the above plat in subparagraph h) 9) B), contain an adequate amount of cement and are constructed or plugged in a manner which will prevent the injection fluid and the fluid in the injection formation from entering USDWs. The types of evidence that will be considered acceptable include, but are not limited to: well completion reports, cementing records, well construction records, cement bond logs, tracer surveys, oxygen activation logs, and plugging records.

11) The Applicant shall submit evidence and/or information showing that the proposed injection interval or formation is not a USDW.

12) The Applicant shall submit information as to the depth (subsea) of the fresh water supply in the nearest known private water well and in the nearest known public water system water well.

13) If the application is for a Class II UIC Commercial Disposal Well, a listing of all previous and current violations of any statute, rule, regulation, permit condition, or order of the Commission, the Arkansas Department of Environmental Quality, the Arkansas Pollution Control and Ecology Commission, or any other state or federal environmental regulatory agency, including those of other states, regarding oil or gas related activities.

i) Notice of the application shall be given by the Applicant by one (1) publication in a legal newspaper having a general circulation in the county, or in each county, if there shall be more than one, in which the one-half mile radius from the proposed disposal well is situated, and by mailing via certified mail, FedEx,UPS,or other method that provides proof of mailing and delivery, a copy of the application to each permit holder of all permitted, drilling or producing wells within a one-half mile radius of the proposed disposal well. Such notice shall be published or mailed no more than thirty (30) days, prior to the date on which the application is filed with the Commission. The cost of such notice and mailing of the application shall be paid for by the Applicant. Attached to the application shall be evidence that the application was mailed or sent asrequired and a proof of publication of the application from the newspaper.

j) If notice is for a commercial disposal well, in addition to compliance with subparagraph i) above, the commercial disposal well application shall also be sent via certified mail, FedEx, or UPS to the County Judge of the county where the well is located and to the landowner (surface owner) where the well is located. In addition, the public notice should be large font and surrounded by a printed border to highlight the published notice.

k) Objections received by the Director, must be received by the Director within fifteen (15) days after the publication date of the notice and the date of mailing or sending to all parties specified in subparagraphs i) and j) above.

l) If an objection is received the application shall be deemed denied. If the application is denied under this section, the Applicant may request to have the application referred to the Commission

for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing procedures, except that no additional filing fee is required.

m) If an objection is not received by the Director and the application is deemed complete, the permit shall be issued following the required notice period specified in subparagraph i) above, unless the Director deems it necessary, for the purpose of protecting USDWs or oil and gas resources, that the application may be referred to the Commission for determination, and no additional filing fee is required from the applicant.

n) If the application does not satisfy the requirements of this Rule, the application shall be denied. If the application is denied under this section, the Applicant may request to have the application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing procedures.

o) If the Applicant satisfies the requirements of all applicable statutes and this Rule, a permit shall be issued, unless:

1) The Applicant has falsified or otherwise misstated any material information on or relative to the permit application; or

2) For purposes of Class II Commercial Disposal Wells, the Applicant:

A) Has an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest in the entity exceeding 5%;

i) That has failed to abate an outstanding violation of the oil and gas statutes or rules, regulations, or comply with an orders of the Commission as specified in a final administrative decision of the Commission; or

ii) For which funds have been obligated and remain outstanding from the Plugging and Restoration Fund to plug wells, under General Rule G-1 or G-2; or

iii) Who is delinquent in payment of any annual well fees under General Rule B-2.

B) Was an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest exceeding 5%;

i) That has failed to abate an outstanding violation of the oil and gas statutes or rules, regulations, or comply with an orders of the Commission as specified in a final administrative decision of the Commission; or

ii) For which funds have been obligated and remain outstanding from the Plugging and Restoration Fund to plug wells, under General Rule G-1 or G-2; or

iii) Who is delinquent in payment of any annual well fees under General Rule B-2.

C) Is a Permit Holder or an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest exceeding 5%;

i) That has failed to abate an outstanding violation of the oil and gas statutes or rules, regulations, or comply with an orders of the Commission as specified in a final administrative decision of the Commission; or

ii) For which funds have been obligated and remain outstanding from the Plugging and Restoration Fund to plug wells, under General Rule G-1 or G-2; or

iii) Who is delinquent in payment of any annual well fees under General Rule B-2.

D) If the Director determines that the applicant, or an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest exceeding 5% in the applicant, has a history of violating an oil and gas statute, rule, regulation, permit condition or order of the Commission, the Arkansas Department of Environmental Quality, the Arkansas Pollution and Ecology Commission, or any other state or federal environmental regulatory agency, including those of other states, regarding oil or gas related activities, which pose a potential danger to the environment and public health and safety. In making the determination, the Director may consider:

i) The danger to the environment and public health and safety if the applicant's proposed activity is not conducted in a competent and responsible manner; and

ii) The degree to which past and present oil and gas related activities directly bear upon the reliability, competence, and responsibility of the applicant.

E) If a permit is not issued in accordance with subparagraph o) 2) above, the Applicant may request to have the permit application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing procedures, except that no additional filing fee is required.

p) The Commission retains jurisdiction to determine zones suitable for disposal injection based on the porosity, permeability, fluid capacity, structure, geology and overall suitability of the zone as a disposal injection interval with respect to protection of USDWs and oil and gas resources.

q) Class II Disposal or Class II Commercial Disposal Well Drilling Permit or Transfer Revocation Procedures

1) The Director may revoke a Class II Disposal or Class II Commercial Disposal Well permit or transfer approval if the Permit Holder fails to meet permit conditions as specified in the Class II Disposal or Class II Commercial Disposal Well permit or transfer approval, the Class II Disposal or Class II Commercial Disposal Well permit or transfer

approval was issued in error, or the Permit Holder falsified or otherwise misstated any material information in the application form.

2) The Director shall notify the Permit Holder of the Class II Disposal or Class II Commercial Disposal Well permit or transfer revocation in writing. Following the revocation notice the Permit Holder is required to plug the Class II Disposal or Class II Commercial Disposal Well. The Permit holder shall have thirty (30) days from the date of the Class II Disposal or Class II Commercial Disposal Well permit or transfer revocation to appeal the Director's Decision to revoke the Class II Disposal or Class II Commercial Disposal Well permit or transfer approval in accordance with General Rule A-2, A-3 and other applicable hearing procedures. Operations may not commence or continue during the appeal process. A revocation of a Class II Disposal or Class II Commercial Disposal Well permit or transfer approval for which an appeal has not been filed, shall become a final administrative decision of the Commission thirty (30) days following the date of the revocation.

r) Class II Disposal or Class II Commercial Disposal Well Transfer Procedures

1) Definitions

A) "Current Permit Holder" means the individual or entity required to hold the permit or to whom the permit was issued and who is the owner of the right to operate said Class II Disposal or Class II Commercial Disposal Well(s), possesses the full rights and responsibilities for operating the Class II Disposal or Class II Commercial Disposal Well(s) in accordance with applicable Arkansas law and has the current obligation to plug said Class II Disposal or Class II Commercial Disposal Well(s), who is the assignor, transferor or seller (whether voluntary or involuntary) of the Class II Disposal or Class II Commercial Disposal Well(s).

B) "New Permit Holder" means the individual or entity acquiring the Class II Disposal or Class II Commercial Disposal Well(s) and the right to operate said Class II Disposal or Class II Commercial Disposal Well(s), who obtains the full rights and responsibilities for operating the Class II Disposal or Class II Commercial Disposal Well(s) in accordance with applicable Arkansas law and/or rule, regulation, or order of the Commission, who~~m~~ will obtain the obligation to plug said Class II Disposal or Class II Commercial Disposal Well(s), and who as owner or operator in accordance with applicable Arkansas law and/or rule, regulation, or order of the Commission is required to hold the permit.

C) "Transfer" means any assignment, devise, release, transfer, takeover, buyout, merger, sale, conveyance, or other transfer of any kind, whether voluntarily or involuntarily.

2) The provisions of this subparagraph apply to all transfers of the interest of the individual or entity required to hold and to whom the Class II Disposal or Class II Commercial Disposal Well transfer approval is issued (Permit Holder), including but not limited to:

A) a change of ownership of the right to drill and/or operate said Class II Disposal or Class II Commercial Disposal Well(s), along with the full rights and responsibilities for operating the Class II Disposal or Class II Commercial

Disposal Well(s) and the obligation to ultimately plug said Class II Disposal or Class II Commercial Disposal Well(s); or

B) a change in the designation of the owner or operator under an operating or other similar agreement; or

C) a change pursuant to the action of the owners of separate interests who designate an owner to be Permit Holder; or

D) a change required by the appointment, by a court of competent jurisdiction, of a trustee or a receiver to exercise custody and control over the Class II Disposal or Class II Commercial Disposal Well(s), including the right to drill and/or operate said well(s) along with the full right and responsibilities for operating the well(s).

3) The provisions of this subparagraph shall not apply to the transfer of working interests not affecting the rights or responsibilities of the Permit Holder.

4) The provisions of this subparagraph shall not apply to transfers of Class II Disposal or Class II Commercial Disposal Well(s) abandoned or orphaned in accordance General Rule G-1 or G-2. Transfers of Class II Disposal or Class II Commercial Disposal Wells deemed abandoned or orphaned are subject to the transfer provisions in General Rule G-3.

5) Notification of a transfer shall be given to the Director, or his designee, by the Current Permit Holder, on a form prescribed by the Director, of the transfer of any Class II Disposal or Class II Commercial Disposal Well or any Class II Disposal or Class II Commercial Disposal Well required to be permitted within thirty (30) days after the effective date of the transfer.

6) A separate form shall be completed for each lease, Class II Disposal or Class II Commercial Disposal Well, or other unit transferred.

7) The notification shall be signed by the Current Permit Holder and the New Permit Holder, or by authorized representatives specified on the Organizational Report filed in accordance with General Rule B-13, except as follows:

A) In lieu of the signature of the Current Permit Holder, the New Permit Holder may submit a court order or other legal document evidencing ownership of the lease or unit to be transferred in the event that the Current Permit Holder cannot be located or refuses to sign the notification of transfer form.

B) In lieu of the signature of the New Permit Holder, the Current Permit Holder may submit documentation evidencing transfer of the ownership of the Class II Disposal or Class II Commercial Disposal Well, lease, or unit in the event the New Permit Holder refuses to sign the notification of transfer form.

8) A New Permit Holder may operate Class II Disposal or Class II Commercial Disposal Wells covered by the Class II Disposal or Class II Commercial Disposal Well transfer request, until such time as the transfer request has been approved or denied by the Director or his designee, provided the request was submitted within thirty (30) days of the actual transfer of the Class II Disposal or Class II Commercial Disposal Well.

However, Class II Disposal or Class II Commercial Disposal Wells may not be operated by the New Permit Holder, until a Class II Disposal or Class II Commercial Disposal Well transfer request is approved, if the request was received by the Director, or his designee, more than thirty (30) days after the actual transfer of the Class II Disposal or Class II Commercial Disposal Well.

9) A New Permit Holder that acquires the right to operate a Class II Disposal or Class II Commercial Disposal Well(s) pursuant to a transfer shall apply for and must receive transfer approval from the Director, or his designee, prior to operating the Class II Disposal or Class II Commercial Disposal Well(s) beyond the timeframe specified in subparagraph (r)(8) above.

10) Prior to the Director, or his designee, approving the transfer request, the New Permit Holder shall provide the required financial assurance, if applicable, in accordance with General Rule B-2, and file the required organizational report, if applicable, in accordance with General Rule B-13.

11) A transfer to a New Permit Holder may be denied by the Director, or his designee, if the New Permit Holder meets any of the conditions specified in subparagraph o) above.

12) The New Permit Holder shall be responsible for all regulatory requirements relative to all Class II Disposal or Class II Commercial Disposal Wells and all other surface production facilities in existence at the time of the transfer related to the Class II Disposal or Class II Commercial Disposal Wells. The New Permit Holder shall not be responsible for regulatory requirements relative to spills of crude oil or other production fluids which occurred prior to the date of the transfer, unless the New Permit Holder has otherwise agreed with the Current Permit Holder.

13) If any Class II Disposal or Class II Commercial Disposal Well, or any lease or other unit associated with the Class II Disposal or Class II Commercial Disposal Well, is in violation at the time of the transfer request to the New Permit Holder, the transfer request shall be denied pending abatement of all violations by the Current Permit Holder. However, if the New Permit Holder, after being notified of the violation(s), agrees in writing to the transfer approval including conditions to abate all violations, the transfer may be approved by the Director, or his designee. Failure to abate the violations within the time period specified by the Director or his designee may result in revocation of the transfer approval in accordance with subparagraph q) above, and/or other applicable enforcement actions in accordance with General Rule A-5.

14) The Current Permit Holder is not responsible for any regulatory violation caused by the actions of the New Permit Holder during the permit transfer process, after notice is given to the Director, or his designee, by the Current Permit Holder of the pending transfer if the transfer is approved. However, if the transfer is denied by the Director or his designee, the Current Permit Holder assumes all responsibility for the violations caused by the New Permit Holder. Nothing in this subsection shall affect the contractual rights and obligations between the person or entity transferring the Class II Disposal or Class II Commercial Disposal Well(s) and the person or entity acquiring the Class II Disposal or Class II Commercial Disposal Well(s).

15) The transfer approval pursuant to this subparagraph shall not affect the rights of the Commission, or any obligation or duty of the Current Permit Holder arising under any

applicable Arkansas laws, or rules, regulations, or orders of the Commission. Any cause of action accruing or any action or proceeding which has commenced, whether administrative, civil or criminal, may be instituted or continued without regard to the transfer approval.

16) The Director shall notify the Current and New Permit Holder of the transfer approval or denial in writing. Following the approval or denial of the transfer approval request, the Current or New Permit holder shall have thirty (30) days from the date of the approval or denial to appeal the Director's Decision in accordance with General Rule A-2, A-3 and other applicable hearing procedures. A transfer request approval or denial, for which an appeal has not been filed, shall become a final administrative decision of the Commission thirty (30) days following the date of the approval or denial.

s) Miscellaneous Provisions and Requirements for Class II Disposal or Class II Commercial Disposal Wells Within General Rule B-43 Section c) lands.

1) Definitions:

a. "Regional Fault" means the identified fault zones named by the Arkansas Geological Survey as the Clinton, Center Ridge, Heber Springs, Enders and Morrilton Fault zones; and which are part of a general east-west turning north-east (approximately N55ºE to N75ºE) trending, down thrown to the south, fault system generally occurring below the Fayetteville Shale Formation displacing the Lower Mississippian through Precambrian strata and truncating upward at the unconformity between the Mississippian and Pennsylvanian age strata; and which are identified on the Arkansas Geological Survey map attached hereto as Exhibit 1 to this Rule; and as updated for purposes of this Rule following notice and a hearing in accordance with General Rule A-2.

b. "Moratorium Zone Deep Faults" means deeper faults associated with the Guy-Greenbrier Earthquake Swarm; and which are part of a general northeast-southwest (approximately N30ºE) trending deeper fault system displacing the Lower Ordovician through Precambrian strata occurring in the general B-43 Section c) lands area.

2) Unless otherwise approved by the Commission after notice and a hearing, no permit to drill, deepen, re-enter, recomplete or operate a Class II Disposal or Class II Commercial Disposal Well may be granted for any Class II or Class II Commercial Disposal wells in any formation within the following area ("Moratorium Zone")located in Cleburne, Conway, Faulkner, Van Buren, and White Counties:

Sections	Township	Range
ALL	4N	13W
ALL	5N	12W
ALL	5N	13W
ALL	5N	14W
ALL	6N	12W
ALL	6N	13W
ALL	7N	11W
ALL	7N	12W
ALL	7N	13W
ALL	8N	11W
ALL	8N	12W
ALL	8N	13W
ALL	9N	10W
ALL	9N	11W
ALL	9N	12W
ALL	10N	10W
ALL	10N	11W
ALL	11N	10W
ALL	11N	11W
1-12, 14-23, 27-33	4N	12W
1-30, 35-36	4N	14W
1-2, 10-15, 23-25	4N	15W
4-9, 17-20, 30-31	5N	11W
25, 35-36	5N	15W
6	6N	10W
1-23, 26-34	6N	11W
1-4, 9-36	6N	14W
24-25, 36	6N	15W
3-9, 16-20, 29-31	7N	10W
1, 11-14, 22-27, 34-36	7N	14W
6-7	8N	9W
1-24, 26-35	8N	10W
25, 36	8N	14W
3-10, 15-21, 29-32	9N	9W
1-5, 7-36	9N	13W
1-23, 27-34	10N	9W
1-3, 9-17, 19-36	10N	12W
25, 33, 34, 36	10N	13W
17-22, 27-35	11N	9W
13, 23-27, 34-36	11N	12W

3) Unless otherwise approved by the Commission after notice and a hearing, no permit to drill or re-enter, a new Class II Disposal or Class II Commercial Disposal Well may be granted within one (1) mile of a Regional Fault or within five (5) miles of a known or identified Moratorium Zone Deep Fault within any remaining B-43 Section c) lands.

4) Unless otherwise approved by the Commission after notice and a hearing, no permit to deepen or re-complete any existing Class II Disposal or Class II Commercial Disposal Well in a zone stratigraphically below the Fayetteville Shale formation, may be granted within one (1) mile of a Regional Fault or within five (5) miles of a known or identified Moratorium Zone Deep Fault within any remaining B-43 Section c) lands.

5) Unless otherwise approved by the Commission after notice and a hearing, the following provisions shall apply to any permit to drill, deepen, or operate a new Class II Disposal or Class II Commercial Disposal Well proposed to be located within in any remaining B-43 Section c) lands:

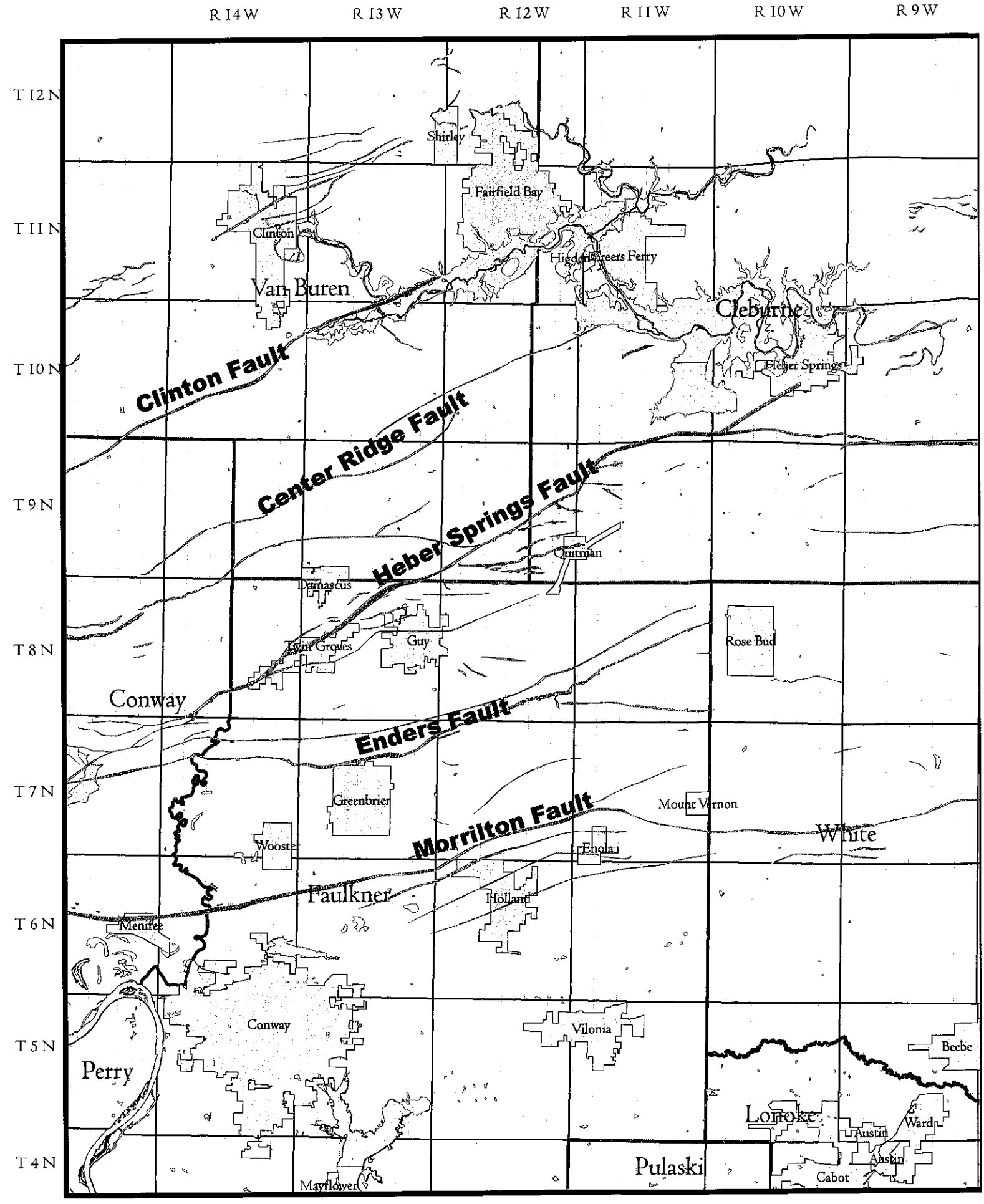
   a) No Class II Disposal or Class II Commercial Disposal Well disposing in a zone occurring stratigraphically below the Fayetteville Shale formation shall be located within five (5) miles of another Class II Disposal or Class II Commercial Disposal Well disposing in a zone occurring stratigraphically below the Fayetteville Shale formation.

   b) No Class II Disposal or Class II Commercial Disposal well disposing in a zone occurring stratigraphically above the Fayetteville Shale formation shall be located within one-half (1/2) mile of another Class II Disposal or Class II Commercial Disposal Well disposing in a zone occurring stratigraphically above the Fayetteville Shale formation.

6) The Applicant shall provide technical information to the Director in support of the application. The technical justification shall include information related to the location of any Moratorium Zone Deep Fault within five (5) miles or Regional Fault within two miles (2) of the proposed location of the Class II Disposal or Class II Commercial Disposal Well, with special emphasis on identifying any deep faults occurring below the Fayetteville Shale formation which extend to the basement rock.

7) Flow meters, or other measuring devices approved by the Director, shall be installed on all Class II Disposal and Class II Commercial Disposal Wells and Permit Holders shall submit accurate injection volume and pressure information, on no less than a daily basis, on a form prescribed by the Director.

Named Regional Faults



SSA 2012

Session: The M5.8 Central Virginia and the M5.6 Oklahoma Earthquakes of 2011

ARE SEISMICITY RATE CHANGES IN THE MIDCONTINENT NATURAL OR MANMADE?

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A remarkable increase in the rate of M 3 and greater earthquakes is currently in progress in the US midcontinent. The average number of M >= 3 earthquakes/year increased starting in 2001, culminating in a six-fold increase over 20th century levels in 2011. Is this increase natural or manmade? To address this question, we take a regional approach to explore changes in the rate of earthquake occurrence in the midcontinent (defined here as 85° to 108° West, 25° to 50° North) using the USGS Preliminary Determination of Epicenters and National Seismic Hazard Map catalogs. These catalogs appear to be complete for M >= 3 since 1970. From 1970 through 2000, the rate of M >= 3 events averaged 21 +- 7.6/year in the entire region. This rate increased to 29 +- 3.5 from 2001 through 2008. In 2009, 2010 and 2011, 50, 87 and 134 events occurred, respectively. The modest increase that began in 2001 is due to increased seismicity in the coal bed methane field of the Raton Basin along the Colorado-New Mexico border west of Trinidad, CO. The acceleration in activity that began in 2009 appears to involve a combination of source regions of oil and gas production, including the Guy, Arkansas region, and in central and southern Oklahoma. Horton, et al. (2012) provided strong evidence linking the Guy, AR activity to deep waste water injection wells. In Oklahoma, the rate of M >= 3 events abruptly increased in 2009 from 1.2/year in the previous half-century to over 25/year. This rate increase is exclusive of the November 2011 M 5.6 earthquake and its aftershocks. A naturally-occurring rate change of this magnitude is unprecedented outside of volcanic settings or in the absence of a main shock, of which there were neither in this region. While the seismicity rate changes described here are almost certainly manmade, it remains to be determined how they are related to either changes in extraction methodologies or the rate of oil and gas production.

Wednesday, April 18th / 3:45 PM Oral / Pacific Salon 4 & 5

DOE/EIA-0383(2012) | June 2012

Annual Energy Outlook 2012

with Projections to 2035

Independent Statistics & Analysis
U.S. Energy Information Administration

For further information . . .

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Complimentary copies are available to certain groups, such as public and academic libraries; Federal, State, local, and foreign governments; EIA survey respondents; and the media. For further information and answers to questions, contact:

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The *Annual Energy Outlook 2012* is available on the EIA website at www.eia.gov/forecasts/aeo. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available, at www.eia.gov/forecasts/aeo/assumptions. Model documentation reports for the National Energy Modeling System are available at website www.eia.gov/analysis/model-documentation.cfm and will be updated for the *Annual Energy Outlook 2012* during 2012.

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Annual Energy Outlook 2012

With Projections to 2035

June 2012

U.S. Energy Information Administration
Office of Integrated and International Energy Analysis
U.S. Department of Energy
Washington, DC 20585

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www.eia.gov/forecasts/aeo

Preface

The *Annual Energy Outlook 2012 (AEO2012)*, prepared by the U.S. Energy Information Administration (EIA), presents long-term projections of energy supply, demand, and prices through 2035, based on results from EIA's National Energy Modeling System (NEMS). EIA published an "early release" version of the *AEO2012* Reference case in January 2012.

The report begins with an "Executive summary" that highlights key aspects of the projections. It is followed by a "Legislation and regulations" section that discusses evolving legislative and regulatory issues, including a summary of recently enacted legislation and regulations, such as: the Mercury and Air Toxics Standards (MATS) issued by the U.S. Environmental Protection Agency (EPA) in December 2011 [*1*]; the Cross-State Air Pollution Rule (CSAPR) as finalized by the EPA in July 2011 [*2*]; the new fuel efficiency standards for medium- and heavy-duty vehicles published by the EPA and the National Highway Traffic Safety Administration (NHTSA) in September 2011 [*3*]; and regulations pertaining to the power sector in California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006 [*4*].

The "Issues in focus" section contains discussions of selected energy topics, including a discussion of the results in two cases that adopt different assumptions about the future course of existing policies: one case assumes the extension of a selected group of existing public policies—corporate average fuel economy (CAFE) standards, appliance standards, production tax credits, and the elimination of sunset provisions in existing energy policies; the other case assumes only the elimination of sunset provisions. Other discussions include: oil price and production trends in the *AEO2012*; potential efficiency improvements and their impacts on end-use energy demand; energy impacts of proposed CAFE standards for light-duty vehicles (LDVs), model years (MYs) 2017 to 2025; impacts of a breakthrough in battery vehicle technology; heavy-duty (HD) natural gas vehicles (NGVs); changing structure of the refining industry; changing environment for fuel use in electricity generation; nuclear power in *AEO2012*; potential impact of minimum pipeline throughput constraints on Alaska North Slope oil production; U.S. crude oil and natural gas resource uncertainty; and evolving Marcellus shale gas resource estimates.

The "Market trends" section summarizes the projections for energy markets. The analysis in *AEO2012* focuses primarily on a Reference case, Low and High Economic Growth cases, and Low and High Oil Price cases. Results from a number of other alternative cases also are presented, illustrating uncertainties associated with the Reference case projections for energy demand, supply, and prices. Complete tables for the five primary cases are provided in Appendixes A through C. Major results from many of the alternative cases are provided in Appendix D. Complete tables for all the alternative cases are available on EIA's website in a table browser at www.eia.gov/oiaf/aeo/tablebrowser.

AEO2012 projections are based generally on Federal, State, and local laws and regulations in effect as of the end of December 2011. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections. In certain situations, however, where it is clear that a law or regulation will take effect shortly after the *AEO* is completed, it may be considered in the projection.

AEO2012 is published in accordance with Section 205c of the U.S. Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

Projections by EIA are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular scenario. The Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other scenarios with different macroeconomic growth rates, world oil prices, and rates of technology progress. The main cases in *AEO2012* generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide policy-neutral baselines that can be used to analyze policy initiatives.

While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2012* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

Updated *Annual Energy Outlook 2012* Reference case (June 2012)

The *Annual Energy Outlook 2012 (AEO2012)* Reference case included as part of this complete report, released in June 2012, was updated from the Reference case released as part of the *AEO2012* Early Release Overview in January 2012. The Reference case was updated to incorporate modeling changes and reflect new legislation or regulation that was not available when the Early Release Overview version of the Reference case was published. Major changes made in the Reference include:

- The Mercury and Air Toxics Standards (MATS) issued by the EPA in December 2011 was incorporated.
- The long-term macroeconomic projection was revised, based on the November 2011 long-term projection from IHS Global Insights, Inc.
- The Cross-State Air Pollution Rule (CSAPR), which was included in the Early Release Reference case, was kept in the final Reference case. In December 2011, a District Court delayed the rule from going into effect while in litigation.
- The California Low Carbon Fuel Standard (LCFS) was removed from the final Reference case, given the Federal court ruling in December 2011 that found some aspects of it to be unconstitutional.
- Historical data and equations for the transportation sector were revised to reflect revised data from NHTSA and FHWA.
- A new cement model was incorporated in the industrial sector.
- Photovoltaic capacity estimates for recent historical years (2009 and 2010) were updated to line up more closely with Solar Energy Industries Association (SEIA) and Interstate Renewable Energy Council (IREC) reports.
- Gulf of Mexico production data were revised downward to reflect data reported by the Bureau of Ocean Energy Management more closely.
- Data in the electricity model were revised to reflect 2009 electric utility financial data (electric utility plant in service, operations and maintenance costs, etc.) and refine the breakdown of associated costs between the generation, transmission, and distribution components.
- Higher capital costs for fabric filters were adopted in the analysis of MATS, based on EPA data.
- Reservoir-level oil data were updated to improve the API gravity and sulfur content data elements.
- The assumed volume of natural gas used at export liquefaction facilities was revised.

Future analyses using the *AEO2012* Reference case will start from the version of the Reference case released with this complete report.

Endnotes for Preface

Links current as of June 2012

1. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," website www.epa.gov/mats.
2. U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)," website epa.gov/airtransport.
3. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *Federal Register*, Vol. 76, No. 179 (September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.
4. California Environmental Protection Agency, Air Resources Board, "Assembly Bill 32: Global Warming Solutions Act of 2006," website www.arb.ca.gov/cc/ab32/ab32.htm.

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Executive summary

The projections in the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2012 (AEO2012)* focus on the factors that shape the U.S. energy system over the long term. Under the assumption that current laws and regulations remain unchanged throughout the projections, the *AEO2012* Reference case provides the basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future. It also serves as a starting point for analysis of potential changes in energy policies. But *AEO2012* is not limited to the Reference case. It also includes 29 alternative cases (see Appendix E, Table E1), which explore important areas of uncertainty for markets, technologies, and policies in the U.S. energy economy. Many of the implications of the alternative cases are discussed in the "Issues in focus" section of this report.

Key results highlighted in *AEO2012* include continued modest growth in demand for energy over the next 25 years and increased domestic crude oil and natural gas production, largely driven by rising production from tight oil and shale resources. As a result, U.S. reliance on imported oil is reduced; domestic production of natural gas exceeds consumption, allowing for net exports; a growing share of U.S. electric power generation is met with natural gas and renewables; and energy-related carbon dioxide emissions remain below their 2005 level from 2010 to 2035, even in the absence of new Federal policies designed to mitigate greenhouse gas (GHG) emissions.

The rate of growth in energy use slows over the projection period, reflecting moderate population growth, an extended economic recovery, and increasing energy efficiency in end-use applications

Overall U.S. energy consumption grows at an average annual rate of 0.3 percent from 2010 through 2035 in the *AEO2012* Reference case. The U.S. does not return to the levels of energy demand growth experienced in the 20 years prior to the 2008-2009 recession, because of more moderate projected economic growth and population growth, coupled with increasing levels of energy efficiency. For some end uses, current Federal and State energy requirements and incentives play a continuing role in requiring more efficient technologies. Projected energy demand for transportation grows at an annual rate of 0.1 percent from 2010 through 2035 in the Reference case, and electricity demand grows by 0.7 percent per year, primarily as a result of rising energy consumption in the buildings sector. Energy consumption per capita declines by an average of 0.6 percent per year from 2010 to 2035 (Figure 1). The energy intensity of the U.S. economy, measured as primary energy use in British thermal units (Btu) per dollar of gross domestic product (GDP) in 2005 dollars, declines by an average of 2.1 percent per year from 2010 to 2035. New Federal and State policies could lead to further reductions in energy consumption. The potential impact of technology change and the proposed vehicle fuel efficiency standards on energy consumption are discussed in "Issues in focus."

Domestic crude oil production increases

Domestic crude oil production has increased over the past few years, reversing a decline that began in 1986. U.S. crude oil production increased from 5.0 million barrels per day in 2008 to 5.5 million barrels per day in 2010. Over the next 10 years, continued development of tight oil, in combination with the ongoing development of offshore resources in the Gulf of Mexico, pushes domestic crude oil production higher. Because the technology advances that have provided for recent increases in supply are still in the early stages of development, future U.S. crude oil production could vary significantly, depending on the outcomes of key uncertainties related to well placement and recovery rates. Those uncertainties are highlighted in this *Annual Energy Outlook*'s "Issues in focus" section, which includes an article examining impacts of uncertainty about current estimates of the crude oil and natural gas resources. The *AEO2012* projections considering variations in these variables show total U.S. crude oil production in 2035 ranging from 5.5 million barrels per day to 7.8 million barrels per day, and projections for U.S. tight oil production from eight selected plays in 2035 ranging from 0.7 million barrels per day to 2.8 million barrels per day (Figure 2).

Figure 1. Energy use per capita and per dollar of gross domestic product, 1980-2035 (index, 1980=1)

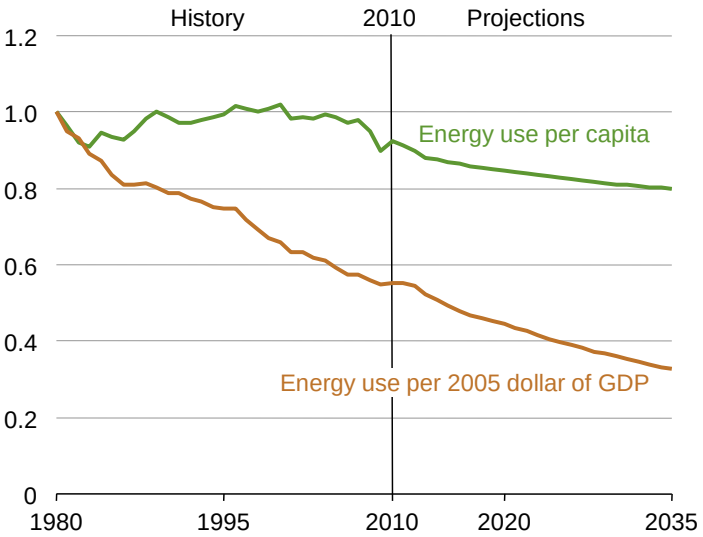
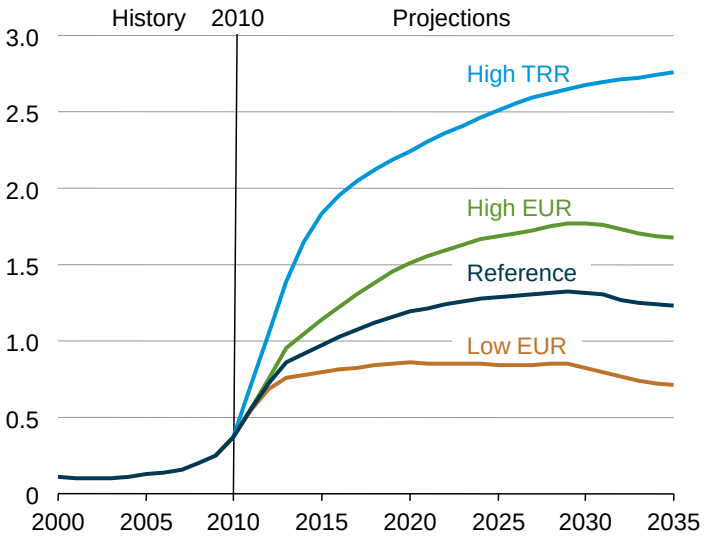


Figure 2. U.S. production of tight oil in four cases, 2000-2035 (million barrels per day)



With modest economic growth, increased efficiency, growing domestic production, and continued adoption of nonpetroleum liquids, net imports of petroleum and other liquids make up a smaller share of total U.S. energy consumption

U.S. dependence on imported petroleum and other liquids declines in the *AEO2012* Reference case, primarily as a result of rising energy prices; growth in domestic crude oil production to more than 1 million barrels per day above 2010 levels in 2020; an increase of 1.2 million barrels per day crude oil equivalent from 2010 to 2035 in the use of biofuels, much of which is produced domestically; and slower growth of energy consumption in the transportation sector as a result of existing corporate average fuel economy standards. Proposed fuel economy standards covering vehicle model years (MY) 2017 through 2025 that are not included in the Reference case would further reduce projected need for liquid imports.

Although U.S. consumption of petroleum and other liquid fuels continues to grow through 2035 in the Reference case, the reliance on imports of petroleum and other liquids as a share of total consumption declines. Total U.S. consumption of petroleum and other liquids, including both fossil fuels and biofuels, rises from 19.2 million barrels per day in 2010 to 19.9 million barrels per day in 2035 in the Reference case. The net import share of domestic consumption, which reached 60 percent in 2005 and 2006 before falling to 49 percent in 2010, continues falling in the Reference case to 36 percent in 2035 (Figure 3). Proposed light-duty vehicles (LDV) fuel economy standards covering vehicle MY 2017 through 2025, which are not included in the Reference case, could further reduce demand for petroleum and other liquids and the need for imports, and increased supplies from U.S. tight oil deposits could also significantly decrease the need for imports, as discussed in more detail in "Issues in focus."

Natural gas production increases throughout the projection period, allowing the United States to transition from a net importer to a net exporter of natural gas

Much of the growth in natural gas production in the *AEO2012* Reference case results from the application of recent technological advances and continued drilling in shale plays with high concentrations of natural gas liquids and crude oil, which have a higher value than dry natural gas in energy equivalent terms. Shale gas production increases in the Reference case from 5.0 trillion cubic feet per year in 2010 (23 percent of total U.S. dry gas production) to 13.6 trillion cubic feet per year in 2035 (49 percent of total U.S. dry gas production). As with tight oil, when looking forward to 2035, there are unresolved uncertainties surrounding the technological advances that have made shale gas production a reality. The potential impact of those uncertainties results in a range of outcomes for U.S. shale gas production from 9.7 to 20.5 trillion cubic feet per year when looking forward to 2035.

As a result of the projected growth in production, U.S. natural gas production exceeds consumption early in the next decade in the Reference case (Figure 4). The outlook reflects increased use of liquefied natural gas in markets outside North America, strong growth in domestic natural gas production, reduced pipeline imports and increased pipeline exports, and relatively low natural gas prices in the United States.

Power generation from renewables and natural gas continues to increase

In the Reference case, the natural gas share of electric power generation increases from 24 percent in 2010 to 28 percent in 2035, while the renewables share grows from 10 percent to 15 percent. In contrast, the share of generation from coal-fired power plants declines. The historical reliance on coal-fired power plants in the U.S. electric power sector has begun to wane in recent years.

Figure 3. Total U.S. petroleum and other liquids production, consumption, and net imports, 1970-2035 (million barrels per day)

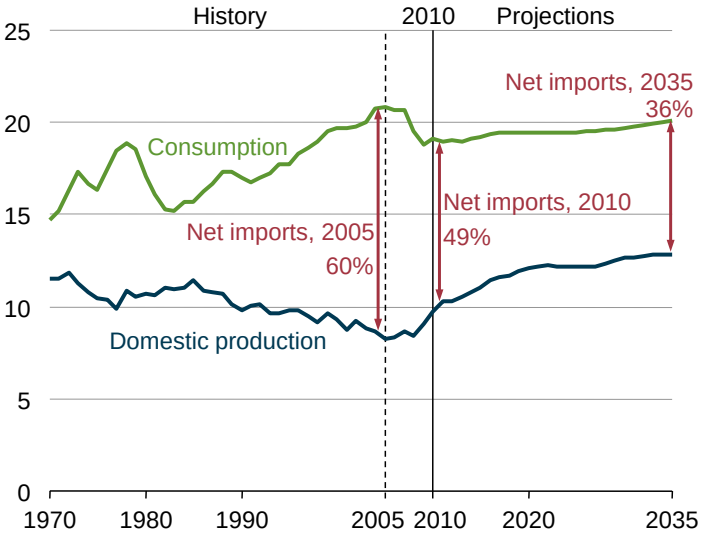
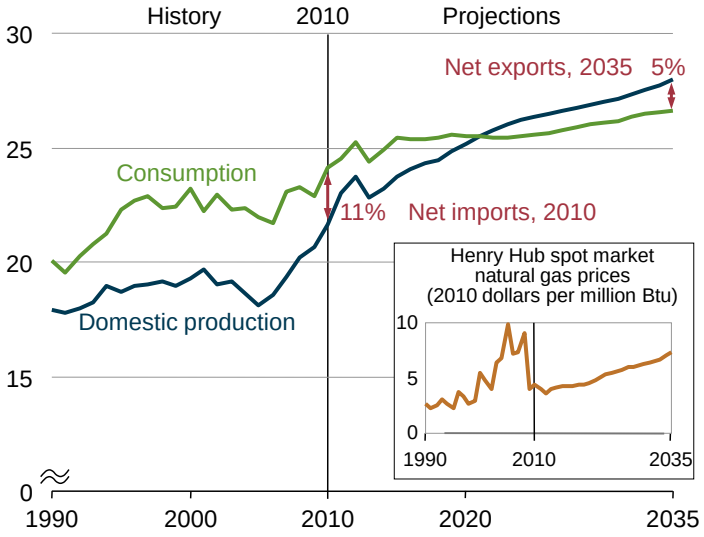


Figure 4. Total U.S. natural gas production, consumption, and net imports, 1990-2035 (trillion cubic feet)



Over the next 25 years, the share of electricity generation from coal falls to 38 percent, well below the 48-percent share seen as recently as 2008, due to slow growth in electricity demand, increased competition from natural gas and renewable generation, and the need to comply with new environmental regulations. Although the current trend toward increased use of natural gas and renewables appears fairly robust, there is uncertainty about the factors influencing the fuel mix for electricity generation. *AEO2012* includes several cases examining the impacts on coal-fired plant generation and retirements resulting from different paths for electricity demand growth, coal and natural gas prices, and compliance with upcoming environmental rules.

While the Reference case projects 49 gigawatts of coal-fired generation retirements over the 2011 to 2035 period, nearly all of which occurs over the next 10 years, the range for cumulative retirements of coal-fired power plants over the projection period varies considerably across the alternative cases (Figure 5), from a low of 34 gigawatts (11 percent of the coal-fired generator fleet) to a high of 70 gigawatts (22 percent of the fleet). The high end of the range is based on much lower natural gas prices than those assumed in the Reference case; the lower end of the range is based on stronger economic growth, leading to stronger growth in electricity demand and higher natural gas prices. Other alternative cases, with varying assumptions about coal prices and the length of the period over which environmental compliance costs will be recovered, but no assumption of new policies to limit GHG emissions from existing plants, also yield cumulative retirements within a range of 34 to 70 gigawatts. Retirements of coal-fired capacity exceed the high end of the range (70 gigawatts) when a significant GHG policy is assumed (for further description of the cases and results, see "Issues in focus").

Total energy-related emissions of carbon dioxide in the United States remain below their 2005 level through 2035

Energy-related carbon dioxide (CO_2) emissions grow slowly in the *AEO2012* Reference case, due to a combination of modest economic growth, growing use of renewable technologies and fuels, efficiency improvements, slow growth in electricity demand, and increased use of natural gas, which is less carbon-intensive than other fossil fuels. In the Reference case, which assumes no explicit Federal regulations to limit GHG emissions beyond vehicle GHG standards (although State programs and renewable portfolio standards are included), energy-related CO_2 emissions grow by just over 2 percent from 2010 to 2035, to a total of 5,758 million metric tons in 2035 (Figure 6). CO_2 emissions in 2020 in the Reference case are more than 9 percent below the 2005 level of 5,996 million metric tons, and they still are below the 2005 level at the end of the projection period. Emissions per capita fall by an average of 1.0 percent per year from 2005 to 2035.

Projections for CO_2 emissions are sensitive to such economic and regulatory factors due to the pervasiveness of fossil fuel use in the economy. These linkages result in a range of potential GHG emissions scenarios. In the *AEO2012* Low and High Economic Growth cases, projections for total primary energy consumption in 2035 are, respectively, 100.0 quadrillion Btu (6.4 percent below the Reference case) and 114.4 quadrillion Btu (7.0 percent above the Reference case), and projections for energy-related CO_2 emissions in 2035 are 5,356 million metric tons (7.0 percent below the Reference case) and 6,117 million metric tons (6.2 percent above the Reference case).

Figure 5. Cumulative retirements of coal-fired generating capacity, 2011-2035 (gigawatts)

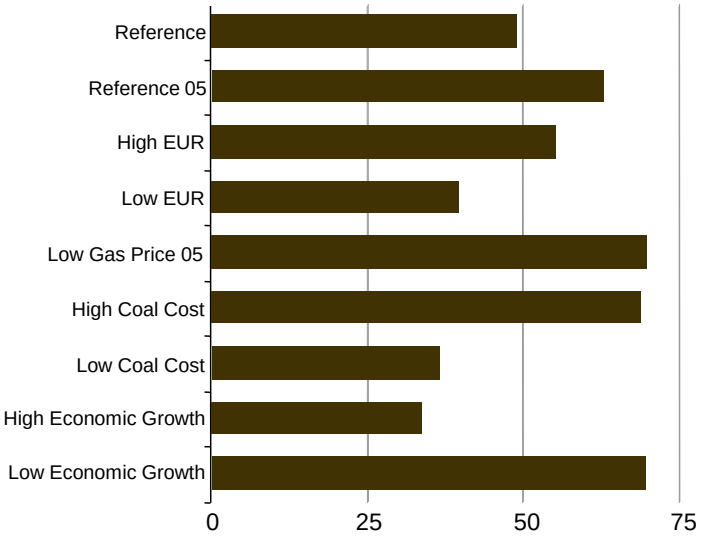
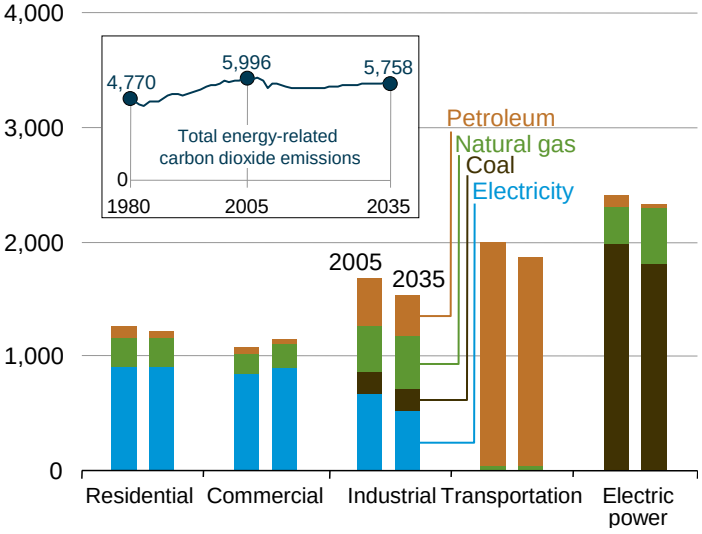


Figure 6. U.S. energy-related carbon dioxide emissions by sector and fuel, 2005 and 2035 (million metric tons)



Legislation and regulations

Introduction

The *Annual Energy Outlook 2012 (AEO2012)* generally represents current Federal and State legislation and final implementation regulations available as of the end of December 2011. The *AEO2012* Reference case assumes that current laws and regulations affecting the energy sector are largely unchanged throughout the projection period (including the implication that laws that include sunset dates do, in fact, become ineffective at the time of those sunset dates) [*5*]. The potential impacts of proposed legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in the *AEO2012* Reference case, but some are considered in alternative cases. This section summarizes Federal and State legislation and regulations newly incorporated or updated in *AEO2012* since the completion of the *Annual Energy Outlook 2011.*

Examples of recently enacted Federal and State legislation and regulations incorporated in the *AEO2012* Reference case include:

- New greenhouse gas (GHG) emissions and fuel consumption standards for medium- and heavy-duty engines and vehicles, published by the U.S. Environmental Protection Agency (EPA) and the National Highway Transportation Safety Administration (NHTSA) in September 2011 [*6*]
- The Cross-State Air Pollution Rule (CSAPR), as finalized by the EPA in July 2011 [*7*]
- Mercury and Air Toxics Standards (MATS) rule, issued by the EPA in December 2011 [*8*].

There are many other pieces of legislation and regulation that appear to have some probability of being enacted in the not-too-distant future, and some laws include sunset provisions that may be extended. However, it is difficult to discern the exact forms that the final provisions of pending legislation or regulations will take, and sunset provisions may or may not be extended. Even in situations where existing legislation contains provisions to allow revision of implementing regulations, those provisions may not be exercised consistently. Many pending provisions are examined in alternative cases included in *AEO2012* or in other analyses completed by the U.S. Energy Information Administration (EIA). In addition, at the request of the Administration and Congress, EIA has regularly examined the potential implications of proposed legislation in Service Reports. Those reports can be found on the EIA website at www.eia.gov/oiaf/service_rpts.htm.

1. Greenhouse gas emissions and fuel consumption standards for heavy-duty vehicles, model years 2014 through 2018

On September 15, 2011, the EPA and NHTSA jointly announced a final rule, called the HD National Program [*9*], which for the first time established GHG emissions and fuel consumption standards for on-road heavy-duty trucks with a gross vehicle weight rating (GVWR) above 8,500 pounds (Classes 2b through 8) [*10*] and their engines. The *AEO2012* Reference case incorporates the new standards for heavy-duty vehicles (HDVs).

Due to the tremendous diversity of HDV uses, designs, and power requirements, the HD National Program separates GHG and fuel consumption standards into discrete vehicle categories within combination tractors, vocational vehicles, and heavy-duty pickups and vans (Table 1). Further, the rule recognizes that reducing GHG emissions and fuel consumption will require changes to both the engine and the body of a vehicle (to reduce the amount of work demanded by an engine). The final rule sets separate standards for the different engines used in combination tractors and vocational vehicles. *AEO2012* represents standard compliance among HDV regulatory classifications that represent the discrete vehicle categories set forth in the rule.

The HD National Program standards begin for model year (MY) 2014 vehicles and engines and are fully phased in by MY 2018. The EPA, under authority granted by the Clean Air Act, has issued GHG emissions standards that begin with MY 2014 for all engine and body categories. NHTSA, operating under regulatory timelines mandated by the Energy Independence and Security Act [*11*], set voluntary fuel consumption standards for MY 2014 and 2015, with the standards becoming mandatory for MY 2016 and beyond, except for diesel engine standards, which become mandatory for MY 2017 and beyond. Standards reach the most stringent levels for combination tractors and vocational vehicles in MY 2017, with subsequent standards then holding constant. Heavy-duty pickup and van standards are required to reach the highest level of stringency in MY 2018. *AEO2012* includes the HD

Table 1. HD National Program vehicle regulatory categories

Category	Description	GVWR
Combination tractors	Combination tractors are semi trucks designed to pull trailers. Standards are set separately for tractor cabs and their engines. There are no GHG or fuel consumption standards for trailers.	Class 7 and 8 (26,001 pounds and above)
Vocational vehicles	Vocational vehicles include a wide range of truck configurations, such as delivery, refuse, utility, dump, cement, fire, and tow trucks, school buses, and ambulances. The rulemaking defines vocational vehicles as all heavy-duty trucks that are not combination tractors or heavy-duty pickups or vans. Vocational vehicle standards are set separately for chassis and engines.	Class 2b through 8 (8,501 pounds and above)
Heavy-duty pickups and vans	Pickup trucks and vans are primarily 3/4-ton or 1-ton pickups used on construction sites or 12- to 15-person passenger vans.	Class 2b and 3 (8,501 to 14,000 pounds)

National Program standards beginning in MY 2014 as set by the GHG emissions portion of the rule, with standards represented by vehicle, including both the chassis and engine. *AEO2012* assumes that vehicle chassis and engine manufacturers comply with the voluntary portion of the rule covering the fuel consumption standard. *AEO2012* does not model the chassis and engine standards separately but allows the use of technologies to meet the HD National Program combined engine and chassis standards.

Although they are not modeled separately in *AEO2012*, GHG emission and fuel consumption standards for combination tractors are set for the tractor cabs and the engines used in those cabs separately in the HD National Program. Combination tractor cab standards are subdivided by GVWR (Class 7 or 8), cab type (day or sleeper), and roof type (low, mid, or high). Combination tractor engine standards are subdivided into medium heavy-duty diesel (for use in Class 7 tractors) and heavy heavy-duty diesel (for use in Class 8 tractors) (Table 2). Each tractor cab and engine combination is required to meet the GHG and fuel consumption standards for a given model year, unless they are made up by credits or other program flexibilities.

Again, although they are not modeled separately in *AEO2012*, GHG emission and fuel consumption standards for vocational vehicles are set separately in the HD National Program for the vehicle chassis and the engines used in the chassis. Vocational vehicle chassis standards are subdivided in the rule by GVWR (Classes 2b to 5, Classes 6 and 7, and Class 8). Vocational vehicle engine standards are subdivided into light heavy-duty diesel (for use in Classes 2b through 5), medium heavy-duty diesel (for use in Classes 6 and 7), heavy heavy-duty diesel (for use in Class 8), and spark-ignited (primarily gasoline) engines (for use in all classes) (Table 3). Each vocational vehicle chassis and engine combination is required to meet the GHG and fuel consumption standard for a given model year, unless made up by credits or other program flexibilities.

Standards for heavy-duty pickups and vans are based on the "work factor"—a weighted average of the vehicle's payload and towing capacity, adjusted for four-wheel drive capability. The standards for heavy-duty pickups and vans are different for diesel

Table 2. HD National Program standards for combination tractor greenhouse gas emissions and fuel consumption (assuming fully compliant engine)

	Day cab		Sleeper cab
Roof type	Class 7	Class 8	Class 8
2014 GHG emissions standards (grams CO_2 per ton-mile)			
Low roof	107	81	68
Mid roof	119	88	76
High roof	124	92	75
2014-2016 voluntary fuel consumption standards (gallons per 1,000 ton-miles)			
Low roof	10.5	8.0	6.7
Mid roof	11.7	8.7	7.4
High roof	12.2	9.0	7.3
2017 GHG emissions standards (grams CO_2 per ton-mile)			
Low roof	104	80	66
Mid roof	115	86	73
High roof	120	89	72
2017 fuel consumption standards (gallons per 1,000 ton-miles)			
Low roof	10.2	7.8	6.5
Mid roof	11.3	8.4	7.2
High roof	11.8	8.7	7.1

Table 3. HD National Program standards for vocational vehicle greenhouse gas emissions and fuel consumption (assuming fully compliant engine)

Standard	Light heavy-duty (Classes 2b-5)	Medium heavy-duty (Classes 6-7)	Heavy heavy-duty (Class 8)
2014 GHG emissions standard (grams CO_2 per ton-mile)	388	234	226
2016 fuel consumption standard (gallons per 1,000 ton-miles)	38.1	23.0	22.2
2017 GHG emissions standards (grams CO_2 per ton-mile)	373	225	222
2017 fuel consumption standard (gallons per 1,000 ton-miles)	36.7	22.1	21.8

and gasoline engines (Figures 7 and 8). They differ from the standards for combination tractors and vocational vehicles in that they apply to the vehicle fleet average for each manufacturer for a given model year, based on a production volume-weighted target for each model, with targets differing by work factor attribute.

The final rulemaking exempts small manufacturers of heavy-duty engines, combination tractor cabs, or vocational vehicle chassis from the GHG emissions and fuel consumption standards. Fuel consumption and GHG emissions for alternative-fuel vehicles, such as compressed natural gas vehicles, will be calculated according to their tailpipe emissions. Finally, the rulemaking contains four provisions designed to give manufacturers flexibility in meeting the GHG and fuel consumption standards. Both the EPA and NHTSA will allow for early compliance credits in MY 2013; manufacturer averaging, banking, and trading; advanced technology credits; and innovative technology credits. Those flexibility provisions are not included in the *AEO2012* Reference case.

2. Cross-State Air Pollution Rule

The CSAPR was created to regulate emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from power plants greater than 25 megawatts that generate electric power from fossil fuels. CSAPR is intended to assist States in achieving their National Ambient Air Quality Standards for fine particulate matter and ground-level ozone. Limits on annual emissions of SO_2 and NO_x are designed to address fine particulate matter. The seasonal NO_x limits address ground-level ozone. Twenty-three States are subject to the annual limits, and 25 States are subject to the seasonal limits [*12*].

CSAPR replaces the Clean Air Interstate Rule (CAIR). CAIR is an interstate emissions cap-and-trade program for SO_2 and NO_x that would have allowed for unlimited trading among 28 eastern States. It was finalized in 2005, and requirements for emissions reductions were scheduled to begin 2009. In 2008, however, the U.S. Court of Appeals for the D.C. Circuit found that CAIR did not sufficiently meet the Clean Air Act requirements and directed the EPA to fix the flaws that it identified while CAIR remained in effect.

In July 2011, the EPA published CSAPR, with State coverage as shown in Figure 9. CSAPR consists of four individual cap-and-trade programs:

- Group 1 SO_2 covers 16 States.
- Group 2 SO_2 covers 7 States [*13*].
- Annual NO_x Group consists of an annual cap-and-trade program that covers all Group 1 and Group 2 SO_2 States.
- Seasonal NO_x Group covers a separate set of States, 20 of which are also in the Annual NO_x Group and 5 of which are not.

There are two SO_2 control groups, because the EPA has determined that the States in Group 1 need to meet more stringent emissions reduction requirements.

All cap-and-trade programs specified in CSAPR are included in *AEO2012*, but because the National Energy Modeling System (NEMS) does not represent electric power markets at the State level, the four group emissions caps and corresponding allowance trading could not be explicitly represented. The cap-and-trade systems for annual SO_2 and NO_x emissions are implemented for the coal demand regions by aggregating the allowance budget for each State within a region.

Figure 7. HD National Program model year standards for diesel pickup and van greenhouse gas emissions and fuel consumption, 2014-2018

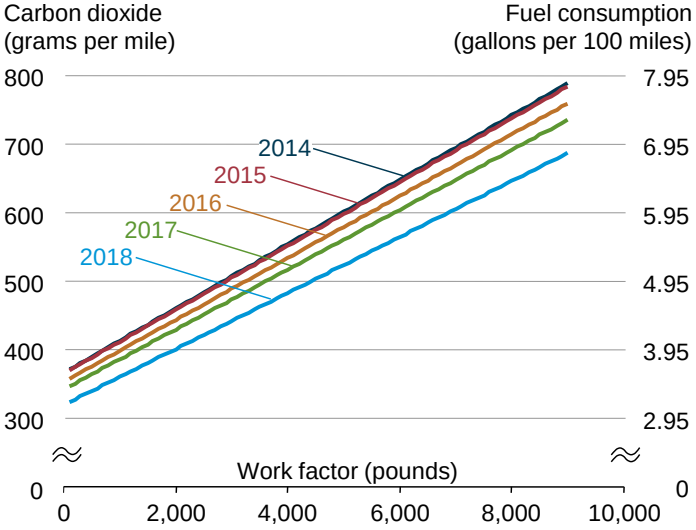
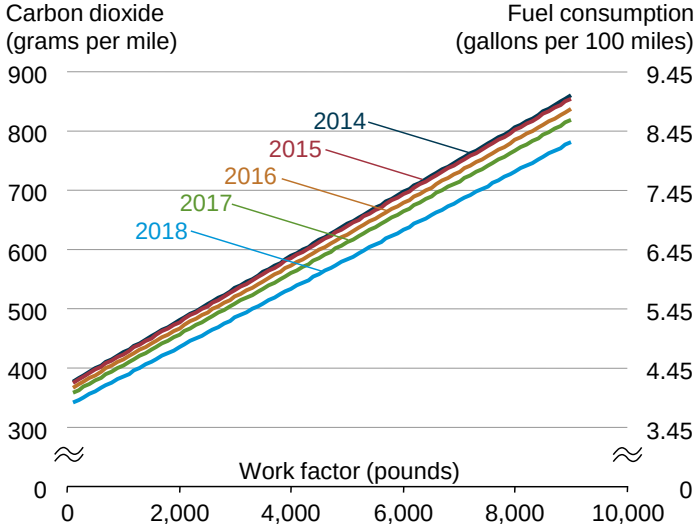


Figure 8. HD National Program model year standards for gasoline pickup and van greenhouse gas emissions and fuel consumption, 2014-2018



The EPA scheduled three annual cap-and-trade programs to commence in January 2012 and the summer season NO_x program to begin in May 2012. For three of the four programs, the initial annual cap does not change over time. For the Group 1 SO_2 program, the emissions cap across States is reduced substantially in 2014.

Emissions trading is unrestricted within a group but is not allowed across groups. Therefore, emissions allowances exist for four independent trading programs. Each State is designated an annual emissions budget, with the sum of the budgets making up the overall group emissions cap. Sources can collectively exceed State emissions budgets by close to 20 percent without any penalty. If the sources collectively exceed the State emission budget by more than the 20 percent, the sources responsible must "pay a penalty" in addition to submitting the additional allowances. The EPA set the penalties with the goal of ensuring that emissions produced by upwind States would not exceed assurance levels and contribute to air quality problems in downwind States. The emissions allowances are allocated to generating units primarily on the basis of historical energy use.

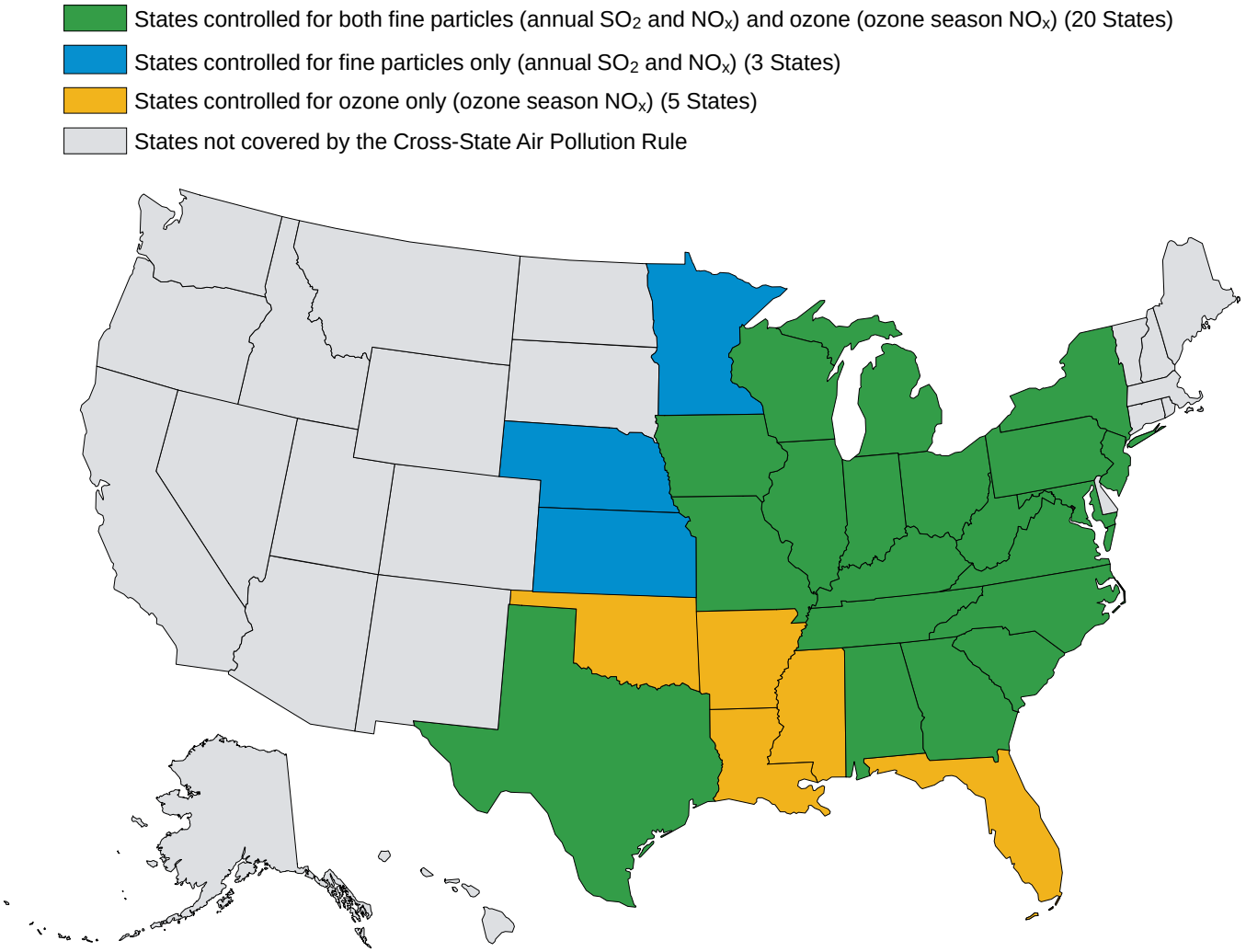
CSAPR was scheduled to begin on January 1, 2012, but the Court of Appeals issued a stay that is delaying implementation while it addresses legal challenges to the rule that have been raised by several power companies and States [*14*]. CSAPR is included in *AEO2012* despite the stay, because the Court of Appeals had not made a final ruling at the time *AEO2012* was completed.

3. Mercury and air toxics standards

The MATS [*15*] are required by Section 112 of the 1990 Clean Air Act Amendments, which requires that maximum achievable control technology be applied to power plants to control emissions of hazardous air pollutants (HAPs) [*16*]. The MATS rule, finalized in December 2011, regulates mercury (Hg) and other HAPs from power plants. MATS applies to Hg and hazardous acid gases, metals, and organics from coal- and oil-fired power plants with nameplate capacities greater than 25 megawatts [*17*]. The standards take effect in 2015.

The *AEO2012* Reference case assumes that all coal-fired generating units with capacity greater than 25 megawatts will comply with the MATS rule beginning in 2015. The MATS rule is not applied to oil-fired steam units in *AEO2012* because of their small size and limited importance. In order to comply with the MATS rule for coal, the NEMS model requires all coal-fired power plants to

Figure 9. States covered by CSAPR limits on emissions of sulfur dioxide and nitrogen oxides



reduce Hg emissions to 90 percent below their uncontrolled emissions levels by using scrubbers and activated carbon injection controls. NEMS does not explicitly model the emissions of acid gases, toxic metals other than Hg, or organic HAPs. Therefore, in order to measure the impact of these rules, specific control technologies—either flue gas desulfurization scrubbers or dry sorbent injection systems—are assumed to be used to achieve compliance. A full fabric filter also is required to meet the limits on emissions of metals other than Hg and to improve the effectiveness of the dry sorbent injection systems. NEMS does not model the best practices associated with reductions in dioxin emissions, which also are covered by the MATS rule.

4. Updated State air emissions regulations

As its first 3-year compliance period came to a close, the Regional Greenhouse Gas Initiative (RGGI) continued to apply to fossil-fuel-fired power plants larger than 25 megawatts capacity in the northeastern United States, despite New Jersey's decision to withdraw from the program at the end of 2011. There are now nine States in the accord, which caps carbon dioxide (CO_2) emissions from covered electricity generating facilities and requires each ton of CO_2 emitted to be offset by an allowance purchased at auction. Because the program is binding, it is included in *AEO2012* as specified in the agreement.

The reduction of CO_2 emissions from the power sector in the RGGI region since 2009 is primarily a result of broader market trends. Since mid-2008, natural gas prices and electricity demand in the Northeast have fallen, while coal prices have increased. Because the RGGI baseline and projected emissions were calculated before the economic recession that began in 2008, the emissions caps are higher than actual emissions have been, leading to an excess of available allowances in recent auctions. In the past seven auctions, allowances have sold at the floor price of $1.89 per ton [*18*], indicating that emissions in the region are at or below the program-mandated ceiling.

As a result of the noncompetitive auctions, in which credits have not actually been traded but simply purchased at a floor price, several States have decided to retire their excess allowances permanently [*19*], which will result in the removal of 67 million tons of CO_2 from the RGGI emissions ceiling. Moreover, the program began a stakeholder hearing process in January 2012 that will last through the summer of 2012. The hearings, which are designed to adjust the program at the end of the first compliance period, may alter the program significantly. Because no changes have been finalized, however, modeling of the provisions in *AEO2012* is the same as in previous *Annual Energy Outlook*s.

The Western Climate Initiative is another program designed to establish a GHG emissions trading program, although the final details of the program remain undecided [*20*]. At the stakeholders meeting in January 2012, the commitment to emissions trading was reaffirmed. Because of the continued uncertainty over the implementation and design of the final program, it is not included in the *AEO2012* projections.

The California cap-and-trade system for GHG emissions, designed by the California Air Resources Board (CARB) in response to California Assembly Bill 32, the Global Warming Solutions Act of 2006 [*21*], is discussed in the following section.

5. California Assembly Bill 32: The Global Warming Solutions Act of 2006

California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, authorized the CARB to set California's GHG reduction goals for 2020 and establish a comprehensive, multi-year program to reduce GHG emissions in California. As one of the major initiatives for AB 32, CARB designed a cap-and-trade program that started on January 1, 2012, with the enforceable compliance obligations beginning in 2013.

The cap-and-trade program is intended to help California achieve its goal of reducing emissions to 1990 levels by 2020. The program covers several GHGs, with the most significant being CO_2 [*22*]. In 2007, CARB determined that 427 million metric tons carbon dioxide equivalent ($MMTCO_2e$) was the total State-wide GHG emissions level in 1990 and, therefore, would be the 2020 emissions target. All electric power plants, large industrial facilities, suppliers of transportation fuel, and suppliers of natural gas in California are required to submit emissions allowances for each ton of CO_2 or CO_2-equivalent emissions they produce, in order to comply with the final rule [*23*]. Emissions resulting from electricity generated outside California but consumed in the State also are subject to the cap.

The cap-and-trade program applies to multiple economic sectors throughout the State's economy, but for *AEO2012*, due to modeling limitations, it is assumed to be implemented only in the electric power sector. *AEO2012* places limits on emissions from electric power plants and cogeneration facilities in California, as well as power plants in other States that sell power to California. The cap is set to begin in 2013 and to decline linearly to 85 percent of the 2013 value by 2020.

The enforceable cap goes into effect in 2013, and there are three compliance periods—multi-year periods for which the compliance obligation is calculated for covered entities. The first compliance period lasts for 2 years, and the second and third periods last for 3 years each, as follows:

- Compliance Period 1: 2013-2014
- Compliance Period 2: 2015-2017
- Compliance Period 3: 2018-2020.

The electricity and industrial sectors are required to comply with the cap starting in 2013. Suppliers of natural gas and transportation fuels are required to comply starting in 2015, when the second compliance period begins. For the first compliance period, covered entities are required to submit allowances for up to 30 percent of their annual emissions in each year; however, at the end of 2014 they are required to account for all the emissions for which they were responsible during the 2-year period.

Annual GHG allowance budgets for the State (i.e., emissions caps) are set by the final rule [*24*] as follows: for 2013, 162.8 $MMTCO_2e$; for 2014, 159.7 $MMTCO_2e$; for 2015, 394.5 $MMTCO_2e$; for 2016, 382.4 $MMTCO_2e$; for 2017, 370.4 $MMTCO_2e$; for 2018, 358.3 $MMTCO_2e$; for 2019, 346.3 $MMTCO_2e$; and for 2020, 334.2 $MMTCO_2e$.

A majority of the allowances (51 percent) [*25*] allocated over the initial 8 years of the program will be distributed through auctions, which will be held quarterly when the program commences. Auctions are set to begin in 2012, and the program caps will take effect in 2013. Revenue gained from the auctions is intended to be used for purposes related to AB 32, as determined by the Governor and the State Legislature.

Twenty-five percent of the allowances are allocated directly to electric utilities that sell electricity to consumers in the State. The utilities are then required to put their allowances up for auction and use the revenue generated from the auction to credit ratepayers. An exception is made for public power agencies, which will be able to keep allowances for compliance.

Seventeen percent of the allowances are allocated directly to industrial facilities covered by the rule, in order to mitigate the economic impact of the cap on the industrial sector. Over the 2013-2020 period, the number of allowances allocated annually to the industrial sector declines linearly, by a total of 50 percent.

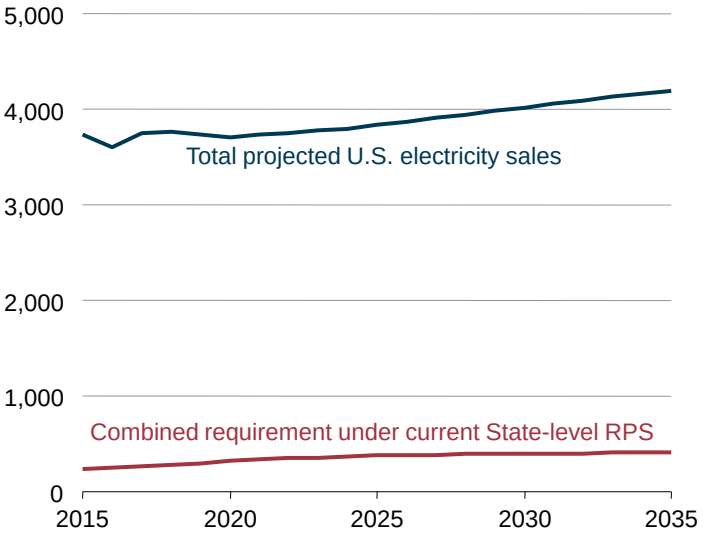
The remaining 7 percent of the allowances issued in a given year go into a cost containment reserve and forward reserve auction. The cost containment reserve is intended to be called on only if allowance prices rise above a set amount. Each entity can also use offsets to meet up to 8 percent of its compliance obligation. Offsets used as part of the program must be approved by the CARB.

6. State renewable energy requirements and goals: Update through 2011

To the extent possible, *AEO2012* incorporates the impacts of State laws requiring the addition of renewable generation or capacity by utilities doing business in the States. Currently, 30 States and the District of Columbia have an enforceable renewable portfolio standard (RPS) or similar laws (Table 4). Under such standards, each State determines its own levels of renewable generation, eligible technologies [*26*], and noncompliance penalties. *AEO2012* includes the impacts of all laws in effect at the end of 2011 (with the exception of Alaska and Hawaii, because NEMS provides electricity market projections for the contiguous lower 48 States only). However, the projections do not include policies with either voluntary goals or targets that can be substantially satisfied with nonrenewable resources. In addition, the model is not able to treat fuel-specific provisions—such as those for solar and offshore wind energy—as distinct targets. Where applicable, these distinct targets (sometimes referred to as "tiers," "set-asides," or "carve-outs") may be subsumed into the broader targets, or are not modeled because they may be met with existing capacity and/or projected growth based on modeled economic and policy factors.

In the *AEO2012* Reference case, States generally are assumed to meet their ultimate RPS targets. The RPS compliance constraint in most regions is approximated, because NEMS is not a State-level model, and each State generally represents only a portion of one of the NEMS electricity regions. Compliance costs in each region are tracked, and the projection for total renewable generation is checked for consistency with any State-level cost-control provisions, such as caps on renewable credit prices, limits on State compliance funding, or impacts on consumer electricity prices. In general, EIA has confirmed the States' requirements through original documentation, although the Database of State Incentives for Renewables & Efficiency was also used to support those efforts [*27*].

Figure 10. Total combined requirement for State renewable portfolio standards, 2015-2035 (billion kilowatthours)



No new RPS programs were enacted over the past year; however, some States with existing RPS programs made modifications in 2011. The aggregate RPS requirement for the various State programs, as modeled in *AEO2012*, is shown in Figure 10. By 2025, these targets account for about 10 percent of U.S. sales. The requirement is derived from the legal targets and projected sales, and does not account for any discretionary or nondiscretionary waivers or limits on compliance found in most State RPS programs. State RPS policies are not the only driver of growth in renewable generation, and a more complete discussion of those factors can be found in "Market trends." The following sections detail the significant changes made by the States. In addition, Table 4 provides a summary of all State RPS laws.

Table 4. Renewable portfolio standards in the 30 States with current mandates

State	Program mandate
AZ	Arizona Corporate Commission Decision No. 69127 requires 15 percent of electricity sales to be renewable by 2025, with interim goals increasing annually. A specific percentage of the target must be from distributed generation. Multiple credits may be provided to solar generation and systems manufactured in-State.
CA	SBX1-2, enacted in 2011, requires that 33 percent of electricity sales be met by renewable sources by 2020. The legislation codifies the 33 percent requirement in Executive Order S-21-09, which served as a continuation of California's first RPS, in which investor-owned utilities (IOUs) were required to deliver 20 percent of sales from renewable sources. Under SBX1-2, both IOUs and publicly owned municipal utilities are subject to the RPS.
CO	Enacted in March of 2010, House Bill (HB) 1001 strengthens the State's existing RPS program by requiring that 20 percent of electricity generated by IOUs in 2015 be renewable, increasing to 30 percent in 2020. There is also a distributed generation requirement. In-State generation receives a 25-percent credit premium.
CT	Public Act 07-242 mandates a 27-percent renewable sales requirement by 2020, including a 4-percent mandate for higher efficiency or combined heat and power systems. Of the overall total, 3 percent may be met by waste-to-energy and conventional biomass facilities.
DE	Senate Substitute 1 amended Senate Bill (SB) 119 to extend the increasing RPS targets to 2025; 25 percent of generation is now required to come from renewable sources in 2025. There is a separate requirement for solar generation (3.5 percent of the total in 2025), and there are penalty payments for compliance failure. Offshore wind generation receives 3.5 times the credit amount, and solar technologies receive 3 times the credit amount.
HI	HB 1464 sets the renewable mandate at 40 percent by 2030. All existing renewable facilities are eligible to meet the target, which has two interim milestones. (Not included in NEMS.)
IL	Public Act 095-0481 created an agency responsible for overseeing the mandate of 25-percent renewable sales by 2025, with escalating annual targets. In addition, 75 percent of the required sales must be generated from wind, 6 percent from solar, and 1 percent from distributed generation. The plan also includes a cap on the incremental costs resulting from the penetration of renewable generation. In 2009, the rule was modified to cover sales outside a utility's home territory.
IA	In 1983, a capacity mandate of 105 megawatts of renewable energy capacity was adopted. By the end of 2010, Iowa had well over 3,000 megawatts of wind-powered capacity alone.
KS	In 2009, HB 2369 established a requirement that 20 percent of installed capacity must use renewable resources by 2020.
ME	In 2007, Public Law 403 was added to the State's RPS requirements. The law requires that 10 percent of sales come from new renewable capacity by 2017, and that level must be maintained in subsequent years. The years leading up to 2017 also have new generation milestones. Generation from eligible community-owned facilities receives a 10-percent credit premium.
MD	In April 2008, HB 375 revised the preceding RPS to contain a 20-percent target by 2022, including a 2-percent solar target. HB 375 also raised penalty payments for "Tier 1" compliance shortfalls to 4 cents per kilowatthour. SB 277, while preserving the 2-percent by 2022 solar target, made the interim solar requirements and penalty payments slightly less stringent. In 2011, SB 717 extended the eligibility of the solar target to include solar water heating systems.
MA	The State RPS has a goal of a 15-percent renewable share of total sales by 2020 and includes necessary payments for compliance shortfalls. Eligible biomass is restricted to low-carbon life cycle emission sources. A Solar Carve-Out Program was also added, which seeks to establish 400 megawatts of solar generating capacity.
MI	Public Act 295, enacted in 2008, established an RPS that will require 10 percent of all electricity sales to be generated from renewable sources by 2015. Double credits are given to solar energy. In addition, the State's large utilities are required to procure an additional combined total of 1,100 megawatts of renewable capacity by 2015, although generation from those facilities may be counted toward the generation-based RPS.
MN	SF 4 created a 30-percent renewable requirement by 2020 for Xcel, the State's largest supplier, and a 25-percent requirement by 2025 for other suppliers. The 30-percent requirement for Xcel consists of 24 percent that must be from wind, 1 percent that can be from wind or solar, and 5 percent that can be from other resources.
MO	In November 2008, Missouri voters approved Proposition C, which mandates a 2-percent renewable energy requirement in 2011, increasing incrementally to 15 percent of generation in 2021. Bonus credits are given to renewable generation within the State.
MT	HB 681, approved in April 2007, expanded the State RPS provisions to all suppliers. Initially the law covered only regulated utilities. A 15-percent share of sales must be renewable by 2015. The State operates a renewable energy credit market.
NV	The State has an escalating renewable target, established in 1997 and most recently revised in 2009 by SB 358, which mandates a 25-percent renewable generation share of sales by 2025. Up to one-quarter of the 25-percent share may be met through efficiency measures. There is also a minimum requirement for photovoltaic systems, which receive bonus credits.

(continued on next page)

Table 4. Renewable portfolio standards in the 30 States with current mandates (continued)

State	Program mandate
NH	HB 873, passed in May 2007, legislated that 23.8 percent of electricity sales must be met by renewables in 2025. Compliance penalties vary by generation type.
NJ	In 2006, the New Jersey Board of Public Utilities revised the State RPS to increase the renewable generation target to 22.5 percent of sales by 2021, with interim targets. Assembly Bill (AB) 3520, enacted in 2010, further refines the mandate to include 5,300 gigawatthours of solar generation by 2026, with the percentage-based RPS component to reach 20.38 percent by 2021, not including the required solar generation. SB 2036 has a specific provision for offshore wind, with a goal to develop 1,100 megawatts of capacity.
NM	SB 418, passed in March 2007, directs investor-owned utilities to derive 20 percent of their sales from renewable generation by 2020. The renewable portfolio must consist of diversified technologies, with wind and solar each accounting for 20 percent of the target. There is a separate standard of 10 percent by 2020 for cooperatives.
NY	The Public Service Commission issued updated RPS rules in January 2010 that expand the program to a 30-percent requirement by 2015. There is also a separate end-use standard. The program is administered and funded by the State.
NC	In 2007, SB 3 created an RPS of 12.5 percent by 2021 for investor-owned utilities. There is also a 10-percent requirement by 2018 for cooperatives and municipals. Through 2018, 25 percent of the target may be met through efficiency standards, increasing to 40 percent in later years. Verifiable electricity demand reduction can also satisfy the RPS, with no upper limit.
OH	SB 221, passed in May 2008, requires 25 percent of electricity sales to be produced from alternative energy resources by 2025, including low-carbon and renewable technologies. One-half of the target must come from renewable sources. Municipals and cooperatives are exempt.
OR	SB 838, signed into law in June 2007, requires that renewable generation account for 25 percent of sales by 2025 for large utilities, and 5 to 10 percent of sales by 2025 for smaller utilities. Renewable electricity on line after 1995 is considered eligible.
PA	The Alternative Energy Portfolio Standard, signed into law in November 2004, has an 18-percent requirement by 2020. Most of the qualifying generation must be renewable, but there is also a provision that allows waste coal resources to receive credits.
RI	The Renewable Energy Standard was signed into law in 2004. The program requires that 16 percent of total sales be renewable by 2019. The interim program targets escalate more rapidly in later years. If the target is not met, a generator must pay an alternative compliance penalty. State utilities also must procure 90 megawatts of new renewable capacity, including 3 megawatts of solar, by 2014.
TX	SB 20, passed in August 2005, strengthened the State RPS by mandating 5,880 megawatts of renewable capacity by 2015. There is also a target of 500 megawatts of renewable capacity other than wind.
WA	In November 2006, Washington voters approved Initiative 937, which specifies that 15 percent of sales from the State's largest generators must come from renewable sources by 2020. There is an administrative penalty of 5 cents per kilowatthour for noncompliance. Generation from any otherwise qualified facility that came on line after 1999 is eligible.
WV	HB 103, passed in June 2009, established a requirement that 25 percent of electricity sales must come from alternative energy resources by 2025. Alternative energy was defined to include various renewables, along with several different fossil energy technologies.
WI	SB 459, passed in March 2006, strengthened the State RPS with a requirement that, by 2015, 10 percent of electricity sales must be generated from renewable resources, and that the renewable share of total generation must be at least 6 percentage points above the average renewable share from 2001 to 2003.

California

The State codified its RPS of 33 percent by 2020 through the passage of SBX1-2, the California Renewable Energy Resources Act [*28*]. The California Public Utilities Commission and California Energy Commission are the primary implementing authorities for SBX1-2, which builds on California's prior RPS mandate for 20 percent of electricity sales by 2010 [*29*]. SBX1-2 extends the application of the RPS to local publicly owned utilities, which had greater flexibility under the State's previous RPS mandate. SBX1-2 supersedes the 2009 Executive Order that charged the CARB with implementing the 33-percent RPS; however, CARB does retain an enforcement role over publicly owned local utilities. Because implementing regulations were not available at the time the *AEO2012* projections were being developed, the 2009 Executive Order was modeled. Although the targets specified in the two programs are similar, enforcement mechanisms may differ significantly.

Connecticut

Public Act 11-80 adds a solar-specific component to the existing RPS target, which requires that renewables should account for 27 percent of sales by 2020 [*30*]. The State's Clean Energy Finance and Investment Authority is tasked with creating an investment program that will result in the procurement of 30 megawatts of residential solar installations that can be counted toward the general RPS requirement.

Delaware

Delaware enacted SB 124, which extends the list of sources eligible to meet the State's RPS to include fuel cells under certain conditions [*31*]. Fuel cell projects that can be fueled by renewable sources and that are owned or operated by qualified providers can apply to earn renewable energy credits and, on a limited basis, solar renewable energy credits.

Illinois

With the enactment of SB 1652, the State augmented its existing RPS to include a distributed generation requirement [*32*]. SB 1652 requires that 1 percent of the renewable target (25 percent of sales from renewable sources by 2025 for large utilities) be fulfilled by distributed generation by mid-2015, with incremental targets beginning to take effect in 2013.

Maryland

The State enacted two pieces of legislation that allow for additional flexibility in meeting the existing RPS target of 20 percent of sales from renewable generation by 2022. SB 690 extends the designation of waste-to-energy facilities as qualifying to meet the 20-percent target beyond 2022, rather than sunsetting [*33*]. In addition, SB 717 specifies that solar water heating systems may also fulfill the solar set-aside requirement, which requires that solar sources account for 2 percent of electricity sales by 2022 [*34*].

North Carolina

North Carolina enacted SB 75, which allows reductions in electricity demand to qualify toward meeting the State's existing renewable energy and energy efficiency portfolio standard. The legislation defines electricity demand reduction as a "measureable reduction in the electricity demand of a retail electric customer that is voluntary, under the real-time control of both the electric power supplier and the retail electric customer, and measured in real time, using two-way communications devices that communicate on the basis of standards" [*35*]. There is no upper limit on the portion of the RPS requirement that can be met by electricity demand reduction.

7. California low carbon fuel standard

The Low Carbon Fuel Standard (LCFS), administered by the CARB [*36*], was signed into law in January 2010. Regulated parties under the legislation generally are the fuel producers and importers who sell motor gasoline or diesel fuel in California. The LCFS legislation is designed to reduce the carbon intensity (CI) of motor gasoline and diesel fuels sold in California by 10 percent between 2012 and 2020 through the increased sale of alternative "low-carbon" fuels. Each alternative low-carbon fuel has its own CI, based on life-cycle analyses conducted under the guidance of CARB for a number of approved fuel pathways. The CIs are calculated on an energy-equivalent basis, measured in grams of CO_2 equivalent emissions per megajoule.

In December 2011, the U.S. District Court for the Eastern Division of California ruled in favor of several trade groups that claimed the LCFS violated the interstate commerce clause of the U.S. Constitution by seeking to regulate farming and ethanol production practices in other States, and granted an injunction blocking enforcement by CARB [*37*]. The future of the LCFS program remains uncertain. After the initial ruling, a request for a stay of the injunction was quickly filed by CARB, which would have allowed the LCFS to remain in place during the appeal process; however, that request was denied by the same judge who initially blocked enforcement of the LCFS [*38*]. A new request for a stay of injunction while CARB appeals the original ruling was filed with the U.S. Ninth District Court of Appeals and was granted as of April 23, 2012 [*39*]. A decision on the appeal filed by CARB is yet to be made. As a result of the initial ruling's timing, along with EIA's prior completion of modeling efforts, the LCFS is not included in the *AEO2012* Reference case [*40*].

Endnotes for Legislation and regulations

Links current as of June 2012

5. A complete list of the laws and regulations included in *AEO2012* is provided in *Assumptions to the Annual Energy Outlook 2012*, Appendix A, website www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2012).pdf.
6. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *Federal Register*, Vol. 76, No. 179 (Washington, DC: September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.
7. U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)," website epa.gov/airtransport.
8. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," website www.epa.gov/mats.
9. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *Federal Register*, Vol. 76, No. 179 (Washington, DC: September 15, 2011), website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.
10. For purposes of this final rulemaking, heavy-duty trucks are those with a gross vehicle weight rating of at least 8,501 pounds, except those Class 2 b vehicles of 8,501 to 10,000 pounds that are currently covered under light-duty vehicle fuel economy and greenhouse gas emissions standards.
11. Congressional Research Service, *Energy Independence and Security Act of 2007: A Summary of Major Provisions*, Order Code RL34294 (Washington, DC: December 2007), website www.seco.noaa.gov/Energy/2007_Dec_21_Summary_Security_Act_2007.pdf.
12. U.S. Environmental Protection Agency, *Cross-State Air Pollution Rule: Reducing Air Pollution, Protecting Public Health* (Washington, DC: December 15, 2011), website www.epa.gov/airtransport/pdfs/CSAPRPresentation.pdf.
13. U.S. Environmental Protection Agency, *Cross-State Air Pollution Rule: Reducing Air Pollution, Protecting Public Health* (Washington, DC: December 15, 2011), Slide 3, website www.epa.gov/airtransport/pdfs/CSAPRPresentation.pdf.
14. T. Schoenberg, B. Wingfield, and J. Johnsson, "EPA Cross-State Emissions Rule Put on Hold by Court," *Bloomberg Businessweek* (January 4, 2012), website www.businessweek.com/news/2012-01-04/epa-cross-state-emissions-rule-put-on-hold-by-court.html.
15. The *AEO2012* Early Release Reference case was prepared before the final MATS rule was issued and, therefore, did not include MATS.
16. U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units," *Federal Register*, Vol. 77, No. 32 (Washington, DC: February 16, 2012), pp. 9304-9513, website www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf.
17. The Clean Air Act, Section 112(a)(8), defines an electric generating unit.
18. Regional Greenhouse Gas Initiative, "CO_2 Auctions, Tracking & Offsets," website www.rggi.org/market.
19. M. Navarro, "Regional Cap-and-Trade Effort Seeks Greater Impact by Cutting Carbon Allowances," *The New York Times* (January 26, 2012), website www.nytimes.com/2012/01/27/nyregion/in-greenhouse-gas-initiative-many-unsold-allowances.html?_r=2.
20. Western Climate Initiative, *WCI Emissions Trading Program Update* (San Francisco, CA: January 12, 2012), website www.westernclimateinitiative.org/document-archives/Partner-Meeting-Materials/Jan-12-Stakeholder-Update-Presentation/%20.
21. California Code of Regulations, Subchapter 10 Climate Change, Article 5, Sections 95800 to 96023, Title 17, "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms" (Sacramento, CA: July 2011), website www.arb.ca.gov/regact/2010/capandtrade10/candtmodreg.pdf.
22. California Code of Regulations, Subchapter 10 Climate Change, Article 5, Sections 95800 to 96023, Title 17, "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms" (Sacramento, CA: July 2011), website www.arb.ca.gov/regact/2010/capandtrade10/candtmodreg.pdf.
23. California Code of Regulations, Subchapter 10 Climate Change, Article 5, Section 95810, "Covered Gases" (Sacramento, CA: July 2011), website www.arb.ca.gov/regact/2010/capandtrade10/candtmodreg.pdf.
24. California Code of Regulations, Subchapter 10 Climate Change, Article 5, Section 95841, "Annual Allowance Budgets for Calendar Years 2013-2020" (Sacramento, CA: July 2011), website www.arb.ca.gov/regact/2010/capandtrade10/candtmodreg.pdf.

25. California Air Resources Board, *Proposed Regulation to Implement the California Cap-and-Trade Program*, Appendix J, "Allowance Allocation" (Sacramento, CA: October 2010), p. 12, website www.arb.ca.gov/regact/2010/capandtrade10/capv4appj.pdf.
26. The eligible technology, and even the definition of the technology or fuel category, will vary by State. For example, one State's definition of renewables may include hydroelectric power generation, while another's definition may not. Table 4 provides more detail on how the technology or fuel category is defined by each State.
27. More information about the Database of State Incentives for Renewables & Efficiency can be found at website www.dsireusa.org/about.
28. State of California, Senate Bill 2, "California Renewable Energy Resources Act" (Sacramento, CA: April 2011), website www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html.
29. State of California, Public Utilities Code, Sections 399.11 to 399.31, website www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=399.11-399.31.
30. State of Connecticut, Public Act 11-80, "An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future" (Hartford, CT: July 1, 2011), website www.cga.ct.gov/2011/ACT/PA/2011PA-00080-R00SB-01243-PA.htm.
31. State of Delaware, Senate Bill 124, "An Act To Amend Title 26 Of The Delaware Code Relating To Delaware's Renewable Energy Portfolio Standards And Delaware-Manufactured Fuel Cells" (Dover, DE: July 7, 2011), website www.legis.delaware.gov/LIS/lis146.nsf/vwLegislation/SB+124/$file/legis.html?open.
32. State of Illinois, Senate Bill 1652, "An Act Concerning Public Utilities" (Springfield, IL: October 26, 2011), website www.ilga.gov/legislation/97/SB/PDF/09700SB1652lv.pdf.
33. State of Maryland, Senate Bill 690, "An Act Concerning Renewable Energy Portfolio – Waste-to-Energy and Refuse-Derived Fuel" (Annapolis, MD: May 29, 2011), website mlis.state.md.us/2011rs/bills/sb/sb0690e.pdf.
34. State of Maryland, Senate Bill 717, "An Act Concerning Renewable Energy Portfolio Standard – Renewable Energy Credits – Solar Water Heating Systems" (Annapolis, MD: May 29, 2011), website http://mlis.state.md.us/2011rs/bills/sb/sb0717e.pdf.
35. General Assembly of North Carolina, Senate Bill 75, "An Act to Promote the Use of Electricity Demand Reduction to Satisfy Renewable Energy Portfolio Standards" (Raleigh, NC: April 28, 2011), website www.ncleg.net/Sessions/2011/Bills/Senate/PDF/S75v4.pdf.
36. California Code of Regulations, Subchapter 10 Climate Change, Article 4, Sections 95480 to 95490, Title 17, Subarticle 7, "Low Carbon Fuel Standard," (Sacramento, CA: July 2011), website www.arb.ca.gov/regact/2009/lcfs09/finalfro.pdf.
37. State of California, "Low Carbon Fuel Standard (LCFS) Supplemental Regulatory Advisory 10-04B" (Sacramento, CA: December 2011), website www.arb.ca.gov/fuels/lcfs/123111lcfs-rep-adv.pdf.
38. Renewable Fuels Association, "Judge Denies California Attempt to Reimplement LCFS" (January 23, 2012), website www.ethanolrfa.org/news/entry/judge-denies-california-attempt-to-reimplement-lcfs.
39. State of California, "LCFS Enforcement Injunction is Lifted" (Sacramento, CA: April 24, 2012), website www.arb.ca.gov/fuels/lcfs/LCFS_Stay_Granted.pdf.
40. The LCFS was included in the *AEO2012* Early Release Reference case, which was completed before the ruling by the Court.

Issues in focus

Introduction

The "Issues in focus" section of the *Annual Energy Outlook (AEO)* provides an in-depth discussion on topics of special interest, including significant changes in assumptions and recent developments in technologies for energy production and consumption. Detailed quantitative results are available in Appendix D. The first topic updates a discussion included in the *Annual Energy Outlook 2011 (AEO2011)* that compared the results of two cases with different assumptions about the future course of existing energy policies. One case assumes the elimination of sunset provisions in existing energy policies; that is, the policies are assumed not to sunset as they would under current law. The other case assumes the extension or expansion of a selected group of existing policies—corporate average fuel economy (CAFE) standards, appliance standards, and production tax credits (PTCs)—in addition to the elimination of sunset provisions.

Other topics discussed in this section as identified by subsection number include (2) oil price and production trends in the *Annual Energy Outlook 2012 (AEO2012)*; (3) potential efficiency improvements and their impacts on end-use energy demand; (4) energy impacts of proposed CAFE standards for light-duty vehicles (LDVs), model years (MYs) 2017 to 2025; (5) impacts of a breakthrough in battery vehicle technology; (6) heavy-duty (HD) natural gas vehicles (NGVs); (7) changing structure of the refining industry; (8) changing environment for fuel use in electricity generation; (9) nuclear power in *AEO2012*; (10) potential impact of minimum pipeline throughput constraints on Alaska North Slope oil production; (11) U.S. crude oil and natural gas resource uncertainty; and (12) evolving Marcellus shale gas resource estimates.

The topics explored in this section represent current and emerging issues in energy markets; but many of the topics discussed in *AEO*s published in recent years also remain relevant today. Table 5 provides a list of titles from the 2011, 2010, and 2009 *AEO*s that are likely to be of interest to today's readers—excluding topics that are updated in *AEO2012*. The articles listed in Table 5 can be found on the U.S. Energy Information Administration (EIA) website at www.eia.gov/analysis/reports.cfm?t=128.

1. No Sunset and Extended Policies cases

Background

The *AEO2012* Reference case is best described as a "current laws and regulations" case, because it generally assumes that existing laws and regulations will remain unchanged throughout the projection period, unless the legislation establishing them sets a sunset date or specifies how they will change. The Reference case often serves as a starting point for the analysis of proposed legislative or regulatory changes. While the definition of the Reference case is relatively straightforward, there may be considerable interest in a variety of alternative cases that reflect the updating or extension of current laws and regulations. In that regard, areas of particular interest include:

- Laws or regulations that have a history of being extended beyond their legislated sunset dates. Examples include the various tax credits for renewable fuels and technologies, which have been extended with or without modifications several times since their initial implementation.

Table 5. Key analyses from "Issues in focus" in recent *AEO*s

AEO2011	*AEO2010*	*AEO2009*
Increasing light-duty vehicle greenhouse gas and fuel economy standards for model years 2017 to 2025	Energy intensity trends in *AEO2010*	Economics of plug-in hybrid electric vehicles
Fuel consumption and greenhouse gas emissions standards for heavy-duty vehicles	Natural gas as a fuel for heavy trucks: Issues and incentives	Impact of limitations on access to oil and natural gas resources in the Federal Outer Continental Shelf
Potential efficiency improvements in alternative cases for appliance standards and building codes	Factors affecting the relationship between crude oil and natural gas prices	Expectations for oil shale production
Potential of offshore crude oil and natural gas resources	Importance of low permeability natural gas reservoirs	Bringing Alaska North Slope natural gas to market
Prospects for shale gas	U.S. nuclear power plants: Continued life or replacement after 60?	Natural gas and crude oil prices in *AEO2009*
Cost uncertainties for new electric power plants	Accounting for carbon dioxide emissions from biomass energy combustion	Greenhouse gas concerns and power sector planning
Carbon capture and storage: Economics and issues		Tax credits and renewable generation
Power sector environmental regulations on the horizon		

- Laws or regulations that call for the periodic updating of initial specifications. Examples include appliance efficiency standards issued by the U.S. Department of Energy (DOE), and CAFE and greenhouse gas (GHG) emissions standards for vehicles issued by the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA).
- Laws or regulations that allow or require the appropriate regulatory agency to issue new or revised regulations under certain conditions. Examples include the numerous provisions of the Clean Air Act that require the EPA to issue or revise regulations if it finds that an environmental quality target is not being met.

To provide some insight into the sensitivity of results to scenarios in which existing tax credits do not sunset, two alternative cases are discussed in this section. No attempt is made to cover the full range of possible uncertainties in these areas, and readers should not view the cases discussed as EIA projections of how laws or regulations might or should be changed.

Analysis cases

The two cases prepared—the No Sunset and Extended Policies cases—incorporate all the assumptions from the *AEO2012* Reference case, except as identified below. Changes from the Reference case assumptions in these cases include the following.

No Sunset case

- Extension through 2035 of the PTC for cellulosic biofuels of up to $1.01 per gallon (set to expire at the end of 2012).
- Extension of tax credits for renewable energy sources in the utility, industrial, and buildings sectors or for energy-efficient equipment in the buildings sector, including:
  - The PTC of 2.2 cents per kilowatthour or the 30-percent investment tax credit (ITC) available for wind, geothermal, biomass, hydroelectric, and landfill gas resources, currently set to expire at the end of 2012 for wind and 2013 for the other eligible resources, are assumed to be extended indefinitely.
  - For solar power investment, a 30-percent ITC that is scheduled to revert to a 10-percent credit in 2016 is, instead, assumed to be extended indefinitely at 30 percent.
  - In the buildings sector, tax credits for the purchase of energy-efficient equipment, including photovoltaics (PV) in new houses, are assumed to be extended indefinitely, as opposed to ending in 2011 or 2016 as prescribed by current law. The business ITCs for commercial-sector generation technologies and geothermal heat pumps are assumed to be extended indefinitely, as opposed to expiring in 2016; and the business ITC for solar systems is assumed to remain at 30 percent instead of reverting to 10 percent.
  - In the industrial sector, the ITC for combined heat and power (CHP) that ends in 2016 in the *AEO2012* Reference case is assumed to be preserved through 2035, the end of the projection period.

Extended Policies case

The Extended Policies case includes additional updates in Federal equipment efficiency standards that were not considered in the Reference case or No Sunset case. Residential end-use technologies subject to updated standards are not eligible for tax credits in addition to the standards. Also, the PTC for cellulosic biofuels beyond 2012 is not included because the renewable fuel standard (RFS) program that is already included in the *AEO2012* Reference case tends to be the binding driver of cellulosic biofuels use. Other than these exceptions, the Extended Policies case adopts the same assumptions as the No Sunset case, plus the following:

- Federal equipment efficiency standards are updated at periodic intervals, consistent with the provisions in the existing law, with the levels based on ENERGY STAR specifications, or Federal Energy Management Program (FEMP) purchasing guidelines for Federal agencies. Standards are also introduced for products that are not currently subject to Federal efficiency standards.
- Updated Federal residential and commercial building energy codes reach 30-percent improvement in 2020 relative to the 2006 International Energy Conservation Code in the residential sector and the American Society of Heating, Refrigerating and Air-Conditioning Engineers Building Energy Code 90.1-2004 in the commercial sector. Two subsequent rounds in 2023 and 2026 each add an assumed 5-percent incremental improvement to building energy codes.

  The equipment standards and building codes assumed for the Extended Policies case are meant to illustrate the potential effects of these policies on energy consumption for buildings. No cost-benefit analysis or evaluation of impacts on consumer welfare was completed in developing the assumptions. Likewise, no technical feasibility analysis was conducted, although standards were not allowed to exceed "maximum technologically feasible" levels described in DOE's technical support documents.
- The *AEO2012* Reference, No Sunset, and Extended Policies cases include both the attribute-based CAFE standards for LDVs for MY 2011 and the joint attribute-based CAFE and vehicle GHG emissions standards for MY 2012 to MY 2016. However, the Reference and No Sunset cases assume that LDV CAFE standards increase to 35 miles per gallon (mpg) by MY 2020, as called for in the Energy Independence and Security Act of 2007 (EISA2007), and that the CAFE standards are then held constant in subsequent model years, although the fuel economy of new LDVs continues to rise modestly over time.

  The Extended Policies case modifies the assumption in the Reference and No Sunset cases by assuming the incorporation of the proposed CAFE standards recently announced by the EPA and NHTSA for MY 2017 through MY 2025, which call for an

annual average increase in fuel economy for new LDVs of 3.9 percent. After 2025, CAFE standards are assumed to increase at an average annual rate of 1.5 percent through 2035.

- In the industrial sector, the ITC for CHP is extended to cover all system sizes (limited to only capacities between 25 and 50 megawatts in the Reference case), which may include multiple units. Also, the ITC is modified to increase the eligible CHP unit cap from 15 megawatts to 25 megawatts. These extensions are consistent with previously proposed or pending legislation.

Analysis results

The changes made to Reference case assumptions in the No Sunset and Extended Policies cases generally lead to lower estimates for overall energy consumption, increased use of renewable fuels, particularly for electricity generation, and reduced energy-related emissions of carbon dioxide (CO_2). Because the Extended Policies case includes most of the assumptions in the No Sunset case but adds others, the impacts in the Extended Policies case tend to be greater than those in the No Sunset case. Although these cases show lower energy prices—because the tax credits and end-use efficiency standards lead to lower energy demand and reduce the cost of renewable fuels—consumers spend more on appliances that are more efficient in order to comply with the tighter appliance standards, and the Government receives lower tax revenues as consumers and businesses take advantage of the tax credits.

Energy consumption

Total energy consumption in the No Sunset case is close to the level in the Reference case (Figure 11). Improvements in energy efficiency lead to reduced consumption in this case, but somewhat lower energy prices lead to higher relative consumption, offsetting some of the impact of the improved efficiency.

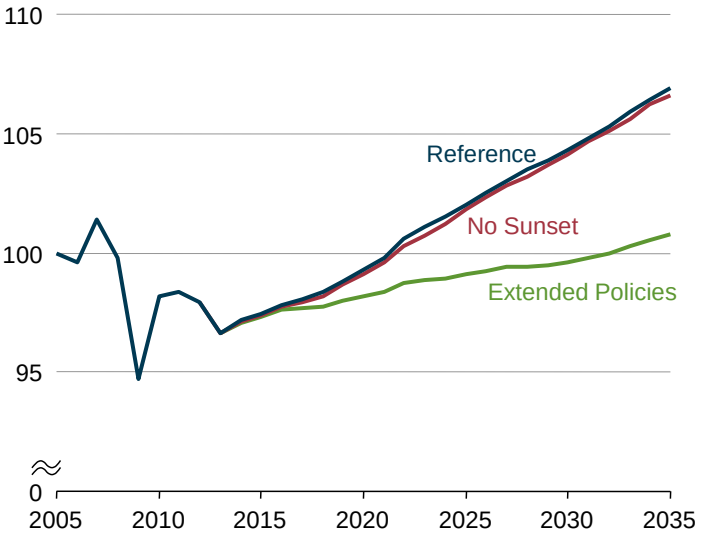
Total energy consumption growth in the Extended Policies case is markedly below the Reference case projection. In 2035, total energy consumption in the Extended Policies case is nearly 6 percent below its projected level in the Reference case.

Buildings energy consumption

The No Sunset case extends tax credits for residential and commercial renewable energy systems and for the purchase of energy-efficient residential equipment. The Extended Policies case builds on the No Sunset case by assuming updated Federal equipment efficiency standards and new standards for some products that are not currently subject to standards. For residential end-use technologies subject to standards, updated standards are assumed to replace any extension of incentives from the No Sunset case. Federal residential and commercial building energy codes are also improved as described above. Renewable distributed generation (DG) technologies (PV systems and wind turbines) provide much of the buildings-related energy savings in the No Sunset case. Extended tax credits in the No Sunset case spur increased adoption of renewable DG systems, leading to 110 billion kilowatthours of onsite electricity generation in 2035—more than four times the amount of onsite electricity generated in 2035 in the Reference case. Similar adoption of renewable DG takes place in the Extended Policies case. With the additional efficiency gains from assumed future standards and more stringent building codes, delivered energy consumption for buildings in 2035 is 6.8 percent (1.5 quadrillion Btu) lower in the Extended Policies case than in the Reference case, a reduction nearly five times as large as the 1.4-percent (0.3 quadrillion Btu) reduction in the No Sunset case.

Electricity use shows the largest reduction relative to the Reference case, with buildings electricity consumption 2.4 percent and 8.2 percent lower, respectively, in the No Sunset and Extended Policies cases in 2035. Space heating and cooling are affected by both assumed standards and building codes, leading to significant savings in energy consumption for heating and cooling in the Extended Policies case. In 2035, energy use for space heating in buildings is 6.9 percent lower, and energy use for space cooling is 17.3 percent lower, in the Extended Policies case than in the Reference case. In addition to improved standards and codes, extended tax credits for PV prompt increased adoption, offsetting some of the purchased electricity for cooling. New standards for televisions and for personal computers (PCs) and related equipment in the Extended Policies case lead to savings of 20.6 percent and 18.2 percent, respectively, in residential electricity use by this equipment in 2035 relative to the Reference case. Residential and commercial natural gas use declines from 8.3 quadrillion Btu in 2010 to 7.9 quadrillion Btu in 2035 in the Extended Policies case, representing a 6.2-percent reduction from the Reference case in 2035.

Figure 11. Total energy consumption in three cases, 2005-2035 (quadrillion Btu)



Industrial energy consumption

The Extended Policies case modifies the Reference case by extending the existing industrial CHP ITC through the end of the projection period, expanding it to include all industrial CHP system sizes, and raising the maximum credit that can be claimed from 15 megawatts of installed capacity to 25 megawatts. These assumptions are based on the current proposals in H.R. 2750 and H.R. 2784 of the 112th Congress. The changes result in 2.7 gigawatts of additional industrial CHP capacity over the Reference case level in 2035. Natural gas consumption in the industrial sector (excluding refining) increases from 7.3 quadrillion Btu in the Reference case to 7.4 quadrillion Btu in the Extended Policies case, a 1.6-percent rise. Electricity purchases are nearly unchanged in the Extended Policies case, as additional demand for electricity relative to the Reference case is fulfilled almost exclusively by increased generation from CHP.

Transportation energy consumption

The Extended Policies case modifies the Reference case and No Sunset case by assuming the incorporation of the CAFE standards recently proposed by the EPA and NHTSA for MY 2017 through 2025, which call for a 3.9-percent annual average increase in fuel economy for new LDVs, with CAFE standards applicable after 2025 assumed to increase at an average annual rate of 1.5 percent through 2035. Sales of vehicles that do not rely solely on a gasoline internal combustion engine for both motive and accessory power (including those that use diesel, alternative fuels, and/or hybrid electric systems) play a substantial role in meeting the higher fuel economy standards, growing to almost 80 percent of new LDV sales in 2035, compared with about 35 percent in the Reference case.

LDV energy consumption declines in the Extended Policies case, from 16.6 quadrillion Btu (8.9 million barrels per day) in 2010 to 12.9 quadrillion Btu (7.3 million barrels per day) in 2035, about a 20-percent reduction from the Reference case in 2035. Petroleum and other liquids fuels consumption in the transportation sector declines in the Extended Policies case, from 13.8 million barrels per day in 2010 to 12.7 million barrels per day in 2035, compared to an increase in the Reference case to 14.4 million barrels per day (Figure 12).

Renewable electricity generation

The extension of tax credits for renewables through 2035 would, over the long run, lead to more rapid growth in renewable generation than in the Reference case. When the renewable tax credits are extended without extending energy efficiency standards, as is assumed in the No Sunset case, there is a significant increase in renewable generation in 2035 relative to the Reference case (Figure 13). Extending both renewable tax credits and energy efficiency standards (Extended Policies case) results in more modest growth in renewable generation, because renewable generation in the near term is a significant source of new generation to meet load growth, and enhanced energy efficiency standards tend to reduce overall electricity consumption and the need for new generation resources.

In the No Sunset and Extended Policies cases, renewable generation more than doubles from 2010 to 2035, as compared with a 77-percent increase in the Reference case. In 2035, the share of total electricity generation accounted for by renewables is between 19 and 20 percent in both the No Sunset and Extended Policies cases, as compared with 15 percent in the Reference case.

In all three cases, the most rapid growth in renewable capacity occurs in the very near term, largely as the result of projects already under construction or planned. After that, the growth slows through 2020 before picking up again. Some of the current surge of renewable capacity additions is occurring in anticipation of the expiration of Federal incentives within the next year (for wind) or two (for other renewable fuels except solar). Results from the No Sunset and Extended Policies cases indicate that, given sufficient

Figure 12. Consumption of petroleum and other liquids for transportation in three cases, 2005-2035 (million barrels per day)

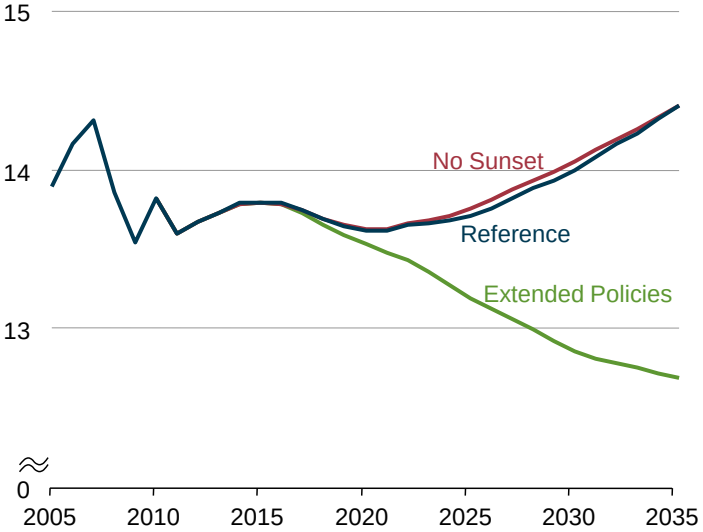
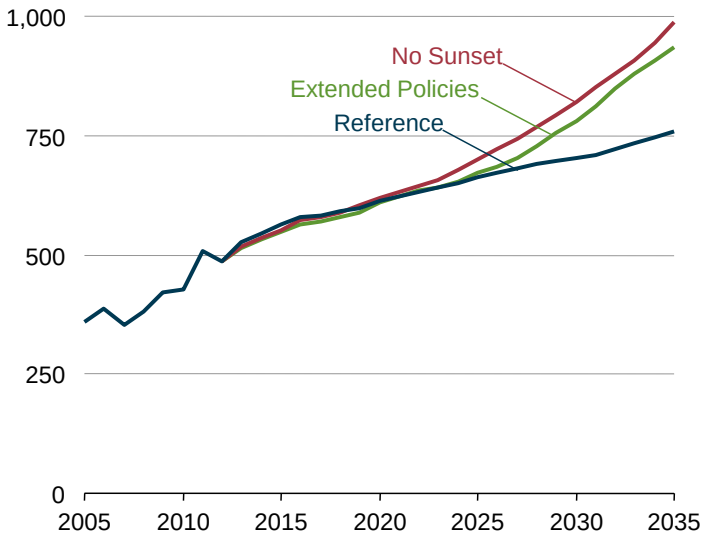


Figure 13. Renewable electricity generation in three cases, 2005-2035 (billion kilowatthours)



lead time, a long-term extension of these expiring provisions could result in the postponement of some near-term activity to better match projected patterns of load growth. With slow growth in electricity demand and the addition of capacity stimulated by renewable incentives, little new capacity is needed between 2015 and 2020. In addition, in some regions, attractive low-cost renewable resources already have been developed, leaving only less favorable sites that may require significant investment in transmission as well as other additional infrastructure costs. Starting around 2020, significant new sources of renewable generation also appear on the market as a result of cogeneration at biorefineries built primarily to produce renewable liquid fuels to meet the Federal RFS, where combustion of waste products to produce electricity is an economically attractive option.

Between 2020 and 2025, renewable generation in the No Sunset and Extended Policies cases starts to increase more rapidly than in the Reference case, and, as a result, generation from nuclear and fossil fuels is reduced from the levels in the Reference case. Natural gas represents the largest source of displaced generation. In 2035, electricity generation from natural gas is 11 percent lower in the No Sunset case and 15 percent lower in the Extended Policies case than in the Reference case (Figure 14).

Energy-related CO_2 emissions

In the No Sunset and Extended Policies cases, lower overall energy demand leads to lower levels of energy-related CO_2 emissions than in the Reference case. The Extended Policies case shows much larger emissions reductions than the No Sunset and Reference cases, due in part to the inclusion of tighter LDV fuel economy standards for MY 2017 through MY 2035. From 2010 to 2035, energy-related CO_2 emissions are reduced by a cumulative total of 4.3 billion metric tons (a 3.0-percent reduction over the period) in the Extended Policies case from the Reference case projection, as compared with 0.9 billion metric tons (a 0.6-percent reduction over the period) in the No Sunset case (Figure 15). The increase in fuel economy standards assumed for new LDVs in the Extended Policies case is responsible for more than 40 percent of the total reduction in CO_2 emissions in 2035 in comparison with the Reference case. The balance of the reduction in CO_2 emissions is a result of greater improvement in appliance efficiencies and increased penetration of renewable electricity generation.

The majority of the emissions reductions in the No Sunset case result from increases in renewable electricity generation. Consistent with current EIA conventions and EPA practice, emissions associated with the combustion of biomass for electricity generation are not counted, because they are assumed to be balanced by carbon uptake when the feedstock is grown. A small reduction in transportation sector emissions in the No Sunset case is counterbalanced by an increase in emissions from refineries during the production of synthetic fuels that receive tax credits. Relatively small incremental reductions in emissions are attributable to renewables in the Extended Policies case, mainly because electricity demand is lower than in the Reference case, reducing the consumption of all fuels used for generation, including biomass.

In the residential sector, in both the No Sunset and Extended Policies cases, water heating, space cooling, and space heating together account for most of the emissions reductions from Reference case levels. In the commercial sector, only the Extended Policies case projects substantial reductions of emissions in those categories. In the industrial sector, the Extended Policies case projects reduced emissions as a result of decreases in electricity purchases and petroleum use that are partially offset by increased reliance on natural gas—for example, increased use of natural gas fired industrial CHP.

Energy prices and tax credit payments

With lower levels of overall energy use and more consumption of renewable fuels in the No Sunset and Extended Policies cases, energy prices are lower than in the Reference case. In 2035, natural gas wellhead prices are $0.44 per thousand cubic feet (6.6

Figure 14. Electricity generation from natural gas in three cases, 2005-2035 (billion kilowatthours)

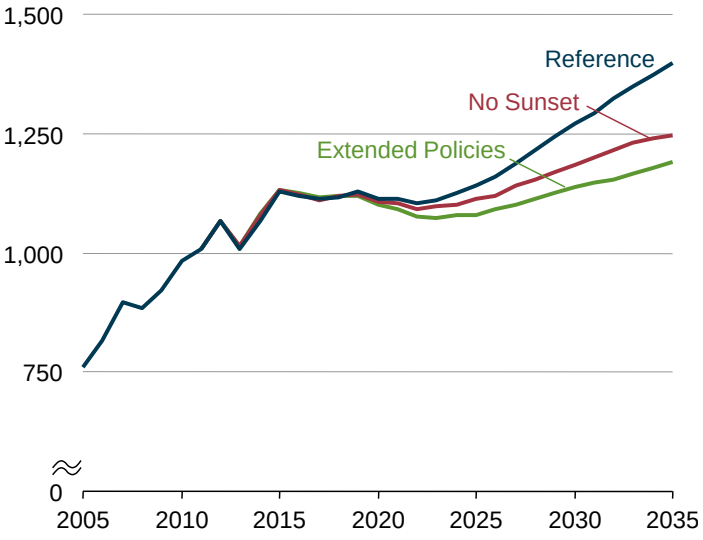
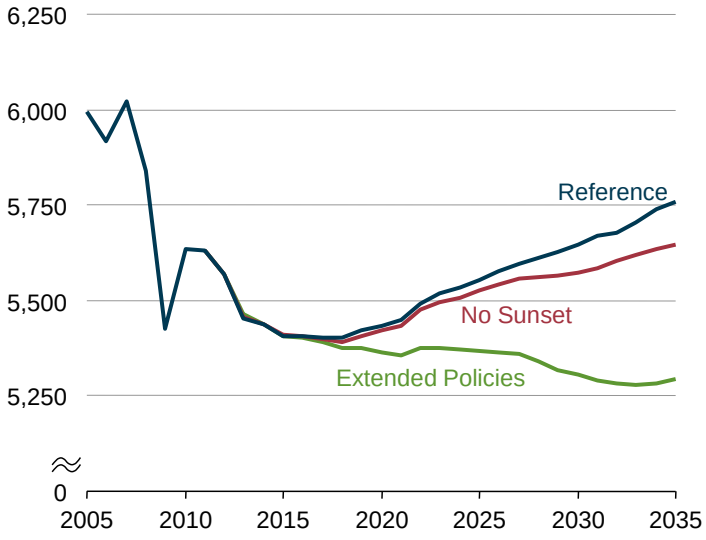


Figure 15. Energy-related carbon dioxide emissions in three cases, 2005-2035 (million metric tons)



percent) and $0.82 per thousand cubic feet (12.3 percent) lower in the No Sunset and Extended Policies cases, respectively, than in the Reference case (Figure 16), and electricity prices are about 2 percent and 5 percent lower than in the Reference case (Figure 17).

The reductions in energy consumption and CO_2 emissions in the Extended Policies case are accompanied by higher equipment costs for consumers and revenue reductions for the U.S. Government. From 2012 to 2035, residential and commercial consumers spend, on average, an additional $19 billion per year (in 2010 dollars) for newly purchased end-use equipment, distributed generation systems, and residential building shell improvements in the Extended Policies case as compared with the Reference case. On the other hand, they save an average of $22 billion per year on energy purchases.

Tax credits paid to consumers in the buildings sector (or, from the Government's perspective, reduced revenue) in the No Sunset case average $5 billion (real 2010 dollars) more per year than in the Reference case, which assumes that existing tax credits expire as currently scheduled, mostly by 2016.

The largest response to Federal tax incentives for new renewable generation is seen in the No Sunset case, with extension of the PTC and the 30-percent ITC resulting in annual average reductions in Government tax revenues of approximately $2.5 billion from 2011 to 2035, as compared with $520 million per year in the Reference case. Additional reductions in Government tax revenue in the No Sunset case result from extensions of the cellulosic biofuels PTC. These reductions increase rapidly from $52 million in 2013 to $7.2 billion (2010 dollars) in 2035 (a cumulative total of $75.1 billion) in comparison with the Reference case.

2. Oil price and production trends in *AEO2012*

The oil price in *AEO2012* is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, which is similar to the price for light, sweet crude oil, West Texas Intermediate (WTI), traded on the New York Mercantile Exchange. *AEO2012* also includes a projection of the U.S. annual average refiners' acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by domestic refiners. Currently there is a price differential between WTI and similar-quality marker crude oils delivered to international ports via tanker (e.g., Brent and Louisiana Light Sweet crudes). The *AEO2012* Reference case assumes that the large discrepancy will fade over time, as construction of more adequate pipeline capacity between Cushing and the Gulf of Mexico eases transportation of crude oil supplies to and from U.S. refineries.

Oil prices are influenced by a number of factors, including some that have mainly short-term impacts. Other factors, such as the Organization of the Petroleum Exporting Countries (OPEC) production decisions and expectations about future world demand for petroleum and other liquids, affect prices in the longer term. Supply and demand in the world oil market are balanced through responses to price movements, and the factors underlying supply and demand expectations are both numerous and complex. The key factors determining long-term supply, demand, and prices for petroleum and other liquids can be summarized in four broad categories: the economics of non-OPEC supply, OPEC investment and production decisions, the economics of other liquids supply, and world demand for petroleum and other liquids.

AEO2012 includes projections of future supply and demand for "petroleum and other liquids." The term "petroleum" refers to crude oil (including tight oil from shale [also referred to as shale oil], chalk, and other low-permeability formations), lease condensate, natural gas plant liquids, and refinery gain. The term "other liquids" refers to biofuels, bitumen (oil sands), coal-to-liquids (CTL), biomass-to-liquids (BTL), gas-to-liquids (GTL), extra-heavy oils (technically petroleum but grouped in "other liquids" in this report), and oil shale [*41*].

Figure 16. Natural gas wellhead prices in three cases, 2005-2035 (2010 dollars per thousand cubic feet)

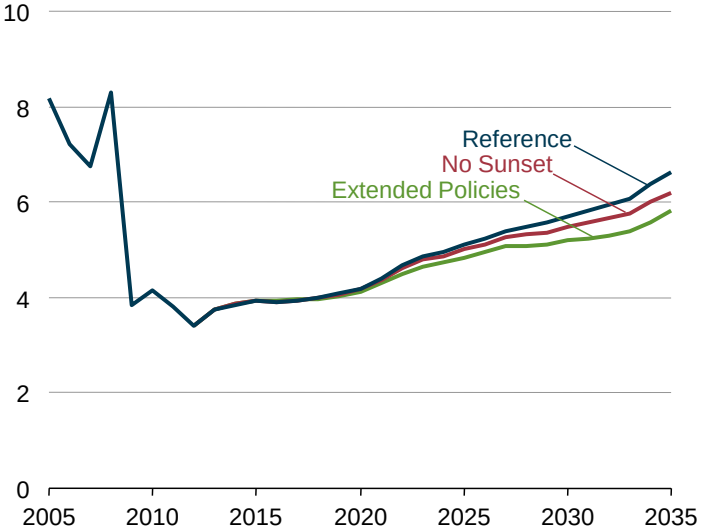
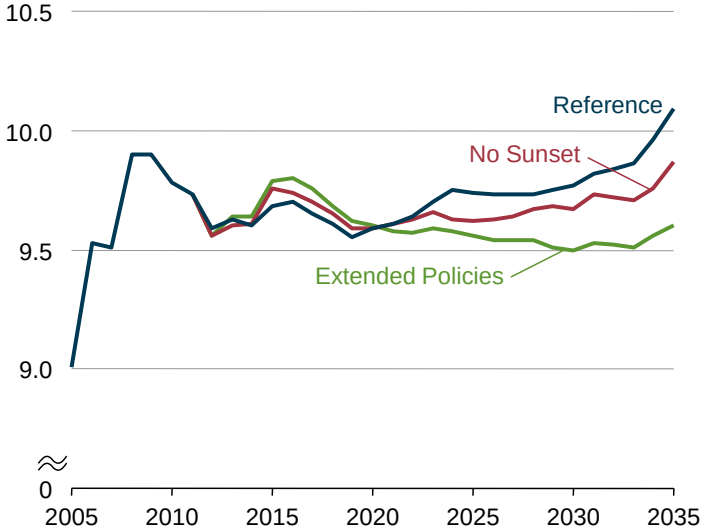


Figure 17. Average electricity prices in three cases, 2005-2035 (2010 cents per kilowatthour)



Reference case

The global oil market projections in the *AEO2012* Reference case are based on the assumption that current practices, politics, and levels of access will continue in the near to mid-term. The Reference case assumes that continued robust economic growth in the non-Organization for Economic Cooperative Development (OECD) nations, including China and India, will more than offset slower growth projected for many OECD nations. In the Reference case, non-OECD petroleum and other liquids consumption is about 21 million barrels per day higher in 2035 than it was in 2010, but OECD consumption grows by less than 2 million barrels per day over the same period. Total world consumption of petroleum and other liquids grows to 106 million barrels per day in 2030 and 110 million barrels per day in 2035.

The Reference case also assumes that limitations on access to resources in many areas restrain the growth of non-OPEC petroleum liquids production over the projection period, and that OPEC production maintains a relatively constant share of total world petroleum and other liquids supply—between 40 and 42 percent. With those constraining factors, satisfying the growing world demand for petroleum and other liquids in coming decades requires production from higher-cost resources, particularly for non-OPEC producers with technically challenging supply projects. In the Reference case, the increased cost of non-OPEC supplies, a constant OPEC market share, and easing of Cushing WTI infrastructure constraints combine to support average increases in real oil prices of about 5 percent per year from 2010 to 2020 and about 1 percent per year from 2020 to 2035. In 2035, the average real price of crude oil in the Reference case is $145 per barrel in 2010 dollars (Figure 18). The rapid increase in the near term is based on the assumption that the WTI price will return to parity with Brent by 2016 as current constraints on pipeline capacity between Cushing and the Gulf of Mexico are eliminated.

Increases in non-OPEC production of petroleum and other liquids in the Reference case come primarily from high-cost petroleum liquids projects in areas with inconsistent or unreliable fiscal or political regimes and from increasingly expensive other liquids projects that are made economical by rising oil prices and advances in production technology (Figure 19). Bitumen production in Canada and biofuels production mostly from the United States and Brazil are the most important components of the world's incremental supply of other liquids from 2010 to 2035 in the Reference case.

Low Oil Price case

In the Low Oil Price case, non-OECD economic growth is lower than in the Reference case, leading to slower growth in demand for petroleum and other liquids. Lower demand, combined with greater access to and production of petroleum liquids resources, results in sustained lower oil prices. In particular, the Low Oil Price case focuses on demand in non-OECD countries, where uncertainty about future growth is much higher than in the mature economies of the OECD. The Low Oil Price case assumes that oil prices fall steadily after 2011 to about $58 per barrel in 2017, then rise slowly to $62 per barrel in 2035. Growth in world demand for petroleum and other liquids is slowed by lower gross domestic product (GDP) growth in the non-OECD countries than is projected in the Reference case. Average annual GDP growth in the non-OECD nations is assumed to be 1.5 percentage points lower than in the Reference case, increasing by only 3.5 percent per year from 2010 to 2035. As a result, non-OECD demand for petroleum and other liquids in 2035 is 7 million barrels per day lower than in the Reference case, and total world consumption in 2035 is 2 million barrels per day lower, at 107 million barrels per day.

In the Low Oil Price case, the market power of OPEC producers is weakened, and they lose the ability to control prices and limit production. As a result, the OPEC market share of world petroleum and other liquids production is 46 percent in 2035, as

Figure 18. Average annual world oil prices in three cases, 1980-2035 (2010 dollars per barrel)

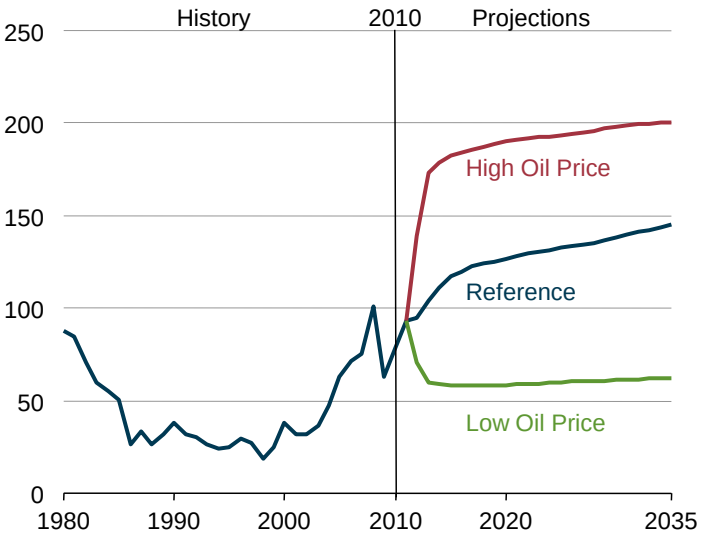
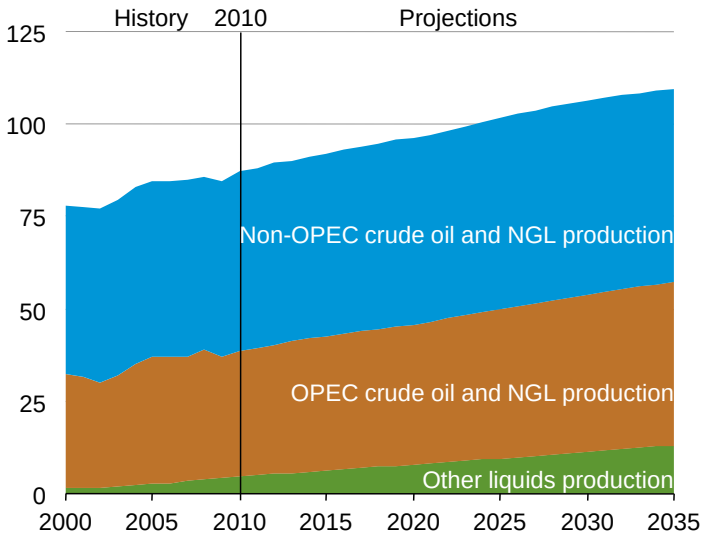


Figure 19. World petroleum and other liquids production in the Reference case, 2000-2035 (million barrels per day)



compared with 40 to 42 percent in the Reference case. Despite lower prices, non-OPEC levels of petroleum liquids production are maintained until about 2020, as projects currently underway or planned are completed and begin production. After 2020, non-OPEC petroleum liquids production declines as existing fields are depleted and not fully replaced by production from new fields and higher cost enhanced recovery technologies.

The Low Oil Price case assumes that technologies for producing biofuels, bitumen, CTL, BTL, GTL and extra-heavy oils achieve much lower costs than in the Reference case. As a result, production of those liquids increases to 16 million barrels per day in 2035 despite significantly lower oil prices.

High Oil Price case

In the High Oil Price case, the assumption of high demand for petroleum and other liquids in the non-OECD nations, combined with more constrained supply availability, results in higher oil prices than in the Reference case. Oil prices ramp up quickly to $186 per barrel (2010 dollars) in 2017 and continue rising slowly thereafter, to about $200 per barrel in 2035. The higher prices result from higher demand for petroleum and other liquid fuels in the non-OECD nations, resulting from the assumption of higher economic growth than in the Reference case. Specifically, GDP growth rates for China and India in 2012 are 1.0 percentage point higher than in the Reference case, and 0.3 percentage point higher in 2035. For most other non-OECD regions, GDP growth rates average about 0.5 percentage point above the Reference case in 2012. For the OECD regions, where prices rather than a higher economic growth rate are the main factor affecting demand, consumption of petroleum and other liquids remains fairly flat over the projection.

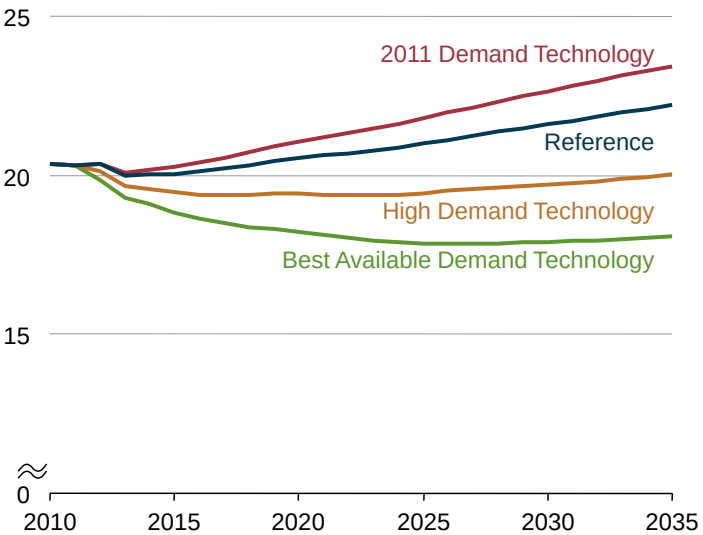
On the supply side, OPEC countries are assumed to reduce their market share somewhat, to less than 41 percent through 2035. Non-OPEC petroleum liquids resources outside the United States are assumed to be less accessible and/or more costly to produce than in the Reference case, and higher prices make other liquids supply more attractive. In 2035, other liquids production totals 17 million barrels per day in the High Oil Price case, about 4 million barrels per day above the Reference case level, and other liquids account for 15 percent of the total supply of petroleum and other liquids.

3. Potential efficiency improvements and their impacts on end-use energy demand

In 2010, the residential and commercial buildings sectors used 20.4 quadrillion Btu of delivered energy, or 28 percent of total U.S. energy consumption. The residential sector accounted for 57 percent of that energy use and the commercial sector 43 percent. In the *AEO2012* Reference case, delivered energy for buildings increases by a total of 9 percent, to 22.2 quadrillion Btu in 2035, which is modest relative to the rate of increase in the number of buildings and their occupants. In contrast, the U.S. population increases by 25 percent, commercial floorspace increases by 27 percent, and the number of households increases by 28 percent. Accordingly, energy use in the buildings sector on a per-capita basis declines in the projection. The decline of buildings energy use per capita in past years has been attributable in part to improvements in the efficiencies of appliances and building shells, and efficiency improvements continue to play a key role in projections of buildings energy consumption.

Existing policies, such as Federal appliance standards, along with evolving State policies, and market forces, are drivers of energy efficiency in the United States. A number of recent changes in the broader context of the U.S. energy system that affect energy prices, such as advances in shale gas extraction and the economic slowdown, also have the potential to affect the dynamics of energy efficiency improvement in the U.S. buildings sector. Although these influences are important, technology improvement remains a critical factor for energy use in the buildings sector. The emphasis for this analysis is on fundamental factors, particularly technology factors, that affect energy efficiency, rather than on potential policy or regulatory options.

Figure 20. Residential and commercial delivered energy consumption in four cases, 2010-2035 (quadrillion Btu)



Three alternative cases in *AEO2012* illustrate the impacts of different assumptions for rates of technology improvement on delivered energy use in the residential and commercial sectors (Figure 20). These cases are in addition to the Extended Policies and No Sunset cases discussed earlier, and they are intended to provide a broader perspective on changes in demand-side technologies. In the High Demand Technology case, high-efficiency technologies are assumed to penetrate end-use markets at lower consumer hurdle rates, with related assumptions in the transportation and industrial sectors. In the Best Available Demand Technology case, new equipment purchases are limited to the most efficient versions of technologies available in the residential and commercial buildings sectors regardless of cost. In the

2011 Demand Technology case, future equipment purchases are limited to the options available in 2011 ("frozen technology"), and 2011 building codes remain unchanged through 2035. Like the High Demand and Best Available Demand Technology cases, the 2011 Demand Technology case includes all current Federal standards.

Without the benefits of technology improvement, buildings energy use in the 2011 Demand Technology case grows to 23.4 quadrillion Btu in 2035, as compared with 22.2 quadrillion Btu in the Reference case. In the High Demand Technology case, energy delivered to the buildings sectors only reaches about 20 quadrillion Btu for any year in the projection period, and in the Buildings Best Available Demand Technology case it declines to 17.9 quadrillion Btu in 2026 before rising slightly to 18.1 quadrillion Btu in 2035.

Background

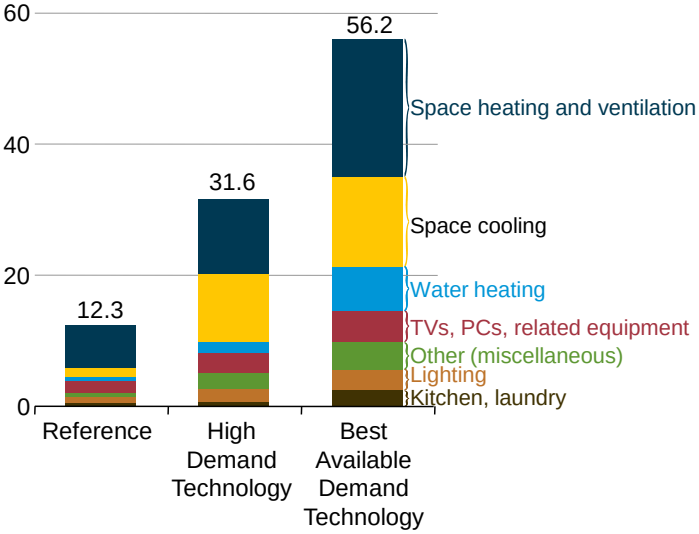
The residential and commercial sectors together are referred to as the "buildings sector." The cases discussed here are not policy-driven scenarios but rather "what-if" cases used to illustrate the impacts of alternative technology penetration trajectories on buildings sector energy use. In a general sense, this approach can be understood as reflecting uncertainty about technological progress itself, or uncertainty about consumer behavior, in that the market response to a new technology is uncertain. This type of uncertainty is being studied through market research, behavioral economics, and related disciplines that examine how purchasers perceive options, differentiate products, and react to information over time. By varying technology progress across the full range of end uses, the integrated demand cases provide estimates of potential changes in energy savings that, in reality, are likely to be less uniform and more specific to certain end uses, technologies, and consumer groups. Specific assumptions for each of the cases are summarized in Tables 6 and 7.

Results for the residential sector

To emphasize that efficiency is persistent and its effects accumulate over time, energy use is discussed in terms of cumulative reductions (2011-2035) relative to a case with no future advances in technology after 2011. An extensive range of residential equipment is covered by Federal efficiency standards, and the continuing effects of those standards contribute to the cumulative reduction in delivered energy use of 12.3 quadrillion Btu through 2035 in the Reference case relative to the 2011 Demand Technology case. Electricity and natural gas account for more than 85 percent of the difference, each showing a cumulative reduction greater than 5 quadrillion Btu over the period. Energy use for space heating shows the most improvement in the Reference case, affected by improvements in building shells and heating equipment (Figure 21). Televisions and PCs and related equipment use 1.9 quadrillion Btu less energy over the projection period, as devices with energy-saving features continue to penetrate the market, and laptops continue to gain market share over desktop PCs.

Cumulative savings in residential energy use from 2011 to 2035 total 31.6 quadrillion Btu in the High Demand Technology case and 56.2 quadrillion Btu in the Best Available Demand Technology case in comparison with the 2011 Demand Technology case. Electricity accounts for the largest share of the reductions in the High Demand Technology case (49 percent) and the Best Available Demand Technology case (51 percent). In addition to adopting more optimistic assumptions in the High Demand Technology and Best Available Demand Technology cases for end-use equipment, residential PV and wind technologies are assumed to have greater cost declines than in the Reference case, contributing to reductions in purchased electricity. In 2035, residential PV and wind systems produce 23 billion kilowatthours more electricity in the Best Available Demand Technology case than in the 2011 Demand Technology case.

Figure 21. Cumulative reductions in residential energy consumption relative to the 2011 Demand Technology case, 2011-2035 (quadrillion Btu)



In the High Demand Technology and Best Available Demand Technology cases, energy use for residential space heating again shows the most improvement relative to the 2011 Demand Technology case. Large kitchen and laundry appliances claim a small share of the reductions, as Federal standards limit increases in energy consumption for those uses even in the 2011 Demand Technology case. Light-emitting diodes (LED) lighting provide the potential for further savings in the High and Best Available Demand Technology cases beyond the reductions realized as a result of the EISA2007 (Public Law 110-140) lighting standards.

Results for the commercial sector

Like the residential sector, analysis results for the commercial sector are discussed here in terms of cumulative reductions relative to the 2011 Demand Technology case, in order to illustrate the effect of efficiency improvements over the period from 2011 to 2035. Buildings in the commercial sector are less homogeneous than those in the residential sector, in terms of both form and function. Although many commercial products

Table 6. Key assumptions for the residential sector in the *AEO2012* integrated demand technology cases

Assumptions	Integrated 2011 Demand Technology	Integrated High Demand Technology[a]	Integrated Buildings Best Available Demand Technology[a]
End-use equipment	Limited to technology menu available in 2011. Promulgated standards still take effect.	Earlier availability, lower cost, and/or higher efficiencies for advanced equipment.	Purchases limited to highest available efficiency for each technology class, regardless of cost.
Hurdle rates	Same as Reference case distribution; varies by end-use technology.	All energy efficiency investments evaluated at 7-percent real interest rate.	All energy efficiency investments evaluated at 7-percent real interest rate.
Building shells	Fixed at 2011 levels.	New buildings meet ENERGY STAR specifications after 2016. Efficiency improvement for existing buildings is 50 percent greater than in the Reference case.	New buildings meet most efficient specifications. Efficiency improvement for existing buildings is 100 percent greater than in the Reference case.
Distributed and combined heat and power generation	No improvement in technology cost or performance after 2011. Learning rates same as in the Reference case.	PV and wind costs based on Advanced Case in EIA Technology reports.[b] Learning rates adjusted for all technologies.	PV and wind costs reduced by twice the difference between the Reference and High Technology costs. Learning rates adjusted for all technologies.
Personal computers	ENERGY STAR sales and enabling rates; LCD and laptop shares fixed at 2011 values.	ENERGY STAR sales and enabling rates. LCD and laptop shares higher than in the Reference case.	ENERGY STAR sales and enabling rates. LCD share approaches 100 percent. Laptop share higher than in the Reference case.
TVs, cable boxes, and satellite systems	Fixed at 2011 values.	Unit energy consumption (UEC) values are average of Reference and Best Available Demand Technology cases.	Per-unit consumption levels reduced to ENERGY STAR specifications.
Miscellaneous electricity end uses	Unit energy consumption (UEC) values fixed at 2011 values.	Most efficient equipment selected after 2014.	Most efficient equipment selected in all years.

[a]All changes from the Reference case start in 2012 unless otherwise stated.
[b]U.S. Energy Information Administration, *Photovoltaic (PV) Costs and Performance Characteristics for Residential and Commercial Applications, Final Report* (August 2010), and *The Cost and Performance of Distributed Wind Turbines, 2010-2035, Final Report* (August 2010).

Table 7. Key assumptions for the commercial sector in the *AEO2012* integrated demand technology cases

Assumptions	Integrated 2011 Demand Technology	Integrated High Demand Technology[a]	Integrated Buildings Best Available Demand Technology[a]
End-use equipment	Limited to technology menu available in 2011. Promulgated standards still take effect.	Earlier availability, lower cost, and/or higher efficiencies for advanced equipment.	Purchases limited to highest available efficiency for each technology class, regardless of cost.
Hurdle rates	Same as Reference case distribution.	All energy efficiency investments evaluated at 7-percent real interest rate.	All energy efficiency investments evaluated at 7-percent real interest rate.
Building shells	Fixed at 2011 levels.	25 percent more improvement than in the Reference case by 2035.	50 percent more improvement than in the Reference case by 2035.
Distributed and combined heat and power generation	No improvement in technology cost or performance after 2011. Learning same as in the Reference case.	PV and wind costs, CHP cost and performance based on Advanced Case in EIA Technology reports.[b] Learning rates adjusted for advanced technologies.	PV and wind costs reduced by twice the difference between the Reference and High Technology costs. CHP based on Advanced Case in EIA Technology reports.[b] Learning rates adjusted for advanced technologies.
PC-related office equipment	ENERGY STAR sales and enabling rates; LCD and laptop shares fixed at 2011 values.	ENERGY STAR sales and enabling rates. LCD and laptop shares higher than in the Reference case.	ENERGY STAR sales and enabling rates. LCD share approaches 100 percent. Laptop share higher than in the Reference case.
Non-PC Office Equipment	Same as Reference case except for elimination of data center efficiency improvements.	Partial adoption of network power management for copiers, etc. Use of higher-efficiency power supplies for servers.	Greater adoption of network power management for copiers, etc. Use of higher-efficiency power supplies and continuous power management for servers.
Miscellaneous electricity	Less efficiency improvement than in the Reference case for uninterruptible power supplies (UPSs), network equipment, elevators, and water services.	Savings from high-efficiency UPSs and network equipment.	Greater savings from high-efficiency UPSs and network equipment.

[a]All changes from the Reference case start in 2012 unless otherwise stated.
[b]U.S. Energy Information Administration, *Photovoltaic (PV) Costs and Performance Characteristics for Residential and Commercial Applications, Final Report* (August 2010), *The Cost and Performance of Distributed Wind Turbines, 2010-2035, Final Report* (August 2010), and *Commercial and Industrial CHP Technology Costs and Performance Data* (June 2010).

are subject to Federal efficiency standards, FEMP guidelines, and ENERGY STAR specifications, coverage is not as comprehensive as in the residential sector. Still, those initiatives and the ensuing efficiency improvements contribute to a cumulative reduction in commercial delivered energy use of 4.1 quadrillion Btu in the Reference case relative to the 2011 Demand Technology case (Figure 22). Virtually all of the reduction is in purchased electricity. Increased adoption of DG and CHP accounts for 0.4 quadrillion Btu (115 billion kilowatthours) of the cumulative reduction in purchased electricity in the Reference case. Commercial natural gas use is actually slightly higher in the Reference case because of the increased penetration of CHP. Office-related computer equipment sees the most significant end-use energy savings relative to the 2011 Demand Technology case, primarily because laptop computers gain market share from desktop computers.

Commercial heating, ventilation and cooling account for almost 50 percent of the 17.1 quadrillion Btu in cumulative energy savings in the High Demand Technology case relative to the 2011 Demand Technology case. The more optimistic assumptions for end-use equipment in the High Demand Technology case offset the additional energy consumed as a result of greater adoption of CHP, resulting in a cumulative reduction in natural gas consumption of 0.9 quadrillion Btu. The increase in distributed and CHP generation contributes 0.8 quadrillion Btu (231 billion kilowatthours) to the cumulative reduction in purchased electricity use.

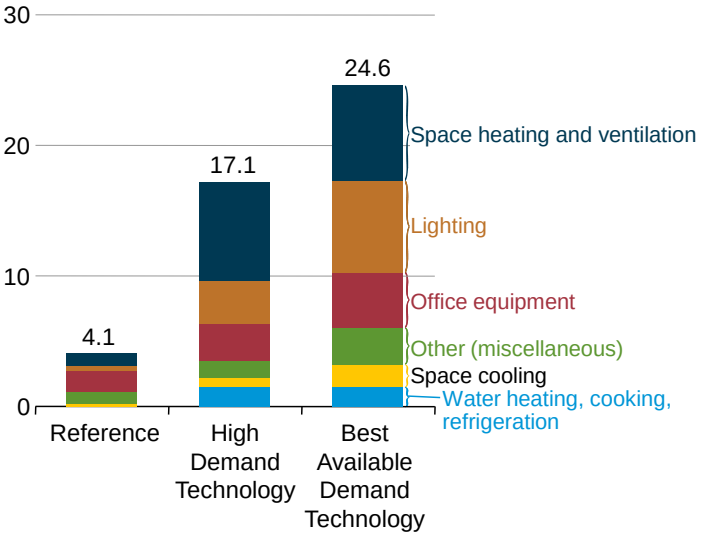
Technologies such as LED lighting result in almost as much improvement as space heating and ventilation in the Best Available Demand Technology case relative to the 2011 Demand Technology case. Significant reductions are seen for all end-use services, with a cumulative reduction in energy consumption of 24.6 quadrillion Btu. Even when consumers choose the most efficient type of each end-use technology, the more optimistic assumptions regarding technology learning for advanced CHP technologies result in more natural gas use in the Best Available Demand Technology case relative to the 2011 Demand Technology case.

In comparison to a case that restricts future equipment to the efficiencies available in 2011, the alternative cases show the potential for reductions in energy consumption from the adoption of more energy-efficient technologies. In the Reference case, technology improvement reduces residential energy consumption by 12.3 quadrillion Btu—equivalent to 4.1 percent of total residential energy use—from 2011 to 2035 in comparison with the 2011 Demand Technology case. In the commercial sector, energy consumption is reduced by 4.1 quadrillion Btu—equivalent to 1.7 percent of total commercial energy use—over the same period. With greater technology improvement in the High Demand Technology case, cumulative energy savings from 2011 to 2035 rise by an additional 6.4 percent and 5.5 percent in the residential and commercial sectors, respectively. In the Best Available Demand Technology case, the cumulative reductions in energy consumption grow by an additional 8.2 percent and 3.1 percent in the residential and commercial sectors, respectively. In the Reference case, a cumulative total of 16.4 quadrillion Btu of energy consumption is avoided over the projection period relative to the 2011 Demand Technology case. That reduction is roughly equivalent to 80 percent of the energy that the buildings sectors consumed in 2010. In the Best Available Demand Technology case, cumulative energy consumption is reduced by an additional 64.3 quadrillion Btu from 2011 to 2035.

4. Energy impacts of proposed CAFE standards for light-duty vehicles, model years 2017 to 2025

In response to environmental, economic, and energy security concerns, EPA and NHTSA in December 2011 jointly issued a proposed rule covering GHG emissions and CAFE standards for passenger cars and light-duty trucks in MY 2017 through MY 2025 [*42*]. EPA and NHTSA expect to announce a final rule in the second half of 2012. In this section, EIA uses the National Energy Modeling System (NEMS), which has been updated since last year but, due to the timing of the modeling process, does not incorporate all information from the pending rulemaking process, to assess potential energy impacts of the regulatory proposal.

Figure 22. Cumulative reductions in commercial energy consumption relative to the 2011 Demand Technology case, 2011-2035 (quadrillion Btu)



EPA is proposing GHG emissions standards that will reach a fleetwide LDV average of 163 grams CO_2 per mile (54.5 mpg equivalent) in MY 2025, or 49.6 mpg for the CAFE-only portion (Table 8). Passenger car standards are made more stringent by reducing the average annual CO_2 emissions allowed by 5 percent per year from MY 2016 through MY 2025. Average annual CO_2 emissions from light-duty trucks are reduced by 3.5 percent per year from MY 2016 through MY 2021, with larger average reductions for smaller light-duty trucks and smaller average reductions for larger light-duty trucks. For MY 2021 through MY 2025, light-duty trucks would be required to achieve a 5-percent average annual reduction rate. In this section, EIA assumes that the reductions in GHG emissions required under EPA standards exceed the reductions required under the NHTSA CAFE standards and are achieved through changes other than those that would provide further improvement in fuel economy as tested for compliance with the NHTSA standards.

NHTSA has proposed CAFE standards for LDVs that will reach a fleetwide average of 49.6 mpg in MY 2025, based on the projected inclusion of reductions in GHG emissions that are achieved by means other than improvements in fuel economy. CAFE standards are proposed for MY 2017 through MY 2021, and conditionally for MY 2022 through MY 2025. The proposed standards for passenger cars increase by 4.1 percent per year for MY 2017 through MY 2021 and 4.3 percent for MY 2022 through MY 2025. For light-duty trucks, the CAFE standards would increase by 2.9 percent per year for MY 2017 through MY 2021, with greater improvement required for smaller light-duty trucks and somewhat smaller improvement required for larger light-duty trucks. For MY 2022 through MY 2025, CAFE standards for all light-duty trucks would increase by 4.7 percent per year. Although there are complex dynamics in play among the CAFE standards and other policies, including those related to biofuels [*43*] and other gasoline alternatives, CAFE standards are the single most powerful regulatory mechanism affecting energy use in the U.S. transportation sector.

AEO2012 includes a CAFE Standards case that incorporates the proposed NHTSA fuel economy standards for MY 2017 through MY 2025. Fuel economy and GHG emissions standards for MY 2011 through MY 2016 have been promulgated already as final rules and are represented in the *AEO2012* Reference case. Further, the Reference case assumes that CAFE standards rise slightly to meet the requirement that LDVs reach 35 mpg by 2020 mandated in EISA2007.

As modeled by EIA, compliance with the more stringent fuel economy standards in the CAFE Standards case leads to a change in the vehicle sales mix. Vehicles that use electric power stored in batteries, or use a combination of a liquid fuel (including gasoline) and electric power stored in batteries for motive and/or accessory power—such as hybrid electric vehicles (HEVs) or plug-in hybrid electric vehicles (PHEVs)—or that use liquid fuels other than gasoline, such as diesel or E85, play a larger role than in the Reference case. The CAFE Standards case also projects a significant improvement in the fuel economy of traditional vehicles with gasoline internal combustion engines with and without micro hybrid technologies. In the analysis, vehicles that combine gasoline internal combustion engines with micro hybrid systems are projected to have the largest increase in sales relative to the Reference case (Figure 23 and Table 9).

Gasoline-only vehicles retain the single largest share of new vehicle sales in 2025. In order to meet increased fuel economy requirements, the average fuel economy of gasoline vehicles, including micro hybrids, is raised by the introduction of new fuel-efficient technologies and improved vehicle designs. The fuel economy of gasoline-only passenger cars, including micro hybrids, increases from 32 mpg in 2010 to 51 mpg in 2025 in the CAFE Standards case, compared with 38 mpg in 2025 in the Reference case. The fuel economy of gasoline-powered light-duty trucks, including micro hybrids, rises similarly, from 24 mpg in 2010 to 37 mpg in 2025 in the CAFE Standards case, compared with 31 mpg in 2025 in the Reference case.

As vehicle attributes, such as horsepower and weight, change in response to the more stringent fuel economy standards, some consumers switch from passenger cars to light trucks. Light-duty trucks account for 39 percent of new LDV sales in 2025 in the CAFE Standards case, higher than their 37 percent share in 2025 in the Reference case but still much lower than their 2005 share of more than 50 percent. In 2025, new passenger cars average 56 mpg and light-duty trucks average 40 mpg in the CAFE Standards case, compared with 41 mpg and 31 mpg, respectively, in the Reference case. Although more stringent standards stimulate sales of vehicles with higher fuel economy, it takes time for new vehicles to penetrate the vehicle fleet in numbers that are sufficiently large to affect the average fuel economy of the entire U.S. LDV stock. Currently there are about 230 million LDVs on the road in the United States, projected to increase to 276 million in 2035. As a consequence of the gradual scrapping of older vehicles and the introduction of new, more fuel-efficient models, the average on-road fuel economy of the LDV stock,

Table 8. Estimated[a] average fuel economy and greenhouse gas emissions standards proposed for light-duty vehicles, model years 2017-2025

	2016 (base)	2017	2018	2019	2020	2021	2022	2023	2024	2025
Fuel economy only (miles per gallon)										
Passenger cars	37.8	40.0	41.4	43.0	44.7	46.6	48.8	51.0	53.5	56.0
Light-duty trucks	28.8	29.4	30.0	30.6	31.2	33.3	34.9	36.6	38.5	40.3
All light-duty vehicles	34.1	35.3	36.4	37.5	38.8	40.9	42.9	45.0	47.3	49.6
Carbon dioxide emissions (grams per mile)										
Passenger cars	225	213	202	192	182	173	165	158	151	144
Light-duty trucks	298	295	285	277	270	250	237	225	214	203
All light-duty vehicles	250	243	232	223	213	200	190	181	172	163

[a]Based on projected mix of LDV sales.

representing the fuel economy realized by all vehicles in use, increases from around 20 mpg in 2010 to 22 mpg in 2016, 27.5 mpg in 2025, and 34.5 mpg in 2035, as compared with 28 mpg in 2035 in the Reference case (Figure 24).

More stringent fuel economy standards lead to reductions in total energy consumption. Total cumulative delivered energy consumption by LDVs from 2017 to 2035 is 8 percent lower in the CAFE Standards case than in the Reference case. LDV delivered energy consumption is 6 percent lower in 2025 in the CAFE Standards case than in the Reference case and 17 percent lower in 2035. Total consumption of petroleum and other liquids in the transportation sector is 0.5 million barrels per day lower in 2025 and 1.4 million barrels per day lower in 2035 in the CAFE Standards case than in the Reference case (Figure 25). The existing standards are modestly exceeded in the Reference case. If the standards are just met, the reduction in liquids consumption is 0.5 million barrels per day in 2025 and 1.6 million barrels per day in 2035 in the CAFE Standards case relative to the Reference case. The reductions in total delivered energy use and liquid fuel consumption become more pronounced later in the projection, as more of the total vehicle stock consists of vehicles with higher fuel economy.

The more stringent regulatory standards in the CAFE Standards case change the composition of the vehicle fleet by fuel type and shift the mix of fuels consumed. Nevertheless, motor gasoline, including gasoline blended with up to 15 percent ethanol (used in vehicles manufactured in MY 2001 and after), remains the predominant fuel by far for LDVs in the CAFE Standards case, accounting for 84 percent of LDV delivered energy consumption in 2035—only slightly less than its 86-percent share in 2035 in the Reference case.

Figure 23. Light-duty vehicle market shares by technology type in two cases, model year 2025 (percent of all light-duty vehicle sales)

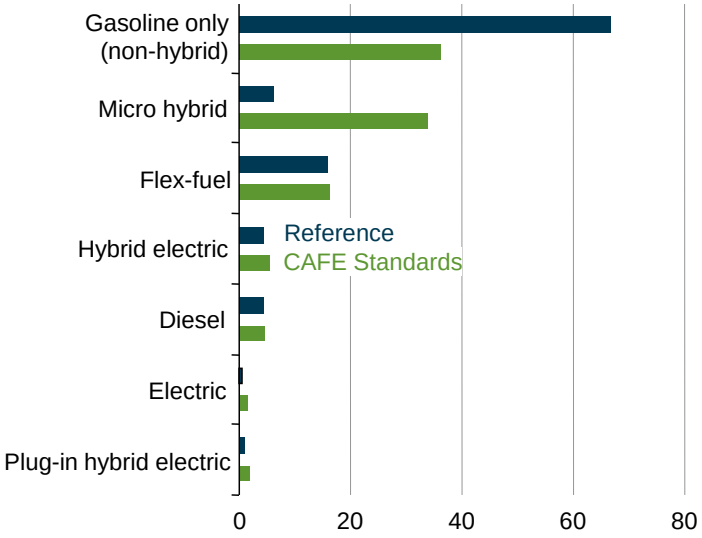


Figure 24. On-road fuel economy of the light-duty vehicle stock in two cases, 2005-2035 (miles per gallon)

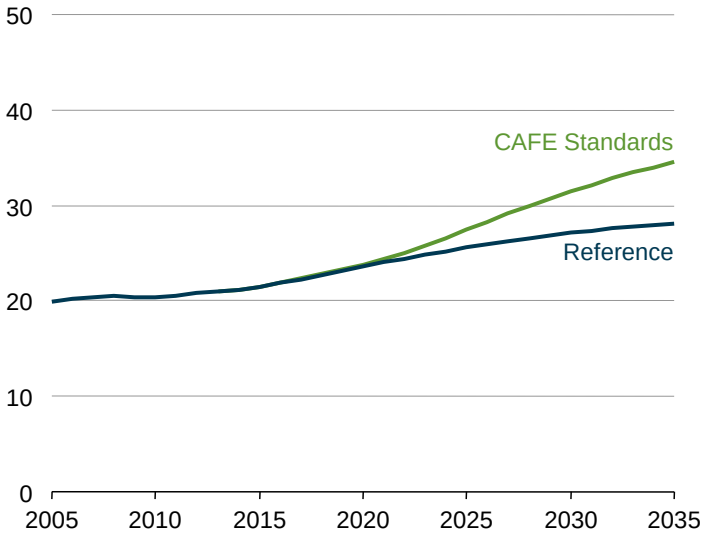


Table 9. Vehicle types that do not rely solely on a gasoline internal combustion engine for motive and accessory power

Vehicle type	Description
Micro hybrid	Vehicles with gasoline engines, larger batteries, and electrically powered auxiliary systems that allow the engine to be turned off when the vehicle is coasting or idling and then quickly restarted. Regenerative braking recharges the batteries but does not provide power to the wheels for traction.
Hybrid electric (gasoline or diesel)	Vehicles that combine internal combustion and electric propulsion engines but have limited all-electric range and batteries that cannot be recharged with grid power.
Diesel	Vehicles that use diesel fuel in a compression-ignition internal combustion engine.
Plug-in hybrid electric	Vehicles that use battery power for driving some distance, until a minimum level of battery power is reached, at which point they operate on a mixture of battery and internal combustion power. Plug-in hybrids also can be engineered to run in a "blended mode," where an onboard computer determines the most efficient use of battery and internal combustion power. The batteries can be recharged from the grid by plugging a power cord into an electrical outlet.
Electric	Vehicles that operate by electric propulsion from batteries that are recharged exclusively by electricity from the grid or through regenerative braking.
Flex-fuel	Vehicles that can run on gasoline or any gasoline-ethanol blend up to 85 percent ethanol.

Total motor gasoline demand for LDVs is 19 percent lower in the CAFE Standards case in 2035 than in the Reference case, and lower demand for motor gasoline reduces the amount of ethanol used in E10 and E15 gasoline blends. As a consequence, more E85 fuel is sold to meet the RFS. E85 accounts for 10 percent of delivered energy consumption by LDVs in 2035, compared with 8 percent in the Reference case. Diesel fuel accounts for 5 percent of LDV delivered energy consumption in 2035, similar to its share in the Reference case. Electricity use by LDVs grows in the CAFE Standards case but still makes up less than 1 percent of LDV delivered energy demand in 2035.

Reductions in LDV delivered energy consumption reduce GHG emissions from the transportation sector. From 2017 and 2035, cumulative CO_2 emissions from transportation are 357 million metric tons (mmt) lower in the CAFE Standards case compared to the Reference case, a reduction of 5 percent. Transportation GHG emissions decline from 1,876 mmt in 2010 to 1,759 mmt in 2025 and to 1,690 mmt in 2035, reductions of 4 percent and 10 percent from the Reference case, respectively (Figure 26).

5. Impacts of a breakthrough in battery vehicle technology

The transportation sector's dependence on petroleum-based fuels has prompted significant efforts to develop technology and alternative fuel options that address associated economic, environmental, and energy security concerns. Electric drivetrain vehicles, including HEVs, PHEVs, and plug-in electric vehicles (EVs), are particularly well suited to meet those objectives, because they reduce petroleum consumption by improving vehicle fuel economy and, in the case of PHEVs and EVs, substitute electric power for gasoline use (see Table 10 for a descriptive list of electric drivetrain technologies).

AEO2012 includes a High Technology Battery case that examines the potential impacts of significant breakthroughs in battery electric vehicle technology on vehicle sales, energy demand, and CO_2 emissions. Breakthroughs may include a dramatic reduction in the cost of battery and nonbattery systems, success in addressing overheating and life-cycle concerns, as well as the introduction of battery-powered electric vehicles in several additional vehicle size classes. A brief summary of the results of the High Technology Battery case follows a discussion of the current market for battery electric vehicles.

Sales of light-duty HEVs, introduced in the United States more than a decade ago, peaked at about 350,000 new sales in 2007 and have maintained a roughly 3-percent share of total LDV sales through 2011. PHEVs were introduced in the United States at the end of 2010 with the production of the Chevy Volt, a PHEV-40 (PHEV with a 40-mile range). Although manufacturer plans call for increased production of PHEVs, sales in the first full year were under 10,000 units [*44*]. EVs were first introduced in the early 1900s, and manufacturers again made EVs available in the 1990s but with a focus on niche markets. The Nissan Leaf, an EV-100 (EV with a 100-mile range) introduced around the same time as the Chevy Volt, has sparked interest in the wider commercial prospects for EVs; however, sales in 2011 remained below 10,000 units.

The individual decision to purchase a vehicle is influenced by many factors, including style, performance, comfort, environmental values, expected use, refueling capability, and expectations of future fuel prices. In general, one of the single most important factors consumers consider when deciding to purchase a vehicle is cost. Specifically, they generally are more willing to purchase new vehicle technologies, such as battery electric systems, instead of conventional gasoline internal combustion engines (ICEs) if the economic benefit over a period of ownership is greater than the initial price of the vehicle. Additional costs and benefits—such as refueling time or difficulty of refueling, increased or decreased maintenance, and resale value—also may enter into vehicle choice decisions. Further, consumers may be unwilling to spend more to purchase a vehicle, even if it accrues fuel cost savings beyond the initial cost over a relatively short period, because they are unfamiliar with the new technology or alternative fuel.

Figure 25. Total transportation consumption of petroleum and other liquids in two cases, 2005-2035 (million barrels per day)

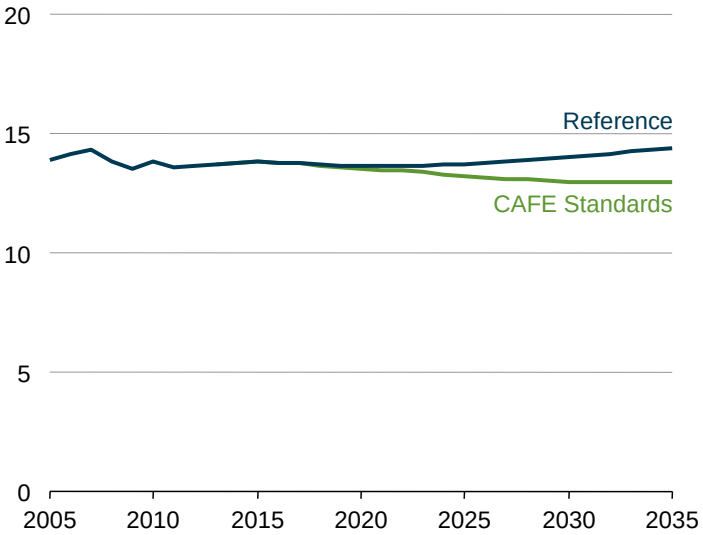
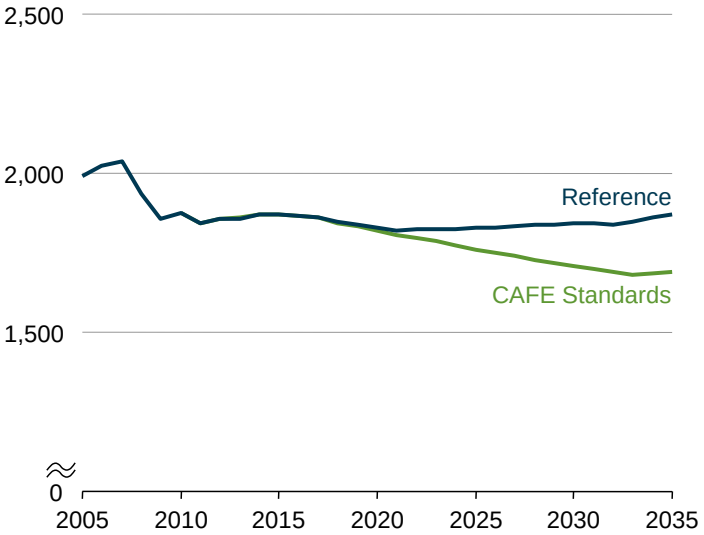


Figure 26. Total carbon dioxide emissions from transportation energy use in two cases, 2005-2035 (million metric tons carbon dioxide equivalent)



Battery electric vehicles offer an economic benefit to consumers over conventional gasoline ICEs in terms of significant fuel cost savings from both increased fuel economy for HEVs and PHEVs and the displacement of gasoline with electricity for PHEVs and EVs. Currently available battery electric vehicles such as the Toyota Prius (HEV), Chevy Volt (PHEV), and Nissan Leaf (EV) achieve much higher fuel economy (mpg) and, with the higher efficiency of electric motors, higher gasoline-equivalent mpg in electric mode, providing consumers with lower fueling costs. The Toyota Prius achieves an EPA-estimated 39 to 53 mpg, depending on trim and driving test cycle. The Chevy Volt achieves 35 to 40 mpg in charge-sustaining mode [*45*] and 93 to 95 mpg equivalent in charge-depleting mode. The Nissan Leaf achieves 99 mpg equivalent. In comparison, the Toyota Corolla, a passenger car generally similar to the Prius, achieves 26 to 34 mpg; the Chevy Cruze, a passenger car in the compact car size class similar to the Volt, achieves 25 to 42 mpg; and the Nissan Versa, a subcompact passenger car similar to the Leaf [*46*], achieves 24 to 34 mpg.

The inclusion of advanced battery technology that increases fuel economy and, in the case of PHEVs and EVs, displaces gasoline with electricity increases the initial cost of the vehicle to the consumer. The Toyota Prius has a manufacturer's suggested retail price (MSRP) between $24,000 and $29,500 (compared with $16,130 to $17,990 for the Toyota Corolla); the Chevy Volt has an MSRP between $39,145 and $42,085 (compared with $16,800 to $23,190 for the Chevy Cruze); and the Nissan Leaf has an MSRP between $35,200 and $37,250 (compared with $14,480 to $18,490 for the Nissan Versa) [*47*]. Based on these MSRPs, the current incremental consumer purchase cost of a battery electric vehicle relative to a comparable conventional gasoline vehicle is around $7,000 for an HEV and $20,000 for a PHEV or EV, before accounting for Federal and State tax incentives.

Although consumers may value high-cost battery electric vehicles for a variety of reasons, it is unlikely that they can achieve wide-scale market penetration while their additional purchase costs remain significantly higher than the present value of future fuel savings. Currently, the discounted fuel savings achieved, assuming five years of ownership with future fuel savings discounted at 7 percent, are significantly less than the incremental purchase cost of the vehicles (Table 11). This result is true even if gasoline is $6.00 per gallon. This calculation does not take into account any difference in maintenance cost or refueling infrastructure.

Recognizing the potential of HEVs, PHEVs, and EVs to reduce U.S. petroleum consumption and save consumers refueling costs, efforts are underway at both the public and private levels to address several of the barriers to wide-scale adoption of battery electric vehicle technology. Paramount among the barriers are reducing the cost of battery electric vehicles by lowering battery and nonbattery system costs and solving battery life-cycle and overheating limitations that will allow battery storage to downsize while maintaining a given driving range. For example, battery and nonbattery systems costs could be reduced by improving the manufacturing process, changing battery chemistry, or improving the electric motor. Solving battery life-cycle and overheating

Table 10. Description of battery-powered electric vehicles

Vehicle type	Description
Micro or "mild" hybrid	Vehicles with ICEs, larger batteries, and electrically powered auxiliary systems that allow the engine to be turned off when the vehicle is coasting or idle and then be quickly restarted. Regenerative braking recharges the batteries but does not provide power to the wheels for traction. Micro and mild hybrids are not connected to the electrical grid for recharging and are not considered as HEVs in this analysis.
Full hybrid electric (HEV)	Vehicles that combine an internal combustion engine with electric propulsion from an electric motor and battery. The vehicle battery is recharged by capturing some of the energy lost during braking. Stored energy is used to eliminate engine operation during idle, operate the vehicle at slow speeds for limited distances, and assist the ICE drivetrain throughout its drive cycle. Full HEV systems are configured in parallel, series, or power split systems, depending on how power is delivered to the drivetrain. HEVs are not connected to the electric grid for recharging.
Plug-in hybrid electric (PHEV)	Vehicles with larger batteries to provide power to drive the vehicle for some distance in charge-depleting mode, until a minimum level of battery power is reached (a "minimum state of charge"), at which point they operate on a mixture of battery and internal combustion power ("charge-sustaining mode"). The minimum state of charge is engineered to about 25 percent of full charge to ensure that the battery's life cycle matches the expected life of the vehicle. PHEVs also can be engineered to run in a "blended mode," using an onboard computer to determine the most efficient use of battery and internal combustion power. The battery can be recharged either from the grid by plugging a power cord into an electrical outlet or by the internal combustion engine. Current PHEV batteries are designed to recharge to about 75 percent of capacity for safety reasons related to battery overheating, leaving a depth of discharge of around 50 percent of total battery capacity. Typically, the distance a fully charged PHEV can travel in charge-depleting mode is indicated by its designation. For example, a PHEV-40 is engineered to travel around 40 miles on battery power alone before switching to charge-sustaining operation.
Plug-in electric (EV)	Vehicles that operate solely on an electric drivetrain with a large battery and electric motor and do not have an ICE to provide motive power. EVs are recharged primarily from the electrical grid by plugging into an electrical outlet, with some additional energy captured through regenerative braking. EV batteries also have a working depth of discharge capacity that is limited to both lower and upper levels due to life-cycle and safety concerns. EVs are designated by the distance a fully charged vehicle can travel in all-electric mode. For example, an EV-100 is designed to travel around 100 miles on battery power. EVs lack the "range extender" capability of PHEVs, which can switch instantly to an ICE when the battery reaches a minimum state of charge.

concerns would allow battery capacity to be downsized, which would improve the depth of discharge and make the battery less expensive. In addition, public and private efforts to address other obstacles to wider adoption of plug-in battery vehicles are underway, including the development of public charging infrastructure.

The *AEO2012* High Technology Battery case examines the potential impacts of battery technology breakthroughs by assuming the attainment of program goals established by DOE's Office of Energy Efficiency and Renewable Energy (EERE) for high-energy battery storage cost, maximum depth of discharge, and cost of a nonbattery traction drive system for 2015 and 2030 (Figures 27 and 28) [*48*]. EERE's program goals represent significant breakthroughs in battery and nonbattery systems, in terms of costs and life-cycle and safety concerns, in comparison with current electric vehicle technologies. Further, with breakthroughs in battery electric vehicle technology, more vehicle size classes are assumed to be available for passenger cars and light-duty trucks.

Reduced costs for battery and nonbattery systems in the High Technology Battery case lead to significantly lower HEV, PHEV, and EV costs to the consumer (Figures 29 and 30). The Reference case already projects a much lower real price to consumers for battery electric vehicles in 2035 relative to 2010 as a result of cost reductions for battery and nonbattery systems. Those declines are furthered in the High Technology Battery case. The prices of HEVs and PHEVs with a 10-mile range decline by an additional $1,500, or 5 percent, in 2035 in the High Technology Battery case relative to the Reference case. For PHEVs with a 40-mile range the relative decline is $3,500, or 11 percent, in 2035. For EVs with 100-mile (EV100) and 200-mile (EV200) ranges the relative declines are $3,600 and $13,300, or 13 percent and 30 percent, respectively, in 2035 relative to the Reference case.

Figure 27. Cost of electric vehicle battery storage to consumers in two cases, 2012-2035 (2010 dollars per kilowatthour)

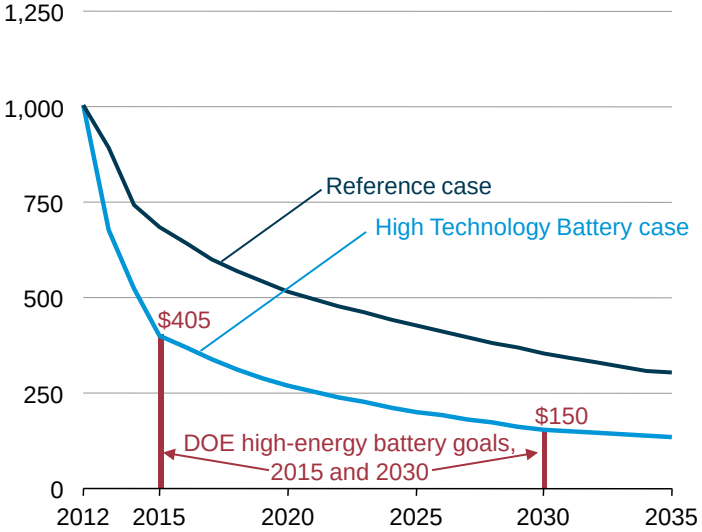


Figure 28. Costs of electric drivetrain nonbattery systems to consumers in two cases, 2012-2035 (2010 dollars)

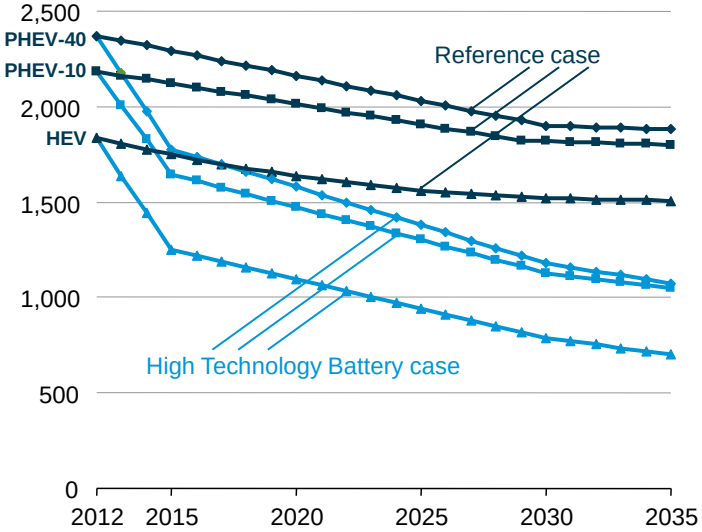


Table 11. Comparison of operating and incremental costs of battery electric vehicles and conventional gasoline vehicles

Characteristics	Hybrid electric vehicle (Prius)	Plug-in hybrid electric vehicle (Volt)	Plug-in electric vehicle (Leaf)
Fuel efficiency (mpg equivalent)	45	38 (charge-sustaining mode) 94 (charge-depleting mode)	99 (charge-depleting mode)
Annual vehicle miles traveled			12,500
Percent vehicle miles traveled electric only	0	58	100
Fuel savings vs. conventional gasoline ICE vehicle (at $3.50 per gallon)[a]	$1,169	$2,036	$3,314
Fuel savings vs. conventional gasoline ICE vehicle (at $6.00 per gallon)[a]	$2,004	$4,340	$7,071
Incremental vehicle cost (2010 dollars) relative to cost of 35-mpg conventional gasoline ICE vehicle[b]	$7,000	$20,000	$20,000

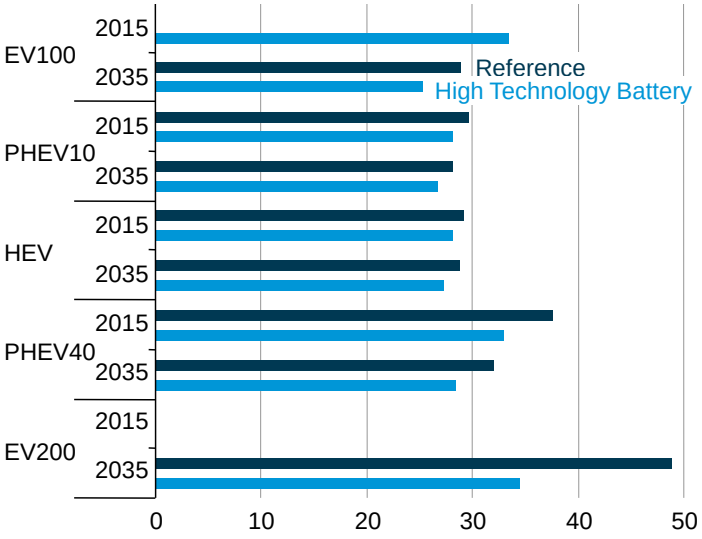
[a]5-year net present value of fuel savings, assuming 35 mpg for ICE, 7% discount rate, and $0.10 per kilowatthour electricity price.
[b]Does not include Federal, State, or local tax credits.

Lower vehicle prices lead to greater penetration of battery electric vehicle sales in the High Technology Battery case than projected in the Reference case. Battery electric vehicles, excluding mild hybrids, grow from 3 percent of new LDV sales in 2013 to 24 percent in 2035, compared with 8 percent in 2035 in the Reference case (Figure 31). Due to the still prohibitive incremental cost, EV200 vehicles do not achieve noticeable market penetration.

Plug-in vehicles, including both PHEVs and EVs, show the largest growth in sales in the High Technology Battery case, resulting from the relatively larger incremental reduction in vehicle costs. Plug-in vehicle sales grow to just over 13 percent of new vehicle sales in 2035, compared with 3 percent in 2035 in the Reference case, with EV sales growing to 8 percent of new LDV sales in 2035, compared with 2 percent in 2035 in the Reference case. Virtually all sales of plug-in vehicles are EVs with a 100-mile range, given the prohibitive cost, even in 2035, of batteries for EVs with a 200-mile range. PHEVs grow to just under 6 percent of total sales, compared with 2 percent in 2035 in the Reference case. Most PHEV sales are vehicles with a 10-mile all-electric range.

Although plug-in vehicle sales increase substantially in the High Technology Battery case, that growth is tempered by the lack of widespread high-speed recharging infrastructure. In the absence of such public infrastructure, consumers must rely almost entirely on recharging at home. According to data from the 2009 Residential Energy Consumption Survey, 49 percent of households that own vehicles park within 20 feet of an electrical outlet [*49*]. A widespread publicly available infrastructure was not considered as part of the High Technology Battery case, which limits the maximum market potential of PHEVs and EVs.

Figure 29. Total prices to consumers for compact passenger cars in two cases, 2015 and 2035 (thousand 2010 dollars)



HEV sales, including an ICE powered by either diesel fuel or gasoline, increase in the High Technology Battery case from 3 percent of sales in 2013 to 11 percent in 2035, compared with 5 percent in 2035 in the Reference case. Although the cost declines for HEVs are modest relative to those for other battery electric vehicle types, HEVs benefit from being unconstrained by the lack of recharging infrastructure.

Increased sales of battery electric vehicles in the High Technology Battery case lead to their gradual penetration throughout the LDV fleet. In 2035, HEVs represent 9 percent of the 276 million LDV stock, as compared with 4 percent in the Reference case. EVs and PHEVs each account for about 5 percent of the LDV stock in the High Technology Battery case in 2035, compared with 1 percent each in the Reference case.

The penetration of battery electric vehicles with relatively higher fuel economy and efficient electric motors reduces total energy use by LDVs from 15.6 quadrillion Btu in 2013 to 14.8 quadrillion Btu in 2035 in the High Technology Battery case, compared with 15.5 quadrillion Btu in 2035 in the Reference case (Figure 32). LDV liquid fuel use declines to

Figure 30. Total prices to consumers for small sport utility vehicles in two cases, 2015 and 2035 (thousand 2010 dollars)

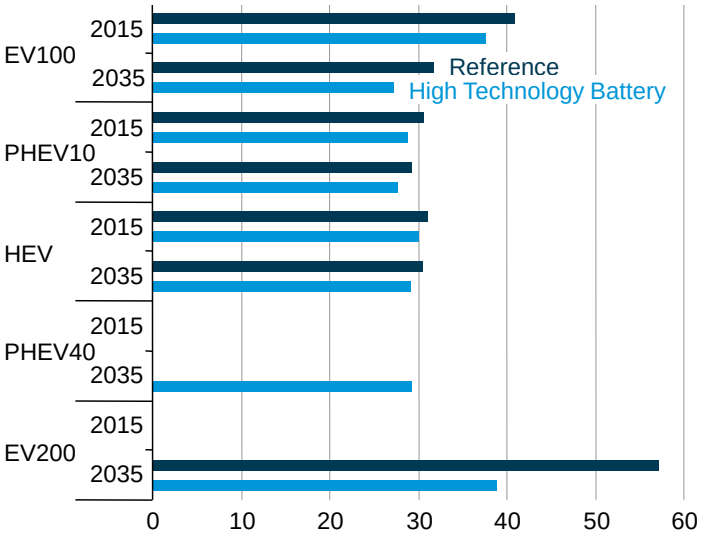
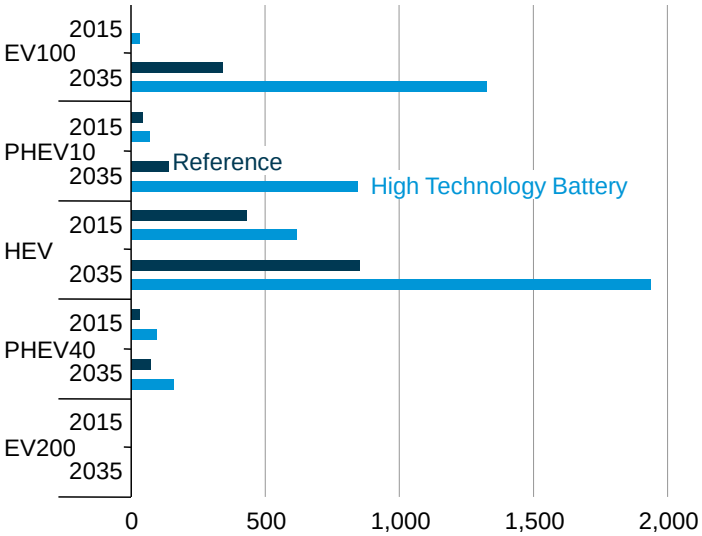


Figure 31. Sales of new light-duty vehicles in two cases, 2015 and 2035 (thousand vehicles)



14.6 quadrillion Btu in 2035 in the High Technology Battery case, and their electricity use increases to 0.2 quadrillion Btu—as compared with 15.4 quadrillion Btu of liquid fuel consumption and essentially no electricity consumption in 2035 in the Reference case. The reduction in liquid fuel consumption in the High Technology Battery case lowers U.S. net imports of petroleum from 8.5 million barrels per day in 2013 to 6.9 million barrels per day in 2035, compared with 7.2 million barrels per day in 2035 in the Reference case.

The reduction in total energy consumption by LDVs and displacement of petroleum and other liquid fuels with electricity decreases LDV energy-related CO_2-equivalent emissions from 1,030 million metric tons in 2013 to 935 million metric tons in 2035 in the High Technology Battery case, which represents a 2-percent decrease from 958 million metric tons in 2035 in the Reference case (Figure 33). CO_2 and other GHG emissions from the electric power consumed by PHEVs and EVs is treated as representative of the national electricity grid and not regionalized. Ultimately, the CO_2 and other GHG emissions of plug-in vehicles will depend on the fuel used in generating electricity.

The High Technology Battery case assumes a breakthrough in the costs of batteries and nonbattery systems for battery electric vehicles. Yet, despite the assumed dramatic decline in battery and nonbattery system costs, battery electric vehicles still face obstacles to wide-scale market penetration.

First, prices for battery electric vehicles remain above those for conventional gasoline counterparts, even with the assumption of technology breakthroughs throughout the projection period. The decline in sales prices relative to those for conventional vehicles may be enough to justify purchases by consumers who drive more frequently, consider relatively longer payback periods, or would purchase a more expensive but environmentally cleaner vehicle for a moderate additional cost. However, relatively more expensive battery electric vehicles may not pay back the higher purchase cost over the ownership period for a significant population of consumers.

In addition, EVs face the added constraint of plug-in infrastructure availability. Currently, there are about 8,000 public locations in the United States with at least one outlet for vehicle recharging, about 2,000 of which are in California [*50*]. In comparison, there are some 150,000 gasoline refueling stations available for public use. Without the construction of a much larger recharging network, consumers will have to rely on residential recharging, which is available for only around 40 percent of U.S. dwellings.

Further, recharging times differ dramatically depending on the voltage of the outlet. Typical 120-volt outlets can take up to 20 hours for a full EV battery to recharge; a 240-volt outlet can reduce the recharging time to about 7 hours [*51*]. Quick-recharging 480-volt outlets are under consideration for 30-minute "ultra-quick" recharges, but they may raise concerns related to safety and residential or commercial building codes. Even with ultra-quick recharging, EVs still would require substantially longer times for refueling than are required for ICE vehicles using liquid fuels. Given the concerns about availability and duration of recharging, the obstacle of severe range limitation, which does not affect PHEVs or HEVs, may inhibit the adoption of EVs by consumers.

Finally, another obstacle to wide-scale adoption of battery electric vehicles and other types of alternative-fuel vehicles is the increase in fuel economy for conventional gasoline vehicles and other types of AFVs resulting from higher fuel economy standards for LDVs. Final standards for LDV fuel economy currently are in place through MY 2016, and new CAFE standards proposed for MY 2017 through MY 2025 would increase combined LDV fuel economy to 49.6 mpg (56.0 mpg for passenger cars and 40.3 mpg for light-duty trucks) [*52*]. While the standards themselves may promote the adoption of battery electric vehicles, they also could considerably change the economic payback of electric drivetrain vehicles by decreasing consumer refueling costs for

Figure 32. Consumption of petroleum and other liquids, electricity, and total energy by light-duty vehicles in two cases, 2000-2035 (quadrillion Btu)

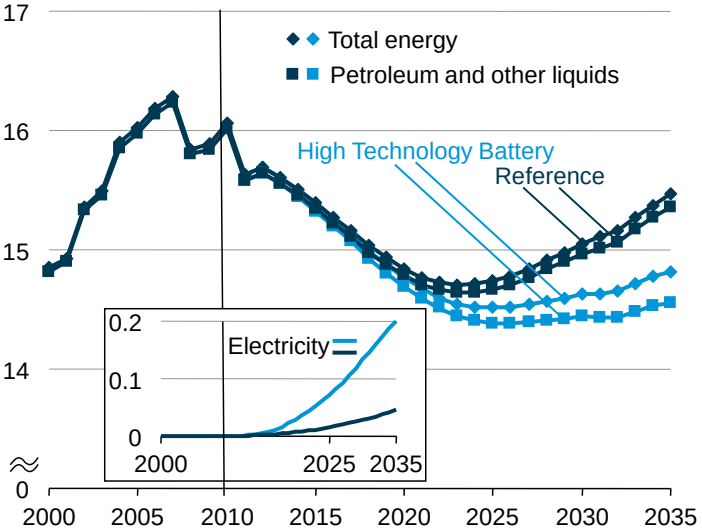
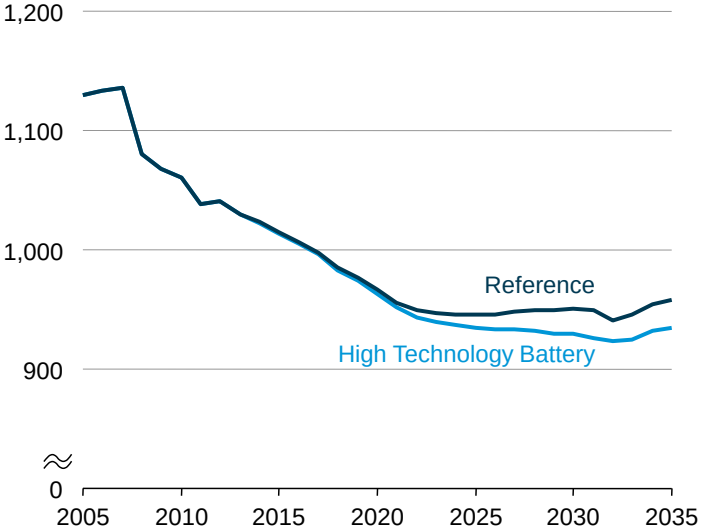


Figure 33. Energy-related carbon dioxide emissions from light-duty vehicles in two cases, 2005-2035 (million metric tons carbon dioxide equivalent)



conventional vehicles, thus lowering the fuel savings of electric drivetrain vehicles and making the upfront incremental cost more prohibitive. The potential impact of CAFE standards on other vehicle attributes, costs, and fuel savings adds to the complexity of this dynamic.

6. Heavy-duty natural gas vehicles

Environmental and energy security concerns, together with recent optimism about natural gas supply and recent lower natural gas prices, have led to significant interest in the potential for fueling heavy-duty vehicles (HDVs) with natural gas produced domestically. Key market uncertainties with regard to natural gas as a fuel for HDVs include fuel and infrastructure issues (such as the build-out process for refueling stations and whether there will be sufficient demand for refueling to cover the required capital outlays, and retail pricing and taxes for liquefied natural gas [LNG] and compressed natural gas [CNG] fuels); and vehicle issues (including incremental costs for HDVs fueled by natural gas, availability of fueling infrastructure, cost-effectiveness in view of average vehicle usage, vehicle residual value, vehicle weight, and vehicle refueling time).

Current state of the market

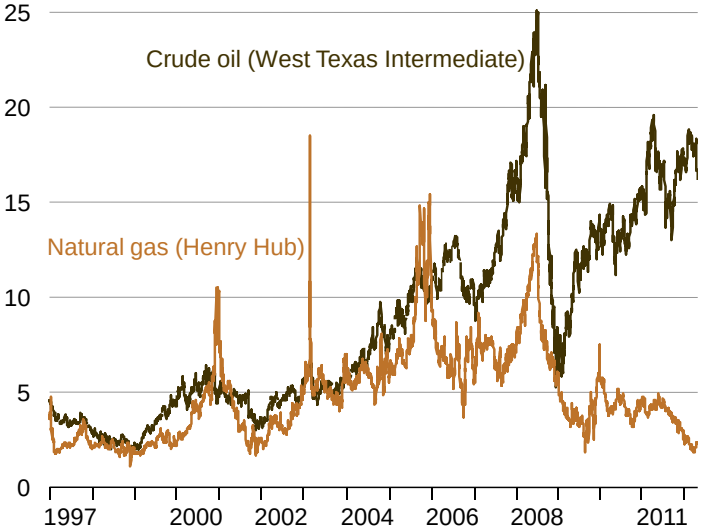
At present, HDVs in the United States are fueled almost exclusively by petroleum-based diesel fuel [*53*]. In 2010, use of petroleum-based diesel fuel by HDVs accounted for 17 percent (2.2 million barrels per day) of total petroleum consumption in the transportation sector (12.8 million barrels per day) and 12 percent of the U.S. total for all sectors (18.3 million barrels per day). Consumption of petroleum-based diesel fuel by HDVs increases to 2.3 million barrels per day in 2035 in the *AEO2012* Reference case, accounting for 19 percent of total petroleum consumption in the transportation sector (12.1 million barrels per day) and 14 percent of the U.S. total for all sectors (17.2 million barrels per day).

Historically, natural gas has played a negligible role as a highway transportation fuel in the United States. In 2010, there were fewer than 40,000 total natural gas HDVs on the road, or 0.4 percent of the total HDV stock of nearly 9 million vehicles. Sales of new HDVs fueled by natural gas peaked at about 8,000 in 2003, and fewer than 1,000 were sold in 2010 out of a total of more 360,000 HDVs sold. With relatively few vehicles on the road, natural gas accounted for 0.3 percent of total energy used by HDVs in 2010.

As of May 2012, there were 1,047 CNG fueling stations and 53 LNG fueling stations in the United States, with 53 percent of the CNG stations and 57 percent of the LNG stations being privately owned and not open to the public [*54*]. Further, the stations were not evenly distributed across the United States, with 22 percent (227) of the CNG stations and 68 percent (36) of the LNG stations located in California. In comparison, nationwide, there were more than 157,000 stations selling motor gasoline in 2010 [*55*].

Developments in natural gas and petroleum markets in recent years have led to significant price disparities between the two fuels and sparked renewed interest in natural gas as a transportation fuel. Led by technological breakthroughs in the production of natural gas from shale formations, domestic production of dry natural gas increased by about 14 percent from 2008 to 2011. In the *AEO2012* Reference case, U.S. natural gas production (including supplemental gas) increases from 21.6 trillion cubic feet in 2010 to 28.0 trillion cubic feet in 2035. Further, although the world market for oil and petroleum products is highly integrated, with prices set in the global marketplace, natural gas markets are less integrated, with significant price differences across regions of the world. With the recent growth in U.S. natural gas production, domestic natural gas prices in 2012 are significantly lower than crude oil prices on an energy-equivalent basis (Figure 34).

Figure 34. U.S. spot market prices for crude oil and natural gas, 1997-2012 (2010 dollars per million Btu)



Fuel and infrastructure issues

Even when it appears that an emerging technology can be profitable with significant market penetration, achieving significant penetration can be difficult and, potentially, unattainable. Refueling stations for NGVs are unlikely to be built without some assurance that there will be sufficient numbers of NGVs to be refueled, soon enough to allow for recovery of the capital investment within a reasonable period of time. In terms of estimating the prices that will be charged for NGV fuels beyond the cost of the dry natural gas itself, and the issue of expected utilization rates, there are additional uncertainties related to capital and operating costs, taxes, and the potential of prices being set on the basis of the prices of competing fuels.

Basic fuel issues

Diesel fuel falls into the category of distillate fuels, which have constituted more than 25 percent of U.S. refinery output in recent years. The cost of diesel fuel is linked closely to the

value of crude oil inputs for the refining process. In 2011, the spot price of Gulf Coast ultra-low sulfur diesel fuel averaged $2.97 per gallon. The wholesale diesel price reflects crude oil costs, as well as the difference between the wholesale price at the refinery gate and the cost of crude oil input, commonly referred to as the "crack spread," which reflects the costs and profits of refineries. Beyond the wholesale price, the pump price of diesel fuel reflects distribution costs, Federal, State, and local fuel taxes, retailing costs, and profits. For diesel fuel, with an average energy content of 138,690 Btu per gallon, the 2011 national average retail price of $3.84 per gallon is equivalent to about $27.80 per million Btu.

Although early models of NGVs sometimes were less fuel-efficient than comparable diesel-fueled vehicles, current technologies allow for natural gas to be used as efficiently as diesel in HDV applications. Therefore, comparisons between natural gas and diesel fueling costs can be based on the price of energy-equivalent volumes of fuel. For this analysis, the cost and price of natural gas fuels are expressed in terms of diesel gallon equivalent (dge). For example, with an energy content of approximately 84,820 Btu per gallon, 1 gallon of LNG is equivalent in energy terms to 0.612 gallons of diesel fuel.

Fuel costs for LNG and CNG vehicles depend on the cost of natural gas used to produce the fuels, the cost of the liquefaction or compression process (including profits), the cost of moving fuel from production to refueling sites (if applicable), taxes, and retailing costs. Costs can vary with the scale of operations, but the significant disparity between current natural gas and crude oil prices suggests that the cost of CNG and LNG fuels in dge terms could be significantly below the price of diesel fuel.

There are different wholesale natural gas prices and capital costs associated with CNG and LNG stations. CNG retail stations, which typically have connections to the pipeline distribution network and thus require compression equipment and special refueling pumps, are likely to pay prices for natural gas that are similar to those paid by commercial facilities. For LNG stations, insulated LNG storage tanks and special refueling pumps are needed. LNG typically would be delivered from a liquefaction facility that, depending on its scale, would pay a natural gas price similar to the prices paid by electric power plants. The costs of liquefying and transporting the fuel to the retail station would ultimately be included in the retail price.

In a competitive market, retail fuel prices should reflect costs, including input, processing, distribution, and retailing costs, normal profit margins for processors, distributors, and retailers, and taxes. For example, the market for diesel fuel, which is produced by a large number of foreign and domestic refiners and is sold through numerous distributors and retail outlets, generally is considered to be a competitive market, in which retail prices follow costs.

CNG and LNG markets, at least in their initial stages, may not be as competitive as diesel fuel markets. For example, at public refueling stations, LNG and CNG currently sell at prices significantly higher than would be suggested by a long-term analysis of cost-based pricing. According to DOE's April 2012 "Clean Cities Alternative Fuel Price Report," the average nationwide nominal retail price for LNG was $3.05 per dge, and the average for CNG was $2.32 per dge [*56*].

If the use of LNG and/or CNG to fuel HDVs starts to grow, it is likely to take some time before fuel production and refueling infrastructure become sufficiently widespread for competition among fuel providers alone to assure that fuel prices are more closely linked to cost-based levels. However, even without many fuel providers, operators of an LNG and/or CNG vehicle fleet may be in a position to negotiate cost-based fuel prices with refueling station operators seeking to lock in demand for their initial investments in refueling infrastructure. Such arrangements provide an alternative to reliance on centrally fueled fleets as a means of circumventing the problem of how to introduce NGVs and natural gas refueling infrastructures concurrently.

Build-out process for refueling stations

It is not clear how NGVs and an expanded natural gas refueling infrastructure ultimately will evolve. One view is that a "hub-and-spoke" model for refueling infrastructure will expand sufficiently in multiple areas for a point-to-point system to take hold eventually. The "hubs" in the model would include the local refueling infrastructure, currently in place primarily to support local fleets. The "spokes" would ensure that refueling infrastructure is in place on the main transportation corridors connecting the hubs.

Several regional efforts are in place to encourage such "hub-and-spoke" growth for NGV refueling facilities. They include the Texas Clean Transportation Triangle [*57*], a strategic plan for CNG and LNG refueling stations between Dallas, San Antonio, and Houston; and the Interstate Clean Transportation Corridor [*58*], which aims to provide LNG fueling stations between such major western cities as Los Angeles, Las Vegas, Phoenix, Reno, Salt Lake City, and San Francisco. There also is a plan for a Pennsylvania Clean Transportation Corridor [*59*], which would provide CNG and LNG fueling stations between Pittsburgh, Harrisburg, Scranton, and Philadelphia.

In several corridors, Federal and State incentives are subsidizing both the construction of refueling stations and the production of heavy-duty LNG vehicles [*60*], in an effort to ensure that both demand and supply will be in place concurrently. A major question is whether gaps between isolated targeted markets can be bridged to provide a nationwide refueling structure that will allow heavy-duty NGVs to travel almost anywhere.

Sufficiency of demand for refueling to cover capital outlay

The cost of providing refueling services for NGVs depends on a number of factors and is distinctly different for CNG and LNG vehicles. Investment decisions are likely to be based on levels of demand. NGV refueling capability can be added at an existing facility or at a separate dedicated facility (which would require an additional investment). The costs depend in part on the number

of fueling hoses added. LNG stations in particular benefit from higher volumes, but they also require significant additional land to accommodate storage tank(s), and they must satisfy special safety requirements—both of which add costs that can vary significantly from place to place. One added cost in operating an LNG station is the need for safety suits and specialized training for station attendants who dispense the fuel.

LNG typically is delivered to refueling stations via tanker truck from a separate liquefaction facility, the proximity of which is a major factor in the cost and frequency of deliveries. Any significant expansion of LNG refueling capacity also will require expanded liquefaction capacity, which currently is not sufficiently dispersed throughout the country to support a nationwide LNG refueling infrastructure. Although there are several dedicated large-scale natural gas liquefaction facilities in the United States, primarily in the West, there are smaller liquefaction plants and LNG storage tanks currently in use for meeting peak-shaving needs of utilities and pipelines during times of high demand. There are more than 100 such facilities in the United States, with a combined liquefaction capacity of more than 6 billion cubic feet per day. The majority are concentrated in the Northeast and Southeast [*61*].

Retail prices and taxes for LNG and CNG fuels

Even if the costs are fully known, retail prices for CNG and LNG transportation fuels remain uncertain, given questions about whether dispensers would charge higher prices in order to recover costs more rapidly if the facility were underutilized or would set prices to be competitive with the price of diesel. Prices charged at private stations for fleet vehicles presumably would be based on cost. With the number of refueling stations limited, competition between retailers is likely to be limited, at least initially. However, NGV refueling stations presumably would want to provide sufficient economic incentive in terms of the competitiveness of fuel prices to encourage more purchases of NGVs.

NGV fuel is taxed at State and Federal levels. Currently, on a Federal level, CNG is taxed at the same rate as gasoline on an energy-equivalent basis ($0.18 per gasoline gallon equivalent, or $0.21 per dge). However, LNG is taxed at a higher effective rate than diesel fuel, because it is taxed volumetrically at $0.24 per LNG gallon equivalent ($0.40 per dge) rather than on the basis of energy content [*62*]. State taxes vary, averaging $0.15 per dge for CNG and $0.24 per dge for LNG.

Vehicle Issues

Incremental vehicle cost

NGVs have significant incremental costs relative to their diesel-powered counterparts because of the need for pressurization and insulation of CNG or LNG tanks and the lower energy content of natural gas as a fuel. Total incremental costs relative to diesel HDVs range from about $9,750 to $36,000 for Class 3 trucks (GVWR 10,001 to 14,000 pounds), $34,150 to $69,250 for Class 4 to 6 trucks (GVWR 14,001 to 26,000 pounds), and $49,000 to $86,125 for Class 7 and 8 trucks (GVWR greater than 26,001 pounds). The incremental costs of heavy-duty NGVs depend in large part on the volume of the vehicle's CNG or LNG storage tank, which can be sized to match its typical daily driving range. Non-storage-tank incremental costs average about $2,000 for Class 3 vehicles, $20,000 for Class 4 to 6 vehicles, and $30,000 for Class 7 to 8 vehicles [*63*]. Fuel storage costs are about $350 per gallon diesel equivalent for CNG, with the incremental cost for Class 3 CNG vehicle storage tanks ranging between about $8,000 and $30,000; and about $475 per gallon diesel equivalent for LNG, with the incremental cost for Class 4 to 8 LNG vehicle storage tanks ranging between about $14,000 and $52,000. Natural gas fuel storage technology is relatively mature, leaving only modest opportunity for cost reductions.

Availability of fueling infrastructure

The absence of widespread public refueling infrastructure can impose a serious constraint on heavy-duty NGV purchases. Owners who typically refuel vehicles at a private central location do not face an absolute constraint based on infrastructure, however, and heavy-duty NGVs currently in operation have tended to be purchased by fleet operators who refuel consistently at a specific central location or in areas where their vehicles routinely operate on dedicated routes.

Cost-effectiveness with average vehicle usage

In order to take advantage of potential fuel cost savings from switching to NGVs, owners must operate the vehicles enough to pay back the higher incremental cost in a reasonable period of time. The payback period varies with miles driven and is shorter for trucks that are used more intensively. Payback periods for the upfront incremental costs of NGVs are greater than 5 years for Class 3 vehicles unless they are driven at least 20,000 to 40,000 miles per year, and for Class 7 and 8 vehicles unless they are driven at least 60,000 to 80,000 miles per year. Shorter payback periods, 3 years or less, may reflect typical owner expectations more accurately [*64*], but they require much more intensive use: around 60,000 to 80,000 miles annually for Class 3 vehicles and more than 100,000 miles annually for Class 7 and 8 vehicles. For example, for a Class 7 or 8 compression ignition NGV with average fuel economy of 6 miles per gallon (which has a similar fuel economy compared to a diesel counterpart) and an incremental cost of $80,000, the payback period would be just over 3 years if the vehicle were driven 100,000 miles per year, assuming a diesel fuel price of $4.00 per gallon and an LNG fuel price of $2.50 per gallon. If the same Class 7 or 8 vehicle were driven 40,000 miles per year, the payback period would be about 8 years. Further, without a widely available infrastructure, heavy-duty NGVs tend to be considered by centrally refueled fleets, which may have less mileage-intensive vehicle use.

According to the Department of Transportation's Vehicle Inventory and Use Survey [65], last completed in 2002, a large segment of the HDV market simply does not drive enough to justify the purchase of an NGV (Figure 35). Around 30 percent of Class 3 vehicles and 75 percent of Class 7 and 8 vehicles are not driven enough to reach the 5-year payback threshold mentioned above. This is a significant portion of the market that would require either more favorable fuel economics or lower vehicle costs before the purchase of an NGV could be justified.

Other market uncertainties

Other factors may also affect market acceptance of heavy-duty NGVs. First, the purchase decision could be affected by the considerable additional weight of CNG or LNG tanks. For owners who typically "weight-out" a vehicle (driving with a full payload), adding heavy CNG or LNG tanks necessitates a reduction in freight payload. The EPA and NHTSA have estimated that about one-third of Class 8 sleeper tractors routinely are "weighted-out" [66].

A diesel tractor with 200 gallons of tank capacity and a fuel economy of 6 miles per gallon can drive 1,200 miles on a single refueling. The same tractor would need up to 110 dge of LNG tank capacity, at a considerable weight penalty and an incremental cost of more than $80,000, to allow for a range of about 650 miles on a single refueling. Because owner/operators typically stop several times per day, the reduction in unrefueled maximum range would not require additional breaks for vehicles with large CNG or LNG tanks. However, CNG and LNG vehicles that do not opt for large tanks because of either weight or incremental cost considerations might have to refuel more frequently.

Finally, the owner perception of the balance of risk and reward for large capital investment is an uncertainty. Higher upfront capital costs can prove economically prohibitive for some potential owners. Even if the payback period for an investment in natural gas vehicles seemed acceptable, financing constraints or returns available on competing investment options could preclude the purchase. Additionally, the residual value of natural gas HDVs could, in theory, affect market uptake. With little natural gas refueling infrastructure in existence, the potential resale market is constrained to owners of centrally operated fleets. However, lease terms tend to limit the importance of this factor.

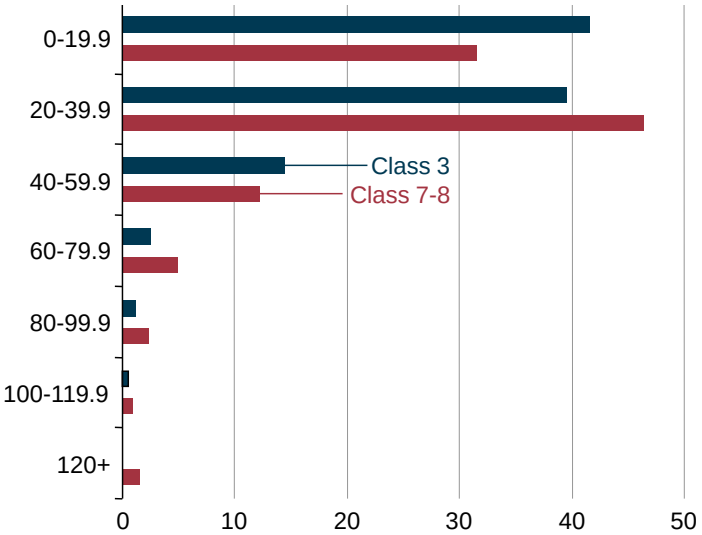
The complex set of factors influencing the potential for natural gas as a fuel for HDVs includes several areas for which policy mechanisms have been discussed. Most policy debates to date have considered the possibility of subsidies to reduce the incremental cost of natural gas vehicles (for example, in Senate and House versions of the New Alternative Transportation to Give Americans Solutions Act [67]) and Federal grant-based or other financial support for fueling station infrastructure. In addition, market hurdles related to consumer acceptance or payback periods might also be addressed through loan guarantees or related financial support policies, both for the vehicles and for the refueling infrastructure.

HD NGV Potential case results

The *AEO2012* HD NGV Potential case examines issues associated with expanded use of heavy-duty NGVs, under an assumption that the refueling infrastructure exists to support such an expansion. The HD NGV Potential case differs from an earlier sensitivity case completed as part of the *Annual Energy Outlook 2010*, which focused on possible subsidies to expand the market potential for heavy-duty NGVs and limited its attention to vehicles operating within 200 miles of a central CNG refueling facility.

The *AEO2012* HD NGV Potential case permits expansion of the HDV market to allow a gradual increase in the share of HDV owners who would consider purchasing an NGV if justified by the fuel economics over a payback distribution with a weighted average of 3 years. The gradual increase in the maximum natural gas market share reflects the fact that a national natural gas refueling program would require time to build out. The natural gas refueling infrastructure is expanded in the HD NGV Potential case simply by assumption; it is not clear how (or whether) specific barriers to natural gas refueling infrastructure investment can be overcome.

Figure 35. Distribution of annual vehicle-miles traveled by light-medium (Class 3) and heavy (Class 7 and 8) heavy-duty vehicles, 2002 (thousand miles)



Incremental costs for NGVs in the HD NGV Potential case differ from those in the Reference case. In the HD NGV Potential case, incremental costs are determined by assuming a set cost for CNG or LNG engines plus a CNG or LNG tank cost based on the average amount of daily travel and vehicle size class. The HD NGV Potential case includes separate delivered CNG and LNG fuel prices for fleet and nonfleet operators. Added per-unit charges to recover infrastructure are set and held constant in real terms throughout the projection period, based on the assumptions that refueling stations would be utilized at a sufficiently high rate to warrant the capital investment, and that the prices charged for the fuel would be cost-based (i.e., station operators would not

set prices on the basis of prices for competing fuels). Motor fuels taxes are assumed to remain at their current levels in nominal terms, maintaining the higher energy-equivalent tax on LNG relative to diesel fuel.

In defining CNG and LNG prices for the HD NGV Potential case, EIA examined current motor fuel taxes and any charges added to the commodity price of dry natural gas sold at private central refueling stations (fleets) and at retail stations where actual data were available. Accordingly, an HDV Reference case was developed from the *AEO2012* Reference case, by including the updated fleet and retail CNG and LNG prices, to provide a consistent basis for comparison with the HD NGV Potential case (Figure 36). The HDV Reference case assumes that Class 3 through 6 vehicles use CNG, obtained from either fleet operators (using fleet prices) or nonfleet operators (using retail prices), and that Class 7 and 8 vehicles, both fleet and nonfleet, use LNG.

Sales of heavy-duty NGVs rise dramatically in the HD NGV Potential case, based on the national availability of refueling infrastructure and expanded market potential (Figure 37). Sales of new heavy-duty NGVs increase from 860 in 2010 (0.2 percent of total new HDV sales) to about 275,000 in 2035 (34 percent of total new vehicle sales), as compared with 26,000 in the HDV Reference case (3 percent of total new HDV sales). New heavy-duty NGVs gradually claim a more significant share of the vehicle stock, from 0.4 percent in 2010 to 21.8 percent (2,750,000 vehicles) in 2035, as compared with 2.4 percent (300,000 vehicles) in 2035 in the HDV Reference case.

As a result of the large projected increase in sales of new heavy-duty NGVs, natural gas demand in the HDV sector rises from about 0.01 trillion cubic feet in 2010 to 1.8 trillion cubic feet in 2035 in the HD NGV Potential case, as compared with 0.1 trillion cubic feet in the HDV Reference case (Figure 38). The natural gas share of total energy use by HDVs grows from 0.2 percent in 2010 to 32 percent in 2035 in the HD NGV Potential case, compared with 1.6 percent in the HDV Reference case.

Roughly speaking, about 1 trillion cubic feet of natural gas consumed per year replaces 0.5 million barrels per day of petroleum and other liquids. Thus, natural gas consumption by HDVs in the HD NGV Potential case displaces about 850,000 barrels per day of petroleum and other liquids consumption in 2035 (Figure 39). Without a major impact on world oil prices, which is not expected to result from the gradual but significant adoption of natural gas as a fuel for U.S. HDVs, nearly all the reduction in petroleum and other liquids use by U.S. HDVs would be reflected by a decline in imports.

In the HD NGV Potential case, projected total U.S. natural gas consumption in 2035 is 1.4 trillion cubic feet (5 percent) higher than in the Reference case, as the increase in natural gas use by vehicles is partially offset by lower consumption in other sectors, in response to higher natural gas prices (Figure 40). The electric power and industrial sectors account for the

Figure 36. Diesel and natural gas transportation fuel prices in the HDV Reference case, 2005-2035 (2010 dollars per diesel gallon equivalent)

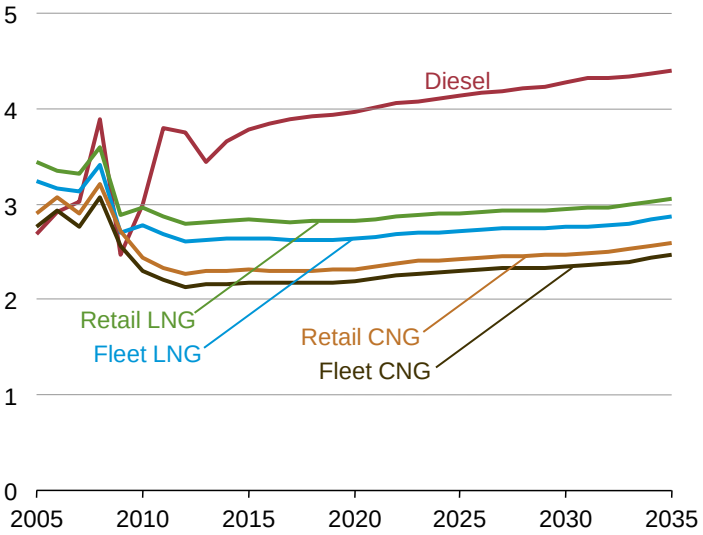


Figure 37. Annual sales of new heavy-duty natural gas vehicles in two cases, 2008-2035 (thousand vehicles)

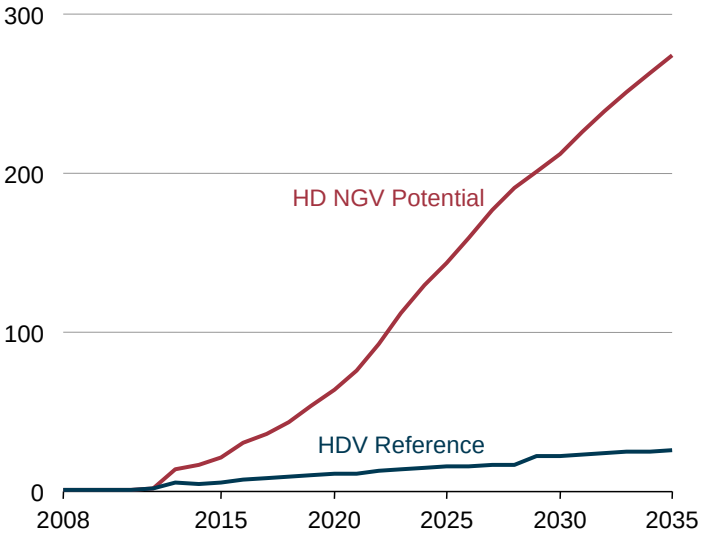
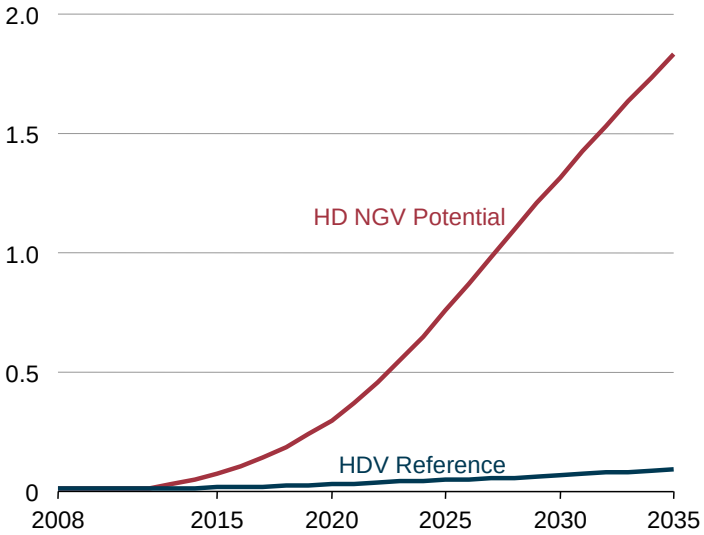


Figure 38. Natural gas fuel use by heavy-duty vehicles in two cases, 2008-2035 (trillion cubic feet)



bulk of the consumption offsets, as their 2035 natural gas use is, respectively, 0.3 trillion cubic feet (3.1 percent) and 0.2 trillion cubic feet (2.7 percent) lower than in the Reference case.

In 2035, U.S. domestic natural gas production in the HD NGV Potential case is 1.1 trillion cubic feet (3.9 percent) higher than in the HDV Reference case. The higher level of natural gas production needed to support the growth in HDV fuel use results in a 10-percent increase in natural gas prices—$0.76 per million Btu (2010 dollars)—at the Henry Hub in 2035 in comparison with the HDV Reference case. Percentage increases in delivered natural gas prices to other sectors, which include transmission and distribution costs that are not affected by higher prices to producers, are smaller, with delivered natural gas prices increasing by 4.9 percent in the residential sector, 5.9 percent in the commercial sector, 8.9 percent in the industrial sector, and 7.9 percent in the electricity generation sector in comparison with the HDV Reference case in 2035.

7. Changing structure of the refining industry

Petroleum-based liquid fuels represent the largest source of U.S. energy consumption, accounting for about 37 percent of total energy consumption in 2010. The mix and composition of liquids, however, have changed in recent years in response to changes in regulations and other factors, and the structure of the liquid fuels production industry has changed in response [*68*]. The changes in the industry require that analytical tools used for market analysis of the liquid fuels produced by the industry also be reevaluated.

In recognition of the fundamental changes in the liquid fuels production industry, EIA is developing a new Liquid Fuels Market Module (LFMM), which it intends to use in place of the existing Petroleum Market Module (PMM) to produce the *Annual Energy Outlook 2013*. The LFMM will allow EIA to address more adequately the current and anticipated domestic and international market environments, to analyze the implications of emerging technologies and fuel alternatives, and to evaluate the impact of complex emerging energy-related policy, legislative, and regulatory issues. Some results from an early simulation of the LFMM, the LFMM case, are provided here.

The landscape for both production and consumption of liquid fuels in the United States continues to evolve, leading to changes in the mix of liquid fuel feedstocks, with greater emphasis on renewable fuels. The liquid fuels markets are not homogeneous; regional differences have become more pronounced. Furthermore, U.S. policymakers are paying more attention to evolving markets for liquid fuels and the potential for improving the efficiency of liquid fuels consumption, reducing GHG emissions associated with the production and consumption of liquid fuels, and improving the Nation's energy security by reducing reliance on imports. Major industry changes and their implications are discussed below.

New feedstocks and technologies

Over the past 25 years, the U.S. liquid fuels production industry has changed from being based primarily on domestic petroleum to using a variety of feedstocks and finished products from sources around the world. Regulatory and policy changes have resulted in the use of feedstocks other than crude oil, such as natural gas and renewable biomass, and could lead to the use of other feedstocks (such as coal) in the coming years. These changes have resulted in a transition from a relatively straightforward supply chain relying on crude oil and finished products to an increasingly complex system, which must be reflected in models to produce valid projections.

Figure 39. Reduction in petroleum and other liquid fuels use by heavy-duty vehicles in the HD NGV Potential case compared with the HDV Reference case, 2010-2035 (thousand barrels per day)

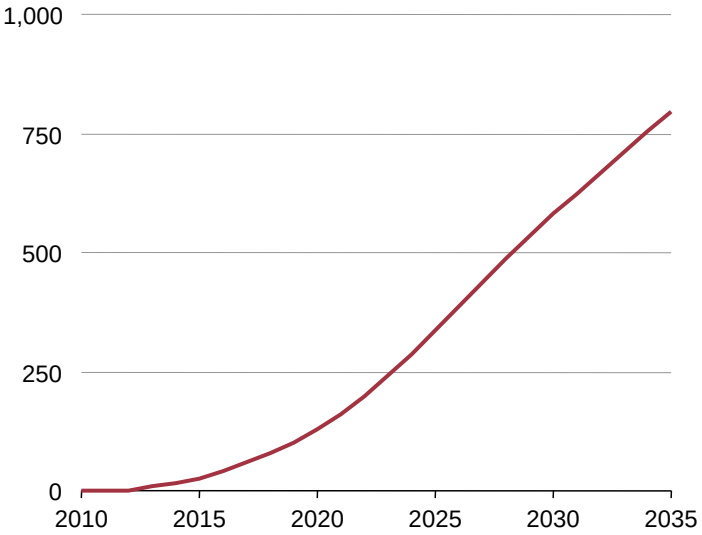
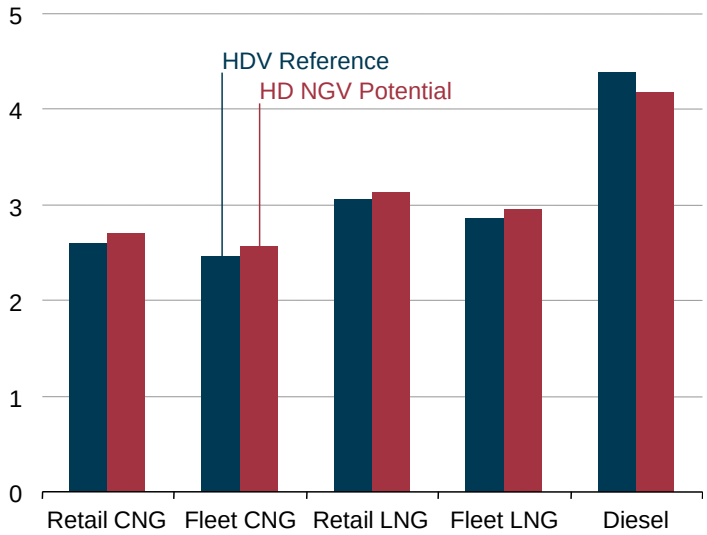


Figure 40. Diesel and natural gas transportation fuel prices in two cases, 2035 (2010 dollars per diesel gallon equivalent)



The term "liquid fuels production industry" refers to all the participants in the production and delivery of liquid fuels, from production of feedstocks to delivery of both liquid and non-liquid end-use products to customers. It includes participants in the more traditional petroleum refining sector, relying on crude oil as a primary feedstock; in the nonpetroleum fossil fuel sector, using natural gas and coal to produce liquid fuels; and in the biofuel sector, using biomass to produce biofuels such as ethanol and biodiesel. The complexity of the industry supply chain is inadequately described by nomenclature predicated on specific feedstocks (e.g., crude oil), processes (e.g. refinery hydrotreating), or end-use products (e.g., diesel fuel and gasoline), which fail to capture the significant economic implications of non-liquid-fuel products for the industry.

The components of the U.S. liquid fuels production industry—including petroleum, nonpetroleum fossil fuel, and biofuel sectors—are shown in Figure 41, along with examples illustrating processes and products. Figure 41 also highlights the differences between the new expanded "liquid fuels production industry," which the entire figure represents, and the less extensive "petroleum and other liquids industry," the components of which are highlighted in red.

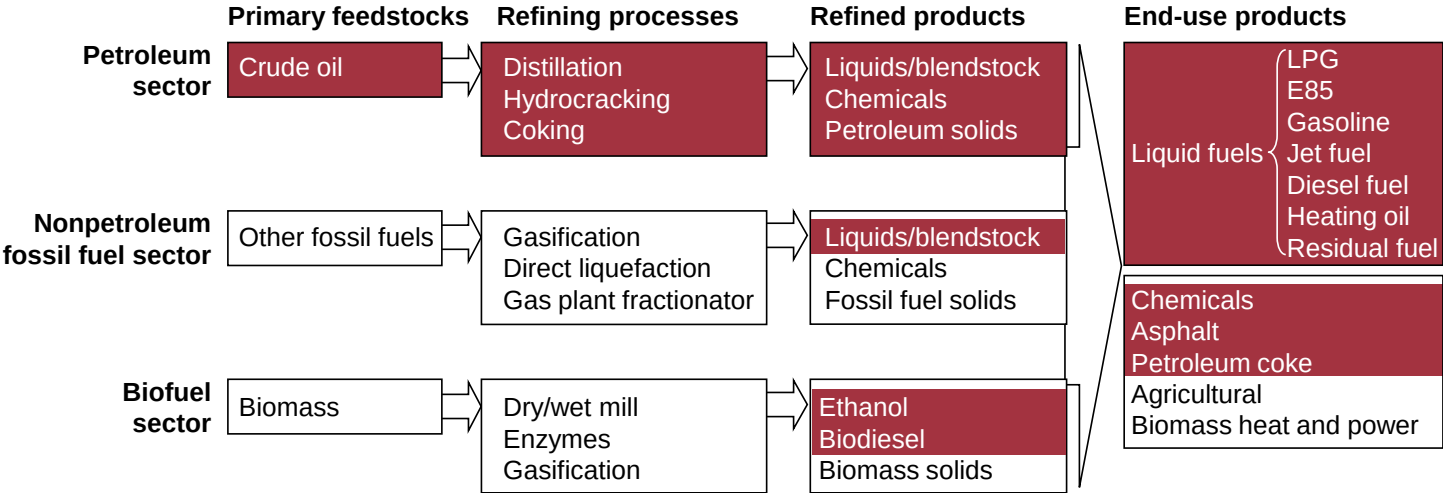
Nonpetroleum feedstocks are used in many new and emerging technologies, such as fermentation, enzymatic conversion, GTL, CTL, biomass-to-liquids, and algae-based biofuels. The new technologies provide valuable non-liquid-fuel co-products—such as chemical feedstocks, distiller's grains, and vegetable oils—that significantly affect the economics of liquid fuels production. The emergence of renewable biofuels has led to the introduction of midstream components such as ethanol and biodiesel, which are blended with petroleum products such as gasoline and diesel fuel during the final stages of the supply chain at refineries, blending sites, or retail pumps. The increase in biofuel production has led to new distribution channels and infrastructure investments and recognition of new production regions, such as the high concentration of ethanol producers in the Midwest. The new LFMM will include the entire liquid fuels production industry, providing greater flexibility for integrating new technologies and their associated products into the liquid fuels supply chain, better reflecting the industry's evolution.

In *AEO2012*, the "petroleum and other liquids" category includes the petroleum sector and those non-petroleum-based liquid products shaded in red in Figure 41, such as ethanol and biodiesel, which are blended with petroleum products to make end-use liquid fuels. Because this approach treats nonpetroleum products as exogenously produced feedstocks, the petroleum and other liquids concept used in *AEO2012* does not explicitly link the industrial processes that yield nonpetroleum liquid fuels (nor their feedstocks, nonpetroleum fossil fuels and biomass) with liquids production. The more inclusive definition of the liquid fuels production industry illustrated in Figure 41 is necessary to capture and model the full range of product flows and economic drivers of decisionmaking by firms involved in this complex industry.

Nonpetroleum feedstocks do not exist in traditional liquid form, and they require a different analytical approach for analysis of their conversion to liquid fuels. Traditional volumetric measures, such as process gain, are not applicable to an analysis of the liquids produced from nonpetroleum feedstocks. It is more appropriate to use the fundamental principles of mass and energy balance to evaluate process performance, market penetration, and supply/demand dynamics when the uses of nonpetroleum feedstocks are being examined. This approach allows for comparison among the different sectors of the liquid fuels production industry. Figure 42 provides an overview of the liquid fuels production industry on a mass basis.

The variety and changing dynamics of nonpetroleum feedstocks and the resulting end-use products also are illustrated in Figure 42. In recent history, biomass has taken significant market share from petroleum feedstocks, correlated with shifts in product yields—a trend that is expected to continue in the future, along with further diversification into nonpetroleum fossil feedstocks. In 2000, nearly all liquid fuels were derived from petroleum. Since then, however, the share of petroleum has dropped while the shares of biomass and other fossil fuels have increased. In 2011, the combined biomass and other fossil fuels share of feedstocks was almost 18 percent, measured on a mass basis. In the LFMM case, the biomass share of feedstock consumption increases to

Figure 41. U.S. liquid fuels production industry



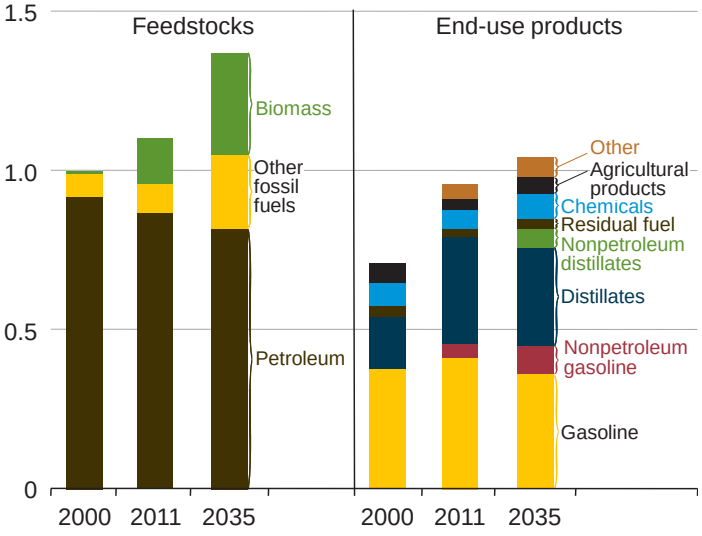
30 percent in 2035, and the petroleum share falls to about 57 percent. The biomass share of end-use products increases only to 10 percent in 2035, reflecting differences in conversion efficiencies between petroleum and nonpetroleum feedstocks, as highlighted by the growing but still small nonpetroleum content of gasoline and distillates.

Changes in crude oil types

Economic growth in the developing countries over the past decade has increased global demand for crude oil. Over the same period, new technologies for recovering crude oil, changes in the yields of existing crude oil fields, and a global increase in exploration have expanded the number and variety of crude oil types. The United States currently imports more than 100 different types of crude oil from around the world, including a growing number from Canada and Mexico, with a wide range of API gravities (between 10.4 and 64.6) and sulfur content (between 0.02 and 5.5 percent). Consequently, it is difficult to group them according to the categories used in the existing NEMS PMM. A new and more comprehensive representation of the numerous crude types is required, as well as flexibility to add new sources.

The United States increasingly is using crude oil extracted from oil sands and oil shale, as well as other nontraditional petroleum sources that require additional processing. The new sources have led to shifts in crude oil flows and changes in the distribution network. The increased variety and regional availability of certain crude types has created new market dynamics and pricing relationships that are difficult to capture using existing methods, especially considering the rapid emergence of "tight oil" production, which, to date, has been substantially different in quality from the crude oil previously expected to be available to U.S. refineries. For example, light sweet crude oil sourced from the Bakken shale formation in North Dakota has been sold to refiners on the Gulf Coast in recent years at a substantial discount relative to heavier imported crudes, because of limitations in the delivery infrastructure.

Figure 42. Mass-based overview of the U.S. liquid fuels production industry in the LFMM case, 2000, 2011, and 2035 (billion tons per year)

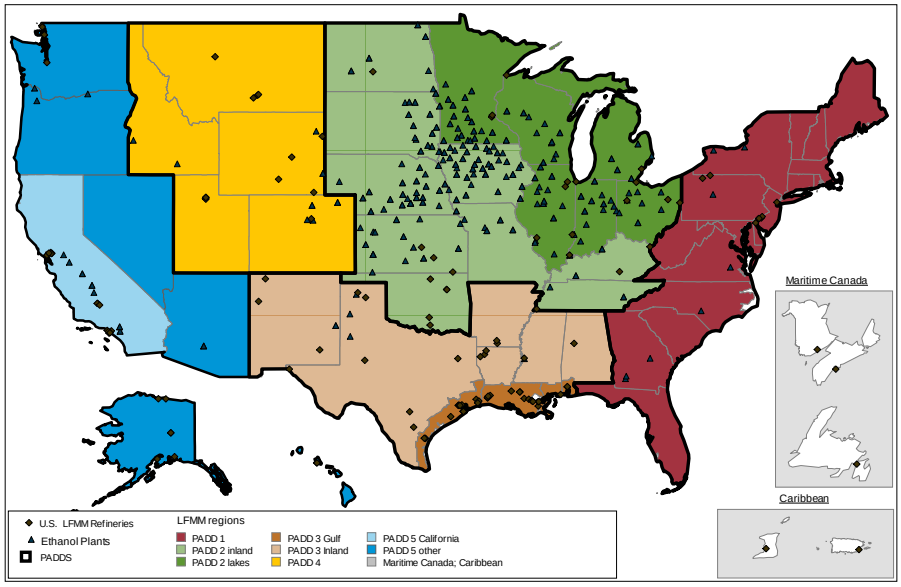


The growing number of sources, changes in characteristics of crudes, and shifting price relationships in crude oil markets require an updated representation of different crude types in NEMS. The model also needs an updated and more dynamic representation of the crude oil distribution network in order to provide better estimates of changes in crude oil flows and potential new regional sources in the future.

Regional updates

The Petroleum Administration for Defense Districts (PADD), which were developed by the Department of Defense during World War II, have been traditionally used as the regional framework for analyzing liquid fuels production. Because the topology and configuration of the liquid fuels market have changed significantly, and new feedstocks have emerged from regions that are subsets of PADDs, the regional definitions for processing liquid fuels need to be redefined. Toward this end, EIA has redefined the refining regions on the basis of market potential and availability of feedstocks. The redefined regions will be further divided as market conditions change. The new regional configuration of the NEMS LFMM will use eight domestic regions and adds a new international region (Figure 43).

Figure 43. New regional format for EIA's Liquid Fuels Market Module (LFMM)



Each new refining region has unique characteristics. PADD 1 has been left unchanged in the new configuration, but can be further divided based on recent and possible future refinery closures and shifts in imports from Europe. PADD 2 was subdivided into the Great Lakes and Inland regions due to the concentrated

production of biofuels and access to Canadian crudes. PADD 3 was divided into the Gulf Coast and Inland regions due to the inability of the interior refineries to handle heavy sour crude. PADD 4 was left unchanged. California was separated from the rest of PADD 5 due to the State's unique gasoline and diesel specifications and regulatory policies. A new international region was added comprising Maritime Canada and the Caribbean.

The modified regional refinery format will allow EIA's analyses to more accurately capture regional refinery trends and potential regional regulatory policies that affect the liquid fuels market. For example, California often enacts its own regulatory policies earlier than the rest of its PADD region, and its individual actions could not be represented accurately in the PADD framework. As a further example, recent refinery closures and other developments on the East Coast evidence the need for a dynamic and flexible representation of the refinery regions that supply the U.S. market.

Changing product markets

Crude oil is still the most important and valuable feedstock for the liquid fuels production industry. More than 650 refineries, located in more than 116 countries, have the capacity to refine 86 million barrels of crude oil per day. In the past, most of the complex refineries that could transform a wide variety of crudes into numerous different products to meet demand were located in the United States. Now, however, complex refineries are becoming more common in Europe and the developing countries of Asia and Latin America, and the products from export-focused merchant refineries in those countries have the potential to compete with U.S. products. An example is the regular export of surplus gasoline from refiners in Europe to the Northeast United States.

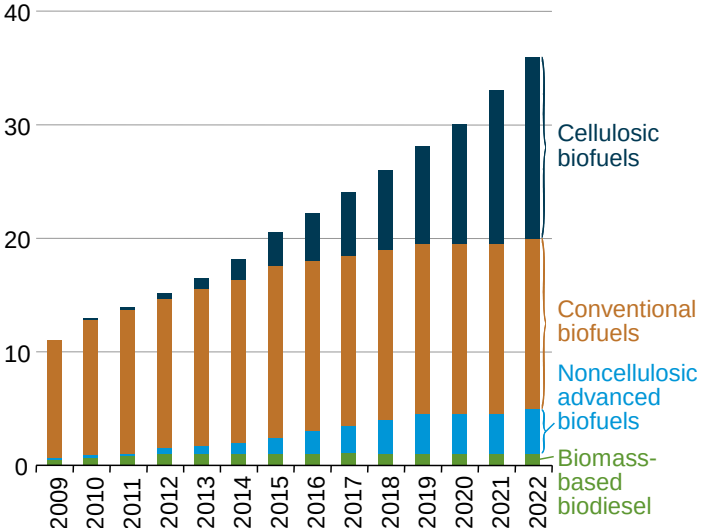
Traditional measures of profitability, such as the 3-2-1 crack spread, require modification in NEMS in view of the changing market for liquid fuels. The calculation of margins requires consideration of multiple feedstocks and multiple products produced in refineries, biorefineries, and production facilities for nonpetroleum fuels. Operators in the liquid fuels production industry are faced with a choice of investing in facilities and modifying their configurations to meet changing market demand, or exchanging domestic feedstocks and products with merchant refineries in a global market. For example, increased U.S. efficiency standards for LDVs have reduced demand for gasoline and increased demand for diesel fuel, which has led to more gasoline exports and more investment to increase diesel output from domestic refineries.

EIA's new LFMM representation of the liquid fuels production industry will need to account for global competition for both crude oil and end-use products. As refineries around the world become larger and more complex, smaller refineries may not be able to compete with imports produced at low margins. Therefore, it is necessary to have a more robust and dynamic representation of the liquid fuel producers, as well as additional flexibility to adjust inputs, refinery configurations, and crude and product demands as the industry evolves.

Regulations and policies

It is important for EIA's models to represent existing laws and regulations accurately, in addition to being flexible enough to model proposed laws and regulations. One of the most important regulations currently affecting the U.S. liquid fuels industry is the RFS, which not only has increased production and use of renewable fuels, but also has changed how fuels are distributed and consumed both here and abroad. The RFS mandates the use of biofuels that are consumed primarily as blends with traditional petroleum products, such as gasoline and diesel fuel (Figure 44). Because of their chemical properties, ethanol, biodiesel, and other first-generation biofuels generally require their own distribution networks or investments in new infrastructure. In addition, because they are produced outside traditional petroleum refineries, the new products are added at different points in the supply chain, either at blending terminals or at retail sites via blender pumps. Modeling those changes requires an update to the traditional PADD regional format used to represent the liquid fuels market, as well as an update to the transportation network that distributes the fuels.

Figure 44. RFS mandated consumption of renewable fuels, 2009-2022 (billion gallons per year)



The RFS also requires consideration of many new technologies and increases the complexity of decisionmaking in the liquid fuels production industry. Fuel volumes by product are mandated by the RFS. For each year, regulated parties must make the decision to either buy the available renewable fuels in proportion to their RFS requirements or purchase the necessary credits. For example, the cellulosic biofuel credit price is set as the greater of $0.25 cents per gallon or $3.00 per gallon minus the wholesale gasoline price, both based on 2008 real dollars. The RFS also contains a general waiver based on technical, economic, or environmental feasibility that the EPA Administrator has discretionary authority to act on to reduce the mandates for advanced and total biofuels.

In addition, use of biofuels has broader implications for the global market, in terms of both feedstocks and the fuels themselves. A good example is ethanol. Its primary feedstocks are corn and sugar, both of which are global commodities in high demand as food sources as well as biofuel feedstocks. U.S. ethanol producers compete globally in other countries, such as Brazil, that have their own renewable fuels mandates.

Finally, coproducts from biofuels production have a significant influence on their economics. For example, the value of the dried distillers grains coproduct from corn ethanol production, which can be sold to the agricultural sector, can offset up to one-third of the purchase cost for the corn feedstock. Thus, the economics of biofuels production are complex, and they require a model that accounts for numerous investment decisions, feedstock markets, and global interactions. The RFS adds to the liquids fuels market a number of fuel technologies, midstream products and coproducts, evolving regional production and distribution networks, and complex domestic and global market interactions.

The U.S. liquid fuels market has evolved substantially over the past 20 years in terms of available fuel types, production regions, global market dynamics, and regulations and policies. The transition has resulted in a liquid fuels market that uses both petroleum- and nonpetroleum-based inputs, distributes them around the country by a variety of methods, and makes investment decisions based on both economic and regulatory factors. The changes are significant enough to make the framework and metrics used in traditional refinery models no longer adaptable or robust enough for proper modeling of the transformed liquid fuels market. EIA currently is in the process of updating its framework to allow better representation of the transformed industry.

8. Changing environment for fuel use in electricity generation

Introduction

The *AEO2012* Reference case shows considerable change in the mix of generating technologies over the next 25 years. Coal remains the dominant source of electricity generation in the Reference case, with a 38-percent share of total generation in 2035, but that is down from shares of 45 percent in 2010 and nearly 50 percent in 2005. The decrease in coal's share of total generation is offset primarily by increases in the shares of natural gas and renewables. Key factors contributing to the shift away from coal are sustained low natural gas prices, higher coal prices, slow growth in electricity demand, and the implementation of Mercury and Air Toxics Standards (MATS) [*69*] and Cross-State Air Pollution Rule (CSAPR) [*70*]. These factors influence how existing plants are used, which plants are retired, and what types of new plants are built.

Fuel prices and dispatch of power plants

The price of fuel is a major component of a power plant's variable operating costs [*71*]. The fuel-related variable cost of generating electricity is a function of the fuel price and the efficiency of the plant's conversion of the fuel into electricity, also referred to as the heat rate. Although natural gas prices declined dramatically in the second half of 2011 and the first half of 2012, coal-fired power plants have generally had the advantage of lower fuel prices and the disadvantage of higher heat rates in comparison to combined-cycle plants fueled by natural gas.

Power plants are dispatched primarily on the basis of their variable costs of operation. Plants with the lowest operating costs generally operate continuously. Plants with higher variable costs are brought on line sequentially as demand for generation increases. Because fuel prices influence variable costs, changes in fuel prices can affect the choice of plants dispatched. For instance, if the price of natural gas decreases, the variable costs for combined-cycle plants may fall below those for competing coal-fired plants, and, as a result, the combined-cycle plant may be dispatched before the coal-fired plant. Coal and natural gas plants can vary their outputs on the basis of fuel prices, but there are some cases in which plants may cycle off completely until they can be operated economically. In order to examine the overall impacts of changes in projected fuel price trends on the electric power sector, *AEO2012* includes alternative cases that assume higher and lower prices for natural gas and coal.

Demand for electricity

Electricity demand determines how much generating capacity is needed. When demand increases, plants with higher operating costs are brought into service, increasing average operating costs and, as a result, average electricity prices. Higher prices, in turn, provide economic incentives for the construction of new capacity. Conversely, when demand declines, plants with higher operating costs are taken off line or run at lower intensities, and the economic incentives for new plant construction are reduced. If a plant is not profitable, the owner may decide to retire it.

Mercury and Air Toxics Standards and Cross-State Air Pollution Rule

Both MATS and CSAPR are included in the *AEO2012* Reference case [*72*]. Both rules have significant implications for the U.S. generating fleet, especially coal-fired power plants. MATS requires all U.S. coal- and oil-fired power plants with capacities greater than 25 megawatts to meet emission limits consistent with the average performance of the top 12 percent of existing units—known as the maximum achievable control technology. MATS applies to three pollutants: mercury, hydrogen chloride (HCl), and fine particulate matter ($PM_{2.5}$). HCl and $PM_{2.5}$ are intended to serve as surrogate pollutants for acid gases and nonmercury metals, respectively. CSAPR is a cap-and-trade program that sets caps on sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from all fossil-fueled plants greater than 25 megawatts in 28 States in most of the eastern half of the United States. CSAPR is scheduled

to begin in 2012, although implementation was delayed by a court-issued stay at the time this article was completed [*73*]. See also "Cross-State Air Pollution Rule" in the "Legislation and regulations" section of this report.

Although the two rules differ in their makeup and the pollutants covered, the technologies that can be used to meet their requirements are not mutually exclusive. For instance, in order to meet the MATS acid gas standard, it is assumed that coal-fired plants without appropriate existing controls will need to install either flue-gas desulfurization (FGD) or dry sorbent injection (DSI) systems, which also reduce SO_2 emissions. Therefore, by complying with the MATS standards for acid gases, plants will lower overall SO_2 emissions, facilitating compliance with CSAPR.

AEO2012 assumes that all coal-fired power plants will be required to reduce mercury emissions to 90 percent below their pre-control levels in order to comply with MATS. The *AEO2012* NEMS explicitly models mercury emissions from power plants. Reductions in mercury emissions can be achieved with a combination of FGDs and selective catalytic reduction, which is primarily used to reduce SO_2 and NO_x emissions, or by installing activated carbon injection (ACI) systems. FGD systems may be effective in reducing mercury emissions from bituminous coal (due to its chemical makeup), but ACI systems may be necessary to remove mercury emissions from plants burning subbituminous and lignite coal.

NEMS does not explicitly model emissions of acid gases or toxic metals other than mercury. In order to represent the MATS limits for those emissions, *AEO2012* assumes that plants must install either FGD or DSI systems to meet the acid gas standard and, in the absence of a scrubber, a full fabric filter to meet the MATS standard for nonmercury metals. *AEO2012* assumes that the appropriate control technologies will be installed by 2015 in order to meet the MATS requirements.

DSI and wet and dry FGD systems are technologies that will allow plants to meet the MATS standards for acid gases. As of 2010, 43 percent of U.S. generating capacity already had FGDs installed [*74*]. For a number of the remaining, uncontrolled plants, operators will need to assess the effectiveness of installing FGD or DSI systems to comply with MATS. There are economic and engineering tradeoffs between the two technologies. FGD systems require significant upfront investment but have relatively low operating costs. DSI systems generally do not require significant capital expenses but may use significant quantities of sorbent to operate effectively, which increases their operating costs. Waste disposal for DSI also may be a significant variable cost, whereas the waste products from FGD systems can be sold as feedstock for industrial processes.

The EPA set an April 2015 compliance deadline for MATS, but the rule allows State environmental permitting agencies to extend the deadline by a year. Beyond 2016, the EPA stated that it will handle noncompliant units that need to operate for reliability purposes on a case-by-case basis [*75*]. *AEO2012* assumes that all plants will comply with MATS by the beginning of 2015.

Economics of plant retirements

The decision to retire a power plant is an economic one. Plant owners must determine whether a plant's future operations will be profitable. Environmental regulations, low natural gas prices, higher coal prices, and future demand for electricity all are key factors in the decision. Coal plants without FGD systems and with high heat rates, high delivered coal costs, and strong competition from neighboring natural gas plants in regions with slow growth in electricity demand may be especially prone to retirement.

Greenhouse gas policy in *AEO2012*

Uncertainty about possible future regulation of GHG emissions will continue to influence investment decisions in the power sector. Despite a lack of Congressional action, many utilities include simulations with a future CO_2 emissions price when evaluating long-term investment decisions. A carbon price would increase the cost of generation for all fossil fuel plants, but the largest impact would be on coal-fired plants. Thus, plant owners could be reluctant to retrofit existing coal plants to control for non-GHG pollutants, given the possibility that GHG regulations might be enacted in the near future. This uncertainty may influence the assumptions plant owners make about the economic lives of particular facilities.

In the Reference case, the costs of environmental retrofits are assumed to be recovered over a 20-year period. Two alternative cases assume that the costs would be recovered over 5 years, reflecting concern that future laws or regulations aimed at limiting GHG emissions will have significant negative effects on the economics of investing in existing coal plants.

AEO2012 also includes two alternative cases that assume enactment of an explicit GHG control policy. In each case, a CO_2 price is applied across all sectors starting in 2013 and increased at a 5-percent annual real rate through 2035. The price starts at $25 per metric ton in the GHG25 case and $15 per metric ton in the GHG15 case. The CO_2 price is applied across sectors and has a significant impact on the cost of generating electricity from fossil fuels, particularly coal.

Alternative cases

In order to illustrate the impacts of the various influences on the electric power sector, *AEO2012* includes several alternative cases that include varying assumptions about fuel prices, electricity demand, and the cost recovery period for environmental control equipment investments:

- The Reference 05 case assumes that the cost recovery period for investments in new environmental controls is reduced from 20 years to 5 years.

- The Low Estimated Ultimate Recovery (EUR) case assumes that the EUR per tight oil or shale gas well is 50 percent lower than in the Reference case, increasing the per-unit cost of developing the resource and, ultimately, the price of natural gas used at power plants (Figure 45).
- The High EUR case assumes that the EUR per tight oil or shale gas well is 50 percent higher than in the Reference case, decreasing the per-unit cost of developing the resource and the price of natural gas for power plants.
- The Low Gas Price 05 case combines the more optimistic assumptions about future volumes of shale gas production from the High EUR case with a 5-year recovery period for investments in new environmental controls.
- The High Coal Cost case assumes lower mining productivity and higher costs for labor, mine equipment, and coal transportation, which ultimately result in higher coal prices for electric power plants.
- The Low Coal Cost case assumes higher mining productivity and lower costs for labor, mine equipment, and coal transportation, which ultimately result in lower coal prices for electric power plants.
- The Low Economic Growth case assumes lower growth rates for population and labor productivity, higher interest rates, and lower growth in industrial output, which ultimately reduce demand for electricity (Figure 46), which is reflected in electricity sales, relative to the Reference case.
- The High Economic Growth case assumes higher growth rates for population and labor productivity. With higher productivity gains and employment growth, inflation and interest rates are lower than in the Reference case, and, consequently, economic output grows at a higher rate, ultimately increasing demand for electricity, which is reflected in electricity sales, relative to the Reference case.
- In the GHG15 case, the CO_2 price is set at $15 per metric ton in 2013 and increases at a real annual rate of 5 percent per year over the projection period. Price is set to target the same reduction in CO_2 emissions as in the *AEO2011* GHG Price Economywide case.
- In the GHG25 case, the CO_2 price is set at $25 per metric ton in 2013 and increases at a real annual rate of 5 percent per year over the projection period. Price is set to target the same dollar amount as in the *AEO2011* GHG Price Economywide case.

Analysis results

Coal-fired plant retirements

Significant amounts of coal-fired generating capacity are retired in all the alternative cases considered (Figure 47). (For a map of the electricity regions projected, see Appendix F.) In the Reference 05 case, 63 gigawatts of coal-fired capacity is retired through 2035, 28 percent higher than in the Reference case. In the High EUR case, 55 gigawatts of coal-fired capacity is retired, as lower wholesale electricity prices and competition from natural gas combined-cycle units makes the operation of some coal plants uneconomical. In the Low Economic Growth case, 69 gigawatts of coal-fired capacity is retired, because lower demand for electricity reduces the need for new capacity and makes investments in older plants unattractive.

The High Economic Growth case results in fewer retirements, as existing coal-fired capacity is needed to meet growing electricity demand, and higher economic growth pushes up natural gas prices. In the Low Coal Cost case, the lower relative coal prices increase the profit margins for coal-fired power plants, making it more likely that investments in retrofit equipment will be recouped over the life of the plants.

Figure 45. Natural gas delivered prices to the electric power sector in three cases, 2010-2035 (2010 dollars per million Btu)

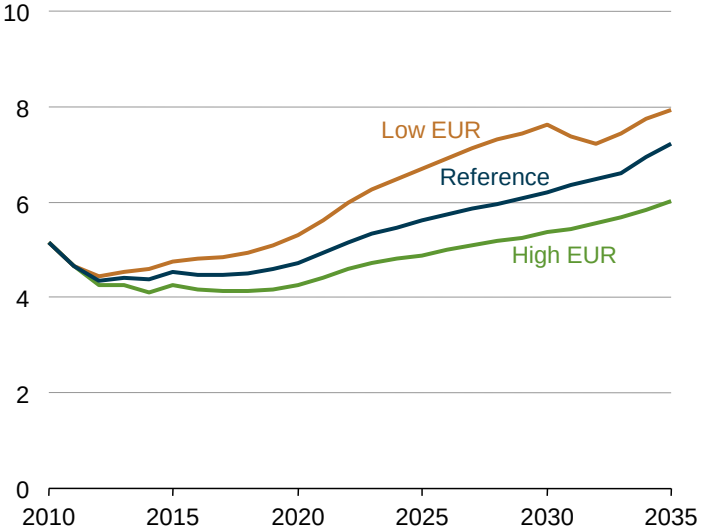
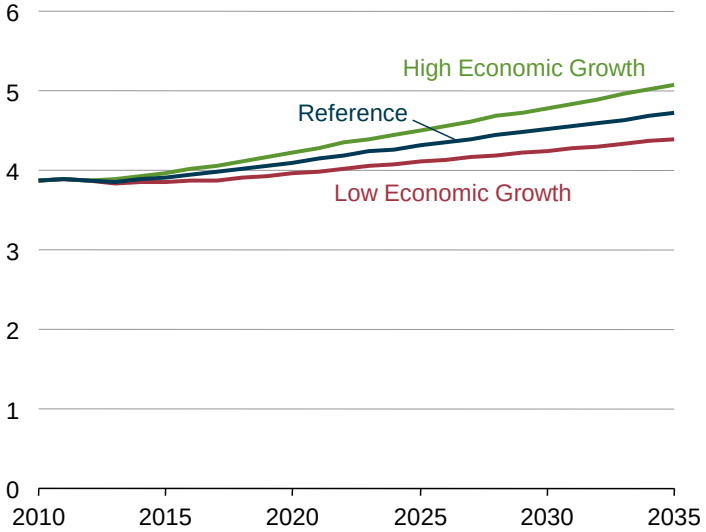


Figure 46. U.S. electricity demand in three cases, 2010-2035 (trillion kilowatthours)



Coal-fired capacity retirements are concentrated in two North American Electric Reliability Corporation (NERC) regions: the SERC Reliability Corporation (SERC) region, which covers the Southeast region, and the Reliability First Corporation (RFC), which includes most of the Mid-Atlantic and Ohio Valley region [*76*]. Many coal-fired plants in those regions are sensitive to the factors that influence retirement decisions, as discussed above. In the SERC and RFC regions, which in 2010 accounted for 65 percent of U.S. coal-fired generating capacity, 43 percent of the coal-fired plants do not have FGD units installed. Coal plants in the RFC and SERC regions are fueled primarily by bituminous coal, generally the coal with the highest cost. Projected demand for electricity in the early years of the Reference case is low nationwide and, especially, in the RFC region, where demand in 2015 is slightly lower than in 2010. In both the GHG15 and GHG25 cases, even larger amounts of coal-fired capacity are retired by 2035 than in the non-GHG policy cases.

Generation by fuel

Coal

In all cases, generation from coal is lower in 2020 than in 2010. Higher coal prices, relatively low natural gas prices, retirements of coal-fired capacity, and slow growth in electricity demand are responsible for the decrease. Generation from coal is lower than in the Reference case in the Reference 05, High EUR, Low Gas Price 05, High Coal Cost, and Low Economic Growth cases as a result of additional retirements of coal-fired capacity, lower natural gas prices, higher coal prices, or lower electricity demand. In cases where the opposite assumptions are incorporated, coal-fired generation is higher.

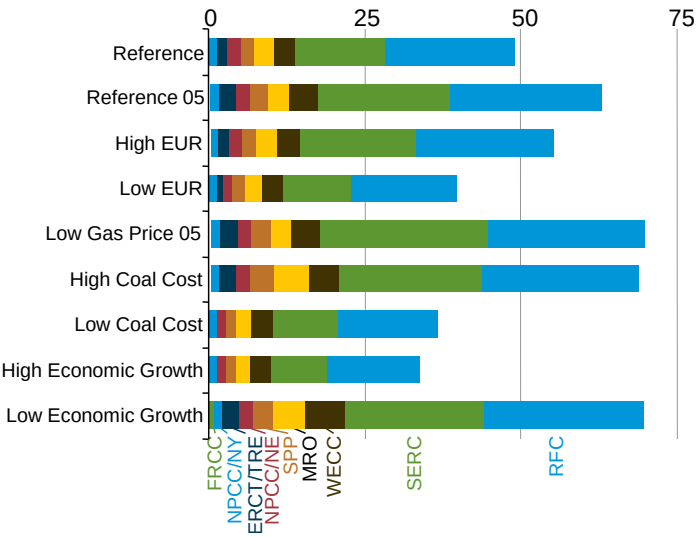
Generation from coal begins to recover after 2020, as electricity demand and natural gas prices start to rise. The strongest increases in coal-fired electricity generation occur in the Low EUR, Low Coal Cost, and High Economic Growth cases. When lower natural gas prices, lower economic growth, and/or higher coal prices are assumed, coal-fired generation still increases after 2020 but at a slower rate. In all cases, utilization of existing coal-fired power plants increases, because there is no significant growth in new coal-fired capacity. In the most optimistic case, the High Economic Growth case, only 3.3 gigawatts of new coal-fired capacity is added from 2017 to 2035 [*77*].

Despite a declining share of the generation mix, coal still has the highest share of total electricity generation in 2035 in all non-GHG or High TRR cases. However, it never again reaches the 2010 share of 45 percent, even in the Low EUR case (where it reaches 40 percent in 2035). Conversely, the coal share of total generation in 2035 is 34 percent in the Low Gas Price 05 case. The lower coal share is offset by increased generation from natural gas, which grows significantly in all the cases. The natural gas share of total generation almost equals that of coal in the Low Gas Price 05 case. In the GHG15 and GHG25 cases, coal-fired generation drops to 16 percent and 4 percent, respectively, of the total generation mix in 2035, and in both cases generation from coal declines significantly as the explicit price on CO_2 emissions increases costs. In the GHG15 and GHG25 cases, decreases in coal-fired generation are offset by a mix of natural gas, nuclear, and renewable generation.

Natural gas

In the *AEO2012* Reference case, electricity generation from natural gas in 2020 is 13 percent above the 2010 level, despite an increase of only 5 percent in overall electricity generation. Low natural gas prices result in greater utilization of existing combined-cycle plants as well as the addition of 16 gigawatts of natural gas combined-cycle capacity from 2010 to 2020. The same trends are amplifed in cases with lower natural gas prices and more coal-fired capacity retirements and muted in cases with higher natural gas prices and fewer coal-fired capacity retirements. Generation from combustion turbines does not change significantly across the cases, demonstrating that changes in the relative economics of coal and natural gas affect primarily the dispatch of combined-cycle plants to meet base and intermediate load requirements, not combustion turbines to meet peak load requirements.

Figure 47. Cumulative retirements of coal-fired generating capacity by Electric Market Module region in nine cases, 2011-2035 (gigawatts)



In the Reference case, 58 gigawatts of natural gas combined-cycle capacity is added from 2020 to 2035, causing an increase in generation from natural gas during the period (Figures 48 and 49). In the Low EUR and Low Coal Cost cases, growth in natural gas combined-cycle capacity is slower. Although generation from natural gas increases overall with the addition of new capacity, utilization of existing combined-cycle plants drops slightly as higher natural gas prices reduce the frequency at which combined-cycle plants are dispatched.

In the GHG15 and GHG25 cases, electricity generation from natural gas exceeds generation from coal in 2020. Natural gas has one-half the CO_2 emissions of coal, and at relatively low CO_2 prices, natural gas generation is seen as an attractive

alternative to coal. However, as CO_2 prices rise over the projection period, the increasing cost of generating electricity with natural gas causes the growth in natural gas generation to slow. In the GHG25 case, natural gas combined-cycle plants with CCS play a role in CO_2 mitigation, with 34 gigawatts of natural gas combined-cycle capacity added between 2022 and 2035.

Nuclear

Generation from nuclear power plants does not change significantly from Reference case levels in any of the non-GHG cases, due to the high cost of new nuclear plant construction relative to natural gas and renewables. In the GHG15 and GHG25 cases, nuclear power plants become more competitive with fossil plants, because they do not emit CO_2 and are needed to replace coal-fired capacity that is retired due to the cost of CO_2 emissions. In the GHG15 and GHG25 cases, generation from nuclear power is 57 percent and 121 percent higher, respectively, in 2035 than in 2010.

Renewables

Generation from renewable energy sources grows by 77 percent from 2010 to 2035 in the Reference case. Most of the growth in renewable electricity generation is a result of State RPS requirements, Federal tax credits, and—in the case of biomass—the availability of low-cost feedstocks. The change in renewable generation over the 2010-2035 period varies from a 102-percent increase in the High Economic Growth case to a 62-percent increase in the Low Economic Growth case. The largest growth in renewable generation is projected in the GHG15 and GHG25 cases, where renewable generation increases by about 150 percent from 2010 and 2035 in both cases. A price on CO_2 emissions makes generation from renewables more competitive with fossil plants without CCS.

Figure 48. Electricity generation by fuel in eleven cases, 2010 and 2020 (trillion kilowatthours)

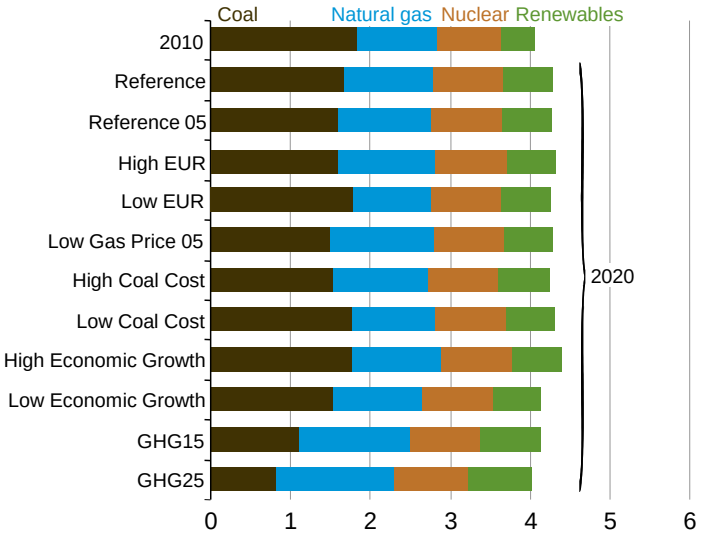
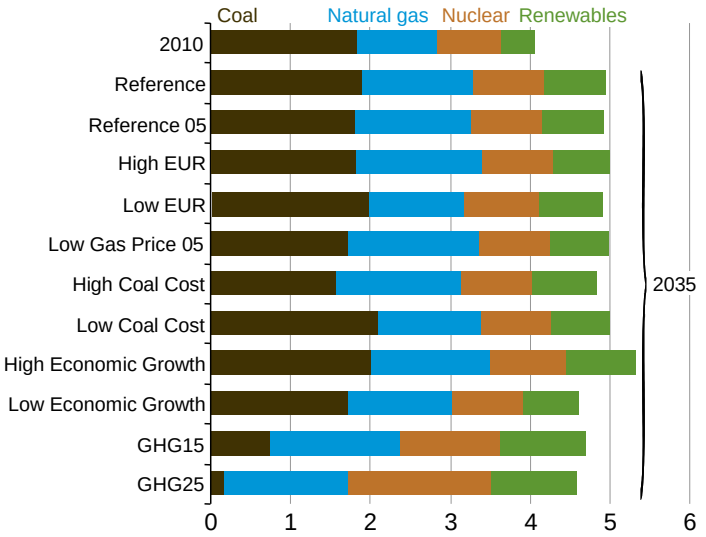


Figure 49. Electricity generation by fuel in eleven cases, 2010 and 2035 (trillion kilowatthours)



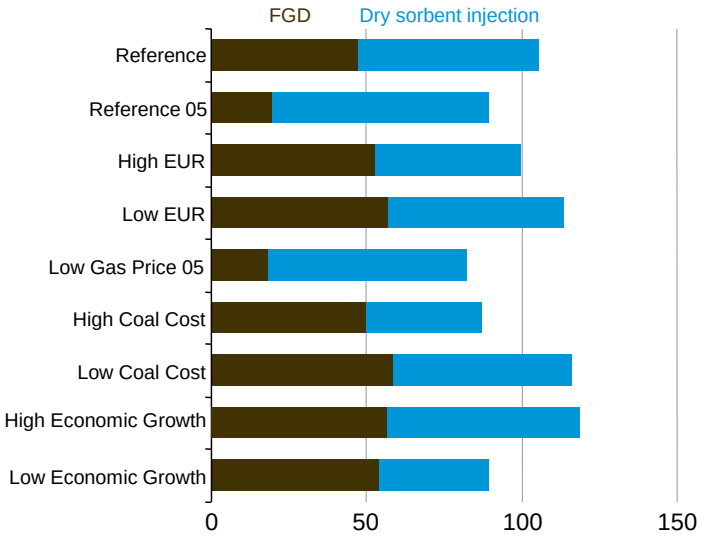
Installations of retrofit equipment

As discussed above, it is assumed that all coal-fired plants must have either FGD or DSI systems installed by 2015 to comply with environmental regulations. Because retirement is the only other option, cases with more retirements have fewer retrofits and vice versa (Figure 50). In the Reference 05 and Low Gas Price 05 cases, the relative cost of FGD units is higher because of the short payback period, making DSI a relatively more attractive option.

Emissions

SO_2 emissions are significantly below 2010 levels in 2015 in all cases, as a result of coal-fired capacity retirements and the installation of pollution control equipment to comply with MATS. *AEO2012* assumes that a DSI system, combined with a fabric filter, will remove 70 percent of a coal plant's SO_2 emissions, and an FGD unit 95 percent. As a result of the requirement for FGD or DSI systems, all coal plants larger than 25 megawatts that did not have FGD units installed in 2010 significantly reduce their SO_2 emissions after 2015 by

Figure 50. Cumulative retrofits of generating capacity with FGD and dry sorbent injection for emissions control, 2011-2020 (gigawatts)



installing control equipment. In all cases, coal-fired generation is down overall, which also contributes to the decline in emissions. SO_2 emissions increase after 2020 in all non-GHG cases, as coal-fired generation increases with rising natural gas prices. Because DSI and FGD retrofits do not remove all the SO_2 from coal-fired power plant emissions, increases in coal-fired generation result in higher SO_2 emissions, although they are still much lower than comparable 2010 levels. Also, the level of SO_2 reduction is proportional to the amount of coal-fired generation, and therefore the cases with the highest projected levels of coal-fired generation also project the highest levels of SO_2 emissions.

The projections for mercury emissions are similar. After a sharp drop in 2015, mercury emissions begin to rise slowly as coal-fired generation increases in all non-GHG cases. However, mercury emissions in 2035 still are significantly below 2010 levels, as the requirement for a 90-percent reduction in uncontrolled emissions of mercury remains binding throughout the projection.

NO_x emissions are not directly affected by MATS, but both annual and seasonal cap-and-trade programs are included in CSAPR. Emissions reductions relative to 2010 levels are small throughout the projection period in most cases, mainly because compliance with CSAPR NO_x regulations is required in only 26 States, and 2010 emissions levels already were close to the cap.

CO_2 emissions from the electric power sector fall slightly in cases that project declines in coal use, but the largest reductions occur in the GHG15 and GHG25 cases. In the GHG15 case, CO_2 emissions from the electric power sector are 46 percent below 2010 levels in 2035, and in the GHG25 case they are 76 percent below 2010 levels.

Electricity prices

Real electricity prices in 2035 are 3 percent above the 2010 level in the Reference case. The increase is relatively modest because natural gas prices increase slowly, and several alternatives for complying with the environmental regulations are available. When lower natural gas prices are assumed, real electricity prices decline relative to the Reference case. Both the GHG15 and GHG25 cases assume that costs for CO_2 emission allowances are passed through directly to customers. Therefore, average electricity prices in the GHG15 and GHG25 cases in 2035 are 25 percent and 33 percent higher, respectively, than in the Reference case. The GHG15 and GHG25 cases do not include any of the rebates to electricity consumers included in some other GHG policy proposals, which would reduce the impact on electricity prices.

9. Nuclear power in *AEO2012*

In the *AEO2012* Reference case, electricity generation from nuclear power in 2035 is 10 percent above the 2010 total. The nuclear share of overall generation, however, declines from 20 percent in 2010 to 18 percent in 2035, reflecting increased shares for natural gas and renewables.

In the Reference case, 15.8 gigawatts of new nuclear capacity is added from 2010 through 2035, including both new builds (a total of 8.5 gigawatts) and power uprates at operating nuclear power plants (7.3 gigawatts). A total of 6.1 gigawatts of nuclear capacity is retired in the Reference case, with most of the retirements coming after 2030. However, given the current uncertainty about likely lifetimes of nuclear plants now in operation and the potential for new builds, *AEO2012* includes several alternative cases to examine the impacts of different assumptions about future nuclear power plant uprates and operating lifetimes.

Uprates

Power plant uprates involve projects that are intended to increase the licensed capacity of existing nuclear power plants and permit those plants to generate more electricity. The U.S. Nuclear Regulatory Commission (NRC) must approve all uprate projects before they are undertaken and verify that the reactors will be able to operate safely at higher levels of output. Power plant uprates can increase plant capacity by 1 to 20 percent, depending on the size and type of the uprate project. Capital expenditures may be small (e.g., installing a more accurate sensor) or significant (e.g., replacing key plant components, such as turbines).

In developing projections for nuclear power, EIA relies on both reported data and estimates. Reported data come from Form EIA-860 [*78*], which requires all nuclear power plant owners to report any plans for building new plants or making major modifications to existing plants (such as uprates) over the next 10 years. In 2010, operators reported that they intended to complete uprate projects sometime during the next 10 years, which together would add a total of 0.8 gigawatts of new capacity. In addition to the reported plans for capacity uprates, EIA assumed that additional power uprates over the period from 2011 to 2035 would add another 6.5 gigawatts of capacity, based on interactions with EIA stakeholders with significant experience in implementing power plant uprates.

New builds

Building a new nuclear power plant is a tremendously complex project that can take many years to complete. Specialized high-wage workers, expensive materials and components, and engineering and construction expertise are required, and only a select group of firms worldwide can provide them. In the current economic environment of low natural gas prices and flat demand for electricity, the overall market conditions for new nuclear power plants are challenging.

Nuclear power plants are among the most expensive options for new generating capacity available today [*79*]. In the *AEO2012* Reference case, the overnight capital costs associated with building a nuclear power plant planned in 2012 are assumed to be $5,335 per kilowatt of capacity, which translates to $11.7 billion for a dual-unit 2,200-megawatt power plant. The overnight costs

do not include additional costs such as financing, interest carried forward, and peripheral infrastructure updates [*80*]. Despite the cost, however, deployment of new nuclear capacity supports the long-term resource plans of many utilities, by allowing fuel diversification and providing a hedge in the future against potential GHG emissions regulations or natural gas prices that are higher than expected.

Incentive programs exist to encourage the construction of new reactors in the United States. At the Federal level, the Energy Policy Act of 2005 (EPACT05) established a loan guarantee program for new nuclear plants completed and in operation by 2020 [*81*]. A total of $18.5 billion is available, of which $8.3 billion has been conditionally committed to the construction of Southern Company's Vogtle Units 3 and 4 [*82*]. EPACT05 also provides a PTC of $18 per megawatthour for electricity produced during the first 8 years of operation for a new nuclear plant [*83*]. New nuclear plants must be operational by 2021 to be eligible for the PTC, and the credit is limited to the first 6 gigawatts of new nuclear plant capacity. In addition to Federal incentives, several States provide favorable regulatory environments for new nuclear plants by allowing plant owners to recover their investments through retail electricity rates.

Several utilities are moving forward with plans to deploy new nuclear power plants in the United States. The Reference case reflects those plans by including 6.8 gigawatts of new nuclear capacity over the projection period. As reported on Form EIA-860, 5.5 gigawatts of new capacity (Vogtle Units 3 and 4, Summer Units 2 and 3, and Watts Bar Unit 2) are expected to be operational by 2020 [*84*]. The Reference case also includes 1.3 gigawatts associated with the construction of Bellefonte Unit 1, which the Tennessee Valley Authority reflects in its Integrated Resource Plan [*85*].

In addition to reported plans for new nuclear power plants, 1.8 gigawatts of unplanned capacity is built in the later years of the Reference case. Higher natural gas prices, recovering demand for electricity, and the need to make up for the loss of a limited amount of nuclear capacity all play a role in the additional builds.

Long-term operation of the existing nuclear power fleet

The NRC has the authority to issue initial operating licenses for commercial nuclear power plants for a period of 40 years. As of December 31, 2011, there were 7 reactors that received their initial full power operating licenses over 40 years ago. Among this set of reactors, Oyster Creek Unit 1 was the first reactor to operate for over 40 years, after receiving its initial full power operating license in August 1969. Oyster Creek Unit 1 was followed by Dresden Units 2 and 3, H.B. Robinson Unit 2, Monticello, Point Beach 1, and R.E. Ginna. The decision to apply for an operating license renewal is made by nuclear power plant owners, typically based on economics and the ability to meet NRC requirements. As of January 2012, the NRC had granted license renewals to 71 of the 104 operating reactors in the United States, allowing them to operate for a total of 60 years [*86*]. Currently, the NRC is reviewing license renewal applications for 15 reactors and expects to receive applications from another 14 reactors between 2012 and 2016 [*87*].

NRC regulations do not limit the number of license renewals a nuclear power plant may be granted. The nuclear power industry is preparing applications for license renewals that would allow continued operation beyond 60 years. The first application seeking approval to operate for 80 years is tentatively scheduled to be submitted by 2013. Some aging nuclear plants may, however, pose a variety of issues that could lead to decisions not to apply for a second license renewal, such as high operation and maintenance costs or the need for large capital expenditures to meet NRC requirements. Industry research on long-term reactor operations and aging management is focused on identifying challenges that aging facilities might encounter and formulating potential approaches to meet those challenges [*88*]. Typical challenges involve materials degradation, safety margins, and assessing the integrity of concrete structures. In the Reference case, 6.1 gigawatts of nuclear power plant capacity is retired by 2035, based on uncertainty related to issues associated with long-term operations and aging management [*89*].

It should be noted that although the Oyster Creek Generating Station in Lacey Township, New Jersey, received a license renewal and could operate until 2029, the plant's owner has reported to EIA that it will be retired in 2019, after 50 years of operation. The *AEO2012* Reference case includes this reported early retirement. Also, given the evolving nature of the NRC's regulatory response to the accident at Japan's Fukushima Daiichi nuclear power plant in March 2011, the Reference case does not include retirements directly related to the accident (for example, retirements prompted by potential new NRC regulatory requirements for safety retrofits).

Sensitivity cases

The *AEO2012* Low Nuclear case assumes that only the planned nuclear plant uprates already reported to EIA will be completed. Uprates that are currently under review or expected to be submitted to the NRC are not included. The Low Nuclear case also assumes that all nuclear power plants will be retired after 60 years of operation, resulting in a 30.9-gigawatt reduction in U.S. nuclear power capacity from 2010 to 2035. Figure 51 shows nuclear capacity retirements in the Low Nuclear case by NERC region. It should be noted that after the retirement of Oyster Creek in 2019, the next nuclear plant retirement occurs in 2029 in the Low Nuclear case. No new nuclear plants are built in the Low Nuclear case beyond the 6.8 gigawatts already planned.

In the High Nuclear case, in addition to plants already under construction, plants with active license applications at the NRC are constructed, provided that they have a tentatively scheduled mandatory hearing before the NRC or Atomic Safety and Licensing Board and deploy a currently certified design for the nuclear steam supply system, such as the AP1000. With this assumption, an additional 6.2 gigawatts of new nuclear capacity is added relative to the Reference case. The High Nuclear case also assumes that all existing nuclear power plants will receive their second license renewals and will operate through 2035. Uprates in the

High Nuclear case are consistent with those in the Reference case. The only retirement included in the High Nuclear case is the announced early retirement of Oyster Creek in 2019.

Results

In the Reference case, 8.5 gigawatts of new nuclear power plant capacity is added from 2010 to 2035, including the 6.8 gigawatts reported to EIA (referred to as "planned") and 1.8 gigawatts built endogenously in NEMS (referred to as "unplanned"). Unplanned capacity is added starting in 2030 in response to rising natural gas prices, which make new nuclear power plants a more competitive option for new electric capacity. In the High Nuclear case, planned capacity additions are almost double those in the Reference case, but unplanned additions are lower. The price of natural gas delivered to the power sector in the High Nuclear case is lower than in the Reference case, making the economics of nuclear power plants slightly less attractive. The additional planned capacity in the High Nuclear case also reduces the need for new unplanned capacity. No unplanned capacity is added in the Low Nuclear case.

Nuclear power generation in 2035 reflects the differences in capacity that occur in the nuclear cases. In the High Nuclear case, nuclear generation in 2035 is 10 percent higher than in the Reference case, and the nuclear share of total generation is 20 percent, as compared with 18 percent in the Reference case. The increase in nuclear capacity in the High Nuclear case contributes to an increase in total electricity generation, in spite of lower levels of generation from natural gas (4 percent lower than in the Reference case in 2035) and coal and renewables (less than 1 percent lower for each fuel).

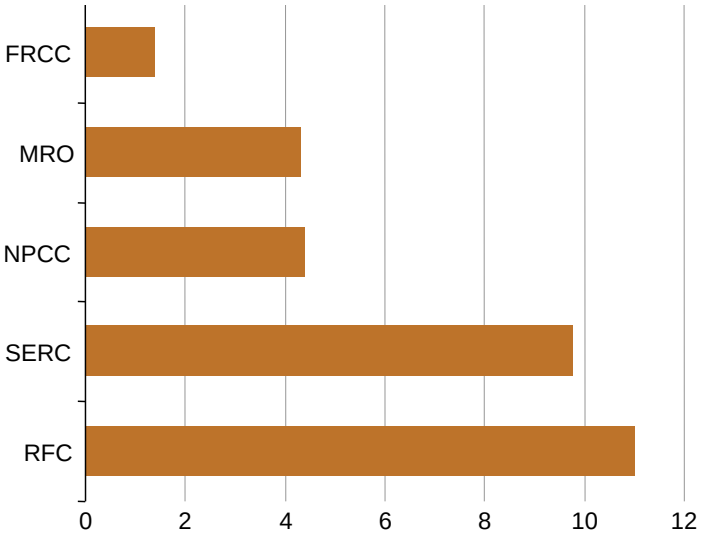
In the Low Nuclear case, generation from nuclear power in 2035 is 30 percent lower than in the Reference case, due to the loss of 30.9 gigawatts of nuclear capacity that is retired after 60 years of operation. As a result, the nuclear share of total generation is reduced to 13 percent. The loss of generation is made up primarily by increased generation from natural gas (12 percent higher than in the Reference case in 2035), coal (1 percent higher), and renewables (3 percent higher).

Real average electricity prices in 2035 are 1 percent lower in the High Nuclear case than in the Reference case, as slightly less natural gas capacity is dispatched, lowering the marginal price of electricity. In the Low Nuclear case, average electricity prices in 2035 are 5 percent higher than in the Reference case as a result of the retirement of a significant amount of nuclear capacity, which has relatively low operating costs, and its replacement with natural gas capacity, which has higher fuel costs that are passed through to consumers in retail electricity prices. With all nuclear power plants being retired after 60 years of operation in the Low Nuclear case, an additional 12 gigawatts of nuclear capacity would be shut down between 2035 and 2040.

The impacts of nuclear plant retirements on retail electricity prices in the Low Nuclear case are more apparent in regions with relatively large amounts of nuclear capacity. For example, electricity prices in the Low Nuclear case are 7 percent higher than in the Reference case for the NERC MRO Region, and 6 percent higher in the Northeast, Mid-Atlantic, and Southeast regions. Even in regions where no nuclear capacity is retired, there are small increases in electricity prices relative to the Reference case, because higher demand for natural gas in regions with nuclear plant retirements affect prices nationwide.

The Reference case projections for CO_2 emissions also are affected by changes in assumptions about nuclear plant lifetimes. In the Low Nuclear case, CO_2 emissions from the electric power sector in 2035 are 3 percent higher than in the Reference case as a result of switching from nuclear generation to natural gas and coal, both which produce more CO_2 emissions. In the High Nuclear case, CO_2 emissions from the power sector are slightly (1 percent) lower than in the Reference case. Table 12 summarizes key results from the *AEO2012* Reference, High Nuclear, and Low Nuclear cases.

Figure 51. Nuclear power plant retirements by NERC region in the Low Nuclear case, 2010-2035 (gigawatts)



10. Potential impact of minimum pipeline throughput constraints on Alaska North Slope oil production

Introduction

Alaska's North Slope oil production has been declining since 1988, when average annual production peaked at 2.0 million barrels per day. In 2010, about 600,000 barrels per day of oil was produced on the North Slope. Although new North Slope oil fields have started production since 1988, the decline of North Slope production has resulted largely from depletion of the North Slope's two largest fields, Prudhoe Bay and Kuparuk River. Recently, Alyeska Pipeline Service Company (Alyeska), the operator of the Trans-Alaska Pipeline System (TAPS), stated that oil pipeline transportation problems could begin when throughput falls below 550,000 barrels per day and become increasingly severe with further declines [*90*].

Alyeska estimates that TAPS operational problems could become considerable when throughput falls below 350,000 barrels per day. The decline of both North Slope oil production

and TAPS throughput raises the possibility that North Slope oil production might be shut down, with the existing oil fields plugged and abandoned sometime before 2035. That possibility is discussed here, as well as alternatives that could prolong the life of North Slope oil fields and TAPS beyond 2035.

Background

Declining TAPS throughput

TAPS is an 800-mile crude oil pipeline that transports North Slope oil production south to the Alyeska marine terminal in Valdez, Alaska. The crude oil is then transported by tankers to West Coast refineries. TAPS currently is the only means for transporting North Slope crude oil to refineries and the petroleum consumption markets they serve.

From 2004 through 2006, Alyeska reconfigured and refurbished TAPS, spending about $400 million to $500 million [*91*] both to reduce operating expenses and to permit TAPS to operate at lower flow rates, with a potential minimum mechanical throughput rate thought to be about 200,000 barrels per day at that time [*92*]. As North Slope oil production has declined, however, concern about TAPS operation under low flow conditions has grown [*93*]. In August 2008, Alyeska initiated its Low Flow Impact Study, which was released on June 15, 2011 [*94*].

The Alyeska study identified the following potential problems that might occur as TAPS throughput declines from the current production levels:

- Water dropout from the crude oil, which could cause pipeline corrosion
- Ice formation in the pipe if the oil temperature drops below freezing
- Wax precipitation and deposition
- Soil heaving.

Other potential operational issues at low flow rates include sludge dropout, reduced ability to remove wax, reduction in pipeline leak detection efficiency, pipeline shutdown and restart, and the running of pipeline pigs that both clean the pipeline and check its integrity.

Although TAPS low flow problems could begin at volumes around 550,000 barrels per day in the absence of any mitigation, their severity is expected to increase as throughput declines further. As the types and severity of problems multiply, the investment required to mitigate these is expected to increase significantly. Because of the many and diverse operational problems expected to occur at throughput volumes below 350,000 barrels per day, considerable investment could be required to keep the pipeline operational below that threshold. The Alyeska study does not provide any estimates of what it might cost to keep the pipeline operational below either 550,000 or 350,000 barrels per day. Currently, Alyeska is conducting tests and analyses to determine the likely efficacy and costs of different remedies.

Mitigating the decline of North Slope oil production

Although much of the public focus has been on the operational capability of TAPS at low flow rates, the more fundamental issue is declining oil production. The TAPS low flow issue would be alleviated most readily by discovery and production of large new sources of oil on the North Slope. Potential sources of significant North Slope oil production are located offshore in the Chukchi and Beaufort Seas and onshore in shale and heavy oil deposits. The Arctic National Wildlife Refuge (ANWR) is also estimated to hold approximately 10.4 billion barrels of technically recoverable oil resources, but Federal oil and gas leasing in ANWR currently is prohibited [*95*]. Another potential source of new TAPS volumes would be the conversion of North Slope natural gas resources to either methanol or Fischer-Tropsch petroleum products that could be transported to market via TAPS. Finally, in the absence of new North Slope petroleum supplies, alternative crude oil transportation facilities could be developed, such as a new small-diameter pipeline running parallel to the TAPS route [*96*] or a new offshore oil terminal for North Slope production.

Table 12. Summary of key results from the Reference, High Nuclear, and Low Nuclear cases, 2010-2035

Projection	Reference	High Nuclear	Low Nuclear
Nuclear plant cumulative retirements (gigawatts)	6.1	0.6	30.9
Generating capacity cumulative additions (gigawatts)			
Coal	16.6	16.1	18.9
Natural gas	141.6	126.2	147.6
Nuclear capacity uprates	7.3	7.3	0.8
Planned nuclear capacity additions	6.8	13.5	6.8
Unplanned nuclear capacity additions	1.8	1.3	--
Renewables	67.4	64.5	73.4
Average delivered electricity price, 2035 (2010 cents per kilowatthour)	10.1	10.0	10.6
Average delivered natural gas price for electric power, 2035 (2010 dollars per million Btu)	7.21	7.00	8.03
CO_2 emissions from electric power generation, 2035 (million metric tons)	2,330	2,301	2,404

Which of these potential low-flow solutions (or combination thereof) may ultimately come to fruition is impossible to determine at this time. Moreover, each solution comes with its own unique set of costs, risks, and lead times. Not only does each solution entail its own set of risks, there is also a significant risk that production from existing North Slope fields might decline much faster than anticipated and/or that the cost of operating those fields might escalate much faster than expected. Under those circumstances, there is a risk that any solution(s) could be both too little and too late, because the North Slope oil fields would be shut down before a TAPS solution could be implemented.

How quickly TAPS flows will decline, the types of low flow problems that might develop, and the degree of mitigation required depend on the success or failure of current offshore and onshore oil exploration and development programs and the quality of the oil produced. For example, low-viscosity oil is less problematic to TAPS operations than heavy, viscous oil. Because the future success of North Slope oil exploration and development is unknown, it is prudent to consider the circumstances under which North Slope oil production might cease altogether, causing a shutdown of the TAPS pipeline.

Aside from the question of what it might cost to keep TAPS operating at lower flow rates, an additional question is what it might cost to keep the existing North Slope oil fields producing. Even if the continued operation of TAPS were not in question, each North Slope oil field's production will eventually decline to a point at which it is no longer economical to keep the field operating. Oil and gas fields typically are shut down and abandoned when operating and maintenance costs exceed production revenues. At that point, wells are plugged and abandoned, surface equipment is removed, and the land is remediated to meet State and Federal requirements.

Although the cost structure of North Slope field production as production declines is unknown, production generally can be sustained profitably at lower production rates when oil prices are higher. Similarly, the economic feasibility of mitigating the problems arising from TAPS low flow rates improves when oil prices are higher. Consequently, revenues generated by North Slope oil production will play a pivotal role in determining the continued economic viability of existing North Slope oil fields, the development of new oil fields, the continued operation of TAPS at lower flow rates, and the potential development of new transportation facilities.

Several basic strategies have been employed to mitigate declining oil production and revenues from existing oil fields. First, the field operator can drill in-fill wells into those portions of the reservoir where oil cannot flow to existing production wells. Second, the operator can use enhanced oil recovery (EOR) that involves injecting steam or gases (along with water) to reduce viscosity and increase oil volumes as an aid to moving oil to the production wells. Currently, methane and natural gas liquids are being reinjected with water into many North Slope oil fields to achieve this outcome, which is referred to as "miscible hydrocarbon" EOR [*97*].

Drilling in-fill and EOR injection wells requires investments that are paid for through "maintenance" capital expenditures [*98*]. Both activities provide diminishing returns over time, as less oil typically is recovered with each new in-fill or EOR well, causing the cost per barrel of oil recovered to rise over time. Table 13 shows the number of in-fill and gas/water injection wells completed in 2010 at the three largest North Slope oil fields.

The diminishing returns from new in-fill and EOR wells is demonstrated in recent remarks by a ConocoPhillips official who noted that approximately $630 million was to be spent on maintenance capital expenditures in 2011, compared with about $240 million in 2001 [*99*]. In 2001 and 2010, ConocoPhillips provided 37.4 percent and 39.1 percent, respectively, of total North Slope oil production [*100*]. Using those percentages to scale up ConocoPhillips maintenance capital expenditures so that they represent total capital expenditures for North Slope maintenance, then total North Slope maintenance costs can be estimated at about $640 million in 2001 and $1.6 billion in 2011—a 150-percent increase over a period in which total North Slope oil production declined from 931,000 barrels per day to 562,000 barrels per day. If maintenance capital expenditures increased at the same rate (150 percent) over the next 10 years, they could be as high as $4 billion in 2021.

Another method for extending oil production is to produce increasing amounts of water relative to oil [*101*]. As oil is produced from a reservoir, water typically enters the formation, causing the water-to-oil ratio to increase exponentially over time as oil production volumes decline [*102*]. Because the cost per barrel for handling and reinjecting reservoir water typically is relatively constant, the operating cost per barrel of oil produced increases exponentially over time.

Shutdown and abandonment assumptions

According to the Alyeska study, a TAPS throughput of about 350,000 barrels per day appears to be the threshold at which significant investment would be required to permit lower TAPS throughput. *AEO2012* adopts the 350,000 barrel per day figure as

Table 13. Alaska North Slope wells completed during 2010 in selected oil fields

Production unit	Miscible hydrocarbon EOR	In-fill development wells	Gas/water injection wells	Total wells
Colville River	Yes	8	6	**14**
Kuparuk River	Yes	25	26	**51**
Prudhoe Bay	Yes	68	8	**76**
Subtotal		101	40	**141**
Total North Slope				**168**

the threshold for either making significant investments in TAPS or the alternatives, or shutting down and decommissioning TAPS and the North Slope oil fields [*103*].

In the *AEO2012* analysis, the shutdown and decommissioning of TAPS and the North Slope oil fields are also conditional on whether North Slope wellhead oil production revenues fall below a specific level. The appropriate revenue threshold is uncertain, because there is little or no information available to the public on operating and maintenance costs for existing oil fields, how those costs have grown historically as production has declined, or how they might grow in the future. Similarly, there are no public data available on what it might cost to keep TAPS operating as throughput declines [*104*]. Given the lack of public information, this analysis endeavors to determine both future North Slope production revenues in alternative oil price cases and an order-of-magnitude estimate of wellhead production costs.

AEO2012 assumes that, in order for the North Slope fields to be shut down, plugged, and abandoned, two conditions would need to be met simultaneously: TAPS throughput at or below 350,000 barrels per day and total North Slope oil production revenues at or below $5 billion per year. It is also assumed that if those two conditions were met, TAPS would be decommissioned and dismantled, and North Slope oil exploration and production activities would cease [*105*].

The $5 billion threshold for North Slope oil production revenue used in *AEO2012* is not intended to be conclusive regarding the conditions under which the North Slope oil fields and TAPS would remain in operation. As noted earlier, in-fill and EOR well drilling requirements could escalate to about $4 billion per year by 2021 [*106*]. Moreover, with the State of Alaska royalty rate currently at about 18.5 percent [*107*], a $5 billion revenue level would equate to almost $1 billion in royalties.

Also, an order of magnitude estimate of operating costs can be made by examining what oil companies report for their annual production expenses. For example, ExxonMobil reported a range of regional production costs per barrel of oil equivalent (excluding taxes) of $6.17 to $20.07 per barrel in 2010, with the U.S. average production cost being $10.67 per barrel [*108*]. At 350,000 barrels per day, a North Slope operating expense of $10 to $20 per barrel would equate to $1.28 to $2.56 billion per year in annual operating expenses. Of course, production costs could well exceed $20 per barrel as North Slope oil production declines.

Although the $5 billion North Slope revenue figure is not conclusive with regard to the actual annual costs faced by North Slope field operators in the future, it is a reasonable estimate in light of the sum of current maintenance capital expenditures ($1.6 billion), estimated operating expenses at 350,000 barrels per day ($1.28 to $2.56 billion), and a royalty cost of about $1 billion. As discussed below, the oil production revenue threshold serves to either advance or delay the date when TAPS and North Slope oil production would be shut down.

The final assumption is that a complete shutdown of North Slope oil production would occur in the year in which both the throughput and revenue criteria are satisfied. In reality, the actual shutdown of North Slope oil production might be extended over a number of years and could begin either before or after the year in which the criteria employed by North Slope producers are met.

Projections

A shutdown of North Slope oil production before 2035 is projected only in the Low Oil Price case, which shows both TAPS throughput and North Slope oil revenues falling below the 350,000 barrels per day and $5 billion per year thresholds, respectively, in 2026 (Figures 52 and 53). In both the Reference and High Oil Price cases, oil prices are sufficiently high both to stimulate the

Figure 52. Alaska North Slope oil production in three cases, 2010-2035 (million barrels per day)

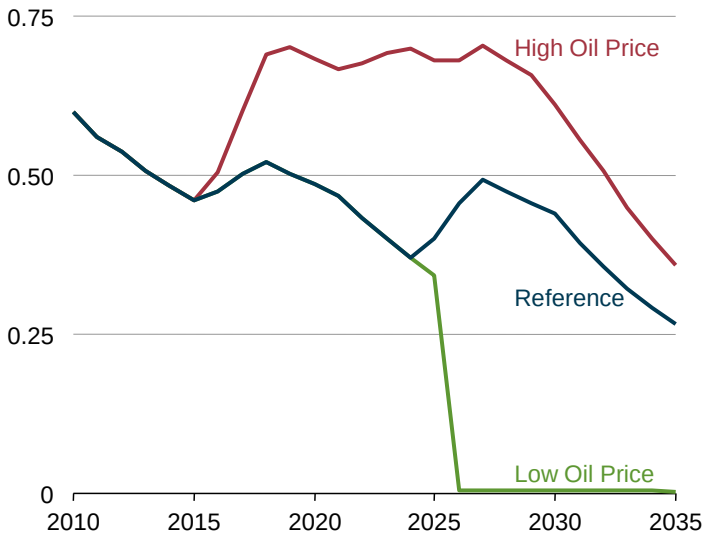
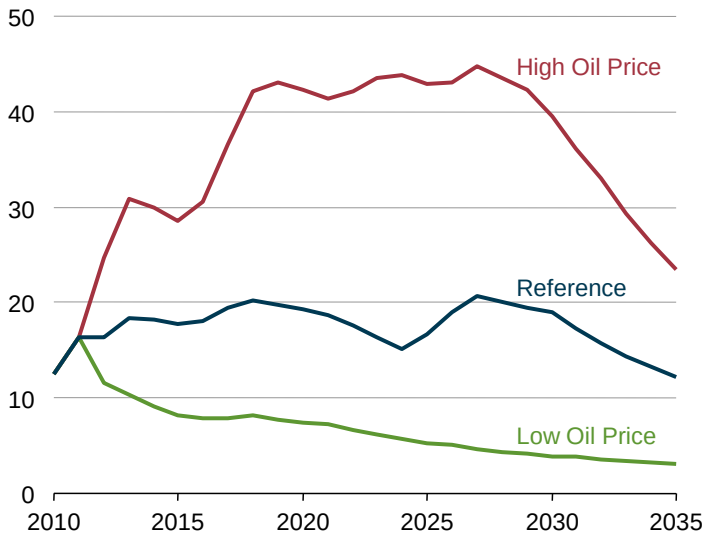


Figure 53. Alaska North Slope wellhead oil revenue in three cases, assuming no minimum revenue requirement, 2010-2035 (billion 2010 dollars per year)



development of new North Slope oil fields, especially offshore, and to provide sufficient oil production revenues to keep the North Slope producing oil through 2035.

Figure 53 shows the projected North Slope oil production revenue stream over time in the three price cases, with North Slope oil production continuing even after production volume and revenue requirements are no longer met in the Low Oil Price case. Thus, if the minimum North Slope revenue requirement were $7.5 billion, a shutdown of North Slope production could occur as soon as 2020, but only in the Low Oil Price case.

There is considerable uncertainty about the long-term viability of North Slope oil production and continued operation of TAPS through 2035. The two most important determinants of their future viability are the wellhead oil price that North Slope producers receive and the availability and cost of developing new North Slope oil resources. Those two factors will determine whether new oil fields are developed, whether existing oil fields remain sufficiently profitable to continue operating, and whether the investments required to keep TAPS operating at flow rates below 350,000 barrels per day are economically feasible.

The *AEO2012* Low and High Oil Price cases suggest that North Slope oil production will remain viable across a wide range of oil prices. Only in the Low Oil Price case are North Slope wellhead oil revenues sufficiently low to cause a shutdown of North Slope oil production. If the Low Oil Price case represents a low-probability outer boundary for future oil prices, then the likely future outcome is that North Slope oil production will continue until at least 2035, if not longer.

11. U.S. crude oil and natural gas resource uncertainty

A common measure of the long-term viability of U.S. domestic crude oil and natural gas as an energy source is the remaining technically recoverable resource (TRR). Estimates of TRR are highly uncertain, however, particularly in emerging plays where few wells have been drilled. Early estimates tend to vary and shift significantly over time as new geological information is gained through additional drilling, as long-term productivity is clarified for existing wells, and as the productivity of new wells increases with technology improvements and better management practices. TRR estimates used by EIA for each *AEO* are based on the latest available well production data and on information from other Federal and State governmental agencies, industry, and academia.

The remaining TRR consist of "proved reserves" and "unproved resources." *Proved reserves* of crude oil and natural gas are the estimated volumes expected to be produced, with reasonable certainty, under existing economic and operating conditions [*109*]. Proved reserves are also company financial assets reported to investors, as determined by U.S. Securities and Exchange Commission regulations. *Unproved resources* are additional volumes estimated to be technically recoverable without consideration of economics or operating conditions, based on the application of current technology [*110*]. As wells are drilled and field equipment is installed, unproved resources become proved reserves and, ultimately, production.

AEO estimates of TRR for shale gas and tight oil [*111*] have changed significantly in recent years (Table 14) [*112*]. In particular, the estimates of shale gas TRRs have changed significantly since the *AEO2011* was published, based on new well performance data and United States Geological Survey (USGS) resource assessments. For example, in the past year the USGS has released resource assessments for five basins: Appalachian (Marcellus only), Arkoma, Texas-Louisiana-Mississippi Salt, Western Gulf, and Anadarko [*113*]. The shale gas and tight oil formations in those five basins were the primary focus of EIA's resource revisions for *AEO2012*. In 2002, the USGS estimated Marcellus TRR at 1.9 trillion cubic feet; in 2011, the updated USGS estimate for Marcellus was 84 trillion cubic feet (see the following article for more discussion). For the four other basins, shale gas and tight oil TRR had not been assessed previously. The USGS has not published an assessment of the Utica play in the Appalachian Basin.

The remainder of this discussion describes how estimates of remaining U.S. unproved technically recoverable resources of shale gas and tight oil are developed for *AEO*, and how uncertainty in those estimates could affect U.S. crude oil and natural gas markets in the future.

Estimating technically recoverable resources of shale gas and tight oil

The remaining unproved TRR for a continuous-type shale gas or tight oil area is the product of (1) land area, (2) well spacing (wells per square mile), (3) percentage of area untested, (4) percentage of area with potential, and (5) EUR per well [*114*]. The USGS periodically publishes shale gas resource assessments that are used as a guide for selection of key parameters in the calculation of the TRR used in the *AEO*. The USGS seeks to assess the recoverability of shale gas and tight oil based on the wells drilled and technologies deployed at the time of the assessment.

The *AEO* TRRs incorporate current drilling, completion, and recovery techniques, requiring adjustments to the USGS estimates, as well as the inclusion of shale gas and tight oil resources not yet assessed by USGS. When USGS assessments and underlying data become publicly available, the USGS assumptions for land area, well spacing, and percentage of area with potential typically are used by EIA to develop the *AEO* TRR estimates. EIA may revise the well spacing assumptions in future *AEOs* to reflect evolving drilling practices. If well production data are available, EIA analyzes the decline curve of producing wells to calculate the expected EUR per well from future drilling.

Of the five basins recently assessed by the USGS, underlying details have been published only for the Marcellus shale play in the Appalachian basin. *AEO2012* assumptions for the other shale plays are based on geologic surveys provided from State agencies (if

available), analysis of available production data, and analogs from current producing plays with similar geologic properties (Table 15). For *AEO2012*, only eight plays are included in the tight oil category (Table 16). Additional tight oil resources are expected to be included in the tight oil category in future *AEOs* as more work is completed in identifying currently producing reservoirs that may be categorized as tight formations, and as new tight oil plays are identified and incorporated.

A key assumption in evaluating the expected profitability of drilling a well is the EUR of the well. EURs vary widely not only across plays but also within a single play. To capture the economics of developing each play, the unproved resources for each play within each basin are divided into subplays—first across States (if applicable), and then into three productivity categories: best, average, and below average. Although the average EUR per well for a play may not change by much from one *AEO* to the next, the range of well performance encompassed by representative EURs can change substantially (Table 17).

For every *AEO*, the EUR for each subplay is determined by fitting a hyperbolic decline curve to the latest production history, so that changes in average well performance can be captured. Annual reevaluations are particularly important for shale gas and tight oil formations that have undergone rapid development. For example, because there has been a dramatic change from drilling vertical wells to drilling horizontal wells in most tight oil and shale gas plays since 2003, EURs for those plays based on vertical well performance are less useful for estimating production from future drilling, given that most new wells are expected to be primarily horizontal.

In addition, the shape of the annual well production profiles associated with the EUR varies substantially across the plays (Figure 54). For example, in the Marcellus, Fayetteville, and Woodford shale gas plays, nearly 65 percent of the well EUR is produced in the first 4 years. In contrast, in the Haynesville and Eagle Ford plays, 95 percent and 82 percent, respectively, of the well EUR is produced in the first four years. For a given EUR level, increased "front loading" of the production profile improves well economics, but it also implies an increased need for additional drilling to maintain production levels.

At the beginning of a shale play's development, high initial well production rates result in significant production growth as drilling activity in the play increases. The length of time over which the rapid growth can be sustained depends on the size of the

Table 14. Unproved technically recoverable resource assumptions by basin

Basin	*AEO2006* (as of 1/1/2004)	*AEO2007* (as of 1/1/2005)	*AEO2008* (as of 1/1/2006)	*AEO2009* (as of 1/1/2007)	*AEO2010* (as of 1/1/2008)	*AEO2011* (as of 1/1/2009)	*AEO2012* (as of 1/1/2010)
Shale gas (trillion cubic feet)							
Appalachian	15	15	14	51	59	441	187
Fort Worth	40	39	38	60	60	20	19
Michigan	11	11	11	10	10	21	18
San Juan	10	10	10	10	10	12	10
Illinois	3	3	3	4	4	11	11
Williston	4	4	4	4	4	7	3
Arkoma	--	42	42	49	45	54	27
Anadarko	--	3	3	7	6	3	13
TX-LA-MS Salt	--	--	--	72	72	80	66
Western Gulf	--	--	--	--	18	21	59
Columbia	--	--	--	--	51	41	12
Uinta	--	--	--	--	7	21	11
Permian	--	--	--	--	--	67	27
Greater Green River	--	--	--	--	--	18	13
Black Warrior	--	--	--	--	--	4	5
Shale gas total	**83**	**126**	**125**	**267**	**347**	**827**	**482**
Tight oil (billion barrels)							
Williston	--	3.7	3.7	3.7	3.6	3.6	5.4
San Joaquin/Los Angeles	--	--	--	--	15.4	15.4	13.7
Rocky Mountain basins	--	--	--	--	5.1	5.1	6.5
Western Gulf	--	--	--	--	5.6	5.6	5.7
Permian	--	--	--	--	--	1.6	1.6
Anadarko	--	--	--	--	--	0.2	0.3
Tight oil total	**--**	**3.7**	**3.7**	**3.7**	**29.7**	**31.5**	**33.2**

technically recoverable resource in each play, the rate at which drilling activity increases, and the extent of the play's "sweet spot" area [*115*]. In the longer term, production growth tapers off as high initial production rates of new wells in "sweet spots" are offset by declining rates of existing wells, and as drilling activity moves into less-productive areas. As a result, in the later stages of a play's resource development, maintaining a stable production rate requires a significant increase in drilling.

Table 15. Attributes of unproved technically recoverable resources for selected shale gas plays as of January 1, 2010

Basin/Play	Area (square miles)	Average well spacing (wells per square mile)	Percent of area untested	Percent of area with potential	Average EUR (billion cubic feet per well)	Number of potential wells	TRR (billion cubic feet)
Appalachian							
Marcellus	104,067	5	99	18	1.56	90,216	140,565
Utica	16,590	4	100	21	1.13	13,936	15,712
Arkoma							
Woodford	3,000	8	98	23	1.97	5,428	10,678
Fayetteville	5,853	8	93	23	1.30	10,181	13,240
Chattanooga	696	8	100	29	0.99	1,633	1,617
Caney	2,890	4	100	29	0.34	3,369	1,135
TX-LA-MS Salt							
Haynesville/Bossier	9,320	8	98	34	2.67	24,627	65,860
Western Gulf							
Eagle Ford	7,600	6	99	47	2.36	21,285	50,219
Pearsall	1,420	6	100	85	1.22	7,242	8,817
Anadarko							
Woodford	3,350	4	99	29	2.89	3,796	10,981
Total, selected shale gas plays						**181,714**	**318,825**
Total, all U.S. shale gas plays						**410,722**	**481,783**

Table 16. Attributes of unproved technically recoverable tight oil resources as of January 1, 2010

Basin/Play	Area (square miles)	Average well spacing (wells per square mile)	Percent of area untested	Percent of area with potential	Average EUR (million barrels per well)	Number of potential wells	TRR (million barrels)
Western Gulf							
Austin Chalk	16,078	3	72	61	0.13	21,165	2,688
Eagle Ford	3,200	5	100	54	0.28	8,665	2,461
Anadarko							
Woodford	3,120	6	100	88	0.02	16,375	393
Permian							
Avalon/Bone Springs	1,313	4	100	78	0.39	4,085	1,593
Spraberry	1,085	6	99	72	0.11	4,636	510
Rocky Mountain basins							
Niobrara	20,385	8	97	80	0.05	127,451	6,500
Williston Bakken[a]	6,522	2	77	97	0.55	9,767	5,372
San Joaquin/Los Angeles							
Monterey/Santos	2,520	12	98	93	0.50	27,584	13,709
Total tight oil						**219,729**	**33,226**

[a]Includes Sanish-Three Forks formation.

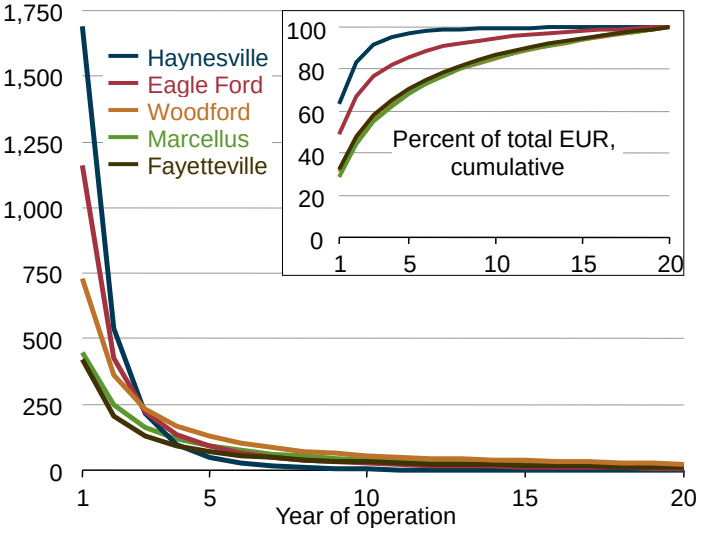
The amount of drilling that occurs each year depends on company budgets and finances and the economics of drilling, completing, and operating a well—determined largely by wellhead prices for oil and natural gas in the area. For example, current high crude oil prices and low natural gas prices are directing drilling toward those plays or portions of plays with a high concentration of liquids (crude oil, condensates, and natural gas plant liquids). Clearly, not all the wells that would be needed to develop each play fully can be drilled in one year—for example, more than 630,000 new wells would be needed to bring total U.S. shale gas and tight oil resources into production. In 2010, roughly 37,500 total oil and natural gas wells were drilled in the United States. It takes time and money to evaluate, develop, and produce hydrocarbon resources.

Although changes in the overall TRR estimates are important, the economics of developing the TRR and the timing of the development determine the projections for production of domestic crude oil and natural gas. TRR adjustments that affect resources which are not economical to develop during the projection period do not affect the *AEO* projections. Thus, significant variation in the overall TRR does not always result in significant changes in projected production.

EUR sensitivity cases and results

Estimated ultimate recovery per well is a key component in estimates of both technically recoverable resources and economically recoverable resources of tight oil and shale gas. The EUR for future wells is highly uncertain, depending on the application of new and/or improved technologies as well as the geology of the formation where the wells will be drilled. EUR assumptions typically have more impact on projected production than do any of the other parameters used to develop TRR estimates. For *AEO2012*, two cases were created to examine the impacts of higher and lower TRR for tight oil and shale gas by varying the assumed EUR per well.

Figure 54. Average production profiles for shale gas wells in major U.S. shale plays by years of operation (million cubic feet per year)



These High and Low EUR cases are not intended to represent a confidence interval for the resource base, but rather to illustrate how different EUR assumptions can affect projections of domestic production, prices, and consumption. To emphasize this point, an additional case was developed that combines a change in the assumed well spacing for all shale gas and tight oil plays with the EUR assumptions in the High EUR case. Well spacing is also highly uncertain, depending on the application of new and/or improved technologies as well as the geology of the formation where the well is being drilled. In the *AEO2012* Reference case, the well spacing for shale gas and tight oil drilling ranges from 2 to 12 wells per square mile.

Table 17. Estimated ultimate recovery for selected shale gas plays in three *AEO*s (billion cubic feet per well)

	AEO2010		*AEO2011*		*AEO2012*	
Basin/Play	Range	Average	Range	Average	Range	Average
Appalachian						
Marcellus	0.25–0.74	0.49	0.86–4.66	1.62	0.02–7.80	1.56
Utica	--	--	--	--	0.10–2.75	1.13
Arkoma						
Woodford	1.43–4.28	2.85	3.00–5.32	4.06	0.40–4.22	1.97
Fayetteville	0.91–2.73	1.82	0.86–2.99	2.03	0.19–3.22	1.30
Chattanooga	--	--	--	--	0.14–1.94	0.99
Caney	--	--	--	--	0.05–0.66	0.34
TX-LA-MS Salt						
Haynesville/Boosier	2.30–6.89	4.59	1.13–8.65	3.58	0.08–5.76	2.67
Western Gulf						
Eagle Ford	1.10–3.29	2.19	1.73–7.32	2.63	0.41–4.93	2.36
Pearsall	--	--	--	--	0.12–2.91	1.22
Anadarko						
Woodford	--	--	2.65–4.54	3.42	0.68–5.37	2.89

Low EUR case. In the Low EUR case, the EUR per tight oil or shale gas well is assumed to be 50 percent lower than in the Reference case, increasing the per-unit cost of developing the resource. The total unproved tight oil TRR is decreased to 17 billion barrels, and the shale gas TRR is decreased to 241 trillion cubic feet, as compared with 33 billion barrels of tight oil and 482 trillion cubic feet of shale gas in the Reference case.

High EUR case. In the HIGH EUR case, the EUR per tight oil or shale gas well is assumed to be 50 percent higher than in the Reference case, decreasing the per-unit cost of developing the resource. The total unproved tight oil TRR is increased to 50 billion barrels and the shale gas TRR is increased to 723 trillion cubic feet.

High TRR case. In the High TRR case, the well spacing for all tight oil and shale gas plays is assumed to be 8 wells per square mile (i.e., each well has an average drainage area of 80 acres), and the EUR per tight oil or shale gas well is assumed to be 50 percent higher than in the Reference case. In addition, the total unproved tight oil TRR is increased to 89 billion barrels and the shale gas TRR is increased to 1,091 trillion cubic feet, more than twice the TRRs for tight oil and shale gas wells in the Reference case.

The effects of the changes in assumptions in the three cases on supply, demand, and prices for oil and for natural gas are significantly different in magnitude, because the domestic oil and natural gas markets are distinctly different markets. Consequently, the following discussion focuses first on how the U.S. oil market is affected in the three sensitivity cases, followed by a separate discussion of how the U.S. natural gas market is affected in the three cases.

Crude oil and natural gas liquid impacts

The primary impact of the Low EUR, High EUR, and High TRR cases with respect to oil production is a change in production of tight oil and natural gas plant liquids (NGPL) (Table 18). NGPL production is discussed in conjunction with tight oil production, because significant volumes of NGPL are produced from tight oil and shale gas formations. Thus, changing the EURs directly affects NGPL production. Relative to the Reference case, tight oil production increases more slowly in the Low EUR case and more rapidly in the High EUR and High TRR cases. On average, tight oil production from 2020 to 2035 is approximately 450,000 barrels per day lower in the Low EUR case, 410,000 barrels per day higher in the High EUR case, and 1.3 million barrels per day higher in the High TRR case than in the Reference case (Figure 55). NGPL production in 2035 is more than 350,000 barrels per day lower in the Low EUR case than in the Reference case, nearly 320,000 barrels per day higher in the High EUR case, and 1.0 million barrels per day higher in the High TRR case.

Tight oil production is highest in the High TRR case, which assumes both higher EUR per well and generally lower drainage area per well than in the Reference case. In the High TRR case, tight oil production increases from roughly 400,000 barrels per day in 2010 to nearly 2.8 million barrels per day in 2035, with the Bakken formation accounting for most of the increase. The TRR estimate for the Bakken is more than 7 times higher in the High TRR case than in the Reference case—39.3 billion barrels compared to 5.4 billion barrels—which supports a continued dramatic production increase through 2015 and a longer plateau at a much higher production level through 2035 than in the Reference case. Bakken crude oil production (excluding NGPLs) increases from roughly 270,000 barrels per day in 2010 to nearly 800,000 barrels per day in 2015 before reaching over 1 million barrels per day in 2021 and remaining at that level through 2035 in the High TRR case, compared with peak tight oil production of roughly 530,000 barrels per day in the Reference case. Cumulative crude oil production from the Bakken from 2010 to 2035 is roughly 8.5 billion barrels in the High TRR case, compared with 4.3 billion barrels in the Reference case.

Table 18. Petroleum supply, consumption, and prices in four cases, 2020 and 2035

		2020				2035			
Projection	2010	Reference	Low EUR	High EUR	High TRR	Reference	Low EUR	High EUR	High TRR
Low-sulfur light crude oil price (2010 dollars per barrel)	79	127	128	125	122	145	147	143	140
Total U.S. production of crude oil and natural gas plant liquids (million barrels per day)	7.5	9.6	8.8	10.3	11.6	9.0	8.1	10.0	11.8
Tight oil	0.4	1.2	0.9	1.5	2.2	1.2	0.7	1.7	2.8
Natural gas plant liquids	2.1	2.9	2.6	3.1	3.6	3.0	2.7	3.3	4.0
Other U.S. crude oil	5.1	5.5	5.3	5.6	5.7	4.8	4.8	4.9	5.0
Tight oil share of total U.S. crude oil and NGPL production (percent)	5	12	10	15	19	14	9	17	23
U.S. net import share of petroleum product supplied (percent)	50	37	41	34	27	36	41	32	24

Every incremental barrel of domestic crude oil production displaces approximately one barrel of imports, because U.S. consumption of liquid fuels varies little across the cases. Consequently, the projected share of net petroleum imports in total U.S. liquid fuel consumption in 2035 varies considerably across the EUR and TRR cases, from 41 percent in the Low EUR case to 24 percent in the High TRR case, as compared with 36 percent in the Reference case. However, additional downstream infrastructure may be required to process the high levels of NGPL production in the High EUR and High TRR cases.

Changes in domestic oil production have only a modest impact on domestic crude oil and petroleum product prices, because any change in domestic oil production is diluted by the much larger world oil market. The United States produced 5.5 million barrels per day, or 7 percent of total world crude oil production of 73.9 million barrels per day in 2010 and is projected generally to maintain that share of world crude oil production through 2035 in the Reference case.

Natural gas impacts

The EUR and TRR cases show more significant impacts on U.S. natural gas supply, consumption, and prices than that projected for crude oil and petroleum products for two reasons (Table 19). First, the U.S. natural gas market constitutes the largest regional submarket within the relatively self-contained North American natural gas market. Second, in the Reference case, shale gas production accounts for 49 percent of total U.S. natural gas production in 2035, while tight oil production accounts for only 14 percent of total U.S. crude oil and NGPL production and 1 percent of world crude oil production. As a result, changes in shale gas production have a commensurately larger impact on North American natural gas prices than tight oil production has on world oil prices.

The projections for domestic shale gas production are highly sensitive to the assumed EUR per well. In 2035, total shale gas production varies from 9.7 trillion cubic feet in the Low EUR case to 16.0 trillion cubic feet in the High EUR case and 20.5 trillion cubic feet in the High TRR case, as compared with 13.6 trillion cubic feet in the Reference case (Figure 56). Because shale gas production accounts for such a large proportion of total natural gas production in 2035, the large changes in shale gas production result in commensurately large swings in total U.S. natural gas production. In 2035, total U.S. natural gas production ranges from 26.1 trillion cubic feet in the Low EUR case to 34.1 trillion cubic feet in the High TRR case, a difference of 8.0 trillion cubic feet production between the two cases.

In comparison with the Reference case, per-unit production costs are nearly double in the Low EUR case and about one-half in the High EUR case. In the Low EUR case, the Henry Hub natural gas price of $8.26 per million Btu in 2035 (2010 dollars) is $0.89 per million Btu higher than the Reference case price of $7.37 per million Btu. In the High EUR case, the 2035 Henry Hub natural gas price of $5.99 per million Btu is $1.38 per million Btu lower than the Reference case price. In the High TRR case, the 2035 Henry Hub natural gas price of $4.25 per million Btu is $3.12 per million Btu less than the Reference case price.

The natural gas prices projected in the Low EUR case are sufficiently high to enable completion of an Alaska gas pipeline, with operations beginning in 2031. Because an Alaska gas pipeline would make up for some of the reduction in Lower 48 shale gas production, differences between the Reference and Low EUR case projections for natural gas production, prices, and consumption in 2035 are somewhat less than would otherwise be expected.

The 2035 price spread of $4.01 per million Btu across the cases is reflected in the projected levels of U.S. natural gas consumption. Higher natural gas prices in the Low EUR case reduce total natural gas consumption to 25.0 trillion cubic feet in 2035, compared with 26.6 trillion cubic feet in the Reference case; and lower natural gas prices in the High EUR and High TRR cases increase consumption in 2035 to 28.4 trillion cubic feet and 31.9 trillion cubic feet, respectively.

Figure 55. U.S. production of tight oil in four cases, 2000-2035 (million barrels per day)

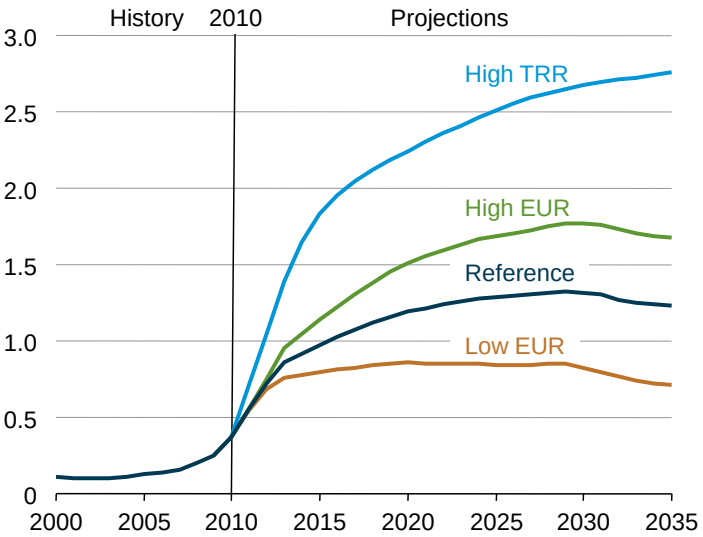
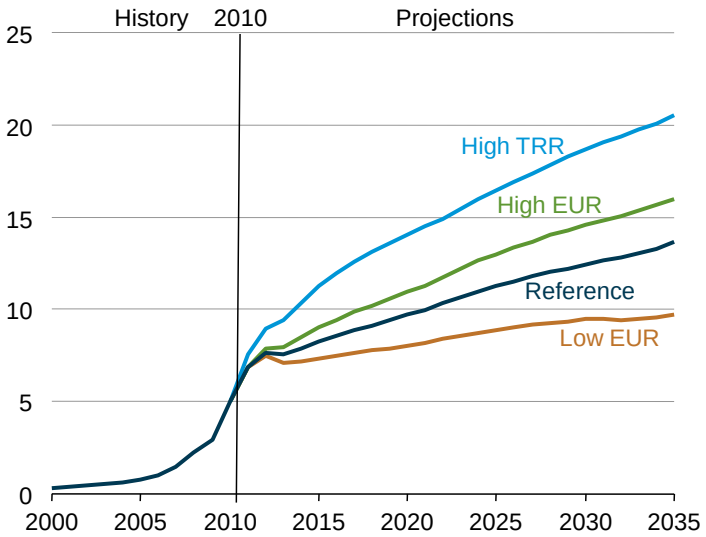


Figure 56. U.S. production of shale gas in four cases, 2000-2035 (trillion cubic feet)



The variation in total U.S. natural gas consumption between the High EUR and High TRR cases is reflected to some degree in each end-use category. The electric power sector shows the greatest sensitivity to natural gas prices, with natural gas use for electricity generation being more responsive to changes in fuel prices than is consumption in the other sectors, because much of the electric power sector's fuel consumption is determined by the dispatching of existing generation units based on the operating cost of each unit, which in turn is determined largely by the costs of competing fuels—especially coal and natural gas. Natural gas consumption in the electric power sector in 2035 totals 7.7 trillion cubic feet in the Low EUR case, compared with 9.0 trillion cubic feet in the Reference case, 10.1 trillion cubic feet in the High EUR case, and 12.6 trillion cubic feet in the High TRR case.

In the end-use consumption sectors, opportunities to switch fuels generally are limited to when a new facility is built or when a facility's existing equipment is retired and replaced. Collectively, for all the end-use sectors, natural gas consumption in 2035 varies by only about 1.9 trillion cubic feet across the cases, from 17.3 trillion cubic feet in the Low EUR case to 19.2 trillion cubic feet in the High TRR case, as compared with 17.7 trillion cubic feet in the Reference case.

In 2035, the United States is projected to be a net exporter of natural gas in all the cases. The projected volumes of net exports vary, with lower natural gas prices resulting in higher net exports. However, the High TRR, High EUR, and Low EUR cases assume that U.S. gross exports of LNG remain constant at 0.9 trillion cubic feet from 2020 through 2035, because of the inherent complexities and uncertainties of projecting foreign natural gas production, consumption, and trade. It is likely, however, that actual levels of net LNG exports would be affected by changes in U.S. prices, which in turn, would dampen the extent of the price difference across the resource cases.

The variation in levels of net U.S. natural gas exports shown in Table 20 reflects the impact of domestic natural gas prices on natural gas pipeline imports and exports. Generally, lower natural gas prices, as in the High TRR case, result in lower natural gas imports from Canada and higher natural gas exports to Mexico. In 2035, net natural gas exports from the United States vary from 1.2 trillion cubic feet in the Low EUR case to 2.4 trillion cubic feet in the High TRR case, as compared with 1.4 trillion cubic feet in the Reference case.

The sensitivity cases in this discussion are not intended to provide a confidence interval for estimates of recoverable resources of domestic tight oil and shale gas but rather to illustrate the significance of key assumptions underlying the tight oil and shale

Table 19. Natural gas prices, supply, and consumption in four cases, 2020 and 2035

		2020				2035			
Projection	2010	Reference	Low EUR	High EUR	High TRR	Reference	Low EUR	High EUR	High TRR
Henry Hub natural gas spot price (2010 dollars per million Btu)	4.39	4.58	5.31	4.04	3.02	7.37	8.26	5.99	4.25
Total U.S. natural gas production (trillion cubic feet)	21.6	25.1	23.6	26.3	29.1	27.9	26.1	30.1	34.1
Onshore lower 48	18.7	22.5	21.0	23.6	26.6	25.0	21.2	27.2	31.7
Shale gas	5.0	9.7	8.0	10.9	14.0	13.6	9.7	16.0	20.5
Other natural gas	13.7	12.8	12.9	12.7	12.6	11.3	11.4	11.2	11.1
Offshore lower 48	2.6	2.3	2.4	2.3	2.2	2.7	3.1	2.6	2.3
Alaska	0.4	0.3	0.3	0.3	0.3	0.2	1.8	0.2	0.2
Shale gas production as percent of total U.S. natural gas production	23	39	34	42	48	49	37	53	60
Total net U.S. imports of natural gas (trillion cubic feet)	2.6	0.3	0.5	0.2	-0.2	-1.4	-1.2	-1.7	-2.4
Total U.S. consumption of natural gas (trillion cubic feet)	24.1	25.5	24.2	26.5	28.9	26.6	25.0	28.4	31.9
Electric Power	7.4	7.9	6.8	8.7	10.5	9.0	7.7	10.1	12.6
Residential	4.9	4.8	4.8	4.9	4.9	4.6	4.6	4.7	4.8
Commercial	3.2	3.4	3.4	3.5	3.6	3.6	3.5	3.7	4.0
Industrial	6.6	7.1	7.0	7.1	7.4	7.0	6.9	7.2	7.6
Other	2.0	2.3	2.2	2.3	2.5	2.4	2.4	2.6	2.8

gas TRRs used in *AEO2012*. TRR estimates are highly uncertain and can be expected to change in subsequent *AEOs* as additional information is gained through continued exploration, development, and production.

12. Evolving Marcellus shale gas resource estimates

As discussed in the preceding article, estimates of crude oil and natural gas TRR are uncertain. Estimates of the Marcellus shale TRR, which have received considerable attention over the past year, are no exception. TRR estimates are likely to continue evolving as drilling continues and more information becomes publicly available. The Marcellus shale gas play covers more than 100,000 square miles in parts of eight States, but most of the drilling to date has been in two areas of northeast Pennsylvania and southwest Pennsylvania/northern West Virginia. Until 2010, the State of Pennsylvania had maintained a 5-year embargo on the release of well-level production data, which severely limited the publicly available information about Marcellus well production. Now Pennsylvania provides well production data on a cumulative basis—annually for the years before 2010 and semi-annually starting in the second half of 2010. Even with more data available, however, it is still a challenge to estimate TRR for the Marcellus play.

In 2002, the USGS estimated that 0.8 trillion cubic feet to 3.7 trillion cubic feet of technically recoverable shale gas resources existed in the Marcellus, with a mean estimate of 1.9 trillion cubic feet [*116*]. At that time, most of the well production data available were for vertical wells drilled in West Virginia. Since 2003, technological improvements have led to more-productive and less-costly wells. The newer horizontal wells have higher EURs [*117*] than the older vertical wells. In 2011, the USGS released an updated assessment for the Marcellus resource, with a mean estimate of 84 trillion cubic feet of undiscovered TRR (ranging from 43 trillion cubic feet to 144 trillion cubic feet) [*118*]. For its 2011 assessment, the USGS evaluated well production data from Pennsylvania and West Virginia that were available in early 2011 and determined that the data were "not sufficient for the construction of individual well Estimated Ultimate Recovery distributions" [*119*]. Instead, the USGS chose analogs from other U.S. shale gas plays to determine the EUR distributions for its three Marcellus assessment units—Foldbelt, Interior, and Western Margin (Figure 57).

Estimates of the TRR for U.S. shale gas are updated each year for the *AEO*. For *AEO2011*, an independent consultant was hired to estimate the Marcellus TRR as the available USGS TRR estimate issued in 2003 was clearly too low, since cumulative production from the Marcellus shale was on a path to exceed it within a year or two. For *AEO2012*, EIA adopted the 2011 USGS estimates of the Marcellus assessment areas, well spacing, and percent of area with potential. However, EIA examines available well production data each year to estimate shale EURs for use in the *AEO* (Table 20).

The revised Marcellus EUR for *AEO2012* is close to the EUR used in *AEO2011* but nearly 70 percent higher than the EUR used in the 2011 USGS assessment. The Interior Assessment Unit EURs developed by EIA reflects the current practice of horizontal drilling and well production data through June 2011 for Pennsylvania and West Virginia [*120*]. Because there has been very little, if any, drilling in the Western Margin and Foldbelt Assessment Units, the USGS EURs were used for the States in those areas. The resulting *AEO2012* estimate for the Marcellus TRR is 67 percent lower than the *AEO2011* estimate, primarily as a result of increased well spacing (132 acres per well vs. 80 acres per well) and a lower percentage of area with potential (18 percent vs. 34 percent) (Table 21).

The estimation of Marcellus shale gas resources is highly uncertain, given both the short production history of current producing wells and the concentration of most producing wells in two small areas, Northeast Pennsylvania and Southwest Pennsylvania/Northern West Virginia. The Marcellus EURs are expected to change as additional data are released and the methodology for developing EURs is refined. Also, as more wells are drilled over a broader area, and as operators optimize well spacing to account for evolving drilling practices, the assumption for average well spacing may be revised. Although the Marcellus shale resource estimate will be updated for every *AEO*, revisions will not necessarily have a significant impact on projected natural gas production, consumption, and prices.

Figure 57. United States Geological Survey Marcellus Assessment Units

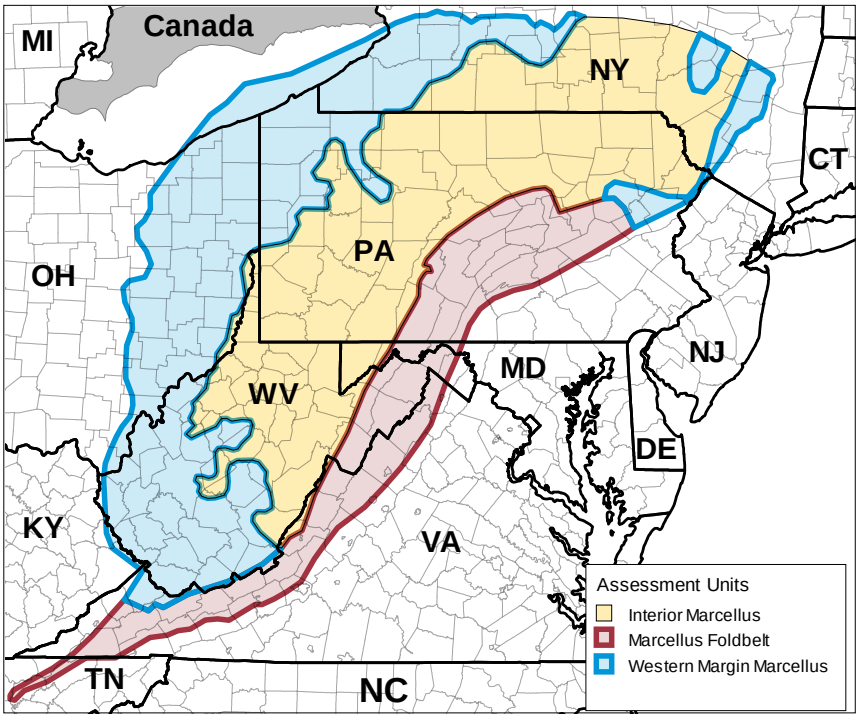


Table 20. Marcellus unproved technically recoverable resources in *AEO2012* (as of January 1, 2010)

Assessment Unit/State	Area (square miles)	Well spacing (wells per square mile)	Percent of area untested	Percent of area with potential	EUR (billion cubic feet per well)				TRR (billion cubic feet)
					High	Mid	Low	Average	
Foldbelt	19,063	4	100	5	0.50	0.18	0.03	0.21	757
Maryland	435	4	100	5	0.50	0.18	0.03	0.21	17
Pennsylvania	7,951	4	100	5	0.50	0.18	0.03	0.21	316
Tennessee	353	4	100	5	0.50	0.18	0.03	0.21	14
Virginia	7,492	4	100	5	0.50	0.18	0.03	0.21	298
West Virginia	2,833	4	100	5	0.50	0.18	0.03	0.21	113
Interior	45,161	4	99	37	6.33	1.41	0.06	1.95	137,677
Maryland	763	4	100	37	2.02	0.30	0.02	0.52	629
New York	10,381	4	100	37	7.80	1.79	0.07	2.43	40,124
Ohio	361	4	99	37	2.02	0.30	0.02	0.52	296
Pennsylvania	23,346	4	98	37	7.80	1.79	0.07	2.43	88,182
Virginia	321	4	100	37	2.02	0.30	0.02	0.52	264
West Virginia	9,989	4	99	37	2.02	0.30	0.02	0.52	8,182
Western	39,844	5	100	7	0.35	0.11	0.03	0.13	2,107
Kentucky	207	5	100	7	0.35	0.11	0.03	0.13	11
New York	7,985	5	100	7	0.35	0.11	0.03	0.13	424
Ohio	13,515	5	100	7	0.35	0.11	0.03	0.13	718
Pennsylvania	6,582	5	100	7	0.35	0.11	0.03	0.13	350
Virginia	653	5	100	7	0.35	0.11	0.03	0.13	35
West Virginia	10,901	5	98	7	0.35	0.11	0.03	0.13	569
Total Marcellus	**104,067**	**5**	**99**	**18**	**5.05**	**1.13**	**0.05**	**1.56**	**140,541**

Table 21. Marcellus unproved technically recoverable resources: *AEO2011*, USGS 2011, and *AEO2012*

Estimate	Area (square miles)	Well spacing		Percent of area untested	Percent of area with potential	Average EUR (billion cubic feet per well)	TRR (billion cubic feet)
		Acres	Wells per square mile				
AEO2011 (as of 1/1/2009)							
Marcellus	**94,893**	**80**	**8**	**99%**	**34%**	**1.62**	**410,374**
USGS (2011 assessment)							
Marcellus	**104,067**	**132**	**4.9**	**99%**	**18%**	**0.93**	**84,198**
Foldbelt	19,063	149	4.3	100%	5%	0.21	765
Interior	45,156	149	4.3	99%	37%	1.15	81,374
Western	39,844	117	5.5	99%	7%	0.13	2,059
AEO2012 (as of 1/1/2010)							
Marcellus	**104,067**	**132**	**4.9**	**99%**	**18%**	**1.56**	**140,541**
Foldbelt	19,063	149	4.3	100%	5%	0.21	757
Interior	45,161	149	4.3	99%	37%	1.95	137,677
Western	39,844	117	5.5	100%	7%	0.13	2,107

Endnotes for Issues in focus

Links current as of June 2012

41. Oil shale liquids, derived from heating kerogen, are distinct from shale oil and also from tight oil, which is classified by EIA as crude oil. Oil shale is not expected to be produced in significant quantities in the United States before 2035.
42. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Proposed Rule," Federal Register, Vol. 76, No. 231 (Washington, DC: December 1, 2011), website www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/2017-25_CAFE_NPRM.pdf.
43. The EISA2007 RFS requirement for increasing volumes of biofuels results in a significant number of FFVs in both the Reference case and the CAFE case.
44. S. Bianco, "Chevy Volt Has Best Month Ever, But Nissan Leaf Still Wins 2011 Plug-in Sales Contest," autobloggreen, website green.autoblog.com/2012/01/04/chevy-volt-has-best-month-ever-but-nissan-leaf-still-wins-2011.
45. Battery electric vehicle charge-depleting mode occurs when the vehicle relies on battery power for operation. Charge-sustaining mode occurs when battery electric power is coupled with power provided by the internal combustion engine. Vehicles can be designed to operate on a blended mode that uses both charge-depleting and charge-sustaining modes while in operation, depending on the drive cycle.
46. Toyota, "Toyota Cars, Trucks, SUVs, and Accessories," website www.toyota.com; Nissan USA, "Nissan Cars, Trucks, Crossovers, & SUVs," website www.nissanusa.com; and Chevrolet, "2012 Cars, SUVs, Trucks, Crossovers & Vans," website www.chevy.com. **Note:** Miles per gallon equivalent, as listed by automotive manufacturers, is derived by the U.S. Environmental Protection Agency, www.fueleconomy.gov.
47. Toyota, "Toyota Cars, Trucks, SUVs, and Accessories," website www.toyota.com; Nissan USA, "Nissan Cars, Trucks, Crossovers, & SUVs," website www.nissanusa.com; and Chevrolet, "2012 Cars, SUVs, Trucks, Crossovers & Vans," website www.chevy.com. **Note:** Miles per gallon equivalent, as listed by automotive manufacturers, is derived by the U.S. Environmental Protection Agency, www.fueleconomy.gov.
48. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Vehicle Technologies Program," website www.eere.energy.gov/vehiclesandfuels/technologies/systems/index.html.
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51. Indiana University, School of Public and Environmental Affairs, "Plug-in Electric Vehicles: A Practical Plan for Progress," website www.indiana.edu/~spea/pubs/TEP_combined.pdf.
52. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Proposed Rule," Federal Register, Vol. 76, No. 231 (Washington, DC: December 1, 2011), website www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/2017-25_CAFE_NPRM.pdf.
53. For this analysis, heavy-duty vehicles include trucks with a Gross Vehicle Weight Rating of 10,001 pounds and higher, corresponding to Gross Vehicle Weight Rating classes 3 through 8 vehicles.
54. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Alternative Fueling Station Database Custom Query" (Washington, DC: June 3, 2010), website www.afdc.energy.gov/afdc/fuels/stations_query.html. Accessed June 30, 2012.
55. National Petroleum News, Market Facts 2011.
56. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Clean Cities Alternative Fuel Price Report* (Washington, DC: April, 2012), website www.afdc.energy.gov/afdc/pdfs/afpr_apr_12.pdf.
57. The Texas Clean Transportation Triangle is supported by Texas State Senate Bill 20, which provides vehicle rebates and fueling grants. See West, Williams, House Research Organization, "Bill Analysis: SB 20" (Austin, TX: May 21, 2011), website www.hro.house.state.tx.us/pdf/ba82r/sb0020.pdf.
58. The Interstate Clean Transportation Corridor was developed in 1996. The corridor is now partially established with LNG truck refueling infrastructure in California and to Reno, Las Vegas, and Phoenix. See Gladstein, Neandross & Associates, "Interstate Clean Transportation Corridor" (Santa Monica, CA: February 2, 2012), website ictc.gladstein.org.

59. The Pennsylvania Clean Transportation Corridor was proposed in a report, "A Road Map to a Natural Gas Vehicle Future" (Canonsburg, PA: April 5, 2011), sponsored by the Marcellus Shale Coalition, website marcelluscoalition.org/wp-content/uploads/2011/04/MSC_NGV_Study.pdf.
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61. For a map of U.S. LNG peak shaving, see U.S. Energy Information Administration, "U.S. LNG Peaking Shaving and Import Facilities, 2008" (Washington, DC: December, 2008), website www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/lngpeakshaving_map.html.
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63. Developed from e-mail correspondence with Graham Williams, 4/11/12.
64. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles," Federal Register Vol. 76, No. 179 (Washington, DC: September 15, 2011), website www.federalregister.gov/articles/2011/09/15/2011-20740/greenhouse-gas-emissions-standards-and-fuel-efficiency-standards-for-medium--and-heavy-duty-engines#p-3.
65. U.S. Census Bureau, "Vehicle Inventory and Use Survey (VIUS) (discontinued after 2002)" (Washington, DC: May 29, 2012), website www.census.gov/econ/overview/se0501.html.
66. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles," Federal Register Vol. 76, No. 179 (Washington, DC: September 15, 2011), website www.federalregister.gov/articles/2011/09/15/2011-20740/greenhouse-gas-emissions-standards-and-fuel-efficiency-standards-for-medium--and-heavy-duty-engines#p-3.
67. For information on the New Alternative Transportation to Give Americans Solutions Act of 2012, see Civic Impulse, LLC, "H.R. 1380: New Alternative Transportation to Give Americans Solutions Act of 2011" (Washington, DC: May 29, 2012), website legacy.govtrack.us/congress/bill.xpd?bill=h112-1380.
68. The liquid fuels production industry includes all participants involved in the production of liquid fuels: producers of feedstocks, petroleum- and nonpetroleum-based refined products and blendstocks, and liquid and non-liquid end-use products.
69. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards" (Washington, DC: March 27, 2012), website www.epa.gov/mats.
70. U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)" (May 25, 2012), website www.epa.gov/airtransport.
71. Other components of variable cost include emissions control technology, waste disposal, and emissions allowance credits.
72. The *AEO2012* Early Release Reference case was prepared before the final MATS rule was issued and, therefore, did not include MATS.
73. United States Court of Appeals for the District of Columbia Circuit, "EME Homer City Generation, L.P., v. Environmental Protection Agency" (Washington, DC: December 30, 2011), website www.epa.gov/airtransport/pdfs/CourtDecision.pdf.
74. U.S. Energy Information Administration, *Electric Power Annual 2010* (Washington, DC, November 2011), Table 3.10, "Number and Capacity of Existing Fossil-Fuel Steam-Electric Generators with Environmental Equipment, 1991 through 2010," website www.eia.gov/electricity/annual/html/table3.10.cfm.
75. U.S. Environmental Protection Agency, Office of Enforcement and Compliance Assurance, "The Environmental Protection Agency's Enforcement Response Policy for Use of Clean Air Act Section 113(a) Administrative Orders in Relation to Electric Reliability and the Mercury and Air Toxics Standard" (Washington, DC: December 16, 2011), website www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf.
76. See Appendix F for a map of the EMM regions.
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80. U.S. Energy Information Administration, "Assumptions to *AEO2012*" (Washington, DC: June 2012), website www.eia.gov/forecasts/aeo/assumptions.

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87. U.S. Nuclear Regulatory Commission, "Status of License Renewal Applications and Industry Activities: Completed Applications" (Washington, DC: May 22, 2012), website www.nrc.gov/reactors/operating/licensing/renewal/applications.html#completed.

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97. The most common miscible gas EOR technique is to alternate the injection of gas and water, referred to as water-alternating-gas or WAG. Source: Oil and Gas Journal, Special Report: EOR/Heavy Oil Survey: 2010 worldwide EOR survey, Volume 108, Issue 14, published April 19, 2010.
98. Capital expenditures can be split into two categories—maintenance and development—with development expenditures allocated to the development of new fields that have not yet reached peak production.
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100. These figures were derived from the CP ownership shares of the Colville River, Kuparuk River, and Prudhoe Bay field units and from the oil production reports of the Alaska Department of Natural Resources—Oil and Gas Division.
101. The volume of water produced relative to the volume of oil produced is referred to as the "water cut."
102. U.S. Geological Survey, *Economics of Undiscovered Oil in Federal Lands on the National Petroleum Reserve—Alaska*, by Emil Attanasi, Open-File Report 03-44 (January 2003), Figures A-2 (Alpine Field) and A-3 (Kuparuk Field).
103. In fact, these decisions would have to be made some time before the 350,000-barrel-per-day threshold is reached so they would be ready for implementation either prior to reaching the threshold or when that threshold is reached.
104. The owners of TAPS and operators of the North Slope fields might not know either at this junction what these future costs might be for both operating TAPS and the North Slope fields as volumes decline; at best they have estimates that might or might not turn out to be true.
105. The assumption that all North Slope exploration activity would cease with the decommissioning of TAPS might not be entirely realistic because some offshore oil fields might be economic to develop using floating production, storage, and offloading facilities (FPSO). This would be especially true in the Chukchi Sea, which has much less of an ice pack problem during the winter than the Beaufort Sea.
106. Maintenance capital expenditures could also decline if the field operators determined that drilling more wells was unprofitable.
107. *Petroleum News*, "Who Produces Crude Oil in Alaska?" Vol. 16, No. 43 (October 23, 2011).
108. ExxonMobil, 2010 Financial & Operating Review, Table entitled: "Oil and Gas Exploration and Production Earnings," p. 70.
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110. The further delineation of unproved resources into inferred reserves and undiscovered resources is not applicable to continuous resources since the extent of the formation is geologically known. For continuous resources, the USGS undiscovered technically recoverable resources are comparable to the EIA unproved resources. The USGS methodology for assessing continuous petroleum resources is at pubs.usgs.gov/ds/547/downloads/DS547.pdf.
111. "Tight oil" refers to crude oil and condensates produced from low-permeability sandstone, carbonate, and shale formations.
112. See shale gas map at www.eia.gov/oil_gas/rpd/shale_gas.pdf for basin locations.
113. Appalachian: pubs.usgs.gov/of/2011/1298/; Arkoma: pubs.usgs.gov/fs/2010/3043/; TX-LA-MS Salt and Western Gulf: pubs.usgs.gov/fs/2011/3020/; Anadarko: pubs.usgs.gov/fs/2011/3003/.
114. A well's estimated ultimate recovery (EUR) equals the cumulative production of that well over a 30-year productive life, using current technology without consideration of economic or operating conditions.
115. "Sweet spot" is an industry term for those select and limited areas within a shale or tight play where the well EURs are significantly greater than the rest of the play, sometimes as much as ten times greater than the lower production areas within a play.
116. USGS Fact Sheet FS-009-03. pubs.usgs.gov/fs/fs-009-03/FS-009-03-508.pdf.
117. A well's EUR equals the cumulative production of that well over a 30-year productive life, using current technology without consideration of economic or operating conditions.
118. USGS Fact Sheet 2011-3092, pubs.usgs.gov/fs/2011/3092/pdf/fs2011-3092.pdf.
119. USGS Open-File Report 2011-1298, pubs.usgs.gov/of/2011/1298/OF11-1298.pdf, page 2.
120. Well-level production from Pennsylvania is provided in two time intervals (annual and semi-annual). To estimate production on a comparable basis, well-level production is converted to an average daily rate by dividing gas quantity by gas production days. Because wells drilled before 2008 are vertical wells and do not reflect the technology currently being deployed, only wells drilled after 2007 are considered in the EUR evaluation. Well-level production for wells drilled in West Virginia is provided on a monthly basis.

Market trends

Projections by the U.S. Energy Information Administration (EIA) are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular case. The Reference case projection is a business-as-usual estimate, given known technology, as well as market, demographic, and technological trends. Most cases in the *Annual Energy Outlook 2012 (AEO2012)* generally assume that current laws and regulations are maintained throughout the projections. Such projections provide a baseline starting point that can be used to analyze policy initiatives. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, rates of technology progress, and policy changes.

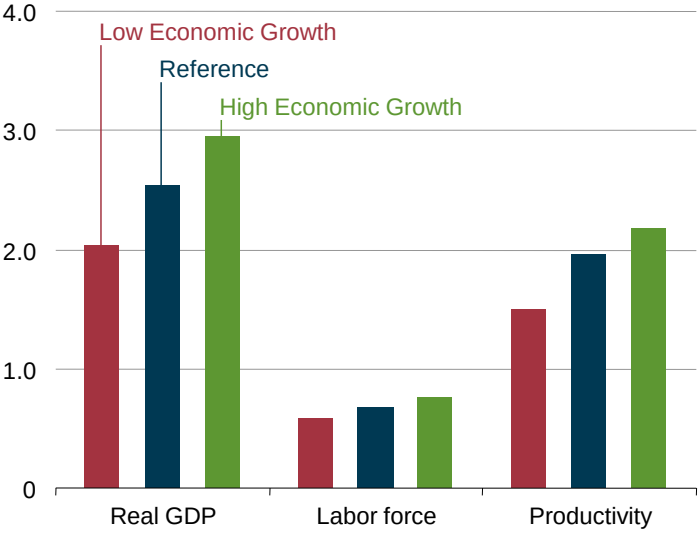
While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2012* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not as a substitute for, a complete and focused analysis of public policy initiatives.

Recovery in real gross domestic product growth continues at a modest rate

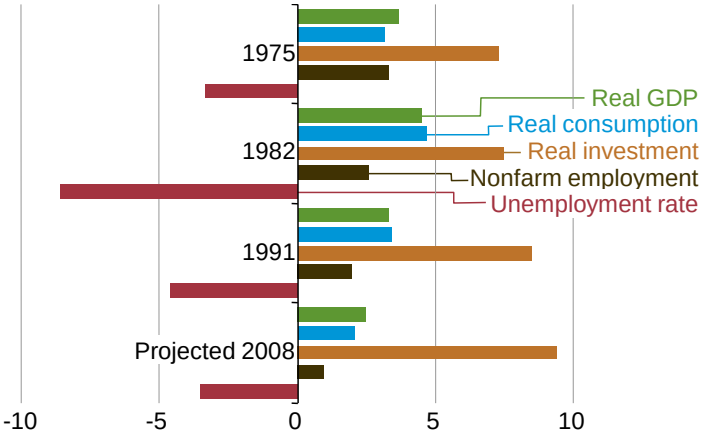
Figure 58. Average annual growth rates of real GDP, labor force, and nonfarm labor productivity in three cases, 2010-2035 (percent per year)



AEO2012 presents three views of U.S. economic growth (Figure 58). In 2011, the world economy experienced shocks that included turmoil in the Middle East and North Africa, a Greek debt crisis with financial impacts spreading to other Eurozone countries, and an earthquake in Japan, all leading to slower economic growth. U.S. growth projections in part reflect those world events.

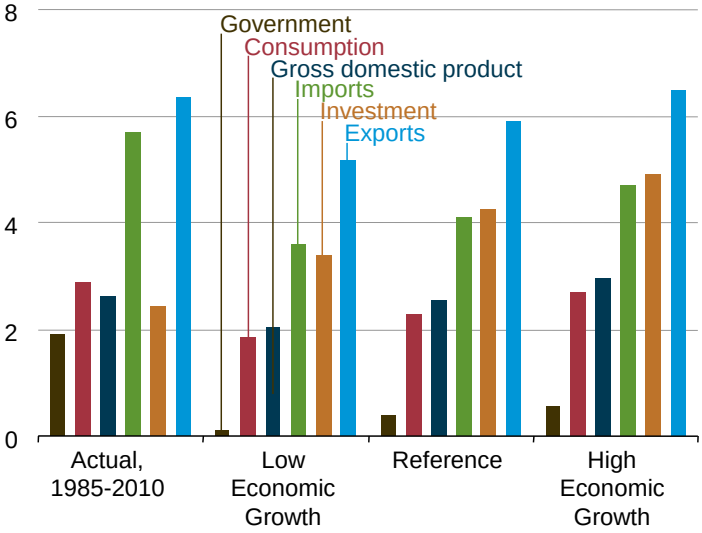
U.S. recovery from the 2007-2008 recession has been slower than past recoveries (Figure 59). A feature of economic recoveries since 1975 has been slowing employment gains, and, following the most recent recession, growth in nonfarm employment has been slower than in any other post-1960 recovery [*121*]. The average rates of growth are strong starting from the trough of the recessions.

Figure 59. Average annual growth rates over 5 years following troughs of U.S. recessions in 1975, 1982, 1991, and 2008 (percent per year)



Slow consumption growth, fast investment growth, and an ever-improving trade surplus

Figure 60. Average annual growth rates for real output and its major components in three cases, 2010-2035 (percent per year)



AEO2012 presents three economic growth cases: Reference, High, and Low. The High Economic Growth case assumes high growth and low inflation; the Low Economic Growth case assumes low growth and high inflation. Figure 60 compares the average annual growth rates for output and its major components in each of the three cases.

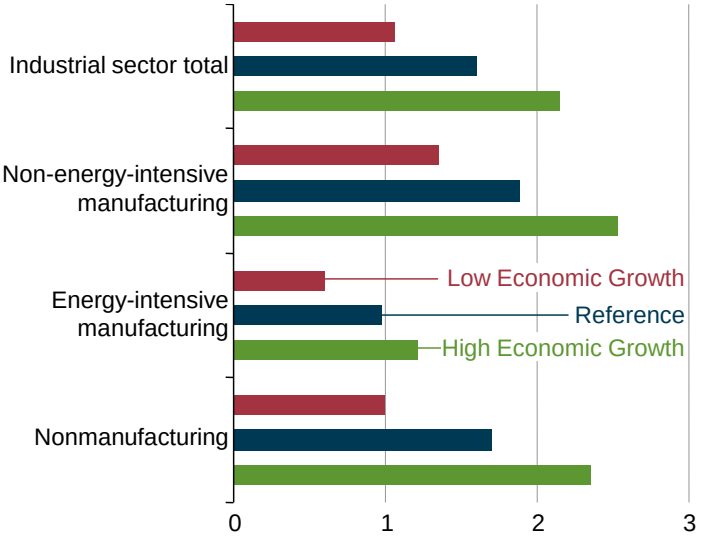
The short-term outlook (5 years) in each case represents current thinking about economic activity in the United States and the rest of the world; about the impacts of domestic fiscal and monetary policies; and about potential risks to economic activity. The long-term outlook projects smooth economic growth, assuming no shocks to the economy.

Differences among the Reference case and the High and Low Economic Growth cases reflect different expectations for growth in population (specifically, net immigration), labor force, capital stock, and productivity, which are above trend in the High Economic Growth case and below trend in the Low Economic Growth case. The average annual growth rate for real gross domestic product (GDP) from 2010 to 2035 in the Reference case is 2.5 percent, as compared with about 3.0 percent in the High Economic Growth case and about 2.0 percent in the Low Economic Growth case.

Compared with the 1985-2010 period, investment growth from 2010 to 2035 is faster in all three cases, whereas consumption, government expenditures, and imports grow more slowly in all three cases. Opportunities for trade are assumed to expand in each of the three cases, resulting in real trade surpluses by 2018 that continue through 2035.

Output growth for energy-intensive industries remains slow

Figure 61. Sectoral composition of industrial output growth rates in three cases, 2010-2035 (percent per year)

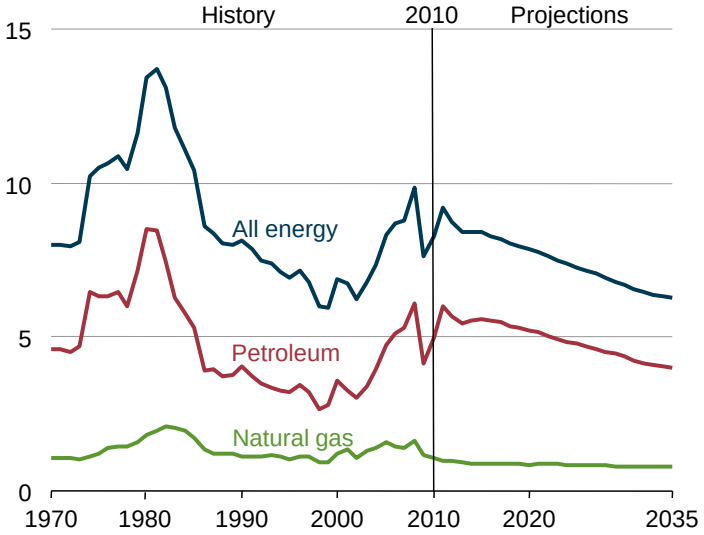


Industrial sector output has grown more slowly than the overall economy in recent decades, with imports meeting a growing share of demand for industrial goods, whereas the service sector has grown more rapidly [*122*]. In the *AEO2012* Reference case, real GDP grows at an average annual rate of 2.5 percent from 2010 to 2035, while both the industrial sector as a whole and its manufacturing component grow by 1.6 percent per year (Figure 61). As the economy recovers from the 2008-2009 recession, growth in U.S. manufacturing output in the Reference case accelerates from 2010 through 2020. After 2020, growth in manufacturing output slows due to increased foreign competition, slower expansion of domestic production capacity, and higher energy prices. These factors weigh heavily on the energy-intensive manufacturing sectors, which taken together grow at a slower rate of about 1.0 percent per year from 2010 to 2035, with variation by industry ranging from 0.8-percent annual growth for bulk chemicals to 1.5-percent annual growth for food processing.

A decline in U.S. dollar exchange rates, combined with modest growth in unit labor costs, stimulates U.S. exports, eventually improving the U.S. current account balance. From 2010 to 2035, real exports of goods and services grow by an average of 5.9 percent per year, and real imports of goods and services grow by an average of 4.1 percent per year. Strong growth in exports is an important component of projected growth in the transportation equipment, electronics, and machinery industries.

Energy expenditures decline relative to gross domestic product and gross output

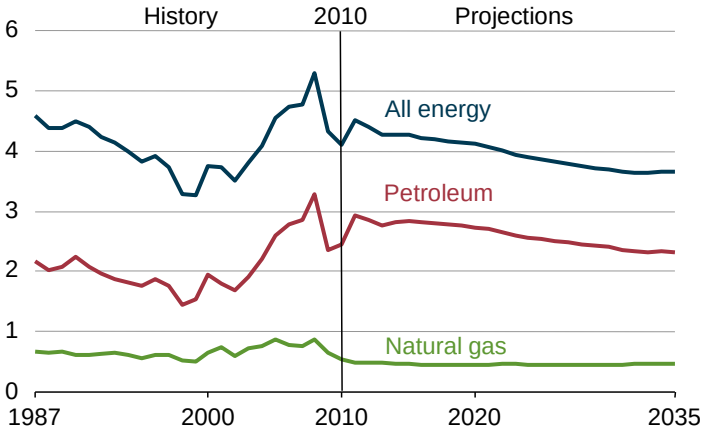
Figure 62. Energy end-use expenditures as a share of gross domestic product, 1970-2035 (nominal expenditures as percent of nominal GDP)



Total U.S. energy expenditures decline relative to GDP in the *AEO2012* Reference case (Figure 62) [*123*]. The projected share of energy expenditures falls from 2011 through 2035, averaging 7.5 percent from 2010 to 2035, which is below the historical average of 8.8 percent from 1970 to 2010.

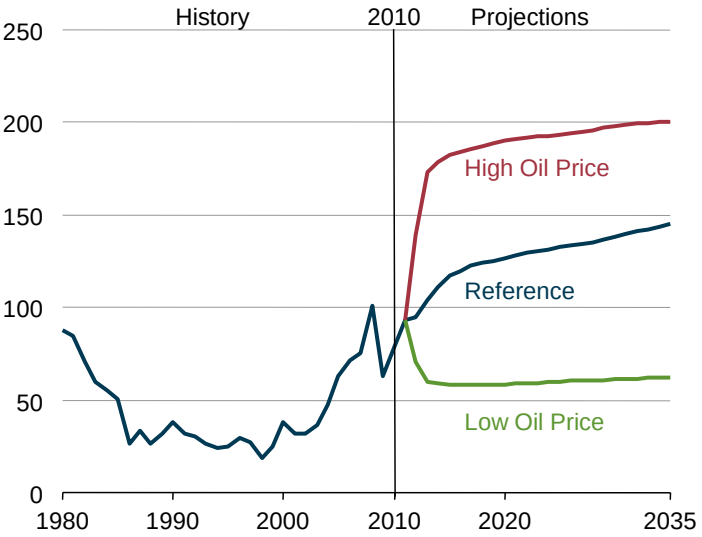
Gross output corresponds roughly to sales in the U.S. economy. Figure 63 provides an approximation of total energy expenditures relative to total sales. Energy expenditures as a share of gross output show roughly the same pattern as do energy expenditures as a share of GDP. The projected average shares of gross output relative to expenditures for total energy, petroleum, and natural gas are close to their historical averages, at 4.1 percent, 2.1 percent, and 0.5 percent, respectively.

Figure 63. Energy end-use expenditures as a share of gross output, 1987-2035 (nominal expenditures as percent of nominal gross output)



Oil price cases depict uncertainty in world oil markets

Figure 64. Average annual oil prices in three cases, 1980-2035 (2010 dollars per barrel)



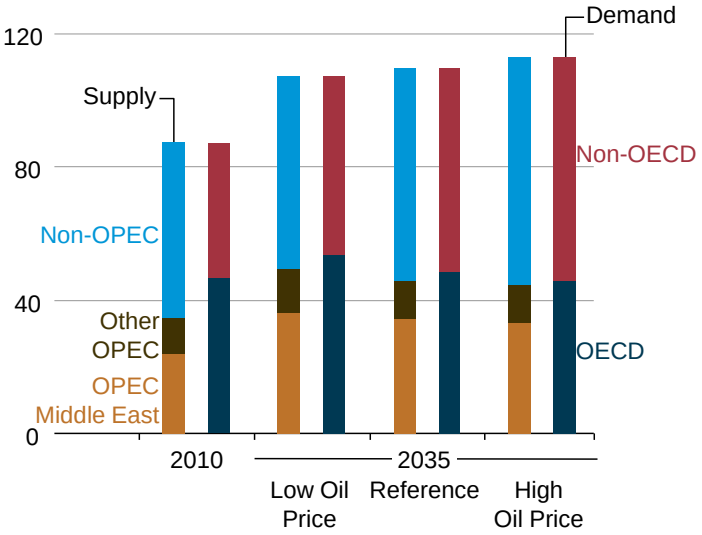
Oil prices in *AEO2012*, defined in terms of the average price of low-sulfur, light crude oil (West Texas Intermediate [WTI]) delivered to Cushing, Oklahoma, span a broad range that reflects the inherent volatility and uncertainty of oil prices (Figure 64). The *AEO2012* price paths are not intended to reflect absolute bounds for future oil prices but rather to provide a basis for analysis of the implications of world oil market conditions that differ from those assumed in the *AEO2012* Reference case. The Reference case assumes that the current price discount for WTI relative to similar "marker" crude oils (such as Brent and Louisiana Light Sweet) will fade when adequate pipeline capacity is built between Cushing and the Gulf of Mexico.

In the Low Oil Price case, GDP growth in countries outside the Organization of the Petroleum Exporting Countries (non-OPEC) is slower than in the Reference case, resulting in lower demand for petroleum and other liquids, and producing countries develop stable fiscal policies and investment regimes that encourage resource development. OPEC nations increase production, achieving approximately a 46-percent market share of total petroleum and other liquids production in 2035.

The High Oil Price case depicts a world oil market in which total GDP growth in countries outside the Organization for Economic Cooperation and Development (non-OECD) is faster than in the Reference case, driving up demand for petroleum and other liquids. Production of crude oil and natural gas liquids (NGL) is restricted by political decisions and limits on access to resources (such as the use of quotas and fiscal regimes) compared with the Reference case. Petroleum and other liquids production in the major producing countries is reduced (for example, the OPEC share averages 40 percent), and the consuming countries turn to more expensive production from other liquids sources to meet demand.

Trends in petroleum and other liquids markets are defined largely by the developing nations

Figure 65. World petroleum and other liquids supply and demand by region in three cases, 2010 and 2035 (million barrels per day)



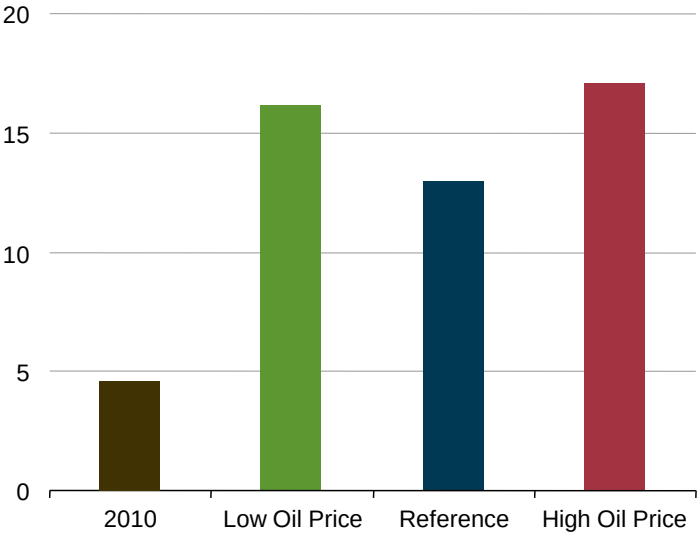
Total use of petroleum and other liquids in the *AEO2012* Reference, High Oil Price, and Low Oil Price cases in 2035 ranges from 107 to 113 million barrels per day (Figure 65). The alternative oil price cases reflect shifts in both supply and demand, with the result that total consumption and production levels do not vary widely. Although demand in the OECD countries is influenced primarily by price, demand in non-OECD regions—where future economic uncertainty is greatest—drives the price projections. That is, non-OECD petroleum and other liquids consumption is lower in the Low Oil Price case and higher in the High Oil Price case than it is in the Reference case.

OECD petroleum and other liquids use grows in the Reference case to 48 million barrels per day in 2035, while non-OECD use grows to 61 million barrels per day. In the Low Oil Price case, OECD petroleum and other liquids use in 2035 is higher than in the Reference case, at 53 million barrels per day, but demand in the slow-growing non-OECD economies in the Low Price case rises to only 54 million barrels per day. In the High Oil Price case the opposite occurs, with OECD consumption falling to 46 million barrels per day in 2035 and fast-growing non-OECD use—driven by higher GDP growth—increasing to 67 million barrels per day in 2035.

The supply response also varies across the price cases. In the Low Oil Price case, OPEC's ability to constrain market share is weakened, and low prices have a negative impact on non-OPEC crude oil supplies relative to the Reference case. Because non-crude oil technologies achieve much lower costs in the Low Price case, supplies of other liquids are more plentiful than in the Reference case. In the High Oil Price case, OPEC restricts production, non-OPEC resources become more economic, and high prices make other liquids more attractive.

Production from resources other than crude oil and natural gas liquids increases

Figure 66. Total world production of nonpetroleum liquids, bitumen, and extra-heavy oil in three cases, 2010 and 2035 (million barrels per day)



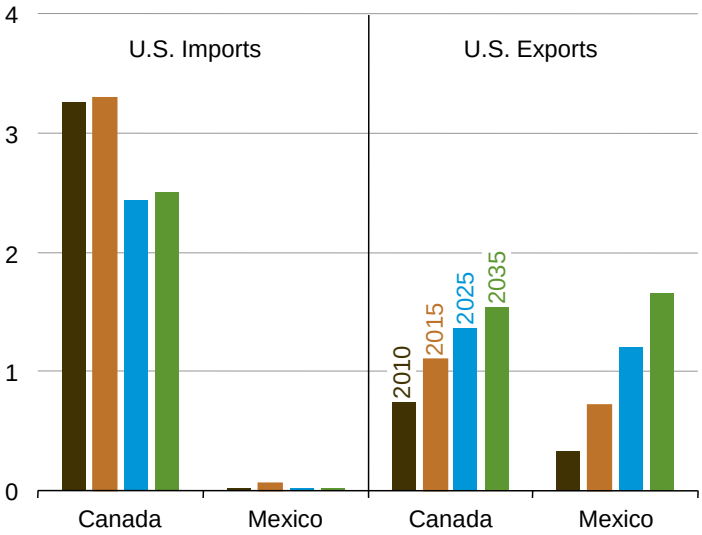
In 2010, world production of liquid fuels from resources other than crude oil and NGL totaled 4.6 million barrels per day, or about 5 percent of all petroleum and other liquids production. Production from those other sources grows to 13.0 million barrels per day (about 12 percent of total global production of petroleum and other liquids) in 2035 in the *AEO2012* Reference case, 16.2 million barrels per day (15 percent of the total) in the Low Oil Price case, and 17.1 million barrels per day (15 percent of the total) in the High Oil Price case (Figure 66). The higher levels of production from other resources result from declining technology costs in the Low Oil Price case and from higher oil prices in the High Oil Price case.

Assumptions about the development of other liquids resources differ across the three cases. In the Reference case, increasingly expensive projects become more economically competitive as a result of rising oil prices and advances in production technology. Bitumen in Canada and biofuels in the United States and Brazil are the most important components of production from sources other than crude oil and NGL. Excluding crude oil and NGL, U.S. and Brazilian biofuels and Canadian bitumen account for more than 70 percent of the total world increase in petroleum and other liquids production from 2010 to 2035 in the Reference case.

In the High Oil Price case, rising prices support increased development of nonpetroleum liquids, bitumen, and extra-heavy oil. A smaller increase is projected in the Low Oil Price case, which assumes significant declines in technology costs, particularly for extra-heavy oil production. Bitumen and biofuels continue to be the most important contributors to this supply category through 2035.

U.S. reliance on imported natural gas from Canada declines as exports grow

Figure 67. North American natural gas trade, 2010-2035 (trillion cubic feet)

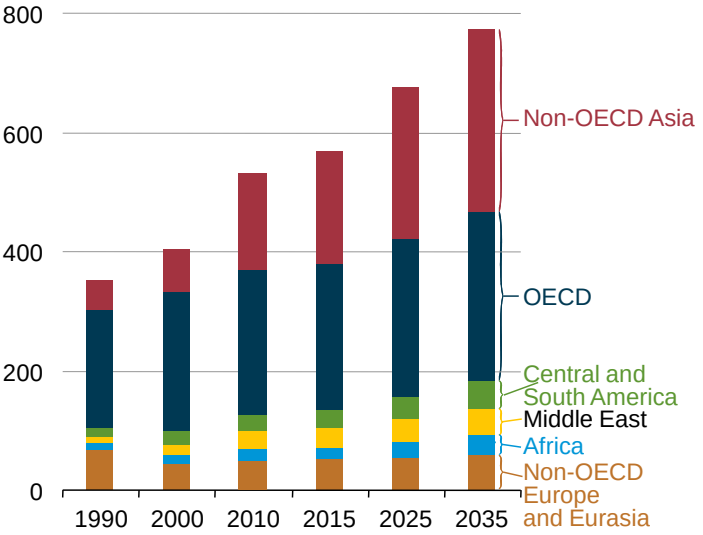


The energy markets of the three North American nations (United States, Canada, and Mexico) are well integrated, with extensive infrastructure that allows cross-border trade between the United States and both Canada and Mexico. The United States, which is by far the region's largest energy consumer, currently relies on Canada and Mexico for supplies of petroleum and other liquid fuels. Canada and Mexico were the largest suppliers of U.S. petroleum and other liquids imports in 2010, providing 2.5 and 1.3 million barrels per day, respectively. In addition, Canada supplies the United States with substantial natural gas supplies, exporting 3.3 trillion cubic feet to U.S. markets in 2010 (Figure 67).

In the *AEO2012* Reference case, energy trade between the United States and the two other North American countries continues. In 2035, the United States still imports 3.4 million barrels per day of petroleum and other liquid fuels from Canada in the Reference case, but imports from Mexico fall to 0.8 million barrels per day. With prospects for domestic U.S. natural gas production continuing to improve, the need for imported natural gas declines. U.S. imports of natural gas from Canada fall to 2.4 trillion cubic feet in 2025 in the Reference case and remain relatively flat through the end of the projection. On the other hand, U.S. natural gas exports to both Canada and Mexico increase. Canada's imports of U.S. natural gas grow from 0.7 trillion cubic feet in 2010 to 1.5 trillion cubic feet in 2035, and Mexico's imports grow from 0.3 trillion cubic feet in 2010 to 1.7 trillion cubic feet in 2035 in the *AEO2012* Reference case.

China and India account for half the growth in world energy use

Figure 68. World energy consumption by region, 1990-2035 (quadrillion Btu)



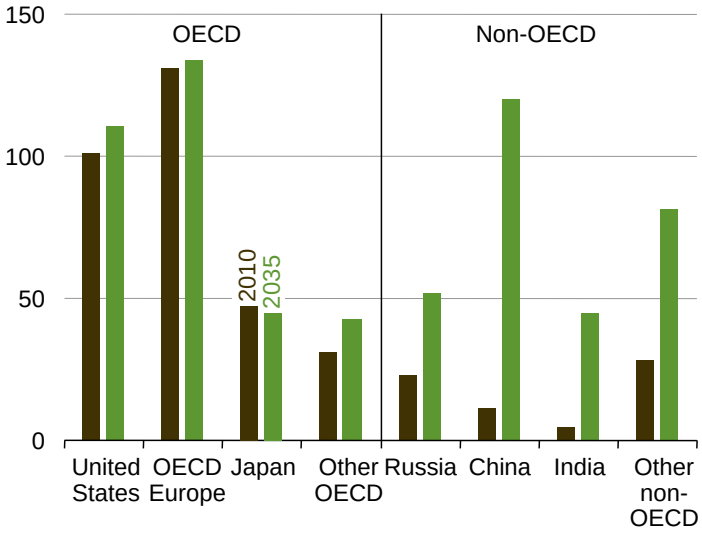
World energy consumption increases by 47 percent from 2010 through 2035 in the *AEO2012* Reference case (Figure 68). Most of the growth is projected for emerging economies outside the OECD, where robust economic growth is accompanied by increased demand for energy. Total non-OECD energy use grows by 72 percent, compared with an 18-percent increase in OECD energy use.

Energy consumption in non-OECD Asia, led by China and India, shows the most robust growth among the non-OECD regions, rising by 91 percent from 2010 to 2035. However, strong growth also occurs in much of the rest of the non-OECD regions: 69 percent in Central and South America, 65 percent in Africa, and 62 percent in the Middle East. The slowest growth among the non-OECD regions is projected for non-OECD Europe and Eurasia (including Russia), where substantial gains in energy efficiency are achieved through replacement of inefficient Soviet-era capital equipment.

Worldwide, the use of energy from all sources increases in the projection. Given expectations that oil prices will remain relatively high, petroleum and other liquids are the world's slowest-growing energy sources. High energy prices and concerns about the environmental consequences of greenhouse gas (GHG) emissions lead a number of national governments to provide incentives in support of the development of alternative energy sources, making renewables the world's fastest-growing source of energy in the outlook.

After Fukushima, prospects for nuclear power dim in Japan and Europe but not elsewhere

Figure 69. Installed nuclear capacity in OECD and non-OECD countries, 2010 and 2035 (gigawatts)



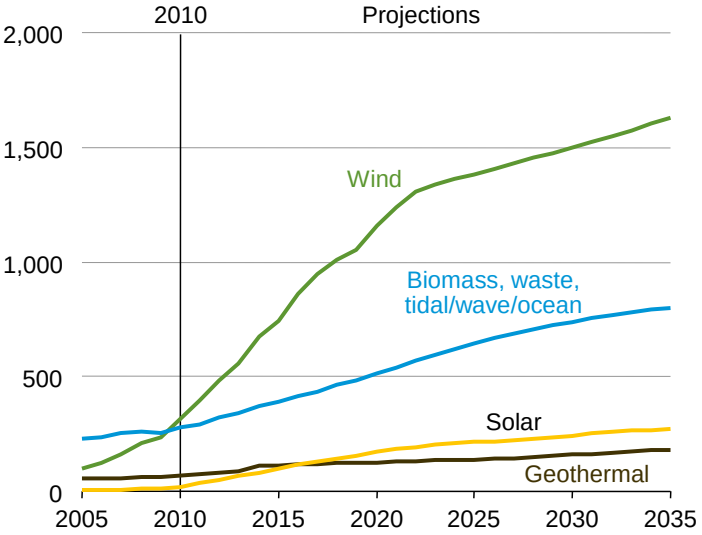
The earthquake and tsunami that hit northeastern Japan in March 2011 caused extensive loss of life and infrastructure damage, including severe damage to several reactors at the Fukushima Daiichi nuclear power plant. In the aftermath, governments in several countries that previously had planned to expand nuclear capacity—including Japan, Germany, Switzerland, and Italy—reversed course. Even China announced a temporary suspension of its approval process for new reactors pending a thorough safety review.

Before the Fukushima event, EIA had projected that all regions of the world with existing nuclear programs would expand their nuclear power capacity. Now, however, Japan's nuclear capacity is expected to contract by about 3 gigawatts from 2010 to 2035 (Figure 69). In OECD Europe, Germany's outlook has been revised to reflect a phaseout of all nuclear power by 2025. As a result, the projected net increase in OECD Europe's nuclear capacity in the *AEO2012* Reference case is only 3 gigawatts from 2010 to 2035.

Significant expansion of nuclear power is projected to continue in the non-OECD region as a whole, with total nuclear capacity more than quadrupling. From 2010 to 2035, nuclear power capacity increases by a net 109 gigawatts in China, 41 gigawatts in India, and 28 gigawatts in Russia, as strong growth in demand for electric power and concerns about security of energy supplies and the environmental impacts of fossil fuel use encourage further development of nuclear power in non-OECD countries.

Wind power leads rise in world renewable generation, solar power also grows rapidly

Figure 70. World renewable electricity generation by source, excluding hydropower, 2005-2035 (billion kilowatthours)



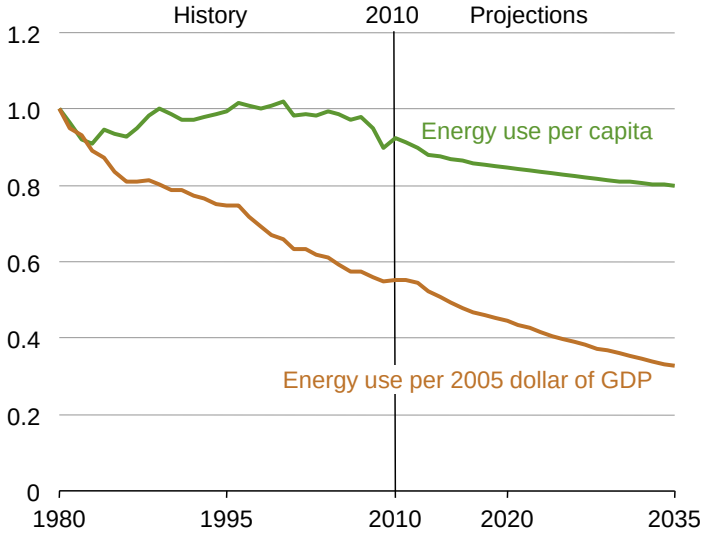
Renewable energy is the world's fastest-growing source of marketed energy in the *AEO2012* Reference case, increasing by an average of 3.0 percent per year from 2010 to 2035, compared to an average of 1.6 percent per year for total world energy consumption. In many parts of the world, concerns about the security of energy supplies and the environmental consequences of GHG emissions have spurred government policies that support rapid growth in renewable energy installations.

Hydropower is well-established worldwide, accounting for 83 percent of total renewable electricity generation in 2010. Growth in hydroelectric generation accounts for about one-half of the world increase in renewable generation in the Reference case. In Brazil and the developing nations of Asia, significant builds of mid- and large-scale hydropower plants are expected, and the two regions together account for two-thirds of the total world increase in hydroelectric generation from 2010 to 2035.

Solar power is the fastest-growing source of renewable energy in the outlook, with annual growth averaging 11.7 percent. However, because it currently accounts for only 0.4 percent of total renewable generation, solar remains a minor part of the renewable mix even in 2035, when its share reaches 3 percent. Wind generation accounts for the largest increment in nonhydropower renewable generation—60 percent of the total increase, as compared with solar's 12 percent (Figure 70). The rate of wind generation slows markedly after 2020 because most government wind goals are achieved and wind must then compete on the basis of economics with fossil fuels. Wind-powered generating capacity has grown swiftly over the past decade, from 18 gigawatts of installed capacity in 2000 to an estimated 179 gigawatts in 2010.

In the United States, average energy use per person declines from 2010 to 2035

Figure 71. Energy use per capita and per dollar of gross domestic product, 1980-2035 (index, 1980 = 1)



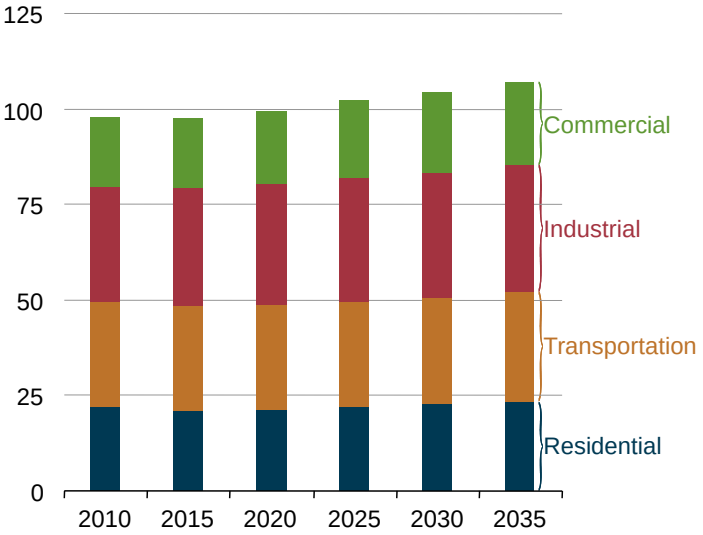
Growth in energy use is linked to population growth through increases in housing, commercial floorspace, transportation, and goods and services. These changes affect not only the level of energy use but also the mix of fuels consumed.

Changes in the structure of the economy and in the efficiency of the equipment deployed throughout the economy also have an impact on energy use per capita. The shift in the industrial sector away from energy-intensive manufacturing toward services is one reason for the projected decline in industrial energy intensity (energy use per dollar of GDP), but its impact on energy consumption per capita is less direct (Figure 71). From 1990 to 2007, the service sectors increased from a 69-percent share of total industrial output to a 75-percent share, but energy use per capita remained fairly constant, between 330 and 350 million British thermal units (Btu) per person, while energy use per dollar of GDP dropped from about 10,500 to 7,700 Btu. Increases in the efficiency of freight vehicles and the shift toward output from the service sectors are projected to continue through 2035, lowering energy use in relation to GDP. Energy use per dollar of GDP is projected to be about 4,400 Btu in 2035, or about one-third of the 1980 level.

Efficiency gains in household appliances and personal vehicles have a direct, downward impact on energy use per capita, as do efficiency gains in the electric power sector, as older, inefficient coal and other fossil steam electricity generating plants are retired in anticipation of lower electricity demand growth, changes in fuel prices, and new environmental regulations. As a result, U.S. energy use per capita declines to 274 million Btu in 2035.

Industrial and commercial sectors lead U.S. growth in primary energy use

Figure 72. Primary energy use by end-use sector, 2010-2035 (quadrillion Btu)



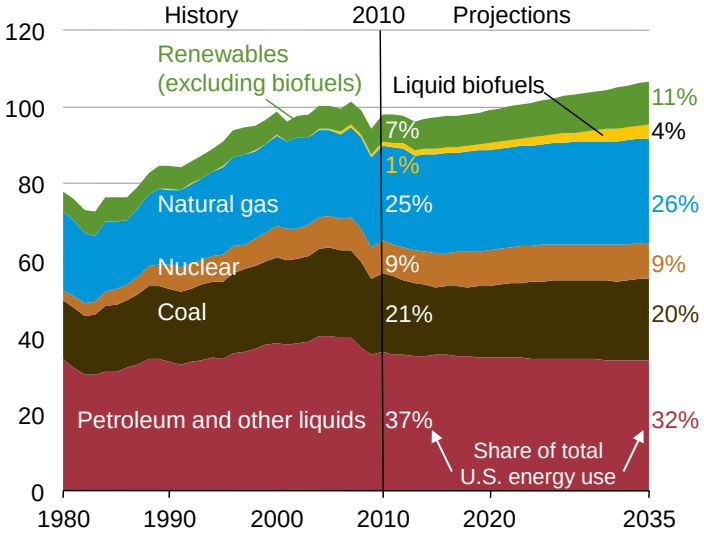
Total primary energy consumption, including fuels used for electricity generation, grows by 0.3 percent per year from 2010 to 2035, to 106.9 quadrillion Btu in 2035 in the *AEO2012* Reference case (Figure 72). The largest growth, 3.3 quadrillion Btu from 2010 to 2035, is in the commercial sector, which currently accounts for the smallest share of end-use energy demand. Even as standards for building shells and energy efficiency are being tightened in the commercial sector, the growth rate for commercial energy use, at 0.7 percent per year, is the highest among the end-use sectors, propelled by 1.0 percent average annual growth in commercial floorspace.

The industrial sector, which was more severely affected than the other end-use sectors by the 2008-2009 economic downturn, shows the second-largest increase in total primary energy use, at 3.1 quadrillion Btu from 2010 to 2035. The total increase in industrial energy consumption is 2.1 quadrillion Btu from 2008 to 2035, attributable to increased production of biofuels to meet the Energy Independence and Security Act of 2007 (EISA2007) renewable fuels standard (RFS) as well as increased use of natural gas in some industries, such as food and paper, to generate their own electricity.

Primary energy use in both the residential and transportation sectors grows by 0.2 percent per year, or by just over 1 quadrillion Btu each from 2010 to 2035. In the residential sector, increased efficiency reduces energy use for space heating, lighting, and clothes washers and dryers. In the transportation sector, light-duty vehicle (LDV) energy consumption declines after 2012 to 14.7 quadrillion Btu in 2023 (the lowest point since 1998) before increasing through 2035, when it is still 4 percent below the 2010 level.

Renewable energy sources lead rise in primary energy consumption

Figure 73. Primary energy use by fuel, 1980-2035 (quadrillion Btu)



With the exception of petroleum and other liquids, which falls through 2032 before increasing slightly in the last 3 years of the projection, consumption of all fuels increases in the *AEO2012* Reference case. In addition, coal consumption increases at a relatively weak average rate of less than 0.1 percent per year from 2010 to 2035, remaining below 2010 levels until after 2031. As a result, the aggregate fossil fuel share of total energy use falls from 83 percent in 2010 to 77 percent in 2035, while renewable fuel use grows rapidly (Figure 73). The renewable share of total energy use (including biofuels) increases from 8 percent in 2010 to 14 percent in 2035 in response to the Federal RFS, availability of Federal tax credits for renewable electricity generation and capacity, and State renewable portfolio standard (RPS) programs.

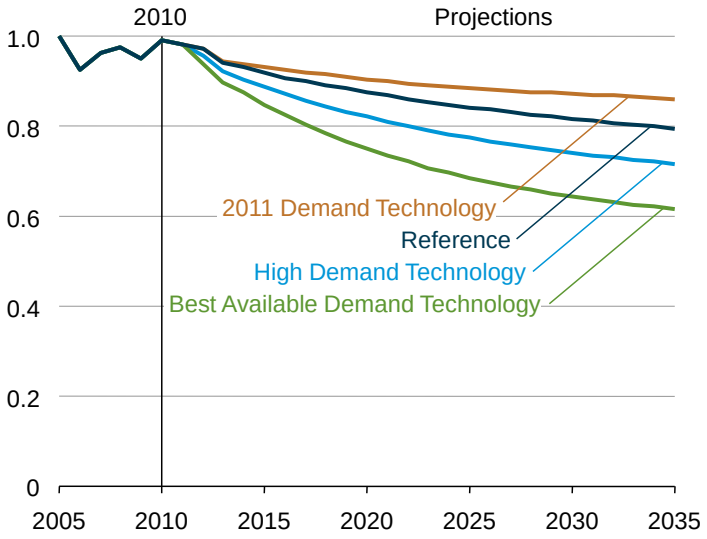
The petroleum and other liquids share of fuel use declines as consumption of other liquids increases. Almost all consumption of liquid biofuels is in the transportation sector. Biofuels, including biodiesel blended into diesel, E85, and ethanol blended into motor gasoline (up to 15 percent), account for 10 percent of all petroleum and other liquids consumption in 2035.

Natural gas consumption grows by about 0.4 percent per year from 2010 to 2035, led by the use of natural gas in electricity generation. Growing production from tight shale keeps natural gas prices below their 2005-2008 levels through 2035.

By the end of 2012, a total of 9.3 gigawatts of coal-fired power plant capacity currently under construction is expected to come online, and another 1.7 gigawatts is added after 2017 in the Reference case, including 0.9 gigawatts with carbon sequestration capability. Additional coal is consumed in the coal-to-liquids (CTL) process to produce heat and power, including electricity generation at CTL plants.

Residential energy use per household declines for a range of technology assumptions

Figure 74. Residential delivered energy intensity in four cases, 2005-2035 (index, 2005 = 1)



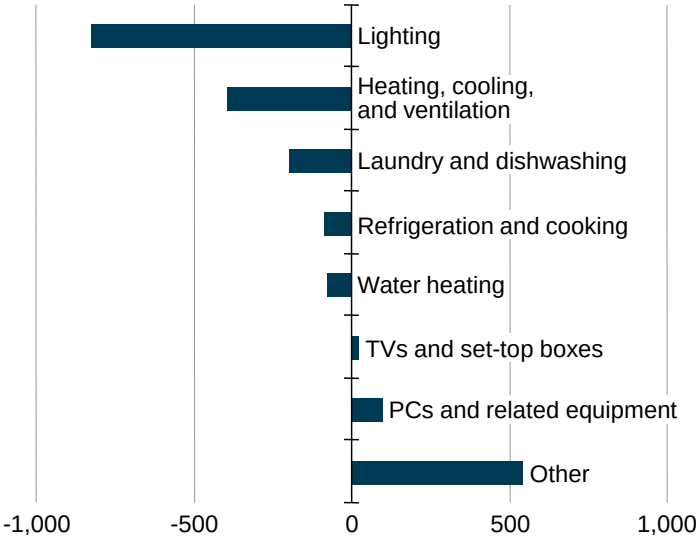
In the *AEO2012* Reference case, residential sector energy intensity, defined as average energy use per household per year, declines by 19.8 percent, to 81.9 million Btu per year in 2035 (Figure 74). Total delivered energy use in the residential sector remains relatively constant from 2010 to 2035, but a 27.5-percent growth in the number of households reduces the average energy intensity of each household. Most residential end-use services become less energy-intensive, with space heating accounting for more than one-half of the decrease. Population shifts to warmer and drier climates also contribute to a reduction in demand for space heating.

Three alternative cases show how different technology assumptions affect residential energy intensity. The 2011 Demand Technology case assumes no improvement in efficiency for end-use equipment or building shells beyond those available in 2011. The High Demand Technology case assumes higher efficiency, earlier availability, lower cost, and more frequent energy-efficient purchases for some advanced equipment. The Best Available Demand Technology case limits customers who purchase new and replacement equipment to the most efficient model available in the year of purchase—regardless of cost—and assumes that new homes are constructed to the most energy-efficient specifications.

From 2010 to 2035, household energy intensity declines by 27.7 percent in the High Demand Technology case and by 37.9 percent in the Best Available Demand Technology case. In the 2011 Demand Technology case, household energy intensity also falls as older appliances are replaced with 2011 vintage equipment. Without further gains in efficiency for residential equipment and building shells, the total decline from 2010 to 2035 is only 13.2 percent.

Electricity use increases with number of households despite efficiency improvement

Figure 75. Change in residential electricity consumption for selected end uses in the Reference case, 2010-2035 (kilowatthours per household)



Despite a decrease in electricity consumption per household, total delivered electricity use in the residential sector grows at an average rate of 0.7 percent per year in the *AEO2012* Reference case, while natural gas use and petroleum and other liquids use fall by 0.2 percent and 1.3 percent per year, respectively, from 2010 to 2035. The increase in efficiency, driven by new standards and improved technology, is not high enough to offset the growth in the number of households and electricity consumption in "other" uses.

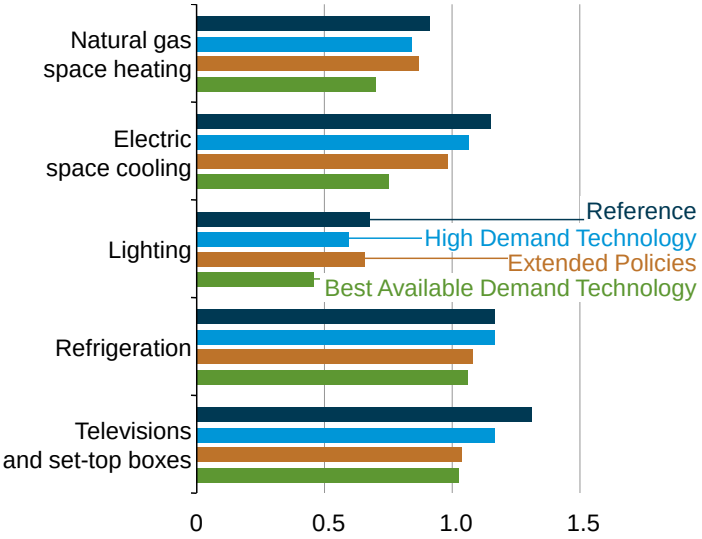
Portions of the Federal lighting standards outlined in EISA2007 went into effect on January 1, 2012. Over the next two years, general-service lamps that provide 310 to 2,600 lumens of light are required to consume about 30 percent less energy than typical incandescent bulbs. High-performance incandescent, compact fluorescent, and light-emitting diode (LED) lamps continue to replace low-efficacy incandescent lamps. In 2035, delivered energy for lighting per household in the Reference case is 827 kilowatthours per household lower, or 47 percent below the 2010 level (Figure 75).

Electricity consumption for three groups of electricity end uses increases on a per-household basis in the Reference case. Electricity use for televisions and set-top boxes grows by an average of 1.1 percent per year, accounting for 7.3 percent of total delivered electricity consumption in 2035. Personal computers (PCs) and related equipment account for 4.6 percent of residential electricity consumption in 2035, averaging 1.8-percent annual growth from their 2010 level. Electricity use by other household electrical devices, for which market penetration increases with little coverage by efficiency standards, increases by 1.8 percent annually and accounts for nearly one-fourth of total residential electricity consumption in 2035.

Residential sector energy demand

Residential consumption varies depending on efficiency assumptions

Figure 76. Ratio of residential delivered energy consumption for selected end uses (ratio, 2035 to 2010)



The *AEO2012* Reference case and three alternative cases demonstrate opportunities for improved energy efficiency to reduce energy consumption in the residential sector. The Reference, High Demand Technology, and Best Available Demand Technology cases include different levels of efficiency improvement without anticipating the enactment of new appliance standards. The Extended Policies case assumes the enactment of new rounds of standards, generally based on improvements seen in current ENERGY STAR equipment.

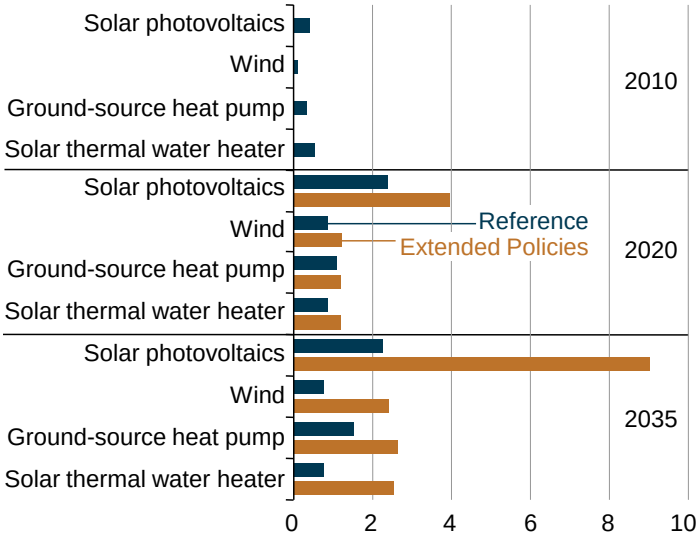
Despite continued growth in the number of households and number of appliances, energy consumption for some end uses is lower in 2035 than in 2010, implying that improved energy efficiency offsets the growth in service demand. In the case of natural gas space heating, population shifts towards warmer and drier climates also reduce consumption; the opposite is true for electric space cooling.

In the Extended Policies case, the enactment of new standards is based on the U.S. Department of Energy's multi-year schedule. For lighting, which already has an EISA2007-based standard that is scheduled to go into effect in 2020, future standards are not assumed until 2026. Among electric end uses, lighting has the largest percentage decline in energy use (more than 50 percent) in the Best Available Demand Technology case from 2010 to 2035 (Figure 76).

Televisions and set-top boxes, which are not currently covered by Federal standards, are assumed to have new standards in 2016 and 2018, respectively, in the Extended Policies case. The enactment of these new standards holds energy use for televisions and set-top boxes at or near their 2010 levels through 2035.

Tax credits could spur growth in renewable energy equipment in the residential sector

Figure 77. Residential market penetration by renewable technologies in two cases, 2010, 2020, and 2035 (percent of households)



Consistent with current law, existing investment tax credits (ITCs) expire at the end of 2016 in the *AEO2012* Reference case. The current credits can offset 30 percent of installed costs for a variety of distributed generation (DG) technologies, fostering their adoption. Installations slow dramatically after the ITCs expire, and in several cases their overall market penetration falls because growth in households exceeds the rise in new renewable installations (Figure 77). In the *AEO2012* Extended Policies case, the ITCs are extended through 2035, and penetration rates for all renewable technologies continue to rise.

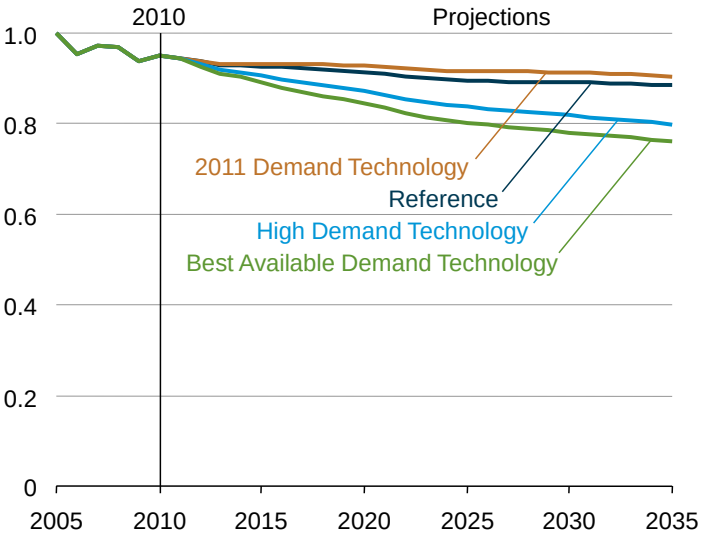
In the Reference case, photovoltaic (PV) and wind capacities grow by average rates of 10.8 percent and 9.2 percent per year, respectively, from 2010 to 2035. In the Extended Policies case, residential PV capacity increases to 54.6 gigawatts in 2035, with annual growth averaging 18.1 percent, and wind capacity grows to 11.0 gigawatts in 2035, averaging 15.9 percent per year.

The ITCs also affect the penetration of renewable space-conditioning and water-heating equipment. Ground-source heat pumps reach a 2.6-percent market share in 2035 in the Extended Policies case, after adding nearly 3.5 million units. In the Reference case, without the ITC extension, their market penetration is only 1.5 percent in 2035, with 1.6 million fewer installations than in the Extended Policies case.

Market penetration of solar water heaters in the Extended Policies case is 2.5 percent in 2035, more than triple the Reference case share. In the Reference case, installations increase by 2.5 percent annually from 2010 to 2035, compared with 7.5 percent annually in the Extended Policies case.

For commercial buildings, pace of decline in energy intensity depends on technology

Figure 78. Commercial delivered energy intensity in four cases, 2005-2035 (index, 2005 = 1)



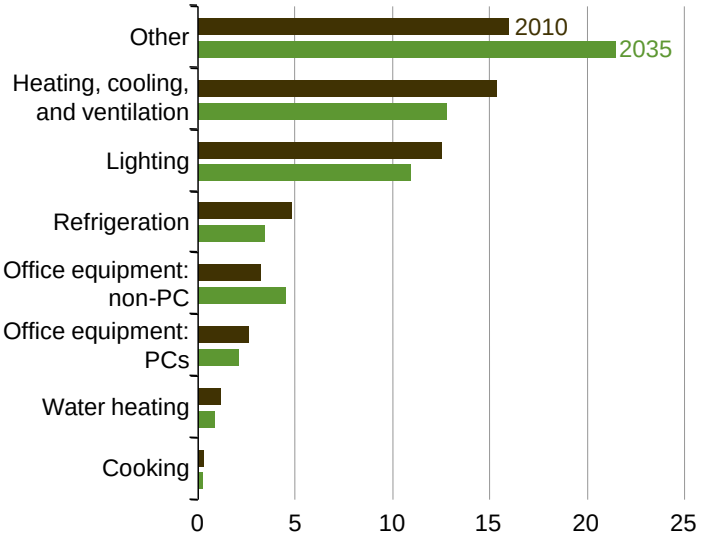
In the *AEO2012* Reference case, average delivered energy use per square foot of commercial floorspace declines by 7.0 percent from 2010 to 2035 (Figure 78). Growth in commercial floorspace (26.9 percent) leads to an increase in delivered energy use (18.1 percent), but efficiency improvements in equipment and building shells reduce energy intensity in commercial buildings. Space heating, space cooling, and lighting contribute most to the decrease in intensity, with space heating accounting for significantly more than cooling and lighting combined.

Three alternative cases show the potential impact of energy-efficient technologies on energy intensity in commercial buildings. The 2011 Demand Technology case limits equipment and building shell technologies in later years to the options available in 2011. The High Demand Technology case assumes higher efficiencies for equipment and building shells, lower costs, earlier availability of some advanced equipment, and decisions by commercial customers that place greater importance on future energy savings. The Best Available Technology case assumes more efficient buildings shells for new and existing buildings than in the High Demand Technology case and also requires commercial customers to choose among the most efficient models for each technology when replacing old or purchasing new equipment.

From 2010 to 2035, the intensity of commercial energy use in the 2011 Technology Demand case declines by 5.0 percent, to 101.9 thousand Btu per square foot of commercial floorspace in 2035. In comparison, intensity decreases faster in the High Demand Technology case (16.0 percent) and fastest in the Best Available Demand Technology case (20.0 percent).

Efficiency standards reduce electric energy intensity in commercial buildings

Figure 79. Energy intensity of selected commercial electric end uses, 2010 and 2035 (thousand Btu per square foot)



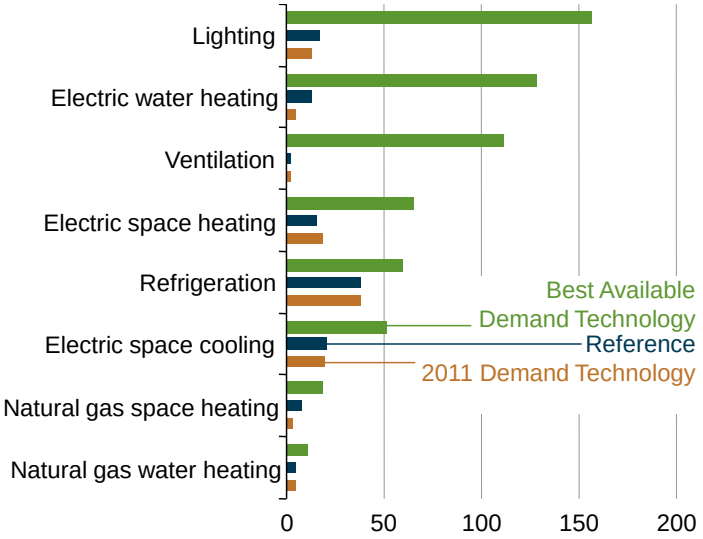
Electricity, which accounted for 52 percent of total commercial delivered energy use in 2010, increases to 56 percent in 2035 in the *AEO2012* Reference case, as commercial floorspace grows at an average annual rate of 1 percent and new electric end uses become more prevalent. Despite such growth, improved efficiency of commercial equipment slows the growth of purchased electricity over the projection period.

Commercial energy intensity in this figure, defined as the ratio of energy consumption in these appliances to floorspace, decreases for most electric end uses from 2010 to 2035 in the Reference case (Figure 79). Electricity intensity decreases by 1.3 percent annually for both cooking and refrigeration, by 0.5 percent annually for lighting, and by 0.7 percent annually for space conditioning (heating, cooling, and ventilation).

End uses such as space heating and cooling, water heating, refrigeration, and lighting are covered by Federal efficiency standards that act to limit growth in energy consumption to less than the growth in commercial floorspace. "Other" electric end uses, some of which are not subject to standards, account for much of the growth in commercial electricity consumption in the Reference case. Electricity consumption for "other" electrical end uses—including video displays and medical devices—increases by an average of 2.2 percent per year and in 2035 accounts for 38 percent of total commercial electricity consumption. Energy consumption for "other" office equipment—including servers and mainframe computers—increases by 2.3 percent per year from 2010 to 2035, as demand for high-speed networks and internet connectivity continues to grow.

Technologies for major energy applications lead efficiency gains in commercial sector

Figure 80. Efficiency gains for selected commercial equipment in three cases, 2035 (percent change from 2010 installed stock efficiency)



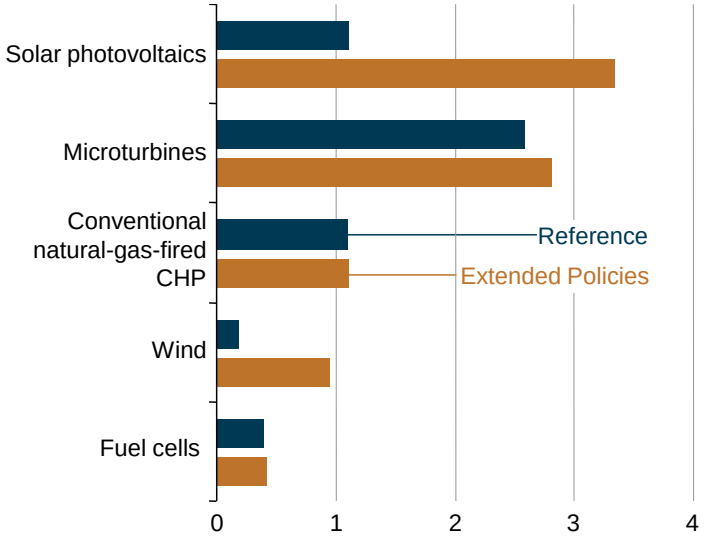
Delivered energy consumption for space heating, ventilation, air conditioning, water heating, lighting, cooking, and refrigeration uses in the commercial sector grows by an average of 0.2 percent per year from 2010 to 2035 in the *AEO2012* Reference case, compared with 1.0-percent annual growth in commercial floorspace. The core end uses, which frequently have been the focus of energy efficiency standards, accounted for just over 60 percent of commercial delivered energy demand in 2010. In 2035, their share falls to 53 percent. Energy consumption for all the remaining end uses grows by 1.3 percent per year, led by office equipment other than computers and other electric end uses.

The percentage gains in efficiency in the Reference case are highest for refrigeration, as a result of provisions in the Energy Policy Act of 2005 and EISA2007. Electric space cooling shows the next-largest percentage improvement, followed by lighting and electric space heating (Figure 80).

The Best Available Demand Technology case demonstrates significant potential for further improvement—especially in electric equipment, led by lighting, water heating, and ventilation. In the Best Available Demand Technology case, the share of total commercial delivered energy use in the core end uses falls to 49 percent in 2035, with significant efficiency gains coming from high-efficiency variable air volume ventilation systems, LED lighting, ground-source heat pumps, high-efficiency rooftop heat pumps, centrifugal chillers, and solar water heaters. Those technologies are relatively costly, however, and thus unlikely to gain wide adoption in commercial applications without improved economics. Additional efficiency improvements could also come from an expansion of standards to include some of the rapidly growing miscellaneous electric applications.

Investment tax credits could increase distributed generation in commercial sector

Figure 81. Additions to electricity generation capacity in the commercial sector in two cases, 2010-2035 (gigawatts)



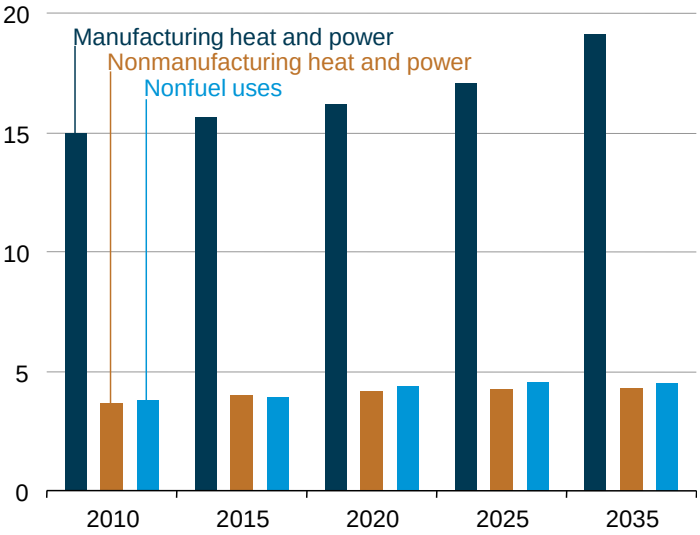
ITCs have a major impact on the growth of renewable DG in the commercial sector. Although most ITCs are set to expire at the end of 2016, the tax credit for solar PV installations reverts from 30 percent to 10 percent and continues indefinitely. Commercial PV capacity increases by 2.7 percent annually from 2010 through 2035 in the *AEO2012* Reference Case. Extending the ITCs to all DG technologies through 2035 in the *AEO2012* Extended Policies case causes PV capacity to increase at an average annual rate of 5.7 percent (Figure 81).

Growth in small-scale wind capacity more than doubles in the Extended Policies case relative to the Reference case, increasing at an average annual rate of 11.4 percent from 2010 to 2035. Wind accounts for 9.2 percent of the 11.1 gigawatts of total commercial DG capacity in 2035 in the Extended Policies case, and PV accounts for 40.6 percent. In the Extended Policies case, renewable energy accounts for 53 percent of all commercial DG capacity, compared with about 37 percent in the Reference case.

Although ITCs affect the rate of adoption of renewable DG by offsetting a portion of capital costs, their potential effects on nonrenewable DG technologies are offset by rising natural gas prices. In the Reference case, microturbine capacity using natural gas grows by an average of 18.1 percent per year from 42 megawatts in 2010 to 2.6 gigawatts in 2035, and the growth rate in the Extended Policies case is only slightly higher, at 18.4 percent. In the Extended Policies case, the microturbine share of total DG capacity in 2035 is 25.6 percent, as compared with 33.4 percent in the Reference case.

Manufacturing heat and power energy consumption increases modestly

Figure 82. Industrial delivered energy consumption by application, 2010-2035 (quadrillion Btu)



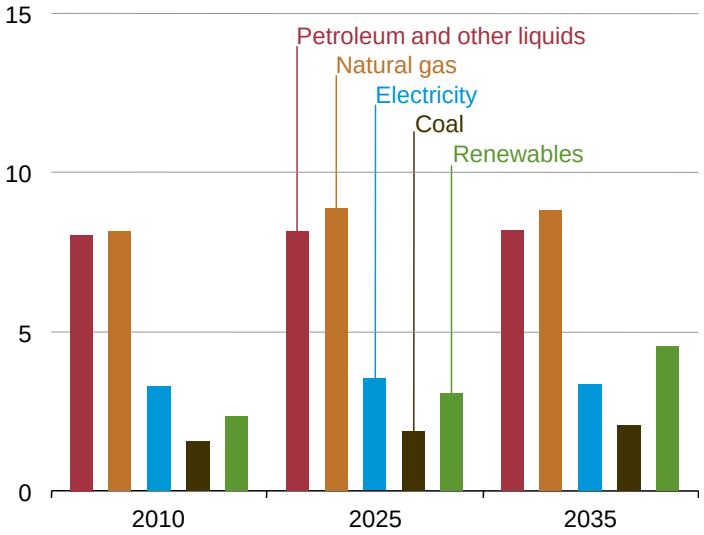
Despite a 49-percent increase in industrial shipments, industrial delivered energy consumption increases by only 15 percent from 2010 to 2035 in the *AEO2012* Reference case, reflecting a shift in the share of shipments from energy-intensive manufacturing industries (which include bulk chemicals, petroleum refineries, paper products, iron and steel, food products, aluminum, cement, and glass) to other, less energy-intensive industries, such as plastics, computers, and transportation equipment. Although energy use for most of the energy-intensive industries continues to grow after 2012, with the stronger growth in refining, declines in the energy intensity of heat and power production offset some the growth in their energy use.

The share of industrial delivered energy consumption used for heat and power in manufacturing increases from 64 percent in 2010 to 71 percent in 2035 (Figure 82). The increase in heat and power energy consumption in manufacturing in the Reference case is primarily a result of a large increase (2 quadrillion Btu) in total energy use in the petroleum refining industry, including production increases for CTL, coal- and biomass-to-liquids (CBTL), and biomass pyrolysis oil production.

Heat and power consumption in the nonmanufacturing industries (agriculture, mining, and construction) is flat in the Reference case projection, accounting for about 16 percent of total industrial energy consumption over the 2010-2035 period. The remaining consumption consists of nonfuel uses of energy—primarily, feedstocks for chemical manufacturing and asphalt for construction. The share of total industrial energy consumption represented by nonfuel use increases by 1.6 percent from 2010 to 2020 as a result of increased shipments of organic chemicals, then declines as competition from foreign producers slows the growth of domestic production.

Reliance on natural gas and natural gas liquids rises as industrial energy use grows

Figure 83. Industrial energy consumption by fuel, 2010, 2025 and 2035 (quadrillion Btu)



Led by increasing use of natural gas, total delivered industrial energy consumption grows at an annual rate of 0.6 percent from 2010 through 2035 in the Reference case. The mix of fuels changes slowly, reflecting limited capability for fuel switching with the current capital stock (Figure 83).

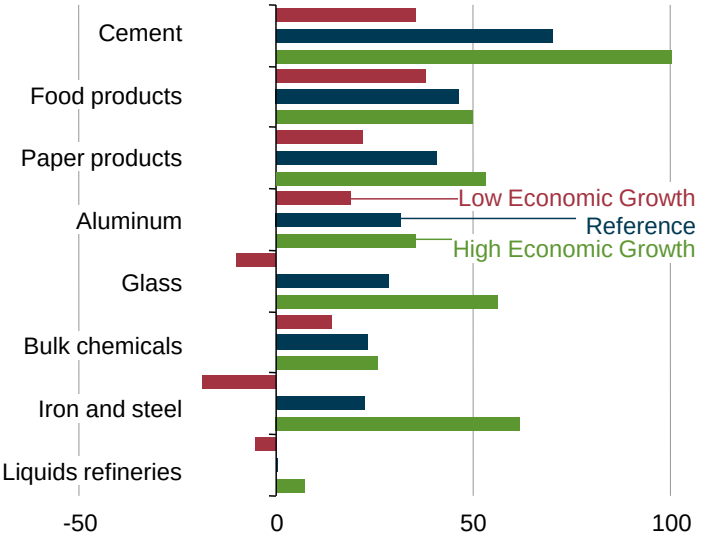
Industrial natural gas use grows by 8 percent from 2010 to 2035, reflecting relatively low natural gas prices. As a result, 33 percent of delivered industrial energy consumption is met with natural gas in 2035. The second-largest share is met by petroleum and other liquids (30 percent) and the remainder by renewables, electricity, and coal (37 percent). NGL, an increasingly valuable liquid component of natural gas processing, are consumed as a feedstock in the bulk chemicals industry and also are used for heat in other sectors. Industrial use of all petroleum and other liquids increases slightly from 2010 to 2035, and in 2035 the chemical industries use nearly one-half of the total as feedstock.

Coal use in the industrial sector for boilers and for smelting in steelmaking declines as more boilers are fired with natural gas and less metallurgical coal is used for steelmaking. After 2016, increased use of coal for CTL and CBTL production fully offsets the decline in the steel industry and boiler fuel use.

A decline in the electricity share of industrial energy consumption reflects modest growth in combined heat and power (CHP), which offsets purchased electricity requirements, as well as efficiency improvements across industries, primarily as a result of rising standards for motor efficiency. With growth in lumber, paper, and other industries that consume biomass-based byproducts, the renewable share of industrial energy use expands.

Iron and steel and cement industries are most sensitive to economic growth rate

Figure 84. Cumulative growth in value of shipments from energy-intensive industries in three cases, 2010-2035 (percent)



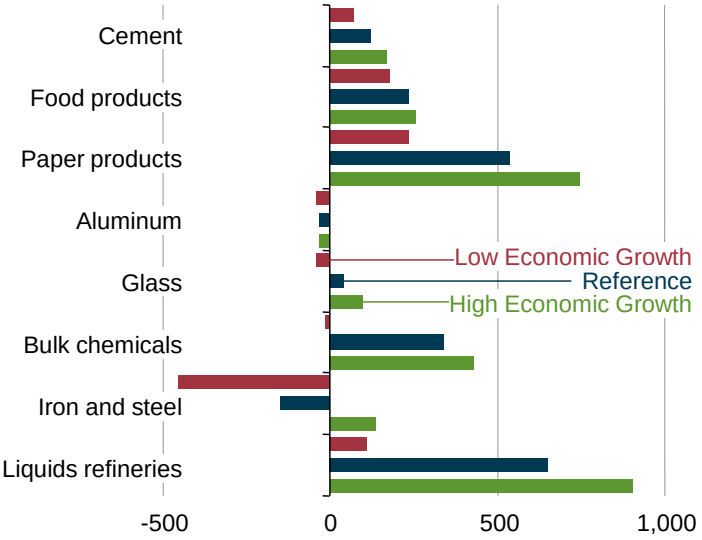
Total shipments from the energy-intensive industries grow by an average of 1 percent per year from 2010 to 2035 in the Reference case, as compared with 0.6 percent in the Low Economic Growth case and 1.2 percent in the High Economic Growth case. The post-recession recovery in shipments is uneven among the industrial subsectors. Paper, bulk chemicals, aluminum, and cement all show strong short-term recoveries from 2010 levels, while shipments from the liquids refinery industry lag. The iron and steel and glass industries show flat to moderate growth in the near term.

Among the energy-intensive industries, the value of shipments in the bulk chemicals, paper, and aluminum take less than 10 years to return to their 2006-2007 pre-recession levels. Others, including cement, iron and steel, and glass, take longer. Shipments from the liquids refinery industry do not reach pre-recession levels by 2035, because demand for transportation fuels is moderated by increasing vehicle efficiencies. Food shipments, which grow in proportion to population and are resistant to recessions, have not shown the same recession-related decline as the other industries. Shipments of bulk chemicals, especially organic chemicals, grow sharply from 2012 to 2025 with the increased use of NGL as feedstock. After 2025, shipments from the bulk chemical industry level off as a result of foreign competition.

The energy-intensive iron and steel and cement industries show the greatest variability in shipments across the three cases (Figure 84), because they supply downstream industries that are sensitive to GDP growth. Construction is a downstream industry for both iron and steel and cement, and the metal-based durables industry is a downstream industry for iron and steel. Shipments in the metal durables industry levels off after 2020, following a decline in iron and steel shipments.

Energy use reflects output and efficiency trends in energy-intensive industries

Figure 85. Change in delivered energy for energy-intensive industries in three cases, 2010-2035 (trillion Btu)



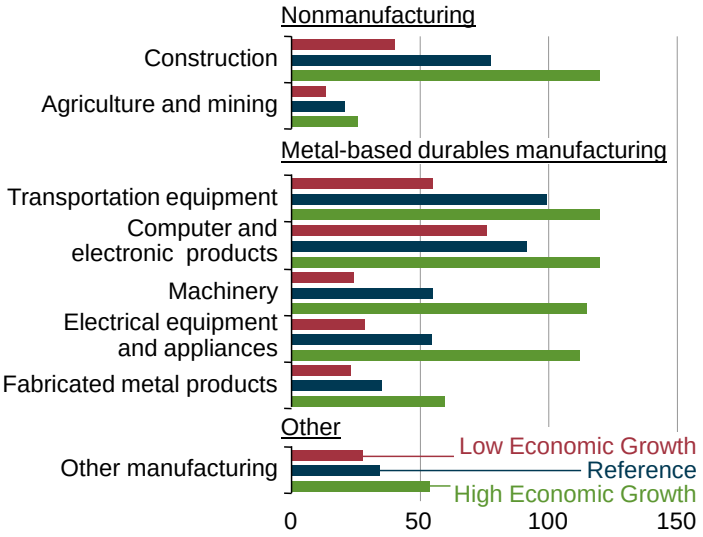
Changes in energy consumption from 2010 to 2035 in the energy-intensive industries ranges from almost nothing in the Low Economic Growth case to 0.8 percent per year or 5 quadrillion Btu in the High Economic Growth case (Figure 85). Changes in energy consumption by the industrial subsector largely reflect the corresponding changes in gross shipments. Energy efficiency improvements and changes in manufacturing methods and requirements, however, also affect energy consumption.

Starting from low levels of economic activity in 2010, shipments from all industries grow over the projection period. For example, steel industry shipments grow by 23 percent in the *AEO2012* Reference case from 2010 to 2035, but energy use declines by 12 percent due to a shift from the use of blast furnace steel production to the use of recycled products and electric arc furnaces. The continued decline of primary aluminum production and concurrent rise in less energy-intensive secondary production lead to a similar decline in aluminum industry energy use despite an increase in shipments. The paper industry shows a far less noticeable improvement in energy efficiency because of greater demand for more energy-intensive products such as paperboard by consumers.

The only industrial subsector that shows an increase in energy intensity is refining. In each of the three Economic Growth cases (Reference, Low Growth, and High Growth), the increase in liquids refinery industry energy consumption exceeds the growth in shipments over the projection period as a result of increased use of coal after 2015 for CTL and CBTL production. Production of alternative fuels is inherently more energy-intensive than production of traditional fuels, because they are refined from solids with relatively low energy densities.

Transportation equipment shows strongest growth in non-energy-intensive shipments

Figure 86. Cumulative growth in value of shipments from non-energy-intensive industries in three cases, 2010-2035 (percent)



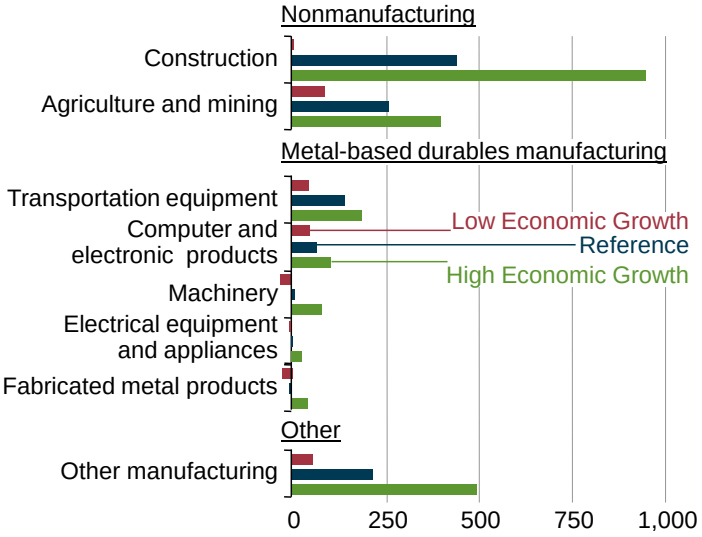
In 2035, non-energy-intensive manufacturing and nonmanufacturing industrial subsectors account for $6.7 trillion (2005 dollars) in shipments in the Reference case—a 57-percent increase from 2010. From 2010 to 2035, growth in those shipments averages 1.2 percent per year in the Low Economic Growth case and 2.5 percent in the High Economic Growth case, compared with 1.8 percent in the Reference case (Figure 86). Non-energy-intensive manufacturing and nonmanufacturing are segments of the industrial sector that primarily consume fuels for thermal or electrical needs, not as raw materials or feedstocks.

In the three cases, shipments from the two subsectors grow at roughly twice the annual rate projected for energy-intensive manufacturing, based on production of high-tech, high-value goods and strong supply chain linkages between energy-intensive manufacturing and many non-energy-intensive manufacturing industries (such as machinery and transportation equipment produced for the metals industries). Recovery in the two subsectors from 2010 to 2015 is rapid because of increased U.S. competiveness in the transportation equipment and machinery industries, as well as a recovering construction industry, which saw residential starts bottom out in 2010. After 2015, the growth is more moderate.

In the Reference case, shipments from the non-energy-intensive manufacturing and nonmanufacturing industries generally exceed pre-recession levels by 2017, reflecting a slow and extended economic recovery. Pre-recession shipment levels are exceeded in 2015 and 2024 in the High Economic Growth and Low Economic Growth cases, respectively.

Nonmanufacturing and transportation equipment lead energy efficiency gains

Figure 87. Change in delivered energy for non-energy-intensive industries in three cases, 2010-2035 (trillion Btu)



From 2010 to 2035, total energy consumption in the non-energy-intensive manufacturing and nonmanufacturing industrial subsectors changes by 2 percent or 178 trillion Btu in the Low Economic Growth case, 15 percent or 1,134 trillion Btu in the Reference case, and 30 percent or 2,282 trillion Btu in the High Economic Growth case (Figure 87). In each of the three cases, those industries together account for more than 40 percent of the projected increase in total industrial natural gas consumption.

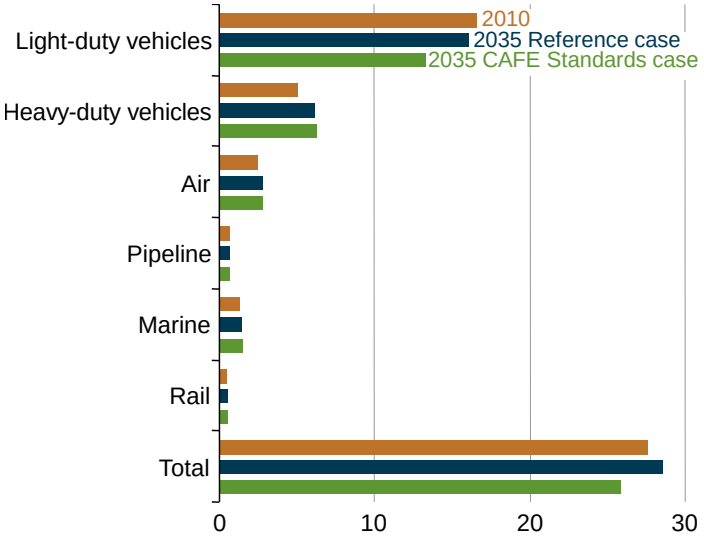
The transportation equipment and construction industries account for roughly 20 percent of the projected increase in energy use but approximately 40 percent of the projected growth in total industrial shipments in all cases. The transportation equipment industry, in particular, shows a rapid decline in energy intensity from 2010 to 2035. Energy consumption increases by 37 percent from 2010 to 2035 and production doubles, yielding an annualized decline in energy intensity of 1.3 percent per year in the transportation equipment industry over the projection period in the *AEO2012* Reference case.

Overall, the combined energy intensity of the non-energy-intensive manufacturing and nonmanufacturing industries declines by 25 percent in the Low Economic Growth case and 29 percent in the High Economic Growth case. The more rapid decline in the High Economic Growth case is consistent with an expectation that energy intensity will fall more rapidly when stronger economic growth facilitates additional investment in more energy-efficient equipment.

Transportation sector energy demand

Transportation energy use grows slowly in comparison with historical trend

Figure 88. Delivered energy consumption for transportation by mode in two cases, 2010 and 2035 (quadrillion Btu)



Transportation sector energy consumption grows at an average annual rate of 0.1 percent from 2010 to 2035 (from 27.6 quadrillion Btu to 28.6 quadrillion Btu), much slower than the 1.2-percent average from 1975 to 2010. The slower growth results primarily from improvement in fuel economy for both LDVs and heavy-duty vehicles (HDVs), as well as relatively modest growth in demand for personal travel.

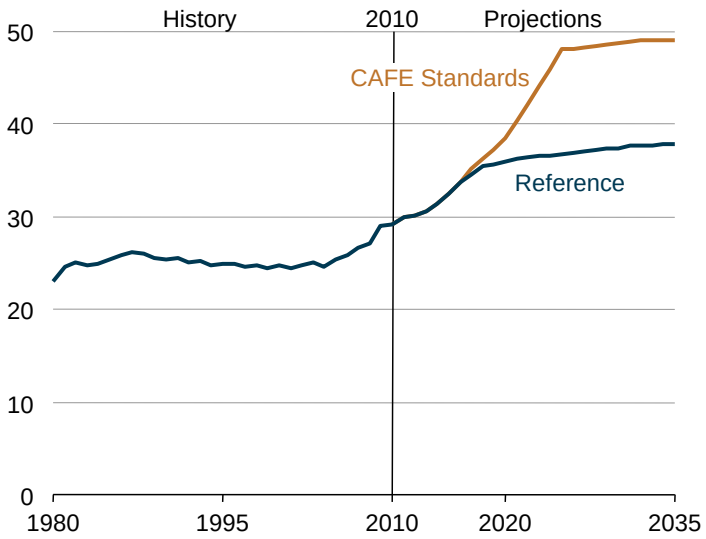
LDV energy demand falls by 3.2 percent (0.5 quadrillion Btu) from 2010 to 2035 (Figure 88). Personal travel demand rises more slowly than in recent history, with the increase more than offset by existing GHG standards for model year (MY) 2012 to 2016 and by EISA2007 fuel economy standards for MY 2017 to 2020. Inclusion of the proposed standards for MY 2017-2025, which are not included in the Reference case, reduce LDV energy demand by 20.0 percent (3.2 quadrillion Btu) from 2010 to 2035.

Energy demand for HDVs (including tractor trailers, buses, vocational vehicles, and heavy-duty pickups and vans) increases by 21 percent, or 1.1 quadrillion Btu, from 2010 to 2035, as a result of increases in vehicle miles traveled (VMT) as economic output recovers. Fuel efficiency and GHG emissions standards temper growth in energy demand even as more miles are traveled overall.

Energy demand for aircraft increases by 11 percent, or 0.3 quadrillion Btu from 2010 to 2035. Higher incomes and moderate growth in fuel costs encourage more personal air travel, the resulting increase in energy use offset by gains in aircraft fuel efficiency. Air freight use of energy grows as a result of export growth. Energy consumption for marine and rail travel also increases, as industrial output grows and more coal is transported. Energy use for pipelines also increases, even though more natural gas production occurs closer to end-use markets.

CAFE and greenhouse gas emissions standards boost vehicle fuel economy

Figure 89. Average fuel economy of new light-duty vehicles in two cases, 1980-2035 (miles per gallon)



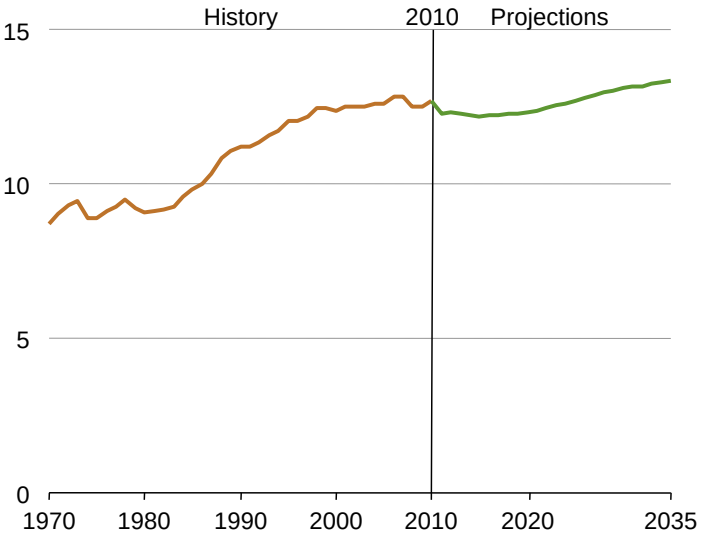
The introduction of Corporate Average Fuel Economy (CAFE) standards for LDVs in 1978 resulted in an increase in fuel economy from 19.9 miles per gallon (mpg) in 1978 to 26.2 mpg in 1987. Over the two decades that followed, despite improvements in LDV technology, fuel economy fell to between 24 and 26 mpg as sales of light-duty trucks increased from 20 percent of new LDV sales in 1980 to almost 55 percent in 2004 [*124*]. The subsequent rise in fuel prices and reduction in sales of light-duty trucks, coupled with tighter CAFE standards for light-duty trucks starting with MY 2008, led to a rise in LDV fuel economy to 29.2 mpg in 2010.

The National Highway Traffic Safety Administration (NHTSA) introduced attribute-based CAFE standards for MY 2011 LDVs in 2009 and, together with the U.S. Environmental Protection Agency (EPA), in 2010 announced CAFE and GHG emissions standards for MY 2012 to MY 2016. EISA2007 further requires that LDVs achieve an average fuel economy of 35 mpg by MY 2020 [*125*]. In the *AEO2012* Reference case, the fuel economy of new LDVs [*126*] rises to 30.0 mpg in 2011, 33.8 mpg in 2016, and 35.9 mpg in 2020 (Figure 89). After 2020, CAFE standards remain constant, with LDV fuel economy increasing moderately to 37.9 mpg in 2035 as a result of more widespread adoption of fuel-saving technologies.

In December 2011, NHTSA and EPA proposed more stringent attribute-based CAFE and GHG emissions standards for MYs 2017 to 2025 [*127*]. The proposal calls for a projected average LDV CAFE of 49.6 mpg by 2025 together with a GHG standard equivalent to 54.5 mpg. With the inclusion of the proposed LDV CAFE standards, LDV fuel economy in the CAFE Standards case increases by nearly 30 percent in 2035 compared to the Reference case.

Travel demand for personal vehicles increases more slowly than in the past

Figure 90. Vehicle miles traveled per licensed driver, 1970-2035 (thousand miles)



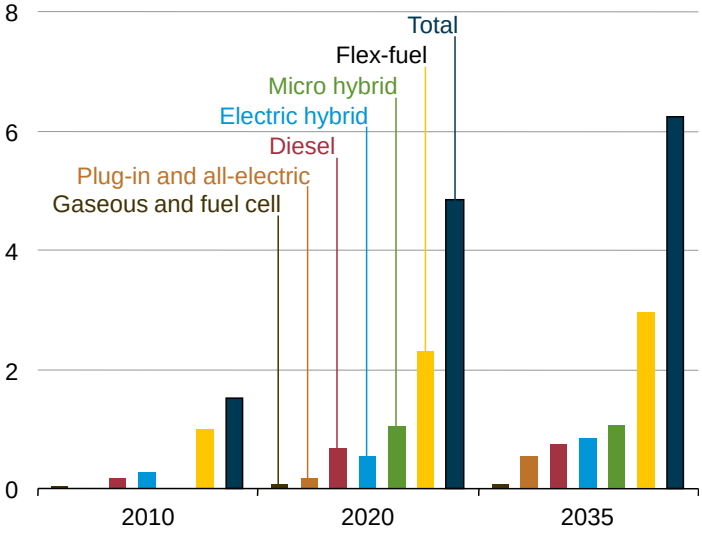
Personal vehicle travel demand, measured as VMT per licensed driver, grew at an average annual rate of 1.1 percent from 1970 to 2007, from about 8,700 miles per driver in 1970 to 12,800 miles per driver in 2007. Increased travel was supported by rising incomes, declining costs of driving per mile (determined by fuel economy and fuel price), and demographic changes (such as women entering the workforce). Between 2007 and 2010, VMT per licensed driver declined to around 12,700 miles per driver because of a spike in the cost of driving per mile and the economic downturn. In the *AEO2012* Reference case, VMT per licensed driver grows by an average of 0.2 percent per year, to 13,350 miles per driver in 2035 (Figure 90).

Although the real price of motor gasoline in the transportation sector increases by 48 percent from 2010 to 2035 in the Reference case, VMT per licensed driver still grows as real disposable personal income climbs by 81 percent. Faster growth in income than in fuel prices ensures that travel demand continues to rise by reducing the percentage of income spent on fuel. In addition, the effect of rising fuel costs is moderated by a 30-percent improvement in new vehicle fuel economy following the implementation of more stringent GHG and CAFE standards for LDVs.

Several demographic forces play a role in moderating the growth in VMT per licensed driver despite the rise in real disposable income. Although LDV sales increase through 2035, the number of vehicles per licensed driver remains relatively constant (at just over 1 per licensed driver). Also, unemployment remains above pre-recession levels in the Reference case until later in the projection, further tempering the increase in personal travel demand.

Sales of alternative fuel, fuel flexible, and hybrid vehicles rise

Figure 91. Sales of light-duty vehicles using non-gasoline technologies by fuel type, 2010, 2020, and 2035 (million vehicles sold)



LDVs that use diesel, other alternative fuels, hybrid-electric, or all-electric systems play a significant role in meeting more stringent GHG emissions and fuel economy standards, as well as offering fuel savings in the face of higher fuel prices. Sales of such vehicles increase from 14 percent of all new LDV sales in 2010 to 35 percent in 2035 in the *AEO2012* Reference case. Sales would be even higher with consideration of the proposed fuel economy standards covering MYs 2017 through 2025 that are not included in the Reference case (see discussion in "Issues in focus").

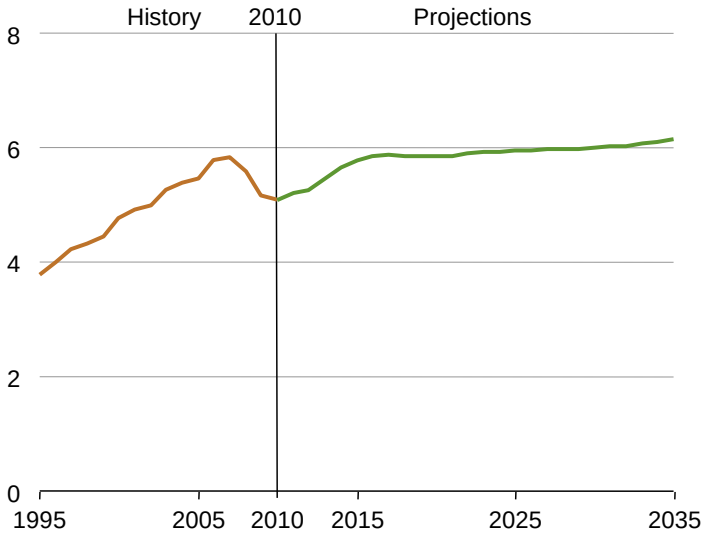
Flex-fuel vehicles (FFVs), which can use blends of ethanol up to 85 percent, represent the largest share of vehicles, at 17 percent of all new vehicle sales. Manufacturers selling FFVs currently receive incentives in the form of fuel economy credits earned for CAFE compliance through MY 2016. FFVs also play a critical role in meeting the RFS for biofuels.

Sales of hybrid electric and all-electric vehicles that use stored electric energy grow considerably in the Reference case (Figure 91). Micro hybrids, which use start/stop technology to manage engine operation while at idle, account for 6 percent of total LDV sales in 2035, which is the largest share for vehicles that use electric storage. Gasoline-electric and diesel-electric hybrid vehicles account for 5 percent of total LDV sales in 2035; and plug-in and all-electric hybrid vehicles account for 3 percent of LDV sales and 9 percent of sales of vehicles using diesel, alternative fuels, hybrid, or all-electric systems.

Sales of diesel vehicles also increase, to 4 percent of total LDV sales in 2035. Light-duty gaseous and fuel cell vehicles account for less than 0.5 percent of new vehicle sales throughout the projection because of the limited availability of a fueling infrastructure and their high incremental cost.

Heavy-duty vehicle energy demand continues to grow but slows from historical rates

Figure 92. Heavy-duty vehicle energy consumption, 1995-2035 (quadrillion Btu)



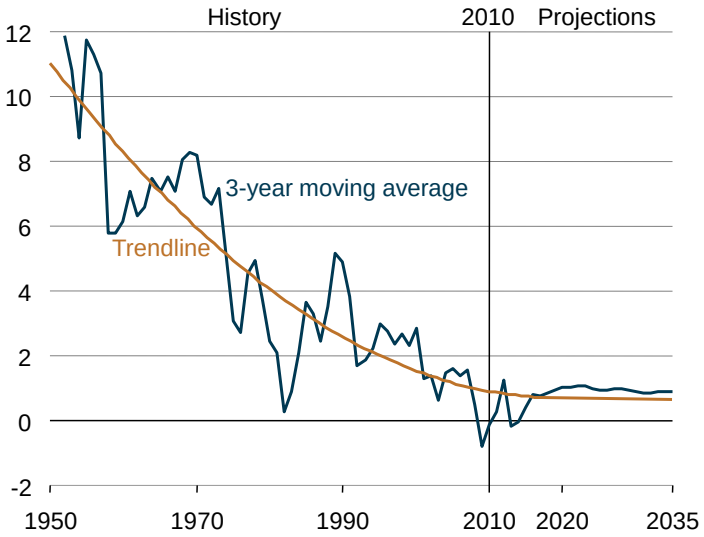
Energy demand for HDVs—including tractor trailers, vocational vehicles, heavy-duty pickups and vans, and buses—increases from 5.1 quadrillion Btu in 2010 to 6.2 quadrillion Btu in 2035, at an average annual growth rate of 0.8 percent, which is the highest among transportation modes. Still, the increase in energy demand for HDVs is lower than the 2-percent annual average from 1995 to 2010, as increases in VMT are offset by improvements in fuel economy following the recent introduction of new standards for HDV fuel efficiency and GHG emissions.

The total number of miles traveled annually by all HDVs grows by 48 percent from 2010 to 2035, from 234 billion miles to 345 billion miles, for an average annual increase of 1.6 percent. The rise in VMT is supported by rising economic output over the projection period and an increase in the number of trucks on the road, from 8.9 million in 2010 to 12.5 million in 2035.

Higher fuel economy for HDVs partially offsets the increase in their VMT, as average new vehicle fuel economy increases from 6.6 mpg in 2010 to 8.2 mpg in 2035. The gain in fuel economy is primarily a consequence of the new GHG emissions and fuel efficiency standards enacted by EPA and NHTSA that begin in MY 2014 and reach the most stringent levels in MY 2018 [*128*]. Fuel economy continues to improve moderately after 2018, as fuel-saving technologies continue to be adopted for economic reasons (Figure 92).

Residential and commercial sectors dominate electricity demand growth

Figure 93. U.S. electricity demand growth, 1950-2035 (percent, 3-year moving average)



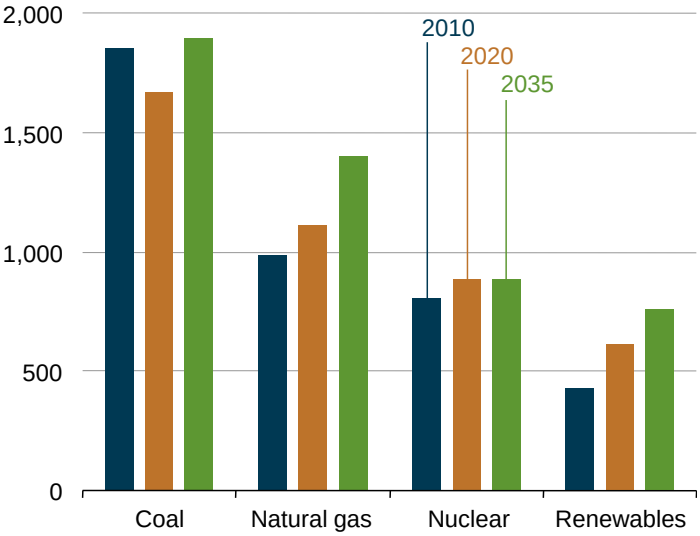
Electricity demand (including retail sales and direct use) growth has slowed in each decade since the 1950s, from a 9.8-percent annual rate of growth from 1949 to 1959 to only 0.7 percent per year in the first decade of the 21st century. In the *AEO2012* Reference case, electricity demand growth rebounds somewhat from those low levels but remains relatively slow, as growing demand for electricity services is offset by efficiency gains from new appliance standards and investments in energy-efficient equipment (Figure 93).

Electricity demand grows by 22 percent in the *AEO2012* Reference case, from 3,877 billion kilowatthours in 2010 to 4,716 billion kilowatthours in 2035. Residential demand grows by 18 percent over the same period, to 1,718 billion kilowatthours in 2035, spurred by population growth, rising disposable income, and continued population shifts to warmer regions with greater cooling requirements. Commercial sector electricity demand increases by 28 percent, to 1,699 billion kilowatthours in 2035, led by demand in the service industries. In the industrial sector, electricity demand has been generally declining since 2000, and it grows by only 2 percent from 2010 to 2035, slowed by increased competition from overseas manufacturers and a shift of U.S. manufacturing toward consumer goods that require less energy to produce. Electricity demand in the transportation sector is small, but it is expected to more than triple from 7 billion kilowatthours in 2010 to 22 billion kilowatthours in 2035 as sales of electric plug-in LDVs increase.

Average annual electricity prices (in 2010 dollars) increase by 3 percent from 2010 to 2035 in the Reference case, generally falling through 2020 in response to lower fuel prices used to generate electricity. After 2020, rising fuel costs more than offset lower costs for transmission and distribution.

Coal-fired plants continue to be the largest source of U.S. electricity generation

Figure 94. Electricity generation by fuel, 2010, 2020, and 2035 (billion kilowatthours)



Coal remains the dominant fuel for electricity generation in the *AEO2012* Reference case (Figure 94), but its share declines significantly. In 2010, coal accounted for 45 percent of total U.S. generation; in 2020 and 2035 its projected share of total generation is 39 percent and 38 percent, respectively. Competition from natural gas and renewables is a key factor in the decline. Overall, coal-fired generation in 2035 is 2 percent higher than in 2010 but still 6 percent below the 2007 pre-recession level.

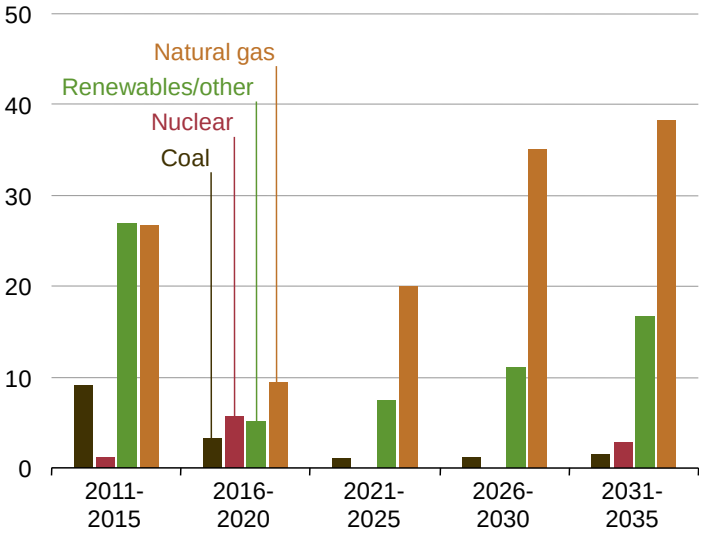
Generation from natural gas grows by 42 percent from 2010 to 2035, and its share of total generation increases from 24 percent in 2010 to 28 percent in 2035. The relatively low cost of natural gas makes the dispatching of existing natural gas plants more competitive with coal plants and, in combination with relatively low capital costs, makes natural gas the primary choice to fuel new generation capacity.

Generation from renewable sources grows by 77 percent in the Reference case, raising its share of total generation from 10 percent in 2010 to 15 percent in 2035. Most of the growth in renewable electricity generation comes from wind and biomass facilities, which benefit from State RPS requirements, Federal tax credits, and, in the case of biomass, the availability of low-cost feedstocks and the RFS.

Generation from U.S. nuclear power plants increases by 10 percent from 2010 to 2035, but the share of total generation declines from 20 percent in 2010 to 18 percent in 2035. Although new nuclear capacity is added by new reactors and uprates of older ones, total generation grows faster and the nuclear share falls. Nuclear capacity grows from 101 gigawatts in 2010 to 111 gigawatts in 2035, with 7.3 gigawatts of additional uprates and 8.5 gigawatts of new capacity between 2010 and 2035. Some older nuclear capacity is retired, which reduces overall nuclear generation.

Most new capacity additions use natural gas and renewables

Figure 95. Electricity generation capacity additions by fuel type, including combined heat and power, 2011-2035 (gigawatts)



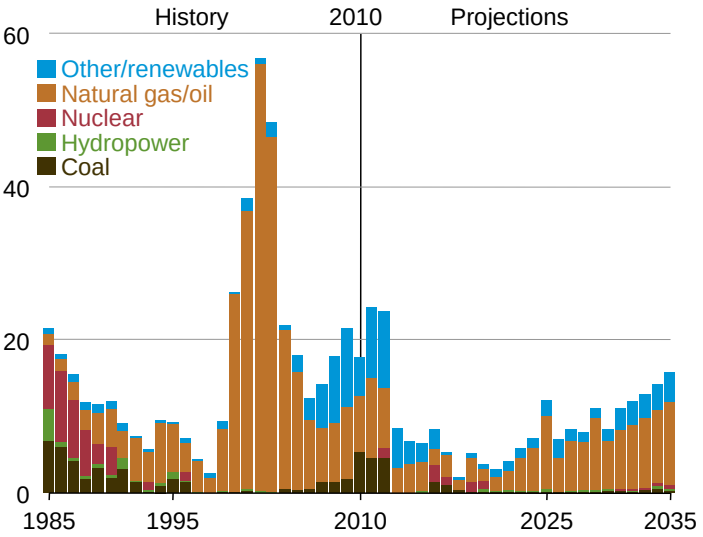
Decisions to add capacity, and the choice of fuel for new capacity, depend on a number of factors [*129*]. With growing electricity demand and the retirement of 88 gigawatts of existing capacity, 235 gigawatts of new generating capacity (including end-use combined heat and power) are projected to be added between 2011 and 2035 (Figure 95).

Natural-gas-fired plants account for 60 percent of capacity additions between 2011 and 2035 in the Reference case, compared with 29 percent for renewables, 7 percent for coal, and 4 percent for nuclear. Escalating construction costs have the largest impact on capital-intensive technologies, which include nuclear, coal, and renewables. However, Federal tax incentives, State energy programs, and rising prices for fossil fuels increase the competitiveness of renewable and nuclear capacity. Current Federal and State environmental regulations also affect fossil fuel use, particularly coal. Uncertainty about future limits on GHG emissions and other possible environmental programs also reduces the competitiveness of coal-fired plants (reflected in *AEO2012* by adding 3 percentage points to the cost of capital for new coal-fired capacity).

Uncertainty about demand growth and fuel prices also affects capacity planning. Total capacity additions from 2011 to 2035 range from 166 gigawatts in the Low Economic Growth case to 305 gigawatts in the High Economic Growth case. In the *AE02012* Low Tight Oil and Shale Gas Resource case, natural gas prices are higher than in the Reference case and new natural gas fired capacity from 2011 to 2035 accounts for 102 gigawatts, which represents 47 percent of total additions. In the High Tight Oil and Shale Gas Resource case, delivered natural gas prices are lower than in the Reference case and natural gas-fired capacity additions by 2035 are 155 gigawatts, or 66 percent of total new capacity.

Additions to power plant capacity slow after 2012 but accelerate beyond 2020

Figure 96. Additions to electricity generating capacity, 1985-2035 (gigawatts)



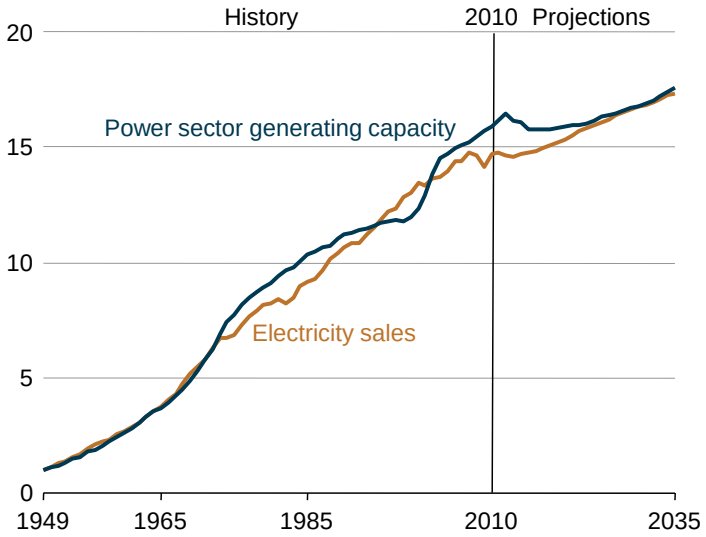
Typically, investments in electricity generation capacity have gone through "boom and bust" cycles. Periods of slower growth have been followed by strong growth in response to changing expectations for future electricity demand and fuel prices, as well as changes in the industry, such as restructuring (Figure 96). A construction boom in the early 2000s saw capacity additions averaging 35 gigawatts a year from 2000 to 2005, much higher than had been seen before. Since then, average annual builds have dropped to 17 gigawatts per year from 2006 to 2010.

In the *AEO2012* Reference case, capacity additions between 2011 and 2035 total 235 gigawatts, including new plants built not only in the power sector but also by end-use generators. Annual additions in 2011 and 2012 remain relatively high, averaging 24 gigawatts per year [*130*]. Of those early builds, about 40 percent are renewable plants built to take advantage of Federal tax incentives and to meet State renewable standards.

Annual builds drop significantly after 2012 and remain below 9 gigawatts per year until 2025. During that period, existing capacity is adequate to meet growth in demand in most regions, given the earlier construction boom and relatively slow growth in electricity demand after the economic recession. Between 2025 and 2035, average annual builds increase to 11 gigawatts per year, as excess capacity is depleted and the rate of total capacity growth is more consistent with electricity demand growth. More than 70 percent of the capacity additions from 2025 to 2035 are natural gas fired, given the higher construction costs for other capacity types and uncertainty about the prospects for future limits on GHG emissions.

Growth in generating capacity parallels rising demand for electricity

Figure 97. Electricity sales and power sector generating capacity, 1949-2035 (index, 1949 = 1.0)



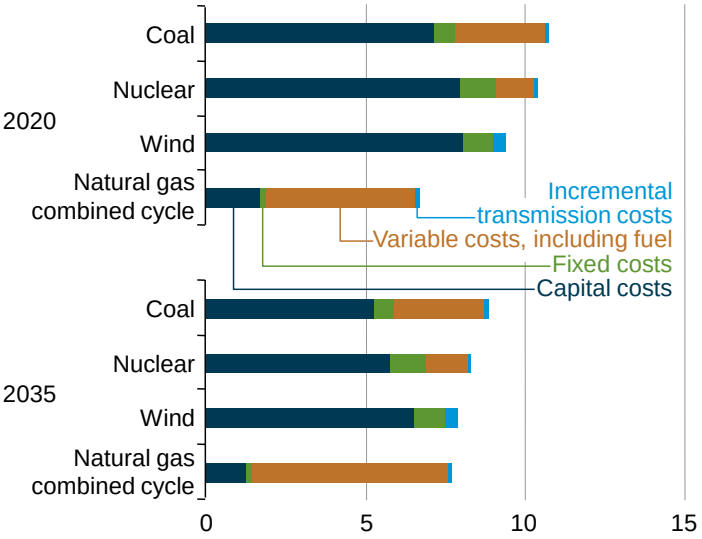
Over the long term, growth in electricity generating capacity parallels the growth in end-use demand for electricity. However, unexpected shifts in demand or dramatic changes affecting capacity investment decisions can cause imbalances that can take years to work out.

Figure 97 shows indexes summarizing relative changes in total generating capacity and electricity demand. During the 1950s and 1960s, the capacity and demand indexes tracked closely. The energy crises of the 1970s and 1980s, together with other factors, slowed electricity demand growth, and capacity growth outpaced demand for more than 10 years thereafter, as planned units continued to come on line. Demand and capacity did not align again until the mid-1990s. Then, in the late 1990s, uncertainty about deregulation of the electricity industry caused a downturn in capacity expansion, and another period of imbalance followed, with growth in electricity demand exceeding capacity growth.

In 2000, a boom in construction of new natural gas fired plants began, quickly bringing capacity back into balance with demand and, in fact, creating excess capacity. Construction of new intermittent wind capacity that sometimes needs backup capacity also began to grow after 2000. More recently, the 2008-2009 economic recession caused a significant drop in electricity demand, which has recovered only partially in the post-recession period. In combination with slow near-term growth in electricity demand, the slow economic recovery creates excess generating capacity in the *AEO2012* Reference case. Capacity currently under construction is completed in the Reference case, but only a limited amount of additional capacity is built before 2025, while older capacity is retired. In 2025, capacity growth and demand growth are in balance again, and they grow at similar rates through 2035.

Costs and regulatory uncertainties vary across options for new capacity

Figure 98. Levelized electricity costs for new power plants, excluding subsidies, 2020 and 2035 (2010 cents per kilowatthour)



Technology choices for new generating capacity are based largely on capital, operating, and transmission costs. Coal, nuclear, and renewable plants are capital-intensive (Figure 98), whereas operating (fuel) expenditures make up most of the costs for natural gas capacity [*131*]. Capital costs depend on such factors as equipment costs, interest rates, and cost recovery periods. Fuel costs vary with operating efficiency, fuel price, and transportation costs.

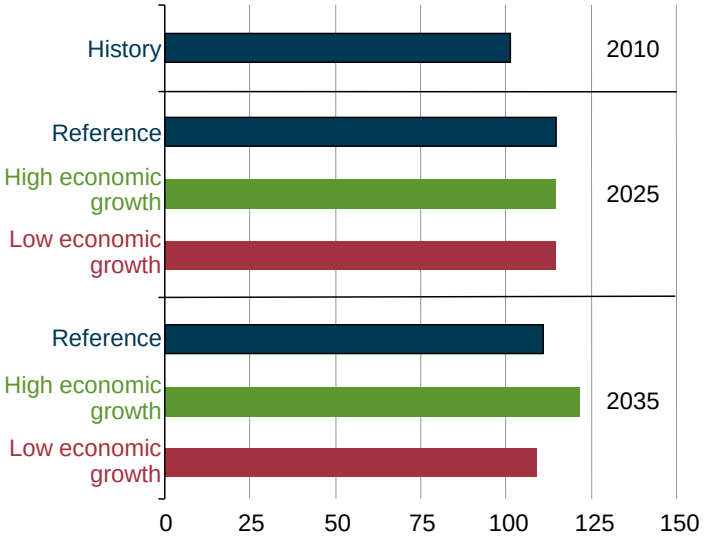
In addition to considerations of levelized costs [*132*], some technologies and fuels receive subsidies, such as production tax credits and ITCs. Also, new plants must satisfy local and Federal emissions standards and must be compatible with the utility's load profile.

Regulatory uncertainty also affects capacity planning. New coal plants may require carbon control and sequestration equipment, resulting in higher material, labor, and operating costs. Alternatively, coal plants without carbon controls could incur higher costs for siting and permitting. Because nuclear and renewable power plants (including wind plants) do not emit GHGs, their costs are not directly affected by regulatory uncertainty in this area.

Capital costs can decline over time as developers gain technology experience, with the largest rate of decline in new technologies. In the *AEO2012* Reference case, the capital costs of new technologies are adjusted upward initially to compensate for the optimism inherent in early estimates of project costs, then decline as project developers gain experience. The decline continues at a progressively slower rate as more units are built. Operating efficiencies also are assumed to improve over time, resulting in reduced variable costs unless increases in fuel costs exceed the savings from efficiency gains.

Nuclear power plant capacity grows slowly through uprates and new builds

Figure 99. Electricity generating capacity at U.S. nuclear power plants in three cases, 2010, 2025, and 2035 (gigawatts)



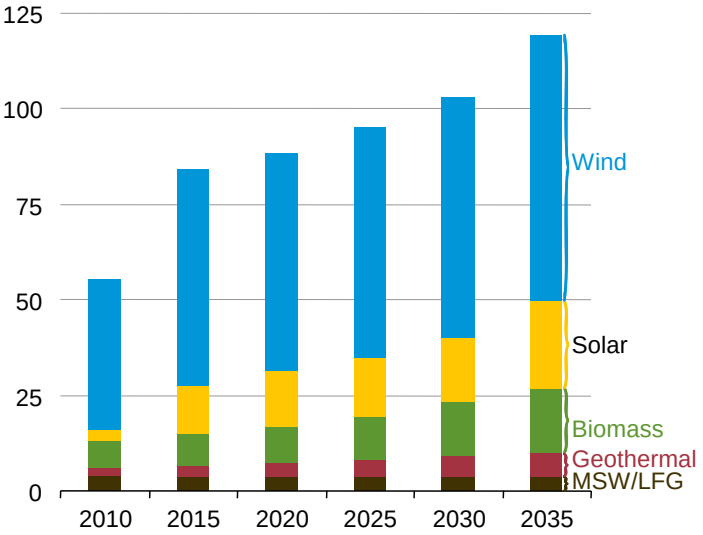
In the *AEO2012* Reference case, nuclear power capacity increases from 101.2 gigawatts in 2010 to a high of 114.7 gigawatts in 2025, before declining to 110.9 gigawatts in 2035 (Figure 99), largely as a result of plant retirements. The capacity increase through 2025 includes 7.3 gigawatts of expansion at existing plants and 6.8 gigawatts of new capacity, which includes completion of two conventional reactors at the Watts Bar and Bellefonte sites. Four advanced reactors, reported as under construction, are also assumed to be brought online by 2020 and to be eligible for Federal financial incentives. High construction costs for nuclear plants, especially relative to natural gas fired plants, make additional options for new nuclear capacity uneconomical until the later years of the projection, when an additional 1.8 gigawatts is added. Nuclear capacity additions vary with assumptions about overall demand for electricity. Across the Economic Growth cases, nuclear capacity additions from 2011 to 2035 range from 6.8 gigawatts in the Low Economic Growth case to 19.2 gigawatts in the High Economic Growth case.

One nuclear unit, Oyster Creek, is expected to be retired at the end of 2019, as announced by Exelon in December 2010. An additional 5.5 gigawatts of nuclear capacity is assumed to be retired by 2035. All other existing nuclear units continue to operate through 2035 in the Reference case, which assumes that they will apply for and receive operating license renewals, including in some cases a second 20-year extension after 60 years of operation (for more discussion, see "Issues in focus"). With costs for natural gas fired generation rising in the Reference case and uncertainty about future regulation of GHG emissions, the economics of keeping existing nuclear power plants in operation are favorable.

Renewable capacity

Wind dominates renewable capacity growth, but solar and biomass gain market share

Figure 100. Nonhydropower renewable electricity generation capacity by energy source, including end-use capacity, 2010-2035 (gigawatts)



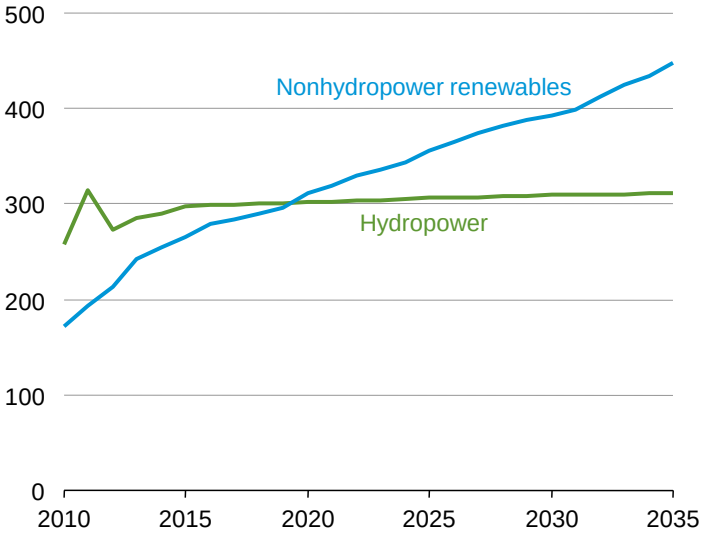
From 2010 to 2035, total nonhydropower renewable generating capacity more than doubles in the *AEO2012* Reference case (Figure 100). Wind accounts for the largest share of that new capacity, increasing from 39 gigawatts in 2010 to 70 gigawatts in 2035. Both solar capacity and biomass capacity grow at faster rates than wind capacity, but they start from smaller levels.

Excluding new projects already under construction, PV accounts for nearly all solar capacity additions both in the end-use sectors (where 11 gigawatts of PV capacity is added from 2010 to 2035) and in the electric power sector (8 gigawatts added from 2010 to 2035). While end-use solar capacity grows throughout the projection, the growth of solar capacity in the electric power sector is concentrated primarily in the last decade of the projection period (2025-2035) when the technology becomes more cost-competitive. Geothermal capacity nearly triples over the projection period, but in 2035 it still accounts for only about 5 percent of total nonhydropower renewable generating capacity.

Renewable capacity additions are supported by State RPS programs, the Federal RFS, and Federal tax credits. Total renewable capacity—particularly, wind and solar—grows rapidly in the near term in the *AEO2012* Reference case. There is, however, relatively little projected need for new generation capacity of any type, including renewables, for the remainder of the current decade, primarily because there is an abundance of existing natural gas fired capacity that can be operated at higher capacity factors. After 2020 there is a need for new generation capacity in the Reference case, resulting in a resurgence in renewable capacity growth.

Nonhydropower renewable generation surpasses hydropower by 2020

Figure 101. Hydropower and other renewable electricity generation, including end-use generation, 2010-2035 (billion kilowatthours)



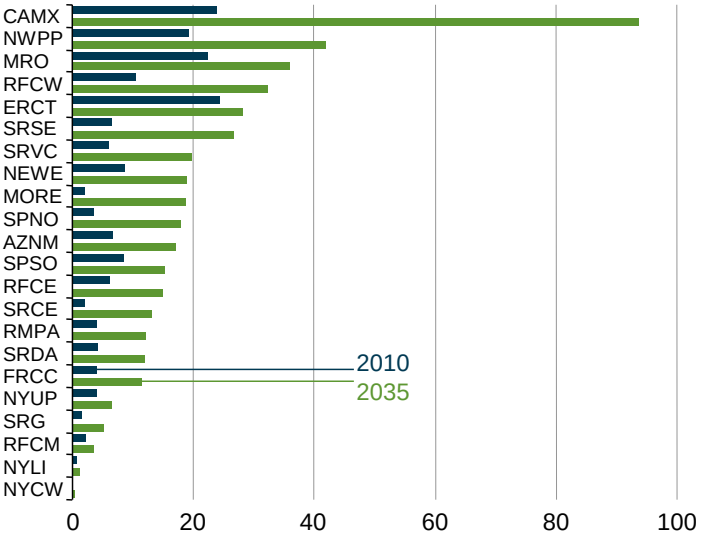
In the *AEO2012* Reference case, nonhydropower renewable generation grows at an average annual rate of 3.9 percent, nearly tripling from 2010 to 2035. Generation from nonhydropower renewable sources has been small historically in comparison with hydroelectric generation; however, nonhydropower renewable generation surpasses hydroelectric generation in 2020 in the Reference case (Figure 101).

The share of the total electricity generation accounted for by nonhydropower renewable generation increases from about 4 percent in 2010 to 9 percent in 2035. Although wind remains the largest source of nonhydropower renewable generation through 2035, both solar and biomass generation grow at faster annual rates. Solar generation increases by an average of nearly 10 percent per year, and biomass generation increases by 6 percent per year.

Both solar and wind energy are intermittent resources, and as a result their contributions to the generation mix are less than their contribution to the capacity mix. Biomass-fired generation, on the other hand, is dispatchable and grows to levels approaching wind generation by the end of the projection, at 145 billion kilowatthours in 2035, as compared with 194 billion kilowatthours for wind-powered generation. Most of the growth in biomass generation comes from CHP units used in the production of biomass-based liquid fuels, primarily in response to the Federal RFS. Biomass co-firing and end-use generation play an important role in satisfying State RPS mandates, particularly from 2010 to 2020, when overall capacity growth is modest.

State renewable portfolio standards increase renewable electricity generation

Figure 102. Regional growth in nonhydropower renewable electricity generation, including end-use generation, 2010-2035 (billion kilowatthours)



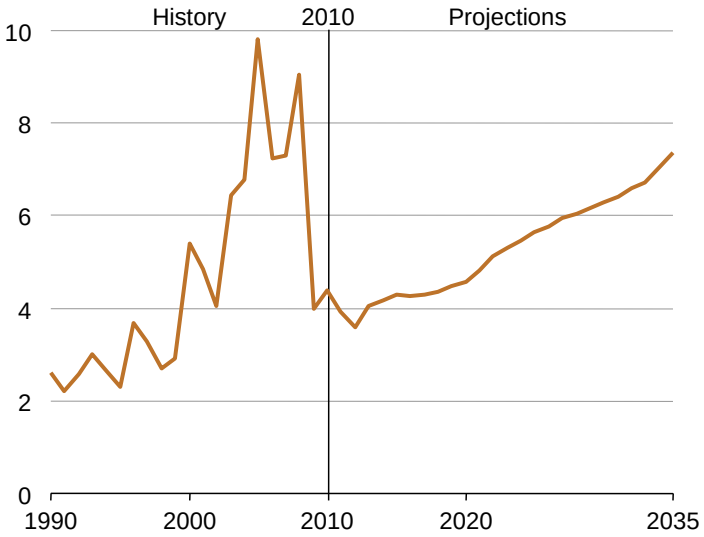
Regional growth in renewable electricity generation is based largely on two factors: availability of renewable energy resources and the existence of State RPS programs that require the use of renewable generation. After a period of robust RPS enactments in several States, the past few years have been relatively quiet in terms of State program expansions, primarily due to the subdued economic climate.

The highest level of nonhydroelectric renewable generation in 2035, 93.9 billion kilowatthours, occurs in the WECC California (CAMX) region (Figure 102), whose area approximates the California State boundaries. (For a map of the electricity regions presented, see Appendix F.) The three largest contributors to the total are wind, solar, and geothermal generation. The region encompassing the Pacific Northwest has more overall renewable generation, the vast majority of which comes from hydroelectric sources.

Although the Western and Southwestern States have the most projected solar installations, State RPS programs heavily influence the growth of solar capacity in the eastern States, where both the Reliability First Corporation/East (RFCE) and the Reliability First Corporation/West (RFCW) regions have large amounts of end-use solar generation, with 1.7 billion kilowatthours and 1.9 billion kilowatthours, respectively. The two regions are not known for a strong solar resource base, and the installations are in response to the ITC as well as solar requirements embedded in State RPS programs. Most biomass capacity—confined largely to the end-use sectors—is built at the sites of cellulosic ethanol plants, many of which are in the Southeast.

Natural gas prices are expected to rise with the marginal cost of production

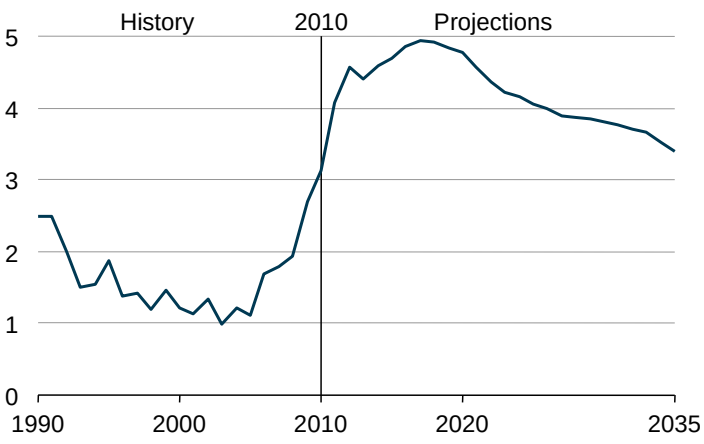
Figure 103. Annual average Henry Hub spot natural gas prices, 1990-2035 (2010 dollars per million Btu)



U.S. natural gas prices are determined largely by supply and demand conditions in North American markets. At current (2012) price levels, natural gas prices are below average replacement cost. However, over time natural gas prices rise with the cost of developing incremental production capacity (Figure 103). After 2017, natural gas prices rise in the *AEO2012* Reference case more rapidly than crude oil prices, but oil prices remain at least three times higher than natural gas prices through the end of the projection (Figure 104).

As of January 1, 2010, total proved and unproved natural gas resources are estimated at 2,203 trillion cubic feet. Development costs for natural gas wells are expected to grow slowly. Henry Hub spot prices for natural gas rise by 2.1 percent per year from 2010 through 2035 in the Reference case, to an annual average of $7.37 per million Btu (2010 dollars) in 2035.

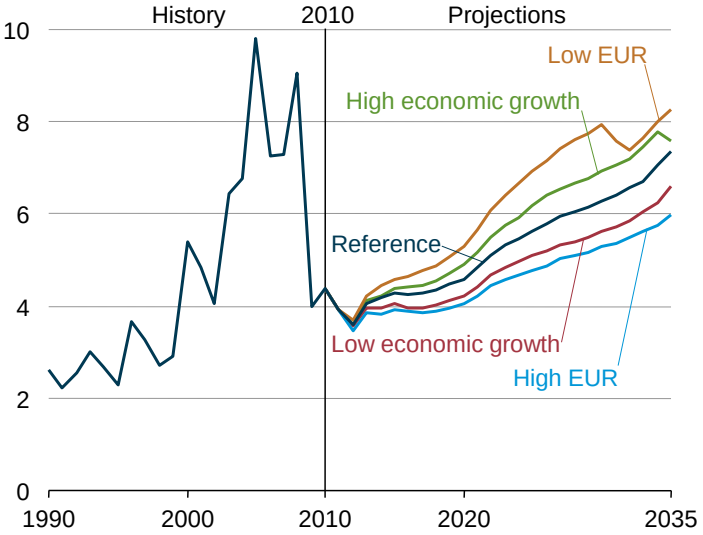
Figure 104. Ratio of low-sulfur light crude oil price to Henry Hub natural gas price on energy equivalent basis, 1990-2035



Natural gas production

Natural gas prices vary with economic growth and shale gas well recovery rates

Figure 105. Annual average Henry Hub spot natural gas prices in five cases, 1990-2035 (2010 dollars per million Btu)



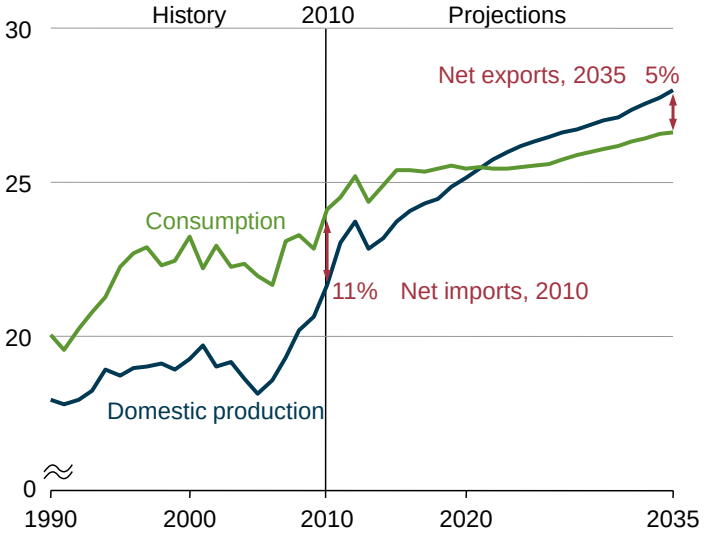
The rate at which natural gas prices change in the future can vary, depending on a number of factors. Two important factors are the future rate of macroeconomic growth and the expected cumulative production of shale gas wells over their lifetimes—the estimated ultimate recovery (EUR) per well. Alternative cases with different assumptions for these factors are shown in Figure 105.

Higher rates of economic growth lead to increased consumption of natural gas, causing more rapid depletion of natural gas resources and a more rapid increase in the cost of developing new incremental natural gas production. Conversely, lower rates of economic growth lead to lower levels of natural gas consumption and, ultimately, a slower increase in the cost of developing new production.

In the High and Low EUR cases, the EUR per shale gas well is increased and decreased by 50 percent, respectively. Future shale gas well recovery rates are an important determinant of future prices. Changes in well recovery rates affect the long-run marginal cost of shale gas production, which in turn affects both natural gas prices and the volumes of new shale gas production developed (further analysis and discussion are included in the "Issues in focus" section of this report). In the Low EUR case, an Alaska gas pipeline starts operating in 2031, accompanied by a dip in natural gas prices. A recent proposal to build a natural gas pipeline along the route of the Alyeska oil pipeline with an LNG export facility could speed up construction. In the High Economic Growth case, the pipeline begins operation in 2035, with a similar effect on prices.

With rising domestic production, the United States become a net exporter of natural gas

Figure 106. Total U.S. natural gas production, consumption, and net imports, 1990-2035 (trillion cubic feet)



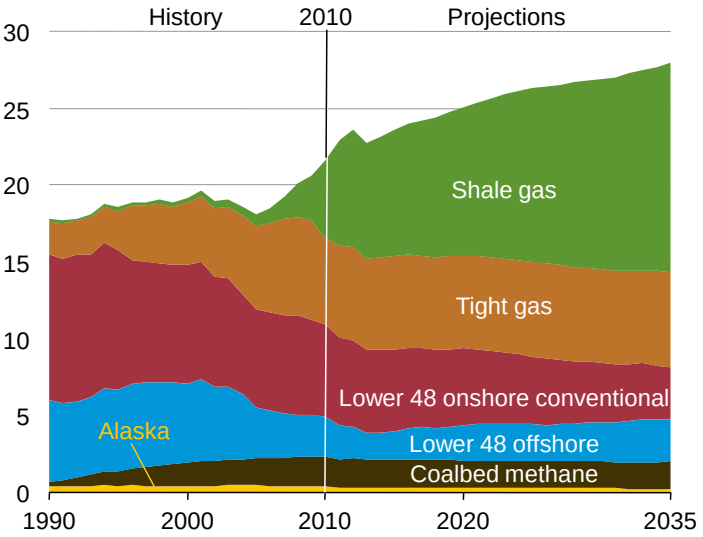
The United States consumed more natural gas than it produced in 2010, importing 2.6 trillion cubic feet from other countries. In the *AEO2012* Reference case, domestic natural gas production grows more quickly than consumption. As a result, the United States becomes a net exporter of natural gas by around 2022, and in 2035 net exports of natural gas from the United States total about 1.4 trillion cubic feet (Figure 106).

U.S. natural gas consumption grows at a rate of 0.4 percent per year from 2010 to 2035 in the Reference case, or by a total of 2.5 trillion cubic feet, to 26.6 trillion cubic feet in 2035. Growth in domestic natural gas consumption depends on many factors, including the rate of economic growth and the delivered prices of natural gas and other fuels. Natural gas consumption in the commercial and industrial sectors grows by less than 0.5 percent per year through 2035, and consumption for electric power generation grows by 0.8 percent per year. Residential natural gas consumption declines over the same period, by a total of 0.3 trillion cubic feet from 2010 to 2035.

U.S. natural gas production grows by 1.0 percent per year, to 27.9 trillion cubic feet in 2035, more than enough to meet domestic needs for consumption, which allows for exports. The prospects for future U.S. natural gas exports are highly uncertain and depend on many factors that are difficult to anticipate, such as the development of new natural gas production capacity in foreign countries, particularly from deepwater reservoirs, shale gas deposits, and the Arctic.

Shale gas provides largest source of growth in U.S. natural gas supply

Figure 107. Natural gas production by source, 1990-2035 (trillion cubic feet)



The increase in natural gas production from 2010 to 2035 in the *AEO2012* Reference case results primarily from the continued development of shale gas resources (Figure 107). Shale gas is the largest contributor to production growth; there is relatively little change in production levels from tight formations, coalbed methane deposits, and offshore fields.

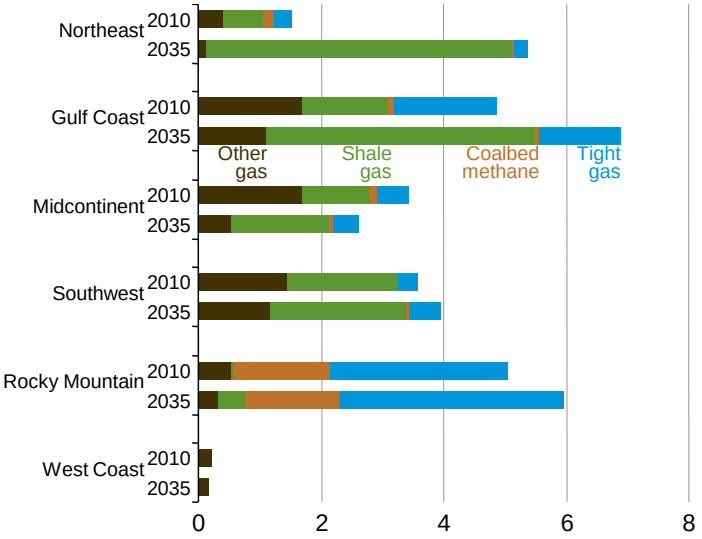
Shale gas accounts for 49 percent of total U.S. natural gas production in 2035, more than double its 23-percent share in 2010. In the Reference case, estimated proved and unproved shale gas resources amount to a combined 542 trillion cubic feet, out of a total U.S. resource of 2,203 trillion cubic feet. Estimates of shale gas resources and well productivity remain uncertain (see "Issues in focus" for discussion).

Tight gas produced from low permeability sandstone and carbonate reservoirs is the second-largest source of domestic supply in the Reference case, averaging 6.1 trillion cubic feet of production per year from 2010 to 2035. Coalbed methane production remains relatively constant throughout the projection, averaging 1.8 trillion cubic feet per year.

Offshore natural gas production declines by 0.8 trillion cubic feet from 2010 through 2014, following the 2010 moratorium on offshore drilling, as exploration and development activities in the Gulf of Mexico focus on oil-directed activity. After 2014 offshore production continues to rise throughout the remainder of the projection period.

In most U.S. regions, natural gas production growth is led by shale gas development

Figure 108. Lower 48 onshore natural gas production by region, 2010 and 2035 (trillion cubic feet)



Shale gas production, which more than doubles from 2010 to 2035, is the largest contributor to the projected growth in total U.S. natural gas production in the Reference case. Regional production growth largely reflects expected increases in production from shale beds. See Figure F4 in Appendix F for a map of U.S. natural gas supply regions.

In the Northeast, natural gas production grows by an average of 5.2 percent per year, or a total of 3.9 trillion cubic feet from 2010 to 2035 (Figure 108). The Marcellus shale, which accounts for 3.0 trillion cubic feet of the expected increase, is particularly attractive for development because of its large resource base, its proximity to major natural gas consumption markets, and the extensive pipeline infrastructure that already exists in the Northeast.

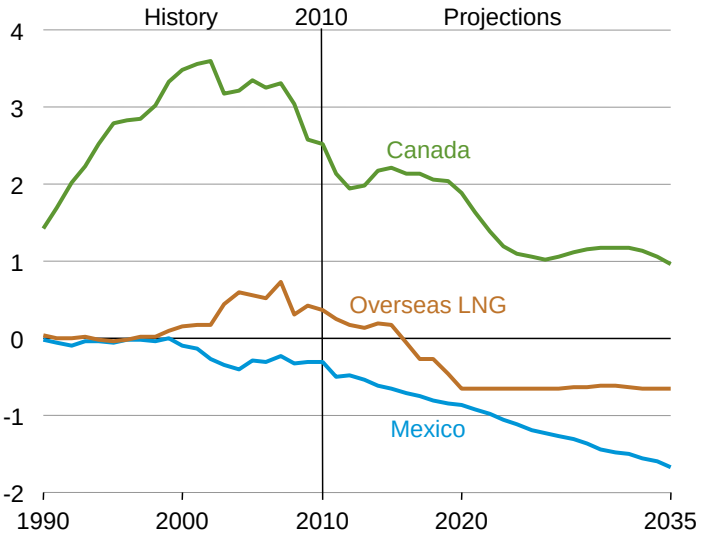
In the Gulf Coast region, natural gas production grows by 2.0 trillion cubic feet from 2010 to 2035, at an average rate of 1.4 percent per year. Natural gas production from the Haynesville/Bossier and Eagle Ford formations increases by 2.8 trillion cubic feet over the period, but declines in production from other natural gas fields in the region offset some of the gains, so that the net increase in production for the region as a whole is only about 2 trillion cubic feet.

In the Rocky Mountain region, natural gas production grows by 0.9 trillion cubic feet from 2010 through 2035, with tight sandstone and carbonate production increasing by 0.8 trillion cubic feet and shale gas production by 0.4 trillion cubic feet. As in the Gulf Coast region, production growth in the Rocky Mountain region is offset in part by production declines in the region's other natural gas fields.

Petroleum and other liquids consumption

The U.S. becomes a net natural gas exporter

Figure 109. U.S. net imports of natural gas by source, 1990-2035 (trillion cubic feet)



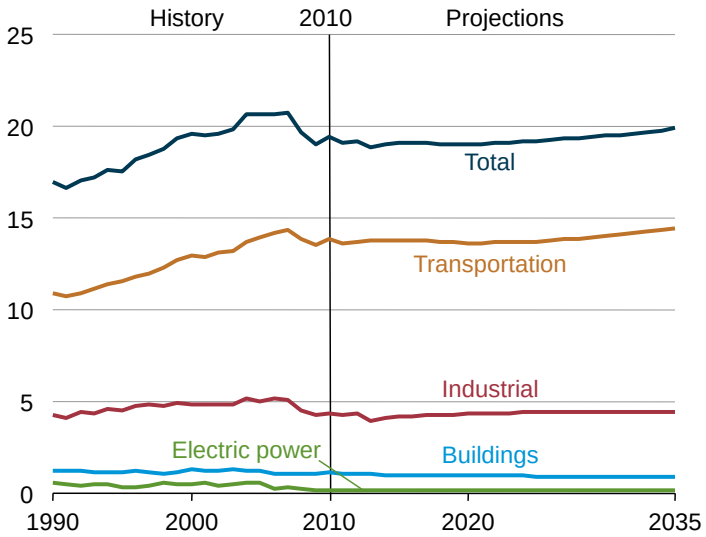
In 2010, the United States imported 11 percent of its total natural gas supply. In the *AEO2012* Reference case, U.S. natural gas production grows faster than consumption, so that early in the next decade exports exceed imports. In 2035, U.S. net natural gas exports are about 1.4 trillion cubic feet (about 4 billion cubic feet per day), half of which is exported overseas as liquefied natural gas (LNG). The other half is transported by pipelines, primarily to Mexico.

U.S. LNG exports supplied from lower 48 natural gas production are assumed to start when LNG export capacity of 1.1 billion cubic feet per day goes into operation in 2016. An additional 1.1 billion cubic feet per day of capacity is expected to come on line in 2019. At full capacity, the facilities could ship 0.8 trillion cubic feet of LNG to overseas consumers per year. Net U.S. LNG exports are somewhat lower than those figures imply, however, because LNG imports to the New England region are projected to continue. In general, future U.S. exports of LNG depend on a number of factors that are difficult to anticipate and thus are highly uncertain.

Net natural gas imports from Canada decline over the next decade in the Reference case and then stabilize at about 1.1 trillion cubic feet per year (Figure 109), when natural gas prices in the U.S. lower 48 States become high enough to motivate Canadian producers to expand their production of shale gas and tight gas. In Mexico, natural gas consumption shows robust growth through 2035, while Mexico's production grows at a slower rate. As a result, increasing volumes of imported natural gas from the United States fill the growing gap between Mexico's production and consumption.

Transportation uses lead growth in consumption of petroleum and other liquids

Figure 110. Consumption of petroleum and other liquids by sector, 1990-2035 (million barrels per day)



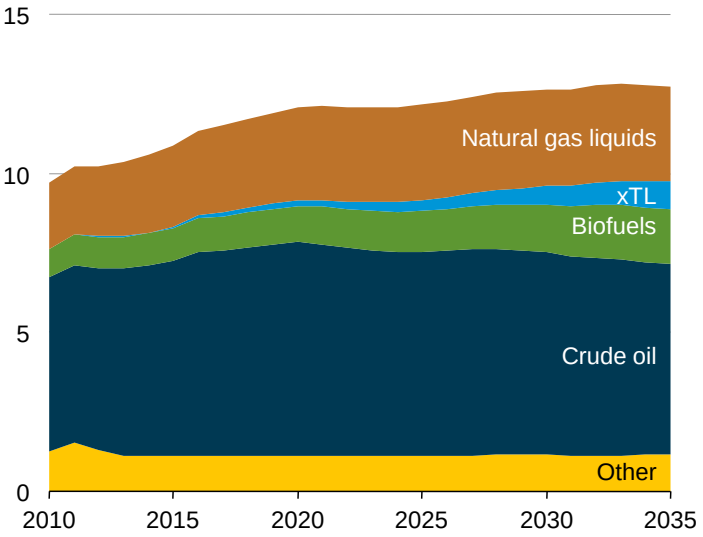
U.S. consumption of petroleum and other liquids totals 19.9 million barrels per day in 2035 in the *AEO2012* Reference case, an increase of 0.7 million barrels per day over the 2010 total (Figure 110). With the exception of the transportation sector, where consumption grows by about 0.6 million barrels per day from 2010 through 2035, petroleum and other liquids consumption remains relatively flat. The transportation sector accounts for 72 percent of total petroleum and other liquids consumption in 2035. Proposed fuel economy standards covering MYs 2017 through 2025 that are not included in the Reference case would further reduce projected petroleum use (see "Issues in focus").

Motor gasoline, ultra-low-sulfur diesel fuel, and jet fuel are the primary transportation fuels, supplemented by biofuels such as ethanol and biodiesel. Petroleum-based motor gasoline consumption drops by approximately 0.9 million barrels per day from 2010 to 2035 in the Reference case, displaced by increased ethanol use in the form of higher blends in gasoline and by E85 consumption, which increases from virtually zero in 2010 to 0.8 million barrels per day in 2035. Diesel fuel consumption increases from 3.3 million barrels per day in 2010 to 4.1 million barrels per day in 2035.

Biodiesel and a number of next-generation biofuels account for a large share of the increase in petroleum and other liquids consumption (excluding ethanol) for transportation from 2010 to 2035 (about 0.7 million barrels per day). The growth in biofuels consumption (including ethanol) is attributable to the EISA2007 RFS mandates, as well as high crude oil prices. The growth in diesel fuel use results primarily from increased sales of light-duty diesel vehicles needed to meet more stringent CAFE standards, with a corresponding increase in domestic production of diesel fuel.

Biofuels and natural gas liquids lead growth in total petroleum and other liquids supply

Figure 111. U.S. production of petroleum and other liquids by source, 2010-2035 (million barrels per day)

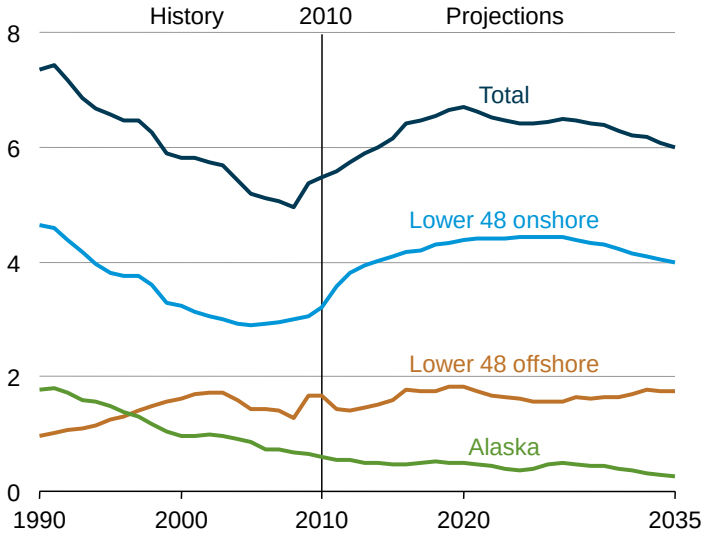


In the *AEO2012* Reference case, domestic production of petroleum and other liquids grows by 3.1 million barrels per day from 2010 to 2035 (Figure 111). Total production grows rapidly, from 9.7 million barrels per day in 2010 to 12.1 million barrels per day in 2020, as production of crude oil and NGL from tight oil formations (including shale plays) increases sharply. After 2020, total U.S. production of petroleum and other liquids grows more slowly, to 12.7 million barrels per day in 2035, as tight oil production levels off despite continued increases in crude oil prices. As production of other liquid fuels increases, the crude oil share of total domestic petroleum and other liquids production declines from 56 percent in 2010 to 47 percent in 2035. NGL production increases by more than 0.9 million barrels per day, to 3.0 million barrels per day in 2035, mainly as a result of strong growth in production of both tight oil and shale gas, which contain significant volumes of NGLs.

Biofuels production grows by 0.8 million barrels per day from 2010 to 2035 as a result of the EISA2007 RFS, with ethanol and biodiesel accounting for 0.7 and 0.1 million barrels per day, respectively, of the increase in the Reference case. The increase in domestic ethanol production reduces consumption of petroleum-based motor gasoline components by about 6 percent in 2035 on an energy-equivalent basis. In the early years of the projection, ethanol is used primarily for blending in E10 (motor gasoline blends containing up to 10 percent ethanol) and E15 (15 percent ethanol). In 2035, 37 percent of domestic ethanol production is used in E85 (85 percent ethanol) and 63 percent in E10 and E15 blends. In addition, growth in next-generation "xTL" production, which includes both biomass-to-liquids and CTL, contributes significantly to the growth in total U.S. petroleum and other liquids production, particularly after 2020, adding about 0.6 and 0.3 million barrels per day of production, respectively, from 2010 to 2035.

U.S. crude oil production increases, led by lower 48 onshore production

Figure 112. Domestic crude oil production by source, 1990-2035 (million barrels per day)



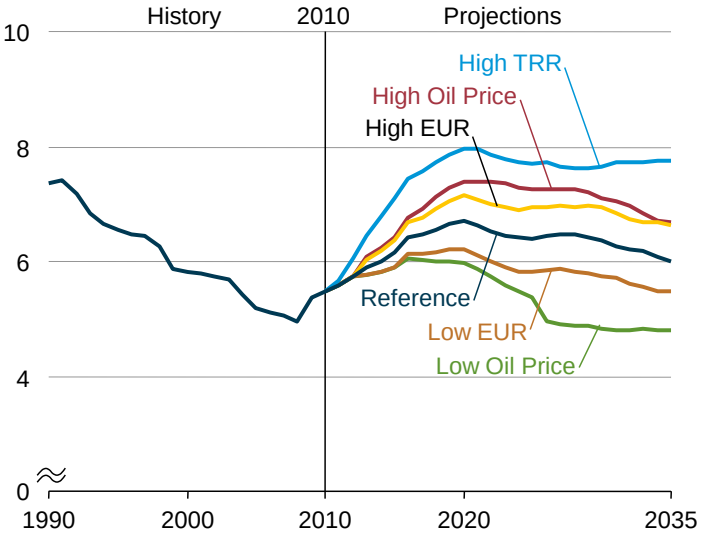
As world oil prices increase in the *AEO2012* Reference case, U.S. production of tight oil (liquid oil embedded in low-permeable sandstone, carbonate, and shale rock) and production using carbon dioxide-enhanced oil recovery (CO_2-EOR) techniques add to the projected increase in domestic crude oil production from 2010 to 2035 (Figure 112). Growth in lower 48 onshore crude oil production comes primarily from the continued development of tight oil resources, mostly from the Bakken and Eagle Ford formations. Tight oil production surpasses 1.3 million barrels per day in 2027 and then declines to about 1.2 million barrels per day in 2035 as "sweet spots" are depleted. *AEO2012* also includes six other tight formations in the projections for tight oil production: the Austin Chalk, Avalon/Bone Springs, Monterey, Niobrara, Spraberry, and Woodford formations. Additional tight oil resources are likely to be identified in the future as more work is completed to identify currently producing reservoirs that may be better categorized as tight formations, and as new tight oil plays are identified and incorporated (see next column).

Crude oil production using CO_2-EOR increases significantly after 2020, when oil prices are higher, the more profitable tight oil deposits are depleted, and affordable anthropogenic sources of carbon dioxide (CO_2) are available. It plateaus at about 650,000 barrels per day from 2032 to 2035, when its profitability is limited by reservoir quality and CO_2 availability. From 2011 through 2035, CO_2-EOR production exceeds 4 billion barrels of oil.

Lower 48 offshore oil production remains relatively constant in the Reference case. The decline in currently producing fields is offset primarily by exploration and development of new fields in the deep waters of the Gulf of Mexico and, after 2029, in the Pacific Outer Continental Shelf.

U.S. crude oil production varies with price and resource assumptions

Figure 113. Total U.S. crude oil production in six cases, 1990-2035 (million barrels per day)

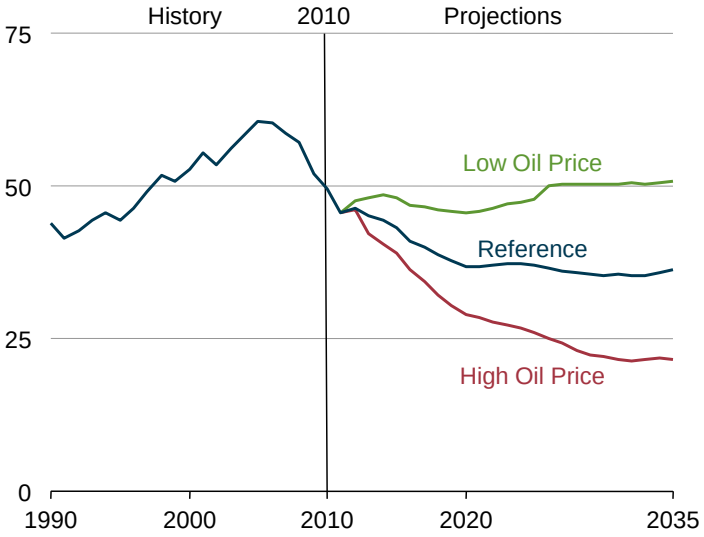


U.S. crude oil production varies with changes in assumptions about the extent of productivity improvement and well spacing in emerging tight oil resources examined in the High Technically Recoverable Resources (TRR) case and in the High and Low EUR cases (see discussion in "Issues in focus") and with changes in assumptions about crude oil prices in the Low and High Crude Oil Price cases (Figure 113). In the High TRR case, assumptions for tight oil allow for more rapid growth in crude oil production in the short and long term than in the Reference case, with production reaching nearly 8 million barrels per day in 2020. In the Low EUR case there is very little growth in domestic crude oil production over the projection period.

Higher oil prices lead to an increase in the level of investment in new oil projects. However, the returns from increased investment diminish as the average size and quality of available reservoirs decline. For example, in the High Oil Price case tight oil production is, on average, 225,000 barrels per day higher from 2020 to 2030 than in the Reference case but returns to Reference case levels in 2035. In contrast, low oil prices result in less investment in new oil projects and encourage producers to plug and abandon existing fields at earlier dates. For example, in the Low Oil Price case, oil production from the Alaska North Slope is shut down by around 2025, when the projected operating costs exceed wellhead production revenues (see "Issues in focus"). From 2020 to 2035, tight oil production is, on average, roughly 300,000 barrels per day lower in the Low Oil Price case than in the Reference case.

U.S. net imports of petroleum and other liquids fall in the Reference case

Figure 114. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2035 (percent)



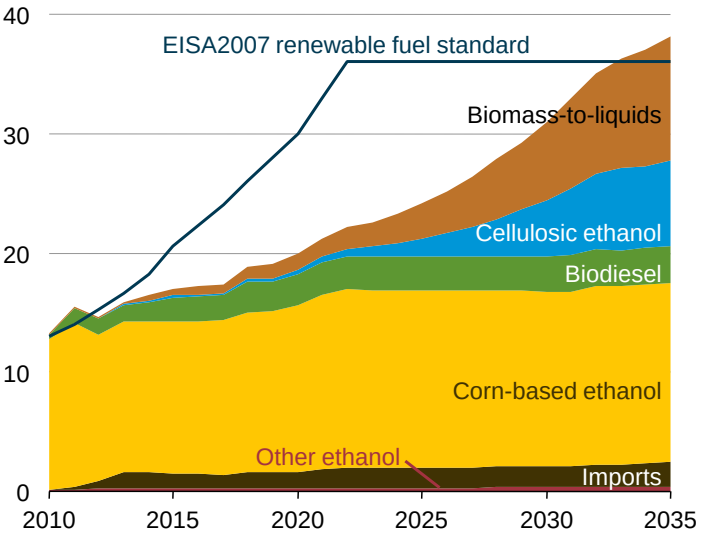
U.S. imports of petroleum and other liquids (including crude oil, petroleum liquids, and liquids derived from nonpetroleum sources) grew steadily from the mid-1980s to 2005 but have declined since then. In the *AEO2012* Reference and High Oil Price cases, U.S. imports of petroleum and other liquids continue to decline from 2010 to 2035, even as they provide a major part of total U.S. supply. Tighter fuel efficiency standards, increased use of biofuels, and greater production of domestic petroleum and other liquids contribute to the decrease in the share of imports. The combination of higher prices and renewable fuel mandates leads to more domestic production of petroleum and biofuels, which, combined with declines in the petroleum share of finished products after 2015, results in sustained net product exports.

The net import share of U.S. petroleum and other liquids consumption, which fell from 60 percent in 2005 to 50 percent in 2010, continues to decline in the Reference case, with the net import share falling to 36 percent in 2035 (Figure 114). In the High Oil Price case, the net import share falls even lower to a 22-percent share in 2035. In the Low Oil Price case, the net import share remains flat in the near term but rises to 51 percent in 2035, as domestic demand increases and imports become cheaper than crude oil produced domestically.

As a result of increased domestic production and slow growth in consumption, the United States becomes a net exporter of petroleum products, with net exports in the Reference case increasing from 0.18 million barrels per day in 2011 to 0.34 million barrels per day in 2035. In the High Oil Price case, net exports of petroleum products increase to 0.9 million barrels per day in 2035.

U.S. consumption of cellulosic biofuels exceeds renewable fuels standard in 2035

Figure 115. EISA2007 RFS credits earned in selected years, 2010-2035 (billion credits)



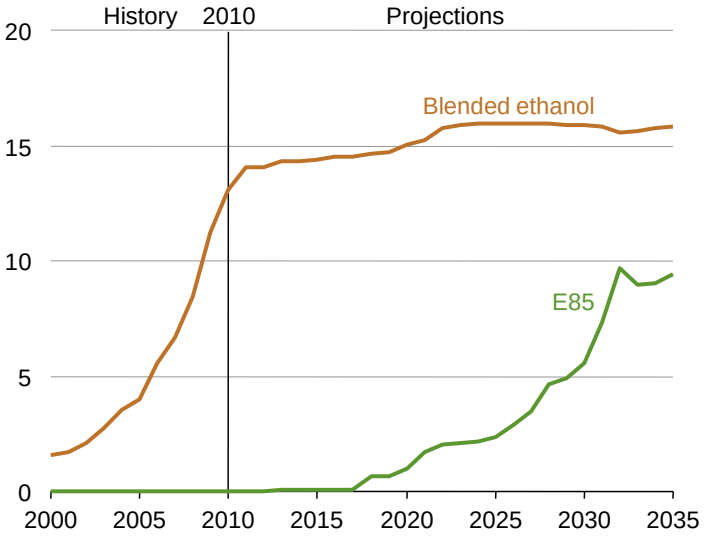
Although biofuel production increases substantially in the *AEO2012* Reference case, it does not meet the mandated RFS of 36 billion gallons in 2022 (Figure 115). Financial and technological hurdles delay the start of many advanced biofuel projects, particularly cellulosic biofuel projects. Three consecutive years of substantial reductions in the cellulosic biofuels mandate [*133*, *134*, *135*] have significantly reduced the possibility that the original RFS levels mandated in EISA2007 will be reached by 2022.

Between 2012 and 2022, it is expected that the EPA will evaluate the status of biofuel capacity annually and revise the production mandates for the following year, according to provisions in the RFS [*136*]. In 2011, after the EPA reduced the cellulosic biofuel mandate for both 2010 and 2011 from 100 million and 250 million gallons, respectively, to approximately 6 million gallons in both years, it also reduced the 2012 mandate from 500 million gallons to about 8 million gallons. Taking into account those modifications and anticipated future changes, only 22.1 billion of RFS credits are generated in 2022 in the Reference case, with 15 billion gallons of credits coming from domestic production of corn-based ethanol.

In the Reference case, the remainder of the biofuel supply consists of imported ethanol, biodiesel, cellulosic ethanol, and smaller volumes of next-generation biofuels. U.S. consumption of cellulosic ethanol grows from 0.6 billion gallons in 2022 to 7.2 billion gallons in 2035, when imports of ethanol and biodiesel total 2.2 billion gallons and 0.2 billion gallons, respectively.

Infrastructure hurdles limit near-term growth in consumption of E15 and E85 fuels

Figure 116. U.S. ethanol use in blended gasoline and E85, 2000-2035 (billion gallons per year)



A number of factors have recently limited the amount of ethanol that can be consumed domestically. Currently, given the limited availability of E85, the primary use of ethanol is as a blendstock for gasoline. With rapid growth in ethanol capacity and production in recent years, ethanol consumption in 2010 approached the legal gasoline blending limit of 10 percent (E10). As of January 2011, the EPA increased the blending limit to 15 percent for vehicles built in 2001 and later [*137*]. Once the final requirements are put in place, blenders will no longer be prohibited from blending beyond 10 percent for the general stock; however, a number of issues are expected to limit the rate at which terminals and retail outlets choose to take advantage of the option.

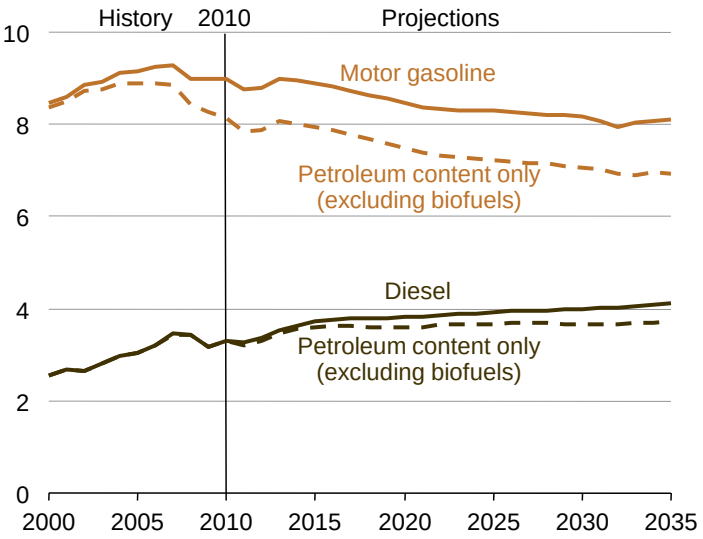
Liability from potential misfueling and infrastructure problems is one of the top concerns expected to slow the widespread adoption of E15. Retailers are hesitant to sell E15, even with the EPA's warning label, if they are not relieved of responsibility for damage to consumers' vehicles that may result from misfueling with the higher ethanol blend or from malfunctions of storage equipment or infrastructure. Consumer acceptance of the new fuel blend will also play a part, and warning labels may deter customers from risking potential damage from the use of E15, which potentially could void vehicle warranties.

In light of those potential issues, ethanol blending in gasoline increases slowly in the Reference case, from 13.2 billion gallons in 2010 (about 9 percent of the gasoline pool) to 15.0 billion gallons in 2020 (about 11 percent) and 15.8 billion gallons in 2035 (12.5 percent). Given the blending limitations, the remaining growth in ethanol use is in E85, which grows from about 0.6 billion gallons in 2018 to 9.5 billion gallons in 2035 (Figure 116).

Coal production

Shifts in fuel consumption guide future investment decisions for refiners

Figure 117. U.S. motor gasoline and diesel fuel consumption, 2000-2035 (million barrels per day)



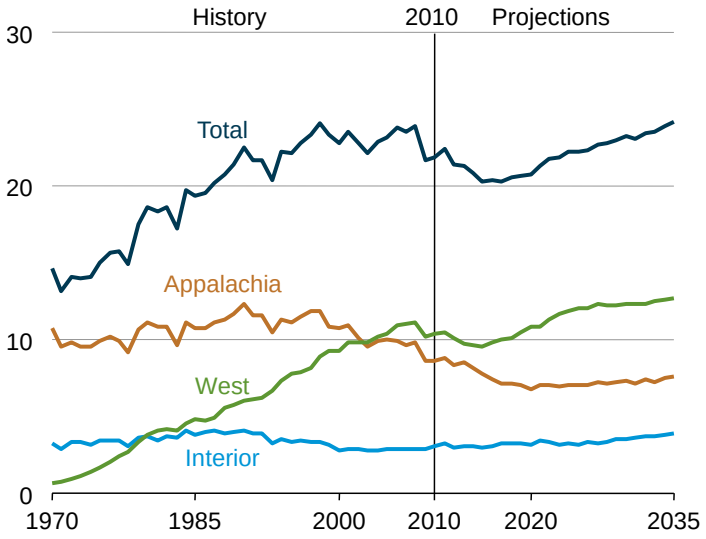
Tighter vehicle efficiency standards for LDVs require new LDVs to average 35 mpg by 2020, and newly issued regulations require increased use of ethanol. The Reference case does not include the proposed fuel economy standards covering MYs 2017 through 2025 that would raise vehicle efficiency standards even higher. Demand for motor gasoline declines in the Reference case. In combination with a tighter market for diesel fuel, the decrease in gasoline consumption leads to a shift in refinery outputs and investments. As some smaller and less integrated refineries begin to idle capacity as a result of higher costs, new refinery projects are focused on shifting production from gasoline to distillate fuels. The restructuring results in a net reduction in refinery capacity of 2.4 million barrels per day over the projection period.

In the Reference case, new capacity that was planned before the economic downturn of 2008-2009 comes on line early in the projection period, adding approximately 400,000 barrels per day of new refining distillation capacity from 2010 to 2015. As a result of refinery economics and concerns about the potential for enactment of legislation that could constrain carbon emissions, raise refiners' costs, and limit the growth in demand for petroleum and other liquids, no additional refinery capacity is built after 2015 until around 2030. Total refining capacity in the United States declines gradually after 2015 as additional capacity is idled.

Motor gasoline consumption and diesel fuel consumption (either including or excluding biofuels) trend in opposite directions in the Reference case (Figure 117). Consumption of diesel fuel increases by approximately 0.8 million barrels per day from 2010 to 2035, while motor gasoline consumption falls by 0.9 million barrels per day.

Early declines in coal production are more than offset by growth after 2015

Figure 118. Coal production by region, 1970-2035 (quadrillion Btu)



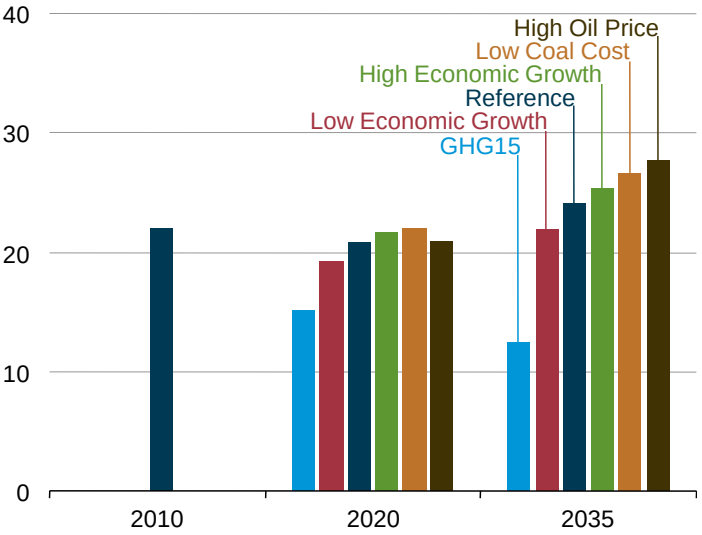
Although higher coal exports provide some support in 2011, U.S. coal production declines for four years thereafter as a result of low natural gas prices, rising coal prices, lack of growth in electricity demand, and increasing generation from renewables. In addition, new requirements to control emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), and air toxics (such as mercury and acid gases), result in the retirement of some coal-fired generating capacity, contributing to the reduction in demand for coal. After 2015, coal production grows at an average annual rate of 1.0 percent through 2035, with coal use for electricity generation increasing as electricity demand grows and natural gas prices rise.More coal is also used for production of synthetic liquids, and coal exports increase.

Western coal production grows through 2035 (Figure 118) but at a much slower rate than in the past, as demand growth continues to slow. Low-cost supplies of coal from the West satisfy much of the additional need for fuel at coal-fired power plants east of the Mississippi River and supply most of the coal used at new CTL and CBTL plants.

Coal production in the Interior region, which has trended downward slightly since the early 1990s, recovers to near historic highs in the *AEO2012* Reference case. Additional production from the Interior region originates from mines tapping into the substantial reserves of mid- and high-sulfur bituminous coal in Illinois, Indiana, and western Kentucky and from lignite mines in Texas and Louisiana. Appalachian coal production declines substantially from current levels, as coal produced from the extensively mined, higher cost reserves of Central Appalachia is supplanted by lower cost coal from other supply regions. An expected increase in production from the northern part of the Appalachia basin, however, moderates the overall production decline in Appalachia.

U.S. coal production is affected by actions to cut GHG emissions from existing power plants

Figure 119. U.S. total coal production in six cases, 2010, 2020, and 2035 (quadrillion Btu)



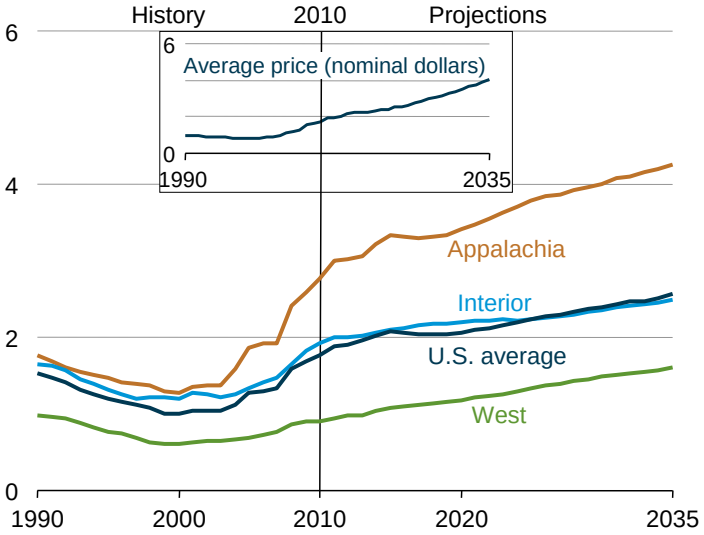
U.S. coal production varies across the *AEO2012* cases, reflecting different assumptions about the costs of producing and transporting coal, the outlook for economic growth, the outlook for world oil prices, and possible restrictions on GHG emissions (Figure 119). As shown in the GHG15 case, where a CO_2 emissions price that grows to $44 per metric ton in 2035 is assumed, actions to restrict or reduce GHG emissions can significantly affect the outlook for U.S. coal production.

Assumptions about economic growth primarily affect the projections for overall electricity demand, which in turn determine the need for coal-fired electricity generation. In contrast, assumptions about the costs of producing and transporting coal primarily affect the choice of technologies for electricity generation, with coal capturing a larger share of the U.S. electricity market in the Low Coal Cost case. In the High Oil Price case, higher oil prices stimulate the demand for coal-based synthetic liquids, leading to more coal use at CTL and CBTL plants. Production of coal-based synthetic liquids totals 1.3 million barrels per day in 2035 in the High Oil Price case, more than four times the amount in the Reference case.

From 2010 to 2035, changes in total annual coal production across the cases (excluding the GHG case) range from a decrease of 1 percent to an increase of 26 percent. In the earlier years of the projections, coal production is lower than in 2010 in most cases, as other sources of electricity generation displace coal-fired generation. From 2010 to 2020, changes in coal production across the cases (excluding the GHG case) range from a decline of 13 percent to virtually no change, with a 6-percent decline projected in the *AEO2012* Reference case.

Average minemouth price continues to rise, but at a slower pace than in recent years

Figure 120. Average annual minemouth coal prices by region, 1990-2035 (2010 dollars per million Btu)



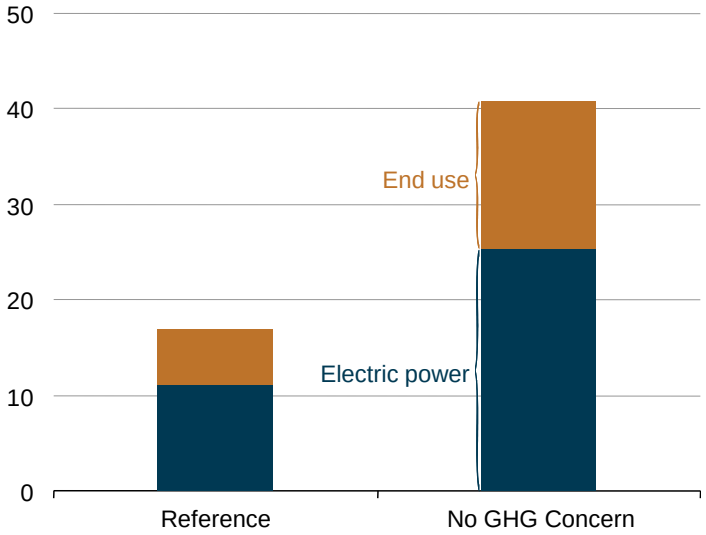
In the *AEO2012* Reference case, the average real minemouth price for U.S. coal increases by 1.5 percent per year, from $1.76 per million Btu in 2010 to $2.56 in 2035, continuing the upward trend in coal prices that began in 2000 (Figure 120). A key factor underlying the higher coal prices in the projection is an expectation that coal mining productivity will continue to decline, but at slower rates than during the 2000s.

In the Appalachian region, the average minemouth coal price increases by 1.7 percent per year from 2010 to 2035. In addition to continued declines in coal mining productivity, the higher price outlook for the Appalachian region reflects a shift to higher-value coking coal, resulting from the combination of growing exports of coking coal and declining shipments of steam/thermal coal to domestic markets. Recent increases in the average price of Appalachian coal, from $1.28 per million Btu in 2000 to $2.77 per million Btu in 2010, in part a result of significant declines in mining productivity over the past decade, have substantially reduced the competitiveness of Appalachian coal with coal from other regions.

In the Western and Interior coal supply regions, declines in mining productivity, combined with increasing production, lead to increases in the real minemouth price of coal, averaging 2.3 percent per year for the Western region and 1.0 percent per year for the Interior region from 2010 to 2035.

Concerns about future GHG policies affect investments in emissions-intensive capacity

Figure 121. Cumulative coal-fired generating capacity additions by sector in two cases, 2011-2035 (gigawatts)

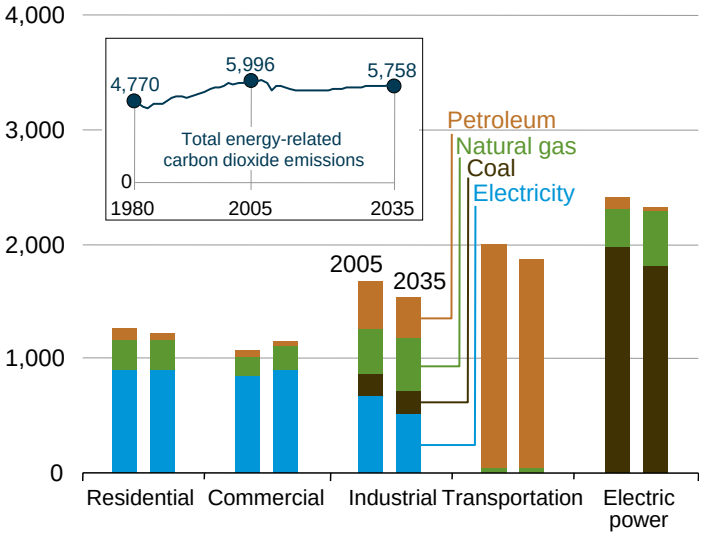


In the *AEO2012* Reference case, the cost of capital for investments in GHG-intensive technologies—including new coal-fired power plants without carbon capture and storage (CCS), new CTL and CBTL plants, and capital investment projects at existing coal-fired power plants (excluding CCS)—is increased by 3 percentage points to reflect the behavior of utilities, other energy companies, and regulators concerning the possible enactment of GHG legislation that could require owners to purchase emissions allowances, invest in CCS, or invest in other projects to offset their emissions in the future. The No GHG Concern case illustrates the potential impact on energy investments when the additional 3 percentage points added to the cost of capital for GHG-intensive technologies is removed.

In the No GHG Concern case, the lower cost of capital leads to 40 gigawatts of new coal-fired capacity additions from 2011 to 2035, up from 17 gigawatts in the Reference case (Figure 121). As a result, additions of both natural gas and renewable generating capacity are lower in the No GHG Concern case than in the Reference case. In the end-use sectors, all new coal-fired capacity additions in the No GHG Concern case are at CTL and CBTL plants, where part of the electricity is used to produce synthetic liquids and the remaining portion is sold to the grid. As a result, production of coal-based synthetic liquids totals 0.7 million barrels per day in 2035, compared with 0.3 million barrels per day in the Reference case. Total coal consumption (including coal converted to synthetic fuels) increases to 24.3 quadrillion Btu in 2035 in the No GHG Concern case, 2.6 quadrillion Btu (12 percent) higher than in the Reference case. Energy-related CO_2 emissions in 2035 are 5,900 million metric tons in the No GHG Concern case, about 2 percent higher than in the Reference case and 2 percent lower than their 2005 level.

Projected energy-related carbon dioxide emissions remain below their 2005 level

Figure 122. U.S. energy-related carbon dioxide emissions by sector and fuel, 2005 and 2035 (million metric tons)



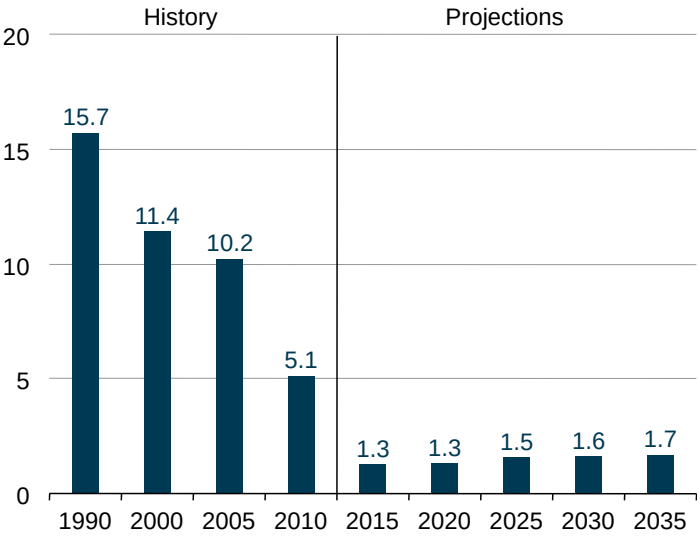
On average, energy-related CO_2 emissions in the *AEO2012* Reference case decline by 0.1 percent per year from 2005 to 2035, as compared with an average increase of 0.9 percent per year from 1980 to 2005. Reasons for the decline include an expected slow and extended recovery from the recession of 2008-2009, growing use of renewable technologies and fuels, efficiency improvements, slower growth in electricity demand, and more use of natural gas, which is less carbon-intensive than other fossil fuels. In the Reference case, energy-related CO_2 emissions remain below 2005 levels through 2035, when they total 5,758 million metric tons—238 million metric tons (4.0 percent) below their 2005 level (Figure 122).

Petroleum remains the largest source of U.S. CO_2 emissions over the projection period, but its share falls to 40 percent in 2035 from 44 percent in 2005. CO_2 emissions from petroleum use, mainly in the transportation sector, were at relatively low levels in 2009. Although they increase somewhat from 2025 to 2035, emissions from petroleum use remain fairly stable, as improvements in transportation fuel economy and the expanded use of ethanol and other biofuels outweigh expected increases in travel demand. CO_2 emissions from petroleum would be even lower if proposed fuel economy standards covering MYs 2017 through 2025 were included in the Reference case.

Emissions from coal, the second largest source of CO_2 emissions, remain below 2005 levels through 2035 in the Reference case. Coal's share of total U.S. CO_2 emissions remains relatively unchanged through 2035, because the percentage decline in emissions from coal combustion is roughly the same as the percentage decline in total CO_2 emissions over the period. The natural gas share of CO_2 emissions increases from just under 20 percent in 2005 to 25 percent in 2035 as the use of natural gas to fuel electricity generation and industrial applications increases.

Power plant emissions of sulfur dioxide are reduced by further environmental controls

Figure 123. Sulfur dioxide emissions from electricity generation, 1990-2035 (million short tons)



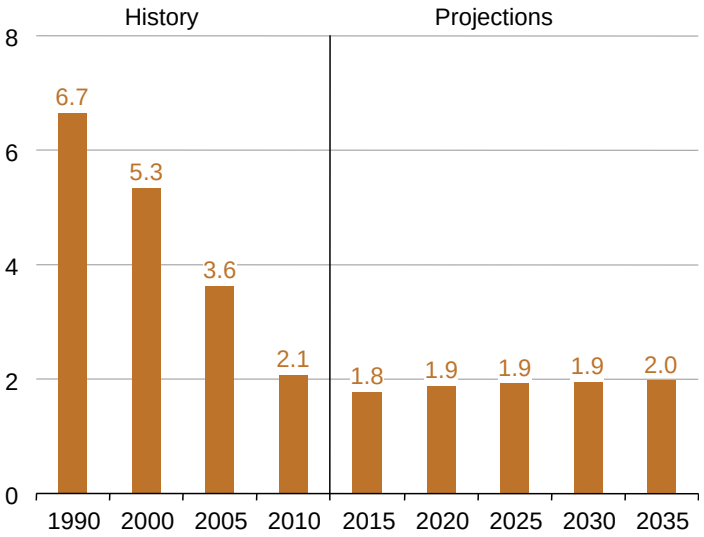
In the *AEO2012* Reference case, SO_2 emissions from the U.S. electric power sector fall from 5.1 million short tons in 2010 to a range of 1.3 to 1.7 million short tons in the 2015-2035 projection period. The reduction occurs in response to the EPA's Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS) [*138*]. Although SO_2 is not directly regulated by the MATS, the reductions are achieved as a result of the technology requirements for acid gas and non-mercury metal controls on coal-fired power plants. *AEO2012* assumes that, in order to continue operating, coal plants must have either flue gas desulfurization (FGD) or dry sorbent injection (DSI) systems installed by 2015. Both technologies, which are used to reduce acid gas emissions, also reduce SO_2 emissions.

EIA assumes a 95-percent SO_2 removal efficiency for FGD units and a 70-percent SO_2 removal efficiency for DSI systems. DSI systems can achieve 70-percent efficiency when they include a baghouse filter, which also is assumed to be needed for compliance with the non-mercury metal component of the MATS.

From 2010 to 2035, approximately 48 gigawatts of coal-fired capacity is retrofitted with FGD units in the Reference case, and another 58 gigawatts is retrofitted with DSI systems. By 2015, all operating coal-fired power plants are assumed to have either DSI or FGD systems installed on units larger than 25 megawatts. As a result, after a 75-percent decrease from 2010 to 2015, SO_2 emissions increase slowly from 2016 to 2035 (Figure 123), as total electricity generation from coal-fired power plants increases.

Nitrogen oxide emissions show little change from 2010 to 2035 in the Reference case

Figure 124. Nitrogen oxide emissions from electricity generation, 1990-2035 (million short tons)



Annual emissions of NO_X from the electric power sector, which totaled 2.1 million short tons in 2010, range between 1.8 and 2.0 million short tons from 2015 to 2035 (Figure 124). Annual NO_X emissions from electricity generation dropped by 43 percent from 2005 to 2010 due to implementation of the Clean Air Interstate Rule (CAIR), which led to the installation of additional NO_X pollution control equipment.

In the *AEO2012* Reference case, NO_X emissions are 5 percent below 2010 levels in 2035, despite a 2-percent increase in coal-fired electricity generation over the same period. The drop in emissions is a result primarily of CSAPR [*139*], which includes both annual and seasonal cap-and-trade systems for NO_X in 28 States. A slight rise in NO_X emissions after 2015 corresponds to a recovery in coal-fired generation as natural gas prices rise in the later years of the projection period.

The MATS does not have a direct effect on NO_X emissions, because none of the potential technologies required to comply with MATS has a significant impact on NO_X emissions. However, because MATS contributes to a reduction in coal-fired generation overall, it indirectly reduces NO_X emissions in the power sector in States without CSAPR where coal- and oil-fired units are used.

Coal-fired power plants can be retrofitted with one of three types of NO_X control technologies: selective catalytic reduction (SCR), selective noncatalytic reduction (SNCR), or low-NO_X burners. The type of retrofit used depends on the specific characteristics of the plant, including the boiler configuration and the type of coal used. From 2010 to 2035, 28 gigawatts of coal-fired capacity is retrofitted with NO_X controls in the Reference case: 69 percent with SCR, 3 percent with SNCR, and 29 percent with low-NO_X burners.

Endnotes for Market trends

Links current as of June 2012

121. In the recessions highlighted in Figure 46, percentage changes in annual GDP relative to the previous year were negative.
122. The industrial sector includes manufacturing, agriculture, construction, and mining. The energy-intensive manufacturing sectors include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.
123. Energy expenditures relative to GDP are not the energy share of GDP, because they include energy as an intermediate product. The energy share of GDP corresponds to the share of value added by domestic energy-producing sectors, excluding the value of energy as an intermediate product.
124. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 30*, ORNL-6986 (Oak Ridge, TN: June 2011), Chapter 4, "Light Vehicles and Characteristics," website cta.ornl.gov/data/index.shtml.
125. The *AEO2012* Reference case does not include the proposed LDV GHG and fuel economy standards published by the EPA and NHTSA in December 2011. (See "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards," website www.nhtsa.gov/fuel-economy.)
126. LDV fuel economy includes AFVs and banked credits toward compliance.
127. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Proposed Rule," Federal Register, Vol. 76, No. 231 (Washington, DC, December 1, 2011), website www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/2017-25_CAFE_NPRM.pdf. 49 CFR Parts 523, 531, 533, 536, and 537.
128. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," Federal Register, Vol. 76, No. 179 (Washington, DC: September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.
129. The factors that influence decisionmaking on capacity additions include electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different generation options, fuel prices, State RPS programs, and the availability of Federal tax credits for some technologies.
130. The 24 gigawatts include the 1.12 gigawatt Watts Bar 2 unit in 2012 that was subsequently delayed by TVA until 2015 due to cost overruns; www.tva.gov/news/releases/aprjun12/0426_board.htm.
131. Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and CHP capacity. Costs reflect the average of regional costs.
132. For detailed discussion of levelized costs, see U.S. Energy Information Administration, "Levelized Cost of New Generation Resources in the Annual Energy Outlook 2012," website www.eia.gov/forecasts/aeo/electricity_generation.cfm.
133. U.S. Environmental Protection Agency, "EPA Finalizes Regulations for the National Renewable Fuel Standard Program for 2010 and Beyond," EPA-420-F-10-007 (Washington, DC: February 2010), website www.epa.gov/otaq/renewablefuels/420f10007.pdf.
134. U.S. Environmental Protection Agency, "EPA Finalizes 2011 Renewable Fuel Standards," EPA-420-F-10-056 (Washington, DC: November 2010), website www.epa.gov/oms/fuels/renewablefuels/420f10056.pdf.
135. U.S. Environmental Protection Agency, "EPA Finalizes 2012 Renewable Fuel Standards," EPA-420-F-11-044 (Washington, DC: December 2011), website www.epa.gov/otaq/fuels/renewablefuels/documents/420f11044.pdf.
136. EISA2007, Section 211(o)(7) of the Clean Air Act.
137. U.S. Environmental Protection Agency, "E15 (a blend of gasoline and ethanol)," website www.epa.gov/otaq/regs/fuels/additive/e15.
138. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," website www.epa.gov/mats.
139. U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)," website epa.gov/airtransport.

Comparison with other projections

Energy Information Administration (EIA) and other contributors have endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives. None of the EIA or any of the other contributors shall be responsible for any loss sustained due to reliance on the information included in this report.

Only IHS Global Insight (IHSGI) produces a comprehensive energy projection with a time horizon similar to that of the *Annual Energy Outlook 2012 (AEO2012)*. Other organizations, however, address one or more aspects of the U.S. energy market. The most recent projection from IHSGI, as well as others that concentrate on economic growth, international oil prices, energy consumption, electricity, natural gas, petroleum, and coal, are compared here with the *AEO2012* Reference case.

1. Economic growth

The range of projected economic growth in the outlooks included in the comparison tends to be wider over the first 5 years of the projection period than over a longer period, because the group of variables—such as population, productivity, and labor force growth—that are used to influence long-run economic growth is smaller than the group of variables that affect projections of short-run growth. The average annual rate of growth of real gross domestic product (GDP) from 2010 to 2015 (in 2005 dollars) ranges from 2.4 percent to 3.4 percent (Table 22). From 2010 to 2020, the 10-year average annual growth rate ranges from 2.5 percent to 3.1 percent.

From 2010 to 2015, real GDP is projected to grow at a 2.5-percent average annual rate in the *AEO2012* Reference case, lower than projected by the Office of Management and Budget (OMB), Congressional Budget Office (CBO), Blue Chip Consensus (Blue Chip), Social Security Administration (in *The 2011 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds*), ExxonMobil, and the Interindustry Forecasting Project at the University of Maryland (INFORUM) and higher than projected by Strategic Energy and Economic Research, Inc. (SEER). The *AEO2012* projection of GDP growth is similar to the IHSGI average annual rate of 2.5 percent over the same period.

The average annual GDP growth of 2.5 percent in the *AEO2012* Reference case from 2010 to 2020 is at the low end of the range of outlooks, with OMB, INFORUM, and the Social Security Administration projecting the strongest recovery from the 2008-2009 recession. INFORUM projects average annual GDP growth of 3.1 percent from 2010 to 2020, while OMB and the Social Security Administration project annual average growth of 3.0 percent over the same period. The CBO, ExxonMobil, Blue Chip, the International Energy Agency's (IEA) November 2011 *World Energy Outlook* Current Policies Scenario, and SEER also project higher growth than the *AEO2012* Reference case from 2010 to 2020, ranging between 2.6 and 2.8 percent per year over the next 10 years.

There are few public or private projections of GDP growth for the United States that extend to 2035. The *AEO2012* Reference case projects 2.5-percent average annual GDP growth from 2010 to 2035, consistent with trends in labor force and productivity growth. IHSGI, ExxonMobil, and the Social Security Administration project GDP growth averaging 2.5 percent per year from 2010 to 2035, and INFORUM (at 2.7 percent) and SEER (at 2.8 percent) project higher GDP growth than in the *AEO2012* Reference Case over the same period. IEA projects a slightly lower rate of 2.4 percent per year from 2010 to 2035.

2. Oil prices

In the *AEO2012* Reference case, oil prices [West Texas Intermediate (WTI)] rise from $79 per barrel in 2010 to about $117 per barrel in 2015 and $127 per barrel in 2020 (Table 23). From the 2020 level, prices increase slowly to $145 per barrel in 2035. This price trend is slightly higher than the trend shown in last year's *AEO2011* Reference case.

Table 22. Projections of average annual economic growth, 2010-2035

	Average annual percentage growth rates			
Projection	2010-2015	2010-2020	2020-2035	2010-2035
AEO2012 (Reference case)	2.5	2.5	2.6	2.5
AEO2011 (Reference case)	3.0	2.8	2.6	2.7
IHSGI (November 2011)	2.5	2.5	2.5	2.5
OMB (January 2012)[a]	3.1	3.0	--	--
CBO (January 2012)[a]	2.7	2.8	--	--
INFORUM (January 2012)	3.4	3.1	2.4	2.7
Social Security Administration (August 2011)	3.3	3.0	2.1	2.5
IEA (2011)[b]	--	2.6	2.4	2.4
Blue Chip Consensus (October 2011)[a]	2.6	2.6	--	--
ExxonMobil	2.7	2.7	2.3	2.5
SEER	2.4	2.7	2.8	2.8

-- = not reported.
[a]OMB, CBO, and Blue Chip forecasts end in 2022, and growth rates cited are for 2010-2022.
[b]IEA publishes U.S. growth rates for certain intervals: 2009-2020 growth is 2.6 percent, and 2009-2035 growth rate is 2.4 percent.

Market volatility and different assumptions about the future of the world economy are reflected in the range of price projections for both the short term and the long term; however, most projections show prices rising over the entire course of the projection period. The projections range from $82 per barrel to $117 per barrel in 2015 (a span of $35 per barrel) and from $98 per barrel to $145 per barrel in 2035 (a span of $47 per barrel). The wide range underscores the uncertainty inherent in the projections. The range of the projections is encompassed in the range of the *AEO2012* Low and High Oil Price cases, from $58 per barrel to $182 per barrel in 2015 and from $62 per barrel to $200 per barrel in 2035.

The measure of oil prices is, by and large, comparable across projections. EIA reports the price of low-sulfur, light crude oil, approximately the same as the WTI price widely cited in the trade press. The only series that do not report projections in WTI terms are IEA, with prices in the Current Policies Scenario expressed as the price of imported crude oil, and INFORUM, with prices expressed as the average U.S. refiner acquisition cost (RAC) of imported crude oil.

3. Total energy consumption

Five projections by other organizations—INFORUM, IHSGI, ExxonMobil, IEA, and BP—include energy consumption by sector. To allow comparison with the IHSGI projection, the *AEO2012* Reference case was adjusted to remove coal-to-liquids (CTL) heat and power, biofuels heat and co-products, and natural gas feedstock use. To allow comparison with the ExxonMobil projection, electricity consumption in each sector was removed from the *AEO2012* Reference case projections. To allow comparison with the IEA and BP projections, the *AEO2012* Reference case projections for the residential and commercial sectors were combined to produce a buildings sector projection. BP does not include the electric power sector in its projection for total energy consumption; however, it does include conversion losses that allow comparison on the basis of total energy consumption. The IEA projections have a base year of 2009, as opposed to 2010 in the other projections, and BP's projections extend only through 2030, not 2035.

Total energy consumption is higher in all projection years in both the IHSGI and INFORUM projections than in the *AEO2012* Reference case. ExxonMobil, IEA, and BP show lower total energy consumption in all years (Table 24). ExxonMobil and BP include a cost for carbon dioxide (CO_2) emissions in their outlooks, which helps to explain the lower level of consumption in those outlooks. While the IEA reference case also includes a cost for CO_2 emissions, the IEA Current Policies Scenario (which assumes that no new policies are added to those in place in mid-2011) was used for comparison in this analysis, because it corresponds better with the assumptions in *AEO2012*.

The INFORUM projection of total energy consumption in 2035 is almost 8 quadrillion Btu higher than the *AEO2012* Reference case projection, with the industrial and electric power sectors each about 2 quadrillion Btu higher and the transportation sector about 3 quadrillion Btu higher. For the transportation sector, the difference appears to result from a higher number of light-duty vehicle miles traveled in the INFORUM results, which offsets slightly higher motor gasoline prices in the INFORUM projection. Vehicle efficiency is essentially the same in the INFORUM and *AEO2012* projections. INFORUM also projects higher revenue passenger-miles for air travel than *AEO2012*. Diesel prices are lower in the INFORUM projection, which leads to higher demand (about 1 quadrillion Btu) than in *AEO2012*. In the industrial sector, INFORUM projects industrial shipments in 2035 that are approximately 1.5 times the level of those in the *AEO2012* Reference case, which helps to explain the higher level of industrial energy consumption in the INFORUM projection relative to *AEO2012*.

IHSGI projects significantly higher electricity consumption for all sectors than in the *AEO2012* Reference case, which helps to explain much of the difference in total energy consumption between the two projections. In the IHSGI projection, the electric power sector consumes 13 quadrillion Btu more energy in 2035 than in the *AEO2012* Reference case. The greater use of electricity in the IHSGI projection, including 300 trillion Btu used by electric vehicles, also results in higher electricity prices than in the *AEO2012* Reference case.

Table 23. Projections of oil prices, 2015-2035 (2010 dollars per barrel)

Projection	2015	2020	2025	2030	2035
AEO2012 (Reference case)	116.91	126.68	132.56	138.49	144.98
AEO2011 (Reference case)	95.41	109.05	118.57	124.17	126.03
EVA	82.24	84.75	89.07	94.78	102.11
IEA (Current Policies Scenario)	106.30	118.10	127.30	134.50	140.00
INFORUM	91.78	105.84	113.35	117.83	116.76
IHSGI	99.16	72.89	87.19	95.65	98.08
Purvin & Gertz	98.75	103.77	106.47	107.37	107.37
SEER	94.20	101.57	107.13	111.26	121.94

Although there are differences in energy consumption by sector between the ExxonMobil and BP projections, in both cases total energy consumption declines from 2010 levels and is lower than in the *AEO2012* Reference case. The difference appears to result primarily from the inclusion of a tax on CO_2 emissions in both the ExxonMobil and BP projections, which is not considered in the *AEO2012* projection. Energy consumption in the transportation sector declines from 2010 levels in both the ExxonMobil and BP projections, driven by policy changes and technology improvement; however, BP projects a much larger drop in transportation energy consumption, a total of 4 quadrillion Btu (or four times the decline in the ExxonMobil projection) between 2010 and 2030.

Although energy consumption in all sectors in the IEA projection is higher in 2035 than in 2010, energy consumption in the transportation and industrial sectors declines from 2020 to 2030, by less than 1 quadrillion Btu in each sector.

IEA projects little change for energy use in those two sectors from 2030 to 2035, with industrial energy consumption declining very slowly and transportation energy consumption increasing very slightly. IEA projects total energy consumption that is higher than BP in 2030 and higher than ExxonMobil in 2035 but considerably lower than in the *AEO2012* Reference case.

4. Electricity

Table 25 compares summary results for the electric power sector from the *AEO2012* Reference case with projections by Energy Ventures Analysis (EVA), IHSGI, and INFORUM. In 2015, total electricity sales range from a low of 3,753 billion kilowatthours in the *AEO2012* Reference case to a high of 4,173 billion kilowatthours in the IHSGI projection. IHSGI shows higher sales across

Table 24. Projections of energy consumption by sector, 2010-2035 (quadrillion Btu)

Sector	*AEO2012* Reference	INFORUM	IHSGI	ExxonMobil	IEA	BP
			2010			
Residential	11.7	11.4	11.2	--	--	--
Residential excluding electricity	6.7	6.5	6.2	6.0	--	--
Commercial	8.7	8.5	8.6	--	--	--
Commercial excluding electricity	4.2	3.9	4.0	4.0	--	--
Buildings sector	20.4	20.0	19.8	10.0	19.1[a]	21.8
Industrial	23.4	23.1	--	--	22.9[a]	23.0
Industrial excluding electricity	20.1	19.9	--	20.0	--	--
Losses[b]	0.8	--	--	--	--	--
Natural gas feedstocks	0.5	--	--	--	--	--
Industrial removing losses and feedstocks	22.0	--	21.4	--	--	--
Transportation	27.6	27.4	26.6	27.0	22.9[a]	22.8
Electric power	39.6	40.1	40.8	37.0	35.6[a]	--
Less: electricity demand[c]	12.8	12.8	12.8	--	14.3[a]	--
Electric power losses	26.8	27.3	--	--	--	23.1
Total primary energy	**98.2**	**97.8**	**--**	**94.0**	**85.7[a]**	**90.7**
Excluding losses[b] and feedstocks	**96.8**	**--**	**95.8**	**--**	**--**	**--**
			2020			
Residential	11.4	11.2	11.8	--	--	--
Residential excluding electricity	6.4	6.4	5.8	6.0	--	--
Commercial	9.2	9.5	9.5	--	--	--
Commercial excluding electricity	4.3	4.3	4.0	4.0	--	--
Buildings sector	20.5	20.7	21.3	9.0	20.4	21.9
Industrial	24.6	27.4	--	--	24.8	23.4
Industrial excluding electricity	21.2	23.9	--	20.0	--	--
Losses[b]	1.2	--	--	--	--	--
Natural gas feedstocks	0.5	--	--	--	--	--
Industrial removing losses and feedstocks	22.9	--	22.5	--	--	--
Transportation	27.3	29.0	27.4	28.0	23.8	21.0
Electric power	40.2	41.6	48.6	39.0	39.3	--
Less: electricity demand[c]	13.3	13.6	15.7	--	16.4	--
Electric power losses	26.9	28.0	--	--	--	23.7
Total primary energy	**99.3**	**105.1**	**--**	**96.0**	**91.4**	**90.1**
Excluding losses[b] and feedstocks	**97.6**	**--**	**104.1**	**--**	**--**	**--**

-- = not reported.
See notes at end of table.

(continued on next page)

all sectors in 2015 in comparison with the other projections. Total electricity sales in 2035 in the IHSGI projection (5,652 billion kilowatthours) are higher than in the others: 4,415 billion kilowatthours in the *AEO2012* Reference case, 4,483 billion kilowatthours in the INFORUM projection, and 4,726 billion kilowatthours in the EVA projection. Although IHSGI projects higher electricity sales in all sectors in 2035, the largest percentage differences between the IHSGI and other projections are in the industrial sector. Electricity sales in the industrial sector in 2035 in the IHSGI projection are 1,387 billion kilowatthours, as compared with 977 billion kilowatthours in the *AEO2012* Reference case, 941 billion kilowatthours in the EVA projection, and 968 billion kilowatthours in the INFORUM projection.

Table 24. Projections of energy consumption by sector, 2010-2035 (quadrillion Btu) (continued)

Sector	*AEO2012* Reference	INFORUM	IHSGI	ExxonMobil	IEA	BP
			2030			
Residential	11.7	11.6	12.6	--	--	--
Residential excluding electricity	6.2	6.3	5.7	5.0	--	--
Commercial	9.9	10.6	10.4	--	--	--
Commercial excluding electricity	4.4	4.5	4.0	4.0	--	--
Buildings sector	21.6	22.1	23.0	9.0	22.0	23.0
Industrial	26.1	28.8	--	--	24.1	23.2
Industrial excluding electricity	22.7	25.3	--	19.0	--	--
Losses[b]	2.4	--	--	--	--	--
Natural gas feedstocks	0.5	--	--	--	--	--
Industrial removing losses and feedstocks	23.3	--	23.0	--	--	--
Transportation	27.9	30.7	27.5	26.0	22.9	18.5
Electric power	43.2	45.0	54.3	41.0	41.6	--
Less: electricity demand[c]	14.5	14.8	18.1	--	17.9	--
Electric power losses	28.7	30.1	--	--	--	24.1
Total primary energy	**104.3**	**111.8**	**--**	**94.0**	**92.3**	**88.9**
Excluding losses[b] and feedstocks	**101.5**	**--**	**109.7**	**--**	**--**	**--**
			2035			
Residential	11.9	11.7	13.0	--	--	--
Residential excluding electricity	6.1	6.2	5.5	5.0	--	--
Commercial	10.3	11.1	10.8	--	--	--
Commercial excluding electricity	4.5	4.6	4.0	3.0	--	--
Buildings sector	22.2	22.8	23.8	8.0	22.9	--
Industrial	26.9	29.1	--	--	23.9	--
Industrial excluding electricity	23.6	25.7	--	18.0	--	--
Losses[b]	3.2	--	--	--	--	--
Natural gas feedstocks	0.4	--	--	--	--	--
Industrial removing losses and feedstocks	23.3	--	23.3	--	--	--
Transportation	28.6	31.9	27.8	25.0	23.1	--
Electric power	44.2	46.2	57.2	40.0	42.5	--
Less: electricity demand[c]	15.1	15.3	19.3	--	18.6	--
Electric power losses	29.2	30.8	--	--	--	--
Total primary energy	**106.9**	**114.7**	**--**	**92.0**	**93.4**	**--**
Excluding losses[b] and feedstocks	**103.3**	**--**	**112.7**	**--**	**--**	**--**

-- = not reported.

[a]IEA data are for 2009.

[b]Losses in CTL and biofuel production.

[c]Energy consumption in the sectors includes electricity demand purchases from the electric power sector, which are subtracted to avoid double counting in deriving total primary energy consumption.

Table 25. Comparison of electricity projections, 2015, 2025, and 2035 (billion kilowatthours, except where noted)

Projection	2010	*AEO2012* Reference case	Other projections EVA	IHSGI	INFORUM
		2015			
Average end-use price (2010 cents per kilowatthour)[a]	9.8	9.7	--	10.2	--
Residential	11.5	11.8	12.8	12.0	10.5
Commercial	10.1	9.9	11.5	10.7	9.3
Industrial	6.7	6.5	7.9	7.0	6.2
Total generation plus imports	**4,152**	**4,181**	**4,053**	**4,611**	**--**
Coal	1,851	1,581	1,591	1,905	--
Petroleum	37	28	--	45	--
Natural gas[b]	982	1,130	1,090	1,223	--
Nuclear	807	830	827	839	--
Hydroelectric/other[c]	449	583	515	576	--
Net imports	26	29	29	24	--
Electricity sales	3,749	3,753	3,921	4,173	3,854
Residential	1,451	1,392	1,481	1,563	1,365
Commercial/other[d]	1,336	1,354	1,414	1,489	1,438
Industrial	962	1,008	1,025	1,121	1,051
Capacity, including CHP (gigawatts)[e]	1,036	1,042	1,094	1,101	--
Coal	318	286	289	309	--
Oil and natural gas	459	464	514	491	--
Nuclear	101	104	106	104	--
Hydroelectric/other[f]	158	188	185	197	--
		2025			
Average end-use price (2010 cents per kilowatthour)[a]	9.8	9.7	--	10.9	--
Residential	11.5	11.6	13.2	12.8	10.5
Commercial	10.1	9.9	11.7	11.4	9.3
Industrial	6.7	6.7	8.0	7.4	6.2
Total generation plus imports	**4,152**	**4,578**	**4,514**	**5,417**	**--**
Coal	1,851	1,786	1,653	1,774	--
Petroleum	37	29	--	45	--
Natural gas[b]	982	1,140	1,335	1,760	--
Nuclear	807	917	870	918	--
Hydroelectric/other[c]	449	683	629	896	--
Net imports	26	22	27	25	--
Electricity sales	3,749	4,090	4,298	4,942	4,167
Residential	1,451	1,533	1,650	1,887	1,468
Commercial/other[d]	1,336	1,525	1,679	1,793	1,660
Industrial	962	1,032	969	1,261	1,039
Capacity, including CHP (gigawatts)[e]	1,036	1,091	1,119	1,274	--
Coal	318	282	267	283	--
Oil and natural gas	459	493	518	566	--
Nuclear	101	115	110	114	--
Hydroelectric/other[f]	158	201	224	312	--

-- = not reported.
See notes at end of table.

(continued on next page)

Only IHSGI and the *AEO2012* Reference case provide average electricity price projections through 2035. Average electricity prices in the *AEO2012* Reference case are 9.8 cents per kilowatthour in 2010 and 9.7 cents per kilowatthour in 2015 and 2025 before reaching 10.1 cents per kilowatthour in 2035. In the IHSGI projection, the average electricity price rises continuously (with the exception of a small decrease from 2017 to 2018), from 9.8 cents per kilowatthour in 2010 to 10.2 cents in 2015, 10.9 cents in 2025, and 12.1 cents per kilowatthour in 2035.

In all the projections, average electricity prices by sector follow patterns similar to changes in the weighted average electricity price across all sectors (including transportation services). The lowest prices by sector in 2015 are in the INFORUM projection (10.5 cents per kilowatthour in the residential sector, 9.3 cents per kilowatthour in the commercial sector, and 6.2 cents per kilowatthour in the industrial sector). The highest average electricity prices by sector in 2015 are in the EVA projection (12.8 cents per kilowatthour in the residential sector, 11.5 cents per kilowatthour in the commercial sector, and 7.9 cents per kilowatthour in the industrial sector).

In the *AEO2012* Reference case, electricity prices for the residential sector are 11.8 cents per kilowatthour in both 2015 and 2035, electricity prices for the commercial sector increase from 9.9 cents per kilowatthour in 2015 to 10.1 cents per kilowatthour in 2035, and electricity prices for the industrial sector increase from 6.5 cents per kilowatthour in 2015 to 7.1 cents per kilowatthour in 2035. When compared with the *AEO2012* Reference case prices in 2035, the largest difference is with the IHSGI projection. The IHSGI price projections are much higher than those in the *AEO2012* Reference case. IHSGI shows real electricity prices rising to 14.3 cents per kilowatthour for the residential sector, 12.5 cents per kilowatthour for the commercial sector, and 8.1 cents per kilowatthour for the industrial sector in 2035.

Table 25. Comparison of electricity projections, 2015, 2025, and 2035 (billion kilowatthours, except where noted) (continued)

Projection	2010	*AEO2012* Reference case	Other projections		
			EVA	IHSGI	INFORUM
		2035			
Average end-use price (2010 cents per kilowatthour)[a]	9.8	10.1	--	12.1	--
Residential	11.5	11.8	12.9	14.3	10.5
Commercial	10.1	10.1	11.3	12.5	9.3
Industrial	6.7	7.1	7.6	8.1	6.2
Total generation plus imports	**4,152**	**5,004**	**--**	**6,199**	**--**
Coal	1,851	1,897	--	1,618	--
Petroleum	37	30	--	45	--
Natural gas[b]	982	1,398	--	2,354	--
Nuclear	807	887	--	1,030	--
Hydroelectric/other[c]	449	780	--	1,124	--
Net imports	26	12	--	28	--
Electricity sales	3,749	4,415	4,726	5,652	4,483
Residential	1,451	1,718	1,778	2,178	1,611
Commercial/other[d]	1,336	1,721	2,008	2,088	1,904
Industrial	962	977	941	1,387	968
Capacity, including CHP (gigawatts)[e]	1,036	1,190	--	1,450	--
Coal	318	285	--	262	--
Oil and natural gas	459	568	--	665	--
Nuclear	101	111	--	128	--
Hydroelectric/other[f]	158	226	--	396	--

-- = not reported.

[a]Average end-use price includes the transportation sector.

[b]Includes supplemental gaseous fuels. For EVA, represents total oil and natural gas.

[c]"Other" includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, solar and wind power, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, petroleum coke, and miscellaneous technologies.

[d]"Other" includes sales of electricity to government and other transportation services.

[e]EIA capacity is net summer capacity, including CHP plants.

[f]"Other" includes conventional hydro, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, wind power, pumped storage, and fuel cells.

Total electricity generation plus imports in 2015 ranges from a low of 4,053 billion kilowatthours in the EVA projection to a high of 4,611 billion kilowatthours in the IHSGI projection, compared with 4,181 billion kilowatthours in the *AEO2012* Reference case. Although coal represents the largest share of generation in 2015 in all the projections, the natural gas share of total generation grows from 2015 to 2035 in all the projections, particularly IHSGI. In the IHSGI projection, coal has a 33-percent share of total generation in 2025, and the natural gas share is 32 percent. IHSGI shows natural gas overtaking coal as a share of total generation by 2035 as a result of the carbon tax assumed in the IHSGI projection and the need to replace existing units that are uneconomical or are being retired for various regulatory or environmental reasons. In 2035, the coal share in the IHSGI projection is 26 percent of total generation, and the natural gas share is 38 percent. In the *AEO2012* Reference case, which does not include a carbon tax, the coal share also decreases but only to 38 percent of total generation, while the natural gas share increases to 28 percent.

Nuclear generation in 2015 ranges from a low of 827 billion kilowatthours in the EVA projection to a high of 839 billion kilowatthours in the IHSGI projection. From 2015 to 2025, EVA projects a 5-percent increase in nuclear generation, to 870 billion kilowatthours. IHSGI and *AEO2012* project increases of 9 percent and 10 percent, respectively. In the IHSGI projection, nuclear generation totals 1,030 billion kilowatthours in 2035, a 12-percent increase from 2025. The *AEO2012* Reference case shows nuclear generation declining to 887 billion kilowatthours in 2035, a 3-percent decrease from 2025, as units are retired when they reach the end of their useful generation lifetimes.

Total generating capacity by fuel in 2015 is relatively similar across the projections, ranging from 1,042 gigawatts in the *AEO2012* Reference case to 1,101 gigawatts in the IHSGI projection, but IHSGI shows a much larger decrease in capacity in 2025. IHSGI projects more aggressive growth in total generating capacity, due to what appears to be a much higher demand projection. Natural gas and oil-fired capacity grows to 566 gigawatts in 2025 in the IHSGI projection, compared with 493 gigawatts in *AEO2012* and 518 gigawatts in the EVA projections. Hydroelectric/other capacity grows to 312 gigawatts in 2025 in the IHSGI projection, higher than the 201 gigawatts in *AEO2012*. The faster growth in natural gas and hydroelectric/other capacity in the IHSGI projection continues through 2035. Natural gas and oil-fired capacity grows to 665 gigawatts in 2035, and hydroelectric/other capacity grows to 396 gigawatts in 2035 in the IHSGI projection. By comparison, natural gas and oil-fired capacity grows to 568 gigawatts and hydroelectric/other capacity grows to 226 gigawatts in the *AEO2012* Reference case in 2035.

5. Natural gas

The projections of natural gas consumption, production, imports, and prices (Table 26) vary significantly as a result of differences in assumptions. For example, the *AEO2012* Reference case assumes that current laws and regulations remain unchanged throughout the projection period (including the implication that laws which include sunset dates do, in fact, become ineffective at the time of those sunset dates), whereas the other projections may include anticipated policy developments over the next 25 years. In particular, the *AEO2012* Reference case does not assume changes in CO_2 emissions policies.

Each of the projections shows an increase in overall natural gas consumption from 2010 to 2035, with the IHSGI projection showing the largest increase, 39 percent. The ExxonMobil projection includes an increase of around 20 percent. The EVA projection shows an increase of 26 percent from 2010 to 2030 (EVA does not extend to 2035). Total natural gas consumption in the *AEO2012*, Deloitte, and SEER projections increases from 2010 to 2035, with total natural gas consumption growing from 4 to 31 percent. IHSGI shows the largest increase and INFORUM the smallest. The IHSGI projection for total natural gas consumption in 2035 is 36 percent higher than the INFORUM projection. In the *AEO2012* Reference case, total natural gas consumption grows by 5 percent from 2015 to 2035.

The IHSGI and ExxonMobil projections for natural gas consumption by electricity generators are much higher than the other projections shown in Table 26. In 2035, natural gas consumption by electricity generators in the IHGSI projection is more than double the consumption projected by INFORUM, and the ExxonMobil projection is 77 percent higher than the INFORUM projection. The *AEO2012* Reference case, SEER, and INFORUM projections show similar levels of natural gas consumption in the electricity generation sector in 2035, with average annual growth of 1 percent or less across the projection period, while consumption grows by an average of 3 percent in the ExxonMobil and IHSGI projections. The slower rate of growth in the *AEO2012* Reference case reflects relatively slower growth in electricity consumption and faster growth in renewable energy consumption than in the other projections.

Industrial natural gas consumption is similar across the projections, but with more rapid growth projected by EVA, Deloitte, and INFORUM. Natural gas consumption increases by 23 percent from 2010 to 2030 in the EVA projection and by 23 percent and 11 percent, respectively, from 2010 to 2035 in the INFORUM and Deloitte projections. All of the growth in industrial natural gas consumption in the Deloitte and INFORUM projections is between 2010 and 2015. In the *AEO2012* Reference case, in contrast, industrial natural gas consumption grows by 6 percent from 2010 to 2035. In the ExxonMobil projection, industrial natural gas consumption remains constant over the projection period; in the IHSGI projection industrial natural gas consumption falls from 2010 to 2035; and in the INFORUM, SEER, and Deloitte projections, after an initial increase, industrial natural gas consumption declines from 2015 to 2035.

The levels of commercial sector natural gas consumption are similar across the projections, but projections for the residential sector vary significantly [*140*]. Three of the seven projections (INFORUM, Deloitte, and EVA) show similar growth in residential consumption through 2030, and INFORUM and Deloitte are similar through 2035; however, the IHSGI and *AEO2012* projections

show larger declines in residential consumption of natural gas from 2010 to 2035 (11 percent and 6 percent, respectively). The SEER projection for residential natural gas consumption shows a decrease of 4 percent from 2015 to 2025, then a partial recovery by 2035.

Table 26. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted)

Projection	2010	*AEO2012* Reference case	Other projections					
			IHSGI	EVA	Deloitte	SEER	ExxonMobil	INFORUM
					2015			
Dry gas production[a]	21.58	23.65	23.81	23.80	24.52	23.66	24.00	24.29
Net imports	**2.58**	**1.73**	**1.62**	**2.20**	**1.30**	**1.73**	**1.20**	**--**
Pipeline	2.21	1.56	--	1.80	1.22	1.56	--	--
LNG	0.37	0.16	--	0.40	0.08	0.16	--	--
Consumption	**24.13**	**25.39**	**25.52**	**26.60**	**24.07[b]**	**26.05**	**25.00[c]**	**23.61[b]**
Residential	4.94	4.85	4.64	4.90	4.86	4.91	8.00[d]	4.87
Commercial	3.20	3.33	3.10	3.20	3.23	3.41	--	3.43
Industrial[e]	6.60	7.01	6.64	7.00	7.51	7.64	8.00	8.19
Electricity generators[f]	7.38	8.08	9.02	9.30	8.46	8.06	9.00	7.12
Others[g]	2.01	2.12	2.11	2.20	--	2.04	--	--
Henry Hub spot market price (2010 dollars per million Btu)	4.39	4.29	4.75	4.07	4.25	4.28	--	--
End-use prices (2010 dollars per thousand cubic feet)								
Residential	11.36	10.56	11.82	--	--	11.68	--	--
Commercial	9.32	8.82	9.88	--	--	8.31	--	--
Industrial[h]	5.65	5.00	6.95	--	--	4.63	--	--
Electricity generators	5.25	4.65	5.20	--	--	5.17	--	--
					2025			
Dry gas production[a]	21.58	26.28	27.23	26.70	27.32	25.88	27.00	27.57
Net imports	**2.58**	**-0.79**	**2.13**	**1.30**	**0.38**	**0.29**	**1.50**	**--**
Pipeline	2.21	-0.13	--	0.90	0.29	1.03	--	--
LNG	0.37	-0.66	--	0.40	0.09	-0.74	--	--
Consumption	**24.13**	**25.53**	**29.39**	**29.00**	**26.36[b]**	**27.10**	**29.00[c]**	**23.43[b]**
Residential	4.94	4.76	4.53	5.00	5.05	4.71	8.00[d]	4.90
Commercial	3.20	3.44	3.15	3.30	3.46	3.53	--	3.60
Industrial[e]	6.60	7.14	6.52	7.70	7.58	7.47	8.00	8.20
Electricity generators[f]	7.38	7.87	12.78	10.50	10.27	9.27	13.00	6.74
Others[g]	2.01	2.31	2.42	2.50	--	2.12	--	--
Henry Hub spot market price (2010 dollars per million Btu)	4.39	5.63	4.82	6.47	5.80	6.29	--	--
End-use prices (2010 dollars per thousand cubic feet)								
Residential	11.36	12.33	11.70	--	--	14.40	--	--
Commercial	9.32	10.27	9.81	--	--	10.68	--	--
Industrial[h]	5.65	6.19	6.99	--	--	6.96	--	--
Electricity generators	5.25	5.73	5.28	--	--	7.47	--	--

-- = not reported.
See notes at end of table.

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With the exception of ExxonMobil, which shows a decline in U.S. production of domestic natural gas between 2030 and 2035, all the projections show increasing U.S. production of domestic natural gas over the projection period, although at different rates. The highest level of natural gas production is projected by IHSGI, exceeding the ExxonMobil projection by 21 percent in 2035. Coupled with a significant decline in net pipeline imports, SEER, INFORUM, and the *AEO2012* Reference case project a strong increase in the share of total U.S. natural gas supply accounted for by domestic production. The other projections show relatively stable and similar percentages for the contribution of domestic natural gas production to total supply, with the exception of IHSGI, which shows a notable increase in net imports after 2015. In all the projections, with the exception of EVA, net LNG imports remain below the 2010 level of 0.4 trillion cubic feet throughout the projection period. In all the projections, however, net pipeline imports decline from 2010 levels, with *AEO2012*, SEER, and Deloitte projecting more severe declines than EVA (only through 2030 since EVA does not show 2035).

The *AEO2012* Reference case and SEER show similar levels of natural gas production and Henry Hub spot prices, both with increasing production and prices over time. EVA shows similar levels of natural gas production as the *AEO2012* Reference case through 2025, but higher Henry Hub spot prices. IHSGI projects a larger increase in natural gas production but at relatively stable prices. In 2015, the Henry Hub spot price in the IHSGI projection is 11 percent higher than the price in the SEER projection; however, the SEER Henry Hub spot price quickly surpasses the IHSGI price, and it is 50 percent higher in 2035. Deloitte, ExxonMobil, and INFORUM did not include price projections.

Only IHSGI and SEER included delivered natural gas prices that can be compared with those in the *AEO2012* Reference case [*141*]. However, there appear to be definitional differences in the projections, based on an examination of 2010 price levels. In particular,

Table 26. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted) (continued)

Projection	2010	*AEO2012* Reference case	Other projections					
			IHSGI	EVA	Deloitte	SEER	ExxonMobil	INFORUM
			2035					
Dry gas production[a]	21.58	27.93	31.35	--	27.87	27.00	26.00	30.71
Net imports	2.58	**-1.36**	**2.36**	**--**	**0.14**	**-0.46**	**2.50**	**--**
Pipeline	2.21	-0.70	--	--	0.07	0.28	--	--
LNG	**0.37**	-0.66	--	--	0.08	-0.74	--	--
Consumption	24.13	**26.63**	**33.54**	**--**	**27.30[b]**	**27.24**	**29.00[c]**	**24.66[b]**
Residential	4.94	4.64	4.38	--	5.03	4.80	7.00[d]	4.83
Commercial	3.20	3.60	3.18	--	3.60	3.64	--	3.83
Industrial[e]	6.60	7.00	6.35	--	7.31	7.30	8.00	8.09
Electricity generators[f]	7.38	8.96	16.90	--	11.37	9.37	14.00	7.90
Others[g]	2.01	2.43	2.72	--	--	2.13	--	--
Henry Hub spot market price (2010 dollars per million Btu)	4.39	7.37	5.13	7.26	6.63	7.70	--	--
End-use prices (2010 dollars per thousand cubic feet)								
Residential	11.36	14.33	11.81	--	--	17.15	--	--
Commercial	9.32	11.93	9.99	--	--	13.09	--	--
Industrial[h]	5.65	7.73	7.22	--	--	9.20	--	--
Electricity generators	5.25	7.37	5.62	--	--	9.75	--	--

-- = not reported.

[a]Does not include supplemental fuels.

[b]Does not includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.

[c]Does not includes lease, plant, and pipeline fuel.

[d]Natural gas consumed in the residential and commercial sectors.

[e]Includes consumption for industrial combined heat and power (CHP) plants and a small number of industrial electricity-only plants, and natural gas-to-liquids heat/power production; excludes consumption by nonutility generators.

[f]Includes consumption of energy by electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators.

[g]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.

[h]The 2010 industrial natural gas price for IHSGI is $6.53.

the IHSGI industrial delivered natural gas price is difficult to compare. The industrial delivered natural gas price for 2010 in the IHSGI projection is $0.88 higher than the industrial price for 2010 in the *AEO2012* Reference case and $1.13 higher than the 2010 industrial price in the SEER projection (all prices in 2010 dollars per thousand cubic feet). From 2010 to 2035, the delivered price for electricity generators increases by 7 percent in the IHSGI projection, by 40 percent in the *AEO2012* Reference case, and by 86 percent in the SEER projection. The SEER projection also shows the largest increases in residential and commercial delivered prices, at 51 percent and 40 percent, respectively, over the same period. IHSGI shows the smallest increases in residential and commercial delivered prices over the projection period, at 4 percent and 7 percent, respectively. The *AEO2012* Reference case projects a 26-percent increase in residential delivered natural gas prices and a 28-percent increase in commercial prices.

6. Liquid fuels

In the *AEO2012* Reference case, the U.S. RAC for imported crude oil (in 2010 dollars) increases to $113.97 per barrel in 2015, $121.21 per barrel in 2025, and $132.95 per barrel in 2035 (Table 27). Prices are lower in the INFORUM projection, ranging from $91.78 per barrel in 2015 to $116.76 per barrel in 2035. BP, EVA, and Purvin & Gertz (P&G) did not report projections of RAC prices.

Domestic crude oil production increases from about 5.5 million barrels per day in 2010 to a peak of 6.7 million barrels per day in 2020, then declines to about 6.0 million barrels per day in 2035 in the *AEO2012* Reference case. Overall, the production level in 2035 is more than 9 percent higher than the 2010 level. The INFORUM projection shows a steady increase in production, to 5.8 million barrels per day in 2035. Domestic crude oil production decreases to 3.2 million barrels per day in 2035 in the P&G projection.

Supply from renewable sources increases to about 1.1 million barrels per day in 2015, almost 1.5 million barrels per day in 2025 (38.5 percent higher than the 2015 level), and more than 2.3 million barrels per day in 2035 (120.2 percent higher than the 2015 level) in the *AEO2012* Reference case. In the BP projection, supplies from renewable sources, on an energy-equivalent basis, increase by 49.5 percent from 2015 to 2025. BP does not report supplies from renewable sources in 2035, and it is not included in the projections by EVA, INFORUM, and P&G.

Prices for both transportation diesel fuel and gasoline increase through 2035 in the *AEO2012* projection, with diesel prices higher than gasoline prices. INFORUM projects rising gasoline prices from 2015 levels but decreasing diesel prices, with the gasoline price consistently higher than the diesel price. The BP, EVA, and P&G projections do not include delivered fuel prices.

7. Coal

Projections from EVA, IHSGI, INFORUM, IEA, ExxonMobil, and BP offer some opportunity to compare other coal outlooks with the *AEO2012* Reference case. Although many of the assumptions used in the other projections are unknown, ExxonMobil does assume a carbon tax, and EVA assumes some additional regulations affecting coal use that are not included in current laws. Such assumptions

Table 27. Comparison of liquids projections, 2015, 2025, and 2035 (million barrels per day, except where noted)

Projection	2010	*AEO2012* Reference case	Other projections			
			BP[a]	EVA	INFORUM	P&G
		2015				
Average U.S. imported RAC (2010 dollars per barrel)	75.87	113.97	--	--	91.78	--
Average WTI price (2010 dollars per barrel)	79.39	116.91	--	82.24	--	98.75
Domestic production	**7.55**	**8.71**	**8.56**	**9.60**	**--**	**7.92**
Crude oil	5.47	6.15	--	6.90	5.43	5.43
Alaska	0.60	0.46	--	0.40	--	0.54
NGL	2.07	2.56	--	2.70	--	2.49
Total net imports	**9.56**	**8.27**	**8.20**	**--**	**9.81**	**--**
Crude oil	9.17	8.52	--	--	8.59	9.69
Products	0.39	-0.25	--	--	1.22	--
Liquids consumption	19.17	19.10	18.26	--	20.04[b]	17.69
Net petroleum import share of liquids supplied (percent)	50	43	45	--	--	--
Supply from renewable sources	0.90	1.05	1.24	--	--	--
Transportation product prices (2010 dollars per gallon)						
Gasoline	2.76	3.54	--	--	3.85	--
Diesel	3.00	3.78	--	--	3.60	--

-- = not reported.
See notes at end of table.

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probably contribute to lower coal consumption levels compared with historical levels and the *AEO2012* Reference case. BP, EVA, ExxonMobil, and IHSGI have the most pessimistic views of coal use, with consumption declining over their respective projection horizons. In contrast, both the *AEO2012* and INFORUM projections show rising coal consumption after an initial decline. INFORUM's projection for coal consumption in 2035 is the highest—12 percent higher than in the *AEO2012* Reference case (Table 28).

Because most coal consumed in the United States is used for electricity generation, the outlooks with the largest declines in total coal consumption also show similar declines in coal use for electric power generation. The *AEO2012* Reference case has the most pessimistic outlook for coal consumption in the power sector in 2015; however, while coal use in the electric power sector recovers after 2015 in the *AEO2012* Reference case, it continues to decline in the EVA, IHSGI, ExxonMobil, and BP projections. ExxonMobil—which includes a carbon tax—shows the largest decline in coal use for electricity generation compared with the other projections,

Table 27. Comparison of liquids projections, 2015, 2025, and 2035 (million barrels per day, except where noted) (continued)

Projection	2010	*AEO2012* Reference case	Other projections			
			BP[a]	EVA	INFORUM	P&G
		2025				
Average U.S. imported RAC (2010 dollars per barrel)	75.87	121.21	--	--	113.35	--
Average WTI price (2010 dollars per barrel)	79.39	132.56	--	89.07	--	106.47
Domestic production	**7.55**	**9.41**	**9.20**	**11.10**	**--**	**7.37**
Crude oil	5.47	6.40	--	7.10	5.74	4.26
Alaska	0.60	0.40	--	0.00	--	0.45
NGL	2.07	3.01	--	4.00	--	3.11
Total net imports	**9.56**	**7.12**	**5.87**	**--**	**9.89**	**--**
Crude oil	9.17	7.24	--	--	8.31	10.71
Products	0.39	-0.12	--	--	1.58	--
Liquids consumption	19.17	19.20	17.30	--	20.38[b]	17.39
Net petroleum import share of liquids supplied (percent)	50	37	34	--	--	--
Supply from renewable sources	0.90	1.45	1.85	--	--	--
Transportation product prices (2010 dollars per gallon)						
Gasoline	2.76	3.85	--	--	4.36	--
Diesel	3.00	4.17	--	--	3.46	--
		2035				
Average U.S. imported RAC (2010 dollars per barrel)	75.87	132.95	--	--	116.76	--
Average WTI price (2010 dollars per barrel)	79.39	144.98	--	102.11	--	107.37
Domestic production	**7.55**	**9.00**	**--**	**--**	**--**	**--**
Crude oil	5.47	5.99	--	--	5.80	3.23
Alaska	0.60	0.27	--	--	--	0.41
NGL	2.07	3.01	--	--	--	--
Total net imports	**9.56**	**7.18**	**--**	**--**	**10.36**	**--**
Crude oil	9.17	7.52	--	--	8.49	11.68
Products	0.39	-0.34	--	--	1.88	--
Liquids consumption	19.17	19.90	--	--	21.31[b]	17.38
Net petroleum import share of liquids supplied (percent)	50	36	--	--	--	--
Supply from renewable sources	0.90	2.31	--	--	--	--
Transportation product prices (2010 dollars per gallon)						
Gasoline	2.76	4.03	--	--	4.49	--
Diesel	3.00	4.44	--	--	3.30	--

-- = not reported.

[a]For BP, liquids production data were converted from million metric tons to barrels at 8.067817 barrels per metric ton, and liquids demand data were converted at 8.162674 barrels per metric ton. One metric ton equals 1,000 kilograms.

[b]For INFORUM, liquids demand data were converted from quadrillion Btus to barrels at 187.84572 million barrels per quadrillion Btu.

and coal consumption in the BP outlook also declines from 2010 levels. The EVA projection for coal consumption in the electric power sector in 2030 is 13 percent lower than the 2010 level, whereas coal consumption returns to 2010 levels in 2030 in the *AEO2012* Reference case. The IEA projection for coal consumption in the electric power sector in 2035, at 19.2 quadrillion Btu, is similar to the *AEO2012* Reference case projection.

EVA, IHSGI, and the *AEO2012* Reference case all project declining use of coal at coking plants through 2030, with EVA including the most pessimistic outlook. INFORUM's industrial coal consumption figure, which appears to include both coking coal consumption

Table 28. Comparison of coal projections, 2015, 2025, 2030, and 2035 (million short tons, except where noted)

		AEO2012 Reference case		Other projections					
Projection	2010	(million short tons)	(quadrillion Btu)	EVA[a]	IHSGI	INFORUM	IEA[b]	Exxon-Mobil[c]	BP[b]
				(million short tons)				(quadrillion Btu)	
				2015					
Production	**1,084**	**993**	**20.24**	**1,017**	**1,144**	**970**	**--**	**--**	**22.00**
East of the Mississippi	446	407	--	411	--	--	--	--	--
West of the Mississippi	638	586	--	606	--	--	--	--	--
Consumption									
Electric power	975	839	16.15	871	1,002	--	--	17.00	18.68
Coke plants	21	22	--	20	21	--	--	--	--
Coal-to-liquids	0	0	--	--	--	--	--	--	--
Other industrial/buildings	55	53	1.66[d]	42	50	1.81[d]	--	--	--
Total consumption (quadrillion Btu)[e]	**20.76**	**--**	**17.80**	**--**	**--**	**--**	**--**	**19.00**	**20.53**
Total consumption (million short tons)	**1,051**	**914**	**--**	**933**	**1,073**	**916[f]**	**--**	**--**	**--**
Net coal exports	**64**	**95**	**2.38**	**100**	**70**	**54**	**--**	**--**	**1.48**
Exports	82	110	2.73	104	89	70	--	--	1.48
Imports	18	15	0.35	4	19	16	--	--	0.00[g]
Minemouth price									
2010 dollars per ton	35.61	42.08	--	--	--	32.80	--	--	--
2010 dollars per Btu	1.76	2.08	--	--	--	--	--	--	--
Average delivered price to electricity generators									
2010 dollars per ton	44.27	45.17	--	--	--	42.72	--	--	--
2010 dollars per Btu	2.26	2.35	--	--	2.39	--	--	--	--
				2025					
Production	**1,084**	**1,118**	**22.25**	**995**	**1,038**	**1,114**	**--**	**--**	**19.40**
East of the Mississippi	446	383	--	403	--	--	--	--	--
West of the Mississippi	638	735	--	592	--	--	--	--	--
Consumption									
Electric power	975	952	18.06	847	927	--	--	15.00	16.16
Coke plants	21	19	--	17	19	--	--	--	--
Coal-to-liquids	0	38	--	--	--	--	--	--	--
Other industrial/buildings	55	55	1.63[d]	33	39	2.07[d]	--	--	--
Total consumption (quadrillion Btu)[e]	**20.76**	**--**	**20.02**	**--**	**--**	**--**	**--**	**15.00**	**17.70**
Total consumption (million short tons)	**1,051**	**1,063**	**--**	**897**	**986**	**1,072[f]**	**--**	**--**	**--**
Net coal exports	**64**	**71**	**1.79**	**113**	**53**	**42**	**--**	**--**	**1.70**
Exports	82	115	2.82	118	73	75	--	--	1.70
Imports	18	44	1.03	4	20	33	--	--	0.00[g]
Minemouth price									
2010 dollars per ton	35.61	44.05	--	--	--	33.43	--	--	--
2010 dollars per Btu	1.76	2.23	--	--	--	--	--	--	--
Average delivered price to electricity generators									
2010 dollars per ton	44.27	48.13	--	--	--	43.58	--	--	--
2010 dollars per Btu	2.26	2.54	--	--	2.48	--	--	--	--

-- = not reported.

See notes at end of table.

(continued on next page)

Table 28. Comparison of coal projections, 2015, 2025, 2030, and 2035 (million short tons, except where noted) (continued)

		AEO2012 Reference case		Other projections					
Projection	2010	(million short tons)	(quadrillion Btu)	EVA[a]	IHSGI	INFORUM	IEA[b]	Exxon-Mobil[c]	BP[b]
				(million short tons)			(quadrillion Btu)		
				2030					
Production	**1,084**	**1,166**	**23.22**	**992**	**984**	**1,177**	**--**	**--**	**17.99**
East of the Mississippi	446	409	--	396	--	--	--	--	--
West of the Mississippi	638	757	--	596	--	--	--	--	--
Consumption									
Electric power	975	975	18.55	847	885	--	19.2	13.00	14.76
Coke plants	21	18	--	16	19	--	--	--	--
Coal-to-liquids	0	51	--	--	--	--	--	--	--
Other industrial/buildings	55	55	1.60[d]	31	35	2.37[d]	1.1[b]	--	--
Total consumption (quadrillion Btu)[e]	**20.76**	**--**	**20.59**	**--**	**--**	**--**	**--**	**13.00**	**16.18**
Total consumption (million short tons)	**1,051**	**1,099**	**--**	**894**	**938**	**1,156[f]**	**--**	**--**	**--**
Net coal exports	**64**	**83**	**2.08**	**113**	**47**	**41**	**--**	**--**	**1.81**
Exports	82	117	2.85	118	68	74	--	--	1.81
Imports	18	33	0.77	5	20	53	--	--	0.00[g]
Minemouth price									
2010 dollars per ton	35.61	47.28	--	--	--	33.21	--	--	--
2010 dollars per Btu	1.76	2.39	--	--	--	--	--	--	--
Average delivered price to electricity generators									
2010 dollars per ton	44.27	50.56	--	--	--	43.31	--	--	--
2010 dollars per Btu	2.26	2.66	--	--	2.52	--	--	--	--
				2035					
Production	**1,084**	**1,212**	**24.14**	**--**	**926**	**1,284**	**--**	**--**	**--**
East of the Mississippi	446	431	--	--	--	--	--	--	--
West of the Mississippi	638	781	--	--	--	--	--	--	--
Consumption									
Electric power	975	998	19.03	--	837	--	19.2	11.00	--
Coke plants	21	17	--	--	18	--	--	--	--
Coal-to-liquids	0	67	--	--	--	--	--	--	--
Other industrial/buildings	55	56	1.58[d]	--	31	2.70[d]	1.1	--	--
Total consumption (quadrillion Btu)[e]	**20.76**	**--**	**21.15**	**--**	**--**	**--**	**--**	**11.00**	**--**
Total consumption (million short tons)	**1,051**	**1,137**	**--**	**--**	**886**	**1,277[f]**	**--**	**--**	**--**
Net coal exports	**64**	**94**	**2.31**	**--**	**42**	**8**	**--**	**--**	**--**
Exports	82	129	3.13	--	63	71	--	--	--
Imports	18	36	0.82	--	20	64	--	--	--
Minemouth price									
2010 dollars per ton	35.61	50.52	--	--	--	33.06	--	--	--
2010 dollars per Btu	1.76	2.56	--	--	--	--	--	--	--
Average delivered price to electricity generators									
2010 dollars per ton	44.27	53.31	--	--	--	43.13	--	--	--
2010 dollars per Btu	2.26	2.80	--	--	2.54	--	--	--	--

-- = not reported.

[a]Regulations known to be accounted for in the EVA projections include MATS, CSAPR, regulations for cooling-water intake structures under Section 316(b) of the Clean Water Act, and regulations for coal combustion residuals under authority of the Resource Conservation and Recovery Act.

[b]For IEA and BP, data were converted from millions of tons oil equivalent (toe) at 39.683 million Btu per toe.

[c]ExxonMobil projections include a carbon tax.

[d]Coal consumption in quadrillion Btu. INFORUM's value appears to include coal consumption at coke plants. To facilitate comparison the *AEO2012* value also includes coal consumption at coke plants.

[e]For *AEO2012*, excludes coal converted to coal-based synthetic liquids.

[f]Calculated as consumption = (production - exports + imports).

[g]Calculated as imports = (consumption – production + exports).

and coal use at industrial steam plants, is higher than projected in the *AEO2012* Reference case. EVA and IHSGI show declines in coal use in the industrial/buildings sector (excluding the coking sector), whereas the *AEO2012* outlook is more stable. According to ExxonMobil's projection, coal is consumed only for electricity generation after 2015, as implied consumption in all other sectors drops to zero. The *AEO2012* Reference case appears to be the only projection that includes coal use in CTL production.

Only EVA provides regional production information for comparison with the *AEO2012* Reference case. Despite much lower total coal consumption than in *AEO2012*, EVA's estimate of coal production east of the Mississippi is similar to that in the *AEO2012* Reference case. The differences in coal production are primarily in basins west of the Mississippi, where *AEO2012* projects 161 million more tons of coal production in 2030 than projected by EVA.

With respect to exports, two broad consensus groups are identifiable among the projections. The most optimistic projections are EVA and *AEO2012*, which show exports remaining above 100 million tons through 2030. However, EVA and *AEO2012* do differ, in that the *AEO2012* Reference case projects stronger growth for coking coal exports, and EVA projects stronger growth for thermal coal exports. The second group of projections, including BP, INFORUM, and IHSGI, shows a less optimistic outlook for U.S. coal exports. Coal exports in 2030 in the *AEO2012* Reference case are 1.0 quadrillion Btu higher than projected by BP. If BP's average heat rate for exports is assumed to be similar to that in *AEO2012*, BP's projected coal exports in 2030 are about 70 million tons, similar to the INFORUM and IHSGI projections for the same year. IHSGI's projection of exports is the lowest of this group, peaking in 2025 and then falling to 63 million tons in 2035.

The outlook for coal imports varies considerably across the projections, with little consensus. In the EVA projection, imports drop to a negligible 4 million tons early on and remain at that level for the balance of the projection; and in the BP projection, there are no coal imports to the United States after 2015. In the IHSGI projection, coal imports vary little through 2035. In 2035, coal imports in the *AEO2012* Reference case are just over one-half those in the INFORUM outlook.

Coal price comparisons can be made only for the *AEO2012*, IHSGI, and INFORUM projections. *AEO2012* includes the highest minemouth coal prices, which rise by 42 percent from 2010 to 2035. IHSGI and the *AEO2012* Reference case do project similar delivered coal prices to the electricity sector through 2020, but after 2020 IHSGI's prices change little, whereas prices in the *AEO2012* Reference case continue to rise. The difference may indicate that IHSGI's more pessimistic coal consumption outlook has less to do with high coal prices than with other factors. Similarly, INFORUM's delivered coal price to the electricity sector falls and then remains constant at around 2015 levels through 2035, lower than the price in 2010.

Endnotes for Comparison with other projections

Links current as of June 2012

140. ExxonMobil's projection for residential consumption includes commercial consumption.

141. SEER's prices include a carbon tax.

List of acronyms

AB	Assembly Bill
AB32	California Assembly Bill 32
ACI	Activated carbon injection
AEO	*Annual Energy Outlook*
AEO2012	*Annual Energy Outlook 2012*
ANWR	Arctic National Wildlife Refuge
ARRA2009	American Recovery and Reinvestment Act of 2009
ASHRAE	American Society of Heating, Refrigerating, and Air-Conditioning Engineers
Blue Chip	Blue Chip Consensus
BTL	Biomass-to-liquids
Btu	British thermal unit
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CARB	California Air Resources Board
CBO	Congressional Budget Office
CBTL	Coal- and biomass-to-liquids
CCS	Carbon capture and storage
CHP	Combined heat and power
CI	Carbon intensity
CMM	Coal Market Module
CNG	Compressed natural gas
CO_2	Carbon dioxide
CO_2-EOR	Carbon dioxide-enhanced oil recovery
CSAPR	Cross-State Air Pollution Rule
CTL	Coal-to-liquids
DG	Distributed generation
dge	Diesel gallon equivalent
DOE	U.S. Department of Energy
DSI	Direct sorbent injection
E10	Motor gasoline blend containing up to 10 percent ethanol
E15	Motor gasoline blend containing up to 15 percent ethanol
E85	Motor fuel containing up to 85 percent ethanol
EERE	Energy Efficiency and Renewable Energy
EIA	U.S. Energy Information Administration
EIEA2008	Energy Improvement and Extension Act of 2008
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPACT05	Energy Policy Act of 2005
EUR	Estimated ultimate recovery
EV	Electric vehicle
EVA	Energy Ventures Analysis
FEMP	Federal Energy Management Program
FFV	Flex-fuel vehicle
FGD	Flue gas desulfurization
GDP	Gross domestic product
GHG	Greenhouse gas
GTL	Gas-to-liquids
GVWR	Gross vehicle weight rating
HAP	Hazardous air pollutant
HB	House Bill
HCl	Hydrogen chloride
HD	Heavy-duty
HDV	Heavy-duty vehicle
HEV	Hybrid electric vehicle
Hg	Mercury
ICE	Internal combustion engine
IDM	Industrial Demand Module
IEA	International Energy Agency
IECC2006	2006 International Energy Conversion Code
IEM	International Energy Module
IHSGI	IHS Global Insight
INFORUM	Interindustry Forecasting Project at the University of Maryland
IOU	Invester-owned utility
IREC	Interstate Renewable Energy Council
ITC	Investment tax credit
LCFS	Low Carbon Fuel Standard
LDV	Light-duty vehicle
LED	Light-emitting diode
LFMM	Liquid Fuels Market Module
LNG	Liquefied natural gas
MATS	Mercury and Air Toxics Standards
MAM	Macroeconomic Activity Module
mmt	Million metric tons
$MMTCO_2e$	Million metric tons carbon dioxide equivalent
mpg	Miles per gallon
MSRP	Manufacturer's suggested retail price
MY	Model year
NAICS	North American Industry Classification System
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NGL	Natural gas liquids
NGPL	Natural gas plant liquids
NGTDM	Natural Gas Transmission and Distribution Module
NGV	Natural gas vehicle
NHTSA	National Highway Traffic Safety Administration
NO_x	Nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
OECD	Organization for Economic Cooperation and Development
OMB	Office of Management and Budget
OPEC	Organization of the Petroleum Exporting Countries
P&G	Purvin & Gertz
PADD	Petroleum Administration for Defense District
PCs	Personal computers
PHEV	Plug-in hybrid electric vehicle
PM	Particulate matter
$PM_{2.5}$	Particulate matter less than 2.5 microns diameter
PMM	Petroleum Market Module
PTC	Production tax credit
PV	Solar photovoltaic
RAC	U.S. Refiner Acquisition Cost
RECS	Residential Energy Consumption Survey
RFM	Renewable Fuels Module
RFS	Renewable fuel standard
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable portfolio standard
SB	Senate Bill
SCR	Selective catalytic reduction
SEER	Strategic Energy and Economic Research, Inc.
SEIA	Solar Energy Industries Association
SNCR	Selective noncatalytic reduction
SO_2	Sulfur dioxide
STEO	Short-Term Energy Outlook
TAPS	Trans-Alaska Pipeline System
TRR	Technically recoverable resource
UEC	Unit energy consumption
UPS	Uninterruptible power supply
USGS	United States Geological Survey
VIUS	Vehicle Inventory and Use Survey
VMT	Vehicle miles traveled
WTI	West Texas Intermediate

Notes and sources

Table notes and sources

Table 1. HD National Program vehicle regulatory categories: U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles: Final Rule," *Federal Register*, Vol. 76, No. 179 (Washington, DC: September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.

Table 2. HD National Program standards for combination tractor greenhouse gas emissions and fuel consumption: U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, *Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles*, 49 CFR Parts 523, 534, and 535, RIN 2060-AP61; 2127-AK74, Federal Register Notice Vol. 76, No. 179, Thursday, September 15, 2011.

Table 3. HD National Program standards for vocational vehicle greenhouse gas emissions and fuel consumption: U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, *Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles*, 49 CFR Parts 523, 534, and 535, RIN 2060-AP61; 2127-AK74, Federal Register Notice Vol. 76, No. 179, Thursday, September 15, 2011.

Table 4. Renewable portfolio standards in the 30 States with current mandates: U.S. Energy Information Administration, Office of Energy Analysis. Based on a review of enabling legislation and regulatory actions from the various States of policies identified by the Database of States Incentives for Renewable Energy as of January 1, 2012, website www.dsireuse.org.

Table 5. Key analyses of interest from "Issues in focus" in recent *AEO*s: U.S. Energy Information Administration, *Annual Energy Outlook 2011*, DOE/EIA-0383(2011) (Washington, DC, April 2011); U.S. Energy Information Administration, *Annual Energy Outlook 2010*, DOE/EIA-0383(2010) (Washington, DC, April 2010); and U.S. Energy Information Administration, *Annual Energy Outlook 2009*, DOE/EIA-0383(2009) (Washington, DC, March 2009).

Table 6. Key assumptions for the residential sector in the *AEO2012* Integrated Demand Technology case: Projections: AEO2012 National Energy Modeling System, runs FROZTECH.D030812A, HIGHTECH.D032812A, and BESTTECH.D032812A.

Table 7. Key assumptions for the commercial sector in the *AEO2012* Integrated Demand Technology case: Projections: AEO2012 National Energy Modeling System, runs FROZTECH.D030812A, HIGHTECH.D032812A, and BESTTECH.D032812A.

Table 8. Estimated average fuel economy and greenhouse gas emissions standards proposed for light-duty vehicles, model years 2017-2025: U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards: Proposed Rule," *Federal Register*, Vol. 76, No. 231 (Washington, DC: December 1, 2011), website www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/2017-25_CAFE_NPRM.pdf.

Table 9. Vehicle types that do not rely solely on a gasoline internal combustion engine for motive and accessory power: U.S. Energy Information Administration, Office of Energy Analysis.

Table 10. Description of battery-powered electric vehicles: U.S. Energy Information Administration, Office of Energy Analysis.

Table 11. Comparison of operating and incremental costs of battery electric vehicles and conventional gasoline vehicles: U.S. Energy Information Administration, Office of Energy Analysis.

Table 12. Summary of key results from the Reference, High Nuclear, and Low Nuclear cases, 2010-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384 (Washington, DC, October 2011). **Projections:** AEO2012 National Energy Modeling System, runs REF2012.D020112C, HINUC12.D022312A and LOWNUC12.D022312b.

Table 13. Alaska North Slope wells completed during 2010 in selected oil fields: Alaska Oil and Gas Conservation Commission, Public Databases Website at doa.alaska.gov/ogc/publicdb.html. The North Slope well total includes exploration wells, water disposal wells, service wells, etc. The Alpine field is the primary field within the Colville River Unit.

Table 14. Unproved technically recoverable resource assumption by basin: U.S. Energy Information Administration, Office of Energy Analysis.

Table 15. *AEO2012* unproved technically recoverable resources for selected shale gas plays as of January 1, 2010: U.S. Energy Information Administration, Office of Energy Analysis. **Note:** Average well spacing, percent of area untested, and percent of area with potential have been rounded to the nearest unit.

Table 16. *AEO2012* unproved technically recoverable tight oil resources as of January 1, 2010: U.S. Energy Information Administration, Office of Energy Analysis. **Note:** Average well spacing, percent of area untested, and percent of area with potential have been rounded to the nearest unit.

Table 17. Estimated ultimate recovery for selected shale gas plays in three *AEO*s: Projections: AEO2012 National Energy Modeling System, runs REF2012.D020112C, AEO2011 National Energy Modeling System, runs REF2011.D0209A, and AEO2010 National Energy Modeling System, runs REF2010.D111809A.

Table 18. Petroleum supply, consumption, and prices in four cases, 2020 and 2035: History: Crude oil lower 48 average wellhead prices: U.S. Energy Information Administration, *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). Lower 48 onshore, lower 48 offshore, and Alaska crude oil production: U.S. Energy Information Administration, *Petroleum Supply Annual 2010*, DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). **Projections:** AE02012 National Energy Modeling System, runs REF2012.D020112C, REF2012.LEUR12.D022112A, REF2012.HEUR12.D022112A, and HTRR12.D050412A.

Table 19. Natural gas prices, supply, and consumption in four cases, 2020 and 2035: History: Alaska and Lower 48 natural gas production, net imports, and other consumption: U.S. Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). Other production: U.S. Energy Information Administration, Office of Energy Analysis. Consumption by sector based on: U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). Henry Hub natural gas prices: U.S. Energy Information Administration, Short-Term Energy Outlook Query System, Monthly Natural Gas Data, Variable NGHHUUS. **Projections:** AE02012 National Energy Modeling System, runs REF2012.D020112C, REF2012.LEUR12.D022112A, REF2012.HEUR12.D022112A, and HTRR12.D050412A.

Table 20. Marcellus unproved technically recoverable resources in *AEO2012* (as of January 1, 2010): U.S. Energy Information Administration, Office of Energy Analysis. **Note:** Average well spacing, percent of area untested, and percent of area with potential have been rounded to the nearest unit.

Table 21. Marcellus unproved technically recoverable resources: *AE02011*, USGS 2011, and *AE02012*: Projections: *AE02011*: AE02011 National Energy Modeling System, run REF2011.D0209A; USGS 2011: USGS 2011 Open-File Report 2011-1298, website pubs.usgs.gov/of/2011/1298; and Fact Sheet 2011-3092, website pubs.usgs.gov/fs/2011/3092; *AE02012*: AE02012 National Energy Modeling System, run REF2012.D020112C. **Note:** Average well spacing, percent of area untested, and percent of area with potential have been rounded to the nearest unit.

Table 22. Projections of average annual economic growth, 2010-2035: *AEO2012* (Reference case): AEO2012 National Energy Modeling System, run AEO2012.REF2012.D020112C. ***AEO2011* (Reference case):** AEO2011 National Energy Modeling System, run AEO2011.REF2011.D020911A. **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2011), website www.ihs.com/products/global-insight/index.aspx (subscription site). **OMB:** Office of Management and Budget, *Fiscal Year 2013 Budget of the U.S. Government* (Washington, DC, February 13, 2012), website www.whitehouse.gov/sites/default/files/omb/budget/fy2013/assets/budget.pdf. **CBO:** Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2012 to 2022* (Washington, DC, January 31, 2012), website www.cbo.gov/publication/42905. **INFORUM:** "Inforum Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, February 2012), website inforumweb.umd.edu/services/models/lift.html. **SSA:** Social Security Administration, *The 2011 Annual Report of the Board of Trustees of the Federal Old-Age And Survivors Insurance And Federal Disability Insurance Trust Funds* (U.S. Government Printing Office: Washington, DC, May 13, 2011), website www.ssa.gov/OACT/TR/2011/tr2011.pdf. **IEA (2011):** International Energy Agency, *World Energy Outlook 2011* (Paris, France, November 2011), website www.worldenergyoutlook.org. **Blue Chip Consensus:** *Blue Chip Economic Indicators* (Aspen Publishers, October 2011), website www.aspenpublishers.com/Topics/Banking-Law-Finance-Economic-Forecast/. **ExxonMobil:** ExxonMobil Corporation, *The Outlook for Energy: A View to 2040* (Irving, TX, 2012), website www.exxonmobil.com/Corporate/energy_outlook.aspx. **SEER:** Strategic Energy and Economic Research, Inc., e-mail from Ron Denhardt (February 21, 2012).

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Figure 72. Primary energy use by end-use sector, 2010-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 73. Primary energy use by fuel, 1980-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 74. Residential delivered energy intensity in four cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** AEO2012 National Energy Modeling System, runs REF2012.D020112C, FROZTECH.D030812A, BESTTECH.D032812A, and HIGHTECH.D032812A.

Figure 75. Change in residential electricity consumption for selected end uses in the Reference case, 2010-2035: AEO2012 National Energy Modeling System, run REF2012.D020112C.

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Figure 84. Cumulative growth in value of shipments from energy-intensive industries in three cases, 2010-2035: AEO2012 National Energy Modeling System, runs REF2012.D020112C, HM2012.D022412A, and LM2012.D022412A.

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Figure 89. Average fuel economy of new light-duty vehicles in two cases, 1980-2035: History: Oak Ridge National Laboratory, *Transportation Energy Data Book*, Edition 30 and Annual (Oak Ridge, TN: 2011). **Projections:** AE02012 National Energy Modeling System, runs REF2012.D020112C and CAFEY.D032112A.

Figure 90. Vehicle miles traveled per licensed driver, 1970-2035: History: Derived from U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics 2010* (Washington, DC: 2012), website www.fhwa.dot.gov/policyinformation/statistics/2010. **Projections:** AE02012 National Energy Modeling System, run REF2012.D020112C.

Figure 91. Sales of light-duty vehicles using non-gasoline technologies by fuel type, 2010, 2020, and 2035: AEO2012 National Energy Modeling System, runs REF2012.D020112C.

Figure 92. Heavy-duty vehicle energy consumption, 1995-2035: History: Derived from U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC: October 2011); and Oak Ridge National Laboratory, *Transportation Energy Data Book*, Edition 30 and Annual (Oak Ridge, TN: 2011); and U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics 2010* (Washington, DC: 2012), website www.fhwa.dot.gov/policyinformation/statistics/2010. **Projections:** AE02012 National Energy Modeling System, run REF2012.D020112C.

Figure 93. U.S. electricity demand growth, 1950-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** AEO2012 National Energy Modeling System, runs REF2012.D020112C.

Figure 94. Electricity generation by fuel, 2010, 2020, and 2035: AEO2012 National Energy Modeling System, runs REF2012.D020112C.

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Figure 96. Additions to electricity generation capacity, 1985-2035: History: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report." **Projections:** AEO2012 National Energy Modeling System, runs REF2012.D020112C.

Figure 97. Electricity sales and power sector generating capacity, 1949-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 98. Levelized electricity costs for new power plants, excluding subsidies, 2020 and 2035: AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 99. Electricity generating capacity at U.S. nuclear power plants in three cases, 2010, 2025, and 2035: AEO2012 National Energy Modeling System, runs REF2012.D020112C, LM2012.D022412A, and HM2012.D022412A.

Figure 100. Nonhydropower renewable electricity generation capacity by energy source, including end-use capacity, 2010-2035: AEO2012 National Energy Modeling System, runs REF2012.D020112.

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Figure 103. Annual average Henry Hub spot natural gas prices, 1990-2035: History: U.S. Energy Information Administration, *Short-Term Energy Outlook* Query System, Monthly Natural Gas Data, Variable NGHHUUS. **Projections:** AE02012 National Energy Modeling System, run REF2012.D020112C.

Figure 104. Ratio of low-sulfur light crude oil price to Henry Hub natural gas price on an energy equivalent basis, 1990-2035: History: U.S. Energy Information Administration, *Short-Term Energy Outlook* Query System, Monthly Natural Gas Data, Variable NGHHUUS, and U.S. Energy Information Administration, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." **Projections:** AE02012 National Energy Modeling System, run REF2012.D020112C.

Figure 105. Annual average Henry Hub spot natural gas prices in seven cases, 1990-2035: History: U.S. Energy Information Administration, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). **Projections:** AEO2012 National Energy Modeling System, runs REF2012.D020112C, REF2012.HEUR12.D022112A, REF2012.LEUR12.D022112A, LM2012.D022412A, and HM2012.D022412A.

Figure 106. Natural gas production, consumption, and net imports, 1990-2035: History: U.S. Energy Information Administration, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). **Projections:** AEO2012 National Energy Modeling System, runs REF2012.D020112C.

Figure 107. Natural gas production by source, 1990-2035: History: U.S. Energy Information Administration, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). **Projections:** AEO2012 National Energy Modeling System, runs REF2012.D020112C.

Figure 108. Lower 48 onshore natural gas production by region, 2010 and 2035: AEO2012 National Energy Modeling System, runs REF2012.D020112C.

Figure 109. U.S. net imports of natural gas by source, 1990-2035: History: U.S. Energy Information Administration, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). **Projections:** AEO2012 National Energy Modeling System, runs REF2012.D020112C.

Figure 110. Consumption of petroleum and other liquids by sector, 1990-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 111. U.S. production of petroleum and other liquids by source, 2010-2035: AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 112. Domestic crude oil production by source, 1990-2035: History: U.S. Energy Information Administration, *Petroleum Supply Annual 2010*, DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). **Projections:** AE02012 National Energy Modeling System, run REF2012.D020112C.

Figure 113. Total U.S. crude oil production in six cases, 1990-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C, LP2012.D022112A, HP2012.D022112A, REF2012.HEUR12.D022112A, REF2012.LEUR.D022112A, and HTRR12.D050412A.

Figure 114. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C, LP2012.D022112A, and HP2012.D022112A.

Figure 115. EISA2007 RFS credits earned in selected years, 2010-2035: AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 116. U.S. ethanol use in blended gasoline and E85, 2000-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 117. U.S. motor gasoline and diesel fuel consumption, 2000-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 118. Coal production by region, 1970-2035: History (short tons): 1970-1990: U.S. Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 2002). **1991-2000:** U.S. Energy Information Administration, *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2010:** U.S. Energy Information Administration, *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011), and previous issues. **History (conversion to quadrillion Btu): 1970-2010: Estimation Procedure:** Estimates of average heat content by region and year are based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu, published in EIA's *Annual Energy Review*. **Sources:** U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Annual Coal Production and Preparation Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; Form EIA-923, "Power Plant Operations Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C. Note: For 1989-2035, coal production includes waste coal.

Figure 119. U.S. total coal production in six cases, 2010, 2020, and 2035: AEO2012 National Energy Modeling System, run REF2012.D020112C, LCCST12.D031312A, HP2012.D022112A, HM2012.D022412A, LM2012.D022412A, and CO2FEE15.D031312A. **Note:** Coal production includes waste coal.

Figure 120. Average annual minemouth coal prices by region, 1990-2035: History (dollars per short ton): 1990-2000: U.S. Energy Information Administration, *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2010:** U.S. Energy Information Administration, *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011), and previous issues. **History (conversion to dollars per million Btu): 1970-2009: Estimation Procedure:** Estimates of average heat content by region and year based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu published in EIA's *Annual Energy Review*. **Sources:** U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Annual Coal Production and Preparation Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; and Form EIA-920, "Combined Heat and Power Plant

Report"; Form EIA-923, "Power Plant Operations Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C. **Note:** Includes reported prices for both open-market and captive mines.

Figure 121. Cumulative coal-fired generating capacity additions by sector in two cases, 2011-2035: AEO2012 National Energy Modeling System, run REF2012.D020112C and NOGHGCONCERN.D031212A.

Figure 122. U.S. energy-related carbon dioxide emissions by sector and fuel, 2005 and 2035: AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 123. Sulfur dioxide emissions from electricity generation, 1990-2035: 1990, 2000, 2005: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA-454/R-00-002 (Washington, DC, March 2000); U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, website ampd.epa.gov/ampd/. **2010 and Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C.

Figure 124. Nitrogen oxide emissions from electricity generation, 1990-2035: History: 1990, 2000, 2005: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA-454/R-00-002 (Washington, DC, March 2000); U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, website ampd.epa.gov/ampd/. **2010 and Projections:** AEO2012 National Energy Modeling System, run REF2012.D020112C.

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Reference case

Table A1. Total energy supply, disposition, and price summary

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Production								
Crude oil and lease condensate	11.35	11.59	13.23	14.40	13.77	13.71	12.89	0.4%
Natural gas plant liquids	2.57	2.78	3.33	3.79	3.93	3.98	3.94	1.4%
Dry natural gas	21.09	22.10	24.22	25.69	26.91	27.58	28.60	1.0%
Coal[1]	21.63	22.06	20.24	20.74	22.25	23.22	24.14	0.4%
Nuclear / uranium[2]	8.36	8.44	8.68	9.28	9.60	9.56	9.28	0.4%
Hydropower	2.67	2.51	2.90	2.95	2.99	3.02	3.04	0.8%
Biomass[3]	3.72	4.05	4.45	5.26	6.26	7.60	9.07	3.3%
Other renewable energy[4]	1.11	1.34	1.99	2.04	2.22	2.41	2.81	3.0%
Other[5]	0.47	0.64	0.60	0.64	0.69	0.79	0.91	1.4%
Total	**72.97**	**75.50**	**79.64**	**84.80**	**88.61**	**91.87**	**94.67**	**0.9%**
Imports								
Crude oil	19.70	20.14	18.87	16.00	16.23	16.04	16.90	-0.7%
Liquid fuels and other petroleum[6]	5.40	5.02	4.32	4.03	4.08	4.04	4.14	-0.8%
Natural gas[7]	3.85	3.81	3.73	3.49	2.75	3.00	2.84	-1.2%
Other imports[8]	0.61	0.52	0.44	0.72	1.07	0.78	0.81	1.8%
Total	**29.56**	**29.49**	**27.37**	**24.25**	**24.14**	**23.86**	**24.69**	**-0.7%**
Exports								
Liquid fuels and other petroleum[9]	4.20	4.81	5.00	4.39	4.46	4.67	4.95	0.1%
Natural gas[10]	1.08	1.15	1.93	3.09	3.51	3.86	4.17	5.3%
Coal	1.51	2.10	2.73	2.36	2.82	2.85	3.13	1.6%
Total	**6.79**	**8.06**	**9.66**	**9.84**	**10.79**	**11.38**	**12.25**	**1.7%**
Discrepancy[11]	**1.04**	**-1.23**	**-0.08**	**-0.10**	**-0.03**	**0.04**	**0.18**	**- -**
Consumption								
Liquid fuels and other petroleum[12]	36.50	37.25	36.72	36.38	36.58	36.99	37.70	0.0%
Natural gas	23.43	24.71	26.00	26.07	26.14	26.72	27.26	0.4%
Coal[13]	19.62	20.76	17.80	18.73	20.02	20.59	21.15	0.1%
Nuclear / uranium[2]	8.36	8.44	8.68	9.28	9.60	9.56	9.28	0.4%
Hydropower	2.67	2.51	2.90	2.95	2.99	3.02	3.04	0.8%
Biomass[14]	2.72	2.88	3.04	3.58	4.17	4.78	5.44	2.6%
Other renewable energy[4]	1.11	1.34	1.99	2.04	2.22	2.41	2.81	3.0%
Other[15]	0.32	0.29	0.30	0.29	0.28	0.25	0.24	-0.6%
Total	**94.71**	**98.16**	**97.43**	**99.32**	**101.99**	**104.32**	**106.93**	**0.3%**
Prices (2010 dollars per unit)								
Petroleum (dollars per barrel)								
Low sulfur light crude oil	62.37	79.39	116.91	126.68	132.56	138.49	144.98	2.4%
Imported crude oil[16]	59.72	75.87	113.97	115.74	121.21	126.51	132.95	2.3%
Natural gas (dollars per million Btu)								
at Henry hub	4.00	4.39	4.29	4.58	5.63	6.29	7.37	2.1%
at the wellhead[17]	3.75	4.06	3.84	4.10	5.00	5.56	6.48	1.9%
Natural gas (dollars per thousand cubic feet)								
at the wellhead[17]	3.85	4.16	3.94	4.19	5.12	5.69	6.64	1.9%
Coal (dollars per ton)								
at the minemouth[18]	33.62	35.61	42.08	40.96	44.05	47.28	50.52	1.4%
Coal (dollars per million Btu)								
at the minemouth[18]	1.68	1.76	2.08	2.06	2.23	2.39	2.56	1.5%
Average end-use[19]	2.32	2.38	2.56	2.58	2.70	2.81	2.94	0.9%
Average electricity (cents per kilowatthour)	9.9	9.8	9.7	9.6	9.7	9.8	10.1	0.1%

Table A1. Total energy supply, disposition, and price summary (continued)

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Prices (nominal dollars per unit)								
Petroleum (dollars per barrel)								
Low sulfur light crude oil	61.65	79.39	125.97	148.87	170.09	197.10	229.55	4.3%
Imported crude oil[16]	59.04	75.87	122.81	136.02	155.52	180.06	210.51	4.2%
Natural gas (dollars per million Btu)								
at Henry hub	3.95	4.39	4.62	5.39	7.23	8.95	11.67	4.0%
at the wellhead[17]	3.71	4.06	4.14	4.81	6.42	7.92	10.26	3.8%
Natural gas (dollars per thousand cubic feet)								
at the wellhead[17]	3.80	4.16	4.24	4.93	6.57	8.11	10.51	3.8%
Coal (dollars per ton)								
at the minemouth[18]	33.24	35.61	45.34	48.13	56.52	67.28	80.00	3.3%
Coal (dollars per million Btu)								
at the minemouth[18]	1.66	1.76	2.24	2.42	2.86	3.41	4.05	3.4%
Average end-use[19]	2.30	2.38	2.76	3.03	3.47	4.01	4.66	2.7%
Average electricity (cents per kilowatthour)	9.8	9.8	10.4	11.3	12.5	13.9	16.0	2.0%

[1]Includes waste coal.

[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.

[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.

[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.

[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.

[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.

[7]Includes imports of liquefied natural gas that is later re-exported.

[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.

[9]Includes crude oil, petroleum products, ethanol, and biodiesel.

[10]Includes re-exported liquefied natural gas.

[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.

[12]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.

[13]Excludes coal converted to coal-based synthetic liquids and natural gas.

[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.

[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.

[16]Weighted average price delivered to U.S. refiners.

[17]Represents lower 48 onshore and offshore supplies.

[18]Includes reported prices for both open market and captive mines.

[19]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.

Btu = British thermal unit.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 natural gas wellhead price: U.S. Department of the Interior, Office of Natural Resources Revenue; and EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2009 and 2010 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011). 2010 petroleum supply values and 2009 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). Other 2009 petroleum supply values: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). 2009 and 2010 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2009 and 2010 coal values: *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011). Other 2009 and 2010 values: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A2. Energy consumption by sector and source

(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Energy consumption								
Residential								
Liquefied petroleum gases	0.51	0.56	0.51	0.50	0.50	0.51	0.51	-0.4%
Kerosene	0.03	0.03	0.02	0.02	0.02	0.02	0.02	-1.7%
Distillate fuel oil	0.60	0.63	0.55	0.48	0.43	0.38	0.35	-2.3%
Liquid fuels and other petroleum subtotal	1.14	1.22	1.08	1.01	0.95	0.91	0.87	-1.3%
Natural gas	4.90	5.06	4.97	4.95	4.88	4.84	4.76	-0.2%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-1.1%
Renewable energy[1]	0.43	0.42	0.43	0.43	0.43	0.43	0.43	0.1%
Electricity	4.66	4.95	4.75	4.96	5.23	5.55	5.86	0.7%
Delivered energy	**11.13**	**11.66**	**11.24**	**11.36**	**11.51**	**11.73**	**11.93**	**0.1%**
Electricity related losses	9.80	10.39	9.58	10.01	10.52	10.95	11.35	0.4%
Total	**20.93**	**22.05**	**20.81**	**21.36**	**22.02**	**22.68**	**23.28**	**0.2%**
Commercial								
Liquefied petroleum gases	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.3%
Motor gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.4%
Kerosene	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.7%
Distillate fuel oil	0.41	0.43	0.35	0.34	0.33	0.33	0.32	-1.2%
Residual fuel oil	0.08	0.08	0.08	0.08	0.08	0.08	0.08	-0.0%
Liquid fuels and other petroleum subtotal	0.68	0.72	0.62	0.62	0.62	0.62	0.62	-0.5%
Natural gas	3.20	3.28	3.41	3.51	3.53	3.60	3.69	0.5%
Coal	0.07	0.06	0.06	0.06	0.06	0.06	0.06	-0.0%
Renewable energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.0%
Electricity	4.46	4.54	4.59	4.88	5.16	5.48	5.80	1.0%
Delivered energy	**8.51**	**8.70**	**8.80**	**9.18**	**9.48**	**9.87**	**10.28**	**0.7%**
Electricity related losses	9.39	9.52	9.27	9.85	10.38	10.82	11.23	0.7%
Total	**17.90**	**18.22**	**18.06**	**19.03**	**19.86**	**20.69**	**21.50**	**0.7%**
Industrial[4]								
Liquefied petroleum gases	2.00	2.00	1.83	2.06	2.17	2.18	2.15	0.3%
Motor gasoline[2]	0.24	0.25	0.28	0.30	0.30	0.30	0.30	0.8%
Distillate fuel oil	1.11	1.16	1.25	1.18	1.19	1.17	1.18	0.1%
Residual fuel oil	0.11	0.12	0.09	0.08	0.08	0.08	0.08	-1.3%
Petrochemical feedstocks	0.90	0.94	1.01	1.20	1.29	1.31	1.30	1.3%
Other petroleum[5]	3.57	3.59	3.44	3.18	3.11	3.09	3.19	-0.5%
Liquid fuels and other petroleum subtotal	7.93	8.05	7.89	7.99	8.13	8.13	8.21	0.1%
Natural gas	6.32	6.76	7.19	7.26	7.32	7.21	7.18	0.2%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[6]	1.31	1.37	1.43	1.55	1.57	1.59	1.63	0.7%
Natural gas subtotal	7.63	8.14	8.62	8.80	8.89	8.80	8.81	0.3%
Metallurgical coal	0.40	0.55	0.57	0.48	0.49	0.46	0.43	-1.0%
Other industrial coal	0.94	1.01	1.03	1.04	1.08	1.08	1.08	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.26	0.36	0.48	0.60	- -
Net coal coke imports	-0.02	-0.01	-0.01	-0.02	-0.03	-0.04	-0.06	9.3%
Coal subtotal	1.32	1.56	1.59	1.76	1.90	1.98	2.06	1.1%
Biofuels heat and coproducts	0.82	0.84	0.81	0.96	1.27	1.92	2.57	4.6%
Renewable energy[7]	1.37	1.50	1.61	1.67	1.82	1.87	1.95	1.1%
Electricity	3.13	3.28	3.44	3.46	3.52	3.44	3.33	0.1%
Delivered energy	**22.20**	**23.37**	**23.96**	**24.64**	**25.53**	**26.14**	**26.94**	**0.6%**
Electricity related losses	6.59	6.89	6.94	6.97	7.09	6.80	6.46	-0.3%
Total	**28.79**	**30.26**	**30.90**	**31.61**	**32.61**	**32.93**	**33.39**	**0.4%**

Table A2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Transportation								
Liquefied petroleum gases	0.05	0.04	0.04	0.04	0.04	0.05	0.05	0.5%
E85[8]	0.00	0.00	0.01	0.13	0.30	0.72	1.22	27.0%
Motor gasoline[2]	16.84	16.91	16.13	15.31	14.90	14.69	14.53	-0.6%
Jet fuel[9]	2.98	3.07	3.03	3.09	3.19	3.27	3.33	0.3%
Distillate fuel oil[10]	5.53	5.77	6.55	6.80	7.03	7.20	7.44	1.0%
Residual fuel oil	0.81	0.90	0.91	0.92	0.93	0.93	0.94	0.2%
Other petroleum[11]	0.16	0.17	0.17	0.17	0.17	0.17	0.17	0.0%
Liquid fuels and other petroleum subtotal	26.36	26.88	26.83	26.46	26.57	27.02	27.67	0.1%
Pipeline fuel natural gas	0.61	0.65	0.68	0.67	0.67	0.68	0.69	0.2%
Compressed / liquefied natural gas	0.04	0.04	0.06	0.09	0.11	0.14	0.16	5.7%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	0.02	0.02	0.03	0.03	0.04	0.06	0.07	4.8%
Delivered energy	**27.04**	**27.59**	**27.60**	**27.25**	**27.40**	**27.90**	**28.60**	**0.1%**
Electricity related losses	0.05	0.05	0.05	0.06	0.08	0.11	0.14	4.5%
Total	**27.09**	**27.63**	**27.65**	**27.32**	**27.49**	**28.01**	**28.75**	**0.2%**
Delivered energy consumption for all sectors								
Liquefied petroleum gases	2.69	2.75	2.51	2.74	2.86	2.88	2.86	0.2%
E85[8]	0.00	0.00	0.01	0.13	0.30	0.72	1.22	27.0%
Motor gasoline[2]	17.13	17.21	16.46	15.66	15.25	15.04	14.88	-0.6%
Jet fuel[9]	2.98	3.07	3.03	3.09	3.19	3.27	3.33	0.3%
Kerosene	0.04	0.04	0.03	0.03	0.03	0.03	0.03	-1.2%
Distillate fuel oil	7.65	7.99	8.69	8.81	8.99	9.08	9.29	0.6%
Residual fuel oil	0.99	1.11	1.08	1.08	1.09	1.09	1.11	0.0%
Petrochemical feedstocks	0.90	0.94	1.01	1.20	1.29	1.31	1.30	1.3%
Other petroleum[12]	3.72	3.76	3.61	3.34	3.27	3.26	3.36	-0.4%
Liquid fuels and other petroleum subtotal	36.10	36.87	36.43	36.08	36.28	36.68	37.38	0.1%
Natural gas	14.46	15.15	15.64	15.81	15.85	15.79	15.79	0.2%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[6]	1.31	1.37	1.43	1.55	1.57	1.59	1.63	0.7%
Pipeline natural gas	0.61	0.65	0.68	0.67	0.67	0.68	0.69	0.2%
Natural gas subtotal	16.38	17.17	17.75	18.03	18.09	18.06	18.11	0.2%
Metallurgical coal	0.40	0.55	0.57	0.48	0.49	0.46	0.43	-1.0%
Other coal	1.01	1.08	1.09	1.10	1.14	1.14	1.15	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.26	0.36	0.48	0.60	- -
Net coal coke imports	-0.02	-0.01	-0.01	-0.02	-0.03	-0.04	-0.06	9.3%
Coal subtotal	1.39	1.62	1.65	1.82	1.96	2.04	2.12	1.1%
Biofuels heat and coproducts	0.82	0.84	0.81	0.96	1.27	1.92	2.57	4.6%
Renewable energy[13]	1.91	2.03	2.15	2.21	2.36	2.41	2.50	0.8%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	12.27	12.79	12.81	13.33	13.96	14.53	15.06	0.7%
Delivered energy	**68.87**	**71.32**	**71.59**	**72.43**	**73.92**	**75.64**	**77.75**	**0.3%**
Electricity related losses	25.83	26.84	25.84	26.89	28.07	28.67	29.18	0.3%
Total	**94.71**	**98.16**	**97.43**	**99.32**	**101.99**	**104.32**	**106.93**	**0.3%**
Electric power[14]								
Distillate fuel oil	0.07	0.08	0.08	0.09	0.09	0.09	0.09	0.5%
Residual fuel oil	0.32	0.30	0.21	0.21	0.22	0.22	0.23	-1.1%
Liquid fuels and other petroleum subtotal	0.39	0.38	0.29	0.30	0.31	0.31	0.32	-0.7%
Natural gas	7.04	7.54	8.25	8.05	8.04	8.66	9.16	0.8%
Steam coal	18.23	19.13	16.15	16.91	18.06	18.55	19.03	-0.0%
Nuclear / uranium[15]	8.36	8.44	8.68	9.28	9.60	9.56	9.28	0.4%
Renewable energy[16]	3.77	3.85	4.96	5.40	5.75	5.87	6.22	1.9%
Electricity imports	0.12	0.09	0.10	0.09	0.08	0.05	0.04	-2.9%
Total[17]	**38.10**	**39.63**	**38.64**	**40.22**	**42.03**	**43.20**	**44.24**	**0.4%**

Table A2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Total energy consumption								
Liquefied petroleum gases	2.69	2.75	2.51	2.74	2.86	2.88	2.86	0.2%
E85[8]	0.00	0.00	0.01	0.13	0.30	0.72	1.22	27.0%
Motor gasoline[2]	17.13	17.21	16.46	15.66	15.25	15.04	14.88	-0.6%
Jet fuel[9]	2.98	3.07	3.03	3.09	3.19	3.27	3.33	0.3%
Kerosene	0.04	0.04	0.03	0.03	0.03	0.03	0.03	-1.2%
Distillate fuel oil	7.72	8.07	8.78	8.89	9.07	9.17	9.38	0.6%
Residual fuel oil	1.32	1.41	1.29	1.29	1.31	1.32	1.34	-0.2%
Petrochemical feedstocks	0.90	0.94	1.01	1.20	1.29	1.31	1.30	1.3%
Other petroleum[12]	3.72	3.76	3.61	3.34	3.27	3.26	3.36	-0.4%
Liquid fuels and other petroleum subtotal	36.50	37.25	36.72	36.38	36.58	36.99	37.70	0.0%
Natural gas	21.51	22.69	23.89	23.85	23.89	24.45	24.94	0.4%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[6]	1.31	1.37	1.43	1.55	1.57	1.59	1.63	0.7%
Pipeline natural gas	0.61	0.65	0.68	0.67	0.67	0.68	0.69	0.2%
Natural gas subtotal	23.43	24.71	26.00	26.07	26.14	26.72	27.26	0.4%
Metallurgical coal	0.40	0.55	0.57	0.48	0.49	0.46	0.43	-1.0%
Other coal	19.23	20.21	17.24	18.01	19.20	19.69	20.18	-0.0%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.26	0.36	0.48	0.60	- -
Net coal coke imports	-0.02	-0.01	-0.01	-0.02	-0.03	-0.04	-0.06	9.3%
Coal subtotal	19.62	20.76	17.80	18.73	20.02	20.59	21.15	0.1%
Nuclear / uranium[15]	8.36	8.44	8.68	9.28	9.60	9.56	9.28	0.4%
Biofuels heat and coproducts	0.82	0.84	0.81	0.96	1.27	1.92	2.57	4.6%
Renewable energy[18]	5.68	5.88	7.11	7.61	8.11	8.29	8.71	1.6%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity imports	0.12	0.09	0.10	0.09	0.08	0.05	0.04	-2.9%
Total	**94.71**	**98.16**	**97.43**	**99.32**	**101.99**	**104.32**	**106.93**	**0.3%**
Energy use and related statistics								
Delivered energy use	68.87	71.32	71.59	72.43	73.92	75.64	77.75	0.3%
Total energy use	94.71	98.16	97.43	99.32	101.99	104.32	106.93	0.3%
Ethanol consumed in motor gasoline and E85	0.96	1.11	1.22	1.35	1.55	1.82	2.15	2.7%
Population (millions)	307.84	310.83	326.16	342.01	358.06	374.09	390.09	0.9%
Gross domestic product (billion 2005 dollars)	12703	13088	14803	16740	19185	21725	24539	2.5%
Carbon dioxide emissions (million metric tons)	5424.8	5633.6	5407.2	5434.4	5552.5	5647.3	5757.9	0.1%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.

[2]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.

[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.

[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.

[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.

[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.

[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (15 percent or less) in motor gasoline.

[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.

[9]Includes only kerosene type.

[10]Diesel fuel for on- and off- road use.

[11]Includes aviation gasoline and lubricants.

[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.

[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.

[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

[15]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.

[16]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.

[17]Includes non-biogenic municipal waste not included above.

[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.

Btu = British thermal unit.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2011. 2009 and 2010 carbon dioxide emissions: EIA, *Monthly Energy Review, October 2011* DOE/EIA-0035(2011/10) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A3. Energy prices by sector and source

(2010 dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Residential								
Liquefied petroleum gases	24.84	27.02	30.70	31.07	32.27	33.29	34.64	1.0%
Distillate fuel oil	18.35	21.21	27.26	28.81	30.15	31.42	32.73	1.8%
Natural gas	11.95	11.08	10.31	10.84	12.03	12.76	13.98	0.9%
Electricity	34.01	33.69	34.59	33.87	34.08	34.06	34.58	0.1%
Commercial								
Liquefied petroleum gases	21.76	23.52	27.42	27.78	28.97	29.96	31.30	1.1%
Distillate fuel oil	16.16	20.77	23.98	25.49	26.86	27.98	29.18	1.4%
Residual fuel oil	13.66	11.07	16.18	17.60	18.24	19.04	18.90	2.2%
Natural gas	9.82	9.10	8.60	8.98	10.02	10.60	11.64	1.0%
Electricity	30.06	29.73	29.03	28.69	29.00	28.68	29.48	-0.0%
Industrial[1]								
Liquefied petroleum gases	20.05	21.80	27.43	27.76	29.24	30.48	32.18	1.6%
Distillate fuel oil	16.74	21.32	24.20	25.73	27.22	28.39	29.53	1.3%
Residual fuel oil	12.16	10.92	19.21	20.53	21.23	21.71	21.65	2.8%
Natural gas[2]	5.33	5.51	4.88	5.12	6.04	6.57	7.54	1.3%
Metallurgical coal	5.49	5.84	7.22	7.58	8.11	8.61	9.11	1.8%
Other industrial coal	2.99	2.71	3.27	3.30	3.38	3.50	3.64	1.2%
Coal to liquids	- -	- -	1.26	2.05	2.08	2.22	2.38	- -
Electricity	20.05	19.63	18.91	18.95	19.60	19.81	20.78	0.2%
Transportation								
Liquefied petroleum gases[3]	25.84	26.88	31.93	32.21	33.38	34.37	35.74	1.1%
E85[4]	20.76	25.21	29.03	29.91	28.81	30.75	31.96	1.0%
Motor gasoline[5]	19.52	22.70	29.26	30.77	32.10	33.03	33.61	1.6%
Jet fuel[6]	12.75	16.22	23.74	25.26	26.45	27.58	29.13	2.4%
Diesel fuel (distillate fuel oil)[7]	18.02	21.87	27.56	28.98	30.42	31.38	32.40	1.6%
Residual fuel oil	10.61	10.42	18.32	19.58	20.62	20.76	20.95	2.8%
Natural gas[8]	14.17	13.20	12.40	12.50	13.29	13.68	14.51	0.4%
Electricity	35.71	32.99	30.50	29.74	31.53	32.54	33.82	0.1%
Electric power[9]								
Distillate fuel oil	14.54	18.73	22.77	24.18	25.35	26.43	27.80	1.6%
Residual fuel oil	8.98	11.89	23.00	24.38	25.40	25.55	25.72	3.1%
Natural gas	4.85	5.14	4.55	4.72	5.60	6.21	7.21	1.4%
Steam coal	2.22	2.26	2.35	2.41	2.54	2.66	2.80	0.9%
Average price to all users[10]								
Liquefied petroleum gases	16.13	17.28	22.99	23.06	24.19	25.23	26.63	1.7%
E85[4]	20.76	25.21	29.03	29.91	28.81	30.75	31.96	1.0%
Motor gasoline[5]	19.47	22.59	29.26	30.77	32.10	33.03	33.61	1.6%
Jet fuel	12.75	16.22	23.74	25.26	26.45	27.58	29.13	2.4%
Distillate fuel oil	17.73	21.65	26.87	28.36	29.81	30.87	31.91	1.6%
Residual fuel oil	10.51	10.82	19.01	20.31	21.31	21.53	21.68	2.8%
Natural gas	7.37	7.16	6.45	6.77	7.74	8.30	9.30	1.1%
Metallurgical coal	5.49	5.84	7.22	7.58	8.11	8.61	9.11	1.8%
Other coal	2.26	2.29	2.41	2.47	2.59	2.71	2.85	0.9%
Coal to liquids	- -	- -	1.26	2.05	2.08	2.22	2.38	- -
Electricity	29.02	28.68	28.38	28.09	28.54	28.65	29.56	0.1%
Non-renewable energy expenditures by sector (billion 2010 dollars)								
Residential	240.88	251.69	246.72	251.77	266.75	280.17	298.72	0.7%
Commercial	177.13	179.08	177.92	187.57	201.89	212.88	231.98	1.0%
Industrial	184.40	198.98	223.88	239.75	261.92	268.58	282.31	1.4%
Transportation	479.66	573.78	746.84	770.94	803.52	829.88	856.65	1.6%
Total non-renewable expenditures	1082.08	1203.54	1395.36	1450.04	1534.08	1591.52	1669.66	1.3%
Transportation renewable expenditures	0.07	0.08	0.25	3.77	8.74	22.00	38.86	28.2%
Total expenditures	**1082.15**	**1203.62**	**1395.61**	**1453.81**	**1542.81**	**1613.52**	**1708.52**	**1.4%**

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Residential								
Liquefied petroleum gases	24.55	27.02	33.08	36.51	41.41	47.38	54.86	2.9%
Distillate fuel oil	18.14	21.21	29.38	33.86	38.68	44.72	51.82	3.6%
Natural gas	11.82	11.08	11.11	12.74	15.43	18.16	22.14	2.8%
Electricity	33.62	33.69	37.27	39.80	43.72	48.47	54.76	2.0%
Commercial								
Liquefied petroleum gases	21.51	23.52	29.54	32.65	37.17	42.65	49.56	3.0%
Distillate fuel oil	15.97	20.77	25.83	29.95	34.47	39.82	46.20	3.2%
Residual fuel oil	13.51	11.07	17.43	20.68	23.41	27.10	29.93	4.1%
Natural gas	9.70	9.10	9.27	10.56	12.86	15.08	18.43	2.9%
Electricity	29.71	29.73	31.28	33.71	37.21	40.82	46.67	1.8%
Industrial[1]								
Liquefied petroleum gases	19.82	21.80	29.56	32.63	37.51	43.38	50.95	3.5%
Distillate fuel oil	16.55	21.32	26.08	30.24	34.93	40.40	46.76	3.2%
Residual fuel oil	12.02	10.92	20.70	24.13	27.24	30.89	34.28	4.7%
Natural gas[2]	5.27	5.51	5.26	6.02	7.75	9.35	11.93	3.1%
Metallurgical coal	5.43	5.84	7.78	8.91	10.40	12.26	14.42	3.7%
Other industrial coal	2.96	2.71	3.52	3.87	4.34	4.98	5.77	3.1%
Coal to liquids	- -	- -	1.36	2.41	2.67	3.16	3.78	- -
Electricity	19.83	19.63	20.38	22.27	25.15	28.20	32.90	2.1%
Transportation								
Liquefied petroleum gases[3]	25.55	26.88	34.41	37.85	42.83	48.91	56.59	3.0%
E85[4]	20.52	25.21	31.28	35.15	36.97	43.77	50.61	2.8%
Motor gasoline[5]	19.29	22.70	31.53	36.17	41.19	47.01	53.22	3.5%
Jet fuel[6]	12.61	16.22	25.58	29.68	33.94	39.25	46.12	4.3%
Diesel fuel (distillate fuel oil)[7]	17.82	21.87	29.69	34.06	39.03	44.66	51.29	3.5%
Residual fuel oil	10.49	10.42	19.74	23.01	26.45	29.55	33.18	4.7%
Natural gas[8]	14.01	13.20	13.36	14.69	17.05	19.47	22.97	2.2%
Electricity	35.31	32.99	32.86	34.95	40.46	46.31	53.55	2.0%
Electric power[9]								
Distillate fuel oil	14.37	18.73	24.53	28.42	32.52	37.61	44.02	3.5%
Residual fuel oil	8.88	11.89	24.78	28.66	32.59	36.37	40.73	5.0%
Natural gas	4.80	5.14	4.90	5.55	7.19	8.84	11.42	3.2%
Steam coal	2.19	2.26	2.53	2.83	3.25	3.78	4.43	2.7%

Table A3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Average price to all users[10]								
Liquefied petroleum gases	15.94	17.28	24.78	27.10	31.04	35.90	42.17	3.6%
E85[4]	20.52	25.21	31.28	35.15	36.97	43.77	50.61	2.8%
Motor gasoline[5]	19.25	22.59	31.53	36.16	41.19	47.01	53.22	3.5%
Jet fuel	12.61	16.22	25.58	29.68	33.94	39.25	46.12	4.3%
Distillate fuel oil	17.53	21.65	28.96	33.33	38.24	43.94	50.52	3.4%
Residual fuel oil	10.39	10.82	20.48	23.87	27.34	30.64	34.33	4.7%
Natural gas	7.28	7.16	6.95	7.96	9.93	11.81	14.73	2.9%
Metallurgical coal	5.43	5.84	7.78	8.91	10.40	12.26	14.42	3.7%
Other coal	2.23	2.29	2.60	2.90	3.32	3.86	4.51	2.8%
Coal to liquids	- -	- -	1.36	2.41	2.67	3.16	3.78	- -
Electricity	28.68	28.68	30.58	33.01	36.62	40.77	46.80	2.0%
Non-renewable energy expenditures by sector (billion nominal dollars)								
Residential	238.13	251.69	265.85	295.89	342.26	398.75	472.99	2.6%
Commercial	175.11	179.08	191.71	220.43	259.04	302.97	367.31	2.9%
Industrial	182.29	198.98	241.24	281.75	336.06	382.26	447.01	3.3%
Transportation	474.19	573.78	804.75	906.02	1030.98	1181.11	1356.41	3.5%
Total non-renewable expenditures	1069.72	1203.54	1503.55	1704.09	1968.35	2265.08	2643.72	3.2%
Transportation renewable expenditures	0.07	0.08	0.27	4.43	11.21	31.31	61.53	30.6%
Total expenditures	**1069.78**	**1203.62**	**1503.82**	**1708.52**	**1979.56**	**2296.40**	**2705.26**	**3.3%**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2009 residential and commercial natural gas delivered prices: EIA,*Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 and 2010 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and estimated State taxes, Federal taxes, and dispensing costs or charges. 2010 transportation sector natural gas delivered prices are model results. 2009 and 2010 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2010/09) (Washington, DC, September 2010). 2009 and 2010 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2010 and April 2011, Table 4.2, and EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2009 and 2010 coal prices based on: EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011) and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. 2009 and 2010 electricity prices: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A4. Residential sector key indicators and consumption

(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Key indicators								
Households (millions)								
Single-family	81.73	82.11	85.49	89.94	94.26	98.56	102.54	0.9%
Multifamily	25.41	25.52	26.98	29.31	31.47	33.70	35.96	1.4%
Mobile homes	6.65	6.56	6.25	6.56	6.86	7.04	7.14	0.3%
Total	**113.78**	**114.19**	**118.73**	**125.82**	**132.60**	**139.30**	**145.64**	**1.0%**
Average house square footage	**1646**	**1653**	**1684**	**1705**	**1725**	**1743**	**1759**	**0.2%**
Energy intensity								
(million Btu per household)								
Delivered energy consumption	97.8	102.1	94.6	90.3	86.8	84.2	81.9	-0.9%
Total energy consumption	184.0	193.1	175.3	169.8	166.1	162.8	159.9	-0.8%
(thousand Btu per square foot)								
Delivered energy consumption	59.4	61.8	56.2	52.9	50.3	48.3	46.6	-1.1%
Total energy consumption	111.8	116.8	104.1	99.6	96.3	93.4	90.9	-1.0%
Delivered energy consumption by fuel								
Electricity								
Space heating	0.28	0.30	0.28	0.30	0.31	0.33	0.34	0.5%
Space cooling	0.81	1.08	1.01	1.06	1.12	1.18	1.24	0.6%
Water heating	0.44	0.45	0.47	0.50	0.52	0.53	0.53	0.7%
Refrigeration	0.38	0.37	0.37	0.38	0.39	0.41	0.43	0.6%
Cooking	0.11	0.11	0.11	0.12	0.13	0.14	0.15	1.4%
Clothes dryers	0.19	0.19	0.19	0.18	0.18	0.17	0.18	-0.3%
Freezers	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.3%
Lighting	0.70	0.69	0.52	0.48	0.46	0.46	0.47	-1.5%
Clothes washers[1]	0.03	0.03	0.03	0.03	0.02	0.02	0.02	-1.2%
Dishwashers[1]	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.4%
Color televisions and set-top boxes	0.32	0.33	0.32	0.34	0.37	0.40	0.43	1.1%
Personal computers and related equipment	0.17	0.17	0.19	0.22	0.24	0.26	0.27	1.8%
Furnace fans and boiler circulation pumps	0.14	0.13	0.14	0.14	0.14	0.15	0.15	0.4%
Other uses[2]	0.90	0.92	0.92	1.03	1.16	1.31	1.44	1.8%
Delivered energy	**4.66**	**4.95**	**4.75**	**4.96**	**5.23**	**5.55**	**5.86**	**0.7%**
Natural gas								
Space heating	3.31	3.50	3.39	3.34	3.27	3.24	3.19	-0.4%
Space cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.3%
Water heating	1.32	1.29	1.31	1.33	1.33	1.31	1.27	-0.1%
Cooking	0.22	0.22	0.22	0.22	0.22	0.23	0.23	0.3%
Clothes dryers	0.05	0.06	0.06	0.06	0.06	0.06	0.07	0.7%
Delivered energy	**4.90**	**5.06**	**4.97**	**4.95**	**4.88**	**4.84**	**4.76**	**-0.2%**
Distillate fuel oil								
Space heating	0.50	0.53	0.48	0.42	0.38	0.34	0.31	-2.1%
Water heating	0.10	0.10	0.07	0.06	0.05	0.04	0.04	-3.9%
Delivered energy	**0.60**	**0.63**	**0.55**	**0.48**	**0.43**	**0.38**	**0.35**	**-2.3%**
Liquefied petroleum gases								
Space heating	0.26	0.30	0.26	0.25	0.24	0.23	0.22	-1.1%
Water heating	0.08	0.07	0.05	0.04	0.04	0.04	0.03	-3.0%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.02	-0.9%
Other uses[3]	0.14	0.16	0.17	0.18	0.20	0.21	0.22	1.3%
Delivered energy	**0.51**	**0.56**	**0.51**	**0.50**	**0.50**	**0.51**	**0.51**	**-0.4%**
Marketed renewables (wood)[4]	0.43	0.42	0.43	0.43	0.43	0.43	0.43	0.1%
Other fuels[5]	0.04	0.04	0.03	0.03	0.03	0.03	0.03	-1.6%

Table A4. Residential sector key indicators and consumption (continued)

(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Delivered energy consumption by end use								
Space heating	4.81	5.08	4.86	4.78	4.67	4.60	4.52	-0.5%
Space cooling	0.81	1.08	1.01	1.06	1.12	1.18	1.24	0.6%
Water heating	1.94	1.91	1.90	1.92	1.94	1.91	1.88	-0.1%
Refrigeration	0.38	0.37	0.37	0.38	0.39	0.41	0.43	0.6%
Cooking	0.35	0.35	0.36	0.37	0.38	0.39	0.40	0.5%
Clothes dryers	0.25	0.25	0.25	0.25	0.24	0.24	0.25	-0.0%
Freezers	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.3%
Lighting	0.70	0.69	0.52	0.48	0.46	0.46	0.47	-1.5%
Clothes washers[1]	0.03	0.03	0.03	0.03	0.02	0.02	0.02	-1.2%
Dishwashers[1]	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.4%
Color televisions and set-top boxes	0.32	0.33	0.32	0.34	0.37	0.40	0.43	1.1%
Personal computers and related equipment	0.17	0.17	0.19	0.22	0.24	0.26	0.27	1.8%
Furnace fans and boiler circulation pumps	0.14	0.13	0.14	0.14	0.14	0.15	0.15	0.4%
Other uses[6]	1.04	1.08	1.09	1.21	1.36	1.52	1.67	1.8%
Delivered energy	**11.13**	**11.66**	**11.24**	**11.36**	**11.51**	**11.73**	**11.93**	**0.1%**
Electricity related losses	**9.80**	**10.39**	**9.58**	**10.01**	**10.52**	**10.95**	**11.35**	**0.4%**
Total energy consumption by end use								
Space heating	5.41	5.70	5.42	5.37	5.29	5.24	5.17	-0.4%
Space cooling	2.52	3.34	3.06	3.19	3.36	3.51	3.65	0.4%
Water heating	2.87	2.85	2.85	2.93	2.98	2.96	2.90	0.1%
Refrigeration	1.17	1.15	1.11	1.14	1.18	1.23	1.28	0.4%
Cooking	0.58	0.58	0.59	0.61	0.64	0.67	0.69	0.7%
Clothes dryers	0.65	0.65	0.64	0.62	0.59	0.58	0.60	-0.4%
Freezers	0.26	0.26	0.25	0.26	0.26	0.26	0.26	0.1%
Lighting	2.18	2.13	1.58	1.45	1.39	1.37	1.37	-1.7%
Clothes washers[1]	0.10	0.10	0.10	0.08	0.07	0.07	0.07	-1.4%
Dishwashers[1]	0.31	0.31	0.30	0.30	0.30	0.31	0.33	0.2%
Color televisions and set-top boxes	1.00	1.02	0.98	1.03	1.10	1.18	1.26	0.9%
Personal computers and related equipment	0.53	0.53	0.57	0.65	0.72	0.76	0.79	1.6%
Furnace fans and boiler circulation pumps	0.42	0.42	0.42	0.43	0.44	0.44	0.44	0.2%
Other uses[6]	2.94	3.01	2.96	3.29	3.70	4.10	4.47	1.6%
Total	**20.93**	**22.05**	**20.81**	**21.36**	**22.02**	**22.68**	**23.28**	**0.2%**
Nonmarketed renewables[7]								
Geothermal heat pumps	0.00	0.01	0.01	0.02	0.02	0.02	0.03	6.4%
Solar hot water heating	0.01	0.01	0.02	0.02	0.02	0.02	0.02	2.4%
Solar photovoltaic	0.00	0.00	0.04	0.05	0.05	0.06	0.06	10.7%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	9.1%
Total	**0.02**	**0.02**	**0.08**	**0.10**	**0.10**	**0.11**	**0.11**	**6.9%**
Heating degree days[8]	**4408**	**4382**	**4208**	**4172**	**4136**	**4101**	**4067**	**-0.3%**
Cooling degree days[8]	**1279**	**1498**	**1392**	**1409**	**1426**	**1443**	**1459**	**-0.1%**

[1]Does not include water heating portion of load.
[2]Includes small electric devices, heating elements, and motors not listed above. Electric vehicles are included in the transportation sector.
[3]Includes such appliances as outdoor grills and mosquito traps.
[4]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2005*.
[5]Includes kerosene and coal.
[6]Includes all other uses listed above.
[7]Represents delivered energy displaced.
[8]See Table A5 for regional detail.
Btu = British thermal unit.
- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A5. Commercial sector key indicators and consumption

(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Key indicators								
Total floorspace (billion square feet)								
Surviving	78.0	79.3	82.4	87.0	91.9	96.2	100.7	1.0%
New additions	2.3	1.8	1.7	2.0	2.0	2.0	2.3	1.0%
Total	**80.3**	**81.1**	**84.1**	**89.1**	**93.9**	**98.2**	**103.0**	**1.0%**
Energy consumption intensity (thousand Btu per square foot)								
Delivered energy consumption	106.0	107.3	104.6	103.1	101.0	100.6	99.8	-0.3%
Electricity related losses	117.0	117.3	110.2	110.6	110.6	110.2	109.0	-0.3%
Total energy consumption	223.0	224.5	214.8	213.7	211.5	210.7	208.8	-0.3%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating[1]	0.18	0.18	0.16	0.16	0.16	0.16	0.16	-0.6%
Space cooling[1]	0.47	0.56	0.50	0.50	0.51	0.52	0.53	-0.2%
Water heating[1]	0.09	0.09	0.09	0.09	0.09	0.09	0.08	-0.4%
Ventilation	0.50	0.51	0.53	0.56	0.58	0.61	0.63	0.9%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.3%
Lighting	1.03	1.01	1.00	1.03	1.06	1.10	1.13	0.4%
Refrigeration	0.40	0.39	0.35	0.34	0.34	0.34	0.35	-0.4%
Office equipment (PC)	0.22	0.21	0.19	0.19	0.20	0.21	0.21	0.0%
Office equipment (non-PC)	0.25	0.26	0.31	0.37	0.40	0.44	0.46	2.3%
Other uses[2]	1.29	1.30	1.43	1.62	1.80	2.00	2.22	2.2%
Delivered energy	**4.46**	**4.54**	**4.59**	**4.88**	**5.16**	**5.48**	**5.80**	**1.0%**
Natural gas								
Space heating[1]	1.61	1.65	1.69	1.73	1.70	1.68	1.64	-0.0%
Space cooling[1]	0.03	0.04	0.04	0.04	0.03	0.03	0.03	-1.1%
Water heating[1]	0.43	0.44	0.48	0.51	0.52	0.53	0.54	0.8%
Cooking	0.17	0.18	0.19	0.20	0.21	0.22	0.22	0.9%
Other uses[3]	0.95	0.98	1.01	1.04	1.07	1.14	1.25	1.0%
Delivered energy	**3.20**	**3.28**	**3.41**	**3.51**	**3.53**	**3.60**	**3.69**	**0.5%**
Distillate fuel oil								
Space heating[1]	0.16	0.14	0.12	0.11	0.10	0.10	0.09	-1.7%
Water heating[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.9%
Other uses[4]	0.22	0.26	0.20	0.20	0.20	0.20	0.19	-1.2%
Delivered energy	**0.41**	**0.43**	**0.35**	**0.34**	**0.33**	**0.33**	**0.32**	**-1.2%**
Marketed renewables (biomass)	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.0%
Other fuels[5]	0.33	0.34	0.33	0.34	0.34	0.35	0.36	0.2%
Delivered energy consumption by end use								
Space heating[1]	1.95	1.97	1.98	2.00	1.96	1.93	1.89	-0.2%
Space cooling[1]	0.50	0.60	0.54	0.54	0.54	0.55	0.57	-0.2%
Water heating[1]	0.55	0.56	0.60	0.63	0.64	0.65	0.66	0.7%
Ventilation	0.50	0.51	0.53	0.56	0.58	0.61	0.63	0.9%
Cooking	0.20	0.20	0.21	0.23	0.23	0.24	0.24	0.8%
Lighting	1.03	1.01	1.00	1.03	1.06	1.10	1.13	0.4%
Refrigeration	0.40	0.39	0.35	0.34	0.34	0.34	0.35	-0.4%
Office equipment (PC)	0.22	0.21	0.19	0.19	0.20	0.21	0.21	0.0%
Office equipment (non-PC)	0.25	0.26	0.31	0.37	0.40	0.44	0.46	2.3%
Other uses[6]	2.90	2.99	3.09	3.30	3.53	3.80	4.13	1.3%
Delivered energy	**8.51**	**8.70**	**8.80**	**9.18**	**9.48**	**9.87**	**10.28**	**0.7%**

Table A5. Commercial sector key indicators and consumption (continued)

(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Electricity related losses	**9.39**	**9.52**	**9.27**	**9.85**	**10.38**	**10.82**	**11.23**	**0.7%**
Total energy consumption by end use								
Space heating[1]	2.34	2.35	2.31	2.33	2.28	2.24	2.19	-0.3%
Space cooling[1]	1.50	1.77	1.54	1.55	1.57	1.58	1.60	-0.4%
Water heating[1]	0.75	0.75	0.78	0.80	0.81	0.82	0.82	0.4%
Ventilation	1.56	1.57	1.60	1.69	1.75	1.81	1.84	0.6%
Cooking	0.25	0.25	0.26	0.27	0.27	0.28	0.29	0.5%
Lighting	3.21	3.14	3.01	3.12	3.21	3.27	3.32	0.2%
Refrigeration	1.24	1.21	1.06	1.02	1.02	1.02	1.04	-0.6%
Office equipment (PC)	0.67	0.66	0.57	0.58	0.59	0.61	0.63	-0.2%
Office equipment (non-PC)	0.77	0.81	0.95	1.10	1.21	1.30	1.36	2.1%
Other uses[6]	5.62	5.71	5.98	6.56	7.15	7.75	8.42	1.6%
Total	**17.90**	**18.22**	**18.06**	**19.03**	**19.86**	**20.69**	**21.50**	**0.7%**
Nonmarketed renewable fuels[7]								
Solar thermal	0.03	0.03	0.03	0.03	0.03	0.04	0.04	1.4%
Solar photovoltaic	0.00	0.01	0.01	0.01	0.01	0.01	0.01	2.8%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.3%
Total	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**1.7%**
Heating Degree Days								
New England	6649	5944	6349	6351	6355	6358	6360	0.3%
Middle Atlantic	5798	5453	5588	5587	5586	5585	5583	0.1%
East North Central	6542	6209	6215	6215	6215	6215	6215	0.0%
West North Central	6837	6585	6456	6461	6463	6466	6468	-0.1%
South Atlantic	2839	3183	2728	2703	2677	2651	2625	-0.8%
East South Central	3599	4003	3474	3480	3485	3491	3496	-0.5%
West South Central	2198	2503	2156	2149	2143	2137	2131	-0.6%
Mountain	4852	4808	4780	4749	4713	4677	4641	-0.1%
Pacific	3188	3202	3130	3135	3138	3140	3143	-0.1%
United States	**4408**	**4382**	**4208**	**4172**	**4136**	**4101**	**4067**	**-0.3%**
Cooling Degree Days								
New England	363	655	518	518	517	517	516	-0.9%
Middle Atlantic	587	997	783	783	783	784	784	-1.0%
East North Central	547	978	779	780	780	781	781	-0.9%
West North Central	720	1123	976	975	974	973	973	-0.6%
South Atlantic	2047	2289	2103	2118	2134	2149	2165	-0.2%
East South Central	1491	1999	1668	1665	1662	1658	1655	-0.8%
West South Central	2582	2755	2602	2607	2611	2615	2619	-0.2%
Mountain	1551	1489	1578	1595	1617	1637	1658	0.4%
Pacific	967	746	891	888	887	885	883	0.7%
United States	**1279**	**1498**	**1392**	**1409**	**1426**	**1443**	**1459**	**-0.1%**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[7]Represents delivered energy displaced.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A6. Industrial sector key indicators and consumption

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Key indicators								
Value of shipments (billion 2005 dollars)								
Manufacturing	4052	4260	4857	5260	5745	6023	6285	1.6%
Nonmanufacturing	1615	1578	1873	2103	2228	2305	2407	1.7%
Total	**5667**	**5838**	**6730**	**7363**	**7973**	**8328**	**8692**	**1.6%**
Energy prices								
(2010 dollars per million Btu)								
Liquefied petroleum gases	20.05	21.80	27.43	27.76	29.24	30.48	32.18	1.6%
Motor gasoline	16.79	16.77	29.20	30.72	32.06	33.01	33.55	2.8%
Distillate fuel oil	16.74	21.32	24.20	25.73	27.22	28.39	29.53	1.3%
Residual fuel oil	12.16	10.92	19.21	20.53	21.23	21.71	21.65	2.8%
Asphalt and road oil	6.59	5.59	9.30	9.94	10.37	10.45	10.69	2.6%
Natural gas heat and power	4.59	4.78	4.16	4.41	5.33	5.88	6.89	1.5%
Natural gas feedstocks	6.16	6.32	5.68	5.93	6.83	7.36	8.33	1.1%
Metallurgical coal	5.49	5.84	7.22	7.58	8.11	8.61	9.11	1.8%
Other industrial coal	2.99	2.71	3.27	3.30	3.38	3.50	3.64	1.2%
Coal for liquids	- -	- -	1.26	2.05	2.08	2.22	2.38	- -
Electricity	20.05	19.63	18.91	18.95	19.60	19.81	20.78	0.2%
(nominal dollars per million Btu)								
Liquefied petroleum gases	19.82	21.80	29.56	32.63	37.51	43.38	50.95	3.5%
Motor gasoline	16.60	16.77	31.46	36.10	41.14	46.98	53.12	4.7%
Distillate fuel oil	16.55	21.32	26.08	30.24	34.93	40.40	46.76	3.2%
Residual fuel oil	12.02	10.92	20.70	24.13	27.24	30.89	34.28	4.7%
Asphalt and road oil	6.52	5.59	10.02	11.68	13.30	14.87	16.93	4.5%
Natural gas heat and power	4.54	4.78	4.49	5.19	6.84	8.37	10.91	3.4%
Natural gas feedstocks	6.09	6.32	6.12	6.96	8.77	10.48	13.18	3.0%
Metallurgical coal	5.43	5.84	7.78	8.91	10.40	12.26	14.42	3.7%
Other industrial coal	2.96	2.71	3.52	3.87	4.34	4.98	5.77	3.1%
Coal for liquids	- -	- -	1.36	2.41	2.67	3.16	3.78	- -
Electricity	19.83	19.63	20.38	22.27	25.15	28.20	32.90	2.1%
Energy consumption (quadrillion Btu)[1]								
Industrial consumption excluding refining								
Liquefied petroleum gases heat and power	0.45	0.41	0.36	0.39	0.41	0.41	0.40	-0.0%
Liquefied petroleum gases feedstocks	1.54	1.58	1.45	1.65	1.75	1.76	1.74	0.4%
Motor gasoline	0.24	0.25	0.28	0.30	0.30	0.30	0.30	0.8%
Distillate fuel oil	1.11	1.15	1.25	1.18	1.19	1.17	1.18	0.1%
Residual fuel oil	0.10	0.11	0.09	0.08	0.08	0.08	0.08	-1.1%
Petrochemical feedstocks	0.90	0.94	1.01	1.20	1.29	1.31	1.30	1.3%
Petroleum coke	0.28	0.16	0.20	0.19	0.15	0.12	0.13	-1.1%
Asphalt and road oil	0.87	0.88	1.00	1.00	0.98	0.94	0.94	0.3%
Miscellaneous petroleum[2]	0.38	0.52	0.14	0.12	0.12	0.11	0.12	-5.8%
Petroleum subtotal	5.87	6.00	5.78	6.11	6.27	6.20	6.19	0.1%
Natural gas heat and power	4.48	4.84	5.23	5.22	5.27	5.23	5.23	0.3%
Natural gas feedstocks	0.47	0.48	0.48	0.51	0.50	0.47	0.44	-0.3%
Lease and plant fuel[3]	1.31	1.37	1.43	1.55	1.57	1.59	1.63	0.7%
Natural gas subtotal	6.25	6.69	7.14	7.27	7.34	7.29	7.31	0.4%
Metallurgical coal and coke[4]	0.38	0.55	0.56	0.46	0.46	0.42	0.38	-1.5%
Other industrial coal	0.88	0.95	0.97	0.98	1.02	1.02	1.02	0.3%
Coal subtotal	1.26	1.50	1.53	1.44	1.47	1.44	1.40	-0.3%
Renewables[5]	1.37	1.50	1.61	1.67	1.82	1.87	1.95	1.1%
Purchased electricity	2.94	3.09	3.24	3.26	3.33	3.24	3.12	0.0%
Delivered energy	**17.69**	**18.78**	**19.30**	**19.75**	**20.23**	**20.04**	**19.97**	**0.2%**
Electricity related losses	6.19	6.47	6.55	6.58	6.69	6.39	6.04	-0.3%
Total	**23.88**	**25.25**	**25.84**	**26.33**	**26.92**	**26.44**	**26.01**	**0.1%**

Table A6. Industrial sector key indicators and consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Refining consumption								
Liquefied petroleum gases heat and power	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.4%
Distillate fuel oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Residual fuel oil	0.01	0.01	0.00	0.00	0.00	0.00	0.00	- -
Petroleum coke	0.52	0.52	0.53	0.49	0.49	0.51	0.53	0.1%
Still gas	1.50	1.50	1.55	1.36	1.34	1.39	1.45	-0.1%
Miscellaneous petroleum[2]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	1.2%
Petroleum subtotal	2.05	2.05	2.11	1.89	1.86	1.93	2.02	-0.1%
Natural gas heat and power	1.38	1.44	1.48	1.53	1.55	1.51	1.51	0.2%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas subtotal	1.38	1.44	1.48	1.53	1.55	1.51	1.51	0.2%
Other industrial coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.0%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.26	0.36	0.48	0.60	- -
Coal subtotal	0.06	0.06	0.06	0.32	0.42	0.54	0.66	10.0%
Biofuels heat and coproducts	0.82	0.84	0.81	0.96	1.27	1.92	2.57	4.6%
Purchased electricity	0.19	0.20	0.20	0.20	0.19	0.20	0.21	0.3%
Delivered energy	**4.51**	**4.60**	**4.66**	**4.89**	**5.30**	**6.10**	**6.97**	**1.7%**
Electricity related losses	0.40	0.41	0.39	0.39	0.39	0.40	0.41	0.0%
Total	**4.91**	**5.01**	**5.05**	**5.28**	**5.69**	**6.50**	**7.39**	**1.6%**
Total industrial sector consumption								
Liquefied petroleum gases heat and power	0.46	0.42	0.38	0.41	0.42	0.42	0.41	-0.0%
Liquefied petroleum gases feedstocks	1.54	1.58	1.45	1.65	1.75	1.76	1.74	0.4%
Motor gasoline	0.24	0.25	0.28	0.30	0.30	0.30	0.30	0.8%
Distillate fuel oil	1.11	1.16	1.25	1.18	1.19	1.17	1.18	0.1%
Residual fuel oil	0.11	0.12	0.09	0.08	0.08	0.08	0.08	-1.3%
Petrochemical feedstocks	0.90	0.94	1.01	1.20	1.29	1.31	1.30	1.3%
Petroleum coke	0.80	0.68	0.73	0.68	0.64	0.63	0.66	-0.1%
Asphalt and road oil	0.87	0.88	1.00	1.00	0.98	0.94	0.94	0.3%
Still gas	1.50	1.50	1.55	1.36	1.34	1.39	1.45	-0.1%
Miscellaneous petroleum[2]	0.40	0.54	0.17	0.14	0.14	0.13	0.14	-5.3%
Petroleum subtotal	7.93	8.05	7.89	7.99	8.13	8.13	8.21	0.1%
Natural gas heat and power	5.86	6.28	6.71	6.75	6.82	6.74	6.74	0.3%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas feedstocks	0.47	0.48	0.48	0.51	0.50	0.47	0.44	-0.3%
Lease and plant fuel[3]	1.31	1.37	1.43	1.55	1.57	1.59	1.63	0.7%
Natural gas subtotal	7.63	8.14	8.62	8.80	8.89	8.80	8.81	0.3%
Metallurgical coal and coke[4]	0.38	0.55	0.56	0.46	0.46	0.42	0.38	-1.5%
Other industrial coal	0.94	1.01	1.03	1.04	1.08	1.08	1.08	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.26	0.36	0.48	0.60	- -
Coal subtotal	1.32	1.56	1.59	1.76	1.90	1.98	2.06	1.1%
Biofuels heat and coproducts	0.82	0.84	0.81	0.96	1.27	1.92	2.57	4.6%
Renewables[5]	1.37	1.50	1.61	1.67	1.82	1.87	1.95	1.1%
Purchased electricity	3.13	3.28	3.44	3.46	3.52	3.44	3.33	0.1%
Delivered energy	**22.20**	**23.37**	**23.96**	**24.64**	**25.53**	**26.14**	**26.94**	**0.6%**
Electricity related losses	6.59	6.89	6.94	6.97	7.09	6.80	6.46	-0.3%
Total	**28.79**	**30.26**	**30.90**	**31.61**	**32.61**	**32.93**	**33.39**	**0.4%**

Table A6. Industrial sector key indicators and consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Energy consumption per dollar of shipments (thousand Btu per 2005 dollar)								
Liquid fuels and other petroleum	1.40	1.38	1.17	1.09	1.02	0.98	0.94	-1.5%
Natural gas	1.35	1.39	1.28	1.20	1.11	1.06	1.01	-1.3%
Coal	0.23	0.27	0.24	0.24	0.24	0.24	0.24	-0.5%
Renewable fuels[5]	0.39	0.40	0.36	0.36	0.39	0.45	0.52	1.0%
Purchased electricity	0.55	0.56	0.51	0.47	0.44	0.41	0.38	-1.5%
Delivered energy	**3.92**	**4.00**	**3.56**	**3.35**	**3.20**	**3.14**	**3.10**	**-1.0%**
Industrial combined heat and power								
Capacity (gigawatts)	25.08	25.64	30.38	35.48	40.71	48.10	55.79	3.2%
Generation (billion kilowatthours)	130.57	141.07	168.00	201.40	235.62	287.62	341.40	3.6%

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 prices for motor gasoline and distillate fuel oil are based on: U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2009 and 2010 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2009 and 2010 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011) and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. 2009 and 2010 electricity prices: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 natural gas prices are based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 refining consumption values are based on: *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). 2010 refining consumption based on: *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). Other 2009 and 2010 consumption values are based on: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 shipments: IHS Global Insight, Global Insight Industry model, August 2011. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A7. Transportation sector key indicators and delivered energy consumption

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Key indicators								
Travel indicators								
(billion vehicle miles traveled)								
Light-duty vehicles less than 8,501 pounds	2625	2662	2710	2881	3111	3363	3583	1.2%
Commercial light trucks[1]	58	64	70	76	83	88	92	1.5%
Freight trucks greater than 10,000 pounds	240	234	273	297	317	330	345	1.6%
(billion seat miles available)								
Air	964	999	1028	1075	1120	1164	1208	0.8%
(billion ton miles traveled)								
Rail	1532	1559	1503	1662	1782	1826	1871	0.7%
Domestic shipping	477	522	549	587	604	617	627	0.7%
Energy efficiency indicators								
(miles per gallon)								
New light-duty vehicle CAFE standard[2]	25.4	25.7	32.4	35.0	35.2	35.3	35.3	1.3%
New car[2]	28.2	28.2	37.0	39.9	39.9	39.9	39.9	1.4%
New light truck[2]	23.0	23.4	27.9	29.2	29.2	29.2	29.2	0.9%
Compliance new light-duty vehicle[3]	29.3	29.2	32.5	35.9	36.8	37.4	37.9	1.0%
New car[3]	34.0	33.8	37.4	40.3	41.3	42.2	42.9	1.0%
New light truck[3]	25.4	25.5	27.7	30.6	31.0	31.2	31.5	0.8%
Tested new light-duty vehicle[4]	28.2	28.3	31.5	35.9	36.8	37.4	37.9	1.2%
New car[4]	33.2	33.3	36.4	40.3	41.2	42.2	42.8	1.0%
New light truck[4]	24.2	24.3	26.7	30.6	31.0	31.2	31.5	1.0%
On-road new light-duty vehicle[5]	23.0	22.9	25.6	29.2	30.0	30.5	30.9	1.2%
New car[5]	27.4	27.3	29.9	33.1	33.9	34.7	35.2	1.0%
New light truck[5]	19.5	19.6	21.6	24.7	24.9	25.2	25.4	1.0%
Light-duty stock[6]	20.4	20.4	21.5	23.6	25.6	27.1	28.2	1.3%
New commercial light truck[1]	15.6	15.7	16.7	18.8	18.9	19.0	19.1	0.8%
Stock commercial light truck[1]	14.3	14.4	15.2	16.7	18.0	18.7	19.0	1.1%
Freight truck	6.7	6.7	6.8	7.3	7.7	8.0	8.1	0.8%
(seat miles per gallon)								
Aircraft	62.0	62.3	62.8	63.8	65.2	67.0	69.3	0.4%
(ton miles per thousand Btu)								
Rail	3.4	3.4	3.5	3.5	3.5	3.5	3.5	0.1%
Domestic shipping	2.4	2.4	2.4	2.5	2.5	2.5	2.5	0.2%
Energy use by mode (quadrillion Btu)								
Light-duty vehicles	15.89	16.06	15.39	14.84	14.73	15.05	15.46	-0.2%
Commercial light trucks[1]	0.51	0.55	0.58	0.57	0.58	0.59	0.61	0.4%
Bus transportation	0.21	0.25	0.26	0.27	0.29	0.30	0.31	0.9%
Freight trucks	4.95	4.82	5.51	5.57	5.66	5.69	5.84	0.8%
Rail, passenger	0.04	0.05	0.05	0.06	0.06	0.06	0.06	1.2%
Rail, freight	0.36	0.45	0.43	0.48	0.51	0.52	0.53	0.6%
Shipping, domestic	0.17	0.22	0.23	0.24	0.25	0.25	0.25	0.5%
Shipping, international	0.77	0.86	0.87	0.87	0.88	0.88	0.89	0.1%
Recreational boats	0.24	0.25	0.26	0.26	0.27	0.28	0.29	0.5%
Air	2.44	2.52	2.55	2.63	2.71	2.76	2.79	0.4%
Military use	0.71	0.77	0.66	0.64	0.66	0.70	0.74	-0.1%
Lubricants	0.13	0.14	0.13	0.14	0.14	0.14	0.14	0.1%
Pipeline fuel	0.61	0.65	0.68	0.67	0.67	0.68	0.69	0.2%
Total	**27.04**	**27.59**	**27.60**	**27.25**	**27.40**	**27.90**	**28.60**	**0.1%**

Table A7. Transportation sector key indicators and delivered energy consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Energy use by mode (million barrels per day oil equivalent)								
Light-duty vehicles	8.50	8.63	8.30	8.05	8.05	8.31	8.64	0.0%
Commercial light trucks[1]	0.26	0.28	0.30	0.29	0.30	0.30	0.31	0.4%
Bus transportation	0.10	0.12	0.13	0.13	0.14	0.14	0.15	0.9%
Freight trucks	2.39	2.32	2.65	2.68	2.72	2.74	2.81	0.8%
Rail, passenger	0.02	0.02	0.02	0.03	0.03	0.03	0.03	1.2%
Rail, freight	0.17	0.22	0.21	0.23	0.24	0.25	0.25	0.6%
Shipping, domestic	0.08	0.10	0.11	0.11	0.11	0.11	0.12	0.5%
Shipping, international	0.34	0.38	0.38	0.38	0.38	0.39	0.39	0.1%
Recreational boats	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.5%
Air	1.18	1.22	1.23	1.27	1.31	1.33	1.35	0.4%
Military use	0.34	0.37	0.32	0.31	0.32	0.34	0.36	-0.1%
Lubricants	0.06	0.07	0.06	0.06	0.07	0.07	0.07	0.1%
Pipeline fuel	0.29	0.31	0.32	0.32	0.32	0.32	0.32	0.2%
Total	**13.87**	**14.17**	**14.17**	**14.01**	**14.14**	**14.48**	**14.95**	**0.2%**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]CAFE standard based on projected new vehicle sales.
[3]Includes CAFE credits for alternative fueled vehicle sales and credit banking.
[4]Environmental Protection Agency rated miles per gallon.
[5]Tested new vehicle efficiency revised for on-road performance.
[6]Combined"on-the-road" estimate for all cars and light trucks.
CAFE = Corporate average fuel economy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010); EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011); Federal Highway Administration, *Highway Statistics 2009* (Washington, DC, April 2011); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 30 and Annual* (Oak Ridge, TN, 2011); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 28, 2010); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2008 (Part II - User and Fuel Data), April 2010; EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010/2009* (Washington, DC, December 2010); EIA, *Fuel Oil and Kerosene Sales 2009*, DOE/EIA-0535(2009) (Washington, DC, February 2011); and United States Department of Defense, Defense Fuel Supply Center, Fact Book (January, 2010). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A8. Electricity supply, disposition, prices, and emissions

(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Generation by fuel type								
Electric power sector[1]								
Power only[2]								
Coal	1712	1799	1531	1604	1710	1757	1803	0.0%
Petroleum	32	32	25	26	26	27	27	-0.6%
Natural gas[3]	723	776	903	874	882	983	1074	1.3%
Nuclear power	799	807	830	887	917	914	887	0.4%
Pumped storage/other[4]	2	2	2	2	2	2	2	-1.2%
Renewable sources[5]	384	390	504	544	579	594	630	1.9%
Distributed generation (natural gas)	0	0	0	1	2	3	4	- -
Total	**3651**	**3806**	**3796**	**3937**	**4118**	**4279**	**4427**	**0.6%**
Combined heat and power[6]								
Coal	29	32	30	30	31	31	31	-0.1%
Petroleum	4	3	1	1	1	1	1	-5.2%
Natural gas	118	122	126	124	124	124	123	0.0%
Renewable sources	5	5	4	5	5	5	4	-0.7%
Total	**159**	**165**	**160**	**160**	**161**	**160**	**159**	**-0.1%**
Total electric power sector generation	**3810**	**3971**	**3956**	**4097**	**4279**	**4439**	**4586**	**0.6%**
Less direct use	14	16	13	13	13	13	13	-0.7%
Net available to the grid	**3796**	**3955**	**3942**	**4084**	**4265**	**4426**	**4572**	**0.6%**
End-use sector[7]								
Coal	15	20	20	38	46	54	63	4.7%
Petroleum	3	3	2	2	2	2	2	-0.7%
Natural gas	80	84	101	113	132	160	198	3.5%
Other gaseous fuels[8]	10	11	16	16	15	15	15	1.2%
Renewable sources[9]	31	34	55	65	78	103	125	5.4%
Other[10]	4	4	3	3	3	3	3	-0.8%
Total end-use sector generation	**143**	**155**	**197**	**237**	**277**	**338**	**406**	**3.9%**
Less direct use	107	112	149	180	208	243	288	3.8%
Total sales to the grid	**36**	**43**	**48**	**57**	**69**	**95**	**118**	**4.1%**
Total electricity generation by fuel								
Coal	1756	1851	1581	1671	1786	1841	1897	0.1%
Petroleum	39	37	28	28	29	29	30	-0.8%
Natural gas	921	982	1130	1113	1140	1270	1398	1.4%
Nuclear power	799	807	830	887	917	914	887	0.4%
Renewable sources[5,9]	420	429	562	614	662	702	760	2.3%
Other[11]	19	21	21	21	21	21	21	-0.0%
Total electricity generation	**3953**	**4126**	**4152**	**4334**	**4556**	**4777**	**4992**	**0.8%**
Net generation to the grid	**3832**	**3998**	**3990**	**4141**	**4335**	**4521**	**4691**	**0.6%**
Net imports	**34**	**26**	**29**	**26**	**22**	**14**	**12**	**-2.9%**
Electricity sales by sector								
Residential	1364	1451	1392	1454	1533	1626	1718	0.7%
Commercial	1307	1329	1346	1431	1513	1607	1699	1.0%
Industrial	917	962	1008	1013	1032	1009	977	0.1%
Transportation	7	7	8	9	12	16	22	4.8%
Total	**3596**	**3749**	**3753**	**3907**	**4090**	**4258**	**4415**	**0.7%**
Direct use	121	128	162	193	221	256	302	3.5%
Total electricity use	**3717**	**3877**	**3915**	**4100**	**4311**	**4514**	**4716**	**0.8%**

Table A8. Electricity supply, disposition, prices, and emissions (continued)

(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
End-use prices								
(2010 cents per kilowatthour)								
Residential	11.6	11.5	11.8	11.6	11.6	11.6	11.8	0.1%
Commercial	10.3	10.1	9.9	9.8	9.9	9.8	10.1	-0.0%
Industrial	6.8	6.7	6.5	6.5	6.7	6.8	7.1	0.2%
Transportation	12.2	11.3	10.4	10.1	10.8	11.1	11.5	0.1%
All sectors average	**9.9**	**9.8**	**9.7**	**9.6**	**9.7**	**9.8**	**10.1**	**0.1%**
(nominal cents per kilowatthour)								
Residential	11.5	11.5	12.7	13.6	14.9	16.5	18.7	2.0%
Commercial	10.1	10.1	10.7	11.5	12.7	13.9	15.9	1.8%
Industrial	6.8	6.7	7.0	7.6	8.6	9.6	11.2	2.1%
Transportation	12.0	11.3	11.2	11.9	13.8	15.8	18.3	2.0%
All sectors average	**9.8**	**9.8**	**10.4**	**11.3**	**12.5**	**13.9**	**16.0**	**2.0%**
Prices by service category								
(2010 cents per kilowatthour)								
Generation	6.1	5.9	5.6	5.7	6.0	6.1	6.4	0.3%
Transmission	1.0	1.0	1.1	1.1	1.1	1.1	1.1	0.3%
Distribution	2.9	2.9	3.0	2.8	2.7	2.6	2.6	-0.5%
(nominal cents per kilowatthour)								
Generation	6.0	5.9	6.0	6.7	7.7	8.7	10.2	2.2%
Transmission	1.0	1.0	1.2	1.3	1.4	1.6	1.8	2.2%
Distribution	2.8	2.9	3.3	3.3	3.4	3.7	4.1	1.4%
Electric power sector emissions[1]								
Sulfur dioxide (million short tons)	5.72	5.11	1.26	1.31	1.55	1.62	1.71	-4.3%
Nitrogen oxide (million short tons)	1.99	2.06	1.79	1.87	1.92	1.94	1.96	-0.2%
Mercury (short tons)	36.25	34.70	6.44	6.74	7.24	7.51	7.86	-5.8%

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The U.S. Energy Information Administration estimates that in 2010 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[5]Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
[6]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes refinery gas and still gas.
[9]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.
[10]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[11]Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 electric power sector generation; sales to the grid; net imports; electricity sales; and electricity end-use prices: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011), and supporting databases. 2009 and 2010 emissions: U.S. Environmental Protection Agency, Clean Air Markets Database. 2009 and 2010 electricity prices by service category: EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. **Projections**: EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A9. Electricity generating capacity
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Electric power sector[2]								
Power only[3]								
Coal	305.9	308.1	276.7	269.8	269.8	269.9	270.4	-0.5%
Oil and natural gas steam[4]	109.1	107.4	90.0	89.4	88.9	88.0	87.2	-0.8%
Combined cycle	167.7	171.7	187.4	187.7	197.6	218.3	246.0	1.4%
Combustion turbine/diesel	133.1	134.8	138.7	145.6	152.7	158.6	169.0	0.9%
Nuclear power[5]	101.1	101.2	103.6	111.2	114.7	114.3	110.9	0.4%
Pumped storage	22.2	22.2	22.2	22.2	22.2	22.2	22.2	0.0%
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7%
Renewable sources[6]	120.3	125.2	144.4	145.8	151.2	156.1	169.3	1.2%
Distributed generation[7]	0.0	0.0	0.2	0.5	0.8	1.3	2.1	- -
Total	**959.5**	**970.6**	**963.2**	**972.1**	**997.8**	**1028.7**	**1077.0**	**0.4%**
Combined heat and power[8]								
Coal	5.3	5.2	4.8	4.8	4.8	4.8	4.8	-0.3%
Oil and natural gas steam[4]	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0%
Combined cycle	25.8	26.3	26.3	26.3	26.3	26.3	26.3	-0.0%
Combustion turbine/diesel	2.8	2.8	2.8	2.8	2.8	2.8	2.8	-0.0%
Renewable sources[6]	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.2%
Total	**35.4**	**35.9**	**35.5**	**35.5**	**35.5**	**35.5**	**35.5**	**-0.0%**
Cumulative planned additions[9]								
Coal	0.0	0.0	9.3	9.3	9.3	9.3	9.3	- -
Oil and natural gas steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combined cycle	0.0	0.0	14.3	14.3	14.3	14.3	14.3	- -
Combustion turbine/diesel	0.0	0.0	5.0	5.0	5.0	5.0	5.0	- -
Nuclear power	0.0	0.0	1.1	6.8	6.8	6.8	6.8	- -
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[6]	0.0	0.0	14.0	14.0	14.0	14.0	14.0	- -
Distributed generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total	**0.0**	**0.0**	**43.7**	**49.3**	**49.3**	**49.3**	**49.3**	**- -**
Cumulative unplanned additions[9]								
Coal	0.0	0.0	0.0	0.9	0.9	1.0	1.7	- -
Oil and natural gas steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combined cycle	0.0	0.0	1.4	1.9	11.8	32.5	60.2	- -
Combustion turbine/diesel	0.0	0.0	5.2	12.9	23.2	30.2	41.5	- -
Nuclear power	0.0	0.0	0.0	0.0	0.0	0.1	1.8	- -
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[6]	0.0	0.0	5.7	7.0	12.4	17.4	30.5	- -
Distributed generation[7]	0.0	0.0	0.2	0.5	0.8	1.3	2.1	- -
Total	**0.0**	**0.0**	**12.4**	**23.2**	**49.1**	**82.5**	**137.8**	**- -**
Cumulative electric power sector additions	**0.0**	**0.0**	**56.1**	**72.5**	**98.5**	**131.8**	**187.1**	**- -**
Cumulative retirements[10]								
Coal	0.0	0.0	41.0	48.9	48.9	48.9	49.0	- -
Oil and natural gas steam[4]	0.0	0.0	17.4	18.0	18.5	19.4	20.3	- -
Combined cycle	0.0	0.0	0.0	0.2	0.2	0.2	0.2	- -
Combustion turbine/diesel	0.0	0.0	6.4	7.2	10.4	11.4	12.4	- -
Nuclear power	0.0	0.0	0.0	0.6	0.6	1.1	6.1	- -
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[6]	0.0	0.0	0.4	0.4	0.4	0.4	0.4	- -
Total	**0.0**	**0.0**	**65.2**	**75.2**	**78.9**	**81.4**	**88.4**	**- -**
Total electric power sector capacity	**994.9**	**1006.5**	**998.7**	**1007.6**	**1033.3**	**1064.2**	**1112.5**	**0.4%**

Table A9. Electricity generating capacity (continued)

(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
End-use generators[11]								
Coal	3.6	4.3	4.2	6.6	7.7	8.8	9.9	3.4%
Petroleum	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.3%
Natural gas	14.7	14.7	17.7	19.8	22.9	27.4	33.2	3.3%
Other gaseous fuels[12]	1.8	1.7	2.5	2.5	2.5	2.5	2.5	1.5%
Renewable sources[6]	6.7	7.6	17.6	21.1	23.4	27.1	30.6	5.7%
Other[13]	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0%
Total	**28.0**	**29.6**	**43.3**	**51.3**	**57.8**	**67.1**	**77.5**	**3.9%**
Cumulative capacity additions[9]	**0.0**	**0.0**	**13.7**	**21.7**	**28.2**	**37.4**	**47.9**	**- -**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Nuclear capacity includes 7.3 gigawatts of uprates through 2035.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[9]Cumulative additions after December 31, 2010.
[10]Cumulative retirements after December 31, 2010.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[12]Includes refinery gas and still gas.
[13]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 capacity and projected planned additions: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A10. Electricity trade

(billion kilowatthours, unless otherwise noted)

Electricity trade	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Interregional electricity trade								
Gross domestic sales								
Firm power	232.1	237.5	139.1	104.4	47.1	24.2	24.2	-8.7%
Economy	231.9	137.0	206.3	211.9	235.4	230.1	235.8	2.2%
Total	**464.0**	**374.4**	**345.3**	**316.3**	**282.5**	**254.3**	**260.0**	**-1.4%**
Gross domestic sales (million 2010 dollars)								
Firm power	13923.7	14244.9	8341.5	6259.9	2824.5	1450.4	1450.4	-8.7%
Economy	9065.6	6611.0	8320.2	10576.4	14143.6	13529.2	14541.9	3.2%
Total	**22989.2**	**20855.9**	**16661.8**	**16836.3**	**16968.1**	**14979.5**	**15992.2**	**-1.1%**
International electricity trade								
Imports from Canada and Mexico								
Firm power	19.3	13.7	24.3	17.1	5.2	0.4	0.4	-13.3%
Economy	33.1	31.4	24.7	27.7	34.7	31.0	28.2	-0.4%
Total	**52.4**	**45.1**	**49.0**	**44.8**	**39.9**	**31.4**	**28.6**	**-1.8%**
Exports to Canada and Mexico								
Firm power	3.3	3.7	3.0	2.1	0.6	0.0	0.0	- -
Economy	14.7	15.7	16.9	16.7	17.0	17.0	16.5	0.2%
Total	**18.1**	**19.4**	**19.9**	**18.8**	**17.6**	**17.0**	**16.5**	**-0.7%**

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports. Firm power sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 2009 and 2010 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 2007; NERC, 2011 Summer Reliability Assessment (May 2011); and NERC, Winter Reliability Assessment 2011/2012 (November 2011). 2009 and 2010 Mexican electricity trade data: U.S. Energy Information Administration (EIA), *Electric Power Annual 2010* DOE/EIA-0348(2010) (Washington, DC, November 2011). 2009 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2009*. 2010 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2010*. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A11. Liquid fuels supply and disposition

(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Crude oil								
Domestic crude production[1]	5.36	5.47	6.15	6.70	6.40	6.37	5.99	0.4%
Alaska	0.65	0.60	0.46	0.49	0.40	0.44	0.27	-3.2%
Lower 48 states	4.72	4.87	5.69	6.21	6.00	5.94	5.72	0.6%
Net imports	8.97	9.17	8.52	7.15	7.24	7.14	7.52	-0.8%
Gross imports	9.01	9.21	8.56	7.19	7.27	7.17	7.55	-0.8%
Exports	0.04	0.04	0.03	0.04	0.03	0.03	0.03	-1.1%
Other crude supply[2]	0.01	0.08	0.00	0.00	0.00	0.00	0.00	- -
Total crude supply	**14.34**	**14.72**	**14.67**	**13.85**	**13.64**	**13.52**	**13.51**	**-0.3%**
Other petroleum supply	**3.59**	**3.50**	**3.25**	**3.73**	**3.80**	**3.70**	**3.52**	**0.0%**
Natural gas plant liquids	1.91	2.07	2.56	2.91	3.01	3.05	3.01	1.5%
Net product imports	0.75	0.39	-0.25	-0.12	-0.12	-0.25	-0.34	- -
Gross refined product imports[3]	1.27	1.23	0.78	0.73	0.79	0.78	0.82	-1.6%
Unfinished oil imports	0.68	0.61	0.64	0.54	0.51	0.50	0.50	-0.8%
Blending component imports	0.72	0.74	0.66	0.64	0.65	0.65	0.66	-0.5%
Exports	1.92	2.19	2.32	2.03	2.07	2.17	2.31	0.2%
Refinery processing gain[4]	0.98	1.07	0.95	0.94	0.91	0.89	0.85	-0.9%
Product stock withdrawal	-0.04	-0.03	0.00	0.00	0.00	0.00	0.00	- -
Other non-petroleum supply	**0.81**	**1.00**	**1.22**	**1.52**	**1.86**	**2.36**	**2.96**	**4.4%**
Supply from renewable sources	0.75	0.87	1.05	1.22	1.48	1.89	2.37	4.1%
Ethanol	0.73	0.85	0.94	1.04	1.19	1.40	1.65	2.7%
Domestic production	0.72	0.88	0.94	1.04	1.17	1.37	1.59	2.4%
Net imports	0.01	-0.02	0.00	0.00	0.02	0.03	0.06	- -
Biodiesel	0.02	0.01	0.09	0.12	0.12	0.13	0.13	9.2%
Domestic production	0.03	0.02	0.09	0.12	0.12	0.13	0.13	7.9%
Net imports	-0.01	-0.01	0.00	0.00	0.00	0.00	-0.00	- -
Other biomass-derived liquids[5]	0.00	0.00	0.03	0.06	0.16	0.36	0.59	23.2%
Liquids from gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from coal	0.00	0.00	0.00	0.12	0.17	0.22	0.28	- -
Other[6]	0.05	0.13	0.17	0.19	0.21	0.25	0.31	3.6%
Total primary supply[7]	**18.74**	**19.22**	**19.14**	**19.10**	**19.29**	**19.57**	**19.99**	**0.2%**
Liquid fuels consumption								
by fuel								
Liquefied petroleum gases	2.13	2.27	1.94	2.11	2.21	2.22	2.21	-0.1%
E85[8]	0.00	0.00	0.01	0.09	0.21	0.49	0.83	27.0%
Motor gasoline[9]	9.00	8.99	8.88	8.48	8.29	8.17	8.09	-0.4%
Jet fuel[10]	1.39	1.43	1.46	1.49	1.54	1.58	1.61	0.5%
Distillate fuel oil[11]	3.63	3.80	4.19	4.24	4.33	4.38	4.48	0.7%
Diesel	3.18	3.32	3.71	3.81	3.92	3.99	4.11	0.9%
Residual fuel oil	0.51	0.54	0.56	0.56	0.57	0.57	0.58	0.3%
Other[12]	2.15	2.14	2.06	2.04	2.06	2.06	2.10	-0.1%
by sector								
Residential and commercial	1.05	1.12	1.00	0.96	0.94	0.92	0.91	-0.9%
Industrial[13]	4.24	4.31	4.17	4.31	4.41	4.41	4.44	0.1%
Transportation	13.54	13.82	13.80	13.62	13.71	14.00	14.41	0.2%
Electric power[14]	0.17	0.17	0.13	0.13	0.14	0.14	0.14	-0.7%
Total	**18.81**	**19.17**	**19.10**	**19.02**	**19.20**	**19.47**	**19.90**	**0.1%**
Discrepancy[15]	**-0.07**	**0.05**	**0.05**	**0.09**	**0.10**	**0.10**	**0.09**	**- -**

Table A11. Liquid fuels supply and disposition (continued)

(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Domestic refinery distillation capacity[16]	17.7	17.6	17.5	15.8	15.5	15.4	15.2	-0.6%
Capacity utilization rate (percent)[17]	83.0	86.0	85.9	89.8	90.1	89.6	90.8	0.2%
Net import share of product supplied (percent)	51.9	49.6	43.2	36.8	37.0	35.4	36.2	-1.2%
Net expenditures for imported crude oil and petroleum products (billion 2010 dollars)	206.18	243.07	373.00	322.55	344.58	353.03	389.97	1.9%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol and ethers blended into gasoline.
[10]Includes only kerosene type.
[11]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[13]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[15]Balancing item. Includes unaccounted for supply, losses, and gains.
[16]End-of-year operable capacity.
[17]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 product supplied based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). Other 2009 data: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). Other 2010 data: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A12. Petroleum product prices

(2010 dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Crude oil prices (2010 dollars per barrel)								
Low sulfur light	62.37	79.39	116.91	126.68	132.56	138.49	144.98	2.4%
Imported crude oil[1]	59.72	75.87	113.97	115.74	121.21	126.51	132.95	2.3%
Delivered sector product prices								
Residential								
Liquefied petroleum gases	2.10	2.29	2.60	2.63	2.73	2.82	2.93	1.0%
Distillate fuel oil	2.54	2.94	3.78	4.00	4.18	4.36	4.54	1.8%
Commercial								
Distillate fuel oil	2.23	2.87	3.30	3.51	3.70	3.85	4.02	1.4%
Residual fuel oil	2.04	1.66	2.42	2.63	2.73	2.85	2.83	2.2%
Residual fuel oil (2010 dollars per barrel)	85.89	69.58	101.70	110.65	114.70	119.73	118.85	2.2%
Industrial[2]								
Liquefied petroleum gases	1.70	1.85	2.32	2.35	2.48	2.58	2.73	1.6%
Distillate fuel oil	2.31	2.93	3.32	3.53	3.74	3.90	4.05	1.3%
Residual fuel oil	1.82	1.63	2.88	3.07	3.18	3.25	3.24	2.8%
Residual fuel oil (2010 dollars per barrel)	76.47	68.62	120.80	129.07	133.47	136.47	136.12	2.8%
Transportation								
Liquefied petroleum gases	2.19	2.28	2.70	2.73	2.83	2.91	3.03	1.1%
Ethanol (E85)[3]	1.98	2.40	2.77	2.85	2.75	2.93	3.05	1.0%
Ethanol wholesale price	1.59	1.71	2.23	2.54	2.33	2.29	2.16	0.9%
Motor gasoline[4]	2.38	2.76	3.54	3.71	3.86	3.97	4.03	1.5%
Jet fuel[5]	1.72	2.19	3.21	3.41	3.57	3.72	3.93	2.4%
Diesel fuel (distillate fuel oil)[6]	2.47	3.00	3.78	3.97	4.17	4.30	4.44	1.6%
Residual fuel oil	1.59	1.56	2.74	2.93	3.09	3.11	3.14	2.8%
Residual fuel oil (2010 dollars per barrel)	66.71	65.53	115.15	123.09	129.62	130.52	131.73	2.8%
Electric power[7]								
Distillate fuel oil	2.02	2.60	3.16	3.35	3.52	3.67	3.86	1.6%
Residual fuel oil	1.34	1.78	3.44	3.65	3.80	3.83	3.85	3.1%
Residual fuel oil (2010 dollars per barrel)	56.46	74.77	144.60	153.30	159.70	160.65	161.71	3.1%
Refined petroleum product prices[8]								
Liquefied petroleum gases	1.37	1.46	1.95	1.95	2.05	2.14	2.26	1.7%
Motor gasoline[4]	2.37	2.74	3.54	3.71	3.85	3.97	4.03	1.6%
Jet fuel[5]	1.72	2.19	3.21	3.41	3.57	3.72	3.93	2.4%
Distillate fuel oil	2.44	2.97	3.69	3.89	4.09	4.23	4.38	1.6%
Residual fuel oil	1.57	1.62	2.85	3.04	3.19	3.22	3.25	2.8%
Residual fuel oil (2010 dollars per barrel)	66.10	68.00	119.50	127.68	133.95	135.33	136.32	2.8%
Average	**2.17**	**2.53**	**3.32**	**3.46**	**3.60**	**3.72**	**3.83**	**1.7%**

Table A12. Petroleum product prices (continued)

(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Crude oil prices (nominal dollars per barrel)								
Low sulfur light	61.65	79.39	125.97	148.87	170.09	197.10	229.55	4.3%
Imported crude oil[1]	59.04	75.87	122.81	136.02	155.52	180.06	210.51	4.2%
Delivered sector product prices								
Residential								
Liquefied petroleum gases	2.08	2.29	2.80	3.09	3.51	4.01	4.65	2.9%
Distillate fuel oil	2.52	2.94	4.07	4.70	5.36	6.20	7.19	3.6%
Commercial								
Distillate fuel oil	2.20	2.87	3.56	4.12	4.75	5.48	6.36	3.2%
Residual fuel oil	2.02	1.66	2.61	3.10	3.50	4.06	4.48	4.1%
Residual fuel oil (nominal dollars per barrel)	84.91	69.58	109.59	130.04	147.17	170.40	188.19	4.1%
Industrial[2]								
Liquefied petroleum gases	1.68	1.85	2.50	2.76	3.18	3.67	4.31	3.5%
Distillate fuel oil	2.28	2.93	3.58	4.15	4.80	5.55	6.42	3.2%
Residual fuel oil	1.80	1.63	3.10	3.61	4.08	4.62	5.13	4.7%
Residual fuel oil (nominal dollars per barrel)	75.59	68.62	130.16	151.68	171.25	194.23	215.53	4.7%
Transportation								
Liquefied petroleum gases	2.16	2.28	2.91	3.21	3.63	4.14	4.79	3.0%
Ethanol (E85)[3]	1.96	2.40	2.98	3.35	3.52	4.17	4.82	2.8%
Ethanol wholesale price	1.57	1.71	2.40	2.98	2.99	3.25	3.42	2.8%
Motor gasoline[4]	2.35	2.76	3.81	4.36	4.95	5.64	6.39	3.4%
Jet fuel[5]	1.70	2.19	3.45	4.01	4.58	5.30	6.23	4.3%
Diesel fuel (distillate fuel oil)[6]	2.44	3.00	4.07	4.67	5.35	6.12	7.03	3.5%
Residual fuel oil	1.57	1.56	2.95	3.44	3.96	4.42	4.97	4.7%
Residual fuel oil (nominal dollars per barrel)	65.95	65.53	124.07	144.66	166.32	185.76	208.57	4.7%
Electric power[7]								
Distillate fuel oil	1.99	2.60	3.40	3.94	4.51	5.22	6.11	3.5%
Residual fuel oil	1.33	1.78	3.71	4.29	4.88	5.44	6.10	5.0%
Residual fuel oil (nominal dollars per barrel)	55.81	74.77	155.81	180.16	204.91	228.64	256.05	5.0%
Refined petroleum product prices[8]								
Liquefied petroleum gases	1.35	1.46	2.10	2.30	2.63	3.04	3.57	3.6%
Motor gasoline[4]	2.35	2.74	3.81	4.36	4.95	5.64	6.39	3.4%
Jet fuel[5]	1.70	2.19	3.45	4.01	4.58	5.30	6.23	4.3%
Distillate fuel oil	2.41	2.97	3.97	4.57	5.25	6.03	6.93	3.4%
Residual fuel oil	1.56	1.62	3.07	3.57	4.09	4.59	5.14	4.7%
Residual fuel oil (nominal dollars per barrel)	65.34	68.00	128.77	150.05	171.87	192.61	215.84	4.7%
Average	**2.14**	**2.53**	**3.57**	**4.06**	**4.62**	**5.29**	**6.06**	**3.6%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2009 and 2010 imported crude oil price: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2009 and 2010 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2009 and 2010 electric power prices based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/09) (Washington, DC, September 2011). 2009 and 2010 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2009 and 2010 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A13. Natural gas supply, disposition, and prices

(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Production								
Dry gas production[1]	20.58	21.58	23.65	25.09	26.28	26.94	27.93	1.0%
Supplemental natural gas[2]	0.07	0.07	0.06	0.06	0.06	0.06	0.06	-0.2%
Net imports	**2.68**	**2.58**	**1.73**	**0.35**	**-0.79**	**-0.89**	**-1.36**	**- -**
Pipeline[3]	2.26	2.21	1.56	1.01	-0.13	-0.27	-0.70	- -
Liquefied natural gas	0.42	0.37	0.16	-0.66	-0.66	-0.62	-0.66	- -
Total supply	**23.32**	**24.22**	**25.45**	**25.50**	**25.55**	**26.11**	**26.63**	**0.4%**
Consumption by sector								
Residential	4.78	4.94	4.85	4.83	4.76	4.72	4.64	-0.2%
Commercial	3.12	3.20	3.33	3.43	3.44	3.52	3.60	0.5%
Industrial[4]	6.17	6.60	7.01	7.08	7.14	7.03	7.00	0.2%
Natural-gas-to-liquids heat and power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas to liquids production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electric power[7]	6.87	7.38	8.08	7.87	7.87	8.47	8.96	0.8%
Transportation[8]	0.04	0.04	0.06	0.08	0.11	0.14	0.16	5.9%
Pipeline fuel	0.60	0.63	0.67	0.66	0.66	0.66	0.67	0.2%
Lease and plant fuel[9]	1.28	1.34	1.39	1.51	1.53	1.55	1.60	0.7%
Total	**22.85**	**24.13**	**25.39**	**25.47**	**25.53**	**26.10**	**26.63**	**0.4%**
Discrepancy[10]	**0.47**	**0.10**	**0.05**	**0.04**	**0.02**	**0.01**	**-0.00**	**- -**
Natural gas prices								
(2010 dollars per million Btu)								
Henry hub spot price	4.00	4.39	4.29	4.58	5.63	6.29	7.37	2.1%
Average lower 48 wellhead price[11]	3.75	4.06	3.84	4.10	5.00	5.56	6.48	1.9%
(2010 dollars per thousand cubic feet)								
Average lower 48 wellhead price[11]	3.85	4.16	3.94	4.19	5.12	5.69	6.64	1.9%
Delivered prices								
(2010 dollars per thousand cubic feet)								
Residential	12.25	11.36	10.56	11.11	12.33	13.08	14.33	0.9%
Commercial	10.06	9.32	8.82	9.21	10.27	10.86	11.93	1.0%
Industrial[4]	5.47	5.65	5.00	5.25	6.19	6.73	7.73	1.3%
Electric power[7]	4.97	5.25	4.65	4.83	5.73	6.35	7.37	1.4%
Transportation[12]	14.52	13.53	12.71	12.81	13.62	14.02	14.87	0.4%
Average[13]	**7.55**	**7.33**	**6.60**	**6.93**	**7.93**	**8.50**	**9.52**	**1.1%**

Table A13. Natural gas supply, disposition, and prices (continued)

(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Natural gas prices								
(nominal dollars per million Btu)								
Henry hub spot price	3.95	4.39	4.62	5.39	7.23	8.95	11.67	4.0%
Average lower 48 wellhead price[11]	3.71	4.06	4.14	4.81	6.42	7.92	10.26	3.8%
(nominal dollars per thousand cubic feet)								
Average lower 48 wellhead price[11]	3.80	4.16	4.24	4.93	6.57	8.11	10.51	3.8%
Delivered prices								
(nominal dollars per thousand cubic feet)								
Residential	12.11	11.36	11.38	13.06	15.82	18.61	22.69	2.8%
Commercial	9.95	9.32	9.50	10.82	13.18	15.46	18.89	2.9%
Industrial[4]	5.40	5.65	5.39	6.17	7.94	9.58	12.23	3.1%
Electric power[7]	4.92	5.25	5.01	5.67	7.35	9.03	11.67	3.2%
Transportation[12]	14.36	13.53	13.70	15.06	17.48	19.95	23.54	2.2%
Average[13]	**7.46**	**7.33**	**7.11**	**8.15**	**10.17**	**12.10**	**15.08**	**2.9%**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[8]Natural gas used as vehicle fuel.
[9]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[10]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2009 and 2010 values include net storage injections.
[11]Represents lower 48 onshore and offshore supplies.
[12]Natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[13]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 supply values; and lease, plant, and pipeline fuel consumption: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 supply values; lease, plant, and pipeline fuel consumption; and wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). Other 2009 and 2010 consumption based on: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 wellhead price: U.S. Department of the Interior, Office of Natural Resources Revenue; and EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2009 residential and commercial delivered prices: EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 and 2010 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2010 and April 2011, Table 4.2, and EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2009 and 2010 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and estimated state taxes, federal taxes, and dispensing costs or charges. 2010 transportation sector delivered prices are model results. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A14. Oil and gas supply

Production and supply	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Crude oil								
Lower 48 average wellhead price[1] (2010 dollars per barrel)	**57.46**	**80.46**	**117.84**	**124.44**	**130.30**	**130.74**	**137.55**	**2.2%**
Production (million barrels per day)[2]								
United States total	5.36	5.47	6.15	6.70	6.40	6.37	5.99	0.4%
Lower 48 onshore	3.04	3.21	4.09	4.38	4.43	4.29	3.99	0.9%
Tight oil[3]	0.25	0.37	0.97	1.20	1.29	1.32	1.23	4.9%
Carbon dioxide enhanced oil recovery	0.27	0.28	0.26	0.33	0.49	0.61	0.66	3.5%
Other	2.52	2.55	2.86	2.85	2.66	2.36	2.10	-0.8%
Lower 48 offshore	1.68	1.67	1.60	1.83	1.57	1.65	1.74	0.2%
Alaska	0.65	0.60	0.46	0.49	0.40	0.44	0.27	-3.2%
Lower 48 end of year reserves[2] (billion barrels)	**18.75**	**18.33**	**20.55**	**23.02**	**23.64**	**24.34**	**24.23**	**1.1%**
Natural gas								
Lower 48 average wellhead price[1] (2010 dollars per million Btu)								
Henry hub spot price	4.00	4.39	4.29	4.58	5.63	6.29	7.37	2.1%
Average lower 48 wellhead price[1]	3.75	4.06	3.84	4.10	5.00	5.56	6.48	1.9%
(2010 dollars per thousand cubic feet)								
Average lower 48 wellhead price[1]	3.85	4.16	3.94	4.19	5.12	5.69	6.64	1.9%
Dry production (trillion cubic feet)[4]								
United States total	20.58	21.58	23.65	25.09	26.28	26.94	27.93	1.0%
Lower 48 onshore	17.50	18.66	21.48	22.48	23.64	24.11	24.97	1.2%
Associated-dissolved[5]	1.40	1.40	1.52	1.54	1.41	1.18	1.00	-1.3%
Non-associated	16.10	17.26	19.96	20.94	22.23	22.93	23.97	1.3%
Tight gas	6.40	5.68	6.08	6.06	6.17	6.07	6.14	0.3%
Shale gas	2.91	4.99	8.24	9.69	11.26	12.42	13.63	4.1%
Coalbed methane	1.99	1.99	1.83	1.79	1.77	1.74	1.76	-0.5%
Other	4.80	4.59	3.82	3.40	3.03	2.70	2.44	-2.5%
Lower 48 offshore	2.70	2.56	1.88	2.34	2.38	2.58	2.72	0.3%
Associated-dissolved[5]	0.70	0.71	0.55	0.75	0.67	0.70	0.73	0.1%
Non-associated	2.00	1.85	1.33	1.59	1.71	1.88	2.00	0.3%
Alaska	0.37	0.36	0.29	0.27	0.25	0.25	0.23	-1.8%
Lower 48 end of year dry reserves[4] (trillion cubic feet)	**263.40**	**260.50**	**274.79**	**290.32**	**299.77**	**307.17**	**311.58**	**0.7%**
Supplemental gas supplies (trillion cubic feet)[6]	**0.07**	**0.07**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**-0.2%**
Total lower 48 wells drilled (thousands)	**34.31**	**43.19**	**49.79**	**53.80**	**59.42**	**60.21**	**65.59**	**1.7%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[4]Marketed production (wet) minus extraction losses.
[5]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[6]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2009 and 2010 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). 2009 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2009) (Washington, DC, November 2010). 2009 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2009 natural gas lower 48 average wellhead price: U.S. Department of the Interior, Office of Natural Resources Revenue; and EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). Other 2009 and 2010 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A15. Coal supply, disposition, and prices

(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Production[1]								
Appalachia	343	336	300	262	271	282	291	-0.6%
Interior	147	156	151	159	163	181	198	1.0%
West	585	592	542	613	684	703	722	0.8%
East of the Mississippi	450	446	407	377	383	409	431	-0.1%
West of the Mississippi	625	638	586	657	735	757	781	0.8%
Total	**1075**	**1084**	**993**	**1034**	**1118**	**1166**	**1212**	**0.4%**
Waste coal supplied[2]	**14**	**14**	**15**	**15**	**16**	**17**	**19**	**1.4%**
Net imports								
Imports[3]	21	18	15	28	44	33	36	2.8%
Exports	59	82	110	95	115	117	129	1.8%
Total	**-38**	**-64**	**-95**	**-67**	**-71**	**-83**	**-94**	**- -**
Total supply[4]	**1050**	**1034**	**914**	**982**	**1064**	**1100**	**1138**	**0.4%**
Consumption by sector								
Residential and commercial	3	3	3	3	3	3	3	-0.3%
Coke plants	15	21	22	18	19	18	17	-1.0%
Other industrial[5]	45	52	50	51	52	52	53	0.0%
Coal-to-liquids heat and power	0	0	0	13	19	26	34	- -
Coal to liquids production	0	0	0	12	18	25	32	- -
Electric power[6]	934	975	839	885	952	975	998	0.1%
Total	**997**	**1051**	**914**	**982**	**1063**	**1099**	**1137**	**0.3%**
Discrepancy and stock change[7]	**53**	**-17**	**-0**	**-0**	**1**	**0**	**0**	**- -**
Average minemouth price[8]								
(2010 dollars per short ton)	33.62	35.61	42.08	40.96	44.05	47.28	50.52	1.4%
(2010 dollars per million Btu)	1.68	1.76	2.08	2.06	2.23	2.39	2.56	1.5%
Delivered prices (2010 dollars per short ton)[9]								
Coke plants	144.66	153.59	189.11	198.45	212.18	225.36	238.32	1.8%
Other industrial[5]	65.62	59.28	70.14	70.89	72.77	75.43	78.53	1.1%
Coal to liquids	- -	- -	18.65	40.67	39.03	40.20	41.54	- -
Electric power								
(2010 dollars per short ton)	43.83	44.27	45.17	45.98	48.13	50.56	53.31	0.7%
(2010 dollars per million Btu)	2.22	2.26	2.35	2.41	2.54	2.66	2.80	0.9%
Average	**46.41**	**47.17**	**49.95**	**49.99**	**51.90**	**54.09**	**56.48**	**0.7%**
Exports[10]	102.61	120.41	140.89	155.03	163.43	172.39	177.66	1.6%

Table A15. Coal supply, disposition, and prices (continued)

(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Average minemouth price[8]								
(nominal dollars per short ton)	33.24	35.61	45.34	48.13	56.52	67.28	80.00	3.3%
(nominal dollars per million Btu)	1.66	1.76	2.24	2.42	2.86	3.41	4.05	3.4%
Delivered prices (nominal dollars per short ton)[9]								
Coke plants	143.01	153.59	203.77	233.22	272.25	320.74	377.36	3.7%
Other industrial[5]	64.87	59.28	75.58	83.31	93.37	107.35	124.34	3.0%
Coal to liquids	- -	- -	20.09	47.80	50.08	57.22	65.77	- -
Electric power								
(nominal dollars per short ton)	43.33	44.27	48.68	54.03	61.76	71.96	84.40	2.6%
(nominal dollars per million Btu)	2.19	2.26	2.53	2.83	3.25	3.78	4.43	2.7%
Average	**45.88**	**47.17**	**53.83**	**58.74**	**66.60**	**76.98**	**89.43**	**2.6%**
Exports[10]	101.44	120.41	151.81	182.19	209.70	245.35	281.30	3.5%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
[8]Includes reported prices for both open market and captive mines.
[9]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[10]F.a.s. price at U.S. port of exit.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011); EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011); and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A16. Renewable energy generating capacity and generation

(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Electric power sector[1]								
Net summer capacity								
Conventional hydropower	78.01	78.03	78.55	79.13	80.14	80.66	81.25	0.2%
Geothermal[2]	2.37	2.37	2.86	3.57	4.45	5.48	6.30	4.0%
Municipal waste[3]	3.20	3.30	3.36	3.36	3.36	3.36	3.36	0.1%
Wood and other biomass[4]	2.43	2.45	2.72	2.72	2.72	2.72	2.89	0.7%
Solar thermal	0.47	0.47	1.36	1.36	1.36	1.36	1.36	4.3%
Solar photovoltaic[5]	0.15	0.38	2.02	2.03	2.30	2.97	8.18	13.0%
Wind	34.52	39.05	54.26	54.31	57.57	60.29	66.65	2.2%
Offshore wind	0.00	0.00	0.20	0.20	0.20	0.20	0.20	- -
Total electric power sector capacity	**121.16**	**126.06**	**145.34**	**146.68**	**152.10**	**157.05**	**170.19**	**1.2%**
Generation (billion kilowatthours)								
Conventional hydropower	271.50	255.32	295.43	300.54	305.00	307.40	310.08	0.8%
Geothermal[2]	15.01	15.67	18.68	24.41	31.53	39.89	46.54	4.5%
Biogenic municipal waste[6]	16.10	16.56	14.66	14.67	14.67	14.67	14.67	-0.5%
Wood and other biomass	10.74	11.51	21.28	51.60	63.90	57.08	49.28	6.0%
Dedicated plants	9.68	10.15	10.13	13.16	13.30	11.81	10.37	0.1%
Cofiring	1.06	1.36	11.15	38.44	50.60	45.27	38.92	14.4%
Solar thermal	0.74	0.82	2.86	2.86	2.86	2.86	2.86	5.1%
Solar photovoltaic[5]	0.16	0.46	3.61	3.62	4.37	6.16	20.19	16.4%
Wind	73.88	94.49	150.22	150.34	160.73	169.64	189.92	2.8%
Offshore wind	0.00	0.00	0.75	0.75	0.75	0.75	0.75	- -
Total electric power sector generation	**388.11**	**394.82**	**507.49**	**548.78**	**583.81**	**598.46**	**634.30**	**1.9%**
End-use sectors[7]								
Net summer capacity								
Conventional hydropower[8]	0.34	0.33	0.33	0.33	0.33	0.33	0.33	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal waste[9]	0.36	0.35	0.35	0.35	0.35	0.35	0.35	0.0%
Biomass	4.56	4.56	5.73	6.68	8.44	11.31	13.81	4.5%
Solar photovoltaic[5]	1.22	2.05	8.98	11.19	11.69	12.41	13.33	7.8%
Wind	0.18	0.36	2.25	2.57	2.60	2.65	2.74	8.5%
Total end-use sector capacity	**6.66**	**7.65**	**17.64**	**21.12**	**23.41**	**27.05**	**30.57**	**5.7%**
Generation (billion kilowatthours)								
Conventional hydropower[8]	1.94	1.76	1.75	1.75	1.75	1.75	1.75	-0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal waste[9]	2.07	2.02	2.79	2.79	2.79	2.79	2.79	1.3%
Biomass	25.31	26.10	33.30	39.53	52.34	76.03	96.17	5.4%
Solar photovoltaic[5]	1.93	3.21	13.88	17.40	18.22	19.40	20.91	7.8%
Wind	0.24	0.47	2.88	3.31	3.36	3.44	3.56	8.5%
Total end-use sector generation	**31.48**	**33.56**	**54.59**	**64.77**	**78.45**	**103.40**	**125.17**	**5.4%**

Table A16. Renewable energy generating capacity and generation (continued)

(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Total, all sectors								
Net summer capacity								
Conventional hydropower	78.35	78.36	78.88	79.46	80.47	80.99	81.58	0.2%
Geothermal	2.37	2.37	2.86	3.57	4.45	5.48	6.30	4.0%
Municipal waste	3.57	3.65	3.71	3.71	3.71	3.71	3.71	0.1%
Wood and other biomass[4]	6.99	7.00	8.45	9.40	11.16	14.03	16.71	3.5%
Solar[5]	1.85	2.90	12.37	14.58	15.35	16.74	22.87	8.6%
Wind	34.70	39.41	56.72	57.07	60.37	63.15	69.59	2.3%
Total capacity, all sectors	**127.83**	**133.70**	**162.98**	**167.80**	**175.51**	**184.10**	**200.76**	**1.6%**
Generation (billion kilowatthours)								
Conventional hydropower	273.44	257.08	297.18	302.28	306.75	309.15	311.83	0.8%
Geothermal	15.01	15.67	18.68	24.41	31.53	39.89	46.54	4.5%
Municipal waste	18.16	18.59	17.45	17.46	17.46	17.46	17.46	-0.3%
Wood and other biomass	36.05	37.61	54.58	91.13	116.24	133.11	145.45	5.6%
Solar[5]	2.82	4.48	20.35	23.87	25.44	28.42	43.96	9.6%
Wind	74.12	94.95	153.85	154.40	164.84	173.83	194.23	2.9%
Total generation, all sectors	**419.59**	**428.38**	**562.08**	**613.55**	**662.25**	**701.85**	**759.46**	**2.3%**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2]Includes both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity generation and is only available after 2025.

[3]Includes municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.

[4]Facilities co-firing biomass and coal are classified as coal.

[5]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2009, EIA estimates that as much as 245 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2009, plus an additional 558 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011), Table 10.9 (annual PV shipments, 1989-2009). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.

[6]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2010 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).

[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[8]Represents own-use industrial hydroelectric power.

[9]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 capacity: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2009 and 2010 generation: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A17. Renewable energy consumption by sector and source

(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Marketed renewable energy[1]								
Residential (wood)	**0.43**	**0.42**	**0.43**	**0.43**	**0.43**	**0.43**	**0.43**	**0.1%**
Commercial (biomass)	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.0%**
Industrial[2]	**2.19**	**2.34**	**2.42**	**2.63**	**3.09**	**3.79**	**4.52**	**2.7%**
Conventional hydroelectric	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.0%
Municipal waste[3]	0.16	0.17	0.18	0.18	0.18	0.18	0.18	0.1%
Biomass	1.19	1.31	1.42	1.48	1.62	1.68	1.76	1.2%
Biofuels heat and coproducts	0.82	0.84	0.81	0.96	1.27	1.92	2.57	4.6%
Transportation	**0.99**	**1.14**	**1.45**	**1.72**	**2.16**	**2.88**	**3.75**	**4.9%**
Ethanol used in E85[4]	0.00	0.00	0.01	0.08	0.20	0.47	0.80	27.0%
Ethanol used in gasoline blending	0.95	1.10	1.21	1.27	1.35	1.35	1.34	0.8%
Biodiesel used in distillate blending	0.04	0.03	0.18	0.23	0.24	0.25	0.26	9.2%
Liquids from biomass	0.00	0.00	0.03	0.11	0.33	0.78	1.31	- -
Renewable diesel and gasoline[5]	0.00	0.01	0.03	0.03	0.03	0.03	0.03	6.2%
Electric power[6]	**3.77**	**3.85**	**4.96**	**5.40**	**5.75**	**5.87**	**6.22**	**1.9%**
Conventional hydroelectric	2.65	2.49	2.88	2.93	2.98	3.00	3.03	0.8%
Geothermal	0.15	0.15	0.18	0.24	0.31	0.39	0.45	4.5%
Biogenic municipal waste[7]	0.07	0.08	0.09	0.09	0.09	0.09	0.09	0.6%
Biomass	0.17	0.19	0.27	0.60	0.73	0.64	0.56	4.4%
Dedicated plants	0.16	0.17	0.16	0.21	0.22	0.18	0.16	-0.1%
Cofiring	0.01	0.02	0.11	0.39	0.52	0.46	0.40	11.8%
Solar thermal	0.01	0.01	0.03	0.03	0.03	0.03	0.03	5.1%
Solar photovoltaic	0.00	0.00	0.04	0.04	0.04	0.06	0.20	16.4%
Wind	0.72	0.92	1.47	1.47	1.58	1.66	1.86	2.8%
Total marketed renewable energy	**7.49**	**7.87**	**9.37**	**10.29**	**11.54**	**13.09**	**15.03**	**2.6%**
Sources of ethanol								
from corn and other starch	0.94	1.14	1.20	1.32	1.39	1.39	1.46	1.0%
from cellulose	0.00	0.00	0.01	0.03	0.13	0.40	0.61	56.6%
Net imports	0.02	-0.03	0.00	0.00	0.03	0.04	0.08	- -
Total	**0.95**	**1.11**	**1.22**	**1.35**	**1.55**	**1.82**	**2.15**	**2.7%**

Table A17. Renewable energy consumption by sector and source (continued)

(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Nonmarketed renewable energy[8]								
Selected consumption								
Residential	**0.02**	**0.02**	**0.08**	**0.10**	**0.10**	**0.11**	**0.11**	**6.9%**
Solar hot water heating	0.01	0.01	0.02	0.02	0.02	0.02	0.02	2.4%
Geothermal heat pumps	0.00	0.01	0.01	0.02	0.02	0.02	0.03	6.4%
Solar photovoltaic	0.00	0.00	0.04	0.05	0.05	0.06	0.06	10.7%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	9.1%
Commercial	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**1.7%**
Solar thermal	0.03	0.03	0.03	0.03	0.03	0.04	0.04	1.4%
Solar photovoltaic	0.00	0.01	0.01	0.01	0.01	0.01	0.01	2.8%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.3%

[1]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A2.

[2]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.

[3]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.

[4]Excludes motor gasoline component of E85.

[5]Renewable feedstocks for the on-site production of diesel and gasoline.

[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, geothermal, solar, and wind. Consumption at hydroelectric, geothermal, solar, and wind facilities determined by using the fossil fuel equivalent of 9,760 Btu per kilowatthour.

[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2010 approximately 0.3 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).

[8]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The U.S. Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.

- - = Not applicable.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 ethanol: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 and 2010 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2009 and 2010 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A18. Energy-related carbon dioxide emissions by sector and source
(million metric tons, unless otherwise noted)

Sector and source	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Residential								
Petroleum	81	85	74	69	65	61	59	-1.5%
Natural gas	259	267	264	263	259	257	252	-0.2%
Coal	1	1	1	1	1	1	1	-1.3%
Electricity[1]	819	879	746	769	816	862	907	0.1%
Total residential	**1159**	**1232**	**1084**	**1101**	**1141**	**1181**	**1218**	**-0.0%**
Commercial								
Petroleum	49	51	44	44	44	44	44	-0.6%
Natural gas	169	173	181	186	187	191	196	0.5%
Coal	6	6	6	6	6	6	6	0.0%
Electricity[1]	785	805	721	757	806	852	897	0.4%
Total commercial	**1009**	**1035**	**952**	**993**	**1043**	**1093**	**1142**	**0.4%**
Industrial[2]								
Petroleum	339	344	364	350	351	351	358	0.2%
Natural gas[3]	383	408	445	454	459	455	456	0.4%
Coal	128	157	154	170	183	190	197	0.9%
Electricity[1]	551	583	540	536	550	535	516	-0.5%
Total industrial	**1401**	**1492**	**1503**	**1509**	**1542**	**1531**	**1527**	**0.1%**
Transportation								
Petroleum[4]	1818	1836	1825	1785	1778	1791	1814	-0.0%
Natural gas[5]	34	36	39	40	42	44	45	0.9%
Electricity[1]	4	4	4	5	7	9	12	4.2%
Total transportation	**1856**	**1876**	**1868**	**1831**	**1827**	**1843**	**1871**	**-0.0%**
Electric power[6]								
Petroleum	34	33	23	23	24	24	25	-1.1%
Natural gas	373	399	438	427	427	459	485	0.8%
Coal	1741	1828	1539	1606	1717	1763	1809	-0.0%
Other[7]	12	12	12	12	12	12	12	0.0%
Total electric power	**2159**	**2271**	**2011**	**2067**	**2179**	**2258**	**2330**	**0.1%**
Total by fuel								
Petroleum[3]	2320	2349	2329	2271	2261	2271	2300	-0.1%
Natural gas	1218	1283	1367	1370	1374	1405	1435	0.4%
Coal	1876	1990	1699	1781	1906	1959	2012	0.0%
Other[7]	12	12	12	12	12	12	12	0.0%
Total	**5425**	**5634**	**5407**	**5434**	**5552**	**5647**	**5758**	**0.1%**
Carbon dioxide emissions (tons per person)	**17.6**	**18.1**	**16.6**	**15.9**	**15.5**	**15.1**	**14.8**	**-0.8%**

[1]Emissions from the electric power sector are distributed to the end-use sectors.
[2]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes lease and plant fuel.
[4]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2009, international bunker fuels accounted for 90 to 126 million metric tons annually.
[5]Includes pipeline fuel natural gas and natural gas used as vehicle fuel.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Note: By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. See "Energy-Related Carbon Dioxide Emissions by End Use" for the emissions from biogenic energy sources as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration. Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 and 2010 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review, October 2011* DOE/EIA-0035(2011/10) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A19. Energy-related carbon dioxide emissions by end use
(million metric tons)

Sector and end use	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Residential								
Space heating	280.90	298.51	277.05	272.48	267.41	264.17	259.97	-0.6%
Space cooling	142.72	191.18	159.32	164.10	174.13	183.61	192.21	0.0%
Water heating	160.15	159.68	151.53	154.46	157.58	156.73	154.55	-0.1%
Refrigeration	66.17	66.06	57.91	58.63	61.36	64.38	67.24	0.1%
Cooking	32.01	32.25	30.98	32.26	33.88	35.40	36.82	0.5%
Clothes dryers	36.78	37.23	33.43	31.76	30.86	30.58	31.50	-0.7%
Freezers	14.50	14.62	13.14	13.17	13.46	13.61	13.81	-0.2%
Lighting	123.36	122.27	81.97	74.77	72.02	71.52	72.33	-2.1%
Clothes washers[1]	5.87	5.79	4.96	4.18	3.86	3.64	3.74	-1.7%
Dishwashers[1]	17.70	17.75	15.48	15.32	15.33	16.16	17.28	-0.1%
Color televisions and set-top boxes	56.62	58.20	50.98	53.06	57.14	61.62	66.45	0.5%
Personal computers and related equipment	29.75	30.47	29.70	33.59	37.07	39.80	41.67	1.3%
Furnace fans and boiler circulation pumps	23.80	23.93	21.88	22.19	22.63	22.80	23.00	-0.2%
Other uses	167.37	173.46	155.66	171.03	194.05	216.69	237.60	1.3%
Discrepancy[2]	1.73	0.16	0.00	-0.00	0.00	0.00	0.00	- -
Total residential	**1159.44**	**1231.57**	**1083.99**	**1101.00**	**1140.80**	**1180.73**	**1218.17**	**-0.0%**
Commercial								
Space heating[3]	129.16	129.68	124.70	124.97	122.24	120.61	118.00	-0.4%
Space cooling[3]	84.66	101.34	80.33	79.94	81.20	82.60	84.17	-0.7%
Water heating[3]	41.32	41.44	41.47	42.83	43.45	44.00	44.04	0.2%
Ventilation	88.64	90.04	83.19	86.87	90.94	94.43	97.04	0.3%
Cooking	13.27	13.58	13.68	14.20	14.47	14.84	15.13	0.4%
Lighting	181.96	180.09	156.69	160.17	166.24	171.06	174.62	-0.1%
Refrigeration	70.13	69.16	55.15	52.64	52.71	53.53	54.79	-0.9%
Office equipment (PC)	38.00	37.69	29.68	29.85	30.75	32.11	33.19	-0.5%
Office equipment (non-PC)	43.86	46.44	49.41	56.62	62.87	67.77	71.49	1.7%
Other uses[4]	317.61	325.18	317.95	345.09	378.20	411.92	449.71	1.3%
Total commercial	**1008.62**	**1034.63**	**952.26**	**993.16**	**1043.07**	**1092.87**	**1142.18**	**0.4%**
Industrial								
Manufacturing								
Refining	261.44	265.88	268.04	278.94	288.94	303.58	322.94	0.8%
Food products	100.97	105.04	98.92	104.00	108.26	111.71	113.98	0.3%
Paper products	77.15	76.70	71.83	71.82	73.13	71.21	69.81	-0.4%
Bulk chemicals	221.74	234.55	213.65	229.11	233.13	225.47	215.77	-0.3%
Glass	18.92	18.59	19.05	20.00	21.33	21.21	20.50	0.4%
Cement manufacturing	25.91	25.67	33.19	35.70	37.08	36.48	37.41	1.5%
Iron and steel	91.87	116.74	117.01	110.23	114.88	107.91	99.25	-0.6%
Aluminum	27.63	30.89	28.68	27.66	26.37	24.89	23.14	-1.1%
Fabricated metal products	36.69	36.14	36.43	36.81	37.90	35.62	33.25	-0.3%
Machinery	22.80	23.76	24.75	24.32	26.46	25.49	23.73	-0.0%
Computers and electronics	30.67	33.07	32.16	33.69	36.48	36.57	36.74	0.4%
Transportation equipment	43.77	45.62	56.18	54.82	54.85	57.23	58.87	1.0%
Electrical equipment	7.86	8.17	8.23	8.25	9.10	8.85	8.55	0.2%
Wood products	16.74	16.90	19.68	19.99	20.46	19.14	18.50	0.4%
Plastics	37.47	38.26	34.96	35.35	34.86	34.29	33.32	-0.6%
Balance of manufacturing	142.01	142.62	133.94	136.85	138.25	133.50	129.25	-0.4%
Total manufacturing	1163.64	1218.60	1196.68	1227.54	1261.49	1253.14	1245.00	0.1%
Nonmanufacturing								
Agriculture	73.84	73.82	69.73	68.13	68.31	67.95	68.29	-0.3%
Construction	76.16	69.67	83.15	91.08	92.27	91.23	91.95	1.1%
Mining	43.45	46.03	44.37	44.16	43.79	43.23	42.83	-0.3%
Total nonmanufacturing	193.45	189.52	197.25	203.37	204.37	202.41	203.08	0.3%
Discrepancy[2]	43.83	83.41	108.76	78.58	76.09	74.99	78.94	-0.2%
Total industrial	**1400.92**	**1491.53**	**1502.69**	**1509.48**	**1541.94**	**1530.55**	**1527.02**	**0.1%**

Table A19. Energy-related carbon dioxide emissions by end use (continued)

(million metric tons)

Sector and end use	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Transportation								
Light-duty vehicles	1068.20	1060.96	1014.74	966.95	945.91	950.30	957.76	-0.4%
Commercial light trucks[5]	35.27	38.02	39.58	38.75	38.76	39.51	40.97	0.3%
Bus transportation	14.85	17.67	17.32	17.17	17.13	17.18	17.32	-0.1%
Freight trucks	356.16	348.09	389.50	391.24	396.52	398.85	409.21	0.6%
Rail, passenger	5.41	5.84	5.76	6.02	6.39	6.70	6.98	0.7%
Rail, freight	26.27	32.99	30.95	33.83	36.05	36.73	37.43	0.5%
Shipping, domestic	13.03	16.31	16.75	17.65	17.97	18.15	18.27	0.5%
Shipping, international	60.55	67.51	67.87	68.23	68.70	69.13	69.55	0.1%
Recreational boats	16.45	17.12	17.27	17.53	17.90	18.42	18.94	0.4%
Air	172.79	178.28	180.48	186.23	192.08	195.53	197.54	0.4%
Military use	50.94	54.70	47.05	45.77	47.13	49.65	52.56	-0.2%
Lubricants	4.71	5.19	5.00	5.10	5.19	5.24	5.28	0.1%
Pipeline fuel	32.53	34.34	36.23	35.81	35.79	35.99	36.36	0.2%
Discrepancy[2]	-1.34	-1.15	-0.21	0.45	1.14	1.81	2.39	- -
Total transportation	**1855.81**	**1875.88**	**1868.28**	**1830.73**	**1826.65**	**1843.20**	**1870.57**	**-0.0%**
Biogenic energy combustion[6]								
Biomass	178.16	190.68	208.91	245.80	271.80	268.87	268.81	1.4%
Electric power sector	15.83	18.00	25.42	56.39	68.61	60.49	52.72	4.4%
Other sectors	162.33	172.68	183.49	189.41	203.18	208.37	216.10	0.9%
Biogenic waste	6.56	7.10	8.20	8.21	8.21	8.21	8.21	0.6%
Biofuels heat and coproducts	77.06	79.11	75.91	89.81	119.14	179.75	241.23	4.6%
Ethanol	65.18	75.71	83.37	92.41	106.14	124.29	146.78	2.7%
Biodiesel	3.07	2.11	12.76	16.51	17.69	18.42	19.18	9.2%
Liquids from biomass	0.00	0.00	2.01	7.99	24.22	57.28	95.80	- -
Renewable diesel and gasoline	0.00	0.50	2.23	2.23	2.23	2.23	2.21	6.2%
Total	**330.03**	**355.21**	**393.39**	**462.96**	**549.43**	**659.05**	**782.23**	**3.2%**

[1]Does not include water heating portion of load.

[2]Represents differences between total emissions by end-use and total emissions by fuel as reported in Table A18. Emissions by fuel may reflect benchmarking and other modeling adjustments to energy use and the associated emissions that are not assigned to specific end uses.

[3]Includes emissions related to fuel consumption for district services.

[4]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus emissions from residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.

[5]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.

[6]By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. Accordingly, the emissions from biogenic energy sources are reported here as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review, October 2011* DOE/EIA-0035(2011/10) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A20. Macroeconomic indicators

(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Real gross domestic product	**12703**	**13088**	**14803**	**16740**	**19185**	**21725**	**24539**	**2.5%**
Components of real gross domestic product								
Real consumption	9037	9221	10218	11250	12697	14359	16220	2.3%
Real investment	1454	1715	2457	2888	3472	4063	4836	4.2%
Real government spending	2540	2557	2355	2407	2525	2667	2818	0.4%
Real exports	1494	1663	2289	3096	4235	5484	6953	5.9%
Real imports	1853	2085	2463	2800	3516	4461	5690	4.1%
Energy intensity (thousand Btu per 2005 dollar of GDP)								
Delivered energy	5.42	5.45	4.84	4.33	3.85	3.48	3.17	-2.1%
Total energy	7.46	7.50	6.58	5.93	5.32	4.80	4.36	-2.1%
Price indices								
GDP chain-type price index (2005=1.000)	1.097	1.110	1.196	1.304	1.424	1.580	1.758	1.9%
Consumer price index (1982-4=1.00)								
All-urban	2.15	2.18	2.42	2.67	2.95	3.30	3.72	2.2%
Energy commodities and services	1.93	2.12	2.62	2.94	3.36	3.86	4.37	2.9%
Wholesale price index (1982=1.00)								
All commodities	1.73	1.85	2.10	2.23	2.39	2.58	2.81	1.7%
Fuel and power	1.59	1.86	2.29	2.57	3.01	3.50	4.12	3.2%
Metals and metal products	1.87	2.08	2.43	2.50	2.57	2.61	2.64	1.0%
Industrial commodities excluding energy	1.76	1.83	2.04	2.13	2.22	2.32	2.43	1.1%
Interest rates (percent, nominal)								
Federal funds rate	0.16	0.18	3.26	4.07	4.29	4.52	4.30	- -
10-year treasury note	3.26	3.21	4.67	5.10	5.06	5.26	5.18	- -
AA utility bond rate	5.75	5.24	6.74	7.41	7.17	7.48	7.56	- -
Value of shipments (billion 2005 dollars)								
Service sectors	19996	20602	22469	24967	28029	30911	33430	2.0%
Total industrial	5667	5838	6730	7363	7973	8328	8692	1.6%
Nonmanufacturing	1615	1578	1873	2103	2228	2305	2407	1.7%
Manufacturing	4052	4260	4857	5260	5745	6023	6285	1.6%
Energy-intensive	1509	1595	1664	1786	1901	1973	2034	1.0%
Non-energy-intensive	2543	2664	3194	3474	3844	4050	4251	1.9%
Total shipments	**25664**	**26440**	**29199**	**32329**	**36002**	**39239**	**42122**	**1.9%**
Population and employment (millions)								
Population, with armed forces overseas	307.8	310.8	326.2	342.0	358.1	374.1	390.1	0.9%
Population, aged 16 and over	241.8	244.3	256.5	269.4	282.6	296.2	309.6	1.0%
Population, over age 65	39.7	40.4	47.1	55.1	64.2	72.3	77.7	2.6%
Employment, nonfarm	130.7	129.8	139.4	147.3	154.2	162.0	166.8	1.0%
Employment, manufacturing	11.8	11.5	12.1	11.9	11.4	10.3	9.2	-0.9%
Key labor indicators								
Labor force (millions)	154.2	153.9	158.0	163.6	168.6	174.5	181.7	0.7%
Nonfarm labor productivity (1992=1.00)	1.06	1.10	1.16	1.26	1.42	1.57	1.75	1.9%
Unemployment rate (percent)	9.28	9.63	7.51	6.47	5.54	5.40	5.54	- -
Key indicators for energy demand								
Real disposable personal income	9883	10062	11035	12472	14286	16268	18217	2.4%
Housing starts (millions)	0.60	0.63	1.75	1.92	1.96	1.90	1.89	4.5%
Commercial floorspace (billion square feet)	80.3	81.1	84.1	89.1	93.9	98.2	103.0	1.0%
Unit sales of light-duty vehicles (millions)	10.40	11.55	16.16	16.40	17.79	18.11	18.64	1.9%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2009 and 2010: IHS Global Insight, Global Insight Industry and Employment models, August 2011. **Projections:** U.S. Energy Information Administration, AEO2012 National Energy Modeling System run REF2012.D020112C.

Table A21. International liquids supply and disposition summary

(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Crude oil prices (2010 dollars per barrel)								
Low sulfur light	62.37	79.39	116.91	126.68	132.56	138.49	144.98	2.4%
Imported crude oil[1]	59.72	75.87	113.97	115.74	121.21	126.51	132.95	2.3%
Crude oil prices (nominal dollars per barrel)								
Low sulfur light	61.65	79.39	125.97	148.87	170.09	197.10	229.55	4.3%
Imported crude oil[1]	59.04	75.87	122.81	136.02	155.52	180.06	210.51	4.2%
Petroleum liquids production[2]								
OPEC[3]								
Middle East	22.30	23.43	25.46	27.16	29.77	32.07	33.94	1.5%
North Africa	3.92	3.89	3.62	3.42	3.37	3.31	3.27	-0.7%
West Africa	4.16	4.45	5.09	5.35	5.40	5.31	5.26	0.7%
South America	2.43	2.29	2.13	1.97	1.92	1.79	1.72	-1.1%
Total OPEC petroleum production	**32.80**	**34.05**	**36.30**	**37.91**	**40.46**	**42.48**	**44.19**	**1.0%**
Non-OPEC								
OECD								
United States (50 states)	8.27	8.79	9.82	10.73	10.53	10.57	10.15	0.6%
Canada	1.96	1.91	1.79	1.82	1.82	1.81	1.78	-0.3%
Mexico and Chile	3.00	2.98	2.65	1.97	1.58	1.65	1.68	-2.3%
OECD Europe[4]	4.70	4.36	3.70	3.33	3.15	3.00	2.83	-1.7%
Japan	0.13	0.13	0.14	0.15	0.15	0.15	0.16	0.7%
Australia and New Zealand	0.65	0.62	0.55	0.54	0.54	0.53	0.53	-0.6%
Total OECD petroleum production	**18.71**	**18.80**	**18.65**	**18.54**	**17.78**	**17.72**	**17.14**	**-0.4%**
Non-OECD								
Russia	9.93	10.14	10.04	10.54	11.06	11.62	12.16	0.7%
Other Europe and Eurasia[5]	3.12	3.22	3.67	4.01	4.37	4.52	4.54	1.4%
China	3.99	4.27	4.29	4.46	4.79	4.93	4.70	0.4%
Other Asia[6]	3.67	3.77	3.79	3.55	3.38	3.17	3.00	-0.9%
Middle East	1.56	1.58	1.43	1.31	1.18	1.06	0.97	-1.9%
Africa	2.44	2.41	2.40	2.54	2.68	2.70	2.68	0.4%
Brazil	2.08	2.19	2.72	3.34	3.87	4.21	4.45	2.9%
Other Central and South America	1.90	2.01	2.29	2.32	2.47	2.67	2.65	1.1%
Total non-OECD petroleum production	**28.69**	**29.59**	**30.63**	**32.07**	**33.80**	**34.88**	**35.15**	**0.7%**
Total petroleum liquids production	**80.21**	**82.44**	**85.58**	**88.52**	**92.04**	**95.08**	**96.47**	**0.6%**
Other liquids production[7]								
United States (50 states)	0.75	0.90	1.05	1.34	1.62	2.08	2.59	4.3%
Other North America	1.69	1.93	2.51	3.08	3.75	4.46	5.16	4.0%
OECD Europe[4]	0.22	0.22	0.23	0.24	0.26	0.27	0.28	1.0%
Middle East	0.01	0.01	0.17	0.21	0.24	0.24	0.24	14.5%
Africa.	0.21	0.21	0.28	0.37	0.38	0.39	0.40	2.6%
Central and South America	1.14	1.20	1.78	2.31	2.61	2.90	3.17	3.9%
Other	0.12	0.13	0.16	0.28	0.61	0.92	1.18	9.1%
Total other liquids production	**4.14**	**4.61**	**6.18**	**7.82**	**9.47**	**11.27**	**13.02**	**4.2%**
Total production	**84.35**	**87.05**	**91.76**	**96.33**	**101.51**	**106.34**	**109.50**	**0.9%**

Table A21. International liquids supply and disposition summary (continued)

(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Liquids consumption[8]								
OECD								
United States (50 states)	18.81	19.17	19.10	19.02	19.20	19.47	19.90	0.1%
United States territories	0.27	0.28	0.31	0.32	0.34	0.36	0.36	1.0%
Canada	2.16	2.21	2.15	2.21	2.25	2.29	2.35	0.2%
Mexico and Chile	2.35	2.34	2.39	2.43	2.50	2.60	2.68	0.5%
OECD Europe[4]	14.66	14.58	14.14	14.43	14.65	14.76	14.74	0.0%
Japan	4.39	4.45	4.51	4.60	4.62	4.51	4.42	-0.0%
South Korea	2.15	2.24	2.25	2.35	2.46	2.53	2.56	0.5%
Australia and New Zealand	1.16	1.13	1.11	1.14	1.17	1.21	1.23	0.3%
Total OECD consumption	**45.94**	**46.40**	**45.95**	**46.50**	**47.19**	**47.72**	**48.24**	**0.2%**
Non-OECD								
Russia	2.73	2.93	3.02	2.94	2.91	2.94	2.97	0.1%
Other Europe and Eurasia[5]	2.15	2.08	2.30	2.35	2.45	2.55	2.63	0.9%
China	8.33	9.19	12.10	14.36	16.03	17.65	18.50	2.8%
India	3.11	3.18	3.70	4.58	5.40	5.79	5.80	2.4%
Other non-OECD Asia[6]	6.43	6.73	7.28	7.95	8.85	9.40	9.89	1.5%
Middle East	6.84	7.35	7.78	7.69	8.16	8.98	9.49	1.0%
Africa	3.23	3.34	3.30	3.37	3.57	3.80	4.09	0.8%
Brazil	2.52	2.65	2.84	2.94	3.15	3.47	3.80	1.5%
Other Central and South America	3.07	3.19	3.49	3.66	3.81	4.05	4.09	1.0%
Total non-OECD consumption	**38.41**	**40.65**	**45.82**	**49.83**	**54.32**	**58.62**	**61.26**	**1.7%**
Total liquids consumption	**84.35**	**87.05**	**91.76**	**96.33**	**101.51**	**106.35**	**109.50**	**0.9%**
OPEC production[9]	33.34	34.58	37.30	39.23	41.91	44.05	45.89	1.1%
Non-OPEC production[9]	51.01	52.47	54.46	57.10	59.60	62.30	63.61	0.8%
Net Eurasia exports	10.25	10.53	11.11	12.60	13.94	14.85	15.54	1.6%
OPEC market share (percent)	39.5	39.7	40.7	40.7	41.3	41.4	41.9	- -

[1]Weighted average price delivered to U.S. refiners.

[2]Includes production of crude oil (including lease condensate and shale oil/tight oil), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, and refinery gains.

[3]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

[4]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.

[5]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.

[6]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.

[7]Includes liquids produced from energy crops, natural gas, coal, extra-heavy oil, bitumen (oil sands), and kerogen (oil shale, not to be confused with shale oil/tight oil). Includes both OPEC and non-OPEC producers in the regional breakdown.

[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.

[9]Includes both petroleum and other liquids production.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2009 and 2010 imported crude oil price: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 quantities derived from: EIA, International Energy Statistics database as of November 2009. **2010 quantities and projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C and EIA, Generate World Oil Balance Model.

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Appendix B

Economic growth case comparisons

Table B1. Total energy supply, disposition, and price summary

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Production										
Crude oil and lease condensate	11.59	13.23	13.23	13.25	13.53	13.77	13.79	12.86	12.89	13.12
Natural gas plant liquids	2.78	3.33	3.33	3.33	3.91	3.93	3.93	3.93	3.94	3.95
Dry natural gas	22.10	24.02	24.22	24.28	26.17	26.91	27.64	27.48	28.60	30.05
Coal[1]	22.06	19.71	20.24	20.79	20.27	22.25	23.65	21.91	24.14	25.33
Nuclear / uranium[2]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.14	9.28	10.13
Hydropower	2.51	2.89	2.90	2.90	2.95	2.99	3.02	3.00	3.04	3.10
Biomass[3]	4.05	4.41	4.45	4.49	6.04	6.26	6.30	8.37	9.07	9.58
Other renewable energy[4]	1.34	2.08	1.99	2.18	2.21	2.22	2.42	2.44	2.81	3.64
Other[5]	0.64	0.60	0.60	0.60	0.68	0.69	0.71	0.83	0.91	0.93
Total	**75.50**	**78.96**	**79.64**	**80.50**	**85.36**	**88.61**	**91.06**	**89.95**	**94.67**	**99.83**
Imports										
Crude oil	20.14	18.34	18.87	19.43	15.20	16.23	17.55	15.30	16.90	18.50
Liquid fuels and other petroleum[6]	5.02	4.19	4.32	4.45	3.72	4.08	4.40	3.63	4.14	4.75
Natural gas[7]	3.81	3.67	3.73	3.76	2.61	2.75	2.89	2.74	2.84	2.86
Other imports[8]	0.52	0.34	0.44	0.47	0.97	1.07	0.95	0.73	0.81	0.96
Total	**29.49**	**26.54**	**27.37**	**28.11**	**22.50**	**24.14**	**25.79**	**22.40**	**24.69**	**27.07**
Exports										
Liquid fuels and other petroleum[9]	4.81	4.90	5.00	5.08	4.32	4.46	4.57	4.68	4.95	5.11
Natural gas[10]	1.15	1.93	1.93	1.92	3.55	3.51	3.48	4.29	4.17	4.07
Coal	2.10	2.73	2.73	2.73	2.78	2.82	2.82	3.09	3.13	3.18
Total	**8.06**	**9.57**	**9.66**	**9.74**	**10.66**	**10.79**	**10.87**	**12.06**	**12.25**	**12.37**
Discrepancy[11]	**-1.23**	**-0.03**	**-0.08**	**-0.09**	**-0.01**	**-0.03**	**-0.06**	**0.25**	**0.18**	**0.15**
Consumption										
Liquid fuels and other petroleum[12]	37.25	36.09	36.72	37.38	34.78	36.58	38.19	35.17	37.70	40.23
Natural gas	24.71	25.73	26.00	26.09	25.21	26.14	27.04	25.93	27.26	28.83
Coal[13]	20.76	17.17	17.80	18.36	18.23	20.02	21.30	19.16	21.15	22.43
Nuclear / uranium[2]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.14	9.28	10.13
Hydropower	2.51	2.89	2.90	2.90	2.95	2.99	3.02	3.00	3.04	3.10
Biomass[14]	2.88	3.01	3.04	3.06	3.95	4.17	4.21	4.96	5.44	5.78
Other renewable energy[4]	1.34	2.08	1.99	2.18	2.21	2.22	2.42	2.44	2.81	3.64
Other[15]	0.29	0.30	0.30	0.30	0.28	0.28	0.28	0.24	0.24	0.25
Total	**98.16**	**95.96**	**97.43**	**98.96**	**97.20**	**101.99**	**106.05**	**100.04**	**106.93**	**114.38**
Prices (2010 dollars per unit)										
Petroleum (dollars per barrel)										
Low sulfur light crude oil[16]	79.39	116.06	116.91	117.83	130.58	132.56	134.77	142.51	144.98	147.82
Imported crude oil[16]	75.87	113.12	113.97	114.90	118.61	121.21	124.15	130.33	132.95	136.68
Natural gas (dollars per million Btu)										
at Henry hub	4.39	4.06	4.29	4.36	5.10	5.63	6.17	6.60	7.37	7.58
at the wellhead[17]	4.06	3.64	3.84	3.91	4.54	5.00	5.46	5.83	6.48	6.66
Natural gas (dollars per thousand cubic feet)										
at the wellhead[17]	4.16	3.73	3.94	4.00	4.65	5.12	5.59	5.97	6.64	6.82
Coal (dollars per ton)										
at the minemouth[18]	35.61	42.70	42.08	41.92	44.24	44.05	44.48	50.92	50.52	51.36
Coal (dollars per million Btu)										
at the minemouth[18]	1.76	2.11	2.08	2.08	2.24	2.23	2.25	2.57	2.56	2.60
Average end-use[19]	2.38	2.55	2.56	2.57	2.68	2.70	2.73	2.90	2.94	3.03
Average electricity (cents per kilowatthour)	9.8	9.9	9.7	9.6	9.7	9.7	9.9	9.8	10.1	10.5

Table B1. Total energy supply, disposition, and price summary (continued)

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Prices (nominal dollars per unit)										
Petroleum (dollars per barrel)										
Low sulfur light crude oil[16]	79.39	127.20	125.97	125.10	197.32	170.09	163.70	313.58	229.55	212.97
Imported crude oil[16]	75.87	123.98	122.81	121.98	179.23	155.52	150.79	286.76	210.51	196.92
Natural gas (dollars per million Btu)										
at Henry hub	4.39	4.45	4.62	4.63	7.70	7.23	7.50	14.52	11.67	10.92
at the wellhead[17]	4.06	3.99	4.14	4.15	6.86	6.42	6.63	12.82	10.26	9.59
Natural gas (dollars per thousand cubic feet)										
at the wellhead[17]	4.16	4.09	4.24	4.25	7.02	6.57	6.79	13.13	10.51	9.82
Coal (dollars per ton)										
at the minemouth[18]	35.61	46.80	45.34	44.50	66.85	56.52	54.03	112.04	80.00	74.00
Coal (dollars per million Btu)										
at the minemouth[18]	1.76	2.31	2.24	2.21	3.39	2.86	2.73	5.64	4.05	3.74
Average end-use[19]	2.38	2.79	2.76	2.73	4.05	3.47	3.32	6.37	4.66	4.36
Average electricity (cents per kilowatthour)	9.8	10.9	10.4	10.2	14.7	12.5	12.0	21.6	16.0	15.1

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that is later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas and natural gas used for liquefaction at export terminals.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Weighted average price delivered to U.S. refiners.
[17]Represents lower 48 onshore and offshore supplies.
[18]Includes reported prices for both open market and captive mines.
[19]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 natural gas supply values and natural gas wellhead price: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2010 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011). 2010 petroleum supply values: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). 2010 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2010 coal values: *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011). Other 2010 values: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System runs LM2012.D022412A, REF2012.D020112C, and HM2012.D022412A.

Table B2. Energy consumption by sector and source

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Energy consumption										
Residential										
Liquefied petroleum gases	0.56	0.51	0.51	0.51	0.49	0.50	0.52	0.48	0.51	0.54
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate fuel oil	0.63	0.55	0.55	0.55	0.43	0.43	0.43	0.35	0.35	0.35
Liquid fuels and other petroleum subtotal	1.22	1.08	1.08	1.08	0.94	0.95	0.97	0.85	0.87	0.91
Natural gas	5.06	4.96	4.97	5.00	4.77	4.88	5.04	4.50	4.76	5.08
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable energy[1]	0.42	0.42	0.43	0.43	0.42	0.43	0.45	0.41	0.43	0.47
Electricity	4.95	4.68	4.75	4.82	4.97	5.23	5.58	5.35	5.86	6.57
Delivered energy	**11.66**	**11.15**	**11.24**	**11.34**	**11.11**	**11.51**	**12.05**	**11.12**	**11.93**	**13.04**
Electricity related losses	10.39	9.43	9.58	9.75	10.03	10.52	11.17	10.47	11.35	12.72
Total	**22.05**	**20.59**	**20.81**	**21.09**	**21.13**	**22.02**	**23.22**	**21.59**	**23.28**	**25.76**
Commercial										
Liquefied petroleum gases	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.16
Motor gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Distillate fuel oil	0.43	0.35	0.35	0.35	0.33	0.33	0.33	0.32	0.32	0.32
Residual fuel oil	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Liquid fuels and other petroleum subtotal	0.72	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.63
Natural gas	3.28	3.43	3.41	3.42	3.56	3.53	3.51	3.70	3.69	3.71
Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.54	4.57	4.59	4.61	5.11	5.16	5.22	5.70	5.80	5.89
Delivered energy	**8.70**	**8.79**	**8.80**	**8.81**	**9.46**	**9.48**	**9.53**	**10.19**	**10.28**	**10.39**
Electricity related losses	9.52	9.21	9.27	9.32	10.30	10.38	10.44	11.15	11.23	11.40
Total	**18.22**	**18.00**	**18.06**	**18.13**	**19.76**	**19.86**	**19.97**	**21.34**	**21.50**	**21.79**
Industrial[4]										
Liquefied petroleum gases	2.00	1.80	1.83	1.83	2.06	2.17	2.18	2.01	2.15	2.20
Motor gasoline[2]	0.25	0.27	0.28	0.29	0.27	0.30	0.33	0.26	0.30	0.33
Distillate fuel oil	1.16	1.16	1.25	1.33	1.04	1.19	1.33	1.01	1.18	1.35
Residual fuel oil	0.12	0.09	0.09	0.09	0.08	0.08	0.09	0.08	0.08	0.09
Petrochemical feedstocks	0.94	1.00	1.01	1.01	1.22	1.29	1.29	1.21	1.30	1.33
Other petroleum[5]	3.59	3.29	3.44	3.60	2.81	3.11	3.45	2.80	3.19	3.60
Liquid fuels and other petroleum subtotal	8.05	7.61	7.89	8.15	7.48	8.13	8.68	7.36	8.21	8.89
Natural gas	6.76	7.04	7.19	7.34	6.81	7.32	7.62	6.49	7.18	7.84
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[6]	1.37	1.42	1.43	1.43	1.54	1.57	1.60	1.57	1.63	1.71
Natural gas subtotal	8.14	8.46	8.62	8.77	8.35	8.89	9.22	8.06	8.81	9.55
Metallurgical coal	0.55	0.55	0.57	0.59	0.41	0.49	0.54	0.34	0.43	0.53
Other industrial coal	1.01	1.01	1.03	1.05	1.02	1.08	1.12	1.01	1.08	1.14
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.11	0.36	0.37	0.31	0.60	0.61
Net coal coke imports	-0.01	-0.01	-0.01	-0.00	-0.03	-0.03	-0.03	-0.05	-0.06	-0.07
Coal subtotal	1.56	1.55	1.59	1.63	1.52	1.90	2.00	1.60	2.06	2.21
Biofuels heat and coproducts	0.84	0.80	0.81	0.82	1.26	1.27	1.27	2.39	2.57	2.69
Renewable energy[7]	1.50	1.59	1.61	1.63	1.67	1.82	1.91	1.74	1.95	2.10
Electricity	3.28	3.34	3.44	3.53	3.22	3.52	3.75	3.01	3.33	3.67
Delivered energy	**23.37**	**23.35**	**23.96**	**24.53**	**23.49**	**25.53**	**26.83**	**24.17**	**26.94**	**29.11**
Electricity related losses	6.89	6.73	6.94	7.15	6.50	7.09	7.50	5.89	6.46	7.10
Total	**30.26**	**30.08**	**30.90**	**31.68**	**29.99**	**32.61**	**34.33**	**30.06**	**33.39**	**36.21**

Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Transportation										
Liquefied petroleum gases	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.04	0.05	0.06
E85[8]	0.00	0.01	0.01	0.01	0.40	0.30	0.21	1.14	1.22	1.22
Motor gasoline[2]	16.91	16.00	16.13	16.29	14.26	14.90	15.49	13.43	14.53	15.38
Jet fuel[9]	3.07	3.01	3.03	3.04	3.15	3.19	3.24	3.25	3.33	3.42
Distillate fuel oil[10]	5.77	6.35	6.55	6.77	6.50	7.03	7.51	7.06	7.44	8.27
Residual fuel oil	0.90	0.91	0.91	0.91	0.92	0.93	0.93	0.93	0.94	0.95
Other petroleum[11]	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.18
Liquid fuels and other petroleum subtotal	26.88	26.48	26.83	27.22	25.43	26.57	27.60	26.03	27.67	29.47
Pipeline fuel natural gas	0.65	0.68	0.68	0.69	0.65	0.67	0.69	0.66	0.69	0.74
Compressed / liquefied natural gas	0.04	0.06	0.06	0.06	0.11	0.11	0.12	0.16	0.16	0.17
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.07	0.07	0.08
Delivered energy	**27.59**	**27.24**	**27.60**	**28.00**	**26.24**	**27.40**	**28.45**	**26.92**	**28.60**	**30.46**
Electricity related losses	0.05	0.05	0.05	0.05	0.08	0.08	0.09	0.13	0.14	0.15
Total	**27.63**	**27.30**	**27.65**	**28.05**	**26.32**	**27.49**	**28.54**	**27.05**	**28.75**	**30.62**
Delivered energy consumption for all sectors										
Liquefied petroleum gases	2.75	2.49	2.51	2.52	2.75	2.86	2.89	2.69	2.86	2.95
E85[8]	0.00	0.01	0.01	0.01	0.40	0.30	0.21	1.14	1.22	1.22
Motor gasoline[2]	17.21	16.32	16.46	16.63	14.58	15.25	15.87	13.75	14.88	15.77
Jet fuel[9]	3.07	3.01	3.03	3.04	3.15	3.19	3.24	3.25	3.33	3.42
Kerosene	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Distillate fuel oil	7.99	8.41	8.69	9.00	8.30	8.99	9.61	8.74	9.29	10.29
Residual fuel oil	1.11	1.07	1.08	1.08	1.08	1.09	1.10	1.09	1.11	1.12
Petrochemical feedstocks	0.94	1.00	1.01	1.01	1.22	1.29	1.29	1.21	1.30	1.33
Other petroleum[12]	3.76	3.45	3.61	3.76	2.97	3.27	3.62	2.97	3.36	3.77
Liquid fuels and other petroleum subtotal	36.87	35.80	36.43	37.07	34.48	36.28	37.87	34.86	37.38	39.90
Natural gas	15.15	15.49	15.64	15.83	15.25	15.85	16.29	14.85	15.79	16.80
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[6]	1.37	1.42	1.43	1.43	1.54	1.57	1.60	1.57	1.63	1.71
Pipeline natural gas	0.65	0.68	0.68	0.69	0.65	0.67	0.69	0.66	0.69	0.74
Natural gas subtotal	17.17	17.58	17.75	17.94	17.44	18.09	18.58	17.08	18.11	19.26
Metallurgical coal	0.55	0.55	0.57	0.59	0.41	0.49	0.54	0.34	0.43	0.53
Other coal	1.08	1.07	1.09	1.11	1.08	1.14	1.18	1.07	1.15	1.21
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.11	0.36	0.37	0.31	0.60	0.61
Net coal coke imports	-0.01	-0.01	-0.01	-0.00	-0.03	-0.03	-0.03	-0.05	-0.06	-0.07
Coal subtotal	1.62	1.62	1.65	1.70	1.58	1.96	2.06	1.67	2.12	2.28
Biofuels heat and coproducts	0.84	0.80	0.81	0.82	1.26	1.27	1.27	2.39	2.57	2.69
Renewable energy[13]	2.03	2.12	2.15	2.17	2.20	2.36	2.47	2.25	2.50	2.68
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.79	12.61	12.81	12.98	13.34	13.96	14.60	14.13	15.06	16.20
Delivered energy	**71.32**	**70.54**	**71.59**	**72.69**	**70.30**	**73.92**	**76.86**	**72.39**	**77.75**	**83.01**
Electricity related losses	26.84	25.42	25.84	26.27	26.91	28.07	29.20	27.65	29.18	31.37
Total	**98.16**	**95.96**	**97.43**	**98.96**	**97.20**	**101.99**	**106.05**	**100.04**	**106.93**	**114.38**
Electric power[14]										
Distillate fuel oil	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Residual fuel oil	0.30	0.21	0.21	0.22	0.21	0.22	0.23	0.22	0.23	0.24
Liquid fuels and other petroleum subtotal	0.38	0.29	0.29	0.30	0.30	0.31	0.32	0.31	0.32	0.34
Natural gas	7.54	8.15	8.25	8.15	7.77	8.04	8.46	8.84	9.16	9.58
Steam coal	19.13	15.56	16.15	16.67	16.65	18.06	19.24	17.50	19.03	20.15
Nuclear / uranium[15]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.14	9.28	10.13
Renewable energy[16]	3.85	5.05	4.96	5.15	5.66	5.75	5.91	5.75	6.22	7.14
Electricity imports	0.09	0.10	0.10	0.10	0.08	0.08	0.08	0.04	0.04	0.04
Total[17]	**39.63**	**38.03**	**38.64**	**39.25**	**40.25**	**42.03**	**43.80**	**41.78**	**44.24**	**47.57**

Table B2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Total energy consumption										
Liquefied petroleum gases	2.75	2.49	2.51	2.52	2.75	2.86	2.89	2.69	2.86	2.95
E85[8]	0.00	0.01	0.01	0.01	0.40	0.30	0.21	1.14	1.22	1.22
Motor gasoline[2]	17.21	16.32	16.46	16.63	14.58	15.25	15.87	13.75	14.88	15.77
Jet fuel[9]	3.07	3.01	3.03	3.04	3.15	3.19	3.24	3.25	3.33	3.42
Kerosene	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Distillate fuel oil	8.07	8.50	8.78	9.08	8.39	9.07	9.70	8.83	9.38	10.38
Residual fuel oil	1.41	1.28	1.29	1.30	1.29	1.31	1.33	1.31	1.34	1.36
Petrochemical feedstocks	0.94	1.00	1.01	1.01	1.22	1.29	1.29	1.21	1.30	1.33
Other petroleum[12]	3.76	3.45	3.61	3.76	2.97	3.27	3.62	2.97	3.36	3.77
Liquid fuels and other petroleum subtotal	37.25	36.09	36.72	37.38	34.78	36.58	38.19	35.17	37.70	40.23
Natural gas	22.69	23.64	23.89	23.97	23.02	23.89	24.74	23.70	24.94	26.38
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[6]	1.37	1.42	1.43	1.43	1.54	1.57	1.60	1.57	1.63	1.71
Pipeline natural gas	0.65	0.68	0.68	0.69	0.65	0.67	0.69	0.66	0.69	0.74
Natural gas subtotal	24.71	25.73	26.00	26.09	25.21	26.14	27.04	25.93	27.26	28.83
Metallurgical coal	0.55	0.55	0.57	0.59	0.41	0.49	0.54	0.34	0.43	0.53
Other coal	20.21	16.63	17.24	17.78	17.73	19.20	20.42	18.57	20.18	21.36
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.11	0.36	0.37	0.31	0.60	0.61
Net coal coke imports	-0.01	-0.01	-0.01	-0.00	-0.03	-0.03	-0.03	-0.05	-0.06	-0.07
Coal subtotal	20.76	17.17	17.80	18.36	18.23	20.02	21.30	19.16	21.15	22.43
Nuclear / uranium[15]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.14	9.28	10.13
Biofuels heat and coproducts	0.84	0.80	0.81	0.82	1.26	1.27	1.27	2.39	2.57	2.69
Renewable energy[18]	5.88	7.18	7.11	7.33	7.85	8.11	8.38	8.00	8.71	9.82
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity imports	0.09	0.10	0.10	0.10	0.08	0.08	0.08	0.04	0.04	0.04
Total	**98.16**	**95.96**	**97.43**	**98.96**	**97.20**	**101.99**	**106.05**	**100.04**	**106.93**	**114.38**
Energy use and related statistics										
Delivered energy use	71.32	70.54	71.59	72.69	70.30	73.92	76.86	72.39	77.75	83.01
Total energy use	98.16	95.96	97.43	98.96	97.20	101.99	106.05	100.04	106.93	114.38
Ethanol consumed in motor gasoline and E85	1.11	1.21	1.22	1.23	1.55	1.55	1.54	1.99	2.15	2.23
Population (millions)	310.83	325.23	326.16	327.19	354.23	358.06	362.48	382.76	390.09	398.74
Gross domestic product (billion 2005 dollars)	13088	14401	14803	15235	17676	19185	20538	21630	24539	27084
Carbon dioxide emissions (million metric tons)	5633.6	5298.2	5407.2	5503.9	5226.8	5552.5	5823.7	5355.8	5757.9	6117.5

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.

[2]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.

[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.

[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.

[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.

[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.

[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (15 percent or less) in motor gasoline.

[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.

[9]Includes only kerosene type.

[10]Diesel fuel for on- and off- road use.

[11]Includes aviation gasoline and lubricants.

[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.

[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.

[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[15]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.

[16]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.

[17]Includes non-biogenic municipal waste not included above.

[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2010 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2011. 2010 carbon dioxide emissions: EIA, *Monthly Energy Review, October 2011* DOE/EIA-0035(2011/10) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System runs LM2012.D022412A, REF2012.D020112C, and HM2012.D022412A.

Table B3. Energy prices by sector and source

(2010 dollars per million Btu, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Residential										
Liquefied petroleum gases	27.02	30.48	30.70	30.86	31.69	32.27	32.91	33.94	34.64	35.27
Distillate fuel oil	21.21	27.00	27.26	27.52	29.17	30.15	30.64	32.01	32.73	33.99
Natural gas	11.08	10.10	10.31	10.39	11.46	12.03	12.61	13.16	13.98	14.38
Electricity	33.69	35.59	34.59	34.31	34.30	34.08	34.20	34.14	34.58	35.27
Commercial										
Liquefied petroleum gases	23.52	27.21	27.42	27.57	28.39	28.97	29.59	30.62	31.30	31.89
Distillate fuel oil	20.77	23.72	23.98	24.23	25.89	26.86	27.30	28.58	29.18	30.43
Residual fuel oil	11.07	16.02	16.18	16.35	17.82	18.24	18.62	18.61	18.90	19.61
Natural gas	9.10	8.40	8.60	8.67	9.51	10.02	10.52	10.92	11.64	11.91
Electricity	29.73	29.65	29.03	28.97	28.81	29.00	29.51	28.42	29.48	30.79
Industrial[1]										
Liquefied petroleum gases	21.80	27.12	27.43	27.66	28.44	29.24	30.12	31.26	32.18	32.98
Distillate fuel oil	21.32	23.95	24.20	24.45	26.23	27.22	27.61	28.93	29.53	30.79
Residual fuel oil	10.92	18.95	19.21	19.45	20.54	21.23	21.59	21.12	21.65	22.44
Natural gas[2]	5.51	4.68	4.88	4.94	5.58	6.04	6.51	6.89	7.54	7.74
Metallurgical coal	5.84	7.30	7.22	7.20	8.24	8.11	8.08	9.24	9.11	9.11
Other industrial coal	2.71	3.27	3.27	3.27	3.38	3.38	3.39	3.61	3.64	3.69
Coal to liquids	- -	1.27	1.26	1.26	2.27	2.08	2.14	2.34	2.38	2.42
Electricity	19.63	19.06	18.91	18.94	19.21	19.60	20.15	19.63	20.78	22.00
Transportation										
Liquefied petroleum gases[3]	26.88	31.71	31.93	32.09	32.80	33.38	34.04	35.02	35.74	36.31
E85[4]	25.21	28.85	29.03	29.26	27.92	28.81	31.30	31.02	31.96	33.04
Motor gasoline[5]	22.70	29.09	29.26	29.49	30.92	32.10	32.42	32.33	33.61	34.78
Jet fuel[6]	16.22	23.48	23.74	24.02	25.61	26.45	26.99	28.41	29.13	30.25
Diesel fuel (distillate fuel oil)[7]	21.87	27.28	27.56	27.83	29.18	30.42	30.85	31.53	32.40	33.80
Residual fuel oil	10.42	17.96	18.32	18.61	19.74	20.62	20.82	20.50	20.95	21.94
Natural gas[8]	13.20	12.17	12.40	12.51	12.51	13.29	13.86	13.42	14.51	14.87
Electricity	32.99	30.67	30.50	30.54	31.37	31.53	32.45	32.36	33.82	35.11
Electric power[9]										
Distillate fuel oil	18.73	22.50	22.77	23.04	24.44	25.35	25.88	27.17	27.80	29.02
Residual fuel oil	11.89	22.67	23.00	23.03	24.55	25.40	25.41	25.25	25.72	26.49
Natural gas	5.14	4.36	4.55	4.61	5.15	5.60	6.10	6.55	7.21	7.40
Steam coal	2.26	2.33	2.35	2.37	2.50	2.54	2.56	2.75	2.80	2.87
Average price to all users[10]										
Liquefied petroleum gases	17.28	22.78	22.99	23.18	23.62	24.19	24.91	25.96	26.63	27.37
E85[4]	25.21	28.85	29.03	29.26	27.92	28.81	31.30	31.02	31.96	33.04
Motor gasoline[5]	22.59	29.09	29.26	29.49	30.91	32.10	32.42	32.33	33.61	34.78
Jet fuel	16.22	23.48	23.74	24.02	25.61	26.45	26.99	28.41	29.13	30.25
Distillate fuel oil	21.65	26.61	26.87	27.14	28.65	29.81	30.23	31.09	31.91	33.27
Residual fuel oil	10.82	18.67	19.01	19.27	20.46	21.31	21.53	21.22	21.68	22.64
Natural gas	7.16	6.27	6.45	6.52	7.29	7.74	8.22	8.63	9.30	9.53
Metallurgical coal	5.84	7.30	7.22	7.20	8.24	8.11	8.08	9.24	9.11	9.11
Other coal	2.29	2.40	2.41	2.43	2.56	2.59	2.62	2.80	2.85	2.92
Coal to liquids	- -	1.27	1.26	1.26	2.27	2.08	2.14	2.34	2.38	2.42
Electricity	28.68	29.05	28.38	28.23	28.55	28.54	28.90	28.73	29.56	30.64
Non-renewable energy expenditures by sector (billion 2010 dollars)										
Residential	251.69	247.63	246.72	248.83	253.92	266.75	285.47	270.07	298.72	336.43
Commercial	179.08	179.38	177.92	178.42	197.28	201.89	208.21	220.10	231.98	244.34
Industrial	198.98	214.83	223.88	231.79	232.07	261.92	285.16	242.72	282.31	317.58
Transportation	573.78	731.18	746.84	764.56	736.46	803.52	848.96	777.83	856.65	950.17
Total non-renewable expenditures	1203.54	1373.02	1395.36	1423.60	1419.73	1534.08	1627.80	1510.72	1669.66	1848.51
Transportation renewable expenditures	0.08	0.24	0.25	0.26	11.22	8.74	6.44	35.33	38.86	40.34
Total expenditures	**1203.62**	**1373.26**	**1395.61**	**1423.86**	**1430.95**	**1542.81**	**1634.24**	**1546.05**	**1708.52**	**1888.85**

Table B3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Residential										
Liquefied petroleum gases	27.02	33.41	33.08	32.76	47.89	41.41	39.98	74.69	54.86	50.81
Distillate fuel oil	21.21	29.60	29.38	29.22	44.08	38.68	37.22	70.42	51.82	48.97
Natural gas	11.08	11.07	11.11	11.03	17.31	15.43	15.32	28.95	22.14	20.72
Electricity	33.69	39.01	37.27	36.43	51.84	43.72	41.53	75.12	54.76	50.81
Commercial										
Liquefied petroleum gases	23.52	29.82	29.54	29.27	42.91	37.17	35.94	67.37	49.56	45.95
Distillate fuel oil	20.77	26.00	25.83	25.73	39.13	34.47	33.15	62.88	46.20	43.85
Residual fuel oil	11.07	17.55	17.43	17.36	26.93	23.41	22.61	40.96	29.93	28.25
Natural gas	9.10	9.21	9.27	9.21	14.37	12.86	12.78	24.03	18.43	17.16
Electricity	29.73	32.49	31.28	30.75	43.53	37.21	35.84	62.54	46.67	44.37
Industrial[1]										
Liquefied petroleum gases	21.80	29.72	29.56	29.37	42.98	37.51	36.59	68.79	50.95	47.52
Distillate fuel oil	21.32	26.25	26.08	25.96	39.64	34.93	33.54	63.67	46.76	44.36
Residual fuel oil	10.92	20.77	20.70	20.64	31.03	27.24	26.22	46.48	34.28	32.33
Natural gas[2]	5.51	5.13	5.26	5.25	8.43	7.75	7.91	15.15	11.93	11.15
Metallurgical coal	5.84	8.00	7.78	7.64	12.45	10.40	9.81	20.34	14.42	13.13
Other industrial coal	2.71	3.59	3.52	3.47	5.11	4.34	4.12	7.95	5.77	5.32
Coal to liquids	- -	1.39	1.36	1.34	3.42	2.67	2.60	5.15	3.78	3.49
Electricity	19.63	20.89	20.38	20.11	29.03	25.15	24.47	43.20	32.90	31.70
Transportation										
Liquefied petroleum gases[3]	26.88	34.76	34.41	34.07	49.57	42.83	41.35	77.05	56.59	52.31
E85[4]	25.21	31.62	31.28	31.06	42.19	36.97	38.02	68.26	50.61	47.60
Motor gasoline[5]	22.70	31.88	31.53	31.31	46.72	41.19	39.38	71.14	53.22	50.11
Jet fuel[6]	16.22	25.74	25.58	25.50	38.70	33.94	32.78	62.51	46.12	43.58
Diesel fuel (distillate fuel oil)[7]	21.87	29.90	29.69	29.55	44.10	39.03	37.47	69.37	51.29	48.70
Residual fuel oil	10.42	19.69	19.74	19.76	29.83	26.45	25.28	45.11	33.18	31.60
Natural gas[8]	13.20	13.34	13.36	13.29	18.91	17.05	16.84	29.54	22.97	21.42
Electricity	32.99	33.62	32.86	32.42	47.41	40.46	39.41	71.19	53.55	50.59
Electric power[9]										
Distillate fuel oil	18.73	24.66	24.53	24.46	36.93	32.52	31.43	59.79	44.02	41.80
Residual fuel oil	11.89	24.85	24.78	24.45	37.10	32.59	30.87	55.56	40.73	38.16
Natural gas	5.14	4.78	4.90	4.90	7.78	7.19	7.41	14.41	11.42	10.66
Steam coal	2.26	2.56	2.53	2.51	3.78	3.25	3.12	6.05	4.43	4.13

Table B3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Average price to all users[10]										
Liquefied petroleum gases	17.28	24.97	24.78	24.61	35.69	31.04	30.26	57.13	42.17	39.44
E85[4]	25.21	31.62	31.28	31.06	42.19	36.97	38.02	68.26	50.61	47.60
Motor gasoline[5]	22.59	31.88	31.53	31.31	46.72	41.19	39.38	71.14	53.22	50.11
Jet fuel	16.22	25.74	25.58	25.50	38.70	33.94	32.78	62.51	46.12	43.58
Distillate fuel oil	21.65	29.16	28.96	28.81	43.29	38.24	36.72	68.42	50.52	47.93
Residual fuel oil	10.82	20.46	20.48	20.46	30.92	27.34	26.15	46.69	34.33	32.61
Natural gas	7.16	6.87	6.95	6.92	11.02	9.93	9.98	18.98	14.73	13.73
Metallurgical coal	5.84	8.00	7.78	7.64	12.45	10.40	9.81	20.34	14.42	13.13
Other coal	2.29	2.63	2.60	2.58	3.87	3.32	3.18	6.17	4.51	4.20
Coal to liquids	- -	1.39	1.36	1.34	3.42	2.67	2.60	5.15	3.78	3.49
Electricity	28.68	31.84	30.58	29.97	43.14	36.62	35.11	63.22	46.80	44.14
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	251.69	271.41	265.85	264.18	383.71	342.26	346.74	594.24	472.99	484.70
Commercial	179.08	196.61	191.71	189.42	298.11	259.04	252.89	484.30	367.31	352.03
Industrial	198.98	235.47	241.24	246.08	350.69	336.06	346.35	534.08	447.01	457.54
Transportation	573.78	801.41	804.75	811.72	1112.90	1030.98	1031.15	1711.49	1356.41	1368.93
Total non-renewable expenditures	1203.54	1504.89	1503.55	1511.41	2145.42	1968.35	1977.13	3324.10	2643.72	2663.20
Transportation renewable expenditures	0.08	0.27	0.27	0.27	16.95	11.21	7.82	77.73	61.53	58.11
Total expenditures	**1203.62**	**1505.16**	**1503.82**	**1511.69**	**2162.37**	**1979.56**	**1984.95**	**3401.83**	**2705.26**	**2721.31**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2010 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2010 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2010 transportation sector natural gas delivered prices are model results. 2010 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/09) (Washington, DC, September 2010). 2010 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2010 and April 2011, Table 4.2, and EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2010 coal prices based on: EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011) and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. 2010 electricity prices: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2012 National Energy Modeling System runs LM2012.D022412A, REF2012.D020112C, and HM2012.D022412A.

Table B4. Macroeconomic indicators

(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	2010	Projections								
		2015			2025			2035		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Real gross domestic product	**13088**	**14401**	**14803**	**15235**	**17676**	**19185**	**20538**	**21630**	**24539**	**27084**
Components of real gross domestic product										
Real consumption	9221	10007	10218	10510	11874	12697	13606	14594	16220	17889
Real investment	1715	2234	2457	2675	2956	3472	3982	3929	4836	5651
Real government spending	2557	2322	2355	2389	2420	2525	2601	2619	2818	2944
Real exports	1663	2243	2289	2322	3828	4235	4558	5846	6953	7979
Real imports	2085	2370	2463	2596	3258	3516	3909	5020	5690	6596
Energy intensity (thousand Btu per 2005 dollar of GDP)										
Delivered energy	5.45	4.90	4.84	4.77	3.98	3.85	3.74	3.35	3.17	3.06
Total energy	7.50	6.66	6.58	6.50	5.50	5.32	5.16	4.63	4.36	4.22
Price indices										
GDP chain-type price index (2005=1.000)	1.110	1.217	1.196	1.178	1.677	1.424	1.348	2.442	1.758	1.599
Consumer price index (1982-4=1)										
All-urban	2.18	2.47	2.42	2.36	3.53	2.95	2.78	5.38	3.72	3.36
Energy commodities and services	2.12	2.67	2.62	2.59	3.82	3.36	3.20	5.83	4.37	4.07
Wholesale price index (1982=1.00)										
All commodities	1.85	2.15	2.10	2.02	2.96	2.39	2.25	4.46	2.81	2.47
Fuel and power	1.86	2.31	2.29	2.27	3.41	3.01	2.92	5.44	4.12	3.85
Metals and metal products	2.08	2.45	2.43	2.45	2.85	2.57	2.53	3.39	2.64	2.56
Industrial commodities excluding energy	**1.83**	**2.08**	**2.04**	**2.02**	**2.63**	**2.22**	**2.12**	**3.47**	**2.43**	**2.24**
Interest rates (percent, nominal)										
Federal funds rate	0.17	3.31	3.26	2.50	5.75	4.29	3.58	7.56	4.30	3.59
10-year treasury note	3.21	6.62	4.67	4.09	8.03	5.06	4.49	8.22	5.18	4.47
AA utility bond rate	5.24	9.31	6.74	5.73	11.61	7.17	6.18	12.74	7.56	6.12
Value of shipments (billion 2005 dollars)										
Service sectors	20602	22047	22469	22970	26671	28029	29342	31392	33430	35331
Total industrial	5838	6407	6730	7072	7109	7973	8737	7606	8692	9954
Non-manufacturing	1578	1702	1873	2065	1885	2228	2554	2024	2407	2823
Manufacturing	4260	4705	4857	5008	5224	5745	6183	5583	6285	7131
Energy-intensive	1595	1633	1664	1692	1781	1901	1971	1854	2034	2155
Non-energy-intensive	2664	3072	3194	3316	3443	3844	4212	3729	4251	4976
Total shipments	**26440**	**28454**	**29199**	**30042**	**33780**	**36002**	**38079**	**38998**	**42122**	**45285**
Population and employment (millions)										
Population with armed forces overseas	310.8	325.2	326.2	327.2	354.2	358.1	362.5	382.8	390.1	398.7
Population, aged 16 and over	244.3	256.0	256.5	257.2	279.9	282.6	285.8	304.2	309.6	316.0
Population, over age 65	40.4	46.7	47.1	47.1	63.4	64.2	64.4	76.9	77.7	78.3
Employment, nonfarm	129.8	138.3	139.4	142.7	150.4	154.2	160.5	158.9	166.8	173.4
Employment, manufacturing	11.5	11.8	12.1	12.3	11.0	11.4	11.9	9.1	9.2	9.9
Key labor indicators										
Labor force (millions)	153.9	157.6	158.0	158.7	167.1	168.6	170.9	178.0	181.7	186.3
Non-farm labor productivity (1992=1.00)	1.10	1.14	1.16	1.18	1.33	1.42	1.47	1.55	1.75	1.85
Unemployment rate (percent)	9.63	8.11	7.51	7.10	6.04	5.54	5.05	6.15	5.54	5.09
Key indicators for energy demand										
Real disposable personal income	10062	10890	11035	11224	13862	14286	14978	17350	18217	19407
Housing starts (millions)	0.63	1.40	1.75	2.22	1.40	1.96	2.78	1.19	1.89	2.95
Commercial floorspace (billion square feet)	81.1	84.0	84.1	84.3	92.7	93.9	95.2	100.5	103.0	105.5
Unit sales of light-duty vehicles (millions)	11.55	15.34	16.16	16.69	16.20	17.79	18.85	15.31	18.64	20.55

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2010: IHS Global Insight, Global Insight Industry and Employment models, August 2011. **Projections:** U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs LM2012.D022412A, REF2012.D020112C, and HM2012.D022412A.

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Appendix C

Price case comparisons

Table C1. Total energy supply, disposition, and price summary

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Production										
Crude oil and lease condensate	11.59	12.66	13.23	13.79	11.57	13.77	15.60	10.29	12.89	14.37
Natural gas plant liquids	2.78	3.15	3.33	3.34	3.84	3.93	4.01	3.80	3.94	4.00
Dry natural gas	22.10	24.02	24.22	24.44	26.20	26.91	27.65	27.80	28.60	29.38
Coal[1]	22.06	20.76	20.24	19.80	22.39	22.25	23.45	23.59	24.14	27.73
Nuclear / uranium[2]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.42	9.28	9.26
Hydropower	2.51	2.90	2.90	2.90	2.99	2.99	2.98	3.05	3.04	3.04
Biomass[3]	4.05	4.52	4.45	4.67	6.14	6.26	7.14	7.92	9.07	11.33
Other renewable energy[4]	1.34	1.94	1.99	2.02	2.18	2.22	2.19	2.87	2.81	2.66
Other[5]	0.64	0.54	0.60	0.82	0.55	0.69	0.77	0.68	0.91	0.90
Total	**75.50**	**79.18**	**79.64**	**80.46**	**85.46**	**88.61**	**93.38**	**89.43**	**94.67**	**102.65**
Imports										
Crude oil	20.14	21.26	18.87	17.01	21.30	16.23	12.08	23.88	16.90	11.22
Liquid fuels and other petroleum[6]	5.02	4.97	4.32	3.89	5.08	4.08	3.43	5.40	4.14	3.26
Natural gas[7]	3.81	3.87	3.73	3.69	3.16	2.75	2.55	3.28	2.84	2.57
Other imports[8]	0.52	0.47	0.44	0.40	0.83	1.07	0.81	0.87	0.81	0.76
Total	**29.49**	**30.58**	**27.37**	**24.98**	**30.37**	**24.14**	**18.88**	**33.42**	**24.69**	**17.82**
Exports										
Liquid fuels and other petroleum[9]	4.81	5.16	5.00	4.95	4.51	4.46	4.58	4.89	4.95	5.02
Natural gas[10]	1.15	1.93	1.93	1.93	3.51	3.51	3.52	4.17	4.17	4.18
Coal	2.10	2.73	2.73	2.73	2.82	2.82	2.67	3.22	3.13	3.13
Total	**8.06**	**9.82**	**9.66**	**9.62**	**10.84**	**10.79**	**10.76**	**12.28**	**12.25**	**12.33**
Discrepancy[11]	**-1.23**	**0.04**	**-0.08**	**0.01**	**0.09**	**-0.03**	**-0.01**	**0.23**	**0.18**	**0.27**
Consumption										
Liquid fuels and other petroleum[12]	37.25	38.73	36.72	35.31	39.70	36.58	35.03	41.86	37.70	35.86
Natural gas	24.71	25.93	26.00	26.18	25.80	26.14	26.57	26.86	27.26	27.67
Coal[13]	20.76	18.35	17.80	17.30	20.17	20.02	20.39	21.05	21.15	22.69
Nuclear / uranium[2]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.42	9.28	9.26
Hydropower	2.51	2.90	2.90	2.90	2.99	2.99	2.98	3.05	3.04	3.04
Biomass[14]	2.88	3.06	3.04	3.13	4.19	4.17	4.48	4.98	5.44	6.45
Other renewable energy[4]	1.34	1.94	1.99	2.02	2.18	2.22	2.19	2.87	2.81	2.66
Other[15]	0.29	0.30	0.30	0.30	0.28	0.28	0.28	0.24	0.24	0.24
Total	**98.16**	**99.89**	**97.43**	**95.82**	**104.90**	**101.99**	**101.52**	**110.34**	**106.93**	**107.87**
Prices (2010 dollars per unit)										
Petroleum (dollars per barrel)										
Low sulfur light crude oil[16]	79.39	58.36	116.91	182.10	59.41	132.56	193.48	62.38	144.98	200.36
Imported crude oil[16]	75.87	55.41	113.97	179.16	48.84	121.21	180.29	53.10	132.95	187.04
Natural gas (dollars per million Btu)										
at Henry hub	4.39	4.21	4.29	4.26	5.61	5.63	5.60	7.36	7.37	7.17
at the wellhead[17]	4.06	3.78	3.84	3.81	4.98	5.00	4.97	6.47	6.48	6.31
Natural gas (dollars per thousand cubic feet)										
at the wellhead[17]	4.16	3.87	3.94	3.91	5.10	5.12	5.09	6.63	6.64	6.46
Coal (dollars per ton)										
at the minemouth[18]	35.61	39.93	42.08	44.26	41.50	44.05	45.62	47.24	50.52	51.12
Coal (dollars per million Btu)										
at the minemouth[18]	1.76	1.98	2.08	2.18	2.10	2.23	2.31	2.40	2.56	2.62
Average end-use[19]	2.38	2.42	2.56	2.68	2.51	2.70	2.81	2.73	2.94	3.07
Average electricity (cents per kilowatthour)	9.8	9.5	9.7	9.9	9.5	9.7	9.9	10.0	10.1	10.2

Table C1. Total energy supply, disposition, and price summary (continued)

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Prices (nominal dollars per unit)										
Petroleum (dollars per barrel)										
Low sulfur light crude oil[165]	79.39	62.81	125.97	195.67	77.32	170.09	245.37	98.91	229.55	314.93
Imported crude oil[16]	75.87	59.64	122.81	192.52	63.56	155.52	228.64	84.19	210.51	294.00
Natural gas (dollars per million Btu)										
at Henry hub	4.39	4.54	4.62	4.57	7.30	7.23	7.10	11.67	11.67	11.26
at the wellhead[17]	4.06	4.07	4.14	4.10	6.48	6.42	6.30	10.26	10.26	9.91
Natural gas (dollars per thousand cubic feet)										
at the wellhead[17]	4.16	4.16	4.24	4.20	6.64	6.57	6.46	10.51	10.51	10.15
Coal (dollars per ton)										
at the minemouth[18]	35.61	42.97	45.34	47.56	54.01	56.52	57.86	74.91	80.00	80.35
Coal (dollars per million Btu)										
at the minemouth[18]	1.76	2.13	2.24	2.34	2.74	2.86	2.93	3.81	4.05	4.12
Average end-use[19]	2.38	2.61	2.76	2.88	3.27	3.47	3.56	4.33	4.66	4.83
Average electricity (cents per kilowatthour)	9.8	10.2	10.4	10.6	12.4	12.5	12.6	15.9	16.0	16.0

[1]Includes waste coal.

[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.

[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.

[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.

[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.

[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.

[7]Includes imports of liquefied natural gas that is later re-exported.

[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.

[9]Includes crude oil, petroleum products, ethanol, and biodiesel.

[10]Includes re-exported liquefied natural gas and natural gas used for liquefaction at export terminals.

[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.

[12]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.

[13]Excludes coal converted to coal-based synthetic liquids and natural gas.

[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.

[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.

[16]Weighted average price delivered to U.S. refiners.

[17]Represents lower 48 onshore and offshore supplies.

[18]Includes reported prices for both open market and captive mines.

[19]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2010 natural gas supply values and natural gas wellhead price: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2010 coal minemouth and delivered coal prices: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 petroleum supply values: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). 2010 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude oil Acquisition Report." Other 2010 coal values: *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011). Other 2010 values: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System runs LP2012.D022112A, REF2012.D020112C, and HP2012.D022112A.

Table C2. Energy consumption by sector and source

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Energy consumption										
Residential										
Liquefied petroleum gases	0.56	0.54	0.51	0.49	0.55	0.50	0.48	0.55	0.51	0.48
Kerosene	0.03	0.03	0.02	0.02	0.03	0.02	0.02	0.02	0.02	0.02
Distillate fuel oil	0.63	0.61	0.55	0.51	0.49	0.43	0.40	0.41	0.35	0.33
Liquid fuels and other petroleum subtotal	1.22	1.17	1.08	1.02	1.07	0.95	0.90	0.99	0.87	0.82
Natural gas	5.06	4.98	4.97	4.98	4.88	4.88	4.90	4.74	4.76	4.78
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable energy[1]	0.42	0.37	0.43	0.48	0.36	0.43	0.48	0.35	0.43	0.47
Electricity	4.95	4.78	4.75	4.71	5.27	5.23	5.20	5.90	5.86	5.83
Delivered energy	**11.66**	**11.31**	**11.24**	**11.19**	**11.58**	**11.51**	**11.48**	**11.98**	**11.93**	**11.91**
Electricity related losses	10.39	9.68	9.58	9.47	10.66	10.52	10.34	11.58	11.35	11.02
Total	**22.05**	**20.99**	**20.81**	**20.66**	**22.24**	**22.02**	**21.82**	**23.56**	**23.28**	**22.93**
Commercial										
Liquefied petroleum gases	0.14	0.16	0.14	0.12	0.18	0.15	0.13	0.19	0.16	0.14
Motor gasoline[2]	0.05	0.06	0.05	0.04	0.06	0.05	0.05	0.07	0.06	0.06
Kerosene	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.01	0.01
Distillate fuel oil	0.43	0.41	0.35	0.32	0.41	0.33	0.30	0.41	0.32	0.30
Residual fuel oil	0.08	0.13	0.08	0.06	0.14	0.08	0.06	0.14	0.08	0.07
Liquid fuels and other petroleum subtotal	0.72	0.76	0.62	0.55	0.79	0.62	0.56	0.81	0.62	0.57
Natural gas	3.28	3.42	3.41	3.42	3.51	3.53	3.55	3.64	3.69	3.72
Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.54	4.61	4.59	4.57	5.19	5.16	5.14	5.81	5.80	5.77
Delivered energy	**8.70**	**8.96**	**8.80**	**8.70**	**9.66**	**9.48**	**9.41**	**10.43**	**10.28**	**10.23**
Electricity related losses	9.52	9.34	9.27	9.18	10.50	10.38	10.21	11.41	11.23	10.90
Total	**18.22**	**18.30**	**18.06**	**17.89**	**20.16**	**19.86**	**19.62**	**21.84**	**21.50**	**21.13**
Industrial[4]										
Liquefied petroleum gases	2.00	1.86	1.83	1.80	2.22	2.17	2.13	2.23	2.15	2.11
Motor gasoline[2]	0.25	0.28	0.28	0.28	0.31	0.30	0.30	0.32	0.30	0.29
Distillate fuel oil	1.16	1.28	1.25	1.24	1.25	1.19	1.17	1.29	1.18	1.16
Residual fuel oil	0.12	0.12	0.09	0.09	0.13	0.08	0.07	0.14	0.08	0.07
Petrochemical feedstocks	0.94	1.01	1.01	1.01	1.30	1.29	1.28	1.32	1.30	1.29
Other petroleum[5]	3.59	3.82	3.44	3.23	3.82	3.11	2.89	4.10	3.19	2.83
Liquid fuels and other petroleum subtotal	8.05	8.39	7.89	7.65	9.03	8.13	7.83	9.40	8.21	7.76
Natural gas	6.76	7.17	7.19	7.21	7.19	7.32	7.38	7.18	7.18	7.29
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.07
Lease and plant fuel[6]	1.37	1.42	1.43	1.44	1.53	1.57	1.63	1.54	1.63	1.71
Natural gas subtotal	8.14	8.59	8.62	8.65	8.72	8.89	9.09	8.71	8.81	9.07
Metallurgical coal	0.55	0.58	0.57	0.56	0.48	0.49	0.49	0.44	0.43	0.43
Other industrial coal	1.01	1.03	1.03	1.02	1.04	1.08	1.08	1.05	1.08	1.09
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.10	0.36	1.12	0.10	0.60	2.74
Net coal coke imports	-0.01	-0.00	-0.01	-0.01	-0.03	-0.03	-0.03	-0.06	-0.06	-0.06
Coal subtotal	1.56	1.60	1.59	1.58	1.60	1.90	2.67	1.54	2.06	4.21
Biofuels heat and coproducts	0.84	0.85	0.81	0.86	1.19	1.27	1.73	1.99	2.57	3.63
Renewable energy[7]	1.50	1.63	1.61	1.63	1.90	1.82	1.75	2.10	1.95	1.87
Electricity	3.28	3.52	3.44	3.40	3.57	3.52	3.51	3.40	3.33	3.32
Delivered energy	**23.37**	**24.57**	**23.96**	**23.76**	**26.02**	**25.53**	**26.58**	**27.14**	**26.94**	**29.85**
Electricity related losses	6.89	7.11	6.94	6.84	7.21	7.09	6.98	6.68	6.46	6.27
Total	**30.26**	**31.69**	**30.90**	**30.60**	**33.24**	**32.61**	**33.56**	**33.82**	**33.39**	**36.12**

Table C2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Transportation										
Liquefied petroleum gases	0.04	0.04	0.04	0.05	0.04	0.04	0.05	0.05	0.05	0.05
E85[8]	0.00	0.01	0.01	0.37	0.02	0.30	1.49	0.20	1.22	2.63
Motor gasoline[2]	16.91	17.23	16.13	14.85	17.02	14.90	12.48	17.96	14.53	11.70
Jet fuel[9]	3.07	3.04	3.03	3.01	3.20	3.19	3.18	3.34	3.33	3.32
Distillate fuel oil[10]	5.77	6.71	6.55	6.45	7.08	7.03	7.14	7.58	7.44	7.57
Residual fuel oil	0.90	0.91	0.91	0.91	0.92	0.93	0.93	0.94	0.94	0.94
Other petroleum[11]	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Liquid fuels and other petroleum subtotal	26.88	28.11	26.83	25.81	28.45	26.57	25.44	30.24	27.67	26.40
Pipeline fuel natural gas	0.65	0.68	0.68	0.69	0.66	0.67	0.69	0.67	0.69	0.69
Compressed / liquefied natural gas	0.04	0.05	0.06	0.08	0.06	0.11	0.21	0.07	0.16	0.30
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.03	0.04	0.06	0.05	0.07	0.11
Delivered energy	**27.59**	**28.86**	**27.60**	**26.61**	**29.20**	**27.40**	**26.40**	**31.03**	**28.60**	**27.49**
Electricity related losses	0.05	0.05	0.05	0.06	0.07	0.08	0.12	0.10	0.14	0.20
Total	**27.63**	**28.92**	**27.65**	**26.67**	**29.27**	**27.49**	**26.52**	**31.12**	**28.75**	**27.69**
Delivered energy consumption for all sectors										
Liquefied petroleum gases	2.75	2.60	2.51	2.46	2.98	2.86	2.79	3.02	2.86	2.79
E85[8]	0.00	0.01	0.01	0.37	0.02	0.30	1.49	0.20	1.22	2.63
Motor gasoline[2]	17.21	17.57	16.46	15.17	17.39	15.25	12.82	18.35	14.88	12.05
Jet fuel[9]	3.07	3.04	3.03	3.01	3.20	3.19	3.18	3.34	3.33	3.32
Kerosene	0.04	0.04	0.03	0.03	0.04	0.03	0.03	0.04	0.03	0.03
Distillate fuel oil	7.99	9.01	8.69	8.52	9.24	8.99	9.02	9.69	9.29	9.36
Residual fuel oil	1.11	1.16	1.08	1.06	1.19	1.09	1.06	1.21	1.11	1.08
Petrochemical feedstocks	0.94	1.01	1.01	1.01	1.30	1.29	1.28	1.32	1.30	1.29
Other petroleum[12]	3.76	3.98	3.61	3.39	3.98	3.27	3.05	4.27	3.36	3.00
Liquid fuels and other petroleum subtotal	36.87	38.42	36.43	35.02	39.35	36.28	34.73	41.44	37.38	35.55
Natural gas	15.15	15.62	15.64	15.68	15.63	15.85	16.04	15.62	15.79	16.08
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.07
Lease and plant fuel[6]	1.37	1.42	1.43	1.44	1.53	1.57	1.63	1.54	1.63	1.71
Pipeline natural gas	0.65	0.68	0.68	0.69	0.66	0.67	0.69	0.67	0.69	0.69
Natural gas subtotal	17.17	17.72	17.75	17.81	17.82	18.09	18.43	17.83	18.11	18.55
Metallurgical coal	0.55	0.58	0.57	0.56	0.48	0.49	0.49	0.44	0.43	0.43
Other coal	1.08	1.09	1.09	1.08	1.11	1.14	1.15	1.11	1.15	1.16
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.10	0.36	1.12	0.10	0.60	2.74
Net coal coke imports	-0.01	-0.00	-0.01	-0.01	-0.03	-0.03	-0.03	-0.06	-0.06	-0.06
Coal subtotal	1.62	1.67	1.65	1.64	1.67	1.96	2.74	1.60	2.12	4.28
Biofuels heat and coproducts	0.84	0.85	0.81	0.86	1.19	1.27	1.73	1.99	2.57	3.63
Renewable energy[13]	2.03	2.10	2.15	2.22	2.37	2.36	2.34	2.56	2.50	2.45
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.79	12.94	12.81	12.71	14.07	13.96	13.91	15.16	15.06	15.02
Delivered energy	**71.32**	**73.71**	**71.59**	**70.26**	**76.47**	**73.92**	**73.87**	**80.58**	**77.75**	**79.48**
Electricity related losses	26.84	26.19	25.84	25.55	28.44	28.07	27.65	29.76	29.18	28.39
Total	**98.16**	**99.89**	**97.43**	**95.82**	**104.90**	**101.99**	**101.52**	**110.34**	**106.93**	**107.87**
Electric power[14]										
Distillate fuel oil	0.08	0.09	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09
Residual fuel oil	0.30	0.22	0.21	0.21	0.27	0.22	0.22	0.33	0.23	0.23
Liquid fuels and other petroleum subtotal	0.38	0.30	0.29	0.29	0.36	0.31	0.31	0.42	0.32	0.32
Natural gas	7.54	8.22	8.25	8.37	7.97	8.04	8.14	9.03	9.16	9.12
Steam coal	19.13	16.68	16.15	15.66	18.50	18.06	17.65	19.45	19.03	18.41
Nuclear / uranium[15]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.42	9.28	9.26
Renewable energy[16]	3.85	4.94	4.96	4.96	5.80	5.75	5.59	6.34	6.22	6.07
Electricity imports	0.09	0.10	0.10	0.10	0.08	0.08	0.08	0.04	0.04	0.04
Total[17]	**39.63**	**39.13**	**38.64**	**38.26**	**42.50**	**42.03**	**41.56**	**44.91**	**44.24**	**43.41**

Table C2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Total energy consumption										
Liquefied petroleum gases	2.75	2.60	2.51	2.46	2.98	2.86	2.79	3.02	2.86	2.79
E85[8]	0.00	0.01	0.01	0.37	0.02	0.30	1.49	0.20	1.22	2.63
Motor gasoline[2]	17.21	17.57	16.46	15.17	17.39	15.25	12.82	18.35	14.88	12.05
Jet fuel[9]	3.07	3.04	3.03	3.01	3.20	3.19	3.18	3.34	3.33	3.32
Kerosene	0.04	0.04	0.03	0.03	0.04	0.03	0.03	0.04	0.03	0.03
Distillate fuel oil	8.07	9.10	8.78	8.60	9.33	9.07	9.10	9.78	9.38	9.45
Residual fuel oil	1.41	1.38	1.29	1.27	1.46	1.31	1.28	1.55	1.34	1.31
Petrochemical feedstocks	0.94	1.01	1.01	1.01	1.30	1.29	1.28	1.32	1.30	1.29
Other petroleum[12]	3.76	3.98	3.61	3.39	3.98	3.27	3.05	4.27	3.36	3.00
Liquid fuels and other petroleum subtotal	37.25	38.73	36.72	35.31	39.70	36.58	35.03	41.86	37.70	35.86
Natural gas	22.69	23.84	23.89	24.05	23.60	23.89	24.17	24.65	24.94	25.20
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.07
Lease and plant fuel[6]	1.37	1.42	1.43	1.44	1.53	1.57	1.63	1.54	1.63	1.71
Pipeline natural gas	0.65	0.68	0.68	0.69	0.66	0.67	0.69	0.67	0.69	0.69
Natural gas subtotal	24.71	25.93	26.00	26.18	25.80	26.14	26.57	26.86	27.26	27.67
Metallurgical coal	0.55	0.58	0.57	0.56	0.48	0.49	0.49	0.44	0.43	0.43
Other coal	20.21	17.77	17.24	16.74	19.61	19.20	18.80	20.56	20.18	19.57
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.10	0.36	1.12	0.10	0.60	2.74
Net coal coke imports	-0.01	-0.00	-0.01	-0.01	-0.03	-0.03	-0.03	-0.06	-0.06	-0.06
Coal subtotal	20.76	18.35	17.80	17.30	20.17	20.02	20.39	21.05	21.15	22.69
Nuclear / uranium[15]	8.44	8.68	8.68	8.68	9.60	9.60	9.60	9.42	9.28	9.26
Biofuels heat and coproducts	0.84	0.85	0.81	0.86	1.19	1.27	1.73	1.99	2.57	3.63
Renewable energy[18]	5.88	7.05	7.11	7.18	8.16	8.11	7.93	8.91	8.71	8.52
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity imports	0.09	0.10	0.10	0.10	0.08	0.08	0.08	0.04	0.04	0.04
Total	**98.16**	**99.89**	**97.43**	**95.82**	**104.90**	**101.99**	**101.52**	**110.34**	**106.93**	**107.87**
Energy use and related statistics										
Delivered energy use	71.32	73.71	71.59	70.26	76.47	73.92	73.87	80.58	77.75	79.48
Total energy use	98.16	99.89	97.43	95.82	104.90	101.99	101.52	110.34	106.93	107.87
Ethanol consumed in motor gasoline and E85	1.11	1.30	1.22	1.36	1.56	1.55	2.14	1.77	2.15	2.80
Population (millions)	310.83	326.16	326.16	326.16	358.06	358.06	358.06	390.09	390.09	390.09
Gross domestic product (billion 2005 dollars)	13088	14990	14803	14666	19146	19185	19380	24596	24539	24703
Carbon dioxide emissions (million metric tons)	5633.6	5592.8	5407.2	5251.2	5770.9	5552.5	5450.8	6049.1	5757.9	5737.1

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.

[2]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.

[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.

[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.

[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.

[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.

[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (15 percent or less) in motor gasoline.

[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.

[9]Includes only kerosene type.

[10]Diesel fuel for on- and off- road use.

[11]Includes aviation gasoline and lubricants.

[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.

[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.

[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[15]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.

[16]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.

[17]Includes non-biogenic municipal waste not included above.

[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2010 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2011. 2010 carbon dioxide emissions: EIA, *Monthly Energy Review, October 2011* DOE/EIA-0035(2011/10) (Washington, DC, October 2011). **Projections:** EIA, AEO2012 National Energy Modeling System runs LP2012.D022112A, REF2012.D020112C, and HP2012.D022112A.

Table C3. Energy prices by sector and source

(2010 dollars per million Btu, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Residential										
Liquefied petroleum gases	27.02	22.54	30.70	39.69	22.18	32.27	40.42	23.49	34.64	42.03
Distillate fuel oil	21.21	16.55	27.26	38.29	17.27	30.15	39.23	18.46	32.73	40.00
Natural gas	11.08	10.22	10.31	10.30	11.96	12.03	12.02	13.97	13.98	13.86
Electricity	33.69	34.06	34.59	35.24	33.37	34.08	34.73	34.31	34.58	35.00
Commercial										
Liquefied petroleum gases	23.52	19.33	27.42	36.38	19.00	28.97	37.09	20.30	31.30	38.66
Distillate fuel oil	20.77	13.91	23.98	34.68	14.39	26.86	35.89	15.51	29.18	36.36
Residual fuel oil	11.07	5.99	16.18	27.80	6.25	18.24	28.32	6.90	18.90	28.11
Natural gas	9.10	8.52	8.60	8.59	9.98	10.02	10.01	11.66	11.64	11.49
Electricity	29.73	28.52	29.03	29.65	28.32	29.00	29.71	29.30	29.48	29.84
Industrial[1]										
Liquefied petroleum gases	21.80	16.98	27.43	38.87	16.33	29.24	39.62	17.95	32.18	41.60
Distillate fuel oil	21.32	14.50	24.20	34.82	14.95	27.22	36.32	16.19	29.53	36.60
Residual fuel oil	10.92	9.51	19.21	30.20	9.60	21.23	30.43	9.97	21.65	30.61
Natural gas[2]	5.51	4.78	4.88	4.88	5.99	6.04	6.01	7.52	7.54	7.38
Metallurgical coal	5.84	7.04	7.22	7.35	7.86	8.11	8.24	8.85	9.11	9.23
Other industrial coal	2.71	3.11	3.27	3.38	3.18	3.38	3.52	3.38	3.64	3.86
Coal to liquids	- -	1.17	1.26	1.32	2.02	2.08	2.26	2.26	2.38	2.64
Electricity	19.63	18.58	18.91	19.26	19.11	19.60	19.96	20.61	20.78	20.97
Transportation										
Liquefied petroleum gases[3]	26.88	23.86	31.93	40.71	23.47	33.38	41.43	24.77	35.74	43.04
E85[4]	25.21	18.16	29.03	38.11	17.18	28.81	41.93	16.59	31.96	39.01
Motor gasoline[5]	22.70	18.53	29.26	41.14	18.20	32.10	43.26	18.49	33.61	42.09
Jet fuel[6]	16.22	12.62	23.74	35.26	12.80	26.45	35.89	13.96	29.13	36.89
Diesel fuel (distillate fuel oil)[7]	21.87	17.99	27.56	38.22	18.14	30.42	39.66	19.15	32.40	39.63
Residual fuel oil	10.42	8.64	18.32	29.02	8.67	20.62	29.37	8.76	20.95	29.86
Natural gas[8]	13.20	12.28	12.40	12.45	13.05	13.29	13.41	14.26	14.51	14.47
Electricity	32.99	30.37	30.50	30.24	30.91	31.53	33.04	33.26	33.82	34.36
Electric power[9]										
Distillate fuel oil	18.73	12.06	22.77	33.56	12.54	25.35	34.16	13.56	27.80	35.05
Residual fuel oil	11.89	13.08	23.00	33.74	12.12	25.40	34.30	11.20	25.72	34.59
Natural gas	5.14	4.46	4.55	4.54	5.58	5.60	5.59	7.18	7.21	7.04
Steam coal	2.26	2.22	2.35	2.47	2.34	2.54	2.68	2.56	2.80	3.00
Average price to all users[10]										
Liquefied petroleum gases	17.28	14.64	22.99	32.23	13.90	24.19	32.57	15.28	26.63	34.20
E85[4]	25.21	18.16	29.03	38.11	17.18	28.81	41.93	16.59	31.96	39.01
Motor gasoline[5]	22.59	18.53	29.26	41.14	18.19	32.10	43.26	18.49	33.61	42.09
Jet fuel	16.22	12.62	23.74	35.26	12.80	26.45	35.89	13.96	29.13	36.89
Distillate fuel oil	21.65	17.16	26.87	37.56	17.45	29.81	39.04	18.54	31.91	39.12
Residual fuel oil	10.82	9.17	19.01	29.82	9.16	21.31	30.21	9.22	21.68	30.63
Natural gas	7.16	6.36	6.45	6.43	7.70	7.74	7.74	9.26	9.30	9.18
Metallurgical coal	5.84	7.04	7.22	7.35	7.86	8.11	8.24	8.85	9.11	9.23
Other coal	2.29	2.28	2.41	2.53	2.39	2.59	2.73	2.61	2.85	3.06
Coal to liquids	- -	1.17	1.26	1.32	2.02	2.08	2.26	2.26	2.38	2.64
Electricity	28.68	27.87	28.38	28.94	27.88	28.54	29.14	29.31	29.56	29.92
Non-renewable energy expenditures by sector (billion 2010 dollars)										
Residential	251.69	236.40	246.72	256.77	255.31	266.75	275.38	289.49	298.72	304.24
Commercial	179.08	171.63	177.92	184.03	193.67	201.89	208.38	225.40	231.98	235.90
Industrial	198.98	175.07	223.88	279.09	194.55	261.92	313.03	212.90	282.31	323.54
Transportation	573.78	489.96	746.84	998.67	491.22	803.52	976.23	537.61	856.65	958.30
Total non-renewable expenditures	1203.54	1073.06	1395.36	1718.56	1134.76	1534.08	1773.02	1265.39	1669.66	1821.97
Transportation renewable expenditures	0.08	0.18	0.25	14.01	0.39	8.74	62.29	3.32	38.86	102.69
Total expenditures	**1203.62**	**1073.25**	**1395.61**	**1732.58**	**1135.15**	**1542.81**	**1835.31**	**1268.71**	**1708.52**	**1924.66**

Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Residential										
Liquefied petroleum gases	27.02	24.26	33.08	42.65	28.87	41.41	51.27	37.25	54.86	66.07
Distillate fuel oil	21.21	17.81	29.38	41.14	22.48	38.68	49.75	29.27	51.82	62.87
Natural gas	11.08	11.00	11.11	11.06	15.57	15.43	15.25	22.15	22.14	21.78
Electricity	33.69	36.66	37.27	37.86	43.43	43.72	44.05	54.40	54.76	55.02
Commercial										
Liquefied petroleum gases	23.52	20.80	29.54	39.09	24.73	37.17	47.04	32.18	49.56	60.77
Distillate fuel oil	20.77	14.97	25.83	37.27	18.73	34.47	45.51	24.59	46.20	57.15
Residual fuel oil	11.07	6.44	17.43	29.87	8.13	23.41	35.92	10.94	29.93	44.18
Natural gas	9.10	9.17	9.27	9.23	12.99	12.86	12.69	18.48	18.43	18.06
Electricity	29.73	30.70	31.28	31.86	36.86	37.21	37.68	46.46	46.67	46.91
Industrial[1]										
Liquefied petroleum gases	21.80	18.28	29.56	41.77	21.25	37.51	50.25	28.46	50.95	65.39
Distillate fuel oil	21.32	15.61	26.08	37.41	19.46	34.93	46.06	25.67	46.76	57.53
Residual fuel oil	10.92	10.23	20.70	32.45	12.49	27.24	38.59	15.80	34.28	48.11
Natural gas[2]	5.51	5.14	5.26	5.24	7.80	7.75	7.63	11.92	11.93	11.60
Metallurgical coal	5.84	7.57	7.78	7.90	10.23	10.40	10.45	14.04	14.42	14.51
Other industrial coal	2.71	3.35	3.52	3.63	4.13	4.34	4.46	5.36	5.77	6.06
Coal to liquids	- -	1.26	1.36	1.42	2.63	2.67	2.86	3.58	3.78	4.14
Electricity	19.63	19.99	20.38	20.69	24.87	25.15	25.31	32.68	32.90	32.96
Transportation										
Liquefied petroleum gases[3]	26.88	25.68	34.41	43.74	30.54	42.83	52.54	39.27	56.59	67.66
E85[4]	25.21	19.55	31.28	40.95	22.36	36.97	53.17	26.31	50.61	61.31
Motor gasoline[5]	22.70	19.94	31.53	44.21	23.68	41.19	54.86	29.32	53.22	66.16
Jet fuel[6]	16.22	13.59	25.58	37.89	16.66	33.94	45.51	22.13	46.12	57.99
Diesel fuel (distillate fuel oil)[7]	21.87	19.36	29.69	41.07	23.61	39.03	50.30	30.37	51.29	62.29
Residual fuel oil	10.42	9.30	19.74	31.18	11.28	26.45	37.25	13.89	33.18	46.93
Natural gas[8]	13.20	13.22	13.36	13.38	16.98	17.05	17.00	22.61	22.97	22.75
Electricity	32.99	32.69	32.86	32.50	40.22	40.46	41.90	52.74	53.55	54.01
Electric power[9]										
Distillate fuel oil	18.73	12.98	24.53	36.06	16.32	32.52	43.32	21.50	44.02	55.10
Residual fuel oil	11.89	14.07	24.78	36.26	15.77	32.59	43.50	17.77	40.73	54.38
Natural gas	5.14	4.80	4.90	4.88	7.27	7.19	7.09	11.38	11.42	11.06
Steam coal	2.26	2.39	2.53	2.65	3.04	3.25	3.40	4.06	4.43	4.72

Table C3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Average price to all users[10]										
Liquefied petroleum gases	17.28	15.75	24.78	34.64	18.08	31.04	41.30	24.23	42.17	53.76
E85[4]	25.21	19.55	31.28	40.95	22.36	36.97	53.17	26.31	50.61	61.31
Motor gasoline[5]	22.59	19.94	31.53	44.21	23.68	41.19	54.86	29.31	53.22	66.16
Jet fuel	16.22	13.59	25.58	37.89	16.66	33.94	45.51	22.13	46.12	57.99
Distillate fuel oil	21.65	18.47	28.96	40.36	22.71	38.24	49.51	29.39	50.52	61.50
Residual fuel oil	10.82	9.87	20.48	32.04	11.92	27.34	38.32	14.63	34.33	48.14
Natural gas	7.16	6.84	6.95	6.91	10.02	9.93	9.82	14.69	14.73	14.42
Metallurgical coal	5.84	7.57	7.78	7.90	10.23	10.40	10.45	14.04	14.42	14.51
Other coal	2.29	2.45	2.60	2.72	3.11	3.32	3.47	4.14	4.51	4.81
Coal to liquids	- -	1.26	1.36	1.42	2.63	2.67	2.86	3.58	3.78	4.14
Electricity	28.68	30.00	30.58	31.10	36.28	36.62	36.96	46.48	46.80	47.03
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	251.69	254.44	265.85	275.92	332.26	342.26	349.24	459.02	472.99	478.21
Commercial	179.08	184.73	191.71	197.75	252.04	259.04	264.27	357.40	367.31	370.80
Industrial	198.98	188.43	241.24	299.90	253.19	336.06	396.99	337.58	447.01	508.54
Transportation	573.78	527.35	804.75	1073.14	639.27	1030.98	1238.06	852.44	1356.41	1506.27
Total non-renewable expenditures	1203.54	1154.96	1503.55	1846.71	1476.75	1968.35	2248.56	2006.43	2643.72	2863.82
Transportation renewable expenditures	0.08	0.20	0.27	15.06	0.51	11.21	78.99	5.26	61.53	161.41
Total expenditures	**1203.62**	**1155.16**	**1503.82**	**1861.77**	**1477.26**	**1979.56**	**2327.55**	**2011.69**	**2705.26**	**3025.22**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2010 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2010 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2010 transportation sector natural gas delivered prices are model results. 2010 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/09) (Washington, DC, September 2010). 2010 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2010 and April 2011, Table 4.2, and EIA, *State Energy Data Report 2009*, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2010 coal prices based on: EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011) and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. 2010 electricity prices: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2012 National Energy Modeling System runs LP2012.D022112A, REF2012.D020112C, and HP2012.D022112A.

Table C4. Liquid fuels supply and disposition

(million barrels per day, unless otherwise noted)

Supply and disposition	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil										
Domestic crude production[1]	5.47	5.88	6.15	6.41	5.38	6.40	7.25	4.79	5.99	6.68
Alaska	0.60	0.46	0.46	0.46	0.34	0.40	0.68	0.00	0.27	0.36
Lower 48 states	4.87	5.42	5.69	5.95	5.04	6.00	6.57	4.79	5.72	6.32
Net imports	9.17	9.63	8.52	7.64	9.58	7.24	5.32	10.74	7.52	4.91
Gross imports	9.21	9.66	8.56	7.67	9.61	7.27	5.36	10.77	7.55	4.95
Exports	0.04	0.03	0.03	0.03	0.03	0.03	0.04	0.03	0.03	0.04
Other crude supply[2]	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude supply	**14.72**	**15.52**	**14.67**	**14.05**	**14.96**	**13.64**	**12.56**	**15.53**	**13.51**	**11.59**
Other petroleum supply	**3.50**	**3.33**	**3.25**	**2.98**	**4.21**	**3.80**	**3.29**	**4.13**	**3.52**	**2.81**
Natural gas plant liquids	2.07	2.40	2.56	2.56	2.94	3.01	3.07	2.91	3.01	3.06
Net product imports	0.39	-0.01	-0.25	-0.50	0.33	-0.12	-0.62	0.31	-0.34	-0.94
Gross refined product imports[3]	1.23	0.97	0.78	0.61	1.06	0.79	0.51	1.14	0.82	0.55
Unfinished oil imports	0.61	0.74	0.64	0.56	0.67	0.51	0.38	0.74	0.50	0.26
Blending component imports	0.74	0.69	0.66	0.63	0.71	0.65	0.61	0.73	0.66	0.61
Exports	2.19	2.41	2.32	2.30	2.12	2.07	2.13	2.31	2.31	2.36
Refinery processing gain[4]	1.07	0.94	0.95	0.92	0.95	0.91	0.84	0.91	0.85	0.69
Product stock withdrawal	-0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other non-petroleum supply	**1.00**	**1.24**	**1.22**	**1.46**	**1.61**	**1.86**	**2.84**	**2.18**	**2.96**	**4.87**
Supply from renewable sources	0.87	1.11	1.05	1.20	1.42	1.48	2.01	1.92	2.37	3.24
Ethanol	0.85	1.00	0.94	1.05	1.20	1.19	1.64	1.36	1.65	2.15
Domestic production	0.88	0.99	0.94	0.99	1.18	1.17	1.47	1.35	1.59	1.96
Net imports	-0.02	0.01	0.00	0.06	0.02	0.02	0.17	0.01	0.06	0.19
Biodiesel	0.01	0.08	0.09	0.12	0.12	0.12	0.13	0.13	0.13	0.14
Domestic production	0.02	0.08	0.09	0.11	0.12	0.12	0.13	0.13	0.13	0.14
Net imports	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.00	-0.00
Other biomass-derived liquids[5]	0.00	0.02	0.03	0.03	0.10	0.16	0.24	0.44	0.59	0.95
Liquids from gas	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.06
Liquids from coal	0.00	0.00	0.00	0.00	0.05	0.17	0.52	0.05	0.28	1.27
Other[6]	0.13	0.14	0.17	0.26	0.15	0.21	0.24	0.20	0.31	0.30
Total primary supply[7]	**19.22**	**20.09**	**19.14**	**18.49**	**20.79**	**19.29**	**18.69**	**21.84**	**19.99**	**19.27**
Liquid fuels consumption										
by fuel										
Liquefied petroleum gases	2.27	2.00	1.94	1.90	2.30	2.21	2.15	2.32	2.21	2.15
E85[8]	0.00	0.01	0.01	0.25	0.02	0.21	1.02	0.14	0.83	1.80
Motor gasoline[9]	8.99	9.48	8.88	8.19	9.45	8.29	6.97	9.97	8.09	6.55
Jet fuel[10]	1.43	1.47	1.46	1.45	1.55	1.54	1.54	1.61	1.61	1.60
Distillate fuel oil[11]	3.80	4.34	4.19	4.10	4.45	4.33	4.34	4.67	4.48	4.51
Diesel	3.32	3.82	3.71	3.66	3.99	3.92	3.96	4.24	4.11	4.16
Residual fuel oil	0.54	0.60	0.56	0.55	0.63	0.57	0.56	0.67	0.58	0.57
Other[12]	2.14	2.23	2.06	1.97	2.38	2.06	1.95	2.51	2.10	1.94
by sector										
Residential and commercial	1.12	1.12	1.00	0.92	1.09	0.94	0.87	1.07	0.91	0.84
Industrial[13]	4.31	4.41	4.17	4.05	4.83	4.41	4.26	5.00	4.44	4.22
Transportation	13.82	14.47	13.80	13.31	14.69	13.71	13.26	15.64	14.41	13.90
Electric power[14]	0.17	0.14	0.13	0.13	0.16	0.14	0.14	0.19	0.14	0.14
Total	**19.17**	**20.14**	**19.10**	**18.41**	**20.77**	**19.20**	**18.53**	**21.90**	**19.90**	**19.12**
Discrepancy[15]	**0.05**	**-0.05**	**0.05**	**0.08**	**0.01**	**0.10**	**0.16**	**-0.06**	**0.09**	**0.15**

Table C4. Liquid fuels supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Domestic refinery distillation capacity[16]	17.6	17.6	17.5	17.1	16.8	15.5	14.6	17.1	15.2	13.8
Capacity utilization rate (percent)[17]	86.0	90.3	85.9	84.0	91.0	90.1	88.0	93.0	90.8	85.7
Net import share of product supplied (percent)	49.6	47.9	43.2	38.9	47.8	37.0	26.0	50.7	36.2	21.6
Net expenditures for imported crude oil and petroleum products (billion 2010 dollars)	243.07	207.99	373.00	523.15	189.41	344.58	384.81	226.36	389.97	363.97

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol and ethers blended into gasoline.
[10]Includes only kerosene type.
[11]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[13]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Balancing item. Includes unaccounted for supply, losses, and gains.
[16]End-of-year operable capacity.
[17]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 product supplied based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). Other 2010 data: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). **Projections:** EIA, AEO2012 National Energy Modeling System runs LP2012.D022112A, REF2012.D020112C, and HP2012.D022112A.

Table C5. Petroleum product prices

(2010 dollars per gallon, unless otherwise noted)

Sector and fuel	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (2010 dollars per barrel)										
Low sulfur light	79.39	58.36	116.91	182.10	59.41	132.56	193.48	62.38	144.98	200.36
Imported crude oil[1]	75.87	55.41	113.97	179.16	48.84	121.21	180.29	53.10	132.95	187.04
Delivered sector product prices										
Residential										
Liquefied petroleum gases	2.288	1.909	2.600	3.361	1.878	2.733	3.423	1.989	2.934	3.560
Distillate fuel oil	2.941	2.295	3.781	5.310	2.395	4.181	5.441	2.560	4.539	5.547
Commercial										
Distillate fuel oil	2.866	1.917	3.303	4.778	1.982	3.699	4.942	2.136	4.019	5.008
Residual fuel oil	1.657	0.896	2.421	4.161	0.935	2.731	4.240	1.033	2.830	4.207
Residual fuel oil (2010 dollars per barrel)	69.58	37.63	101.70	174.76	39.28	114.70	178.07	43.37	118.85	176.71
Industrial[2]										
Liquefied petroleum gases	1.846	1.438	2.323	3.292	1.383	2.476	3.355	1.520	2.725	3.523
Distillate fuel oil	2.932	1.991	3.322	4.780	2.053	3.737	4.986	2.223	4.054	5.025
Residual fuel oil	1.634	1.423	2.876	4.521	1.436	3.178	4.554	1.492	3.241	4.582
Residual fuel oil (2010 dollars per barrel)	68.62	59.77	120.80	189.87	60.33	133.47	191.28	62.65	136.12	192.45
Transportation										
Liquefied petroleum gases	2.276	2.021	2.704	3.447	1.987	2.827	3.508	2.097	3.026	3.645
Ethanol (E85)[3]	2.402	1.731	2.766	3.631	1.638	2.746	3.996	1.581	3.046	3.717
Ethanol wholesale price	1.712	2.356	2.228	2.622	2.215	2.333	2.741	1.985	2.159	2.571
Motor gasoline[4]	2.756	2.240	3.538	4.974	2.185	3.855	5.196	2.219	4.034	5.053
Jet fuel[5]	2.190	1.704	3.205	4.760	1.728	3.571	4.845	1.884	3.932	4.981
Diesel fuel (distillate fuel oil)[6]	2.998	2.465	3.776	5.237	2.486	4.168	5.435	2.624	4.439	5.430
Residual fuel oil	1.560	1.294	2.742	4.344	1.298	3.086	4.397	1.311	3.136	4.469
Residual fuel oil (2010 dollars per barrel)	65.53	54.33	115.15	182.43	54.50	129.62	184.67	55.06	131.73	187.70
Electric power[7]										
Distillate fuel oil	2.598	1.673	3.157	4.655	1.739	3.515	4.737	1.880	3.856	4.861
Residual fuel oil	1.780	1.957	3.443	5.051	1.814	3.802	5.135	1.677	3.850	5.178
Residual fuel oil (2010 dollars per barrel)	74.77	82.21	144.60	212.13	76.19	159.70	215.65	70.44	161.71	217.49
Refined petroleum product prices[8]										
Liquefied petroleum gases	1.464	1.239	1.947	2.729	1.177	2.049	2.758	1.294	2.255	2.896
Motor gasoline[4]	2.743	2.240	3.538	4.974	2.185	3.855	5.196	2.219	4.034	5.053
Jet fuel[5]	2.190	1.704	3.205	4.760	1.728	3.571	4.845	1.884	3.932	4.981
Distillate fuel oil	2.975	2.355	3.687	5.153	2.394	4.089	5.355	2.543	4.376	5.366
Residual fuel oil	1.619	1.372	2.845	4.464	1.371	3.189	4.523	1.381	3.246	4.585
Residual fuel oil (2010 dollars per barrel)	68.00	57.63	119.50	187.48	57.57	133.95	189.96	57.99	136.32	192.56
Average	**2.528**	**2.059**	**3.316**	**4.691**	**2.015**	**3.600**	**4.808**	**2.101**	**3.830**	**4.785**

Table C5. Petroleum product prices (continued)

(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (nominal dollars per barrel)										
Low sulfur light	79.39	62.81	125.97	195.67	77.32	170.09	245.37	98.91	229.55	314.93
Imported crude oil[1]	75.87	59.64	122.81	192.52	63.56	155.52	228.64	84.19	210.51	294.00
Delivered sector product prices										
Residential										
Liquefied petroleum gases	2.288	2.054	2.801	3.612	2.445	3.507	4.341	3.154	4.645	5.595
Distillate fuel oil	2.941	2.470	4.074	5.706	3.117	5.365	6.901	4.060	7.188	8.719
Commercial										
Distillate fuel oil	2.866	2.063	3.559	5.135	2.580	4.747	6.268	3.387	6.364	7.872
Residual fuel oil	1.657	0.964	2.609	4.471	1.217	3.504	5.377	1.637	4.481	6.613
Industrial[2]										
Liquefied petroleum gases	1.846	1.548	2.503	3.537	1.800	3.177	4.255	2.410	4.315	5.537
Distillate fuel oil	2.932	2.143	3.580	5.136	2.671	4.795	6.323	3.524	6.419	7.898
Residual fuel oil	1.634	1.532	3.099	4.858	1.869	4.077	5.776	2.365	5.132	7.202
Transportation										
Liquefied petroleum gases	2.276	2.175	2.914	3.704	2.586	3.627	4.449	3.326	4.792	5.729
Ethanol (E85)[3]	2.402	1.863	2.981	3.902	2.131	3.523	5.067	2.507	4.823	5.843
Ethanol wholesale price	1.712	2.535	2.400	2.818	2.883	2.994	3.477	3.147	3.419	4.041
Motor gasoline[4]	2.756	2.411	3.812	5.345	2.843	4.946	6.589	3.519	6.388	7.943
Jet fuel[5]	2.190	1.834	3.454	5.115	2.249	4.582	6.144	2.988	6.226	7.829
Diesel fuel (distillate fuel oil)[6]	2.998	2.653	4.069	5.628	3.235	5.348	6.893	4.161	7.029	8.535
Residual fuel oil	1.560	1.392	2.954	4.668	1.689	3.960	5.576	2.079	4.966	7.025
Electric power[7]										
Distillate fuel oil	2.598	1.801	3.402	5.002	2.263	4.510	6.008	2.982	6.105	7.641
Residual fuel oil	1.780	2.107	3.710	5.427	2.361	4.879	6.512	2.659	6.096	8.140
Refined petroleum product prices[8]										
Liquefied petroleum gases	1.464	1.334	2.098	2.933	1.531	2.629	3.498	2.052	3.571	4.552
Motor gasoline[4]	2.743	2.411	3.812	5.345	2.843	4.946	6.589	3.519	6.387	7.942
Jet fuel[5]	2.190	1.834	3.454	5.115	2.249	4.582	6.144	2.988	6.226	7.829
Distillate fuel oil	2.975	2.534	3.973	5.537	3.115	5.246	6.791	4.032	6.930	8.434
Residual fuel oil (nominal dollars per barrel)	68.00	62.03	128.77	201.46	74.93	171.87	240.90	91.95	215.84	302.67
Average	**2.528**	**2.216**	**3.573**	**5.041**	**2.623**	**4.620**	**6.097**	**3.331**	**6.064**	**7.520**

[1]Weighted average price delivered to U.S. refiners.

[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.

[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.

[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[5]Includes only kerosene type.

[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.

[7]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Note: Data for 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2010 low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude oil Acquisition Report." 2010 imported crude oil price: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2010 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2010 electric power prices based on: *Monthly Energy Review*, DOE/EIA-0035(2011/09) (Washington, DC, September 2011). 2010 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2010 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2012 National Energy Modeling System runs LP2012.D022112A, REF2012.D020112C, and HP2012.D022112A.

Table C6. International liquids supply and disposition summary

(million barrels per day, unless otherwise noted)

Supply and disposition	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (2010 dollars per barrel)										
Low sulfur light	79.39	58.36	116.91	182.10	59.41	132.56	193.48	62.38	144.98	200.36
Imported crude oil[1]	75.87	55.41	113.97	179.16	48.84	121.21	180.29	53.10	132.95	187.04
Crude oil prices (nominal dollars per barrel)[1]										
Low sulfur light	79.39	62.81	125.97	195.67	77.32	170.09	245.37	98.91	229.55	314.93
Imported crude oil[1]	75.87	59.64	122.81	192.52	63.56	155.52	228.64	84.19	210.51	294.00
Petroleum liquids production[2]										
OPEC[3]										
Middle East	23.43	29.09	25.46	23.39	33.98	29.77	28.26	35.70	33.94	32.96
North Africa	3.89	4.01	3.62	3.48	3.66	3.37	3.41	3.12	3.27	3.28
West Africa	4.45	5.57	5.09	4.86	5.92	5.40	5.47	5.74	5.26	5.27
South America	2.29	2.37	2.13	2.05	2.06	1.92	1.94	1.63	1.72	1.72
Total OPEC petroleum production	**34.05**	**41.03**	**36.30**	**33.78**	**45.62**	**40.46**	**39.09**	**46.18**	**44.19**	**43.24**
Non-OPEC										
OECD										
United States (50 states)	8.79	9.36	9.82	10.15	9.42	10.53	11.40	8.81	10.15	10.72
Canada	1.91	1.79	1.79	1.82	1.77	1.82	1.85	1.75	1.78	1.87
Mexico	2.98	2.65	2.65	2.59	1.46	1.58	1.50	1.27	1.68	1.67
OECD Europe[4]	4.36	3.72	3.70	3.63	3.03	3.15	3.01	2.79	2.83	2.82
Japan	0.13	0.15	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.16
Australia and New Zealand	0.62	0.55	0.55	0.54	0.52	0.54	0.52	0.52	0.53	0.53
Total OECD petroleum production	**18.80**	**18.22**	**18.65**	**18.88**	**16.34**	**17.78**	**18.42**	**15.29**	**17.14**	**17.76**
Non-OECD										
Russia	10.14	9.74	10.04	9.79	9.73	11.06	10.38	8.96	12.16	12.02
Other Europe and Eurasia[5]	3.22	3.68	3.67	3.58	4.02	4.37	4.11	3.27	4.54	4.49
China	4.27	4.32	4.29	4.21	4.55	4.79	4.52	4.66	4.70	4.67
Other Asia[6]	3.77	3.80	3.79	3.73	3.23	3.38	3.22	2.97	3.00	2.99
Middle East	1.58	1.43	1.43	1.40	1.12	1.18	1.11	0.97	0.97	0.97
Africa	2.41	2.41	2.40	2.36	2.55	2.68	2.54	2.67	2.68	2.67
Brazil	2.19	2.73	2.72	2.66	3.47	3.87	3.64	3.32	4.45	4.40
Other Central and South America	2.01	2.30	2.29	2.26	2.36	2.47	2.35	2.64	2.65	2.63
Total non-OECD petroleum	**29.59**	**30.40**	**30.63**	**29.99**	**31.02**	**33.80**	**31.86**	**29.47**	**35.15**	**34.83**
Total petroleum liquids production	**82.44**	**89.66**	**85.58**	**82.65**	**92.98**	**92.04**	**89.37**	**90.93**	**96.47**	**95.83**
Other liquids production[7]										
United States (50 states)	0.90	1.10	1.05	1.14	1.45	1.62	2.42	1.96	2.59	4.38
Other North America	1.93	2.55	2.51	2.90	4.09	3.75	4.78	5.53	5.16	6.53
OECD Europe[3]	0.22	0.28	0.23	0.27	0.37	0.26	0.30	0.45	0.28	0.32
Middle East	0.01	0.13	0.17	0.14	0.23	0.24	0.21	0.22	0.24	0.22
Africa.	0.21	0.27	0.28	0.28	0.42	0.38	0.39	0.53	0.40	0.41
Central and South America	1.20	2.15	1.78	2.06	4.07	2.61	2.97	5.75	3.17	3.51
Other	0.13	0.21	0.16	0.24	0.81	0.61	1.15	1.75	1.18	1.69
Total other liquids production	**4.61**	**6.70**	**6.18**	**7.01**	**11.43**	**9.47**	**12.22**	**16.19**	**13.02**	**17.07**
Total production	**87.05**	**96.36**	**91.76**	**89.67**	**104.42**	**101.51**	**101.59**	**107.13**	**109.50**	**112.90**

Table C6. International liquids supply and disposition summary (continued)

(million barrels per day, unless otherwise noted)

Supply and disposition	2010	Projections								
		2015			2025			2035		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Liquids consumption[8]										
OECD										
United States (50 states)	19.17	20.14	19.10	18.41	20.77	19.20	18.53	21.90	19.90	19.12
United States territories	0.28	0.32	0.31	0.30	0.32	0.34	0.34	0.31	0.36	0.38
Canada	2.21	2.27	2.15	2.09	2.46	2.25	2.22	2.56	2.35	2.40
Mexico	2.34	2.50	2.38	2.30	2.78	2.50	2.32	3.20	2.68	2.43
OECD Europe[3]	14.58	14.86	14.14	13.69	15.97	14.65	13.85	16.10	14.74	13.93
Japan	4.45	4.80	4.51	4.35	5.14	4.62	4.33	4.92	4.42	4.14
South Korea	2.24	2.39	2.25	2.18	2.73	2.46	2.31	2.93	2.56	2.39
Australia and New Zealand	1.13	1.16	1.11	1.07	1.25	1.17	1.09	1.30	1.23	1.13
Total OECD consumption	**46.40**	**48.43**	**45.95**	**44.38**	**51.42**	**47.19**	**44.97**	**53.23**	**48.24**	**45.90**
Non-OECD										
Russia	2.93	3.14	3.02	2.96	2.88	2.91	2.93	2.71	2.97	3.12
Other Europe and Eurasia[5]	2.08	2.37	2.30	2.26	2.35	2.45	2.44	2.32	2.63	2.69
China	9.19	12.64	12.10	12.06	15.65	16.03	17.21	16.35	18.50	20.87
India	3.18	3.88	3.70	3.64	5.22	5.40	5.78	4.93	5.80	6.54
Other Asia	6.73	7.56	7.28	7.19	8.44	8.85	9.15	8.48	9.89	10.78
Middle East	7.35	8.26	7.78	7.72	8.35	8.16	8.51	9.03	9.49	10.46
Africa	3.34	3.44	3.30	3.24	3.43	3.57	3.57	3.47	4.09	4.21
Brazil	2.65	3.00	2.84	2.78	3.01	3.15	3.22	3.13	3.80	4.13
Other Central and South America	3.19	3.63	3.49	3.42	3.67	3.81	3.82	3.49	4.09	4.21
Total non-OECD consumption	**40.65**	**47.92**	**45.82**	**45.29**	**52.99**	**54.32**	**56.62**	**53.90**	**61.26**	**67.00**
Total liquids consumption	**87.05**	**96.36**	**91.76**	**89.67**	**104.42**	**101.51**	**101.59**	**107.13**	**109.50**	**112.90**
OPEC production[9]	34.58	42.18	37.30	34.88	47.89	41.91	40.63	49.42	45.89	45.01
Non-OPEC production[9]	52.47	54.18	54.46	54.79	56.52	59.60	60.97	57.71	63.61	67.89
Net Eurasia exports	10.53	10.64	11.11	10.81	12.00	13.94	12.75	10.52	15.54	15.10
OPEC market share (percent)	39.7	43.8	40.7	38.9	45.9	41.3	40.0	46.1	41.9	39.9

[1]Weighted average price delivered to U.S. refiners.

[2]Includes production of crude oil (including lease condensate and shale oil/tight oil), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, and refinery gains.

[3]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

[4]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.

[5]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Slovenia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.

[6]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.

[7]Includes liquids produced from energy crops, natural gas, coal, extra-heavy oil, bitumen (oil sands), and kerogen (oil shale, not to be confused with shale oil/tight oil). Includes both OPEC and non-OPEC producers in the regional breakdown.

[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.

[9]Includes both petroleum and other liquids production.

Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2010 low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude oil Acquisition Report." 2010 imported crude oil price: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). **2010 quantities and projections:** EIA, AEO2012 National Energy Modeling System runs LP2012.D022112A, REF2012.D020112C, and HP2012.D022112A and EIA, Generate World Oil Balance Model.

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Appendix D

Results from side cases

Table D1. Key results for residential and commercial sector technology cases

Energy consumption	2010	2015				2025			
		Integrated 2011 Demand Technology	Reference	Integrated High Demand Technology	Integrated Best Available Demand Technology	Integrated 2011 Demand Technology	Reference	Integrated High Demand Technology	Integrated Best Available Demand Technology
Residential									
Energy consumption (quadrillion Btu)									
Liquefied petroleum gases	0.56	0.52	0.51	0.51	0.50	0.52	0.50	0.48	0.48
Kerosene	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate fuel oil	0.63	0.56	0.55	0.54	0.53	0.46	0.43	0.41	0.39
Liquid fuels and other petroleum subtotal	1.22	1.10	1.08	1.07	1.05	1.00	0.95	0.91	0.88
Natural gas	5.06	5.03	4.97	4.83	4.63	5.12	4.88	4.51	4.00
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable energy[1]	0.42	0.43	0.43	0.42	0.41	0.47	0.43	0.41	0.37
Electricity	4.95	4.83	4.75	4.53	4.28	5.48	5.23	4.74	4.10
Delivered energy	**11.66**	**11.40**	**11.24**	**10.85**	**10.38**	**12.08**	**11.51**	**10.57**	**9.36**
Electricity related losses	10.39	9.75	9.58	9.09	8.52	10.98	10.52	9.53	8.17
Total	**22.05**	**21.15**	**20.81**	**19.95**	**18.90**	**23.07**	**22.02**	**20.10**	**17.53**
Delivered energy intensity (million Btu per household)	**102.1**	**96.0**	**94.6**	**91.4**	**87.4**	**91.1**	**86.8**	**79.7**	**70.6**
Nonmarketed renewables consumption (quadrillion Btu)	**0.02**	**0.08**	**0.08**	**0.08**	**0.09**	**0.10**	**0.10**	**0.11**	**0.13**
Commercial									
Energy consumption (quadrillion Btu)									
Liquefied petroleum gases	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15
Motor gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.43	0.35	0.35	0.35	0.35	0.33	0.33	0.32	0.32
Residual fuel oil	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Liquid fuels and other petroleum subtotal	0.72	0.62	0.62	0.62	0.62	0.62	0.62	0.61	0.61
Natural gas	3.28	3.42	3.41	3.39	3.41	3.53	3.53	3.48	3.56
Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.54	4.64	4.59	4.42	4.26	5.39	5.16	4.62	4.17
Delivered energy	**8.70**	**8.85**	**8.80**	**8.60**	**8.46**	**9.71**	**9.48**	**8.87**	**8.50**
Electricity related losses	9.52	9.38	9.27	8.88	8.48	10.79	10.38	9.29	8.30
Total	**18.22**	**18.24**	**18.06**	**17.48**	**16.94**	**20.50**	**19.86**	**18.16**	**16.80**
Delivered energy intensity (thousand Btu per square foot)	**107.3**	**105.3**	**104.6**	**102.2**	**100.6**	**103.4**	**101.0**	**94.5**	**90.5**
Commercial sector generation									
Net summer generation capacity (megawatts)									
Natural gas	711	843	865	900	914	1455	1955	2605	3066
Solar photovoltaic	1197	1251	1253	1254	1262	1490	1578	1753	2235
Wind	83	90	91	94	106	106	132	138	225
Electricity generation (billion kilowatthours)									
Natural gas	5.17	6.13	6.29	6.54	6.64	10.58	14.22	18.95	22.30
Solar photovoltaic	1.87	1.96	1.96	1.96	1.97	2.34	2.51	2.80	3.58
Wind	0.10	0.12	0.12	0.12	0.14	0.14	0.18	0.19	0.31
Nonmarketed renewables consumption (quadrillion Btu)	**0.03**	**0.04**	**0.04**	**0.05**	**0.05**	**0.04**	**0.04**	**0.07**	**0.08**

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System, runs FROZTECH.D030812A, REF2012.D020112C, HIGHTECH.D032812A, and BESTTECH.D032812A.

2035				Annual Growth 2010-2035 (percent)			
Integrated 2011 Demand Technology	Reference	Integrated High Demand Technology	Integrated Best Available Demand Technology	Integrated 2011 Demand Technology	Reference	Integrated High Demand Technology	Integrated Best Available Demand Technology
0.53	0.51	0.48	0.47	-0.2%	-0.4%	-0.6%	-0.7%
0.02	0.02	0.02	0.02	-1.2%	-1.7%	-2.1%	-2.4%
0.40	0.35	0.32	0.29	-1.8%	-2.3%	-2.7%	-3.1%
0.95	0.87	0.82	0.78	-1.0%	-1.3%	-1.6%	-1.8%
5.23	4.76	4.28	3.67	0.1%	-0.2%	-0.7%	-1.3%
0.01	0.01	0.00	0.00	-0.5%	-1.1%	-1.5%	-1.8%
0.50	0.43	0.39	0.34	0.6%	0.1%	-0.3%	-0.9%
6.23	5.86	5.26	4.45	0.9%	0.7%	0.2%	-0.4%
12.91	**11.93**	**10.75**	**9.24**	**0.4%**	**0.1%**	**-0.3%**	**-0.9%**
12.14	11.35	10.31	8.65	0.6%	0.4%	-0.0%	-0.7%
25.05	**23.28**	**21.06**	**17.89**	**0.5%**	**0.2%**	**-0.2%**	**-0.8%**
88.7	**81.9**	**73.8**	**63.4**	**-0.6%**	**-0.9%**	**-1.3%**	**-1.9%**
0.10	**0.11**	**0.14**	**0.19**	**6.4%**	**6.9%**	**7.7%**	**9.2%**
0.15	0.16	0.16	0.16	0.3%	0.3%	0.4%	0.4%
0.06	0.06	0.06	0.06	0.4%	0.4%	0.4%	0.4%
0.01	0.01	0.01	0.01	0.7%	0.7%	0.7%	0.7%
0.32	0.32	0.30	0.30	-1.2%	-1.2%	-1.4%	-1.5%
0.08	0.08	0.08	0.08	-0.1%	-0.0%	-0.0%	-0.0%
0.62	0.62	0.61	0.60	-0.6%	-0.5%	-0.7%	-0.7%
3.63	3.69	3.64	3.74	0.4%	0.5%	0.4%	0.5%
0.06	0.06	0.06	0.06	-0.0%	-0.0%	-0.0%	-0.0%
0.11	0.11	0.11	0.11	0.0%	0.0%	0.0%	0.0%
6.07	5.80	4.87	4.33	1.2%	1.0%	0.3%	-0.2%
10.49	**10.28**	**9.28**	**8.84**	**0.8%**	**0.7%**	**0.3%**	**0.1%**
11.82	11.23	9.54	8.41	0.9%	0.7%	0.0%	-0.5%
22.32	**21.50**	**18.82**	**17.25**	**0.8%**	**0.7%**	**0.1%**	**-0.2%**
101.9	**99.8**	**90.1**	**85.8**	**-0.2%**	**-0.3%**	**-0.7%**	**-0.9%**
2514	4795	6609	7235	5.2%	7.9%	9.3%	9.7%
1832	2311	3177	5546	1.7%	2.7%	4.0%	6.3%
178	270	269	375	3.1%	4.8%	4.8%	6.2%
18.29	34.88	48.08	52.63	5.2%	7.9%	9.3%	9.7%
2.88	3.74	5.17	9.02	1.7%	2.8%	4.2%	6.5%
0.24	0.38	0.38	0.53	3.5%	5.3%	5.3%	6.7%
0.04	**0.05**	**0.11**	**0.12**	**1.0%**	**1.7%**	**4.8%**	**5.1%**

Table D2. Key results for integrated technology cases

Consumption and emissions	2010	2015			2025			2035		
		Integrated 2011 Technology	Reference	Integrated High Technology	Integrated 2011 Technology	Reference	Integrated High Technology	Integrated 2011 Technology	Reference	Integrated High Technology
Energy consumption by sector (quadrillion Btu)										
Residential	11.66	11.39	11.24	10.87	12.08	11.51	10.60	12.90	11.93	10.80
Commercial	8.70	8.85	8.80	8.62	9.70	9.48	8.90	10.48	10.28	9.33
Industrial[1]	23.37	23.99	23.96	24.03	25.24	25.53	25.88	25.68	26.94	27.69
Transportation	27.59	27.61	27.60	27.48	27.45	27.40	26.80	28.57	28.60	27.64
Electric power[2]	39.63	39.09	38.64	37.46	43.38	42.03	39.08	46.11	44.24	40.45
Total	**98.16**	**98.00**	**97.43**	**96.02**	**103.43**	**101.99**	**98.25**	**108.09**	**106.93**	**102.23**
Energy consumption by fuel (quadrillion Btu)										
Liquid fuels and other petroleum[3]	37.25	36.77	36.72	36.54	36.67	36.58	35.84	37.67	37.70	36.52
Natural gas	24.71	26.02	26.00	25.69	26.77	26.14	25.13	28.64	27.26	25.23
Coal	20.76	18.14	17.80	16.64	20.73	20.02	17.87	21.89	21.15	18.45
Nuclear / uranium	8.44	8.68	8.68	8.68	9.60	9.60	9.34	9.14	9.28	9.55
Renewable energy[4]	6.72	8.10	7.92	8.17	9.38	9.38	9.80	10.48	11.29	12.24
Other[5]	0.29	0.30	0.30	0.30	0.28	0.28	0.27	0.26	0.24	0.24
Total	**98.16**	**98.00**	**97.43**	**96.02**	**103.43**	**101.99**	**98.25**	**108.09**	**106.93**	**102.23**
Energy intensity (thousand Btu per 2005 dollar of GDP)	**7.50**	**6.62**	**6.58**	**6.49**	**5.39**	**5.32**	**5.12**	**4.41**	**4.36**	**4.17**
Carbon dioxide emissions by sector (million metric tons)										
Residential	353	343	338	331	341	324	302	342	312	284
Commercial	229	231	231	230	237	237	233	242	246	242
Industrial[1]	909	964	963	962	993	992	983	1015	1011	995
Transportation	1872	1865	1864	1856	1829	1820	1772	1883	1859	1787
Electric power[6]	2271	2040	2011	1884	2268	2179	1942	2446	2330	1992
Total	**5634**	**5443**	**5407**	**5263**	**5668**	**5552**	**5232**	**5928**	**5758**	**5300**
Carbon dioxide emissions by fuel (million metric tons)										
Petroleum	2349	2332	2329	2315	2275	2261	2201	2327	2300	2208
Natural gas	1283	1368	1367	1350	1407	1374	1320	1508	1435	1327
Coal	1990	1731	1699	1586	1974	1906	1700	2081	2012	1753
Other[7]	12	12	12	12	12	12	12	12	12	12
Total	**5634**	**5443**	**5407**	**5263**	**5668**	**5552**	**5232**	**5928**	**5758**	**5300**
Carbon dioxide emissions (tons per person)	**18.1**	**16.7**	**16.6**	**16.1**	**15.8**	**15.5**	**14.6**	**15.2**	**14.8**	**13.6**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen.
[4]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; biogenic municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol component of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[5]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs LTRKITEN.D031312A, REF2012.D020112C, and HTRKITEN.D032812A.

Table D3. Key results for transportation sector light-duty vehicle efficiency cases

Consumption and indicators	2010	2015		2025		2035	
		Reference	CAFE Standards	Reference	CAFE Standards	Reference	CAFE Standards
Level of travel							
(billion vehicle miles traveled)							
Light-duty vehicles less than 8,501 pounds	2662	2710	2710	3111	3129	3583	3650
Commercial light trucks[1]	64	70	70	83	83	92	93
Freight trucks greater than 10,000 pounds	234	273	273	317	318	345	346
(billion seat miles available)							
Air	999	1028	1028	1120	1120	1208	1208
(billion ton miles traveled)							
Rail	1559	1503	1505	1782	1789	1871	1878
Domestic shipping	522	549	549	604	604	627	625
Energy efficiency indicators							
(miles per gallon)							
Tested new light-duty vehicle[2]	28.3	31.5	31.5	36.8	48.1	37.9	49.0
New car[2]	33.3	36.4	36.4	41.2	55.6	42.8	56.9
New light truck[2]	24.3	26.7	26.7	31.0	39.6	31.5	39.8
Light-duty stock[3]	20.4	21.5	21.5	25.6	27.5	28.2	34.5
New commercial light truck[1]	15.7	16.7	16.7	18.9	22.5	19.1	23.3
Stock commercial light truck[1]	14.4	15.2	15.2	18.0	19.0	19.0	22.5
Freight truck	6.7	6.8	6.8	7.7	7.7	8.1	8.1
(seat miles per gallon)							
Aircraft	62.3	62.8	62.8	65.2	65.2	69.3	69.3
(ton miles per thousand Btu)							
Rail	3.4	3.5	3.5	3.5	3.5	3.5	3.5
Domestic shipping	2.4	2.4	2.4	2.5	2.5	2.5	2.5
Energy use (quadrillion Btu)							
by mode							
Light-duty vehicles	16.06	15.39	15.39	14.73	13.78	15.46	12.84
Commercial light trucks[1]	0.55	0.58	0.58	0.58	0.55	0.61	0.52
Bus transportation	0.25	0.26	0.26	0.29	0.29	0.31	0.31
Freight trucks	4.82	5.51	5.51	5.66	5.67	5.84	5.87
Rail, passenger	0.05	0.05	0.05	0.06	0.06	0.06	0.06
Rail, freight	0.45	0.43	0.44	0.51	0.51	0.53	0.53
Shipping, domestic	0.22	0.23	0.23	0.25	0.25	0.25	0.25
Shipping, international	0.86	0.87	0.87	0.88	0.88	0.89	0.89
Recreational boats	0.25	0.26	0.26	0.27	0.27	0.29	0.29
Air	2.52	2.55	2.55	2.71	2.71	2.79	2.79
Military use	0.77	0.66	0.66	0.66	0.66	0.74	0.74
Lubricants	0.14	0.13	0.13	0.14	0.14	0.14	0.14
Pipeline fuel	0.65	0.68	0.68	0.67	0.67	0.69	0.68
Total	**27.59**	**27.60**	**27.60**	**27.40**	**26.44**	**28.60**	**25.92**
by fuel							
Liquefied petroleum gases	0.04	0.04	0.04	0.04	0.04	0.05	0.04
E85[4]	0.00	0.01	0.01	0.30	0.44	1.22	1.37
Motor gasoline[5]	16.91	16.13	16.13	14.90	13.81	14.53	11.82
Jet fuel[6]	3.07	3.03	3.03	3.19	3.19	3.33	3.33
Distillate fuel oil[7]	5.77	6.55	6.55	7.03	7.02	7.44	7.31
Residual fuel oil	0.90	0.91	0.91	0.93	0.93	0.94	0.94
Other petroleum[8]	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Liquid fuels and other petroleum	26.88	26.83	26.83	26.57	25.60	27.67	24.99
Pipeline fuel natural gas	0.65	0.68	0.68	0.67	0.67	0.69	0.68
Compressed/liquefied natural gas	0.04	0.06	0.06	0.11	0.11	0.16	0.15
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.04	0.05	0.07	0.09
Delivered energy	**27.59**	**27.60**	**27.60**	**27.40**	**26.44**	**28.60**	**25.92**
Electricity related losses	0.05	0.05	0.05	0.08	0.10	0.14	0.18
Total	**27.63**	**27.65**	**27.65**	**27.49**	**26.54**	**28.75**	**26.11**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[6]Includes only kerosene type.
[7]Diesel fuel for on- and off- road use.
[8]Includes aviation gasoline and lubricants.
CAFE = Corporate average fuel economy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs REF2012.D020112C and CAFEY.D032112A.

Table D4. Key results for HD NGV Potential case

Sales, consumption, and efficiency	2010	2015		2025		2035	
		Heavy Duty Vehicle Reference	Heavy Duty Natural Gas Vehicle Potential	Heavy Duty Vehicle Reference	Heavy Duty Natural Gas Vehicle Potential	Heavy Duty Vehicle Reference	Heavy Duty Natural Gas Vehicle Potential
Truck sales by size class (millions)	**0.36**	**0.56**	**0.56**	**0.65**	**0.65**	**0.80**	**0.81**
Medium	0.21	0.29	0.29	0.33	0.33	0.40	0.40
Diesel	0.13	0.20	0.20	0.24	0.20	0.28	0.21
Motor gasoline	0.07	0.08	0.08	0.08	0.07	0.10	0.08
Liquefied petroleum gases	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Natural gas	0.00	0.00	0.01	0.01	0.06	0.02	0.11
Heavy	0.15	0.27	0.27	0.32	0.32	0.40	0.40
Diesel	0.15	0.26	0.25	0.30	0.22	0.37	0.23
Motor gasoline	0.00	0.01	0.01	0.01	0.01	0.02	0.01
Liquefied petroleum gases	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas	0.00	0.00	0.01	0.00	0.08	0.01	0.16
Consumption by size class (quadrillion Btu)	**4.82**	**5.50**	**5.51**	**5.66**	**5.68**	**5.85**	**5.93**
Medium	0.83	1.03	1.03	1.12	1.12	1.15	1.16
Diesel	0.56	0.72	0.71	0.79	0.72	0.83	0.65
Motor gasoline	0.26	0.30	0.30	0.28	0.27	0.26	0.21
Liquefied petroleum gases	0.01	0.01	0.01	0.01	0.01	0.02	0.02
Natural gas	0.01	0.01	0.02	0.03	0.12	0.05	0.28
Heavy	3.99	4.47	4.48	4.55	4.56	4.71	4.77
Diesel	3.87	4.36	4.32	4.44	3.82	4.57	3.11
Motor gasoline	0.11	0.09	0.09	0.08	0.07	0.08	0.06
Liquefied petroleum gases	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Natural gas	0.00	0.01	0.06	0.02	0.66	0.05	1.59
New truck fuel efficiency by size class (gasoline equivalent miles per gallon)	**6.63**	**7.41**	**7.38**	**8.11**	**7.88**	**8.22**	**7.82**
Medium	11.92	13.42	13.34	15.06	14.32	15.43	14.12
Diesel	13.50	14.49	14.49	16.29	16.29	16.37	16.35
Motor gasoline	10.13	10.49	10.49	11.87	11.87	13.07	13.07
Liquefied petroleum gases	9.95	10.56	10.56	12.11	12.11	13.39	13.39
Natural gas	9.17	9.99	9.99	11.07	11.07	11.07	11.07
Heavy	5.79	6.82	6.80	7.46	7.29	7.58	7.29
Diesel	5.79	6.85	6.85	7.50	7.49	7.63	7.59
Motor gasoline	5.50	5.35	5.35	5.45	5.45	5.46	5.46
Liquefied petroleum gases	5.15	5.58	5.58	5.75	5.75	5.75	5.75
Natural gas	5.56	6.04	6.35	6.40	6.87	6.42	6.95
Stock fuel efficiency by size class (gasoline equivalent miles per gallon)	**6.66**	**6.83**	**6.82**	**7.72**	**7.61**	**8.12**	**7.81**
Medium	11.48	12.06	12.05	13.90	13.60	14.99	14.04
Diesel	13.87	13.89	13.89	15.54	15.49	16.27	16.23
Motor gasoline	9.23	9.66	9.66	10.82	10.79	12.35	12.30
Liquefied petroleum gases	8.67	9.59	9.59	11.31	11.31	12.87	12.86
Natural gas	8.69	9.32	9.49	10.85	10.95	11.05	11.06
Heavy	6.05	6.16	6.16	7.05	6.97	7.44	7.22
Diesel	6.07	6.19	6.18	7.09	7.04	7.50	7.44
Motor gasoline	5.36	5.34	5.34	5.38	5.38	5.44	5.44
Liquefied petroleum gases	5.43	5.43	5.43	5.62	5.62	5.71	5.71
Natural gas	5.51	5.75	6.06	6.31	6.79	6.41	6.92

[1]Includes lease condensate.
[2]Includes natural gas plant liquids, refinery processing gain, other crude oil supply, and stock withdrawals.
[3]Includes liquids, such as ethanol and biodiesel, derived from biomass, natural gas, and coal. Includes net imports of ethanol and biodiesel.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 data based on: Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 28 and Annual* (Oak Ridge, TN, 2009); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); Federal Highway Administration, *Highway Statistics 2007* (Washington, DC, October 2008); U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011); and EIA, AEO2012 National Energy Modeling System run RFNGV12.D050412A. **Projections:** EIA, AEO2012 National Energy Modeling System runs RFNGV12.D050412A and NOSUBNGV12.D050412A.

Table D5. Energy consumption and carbon dioxide emissions for extended policy cases

Consumption and emissions	2010	2015			2025			2035		
		Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies
Energy consumption by sector (quadrillion Btu)										
Residential	11.66	11.24	11.21	11.22	11.51	11.34	11.03	11.93	11.58	10.92
Commercial	8.70	8.80	8.79	8.78	9.48	9.49	9.20	10.28	10.31	9.79
Industrial[1]	23.37	23.96	23.95	23.96	25.53	25.73	25.42	26.94	26.99	26.60
Transportation	27.59	27.60	27.59	27.59	27.40	27.43	26.41	28.60	28.57	25.42
Electric power[2]	39.63	38.64	38.60	38.53	42.03	41.63	40.45	44.24	43.95	42.24
Total	**98.16**	**97.43**	**97.35**	**97.30**	**101.99**	**101.78**	**99.11**	**106.93**	**106.64**	**100.79**
Energy consumption by fuel (quadrillion Btu)										
Liquid fuels and other petroleum[3]	37.25	36.72	36.72	36.71	36.58	36.57	35.44	37.70	37.62	34.20
Natural gas	24.71	26.00	25.98	26.00	26.14	25.93	25.52	27.26	26.37	25.42
Coal	20.76	17.80	17.84	17.82	20.02	19.96	19.27	21.15	20.59	19.82
Nuclear / uranium	8.44	8.68	8.68	8.68	9.60	9.60	9.50	9.28	9.16	9.05
Renewable energy[4]	6.72	7.92	7.82	7.79	9.38	9.45	9.10	11.29	12.66	12.05
Other[5]	0.29	0.30	0.30	0.30	0.28	0.27	0.27	0.24	0.24	0.24
Total	**98.16**	**97.43**	**97.35**	**97.30**	**101.99**	**101.78**	**99.11**	**106.93**	**106.64**	**100.79**
Energy intensity (thousand Btu per 2005 dollar of GDP)	**7.50**	**6.58**	**6.58**	**6.58**	**5.32**	**5.30**	**5.16**	**4.36**	**4.35**	**4.11**
Carbon dioxide emissions by sector (million metric tons)										
Residential	353	338	337	338	324	322	319	312	307	293
Commercial	229	231	231	231	237	238	232	246	248	236
Industrial[1]	909	963	962	963	992	993	983	1011	1016	991
Transportation	1872	1864	1864	1863	1820	1813	1749	1859	1853	1642
Electric power[6]	2271	2011	2015	2012	2179	2161	2084	2330	2221	2133
Total	**5634**	**5407**	**5409**	**5407**	**5552**	**5526**	**5367**	**5758**	**5645**	**5295**
Carbon dioxide emissions by fuel (million metric tons)										
Petroleum	2349	2329	2329	2328	2261	2251	2180	2300	2289	2061
Natural gas	1283	1367	1366	1367	1374	1363	1341	1435	1387	1337
Coal	1990	1699	1702	1700	1906	1901	1835	2012	1957	1885
Other[7]	12	12	12	12	12	12	12	12	12	12
Total	**5634**	**5407**	**5409**	**5407**	**5552**	**5526**	**5367**	**5758**	**5645**	**5295**
Carbon dioxide emissions (tons per person)	**18.1**	**16.6**	**16.6**	**16.6**	**15.5**	**15.4**	**15.0**	**14.8**	**14.5**	**13.6**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen.
[4]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; biogenic municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol component of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[5]Includes non-biogenic municipal waste and net electricity imports.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs REF2012.D020112C, NOSUNSET.D032112A, and EXTENDED.D050612B.

Table D6. Electricity generation and generating capacity in extended policy cases

(gigawatts, unless otherwise noted)

Net summer capacity, generation, consumption, and emissions	2010	2015			2025			2035		
		Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies
Capacity	**1036.1**	**1042.0**	**1020.7**	**1011.3**	**1091.1**	**1088.5**	**1059.4**	**1190.0**	**1232.9**	**1167.6**
Electric power sector[1]	1006.5	998.7	977.3	967.6	1033.3	1004.8	976.6	1112.5	1098.0	1032.8
Pulverized coal	312.8	280.7	271.7	264.2	272.8	265.8	257.0	273.6	265.7	256.9
Coal gasification combined-cycle	0.5	0.9	0.9	0.9	1.8	1.8	1.7	1.7	1.7	1.5
Conventional natural gas combined-cycle	198.0	212.4	212.4	212.5	213.5	213.0	212.4	218.8	215.7	213.6
Advanced natural gas combined-cycle	0.0	1.2	1.0	1.3	10.3	4.7	2.4	53.4	20.5	8.4
Conventional combustion turbine	137.6	136.3	133.5	133.0	132.3	129.7	127.8	130.3	129.2	126.8
Advanced combustion turbine	0.0	5.2	3.7	4.0	23.2	11.7	6.8	41.5	24.9	10.2
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear / uranium	101.2	103.6	103.6	103.6	114.7	114.7	113.6	110.9	109.3	108.1
Oil and natural gas steam	108.1	90.7	85.2	84.2	89.6	83.3	81.4	87.9	83.1	80.6
Renewable sources	126.1	145.3	143.0	141.6	152.1	157.5	151.2	170.2	224.4	203.8
Pumped storage	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Distributed generation	0.0	0.2	0.1	0.1	0.8	0.5	0.3	2.1	1.3	0.5
Combined heat and power[2]	29.6	43.3	43.4	43.7	57.8	83.7	82.8	77.5	134.9	134.9
Fossil fuels / other	22.0	25.7	25.7	26.0	34.4	35.7	35.8	47.0	49.9	49.6
Renewable fuels	7.6	17.6	17.7	17.7	23.4	48.0	47.0	30.6	85.0	85.3
Cumulative additions	**0.0**	**69.8**	**65.8**	**65.3**	**126.7**	**140.0**	**124.8**	**235.0**	**290.9**	**240.4**
Electric power sector[1]	0.0	56.1	52.0	51.2	98.5	85.9	71.6	187.1	185.6	135.2
Pulverized coal	0.0	8.7	8.7	8.7	8.7	8.7	8.7	9.4	8.7	8.7
Coal gasification combined-cycle	0.0	0.6	0.6	0.6	1.5	1.5	1.5	1.5	1.5	1.5
Conventional natural gas combined-cycle	0.0	14.5	14.5	14.5	15.8	15.3	14.7	21.1	18.0	15.9
Advanced natural gas combined-cycle	0.0	1.2	1.0	1.3	10.3	4.7	2.4	53.4	20.5	8.4
Conventional combustion turbine	0.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Advanced combustion turbine	0.0	5.2	3.7	4.0	23.2	11.7	6.8	41.5	24.9	10.2
Nuclear / uranium	0.0	1.1	1.1	1.1	6.8	6.8	6.8	8.5	6.9	6.8
Renewable sources	0.0	19.6	17.3	15.9	26.4	31.8	25.5	44.5	98.7	78.1
Distributed generation	0.0	0.2	0.1	0.1	0.8	0.5	0.3	2.1	1.3	0.5
Combined heat and power[2]	0.0	13.7	13.8	14.1	28.2	54.1	53.2	47.9	105.3	105.3
Fossil fuels / other	0.0	3.7	3.8	4.1	12.4	13.7	13.9	25.0	27.9	27.6
Renewable fuels	0.0	10.0	10.0	10.0	15.8	40.3	39.3	22.9	77.4	77.7
Cumulative retirements	**0.0**	**65.2**	**82.5**	**91.4**	**78.9**	**94.9**	**108.8**	**88.4**	**101.3**	**116.2**
Generation by fuel (billion kilowatthours)	**4126**	**4152**	**4147**	**4142**	**4556**	**4559**	**4427**	**4992**	**5004**	**4813**
Electric power sector[1]	3971	3956	3950	3944	4279	4229	4106	4586	4498	4310
Coal	1831	1562	1565	1563	1741	1736	1673	1834	1781	1711
Petroleum	34	26	26	26	27	27	26	28	28	27
Natural gas	898	1028	1030	1030	1006	971	938	1196	1030	976
Nuclear / uranium	807	830	830	830	917	917	909	887	875	865
Renewable sources	395	508	498	493	584	574	557	634	780	728
Pumped storage	2	2	2	2	2	2	2	2	2	2
Distributed generation	0	0	0	0	2	1	1	4	2	1
Combined heat and power[2]	155	197	197	198	277	330	321	406	506	502
Fossil fuels / other	122	142	142	144	198	206	206	281	298	294
Renewable fuels	34	55	55	55	78	124	115	125	208	208
Average electricity price (cents per kilowatthour)	**9.8**	**9.7**	**9.8**	**9.8**	**9.7**	**9.6**	**9.6**	**10.1**	**9.9**	**9.6**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[2]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.

Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs REF2012.D020112C, NOSUNSET.D032112A, and EXTENDED.D050612B.

Table D7. Key results for advanced nuclear plant life cases

(gigawatts, unless otherwise noted)

Net summer capacity, generation, emissions, and fuel prices	2010	2015			2025			2035		
		Low Nuclear	Reference	High Nuclear	Low Nuclear	Reference	High Nuclear	Low Nuclear	Reference	High Nuclear
Capacity										
Coal steam	313.4	280.7	281.6	281.3	273.4	274.7	275.3	276.2	275.2	275.4
Oil and natural gas steam	108.1	88.2	90.7	91.0	87.0	89.6	89.4	84.5	87.9	86.9
Combined cycle	198.0	212.6	213.6	213.8	224.1	223.8	219.0	279.8	272.2	257.3
Combustion turbine / diesel	137.6	138.1	141.5	141.3	150.8	155.5	155.4	168.1	171.8	172.6
Nuclear / uranium	101.2	103.1	103.6	103.6	108.2	114.7	121.4	77.9	110.9	122.7
Pumped storage	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable sources	126.1	145.4	145.3	145.0	153.2	152.1	151.4	175.7	170.2	167.4
Distributed generation (natural gas)	0.0	0.1	0.2	0.2	0.7	0.8	0.8	1.7	2.1	2.1
Combined heat and power[1]	29.6	43.4	43.3	43.3	57.8	57.8	58.0	78.6	77.5	77.4
Total	**1036.1**	**1033.8**	**1042.0**	**1041.6**	**1077.4**	**1091.1**	**1093.0**	**1164.8**	**1190.0**	**1183.9**
Cumulative additions										
Coal steam	0.0	9.3	9.3	9.3	10.2	10.2	10.2	13.2	10.9	10.4
Oil and natural gas steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle	0.0	14.7	15.7	15.9	26.4	26.1	21.3	82.1	74.5	59.6
Combustion turbine / diesel	0.0	8.6	10.2	10.2	25.7	28.2	28.0	44.7	46.5	46.0
Nuclear / uranium	0.0	1.1	1.1	1.1	6.8	6.8	13.5	6.8	8.5	14.8
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable sources	0.0	19.7	19.6	19.3	27.5	26.4	25.7	50.0	44.5	41.7
Distributed generation	0.0	0.1	0.2	0.2	0.7	0.8	0.8	1.7	2.1	2.1
Combined heat and power[1]	0.0	13.8	13.7	13.7	28.2	28.2	28.4	49.0	47.9	47.7
Total	**0.0**	**67.2**	**69.8**	**69.7**	**125.5**	**126.7**	**127.9**	**247.5**	**235.0**	**222.4**
Cumulative retirements	**0.0**	**70.4**	**65.2**	**65.4**	**85.0**	**78.9**	**78.3**	**119.6**	**88.4**	**81.9**
Generation by fuel (billion kilowatthours)										
Coal	1831	1570	1562	1565	1760	1741	1727	1853	1834	1822
Petroleum	34	26	26	26	27	27	27	28	28	28
Natural gas	898	1022	1028	1026	1029	1006	972	1361	1196	1136
Nuclear / uranium	807	826	830	830	866	917	970	625	887	979
Pumped storage	2	2	2	2	2	2	2	2	2	2
Renewable sources	395	508	508	507	585	584	585	653	634	632
Distributed generation	0	0	0	0	2	2	2	3	4	4
Combined heat and power[1]	155	197	197	197	277	277	278	412	406	404
Total	**4124**	**4151**	**4152**	**4152**	**4547**	**4556**	**4562**	**4936**	**4992**	**5006**
Carbon dioxide emissions by the electric power sector (million metric tons)[2]										
Petroleum	33	23	23	23	24	24	24	24	25	25
Natural gas	399	436	438	437	435	427	415	545	485	467
Coal	1828	1547	1539	1543	1737	1717	1703	1823	1809	1798
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2271**	**2017**	**2011**	**2014**	**2207**	**2179**	**2154**	**2404**	**2330**	**2301**
Prices to the electric power sector[2] (2010 dollars per million Btu)										
Petroleum	13.32	22.93	22.93	22.94	25.38	25.38	25.38	26.53	26.31	26.13
Natural gas	5.14	4.52	4.55	4.54	5.70	5.60	5.46	8.03	7.21	7.00
Coal	2.26	2.36	2.35	2.35	2.54	2.54	2.53	2.81	2.80	2.78

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.

[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.

Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs LOWNUC12.D022312A, REF2012.D020112C, and HINUC12.D022312A.

Table D8. Key results for Low Renewable Technology Cost case

Capacity, generation, and emissions	2010	2015		2025		2035	
		Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost
Net summer capacity (gigawatts)							
Electric power sector[1]							
Conventional hydropower	78.03	78.55	78.76	80.14	81.34	81.25	84.36
Geothermal[2]	2.37	2.86	2.58	4.45	4.37	6.30	6.82
Municipal waste[3]	3.30	3.36	3.36	3.36	3.36	3.36	3.36
Wood and other biomass[4]	2.45	2.72	2.72	2.72	2.82	2.89	4.31
Solar thermal	0.47	1.36	1.36	1.36	1.36	1.36	1.36
Solar photovoltaic	0.38	2.02	2.05	2.30	5.12	8.18	34.27
Wind	39.05	54.46	61.41	57.77	65.59	66.85	105.87
Total	**126.06**	**145.34**	**152.25**	**152.10**	**163.96**	**170.19**	**240.35**
End-use sector[5]							
Conventional hydropower	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal waste[6]	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Wood and other biomass	4.56	5.73	5.89	8.44	10.52	13.81	17.21
Solar photovoltaic	2.05	8.98	9.19	11.69	14.29	13.33	23.29
Wind	0.36	2.25	3.18	2.60	4.06	2.74	5.26
Total	**7.65**	**17.64**	**18.95**	**23.41**	**29.55**	**30.57**	**46.43**
Generation (billion kilowatthours)							
Electric power sector[1]							
Coal	1831	1562	1547	1741	1731	1834	1780
Petroleum	34	26	26	27	27	28	28
Natural gas	898	1028	1018	1006	974	1196	1037
Total fossil	**2764**	**2616**	**2591**	**2774**	**2732**	**3058**	**2846**
Conventional hydropower	255.32	295.43	296.17	305.00	310.24	310.08	321.78
Geothermal	15.67	18.68	16.42	31.53	30.91	46.54	50.89
Municipal waste[7]	16.56	14.66	14.66	14.67	14.67	14.67	14.67
Wood and other biomass[4]	11.51	21.28	24.10	63.90	68.89	49.28	78.41
Dedicated plants	10.15	10.13	12.58	13.30	12.84	10.37	23.13
Cofiring	1.36	11.15	11.52	50.60	56.05	38.92	55.28
Solar thermal	0.82	2.86	2.86	2.86	2.86	2.86	2.86
Solar photovoltaic	0.46	3.61	3.68	4.37	11.91	20.19	84.04
Wind	94.49	150.97	174.49	161.49	188.46	190.67	310.55
Total renewable	**394.82**	**507.49**	**532.38**	**583.81**	**627.94**	**634.30**	**863.20**
End-use sector[5]							
Total fossil	**106**	**123**	**123**	**180**	**177**	**262**	**260**
Conventional hydropower[8]	1.76	1.75	1.75	1.75	1.75	1.75	1.75
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal waste[6]	2.02	2.79	2.79	2.79	2.79	2.79	2.79
Wood and other biomass	26.10	33.30	34.27	52.34	67.01	96.17	118.46
Solar photovoltaic	3.21	13.88	14.20	18.22	22.41	20.91	37.06
Wind	0.47	2.88	3.92	3.36	5.09	3.56	6.78
Total renewable	**33.56**	**54.59**	**56.92**	**78.45**	**99.05**	**125.17**	**166.82**
Carbon dioxide emissions by the electric power sector (million metric tons)[1]							
Coal	1828	1539	1525	1717	1706	1809	1754
Petroleum	33	23	23	24	24	25	25
Natural gas	399	438	434	427	416	485	435
Other[9]	12	12	12	12	12	12	12
Total	**2271**	**2011**	**1993**	**2179**	**2157**	**2330**	**2225**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes all municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Includes projections for energy crops after 2010.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[6]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities.
[8]Represents own-use industrial hydroelectric power.
[9]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs REF2012.D020112C, and LORENCST12.D041312A.

Table D9. Key results for environmental cases

Net summer capacity, generation, emissions, and fuel prices	2010	2035					
		Reference	Reference 05	High EUR	Low Gas Price 05	Greenhouse Gas $15	Greenhouse Gas $25
Capacity (gigawatts)							
Coal steam	313.4	275.2	261.6	268.3	254.2	124.3	39.1
Oil and natural gas steam	108.1	87.9	86.5	88.1	90.7	81.9	72.3
Combined cycle	198.0	272.2	276.2	273.1	285.6	298.0	312.7
Combustion turbine / diesel	137.6	171.8	173.9	181.5	178.4	154.7	142.9
Nuclear / uranium	101.2	110.9	111.1	109.3	109.3	160.5	225.0
Pumped storage	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Renewable sources	126.1	170.2	174.2	159.4	165.3	227.6	257.6
Distributed generation (natural gas)	0.0	2.1	2.0	5.2	5.6	0.3	0.2
Combined heat and power[1]	29.6	77.5	78.3	80.8	81.2	96.7	105.2
Total	**1036.1**	**1190.0**	**1186.0**	**1187.8**	**1192.5**	**1166.0**	**1177.3**
Cumulative additions (gigawatts)							
Coal steam	0.0	10.9	11.1	10.2	10.6	10.2	10.3
Combined cycle	0.0	74.5	78.4	75.4	87.9	100.3	115.0
Combustion turbine / diesel	0.0	46.5	43.4	52.1	48.0	38.9	24.7
Nuclear / uranium	0.0	8.5	8.7	6.9	6.9	58.1	122.7
Renewable sources	0.0	44.5	48.5	33.7	39.6	101.9	131.9
Distributed generation	0.0	2.1	2.0	5.2	5.6	0.3	0.2
Combined heat and power[1]	0.0	47.9	48.7	51.2	51.6	67.0	75.6
Total	**0.0**	**235.0**	**240.8**	**234.6**	**250.2**	**376.8**	**480.4**
Cumulative retirements (gigawatts)	**0.0**	**88.4**	**98.3**	**90.2**	**101.1**	**254.1**	**346.6**
Generation by fuel (billion kilowatthours)							
Coal	1831	1834	1752	1748	1664	699	102
Petroleum	34	28	27	29	28	24	21
Natural gas	898	1196	1253	1347	1404	1351	1306
Nuclear / uranium	807	887	889	875	875	1268	1782
Pumped storage	5	2	2	2	2	2	2
Renewable sources	395	634	642	601	618	888	876
Distributed generation	0	4	4	16	16	0	0
Combined heat and power[1]	155	406	410	426	428	512	545
Total	**4126**	**4992**	**4979**	**5044**	**5034**	**4743**	**4634**
Emissions by the electric power sector [2]							
Carbon dioxide (million metric tons)	2271	2330	2263	2310	2238	1228	555
Sulfur dioxide (million short tons)	5.11	1.71	1.68	1.54	1.57	0.61	0.15
Nitrogen oxides (million short tons)	2.06	1.96	1.93	1.93	1.93	0.85	0.42
Mercury (short tons)	34.70	7.86	7.57	7.49	7.15	3.40	0.91
Retrofits (gigawatts)							
Scrubber	0.00	47.57	19.91	52.97	18.31	30.07	25.69
Nitrogen oxide controls							
Combustion	0.00	7.97	6.08	4.16	1.51	2.38	2.38
Selective catalytic reduction post-combustion	0.00	19.17	10.29	13.44	6.10	7.67	5.91
Selective non-catalytic reduction post-combustion	0.00	0.71	0.71	0.71	0.71	0.70	2.50
Prices to the electric power sector[2] (2010 dollars per million Btu)							
Natural gas	5.14	7.21	7.35	6.03	6.14	9.37	11.10
Coal	2.26	2.80	2.77	2.73	2.70	6.64	9.45

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.

EUR = Estimated ultimate recovery.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.

Source: U.S. Energy Information Administration, AEO2012 National Energy Modeling System runs REF2012.D020112C, REF12_R05.D030712A, HEUR12.D022212A, HEUR12_R05.D022312A, CO2FEE15.D031312A, and CO2FEE25.D031312A.

Table D10. Natural gas supply and disposition, oil and gas resource cases

(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	2010	2015				2025				2035			
		Low EUR	Reference	High EUR	High TRR	Low EUR	Reference	High EUR	High TRR	Low EUR	Reference	High EUR	High TRR
Natural gas prices (2010 dollars per million Btu)													
Henry Hub spot price	4.39	4.58	4.29	3.94	3.10	6.93	5.63	4.77	3.45	8.26	7.37	5.99	4.25
Average lower 48 wellhead	4.06	4.10	3.84	3.54	2.80	6.11	5.00	4.26	3.11	7.24	6.48	5.31	3.81
(2010 dollars per thousand cubic feet)													
Average lower 48 wellhead	4.16	4.19	3.94	3.62	2.87	6.25	5.12	4.36	3.19	7.41	6.64	5.43	3.90
Dry gas production[2]	**21.58**	**22.80**	**23.65**	**24.38**	**26.54**	**24.25**	**26.28**	**27.81**	**30.85**	**26.11**	**27.93**	**30.07**	**34.15**
Lower 48 onshore	18.66	20.62	21.48	22.20	24.37	21.48	23.64	25.24	28.60	21.19	24.97	27.19	31.66
Associated-dissolved	1.40	1.47	1.52	1.58	1.70	1.31	1.41	1.50	1.60	0.90	1.00	1.13	1.29
Non-associated	17.26	19.15	19.96	20.62	22.68	20.17	22.23	23.74	27.00	20.28	23.97	26.07	30.37
Tight gas	5.68	6.13	6.08	6.01	5.88	6.40	6.17	6.02	5.86	6.30	6.14	5.93	5.76
Shale gas	4.99	7.35	8.24	8.99	11.24	8.88	11.26	12.98	16.44	9.74	13.63	16.01	20.53
Coalbed methane	1.99	1.85	1.83	1.80	1.74	1.84	1.77	1.73	1.69	1.80	1.76	1.70	1.66
Other	4.59	3.81	3.82	3.82	3.82	3.04	3.03	3.02	3.02	2.44	2.44	2.43	2.42
Lower 48 offshore	2.56	1.89	1.88	1.88	1.87	2.51	2.38	2.31	1.99	3.12	2.72	2.64	2.27
Associated-dissolved	0.71	0.55	0.55	0.55	0.55	0.71	0.67	0.67	0.59	0.84	0.73	0.71	0.60
Non-associated	1.85	1.34	1.33	1.33	1.32	1.81	1.71	1.65	1.40	2.28	2.00	1.93	1.67
Alaska	0.36	0.29	0.29	0.29	0.29	0.25	0.25	0.25	0.25	1.80	0.23	0.23	0.22
Supplemental natural gas[3]	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net imports	**2.58**	**1.77**	**1.73**	**1.65**	**1.42**	**-0.39**	**-0.79**	**-1.06**	**-1.62**	**-1.16**	**-1.36**	**-1.73**	**-2.35**
Pipeline[4]	2.21	1.61	1.56	1.49	1.27	0.22	-0.13	-0.40	-0.95	-0.50	-0.70	-1.07	-1.69
Liquefied natural gas	0.37	0.17	0.16	0.16	0.15	-0.61	-0.66	-0.66	-0.66	-0.66	-0.66	-0.66	-0.66
Total supply	**24.22**	**24.64**	**25.45**	**26.09**	**28.02**	**23.92**	**25.55**	**26.81**	**29.30**	**25.01**	**26.63**	**28.40**	**31.86**
Consumption by sector													
Residential	4.94	4.83	4.85	4.88	4.94	4.69	4.76	4.82	4.92	4.59	4.64	4.72	4.84
Commercial	3.20	3.30	3.33	3.37	3.47	3.32	3.44	3.54	3.71	3.50	3.60	3.75	3.97
Industrial[5]	6.60	6.99	7.01	7.07	7.20	6.96	7.14	7.26	7.51	6.85	7.00	7.24	7.61
Electric power[6]	7.38	7.40	8.08	8.56	10.07	6.74	7.87	8.78	10.54	7.67	8.96	10.13	12.62
Transportation[7]	0.04	0.06	0.06	0.06	0.06	0.11	0.11	0.12	0.12	0.15	0.16	0.17	0.18
Pipeline fuel	0.63	0.66	0.67	0.67	0.69	0.64	0.66	0.67	0.69	0.72	0.67	0.69	0.74
Lease and plant fuel[8]	1.34	1.35	1.39	1.43	1.55	1.44	1.53	1.60	1.78	1.54	1.60	1.70	1.91
Total	**24.13**	**24.59**	**25.39**	**26.04**	**27.97**	**23.90**	**25.53**	**26.79**	**29.28**	**25.01**	**26.63**	**28.40**	**31.87**
Discrepancy[9]	**0.10**	**0.05**	**0.05**	**0.05**	**0.05**	**0.02**	**0.02**	**0.02**	**0.02**	**-0.00**	**-0.00**	**-0.01**	**-0.01**
Lower 48 end of year reserves	**260.50**	**265.85**	**274.79**	**283.88**	**298.90**	**280.90**	**299.77**	**318.24**	**347.21**	**291.70**	**311.58**	**333.43**	**371.70**

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[4]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[5]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Natural gas used as a vehicle fuel.
[8]Represents natural gas used in field gathering and processing plant machinery.
[9]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2010 values include net storage injections.

EUR = Estimated ultimate recovery.
TRR = Technically recoverable resources.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 supply values; lease, plant, and pipeline fuel consumption; and wellhead price: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). Other 2010 consumption based on: EIA, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011).
Projections: EIA, AEO2012 National Energy Modeling System runs LEUR12.D022212A, REF2012.D020112C, HEUR12.D022212A., and HTRR12.D050412A

Table D11. Liquid fuels supply and disposition, oil and gas resource cases

(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2010	2015				2025				2035			
		Low EUR	Reference	High EUR	High TRR	Low EUR	Reference	High EUR	High TRR	Low EUR	Reference	High EUR	High TRR
Prices (2010 dollars per barrel)													
Low sulfur light crude oil[1]	79.39	117.84	116.91	116.11	113.74	134.54	132.56	130.60	127.97	146.78	144.98	143.27	139.78
Imported crude oil[1]	75.87	114.90	113.97	113.17	110.80	123.99	121.21	118.63	115.77	135.38	132.95	131.20	127.55
Crude oil supply													
Domestic production[2]	5.47	5.91	6.15	6.38	7.09	5.82	6.40	6.95	7.69	5.49	5.99	6.62	7.76
Alaska	0.60	0.46	0.46	0.46	0.46	0.40	0.40	0.40	0.34	0.27	0.27	0.27	0.38
Lower 48 onshore	3.21	3.85	4.09	4.32	5.04	3.77	4.43	5.00	5.98	3.22	3.99	4.67	5.97
Lower 48 offshore	1.67	1.60	1.60	1.60	1.59	1.65	1.57	1.54	1.36	2.00	1.74	1.69	1.41
Net imports	9.17	8.80	8.52	8.28	7.57	7.87	7.24	6.68	5.89	8.12	7.52	6.90	5.65
Other crude oil supply	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude oil supply	**14.72**	**14.71**	**14.67**	**14.65**	**14.66**	**13.69**	**13.64**	**13.63**	**13.58**	**13.61**	**13.51**	**13.52**	**13.40**
Other petroleum supply	**3.50**	**3.17**	**3.25**	**3.33**	**3.40**	**3.66**	**3.80**	**3.94**	**4.13**	**3.40**	**3.52**	**3.73**	**4.02**
Natural gas plant liquids	2.07	2.43	2.56	2.68	2.97	2.67	3.01	3.27	3.91	2.66	3.01	3.33	4.04
Net product imports[3]	0.39	-0.20	-0.25	-0.30	-0.54	0.08	-0.12	-0.24	-0.69	-0.12	-0.34	-0.43	-0.89
Refinery processing gain[4]	1.07	0.94	0.95	0.94	0.97	0.90	0.91	0.91	0.91	0.86	0.85	0.83	0.86
Product stock withdrawal	-0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other non-petroleum supply	**1.00**	**1.22**	**1.22**	**1.22**	**1.22**	**1.87**	**1.86**	**1.86**	**1.85**	**2.91**	**2.96**	**2.87**	**2.81**
From renewable sources[5]	0.87	1.05	1.05	1.05	1.05	1.48	1.48	1.48	1.49	2.33	2.37	2.32	2.27
From non-renewable sources[6]	0.13	0.17	0.17	0.17	0.16	0.38	0.38	0.37	0.36	0.58	0.58	0.55	0.53
Total primary supply[7]	**19.22**	**19.10**	**19.14**	**19.20**	**19.27**	**19.21**	**19.29**	**19.42**	**19.56**	**19.91**	**19.99**	**20.11**	**20.23**
Refined petroleum products supplied													
Residential and commercial	1.12	1.00	1.00	1.00	1.00	0.93	0.94	0.94	0.95	0.90	0.91	0.91	0.92
Industrial[8]	4.31	4.17	4.17	4.19	4.19	4.38	4.41	4.44	4.46	4.41	4.44	4.46	4.47
Transportation	13.82	13.78	13.80	13.82	13.88	13.66	13.71	13.79	13.88	14.37	14.41	14.49	14.57
Electric power[9]	0.17	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.15	0.14
Total	**19.17**	**19.07**	**19.10**	**19.14**	**19.21**	**19.11**	**19.20**	**19.31**	**19.44**	**19.83**	**19.90**	**20.01**	**20.10**
Discrepancy[10]	**0.05**	**0.03**	**0.05**	**0.06**	**0.07**	**0.10**	**0.10**	**0.11**	**0.12**	**0.09**	**0.09**	**0.11**	**0.12**
Lower 48 end of year reserves (billion barrels)[2]	**18.33**	**19.39**	**20.55**	**21.66**	**23.49**	**21.36**	**23.64**	**25.77**	**27.83**	**22.68**	**24.23**	**26.27**	**29.06**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes ethanol (including imports), biodiesel (including imports), pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks for the production of green diesel and gasoline.
[6]Includes alcohols, ethers, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[9]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[10]Balancing item. Includes unaccounted for supply, losses and gains.
EUR = Estimated ultimate recovery.
TRR = Technically recoverable resources.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2010 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2010 data: EIA, *Petroleum Supply Annual 2010,* DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). **Projections:** EIA, AEO2012 National Energy Modeling System runs LEUR12.D022212A, REF2012.D020112C, HEUR12.D022212A, and HTRR.D050412A.

Table D12. Volumetric and mass representations of liquid fuels production cases

(volume in million barrels per day, mass in billion tons, unless otherwise noted)

Supply and disposition	2000		2011			2035		
	Volume	Mass	PMM Volume	LFMM Volume	LFMM Mass	PMM Volume	LFMM Volume	LFMM Mass
Primary feedstocks[1]								
Crude oil[2]	15.36	0.83	15.37	14.87	0.83	14.05	13.73	0.78
Natural gas[3]	0.00	0.00	0.00	0.00	0.00	0.00	2.95	0.03
Natural gas plant liquids[4]	1.91	0.07	2.16	1.21	0.09	3.01	0.30	0.11
Coal[5]	0.00	0.00	0.00	0.00	0.00	0.28	0.27	0.09
Biomass[6]	0.10	0.01	0.92	13.99	0.14	2.37	14.64	0.31
Total primary feedstocks	**17.37**	**0.91**	**18.45**	**- -**	**1.06**	**19.71**	**- -**	**1.32**
Refined products[1]								
Residual fuel oil	0.91	0.04	0.47	0.52	0.03	0.58	0.58	0.03
Middle distillates[7]	2.55	0.26	3.21	5.90	0.30	3.73	6.69	0.34
Biodiesel[8]	0.00	0.00	0.05	0.02	0.00	0.13	0.01	0.00
Gasoline blendstocks[9]	8.37	0.37	7.84	8.57	0.41	6.94	7.73	0.37
Ethanol[10]	0.10	0.00	0.86	0.95	0.05	1.65	1.61	0.08
Chemicals[11]	2.62	0.10	2.11	2.17	0.05	2.10	3.20	0.08
Solid products[12]	- -	0.05	- -	- -	0.07	- -	- -	0.08
Fuel consumption and other[13]	- -	0.10	- -	0.00	0.15	0.00	0.00	0.34
Total refined products	**14.55**	**0.91**	**14.54**	**18.13**	**1.06**	**15.13**	**19.82**	**1.32**
End use products								
Residual fuel oil	0.91	0.04	0.47	0.50	0.03	0.58	0.57	0.03
Heating oil[14]	1.17	0.03	0.62	0.53	0.03	0.37	0.37	0.02
Diesel fuel[15]	2.55	0.16	3.27	3.40	0.17	4.11	4.19	0.21
Jet fuel	1.73	0.08	1.44	1.51	0.08	1.61	1.67	0.08
Motor Gasoline[16]	8.47	0.38	8.76	9.29	0.44	8.09	8.32	0.40
E85[17]	0.00	0.00	0.00	0.00	0.00	0.83	0.84	0.04
Liquefied petroleum gases	2.43	0.02	2.26	0.46	0.01	2.21	0.74	0.01
Chemical feedstocks[18]	0.40	0.07	0.33	1.70	0.06	0.57	2.47	0.06
Agricultural products[19]	- -	0.00	- -	- -	0.05	- -	- -	0.06
Biomass heat and power[20]	- -	0.00	- -	- -	0.00	- -	- -	0.02
Other[21]	1.91	0.04	1.89	0.34	0.02	1.79	0.36	0.02
Total end use products	**19.57**	**0.82**	**19.04**	**17.73**	**0.89**	**20.16**	**19.53**	**0.95**

[1]Includes domestic production and net imports.
[2]Includes unfinished oils and lease condensate.
[3]Natural gas that remains after the liquefiable hydrocarbon portion has been removed from the gas stream at lease and/or plant separation facilities. Volume in billion cubic feet per day.
[4]Liquids in the natural gas production stream that stay in gaseous form at the surface and are separated at a gas processing plant. Once extracted, these liquids are separated into distinct products, or "fractions", such as propane, butane, and ethane.
[5]Coal input to the coal-to-liquids process. Volume in million barrels per day fuel oil equivalent.
[6]Biological material from living, or recently living organisms such as grain crops, sugars, cellulosic biomass, or renewable oils. Volume in million barrels per day fuel oil equivalent.
[7]Includes all fuels that meet ASTM D396 and D975 (#4 and lighter) and D1655/D6615, including those derived from fossil and renewable feedstock.
[8]Methyl ester based fuel produced from fatty acids in renewable oils.
[9]Includes all blendstocks that meet ASTM D4814, including those derived from fossil and renewable feedstock.
[10]Includes denaturant.
[11]Includes liquefied petroleum gases and petrochemical feestocks.
[12]Includes petroleum coke, distillers grains, sulfur, and asphalt sales.
[13]Includes fuels burned for internal use, heat and power sales, solid waste, and process emissions.
[14]A distillate fuel oil for use in atomizing type burners for domestic heating or for use in medium capacity commercial-industrial burner units.
[15]For on-road use.
[16]Includes ethanol and ethers blended into motor gasoline.
[17]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[18]Includes petrochemical feedstocks and chemicals from Fischer-Tropsch processes, such as coal-to-liquids, biomass-to-liquids, and natural gas-to-liquids.
[19]Non-liquid co-products for use in the agricultural sector. Includes dried distiller grains.
[20]Heat and power generated from the burning of residual biomass.
[21]Includes petroleum coke, asphalt, road oil, and still gas.
- - = Not applicable.
PMM = Petroleum market module.
LFMM = Liquid fuels market module.
Note: PMM and LFMM projections do not exactly match due to differences in accounting for additional materials and updated refinery stream representations. Totals may not equal sum of components due to independent rounding. Data for 2000 are model results and may differ slightly from official EIA data reports.
Sources: 2000 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2000 crude oil production: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2000 data: EIA, *Petroleum Supply Annual 2000,* DOE/EIA-0340(2000)/1 (Washington, DC, June 2001). **Projections:** EIA, AEO2012 National Energy Modeling System runs REF2012.D020112C, and REF_LFMM.D050312A.

Table D13. Key results for No GHG Concern case

(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	2010	2015		2025		2035	
		Reference	No GHG Concern	Reference	No GHG Concern	Reference	No GHG Concern
Production[1]	**1084**	**993**	**1016**	**1118**	**1169**	**1212**	**1339**
Appalachia	336	300	301	271	263	291	301
Interior	156	151	156	163	173	198	216
West	592	542	558	684	733	722	822
Waste coal supplied[2]	**14**	**15**	**18**	**16**	**16**	**19**	**24**
Net imports[3]	**-64**	**-95**	**-97**	**-71**	**-57**	**-94**	**-88**
Total supply[4]	**1034**	**914**	**936**	**1064**	**1128**	**1138**	**1276**
Consumption by sector							
Residential and commercial	3	3	3	3	3	3	3
Coke plants	21	22	22	19	19	17	17
Other industrial[5]	52	50	50	52	52	53	53
Coal-to-liquids heat and power	0	0	0	19	47	34	90
Coal-to-liquids liquids production	0	0	0	18	44	32	85
Electric power[6]	975	839	861	952	962	998	1028
Total coal use	**1051**	**914**	**936**	**1063**	**1127**	**1137**	**1276**
Average minemouth price[7]							
(2010 dollars per short ton)	35.61	42.08	41.83	44.05	43.14	50.52	49.88
(2010 dollars per million Btu)	1.76	2.08	2.07	2.23	2.21	2.56	2.54
Delivered prices[8]							
(2010 dollars per short ton)							
Coke plants	153.59	189.11	188.05	212.18	212.06	238.32	237.86
Other industrial[5]	59.28	70.14	70.04	72.77	73.23	78.53	79.88
Coal to liquids	- -	18.65	18.62	39.03	36.06	41.54	43.46
Electric power[6]							
(2010 dollars per short ton)	44.27	45.17	44.94	48.13	48.40	53.31	55.05
(2010 dollars per million Btu)	2.26	2.35	2.34	2.54	2.55	2.80	2.87
Average	**47.17**	**49.95**	**49.60**	**51.90**	**51.28**	**56.48**	**56.89**
Exports[9]	120.41	140.89	140.22	163.43	163.15	177.66	176.61
Cumulative electricity generating capacity additions (gigawatts)[10]							
Coal	0.0	9.1	9.1	13.5	18.4	16.6	39.9
Conventional	0.0	8.7	8.7	8.7	9.1	9.4	21.8
Advanced without sequestration	0.0	0.6	0.6	0.6	0.7	0.6	2.0
Advanced with sequestration	0.0	0.0	0.0	0.9	0.9	0.9	0.9
End-use generators[11]	0.0	-0.1	-0.1	3.4	7.8	5.6	15.2
Petroleum	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Natural gas	0.0	29.1	28.0	63.3	61.4	141.6	128.9
Nuclear / uranium	0.0	1.1	1.1	6.8	6.8	8.5	7.4
Renewables [12]	0.0	29.6	29.3	42.2	41.3	67.4	58.2
Other	0.0	0.8	0.8	0.8	0.8	0.8	0.8
Total	**0.0**	**69.8**	**68.4**	**126.7**	**128.8**	**235.0**	**235.3**
Liquids from coal (million barrels per day)	0.00	0.00	0.00	0.17	0.38	0.28	0.73

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes reported prices for both open market and captive mines.
[8]Prices weighted by consumption tonnage; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[9]F.a.s. price at U.S. port of exit.
[10]Cumulative additions after December 31, 2010. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[12]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
- - = Not applicable.
Btu = British thermal unit.
GHG = Greenhouse gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011); EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011); and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.
Projections: EIA, AEO2012 National Energy Modeling System runs REF2012.D020112C and NOGHGCONCERN.D031212A.

Table D14. Key results for coal cost cases

(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	2010	2020			2035			Annual growth 2010-2035 (percent)		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Production[1]	**1084**	**1096**	**1034**	**962**	**1336**	**1212**	**946**	**0.8%**	**0.4%**	**-0.5%**
Appalachia	336	281	262	253	309	291	261	-0.3%	-0.6%	-1.0%
Interior	156	168	159	159	194	198	202	0.9%	1.0%	1.0%
West	592	647	613	550	833	722	483	1.4%	0.8%	-0.8%
Waste coal supplied[2]	14	13	15	18	14	19	40	0.2%	1.4%	4.4%
Net imports[3]	-64	-78	-67	-73	-87	-94	-59	1.2%	1.5%	-0.3%
Total supply[4]	**1034**	**1031**	**982**	**907**	**1263**	**1138**	**927**	**0.8%**	**0.4%**	**-0.4%**
Consumption by sector										
Residential and commercial	3	3	3	3	3	3	3	-0.2%	-0.3%	-0.4%
Coke plants	21	19	18	18	17	17	16	-0.8%	-1.0%	-1.1%
Other industrial[5]	52	51	51	50	53	53	52	0.1%	0.0%	-0.0%
Coal-to-liquids heat and power	0	15	13	12	57	34	29	- -	- -	- -
Coal-to-liquids liquids production	0	14	12	11	54	32	27	- -	- -	- -
Electric power[6]	975	929	885	812	1079	998	800	0.4%	0.1%	-0.8%
Total coal use	**1051**	**1031**	**982**	**907**	**1263**	**1137**	**926**	**0.7%**	**0.3%**	**-0.5%**
Average minemouth price[7]										
(2010 dollars per short ton)	35.61	32.70	40.96	52.91	25.80	50.52	106.78	-1.3%	1.4%	4.5%
(2010 dollars per million Btu)	1.76	1.64	2.06	2.65	1.31	2.56	5.24	-1.2%	1.5%	4.5%
Delivered prices[8]										
(2010 dollars per short ton)										
Coke plants	153.59	165.27	198.45	239.32	136.73	238.32	413.77	-0.5%	1.8%	4.0%
Other industrial[5]	59.28	60.23	70.89	84.14	50.11	78.53	127.31	-0.7%	1.1%	3.1%
Coal to liquids	- -	34.43	40.67	49.20	25.22	41.54	68.76	- -	- -	- -
Electric power[6]										
(2010 dollars per short ton)	44.27	39.19	45.98	55.09	34.16	53.31	94.16	-1.0%	0.7%	3.1%
(2010 dollars per million Btu)	2.26	2.04	2.41	2.89	1.77	2.80	4.79	-1.0%	0.9%	3.0%
Average	**47.17**	**42.38**	**49.99**	**60.26**	**35.44**	**56.48**	**100.09**	**-1.1%**	**0.7%**	**3.1%**
Exports[9]	120.41	121.34	155.03	187.16	96.75	177.66	338.54	-0.9%	1.6%	4.2%
Cumulative electricity generating capacity additions (gigawatts)[10]										
Coal	0.0	12.9	12.5	12.2	30.7	16.6	14.5	- -	- -	- -
Conventional	0.0	8.7	8.7	8.7	19.8	9.4	8.7	- -	- -	- -
Advanced without sequestration	0.0	0.6	0.6	0.6	1.0	0.6	0.6	- -	- -	- -
Advanced with sequestration	0.0	0.9	0.9	0.9	0.9	0.9	0.9	- -	- -	- -
End-use generators[11]	0.0	2.7	2.3	2.1	9.0	5.6	4.3	- -	- -	- -
Petroleum	0.0	0.1	0.1	0.1	0.1	0.1	0.1	- -	- -	- -
Natural gas	0.0	36.6	39.7	43.1	128.1	141.6	131.7	- -	- -	- -
Nuclear / uranium	0.0	6.8	6.8	6.8	7.3	8.5	7.7	- -	- -	- -
Renewables[12]	0.0	34.2	34.5	41.0	67.9	67.4	65.9	- -	- -	- -
Other	0.0	0.8	0.8	0.8	0.8	0.8	0.8	- -	- -	- -
Total	**0.0**	**91.3**	**94.3**	**104.0**	**234.9**	**235.0**	**220.6**	**- -**	**- -**	**- -**
Liquids from coal (million barrels per day)	0.00	0.14	0.12	0.11	0.45	0.28	0.21	- -	- -	- -

Table D14. Key results for coal cost cases (continued)

(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	2010	2020			2035			Annual growth 2010-2035 (percent)		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Cost indices										
(constant dollar index, 2010=1.000)										
Transportation rate multipliers										
Eastern railroads	1.000	0.970	1.067	1.170	0.780	1.044	1.300	-1.0%	0.2%	1.1%
Western railroads	1.000	0.870	0.963	1.050	0.750	0.999	1.250	-1.1%	-0.0%	0.9%
Mine equipment costs										
Underground	1.000	0.914	1.000	1.094	0.786	1.000	1.270	-1.0%	0.0%	1.0%
Surface	1.000	0.914	1.000	1.094	0.786	1.000	1.270	-1.0%	0.0%	1.0%
Other mine supply costs										
East of the Mississippi: all mines	1.000	0.914	1.000	1.094	0.786	1.000	1.270	-1.0%	0.0%	1.0%
West of the Mississippi: underground	1.000	0.914	1.000	1.094	0.786	1.000	1.270	-1.0%	0.0%	1.0%
West of the Mississippi: surface	1.000	0.914	1.000	1.094	0.786	1.000	1.270	-1.0%	0.0%	1.0%
Coal mining labor productivity (short tons per miner per hour)	5.55	6.29	4.92	3.67	8.06	3.88	1.68	1.5%	-1.4%	-4.7%
Average coal miner wage (2010 dollars per year)	77,466	84,135	92,285	100,436	78,164	99,537	124,954	0.0%	1.0%	1.9%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal to liquids process.
[6]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes reported prices for both open market and captive mines.
[8]Prices weighted by consumption tonnage; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[9]F.a.s. price at U.S. port of exit.
[10]Cumulative additions after December 31, 2010. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[12]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2010 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2010*, DOE/EIA-0584(2010) (Washington, DC, November 2011); EIA, *Quarterly Coal Report, October-December 2010*, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011); U.S. Department of Labor, Bureau of Labor Statistics, Average Hourly Earnings of Production Workers: Coal Mining, Series ID : ceu1021210008; and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C. **Projections:** EIA, AEO2012 National Energy Modeling System runs LCCST12.D031312A, REF2012.D020112C, and HCCST12.D031312A.

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Appendix E

NEMS overview and brief description of cases

The National Energy Modeling System

Projections in the *Annual Energy Outlook 2012 (AEO2012)* are generated using the National Energy Modeling System (NEMS) [*142*], developed and maintained by the Office of Energy Analysis of the U.S. Energy Information Administration (EIA). In addition to its use in developing the *Annual Energy Outlook (AEO)* projections, NEMS is also used to complete analytical studies for the U.S. Congress, the Executive Office of the President, other offices within the U.S. Department of Energy (DOE), and other Federal agencies. NEMS is also used by other nongovernment groups, such as the Electric Power Research Institute, Duke University, Georgia Institute of Technology, and OnLocation, Inc. In addition, the *AEO* projections are used by analysts and planners in other government agencies and nongovernment organizations.

The projections in NEMS are developed with the use of a market-based approach, subject to regulations and standards. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS extends to 2035. To represent regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; 22 regions and subregions of the North American Electric Reliability Corporation for electricity; and the five Petroleum Administration for Defense Districts (PADDs) for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. The modular design also permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS executes each of the component modules to solve for prices of energy delivered to end users and the quantities consumed, by product, region, and sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to end users. The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. A solution is reached annually through the projection horizon. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence.

Each NEMS component represents the impacts and costs of legislation and environmental regulations that affect that sector. NEMS accounts for all combustion-related carbon dioxide (CO_2) emissions, as well as emissions of sulfur dioxide, nitrogen oxides, and mercury from the electricity generation sector.

The version of NEMS used for *AEO2012* generally represents current legislation and environmental regulations, including recent government actions, for which implementing regulations were available as of December 31, 2011, such as: the Mercury and Air Toxics Standards (MATS) [*143*] issued by the U.S. Environmental Protection Agency (EPA) in December 2011; the Cross-State Air Pollution Rule (CSAPR) [*144*] as finalized by the EPA in July 2011; the new fuel efficiency standards for medium- and heavy-duty vehicles (HDVs) published by the EPA and the National Highway Traffic Safety Administration (NHTSA) in September 2011 [*145*]; California's cap-and-trade program authorized by Assembly Bill (AB) 32, the Global Warming Solutions Act of 2006 [*146*]; the EPA policy memo regarding compliance of surface coal mining operations in Appalachia [*147*], issued on July 21, 2011; and the American Recovery and Reinvestment Act of 2009 (ARRA2009) [*148*], which was enacted in mid-February 2009.

The potential impacts of proposed Federal and State legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS. However, many pending provisions are examined in alternative cases included in *AEO2012* or in other analyses completed by EIA.

In general, the historical data presented with the *AEO2012* projections are based on EIA's *Annual Energy Review 2010*, published in October 2011 [*149*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2010. Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to the *AEO2012* appendix tables indicate the definitions and sources of historical data.

Where possible, the *AEO2012* projections for 2011 and 2012 incorporate short-term projections from EIA's December 2011 *Short-Term Energy Outlook (STEO).* For short-term energy projections, readers are referred to monthly updates of the *STEO* [*150*].

Component modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing prices or expenditures for energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) provides a set of macroeconomic drivers to the energy modules and receives energy-related indicators from the NEMS energy components as part of the macroeconomic feedback mechanism within NEMS.

Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, value of industrial shipments, new housing starts, sales of new light-duty vehicles (LDVs), interest rates, and employment. Key energy indicators fed back to the MAM include aggregate energy prices and costs. The MAM uses the following models from IHS Global Insight: Macroeconomic Model of the U.S. Economy, National Industry Model, and National Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to project regional economic drivers, and a Commercial Floorspace Model to project 13 floorspace types in 9 Census divisions. The accounting framework for industrial value of shipments uses the North American Industry Classification System (NAICS).

International Energy Module

The International Energy Module (IEM) uses assumptions of economic growth and expectations of future U.S. and world petroleum and other liquids production and consumption, by year, to project the interaction of U.S. and international petroleum and other liquids markets. The IEM computes world oil prices, provides a world crude-like liquids supply curve, generates a worldwide oil supply/demand balance for each year of the projection period, and computes initial estimates of crude oil and light and heavy petroleum product imports to the United States by PADD regions. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international petroleum and other liquids supply and demand, current investment trends in exploration and development, and long-term resource economics by country and territory. The oil production estimates include both conventional and other liquids supply recovery technologies.

In interacting with the rest of NEMS, the IEM changes the oil price—which is defined as the price of light, low-sulfur crude oil delivered to Cushing, Oklahoma (PADD 2)—in response to changes in expected production and consumption of crude oil and other liquids in the United States.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by Census division, housing type, and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and changes in the housing stock. The Commercial Demand Module projects energy consumption in the commercial sector by Census division, building type, and category of end use, based on delivered prices of energy, availability of renewable sources of energy, and changes in commercial floorspace.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, representations of renewable energy technologies, and the effects of both building shell and appliance standards. The modules also include projections of distributed generation. The Commercial Demand Module also incorporates combined heat and power (CHP) technology. Both modules incorporate changes to "normal" heating and cooling degree-days by Census division, based on a 10-year average and on State-level population projections. The Residential Demand Module projects an increase in the average square footage of both new construction and existing structures, based on trends in new construction and remodeling.

Industrial Demand Module

The Industrial Demand Module (IDM) projects the consumption of energy for heat and power, as well as the consumption of feedstocks and raw materials in each of 21 industry groups, subject to the delivered prices of energy and macroeconomic estimates of employment and the value of shipments for each industry. As noted in the description of the MAM, the representation of industrial activity in NEMS is based on the NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Of the eight energy-intensive manufacturing industries, seven are modeled in the IDM, including energy-consuming components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Energy demand for petroleum refining (the eighth energy-intensive manufacturing industry) is modeled in the Petroleum Market Module (PMM), as described below, but the projected consumption is reported under the industrial totals.

There are several updates and upgrades in the representations of select industries. The base year for the bulk chemical industry has been updated to 2006 in keeping with updates to EIA's 2006 Manufacturing Energy Consumption Survey [*151*]. *AEO2012* also includes an upgraded representation for the cement and lime industries and agriculture. Instead of assuming that technological development for a particular process occurs on a predetermined (exogenous) path based on engineering judgment, these upgrades allow IDM technological change to be modeled endogenously, while using more detailed process representation. The upgrade allows for technological change, and therefore energy intensity, to respond to economic, regulatory, and other conditions. For subsequent *AEO*s, other industries represented in the IDM projections will be similarly upgraded.

A generalized representation of CHP is included. A revised methodology for CHP systems, implemented for *AEO2012*, simulates the utilization of installed CHP systems based on historical utilization rates and is driven by end-use electricity demand. To evaluate the economic benefits of additional CHP capacity, the model also includes an updated appraisal incorporating historical rather than assumed capacity factors and regional acceptance rates for new CHP facilities. The evaluation of CHP systems still uses a discount rate, which is equal to the projected 10-year Treasury bill rate plus a risk premium.

Transportation Demand Module

The Transportation Demand Module projects consumption of energy in the transportation sector—including petroleum products, electricity, methanol, ethanol, compressed natural gas (CNG), and hydrogen—by transportation mode, subject to delivered energy prices and macroeconomic variables such as disposable personal income, GDP, population, interest rates, and industrial shipments. The Transportation Demand Module includes legislation and regulations, such as the Energy Policy Act of 2005 (EPACT2005), the Energy Improvement and Extension Act of 2008 (EIEA2008), and the ARRA2009, which contain tax credits for the purchase of alternatively fueled vehicles. Fleet vehicles are also modeled, allowing for analysis of legislative proposals specific to those markets. Representations of LDV Corporate Average Fuel Economy (CAFE) and greenhouse gas (GHG) emissions standards, HDV fuel consumption and GHG emissions standards, and biofuels consumption in the module reflect standards enacted by NHTSA and the EPA, as well as provisions in the Energy Independence and Security Act of 2007 (EISA2007).

The air transportation component of the Transportation Demand Module explicitly represents air travel in domestic and foreign markets and includes the industry practice of parking aircraft in both domestic and international markets to reduce operating costs, as well as the movement of aging aircraft from passenger to cargo markets. For passenger travel and air freight shipments, the module represents regional fuel use in regional, narrow-body, and wide-body aircraft. An infrastructure constraint, which is also modeled, can potentially limit overall growth in passenger and freight air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

There are three primary submodules of the Electricity Market Module—capacity planning, fuel dispatching, and finance and pricing. The capacity expansion submodule uses the stock of existing generation capacity, the cost and performance of future generation capacity, expected fuel prices, expected financial parameters, expected electricity demand, and expected environmental regulations to project the optimal mix of new generation capacity that should be added in future years. The fuel dispatching submodule uses the existing stock of generation equipment types, their operation and maintenance costs and performance, fuel prices to the electricity sector, electricity demand, and all applicable environmental regulations to determine the least-cost way to meet that demand. The submodule also determines transmission and pricing of electricity. The finance and pricing submodule uses capital costs, fuel costs, macroeconomic parameters, environmental regulations, and load shapes to estimate generation costs for each technology.

All specifically identified options promulgated by the EPA for compliance with the Clean Air Act Amendments of 1990 are explicitly represented in the capacity expansion and dispatch decisions. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several States, primarily in the Northeast, have enacted air emission regulations for CO_2 that affect the electricity generation sector, and those regulations are represented in *AEO2012*. The *AEO2012* Reference case also imposes a limit on power sector CO_2 emissions for plants serving California, to represent the power sector impacts of California's AB 32. The *AEO2012* Reference case reflects the CSAPR as finalized by the EPA on July 6, 2011, requiring reductions in emissions from power plants that contribute to ozone and fine particle pollution in 28 States. Reductions in mercury emissions from coal- and oil-fired power plants also are reflected through the inclusion of the mercury and air toxics standards for power plants, finalized by the EPA on December 16, 2011.

Although currently there is no Federal legislation in place that restricts GHG emissions, regulators and the investment community have continued to push energy companies to invest in technologies that are less GHG-intensive. The trend is captured in the *AEO2012* Reference case through a 3-percentage-point increase in the cost of capital, when evaluating investments in new coal-fired power plants, new coal-to-liquids (CTL) plants without carbon capture and storage (CCS), and for pollution control retrofits.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (dedicated biomass plants and co-firing in existing coal plants), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and both onshore and offshore wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits (ITCs) for renewable fuels are incorporated, as currently enacted, including a permanent 10-percent ITC for business investment in solar energy (thermal nonpower uses as well as power uses) and geothermal power (available only to those projects not accepting the production tax credit [PTC] for geothermal power). In addition, the module reflects the increase in the ITC to 30 percent for solar energy systems installed before January 1, 2017. The extension of the credit to individual homeowners under EIEA2008 is reflected in the Residential and Commercial Demand Modules.

PTCs for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants also are represented. They provide a credit of up to 2.2 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2012*, new wind plants coming on line before January 1, 2013, are eligible to receive the PTC; other eligible plants must be in service before January 1, 2014. As part of the ARRA2009, plants eligible for the PTC may instead elect to receive a 30-percent ITC or an equivalent direct grant. *AEO2012* also accounts for new renewable energy capacity resulting from State renewable portfolio standard programs, mandates, and goals, as described in *Assumptions to the Annual Energy Outlook 2012* [*152*].

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply—onshore, offshore, and Alaska—by all production techniques, including natural gas recovery from coalbeds and low-permeability formations of sandstone and shale. The framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and natural gas production activities are modeled for 12 supply regions, including 6 onshore, 3 offshore, and 3 Alaskan regions.

The Onshore Lower 48 Oil and Gas Supply Submodule evaluates the economics of future exploration and development projects for crude oil and natural gas at the play level. Crude oil resources include conventional resources as well as highly fractured continuous zones, such as the Austin chalk and Bakken shale formations. Production potential from advanced secondary recovery techniques (such as infill drilling, horizontal continuity, and horizontal profile) and enhanced oil recovery (such as CO_2 flooding, steam flooding, polymer flooding, and profile modification) are explicitly represented. Natural gas resources include high-permeability carbonate and sandstone, tight gas, shale gas, and coalbed methane.

Domestic crude oil production quantities are used as inputs to the PMM in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are used as inputs to the Natural Gas Transmission and Distribution Module (NGTDM) for determining natural gas wellhead prices and domestic production.

Natural Gas Transmission and Distribution Module

The NGTDM represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting the domestic and foreign supply regions with 12 lower 48 U.S. demand regions. The 12 lower 48 regions align with the 9 Census divisions, with three subdivided, and Alaska handled separately. The flow of natural gas is determined for both a peak and off-peak period in the year, assuming a historically based seasonal distribution of natural gas demand. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. An algorithm is included to project the addition of CNG retail fueling capability. The module also accounts for foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, as well as liquefied natural gas (LNG) imports and exports. For *AEO2012*, LNG exports and re-exports were set exogenously and assumed to reach and maintain a total level of 903 billion cubic feet per year by 2020.

Petroleum Market Module

The PMM projects prices of petroleum products, crude oil and product import activity, and domestic refinery operations, subject to demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and biofuels—ethanol, biodiesel, biomass-to-liquids (BTL), CTL, gas-to-liquids (GTL), and coal-and-biomass-to-liquids (CBTL). Costs, performance, and first dates of commercial availability for the advanced other liquids technologies [*153*] are reviewed and updated annually.

The module represents refining activities in the five PADDs, as well as a less detailed representation of refining activities in the rest of the world. It models the costs of automotive fuels, such as conventional and reformulated gasoline, and includes production of biofuels for blending in gasoline and diesel. Fuel ethanol and biodiesel are included in the PMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent or less by volume (E10), 15 percent by volume (E15) in States that lack explicit language capping ethanol volume or oxygen content, and up to 85 percent by volume (E85) for use in flex-fuel vehicles.

The PMM includes representation of the Renewable Fuels Standard (RFS) included in EISA2007, which mandates the use of 36 billion gallons of ethanol equivalent renewable fuel by 2022. Both domestic and imported ethanol count toward the RFS. Domestic ethanol production is modeled for three feedstock categories: corn, cellulosic plant materials, and advanced feedstock materials. Starch-based ethanol plants are numerous (more than 190 are now in operation, with a total maximum sustainable nameplate capacity of more than 14 billion gallons annually), and they are based on a well-known technology that converts starch and sugar into ethanol. Ethanol from cellulosic sources is a new technology with only a few small pilot plants in operation. Ethanol from advanced feedstocks—defined as plants that ferment and distill grains other than corn and reduce GHG emissions by at least 50 percent—is also a new technology modeled in the PMM.

Fuels produced by Fischer-Tropsch synthesis and through a pyrolysis process are also modeled in the PMM, based on their economics relative to competing feedstocks and products. The five processes modeled are CTL, CBTL, GTL, BTL, and pyrolysis.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM by 41 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves respond to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of

U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by region and sector, environmental restrictions, and accounting for minemouth prices, transportation costs, and coal supply contracts. Over the projection horizon, coal transportation costs in the CMM vary in response to changes in the cost of rail investments.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports in the context of world coal trade, determining the pattern of world coal trade flows that minimizes production and transportation costs while meeting a specified set of regional world coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in 3 types of coal for 17 export regions and 20 import regions. U.S. coal production and distribution are computed for 14 supply regions and 16 demand regions.

Annual Energy Outlook 2012 cases

Table E1 provides a summary of the cases produced as part of *AEO2012*. For each case, the table gives the name used in *AEO2012*, a brief description of the major assumptions underlying the projections, and a reference to the pages in the body of the report and in this appendix where the case is discussed. The text sections following Table E1 describe the various cases. The Reference case assumptions for each sector are described in *Assumptions to the Annual Energy Outlook 2012* [*154*]. Regional results and other details of the projections are available at website www.eia.gov/aeo/supplement.

Macroeconomic growth cases

In addition to the *AEO2012* Reference case, Low Economic Growth and High Economic Growth cases were developed to reflect the uncertainty in projections of economic growth. The alternative cases are intended to show the effects of alternative growth assumptions on energy market projections. The cases are described as follows:

- In the Reference *case*, population grows by 0.9 percent per year, nonfarm employment by 1.0 percent per year, and labor productivity by 1.9 percent per year from 2010 to 2035. Economic output as measured by real GDP increases by 2.5 percent per year from 2010 through 2035, and growth in real disposable income per capita averages 1.5 percent per year.
- The Low Economic Growth case assumes lower growth rates for population (0.8 percent per year) and labor productivity (1.5 percent per year), resulting in lower nonfarm employment (0.8 percent per year), higher prices and interest rates, and lower growth in industrial output. In the Low Economic Growth case, economic output as measured by real GDP increases by 2.0 percent per year from 2010 through 2035, and growth in real disposable income per capita averages 1.3 percent per year.
- The High Economic Growth case assumes higher growth rates for population (1.0 percent per year) and labor productivity (2.2 percent per year), resulting in higher nonfarm employment (1.2 percent per year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the Reference case, and consequently economic output grows at a higher rate (3.0 percent per year) than in the Reference case (2.5 percent). Disposable income per capita grows by 1.6 percent per year, compared with 1.5 percent in the Reference case.

Oil price cases

The oil price in *AEO2012* is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and is similar to the price for light, sweet crude oil traded on the New York Mercantile Exchange, referred to as West Texas Intermediate (WTI). *AEO2012* also includes a projection of the U.S. annual average refiners' acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by domestic refiners.

The historical record shows substantial variability in oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2012* considers three oil price cases (Reference, Low Oil Price, and High Oil Price) to allow an assessment of alternative views on the future course of oil prices.

The Low and High Oil Price cases reflect a wide range of potential price paths, resulting from variation in demand by countries outside the Organization for Economic Cooperation and Development (OECD) for petroleum and other liquid fuels due to different levels of economic growth. The Low and High Oil Price cases also reflect different assumptions about decisions by members of the Organization of the Petroleum Exporting Countries (OPEC) regarding the preferred rate of oil production and about the future finding and development costs and accessibility of conventional oil resources outside the United States.

- In the Reference case, real oil prices rise from a $93 per barrel (2010 dollars) in 2011 to $145 per barrel in 2035. The Reference case represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources. It also assumes that OPEC producers will choose to maintain their share of the market and will schedule investments in incremental production capacity so that OPEC's conventional oil production will represent about 40 percent of the world's total petroleum and other liquids production over the projection period.
- In the Low Oil Price case, crude oil prices are only $62 per barrel (2010 dollars) in 2035, compared with $145 per barrel in the Reference case. In the Low Oil Price case, the low price results from lower demand for petroleum and other liquid fuels in the non-OECD nations. Lower demand is derived from lower economic growth relative to the Reference case. In this case, GDP growth in the non-OECD countries is reduced by 1.5 percentage points relative to Reference case in each projection year, beginning in 2015. The OECD projections are affected only by the price impact. On the supply side, OPEC countries increase

Table E1. Summary of the *AEO2012* cases

Case name	Description	Reference in text	Reference in Appendix E
Reference	Baseline economic growth (2.5 percent per year from 2010 through 2035), oil price, and technology assumptions. Complete projection tables in Appendix A. Light, sweet crude oil prices rise to about $145 per barrel (2010 dollars) in 2035. Assumes RFS target to be met as soon as possible.	--	--
Low Economic Growth	Real GDP grows at an average annual rate of 2.0 percent from 2010 to 2035. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	p. 72	p. 221
High Economic Growth	Real GDP grows at an average annual rate of 3.0 percent from 2010 to 2035. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	p. 72	p. 221
Low Oil Price	Low prices result from a combination of low demand for petroleum and other liquid fuels in the non-OECD nations and higher global supply. Lower demand is measured by lower economic growth relative to the Reference case. In this case, GDP growth in the non-OECD is reduced by 1.5 percentage points in each projection year relative to Reference case assumptions, beginning in 2015. On the supply side, OPEC increases its market share to 46 percent, and the costs of other liquids production technologies are lower than in the Reference case. Light, sweet crude oil prices fall to $62 per barrel in 2035. Partial projection tables in Appendix C.	p. 74	p. 221
High Oil Price	High prices result from a combination of higher demand for petroleum and other liquid fuels in the non-OECD nations and lower global supply. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth rates for China and India are raised by 1.0 percentage point relative to the Reference case in 2012 and decline to 0.3 percentage point above the Reference case in 2035. GDP growth rates for other non-OECD regions average about 0.5 percentage point above the Reference case. OPEC market share remains at about 40 percent throughout the projection, and non-OPEC petroleum production expands more slowly in the short to middle term relative to the Reference case. Light, sweet crude oil prices rise to $200 per barrel (2010 dollars) in 2035. Partial projection tables in Appendix C.	p. 74	p. 224
No Sunset	Begins with the Reference case and assumes extension of all existing energy policies and legislation that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs) and those that involve extensive regulatory analysis, such as CAFE improvements and periodic updates of efficiency standards. Partial projection tables in Appendix D.	p. 18	p.229
Extended Policies	Begins with the No Sunset case but excludes extension of tax credits for blenders and for other biofuels that were included in the No Sunset case. Assumes an increase in the capacity limitations on the ITC and extension of the program. The case includes additional rounds of efficiency standards for residential and commercial products, as well as new standards for products not yet covered, adds multiple rounds of national building codes by 2026, and increases LDV fuel economy standards in the transportation sector to 62 miles per gallon in 2035. Partial projection tables in Appendix D.	p. 18	p. 230
Transportation: CAFE Standards	Explores energy and market impacts assuming that LDV CAFE and GHG emissions standards proposed for model years 2017-2025 are enacted. Partial projection tables in Appendix D.	p. 29	p. 226
Transportation: High Technology Battery	Explores the impact of significant improvement in vehicle battery and non-battery system cost and performance on new LDV sales, energy consumption, and GHG emissions. Partial projection tables in Appendix D.	p. 31	p. 226
Transportation: HDV Reference	Incorporates revised CNG and LNG pricing assumptions and HDV market acceptance relative to the *AEO2012* Reference case. Partial projection tables in Appendix D.	p.40	p. 226
Transportation: HD NGV Potential	Using the HDV Reference case, explores energy and market issues associated with the assumed expansion of natural gas refueling infrastructure for the HDV market. Partial projection tables in Appendix D.	p. 39	p. 226

Table E1. Summary of the *AEO2012* cases (continued)

Case name	Description	Reference in text	Reference in Appendix E
Electricity: Low Nuclear	Assumes that all nuclear plants are limited to a 60-year life (31 gigawatts of retirements), uprates are limited to the 1 gigawatt that has been reported to EIA, and planned additions are the same as in the Reference case. Partial projection tables in Appendix D.	p. 51	p. 226
Electricity: High Nuclear	Assumes that all nuclear plants are life-extended beyond 60 years (except for one announced retirement), and uprates are the same as in the Reference case. New plants include those under construction and plants that have a scheduled U.S. Nuclear Regulatory Commission (NRC) or Atomic Safety and Licensing Board hearing and use a currently certified design (e.g., AP1000). Partial projection tables in Appendix D.	p. 52	p. 227
Electricity: Reference 05	Includes CSAPR and MATS as in the Reference case, with reduced 5-year environmental investment recovery. Partial projection tables in Appendix D.	p. 47	p. 227
Electricity: Low Gas Price 05	Includes CSAPR and MATS as in the Reference case, with reduced 5-year environmental investment recovery combined with the High Estimated Ultimate Recovery (EUR) case. Partial projection tables in Appendix D.	p. 47	p. 227
Renewable Fuels: Low Renewable Technology Cost	Costs for new nonhydropower renewable generating technologies start 20 percent lower in 2012 and decline to 40 percent lower than Reference case levels in 2035. Capital costs of renewable other liquid fuel technologies start 20 percent lower in 2012 and decline to approximately 40 percent lower than Reference case levels in 2035. Partial projection tables in Appendix D.	p. 208	p. 227
Petroleum: LFMM	Changes in the refining industry in the past and prospective future are discussed in the context of the development of the Liquid Fuels Market Module (LFMM) developed for NEMS. Provides overview of large-scale trends and highlights of specific issues that may require further analysis. Partial projection tables in Appendix D.	p. 43	p. 228
Oil and Gas: Low EUR	EUR per tight oil or shale gas well is 50 percent lower than in the Reference case.	p. 60	p. 227
Oil and Gas: High EUR	The EUR per tight oil and shale gas well is 50 percent higher than in the Reference case. Partial projection tables in Appendix D	p. 60	p. 227
Oil and Gas: High Technically Recoverable Resources (TRR)	The well spacing for all tight oil and shale gas plays is 8 wells per square mile (i.e., each well has an average drainage area of 80 acres), and the EUR for tight oil and shale gas wells is 50 percent higher than in the Reference case. Partial projection tables in Appendix D.	p. 60	p. 227
Coal: Low Coal Cost	Regional productivity growth rates for coal mining are approximately 2.8 percent per year higher than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates in 2035 are between 21 and 25 percent lower than in the Reference case. Partial projection tables in Appendix D.	p. 101	p. 228
Coal: High Coal Cost	Regional productivity growth rates for coal mining are approximately 2.8 percent per year lower than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates in 2035 are between 25 and 27 percent higher than in the Reference case. Partial projection tables in Appendix D.	p. 214	p. 228
Integrated 2011 Demand Technology	Referred to in text as "2011 Demand Technology." Assumes future equipment purchases in the residential and commercial sectors are based only on the range of equipment available in 2011. Energy efficiency of new industrial plant and equipment is held constant at the 2012 level over the projection period. Partial projection tables in Appendix D.	p. 27	p. 224
Integrated Best Available Demand Technology	Referred to in text as "Best Available Demand Technology." Assumes all future equipment purchases in the residential and commercial sectors are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. Partial projection tables in Appendix D.	p. 27	p. 225

Table E1. Summary of the *AEO2012* cases (continued)

Case name	Description	Reference in text	Reference in Appendix E
Integrated High Demand Technology	Referred to in text as "High Demand Technology." Assumes earlier availability, lower costs, and higher efficiencies for more advanced residential and commercial equipment. For new residential and commercial construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016. Industrial sector assumes earlier availability, lower costs, and higher efficiency for more advanced equipment and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes. In the transportation sector, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs. Freight trucks are assumed to see more rapid improvement in fuel efficiency for engine and emissions control technologies. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors. Partial projection tables in Appendix D.	p. 27	p. 225
Integrated 2011 Technology	Referred to in text as "2011 Technology." Combination of the Integrated 2011 Demand Technology case with the assumption that costs of new power plants do not improve from 2012 levels throughout the projection. Partial projection tables in Appendix D.	p. 202	p. 229
Integrated High Technology	Referred to in text as "High Technology." Combination of the Integrated High Demand Technology case and the Low Renewable Technology Cost case. Also assumes that costs for new nuclear and fossil-fired power plants are lower than Reference case levels, by 20 percent in 2012 and 40 percent in 2035. Partial projection tables in Appendix D.	p. 202	p. 229
No GHG Concern	No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy. Partial projection tables in Appendix D.	p. 102	p. 229
GHG15	Applies a price for CO_2 emissions throughout the economy, starting at $15 per metric ton in 2013 and rising by 5 percent per year through 2035. The price is set to target the same reduction in CO_2 emissions as in the *Annual Energy Outlook 2011 (AEO2011)* GHG Price Economywide case. Partial projection tables in Appendix D.	p. 46	p. 229
GHG25	Applies a price for CO_2 emissions throughout the economy, starting at $25 per metric ton in 2013 and rising by 5 percent per year through 2035. The price is set at the same dollar amount as in the *AEO2011* GHG Price Economywide case. Partial projection tables in Appendix D.	p. 46	p. 229

their conventional oil production to obtain a 46-percent share of total world petroleum and other liquids production, and oil resources outside the United States are more accessible and/or less costly to produce (as a result of technology advances, more attractive fiscal regimes, or both) than in the Reference case.

- In the High Oil Price case, oil prices reach about $200 per barrel (2010 dollars) in 2035. In the High Oil Price case, the high prices result from higher demand for petroleum and other liquid fuels in the non-OECD nations. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth in the non-OECD region is raised by 0.1 to 1.0 percentage point relative to the Reference case in each projection year, starting in 2012. GDP growth rates for China and India are raised by 1.0 percentage points relative to the Reference case in 2012, declining to 0.3 percentage point above the Reference case in 2035. GDP growth rates for most other non-OECD regions average about 0.5 percentage point above the Reference case in each projection year. The OECD projections are affected only by the price impact. On the supply side, OPEC countries are assumed to reduce their market share somewhat, and oil resources outside the United States are assumed to be less accessible and/or more costly to produce than in the Reference case.

Buildings sector cases

In addition to the *AEO2012* Reference case, three technology-focused cases using the Demand Modules of NEMS were developed to examine the effects of changes in technology. Buildings sector assumptions for the Integrated 2011 Demand Technology case and the Integrated High Demand Technology case are also used in the appropriate Integrated Technology cases.

Residential sector assumptions for the technology-focused cases are as follows:

- For the Integrated 2011 Demand Technology case it is assumed that all future residential equipment purchases are based only on the range of equipment available in 2011. Existing building shell efficiencies are assumed to be fixed at 2011 levels (no further improvements). For new construction, building shell technology options are constrained to those available in 2011.

- For the Integrated High Demand Technology case it is assumed that residential advanced equipment is available earlier, at lower costs, and/or at higher efficiencies [*155*]. For new construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016. Consumers evaluate investments in energy efficiency at a 7-percent real discount rate.
- For the Integrated Best Available Demand Technology case it is assumed that all future residential equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. For new construction, building shell efficiencies are assumed to meet the criteria for the most efficient components after 2011.

Commercial sector assumptions for the technology-focused cases are as follows:

- For the Integrated 2011 Demand Technology case it is assumed that all future commercial equipment purchases are based only on the range of equipment available in 2011. Building shell efficiencies are assumed to be fixed at 2011 levels.
- For the Integrated High Demand Technology case it is assumed that commercial advanced equipment is available earlier, at lower costs, and/or with higher efficiencies than in the Reference case [*156*]. Energy efficiency investments are evaluated at a 7-percent real discount rate. Building shell efficiencies for new and existing buildings in 2035 assume a 25-percent improvement relative to the Reference case.
- For the Integrated Best Available Demand Technology case it is assumed that all future commercial equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. Building shell efficiencies for new and existing buildings in 2035 assume a 50-percent improvement relative to the Reference case.

The Residential and Commercial Demand Modules of NEMS were also used to complete the Low Renewable Technology Cost case, which is discussed in more detail below, in the renewable fuels cases section. In combination with assumptions for electricity generation from renewable fuels in the electric power sector and industrial sector, this sensitivity case analyzes the impacts of changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- The Low Renewable Technology Cost case assumes greater improvements in residential and commercial PV and wind systems than in the Reference case. The assumptions for capital cost estimates are 20 percent below Reference case assumptions in 2012 and decline to at least 40 percent lower than Reference case costs in 2035.

The No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the Residential and Commercial Demand Modules of NEMS. The Extended Policies case builds on the No Sunset case and adds multiple rounds of appliance standards and building codes as described below.

- The No Sunset case assumes that selected policies with sunset provisions will be extended indefinitely rather than allowed to sunset as the law currently prescribes. For the residential sector, these extensions include: personal tax credits for selected end-use equipment, including furnaces, heat pumps, and central air conditioning; personal tax credits for PV installations, solar water heaters, small wind turbines, and geothermal heat pumps; and manufacturer tax credits for refrigerators, dishwashers, and clothes washers, passed on to consumers at 100 percent of the tax credit value. For the commercial sector, business ITCs for PV installations, solar water heaters, small wind turbines, geothermal heat pumps, and CHP are extended to the end of the projection. The business tax credit for solar technologies remains at the current 30-percent level without reverting to 10 percent as scheduled.
- The Extended Policies case includes updates to appliance standards, as prescribed by the timeline in DOE's multiyear plan, and introduces new standards for products currently not covered by DOE. Efficiency levels for the updated residential appliance standards are based on current ENERGY STAR guidelines. Residential end-use technologies subject to updated standards are not eligible for No Sunset incentives in addition to the standards. Efficiency levels for updated commercial equipment standards are based on the technology menu from the *AEO2012* Reference case and purchasing specifications for Federal agencies designated by the Federal Energy Management Program (FEMP). The case also adds national building codes to reach 30-percent improvement relative to the 2006 International Energy Conservation Code (IECC 2006) for residential households and to American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) Standard 90.1-2004 for commercial buildings by 2020, with additional rounds of improved codes in 2023 and 2026.

Industrial sector cases

In addition to the *AEO2012* Reference case, two technology-focused cases using the IDM of NEMS were developed that examine the effects of less rapid and more rapid technology change and adoption. The energy intensity changes discussed in this section exclude the refining industry, which is modeled separately from the IDM in the PMM. Different assumptions for the IDM were also used as part of the Integrated Low Renewable Technology Cost case, No Sunset case, and Extended Policies case, but each is structured on a set of the initial industrial assumptions used for the Integrated 2011 Demand Technology case and Integrated High Demand Technology case. For the industrial sector, assumptions for those two technology-focused cases are as follows:

- For the Integrated 2011 Demand Technology case, the energy efficiency of new industrial plant and equipment is held constant at the 2012 level over the projection period. Changes in aggregate energy intensity may result both from changing equipment and

production efficiency and from changing composition of output within an individual industry. Because all *AEO2012* side cases are integrated runs, potential feedback effects from energy market interactions are captured. Hence, the level and composition of overall industrial output varies from the Reference case, and any change in energy intensity in the two technology side cases is attributable to process and efficiency changes and increased use of CHP, as well as changes in the level and composition of overall industrial output.

- For the Integrated High Demand Technology case, the IDM assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*157*] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes—i.e., 0.7 percent per year, as compared with 0.4 percent per year in the Reference case. The same assumption is incorporated in the Low Renewable Technology Cost case, which focuses on electricity generation. Although the choice of the 0.7-percent annual rate of improvement in byproduct recovery is an assumption in the High Demand Technology case, it is based on the expectation of higher recovery rates and substantially increased use of CHP in that case. Due to integration with other NEMS modules, potential feedback effects from energy market interactions are captured.

The industrial No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the IDM of NEMS. The Extended Policies case builds on the No Sunset case and modifies select industrial assumptions, which are as follows:

- The No Sunset case and Extended Policies case include an assumption for CHP that extends the existing industrial CHP ITC through the end of the projection period. Additionally, the Extended Policies case includes an increase in the capacity limitations on the ITC by increasing the cap on CHP equipment from 15 megawatts to 25 megawatts and eliminating the system-wide cap of 50 megawatts. These assumptions are based on the current proposals in H.R. 2750 and H.R. 2784 of the 112th Congress.

Transportation sector cases

In addition to the *AEO2012* Reference case, the NEMS Transportation Demand Module was used to examine the effects of advanced technology costs and efficiency improvement on technology adoption and vehicle fuel economy as part of the Integrated High Demand Technology case [*158*]. For the Integrated High Demand Technology case, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs. In the freight truck sector, the High Demand Technology case assumes more rapid incremental improvement in fuel efficiency and lower costs for engine and emissions control technologies. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors.

Three additional integrated cases were developed to examine the potential energy impacts associated with the implementation of proposed model year 2017 to 2025 LDV CAFE standards, the impact of the successful development of advanced batteries, and the impact of the penetration of HDVs using LNG. The specific cases include:

- The CAFE Standards case examines the energy, GHG, and vehicle market impacts of increasing LDV fuel economy standards to reflect those proposed by the EPA and NHTSA for model years 2017-2025. Fuel economy standards are assumed to remain constant after model year 2025.
- The High Technology Battery case examines the energy, GHG emissions, and sales impacts on new LDVs associated with rapid improvement in battery cost and non-battery systems performance.
- The HDV Reference case incorporates revised pricing assumptions for CNG and LNG highway fuels and HDV market acceptance.
- The HD NGV Potential case examines the energy and GHG impacts associated with assumed significant increases in LNG refueling infrastructure to enable market adoption of natural gas use by HDVs in long-haul corridors relative to the HDV Reference case.

Electricity sector cases

In addition to the Reference case, several integrated cases with alternative electric power assumptions were developed to support discussions in the "Issues in focus" section of *AEO2012*. Two alternative cases were run for nuclear power plants, to address uncertainties about the operating lives of existing reactors, the potential for new nuclear capacity, and capacity uprates at existing plants. These scenarios are discussed in the "Issues in focus" article, "Nuclear power in *AEO2012*."

In addition, two alternative cases were run to analyze uncertainties related to the lifetimes of coal-fired power plants due to recent environmental regulations and potential GHG legislation in the future. Over the next few years, electricity generators will begin taking steps to comply with a number of new environmental regulations, primarily by adding environmental controls at existing coal-fired power plants. The additional cases examine the impacts of shorter economic recovery periods for the environmental controls, with the natural gas prices used in the *AEO2012* Reference case and lower natural gas prices.

Nuclear cases

- The Low Nuclear case assumes that all existing nuclear plants are retired after 60 years of operation. In the Reference case, existing plants are assumed to run as long as they continue to be economic, implicitly assuming that a second 20-year license renewal will be obtained for most plants that reach 60 years before 2035. The Low Nuclear case was run to analyze the impact

of additional nuclear retirements, which could occur if the oldest plants do not receive a second license extension. In this case, 31 gigawatts of nuclear capacity is assumed to be retired by 2035. The Low Nuclear case assumes that no new nuclear capacity will be added throughout the projection, excluding capacity already planned or under construction. The case also assumes that only those capacity uprates reported to EIA will be completed (1 gigawatt). The Reference case assumes additional uprates based on NRC surveys and industry reports.

- The High Nuclear case assumes that all existing nuclear units will receive a second license renewal and operate beyond 60 years (excluding one announced retirement). In the Reference case, beyond the announced retirement of Oyster Creek, an additional 5.5 gigawatts of nuclear capacity is assumed to be retired through 2035, reflecting uncertainty about the impacts and/or costs of future aging. This case was run to provide a more optimistic outlook, with all licenses renewed and all plants continuing to operate economically beyond 60 years. The High Nuclear case also assumes that additional planned nuclear capacity is completed based on combined license applications issued by the NRC. The Reference case assumes that 6.8 gigawatts of planned capacity is added, compared with 13.5 gigawatts of planned capacity additions in the High Nuclear case.

Environmental Rules cases

- The Reference 05 case assumes that the economic recovery period for investments in new environmental controls in the electric power sector is reduced from 20 years to 5 years.
- The Low Gas Price 05 case uses more optimistic assumptions about future volumes of shale gas production, leading to lower natural gas prices, combined with the 5-year recovery period for new environmental controls in the electric power sector. The domestic shale gas resource assumption comes from the High EUR case.

Renewable fuels cases

In addition to the *AEO2012* Reference case, EIA developed a case with alternative assumptions about renewable fuels to examine the effects of more aggressive improvement in the cost of renewable technologies.

- In the Low Renewable Technology Cost case, the levelized costs of new nonhydropower renewable generating technologies are assumed to start at 20 percent below Reference case assumptions in 2012 and decline to 40 percent below the Reference case costs for the same resources in 2035. In general, lower costs are represented by reducing the capital costs of new plant construction. Biomass fuel supplies also are assumed to be 40 percent less expensive than for the same resource quantities used in the Reference case. Assumptions for other generating technologies are unchanged from those in the Reference case. In the Low Renewable Technology Cost case, the rate of improvement in recovery of biomass byproducts from industrial processes also is increased.
- In the No Sunset case and the Extended Policies case, expiring Federal tax credits targeting renewable electricity are assumed to be permanently extended. This applies to the PTC, which is a tax credit of 2.2 cents per kilowatthour available for the first 10 years of production by new generators using wind, geothermal, and certain biomass fuels, or a tax credit of 1.1 cents per kilowatthour available for the first 10 years of production by new generators using geothermal energy, certain hydroelectric technologies, and biomass fuels not eligible for the full credit of 2.2 cents per kilowatthour. This tax credit is scheduled to expire on December 31, 2012, for wind and 1 year later for other eligible technologies. The same schedule applies to the 30-percent ITC, which is available to new solar installations through December 31, 2016, and may also be claimed in lieu of the PTC for eligible technologies, expiring concurrently with the PTC expiration dates indicated above.

Oil and gas supply cases

The sensitivity of the *AEO2012* projections to changes in assumptions regarding technically recoverable tight oil and shale gas resources are examined in two cases:

- In the Low EUR case, the EUR per tight oil or shale gas well is assumed to be 50 percent lower than in the Reference case, increasing the per-unit cost of developing the resource. The total unproved TRR of tight oil is decreased to 17 billion barrels, and the shale gas resource is decreased to 241 trillion cubic feet, as compared with unproved resource estimates of 33 billion barrels of tight oil and 482 of shale gas in the Reference case as of January 1, 2010.
- In the High EUR case, the EUR per tight oil and shale gas well is assumed to be 50 percent higher than in the Reference case, decreasing the per-unit cost of developing the resource. The total unproved technically recoverable tight oil resource is increased to 50 billion barrels, and the shale gas resource is increased to 723 trillion cubic feet.
- In the High TRR case, the well spacing for all tight oil and shale gas plays is assumed to be 8 wells per square mile (i.e., each well has an average drainage area of 80 acres), and the EUR for tight oil and shale gas wells is assumed to be 50 percent higher than in the Reference case. The total unproved technically recoverable tight oil resource is increased to 89 billion barrels, and the shale gas resource is increased to 1,091 trillion cubic feet, more than twice the Reference case assumptions for tight oil and shale gas resources.

Petroleum market cases

Production of petroleum and other liquid fuels has evolved and changed significantly in recent years as a result of changes in the mix of feedstocks, production regions, technologies, regulation and policy, and international markets. To better reflect those changes, a new LFMM has been developed for use as part of NEMS. The intent is to use the LFMM in developing the *Annual Energy Outlook 2013 (AEO2013).* The LFMM was designed as a data-driven tool using a generalized algebraic modeling system. The LFMM uses nine types of crude oil (compared to five types in the current model). The LFMM configuration uses nine refining regions instead of the traditional five PADDs—eight domestic regions and one maritime Canada and Caribbean region that captures imports of refined products into the northeastern United States.

Market conditions and regulations have resulted in the implementation of new technologies using nonpetroleum feedstocks such as grains, biomass, pyrolysis oils, coal, biomass, and natural gas. The EISA2007 RFS mandates the use 36 billion gallons of renewable fuels by 2022, and the LFMM allows analysis of different renewable fuel capacities required to meet the mandate. Because the LFMM is a data-driven model, new technologies can be added easily to help in analysis of the RFS mandate. In addition, the LFMM has extensive representation of the RFS and other policies that affect its implementation. The technologies associated with the RFS have high development costs, and capital recovery is uncertain. That uncertainty can be analyzed by varying the market penetration rates for the technologies under different assumptions. Further, to accommodate evolving international markets, LFMM uses different approaches while interfacing with NEMS PMM. The new interface is able to work with newer crude types, as well as changes in prices for crude oil and petroleum products.

For *AEO2012*, an LFMM case was developed to test the new model and compare results with those produced by the PMM—which is the current model used for *AEO2012*—for the Reference, Low Economic Growth, High Economic Growth, Low Oil Price, and High Oil Price cases produced using the current version of the NEMS. The intent is to highlight areas where the two models produce significantly different results and explore the basis of those differences so that EIA will be able to ensure that the LFMM is ready for use as part of *AEO2013*.

Coal market cases

Two alternative coal cost cases examine the impacts on U.S. coal supply, demand, distribution, and prices that result from alternative assumptions about mining productivity, labor costs, mine equipment costs, and coal transportation rates. The alternative productivity and cost assumptions are applied in every year from 2012 through 2035. For the coal cost cases, adjustments to the Reference case assumptions for coal mining productivity are based on variation in the average annual productivity growth of 2.8 percent observed since 2000. Transportation rates are lowered (in the Low Coal Cost case) or raised (in the High Coal Cost case) from Reference case levels to achieve a 25-percent change in rates relative to the Reference case in 2035. The Low and High Coal Cost cases represent fully integrated NEMS runs, with feedback from the macroeconomic activity, international, supply, conversion, and enduse demand modules.

- In the Low Coal Cost case, the average annual growth rates for coal mining productivity are higher than those in the Reference case and are applied at the supply curve level. As an example, the average annual productivity growth rate for Wyoming's Southern Powder River Basin supply curve is increased from -1.8 percent in the Reference case for the years 2012 through 2035 to 0.8 percent in the Low Coal Cost case. Coal mining wages, mine equipment costs, and other mine supply costs all are assumed to be about 21 percent lower in 2035 in real terms in the Low Coal Cost case than in the Reference case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be 25 percent lower in 2035.
- In the High Coal Cost case, the average annual productivity growth rates for coal mining are lower than those in the Reference case and are applied as described in the Low Coal Cost case. Coal mining wages, mine equipment costs, and other mine supply costs in 2035 are assumed to be about 27 percent higher than in the Reference case, and coal transportation rates in 2035 are assumed to be 25 percent higher.

Additional details of the productivity, wage, mine equipment cost, and coal transportation rate assumptions for the Reference and alternative coal cost cases are provided in Appendix D.

Cross-cutting integrated cases

A series of cross-cutting integrated cases are used in *AEO2012* to analyze specific cases with broader sectoral impacts. For example, three integrated technology progress cases analyze the impacts of more rapid and slower technology improvement rates in the demand sector (partially described in the sector-specific sections above), and two other integrated technology cases examine the impacts of more rapid and slower technology improvement rates across both demand and supply/conversion sectors. In addition, two cases also were run with alternative assumptions about expectations of future regulation of GHG emissions.

Integrated technology cases

In the demand sectors (residential, commercial, industrial, and transportation), technology improvement typically means greater efficiency of energy use and/or reduced cost. In the energy supply/conversion sectors (electricity generation, natural gas and petroleum and other liquids supply, petroleum refining, etc.), technology improvement tends to mean greater availability of energy supplies and/or reduced cost of production (and ultimately prices). When alternative cases that examine the impacts of variation

in the rate of technology improvement are completed, combining the demand and supply/conversion sectors, the impacts on energy markets are sometimes masked because of the offsetting nature of technology improvements in the two areas.

Two sets of alternative cases are used in *AEO2012* to examine the potential impacts of variation in the rate of technology improvement. The first set looks at impacts on the demand sector in isolation. The second set looks at the combined impacts of technology changes in both the demand and supply/conversion sectors. The three demand technology cases—Integrated 2011 Demand Technology, Integrated Best Available Demand Technology, and Integrated High Demand Technology—examine the impacts on the end-use demand sectors of variations in the rate of technology improvement, independent of the offsetting impacts of variations in technology improvement in the supply/conversion sectors.

EIA also completed two fully integrated technology cases that examine combined impacts on the demand and supply/conversion sectors. The Integrated 2011 Technology case combines the assumptions from the Integrated 2011 Demand Technology case with an assumption that the costs of new fossil, nuclear, and nonhydroelectric renewable power plants are fixed at 2012 levels and do not improve due to learning during the projection period. The Integrated High Technology case combines the assumptions from the Integrated High Demand Technology and the Low Renewable Technology Cost case with an assumption that the costs of new nuclear and fossil-fired power plants are lower than assumed in the Reference case, with costs 20 percent lower than Reference case levels in 2012 and 40 percent lower than Reference case levels in 2035.

Greenhouse gas cases

On May 13, 2010, the EPA promulgated standards for GHG emissions in the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" [*159*]. The rule sets up levels of CO_2-equivalent emissions at new and existing facilities that make major modifications that increase GHG emissions which trigger coverage of the facilities in the New Source Review and Title V permitting program. As a result of this and prior actions, regulators and the investment community are beginning to push energy companies to invest in less GHG-intensive technologies. To reflect the market reaction to potential future GHG regulation, a 3-percentage-point increase in the cost of capital is assumed for investments in new coal-fired power plants without CCS and new CTL plants without CCS in the Reference case and all other *AEO2012* cases except the No GHG Concern, GHG15, and GHG25 cases. Those assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs when a new plant begins operation.

The three alternative GHG cases are used to provide a range of potential outcomes, from no concern about future GHG legislation to the imposition of a specific economywide carbon allowance price. *AEO2012* includes two economywide CO_2 price cases, the GHG15 and GHG25 cases, which examine the impacts of economywide carbon allowance prices. In the GHG15 case, the price is set at $15 per metric ton CO_2 in 2013. In the GHG25 case, the price is set at $25 per metric ton CO_2 in 2013. In both cases the price begins to rise in 2014 at 5 percent per year. The GHG cases are intended to measure the sensitivity of the *AEO2012* assumptions to different CO_2 prices that are consistent with previously proposed legislation. At the time the *AEO2012* was completed, no legislation including a GHG price was pending, but the EPA is developing technology-based CO_2 standards for new coal-fired power plants. In the two GHG cases for *AEO2012*, no assumptions are made with regard to offsets, bonus allowances for CCS, or specific allocation of allowances.

The No GHG Concern case was run without any adjustment for concern about potential GHG regulations (without the 3-percentage-point increase in the cost of capital). In the No GHG Concern case, the same cost of capital is used to evaluate all new capacity builds, regardless of type.

No Sunset case

In addition to the *AEO2012* Reference case, a No Sunset case was run assuming that selected policies with sunset provisions—such as the PTC, ITC, and tax credits for energy-efficient equipment in the buildings and industrial sectors—will be extended indefinitely rather than allowed to sunset as the law currently prescribes.

For the residential sector, the extensions include: (a) personal tax credits for selected end-use equipment, including furnaces, heat pumps, and central air conditioning; (b) personal tax credits for PV installations, solar water heaters, small wind turbines, and geothermal heat pumps; (c) manufacturer tax credits for refrigerators, dishwashers, and clothes washers, passed on to consumers at 100 percent of the tax credit value.

For the commercial sector, business ITCs for PV installations, solar water heaters, small wind turbines, geothermal heat pumps, and CHP are extended to the end of the projection. The business tax credit for solar technologies remains at the current 30-percent level without reverting to 10 percent as scheduled.

In the industrial sector, the existing ITC for industrial CHP, which currently ends in 2016, is extended to 2035.

For the refinery sector, blending credits are extended; the $1.00 per gallon biodiesel tax credit is extended; the $0.54 per gallon tariff on imported ethanol is extended; and the $1.01 per gallon PTC for cellulosic biofuels is extended.

For renewables, the PTC of 2.2 cents per kilowatthour for wind, geothermal, and certain biomass and the PTC of 1.1 cents per kilowatthour for hydroelectric and landfill gas resources, which currently are set to expire at the end of 2012 for wind and the end of 2013 for other eligible resources, are extended to 2035; and the 30-percent solar power ITC, which currently is scheduled to revert to 10 percent in 2016, is extended indefinitely.

Extended Policies case

In the Extended Policies case, assumptions for tax credit extensions are the same as in the No Sunset case described above with the exception of the PTC extension for cellulosic biofuels and the tax credits for residential equipment subject to updated Federal efficiency standards, which are dropped. Further, updates to Federal appliance efficiency standards are assumed to occur at regular intervals, and new standards for products not currently covered by DOE are assumed to be introduced. Finally, proposed rules by NHTSA and the EPA for national tailpipe CO_2-equivalent emissions and fuel economy standards for LDVs, including both passenger cars and light-duty trucks, are harmonized and incorporated in this case.

Updates to appliance standards are assumed to occur as prescribed by the timeline in DOE's multi-year plan, and new standards for products currently not covered by DOE are introduced by 2019. The efficiency levels chosen for the updated residential appliance standards are based on current ENERGY STAR guidelines. Residential end-use technologies subject to updated standards are not eligible for No Sunset incentives in addition to the standards. The efficiency levels chosen for updated commercial equipment standards are based on the technology menu from the *AEO2011* Reference case and either FEMP-designated purchasing specifications for Federal agencies or ENERGY STAR guidelines. National building codes are added to reach 30-percent improvement relative to IECC 2006 for residential households and ASHRAE 90.1-2004 for commercial buildings by 2020, with additional rounds of improvements in 2023 and 2026.

In the industrial sector, the ITC for industrial CHP is further extended to cover all system sizes rather than applying only to systems under 50 megawatts; and the CHP equipment cap is increased from 15 megawatts to 25 megawatts. These extensions are consistent with previously proposed legislation (S. 1639) or pending legislation (H.R. 2750 and 2784).

For transportation, the Extended Policies case assumes that the standards are further increased, so that the minimum fuel economy standard achieved by LDVs continues to increase through 2035.

Endnotes for Appendix E

Links current as of April 2012

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148. For the complete text of the American Recovery and Reinvestment Act of 2009, see website www.gpo.gov/fdsys/pkg/PLAW-111publ5/html/PLAW-111publ5.htm.
149. U.S. Energy Information Administration, *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC: October 2011), website www.eia.gov/aer.
150. U.S. Energy Information Administration, "Short-Term Energy Outlook," website www.eia.gov/forecasts/steo. Portions of the preliminary information were also used to initialize the NEMS Petroleum Market Module projection.
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153. Alternative other liquids technologies include all biofuels technologies plus CTL and GTL.
154. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2012*, DOE/EIA-0554(2012) (Washington, DC: June 2012), website www.eia.gov/forecasts/aeo/assumptions.
155. High technology assumptions for the residential sector are based on U.S. Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case* (Navigant Consulting, Inc. with SAIC, September 2011), and *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., September 2008).
156. High technology assumptions for the commercial sector are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case* (Navigant Consulting, Inc. with SAIC, September 2011), and *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., September 2008).
157. These assumptions are based in part on Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).
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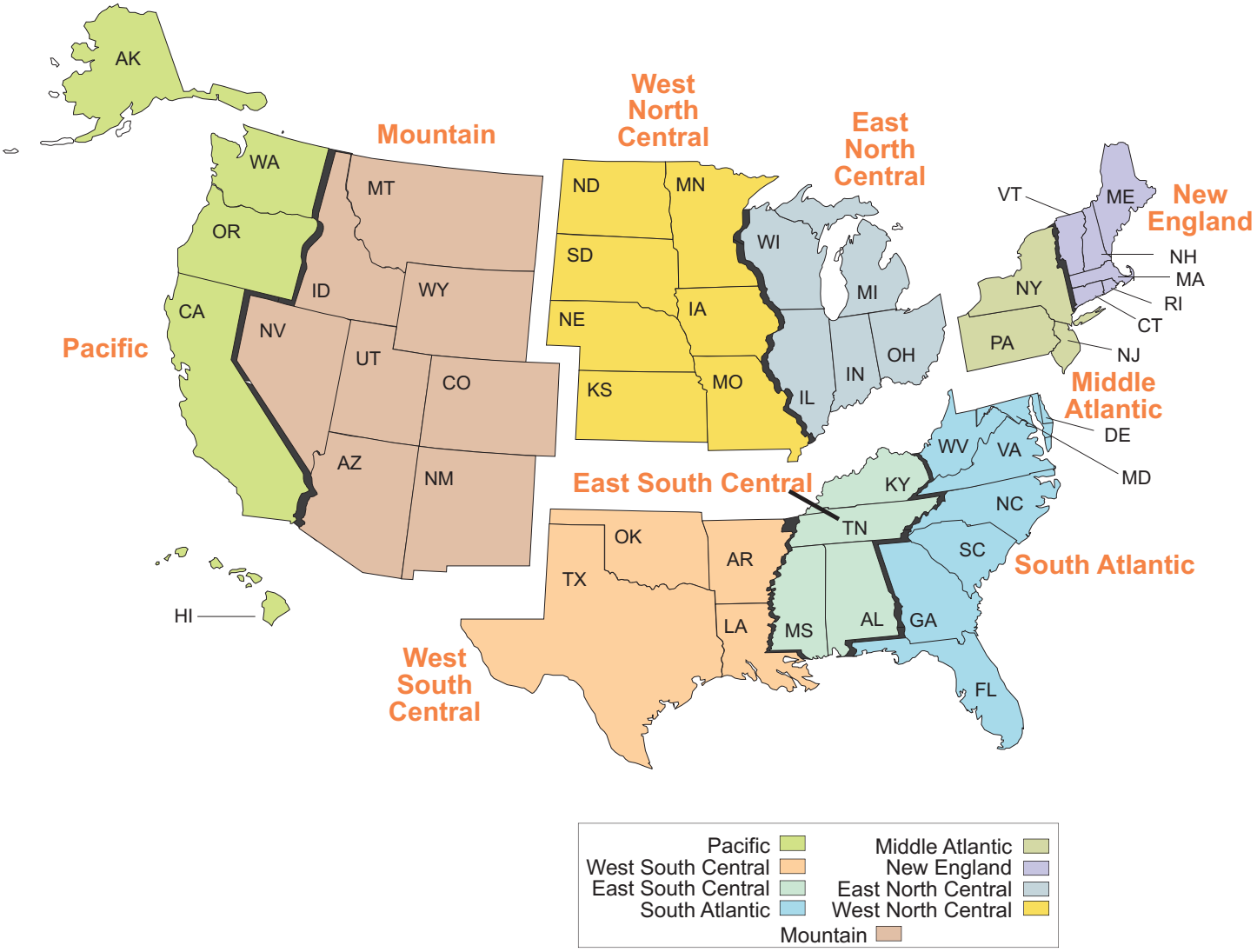
Appendix F

Regional Maps

Figure F1. United States Census Divisions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F1. United States Census Divisions (continued)

Division 1
New England

Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2
Middle Atlantic

New Jersey
New York
Pennsylvania

Division 3
East North Central

Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4
West North Central

Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5
South Atlantic

Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6
East South Central

Alabama
Kentucky
Mississippi
Tennessee

Division 7
West South Central

Arkansas
Louisiana
Oklahoma
Texas

Division 8
Mountain

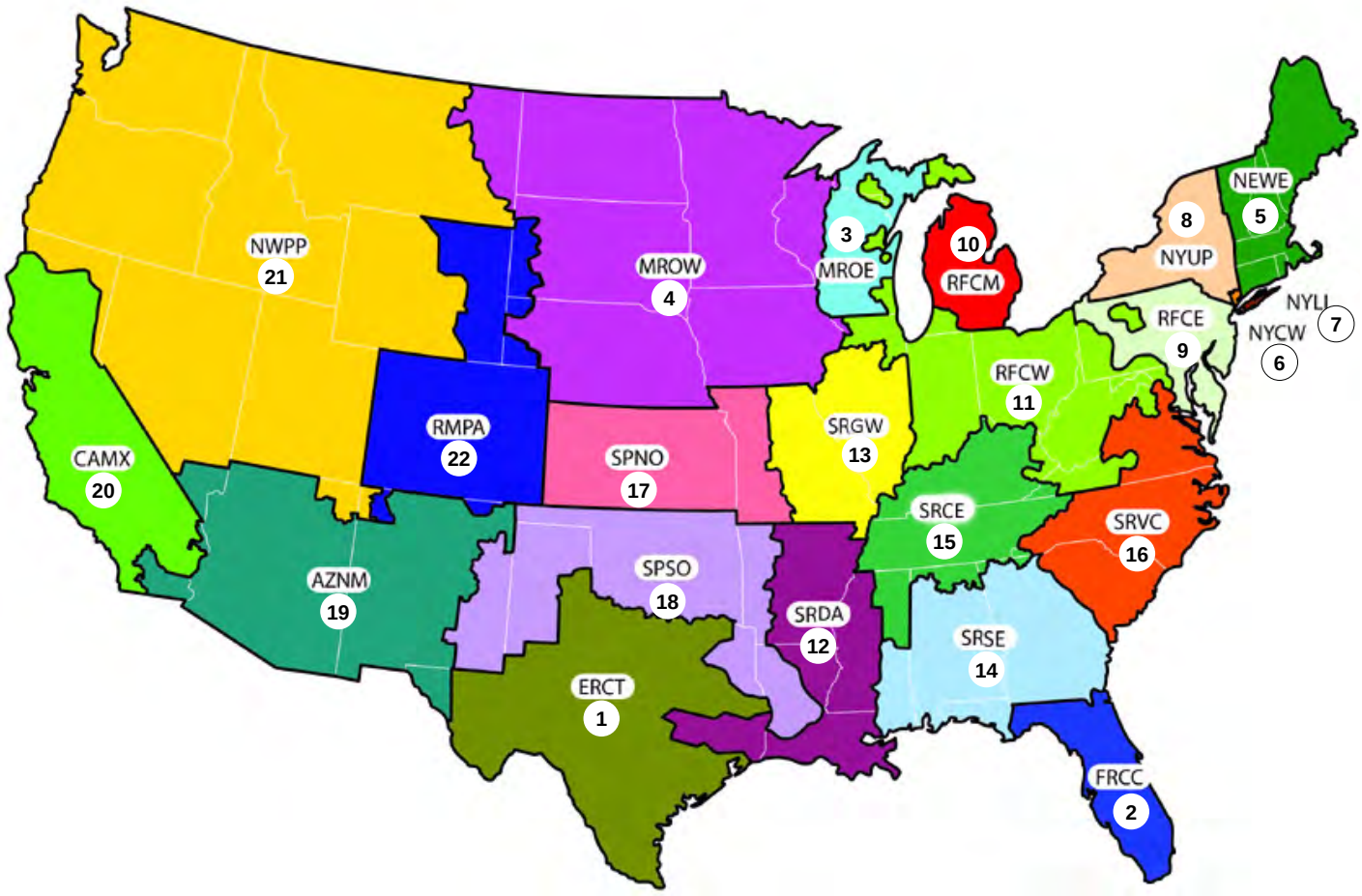
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9
Pacific

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Energy Analysis.

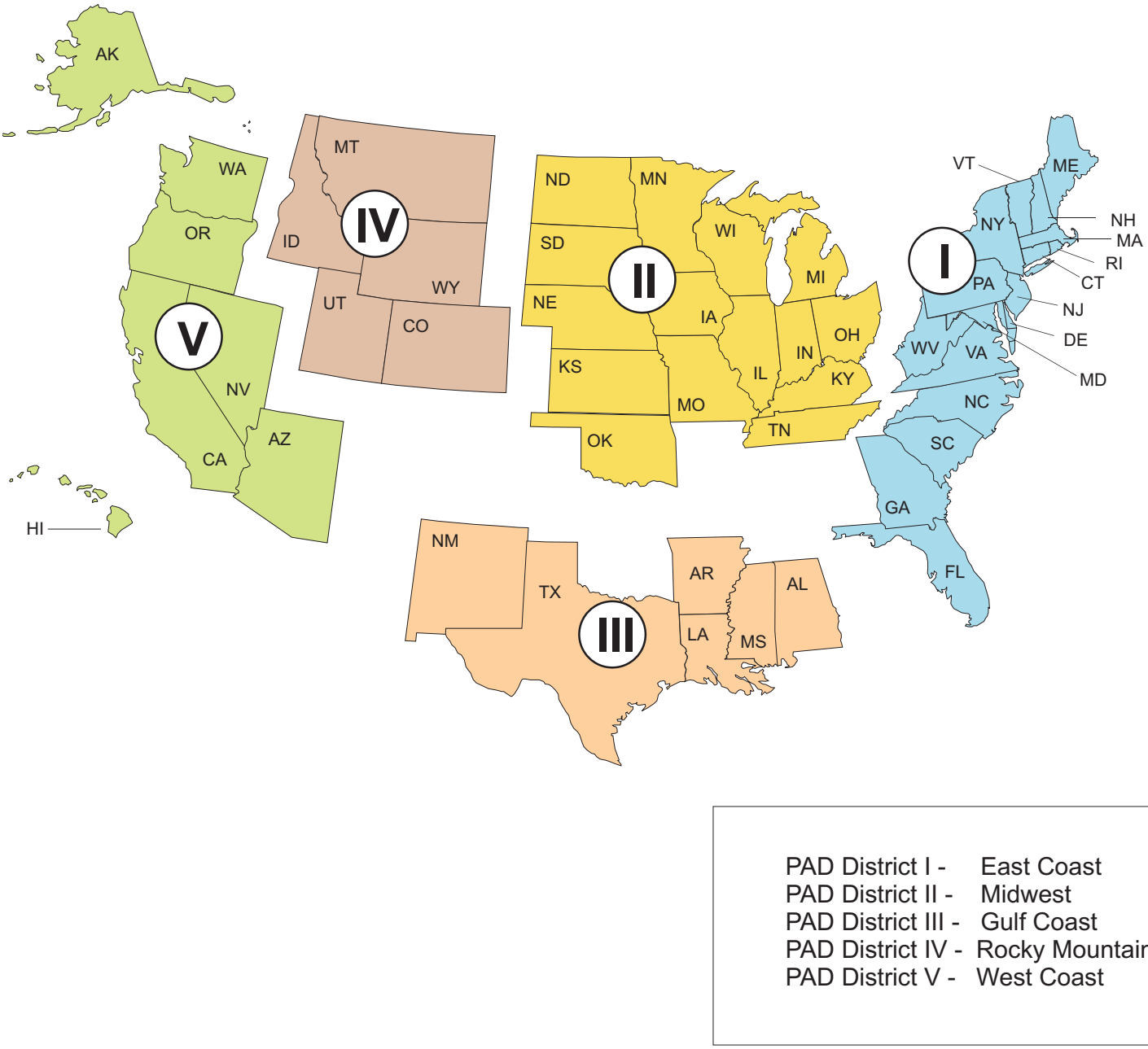
Figure F2. Electricity market module regions



1.	ERCT	TRE All
2.	FRCC	FRCC All
3.	MROE	MRO East
4.	MROW	MRO West
5.	NEWE	NPCC New England
6.	NYCW	NPCC NYC/Westchester
7.	NYLI	NPCC Long Island
8.	NYUP	NPCC Upstate NY
9.	RFCE	RFC East
10.	RFCM	RFC Michigan
11.	RFCW	RFC West
12.	SRDA	SERC Delta
13.	SRGW	SERC Gateway
14.	SRSE	SERC Southeastern
15.	SRCE	SERC Central
16.	SRVC	SERC VACAR
17.	SPNO	SPP North
18.	SPSO	SPP South
19.	AZNM	WECC Southwest
20.	CAMX	WECC California
21.	NWPP	WECC Northwest
22.	RMPA	WECC Rockies

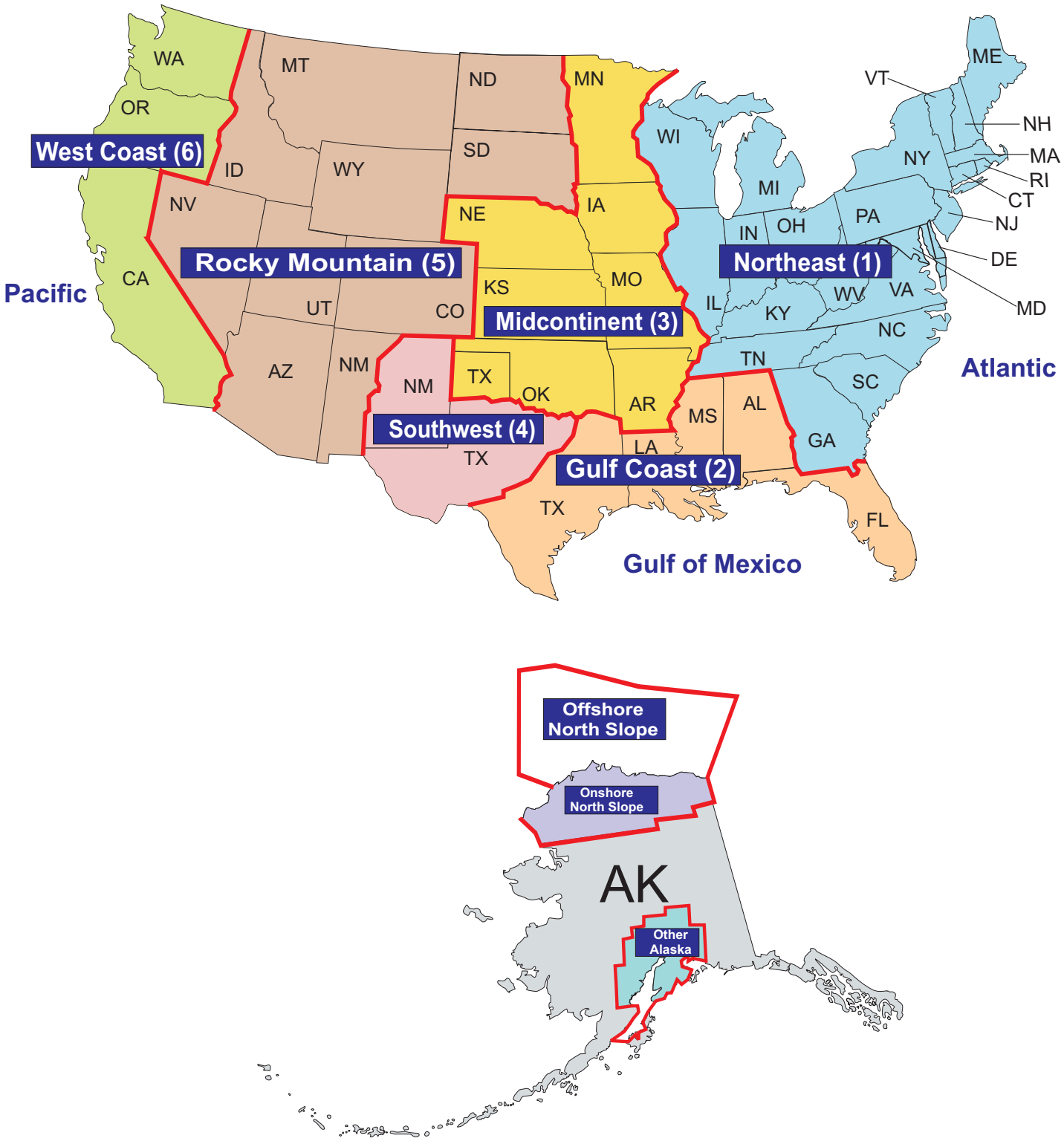
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F3. Petroleum Administration for Defense Districts



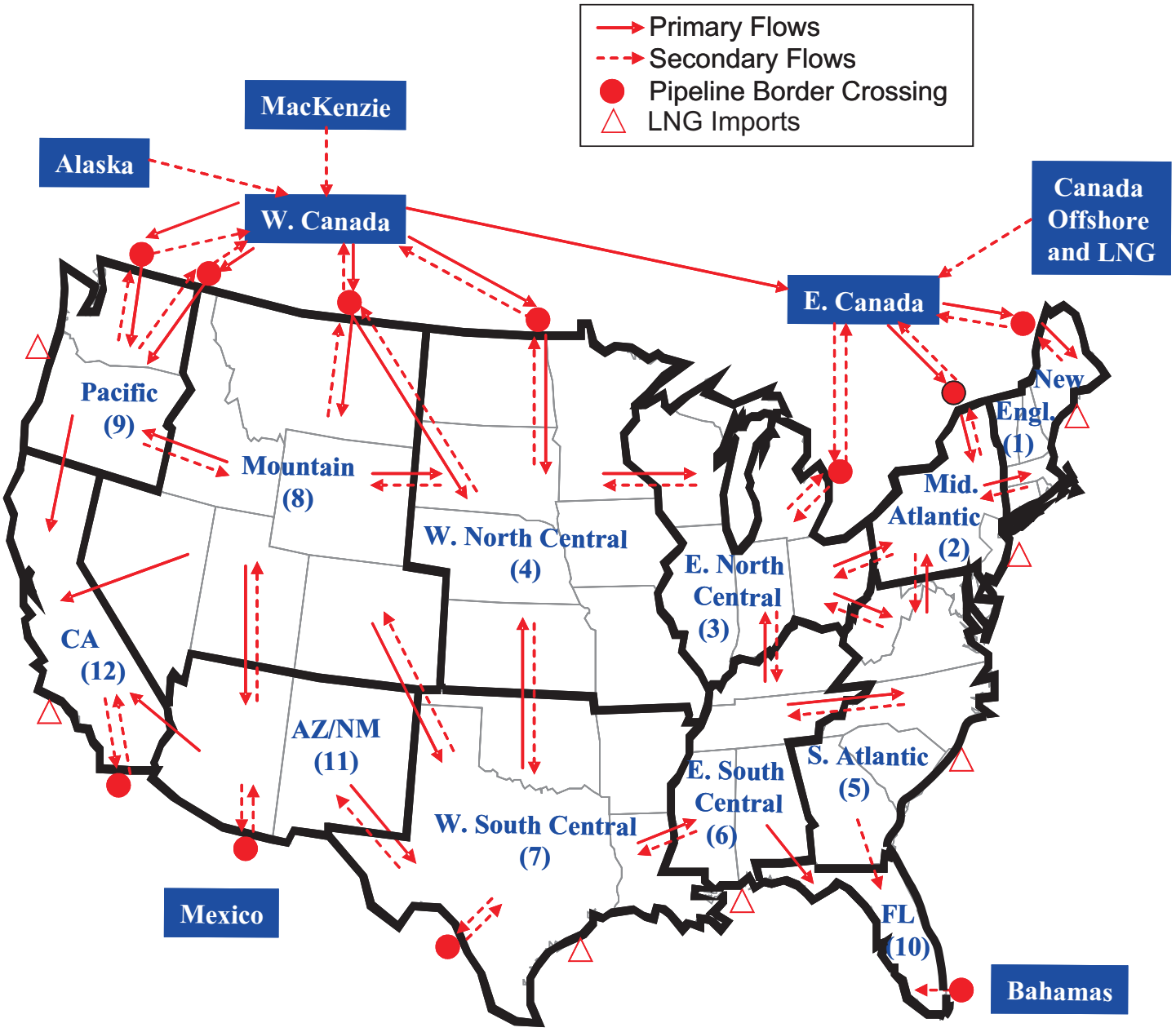
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F4. Oil and gas supply model regions



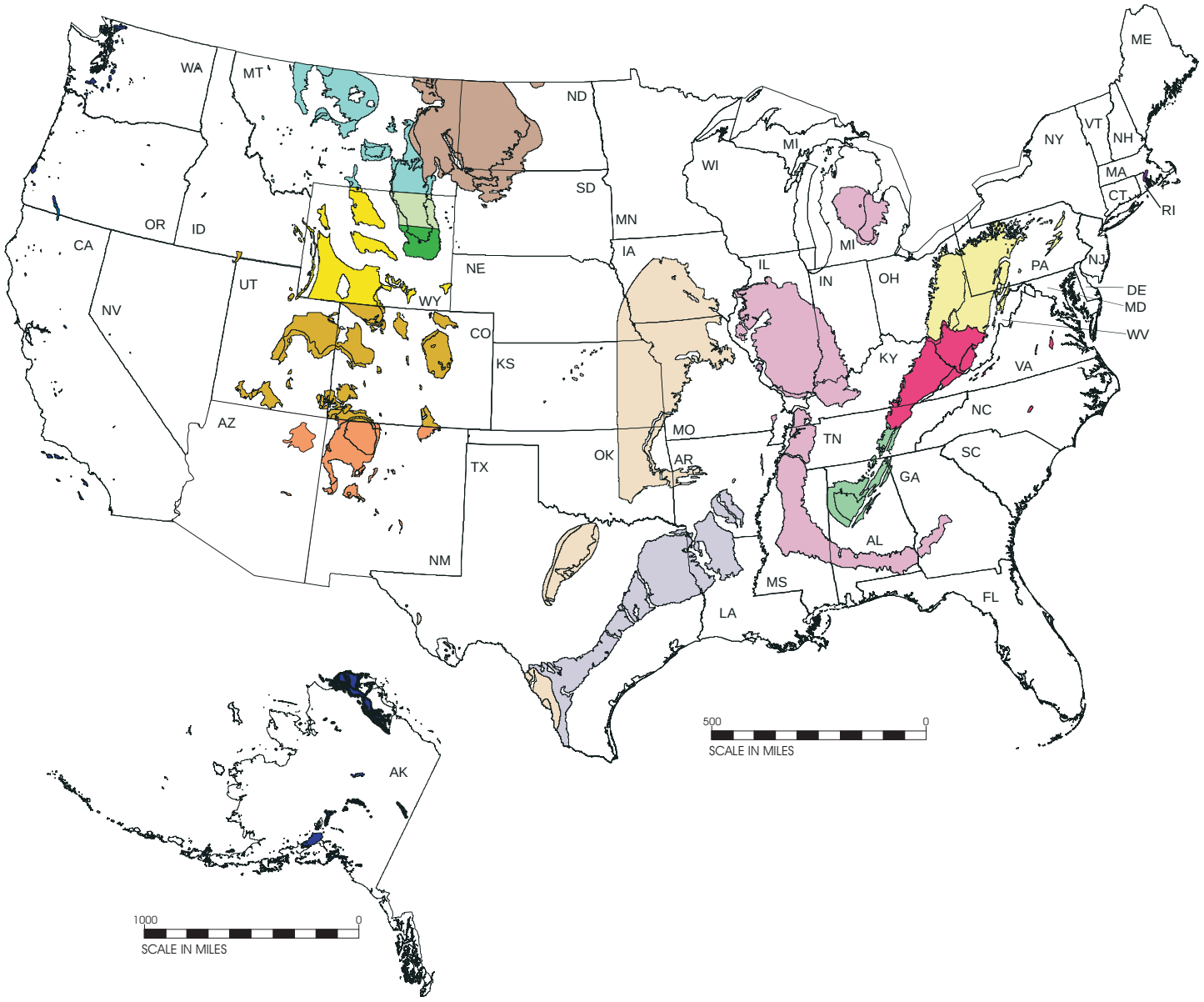
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F5. Natural gas transmission and distribution model regions



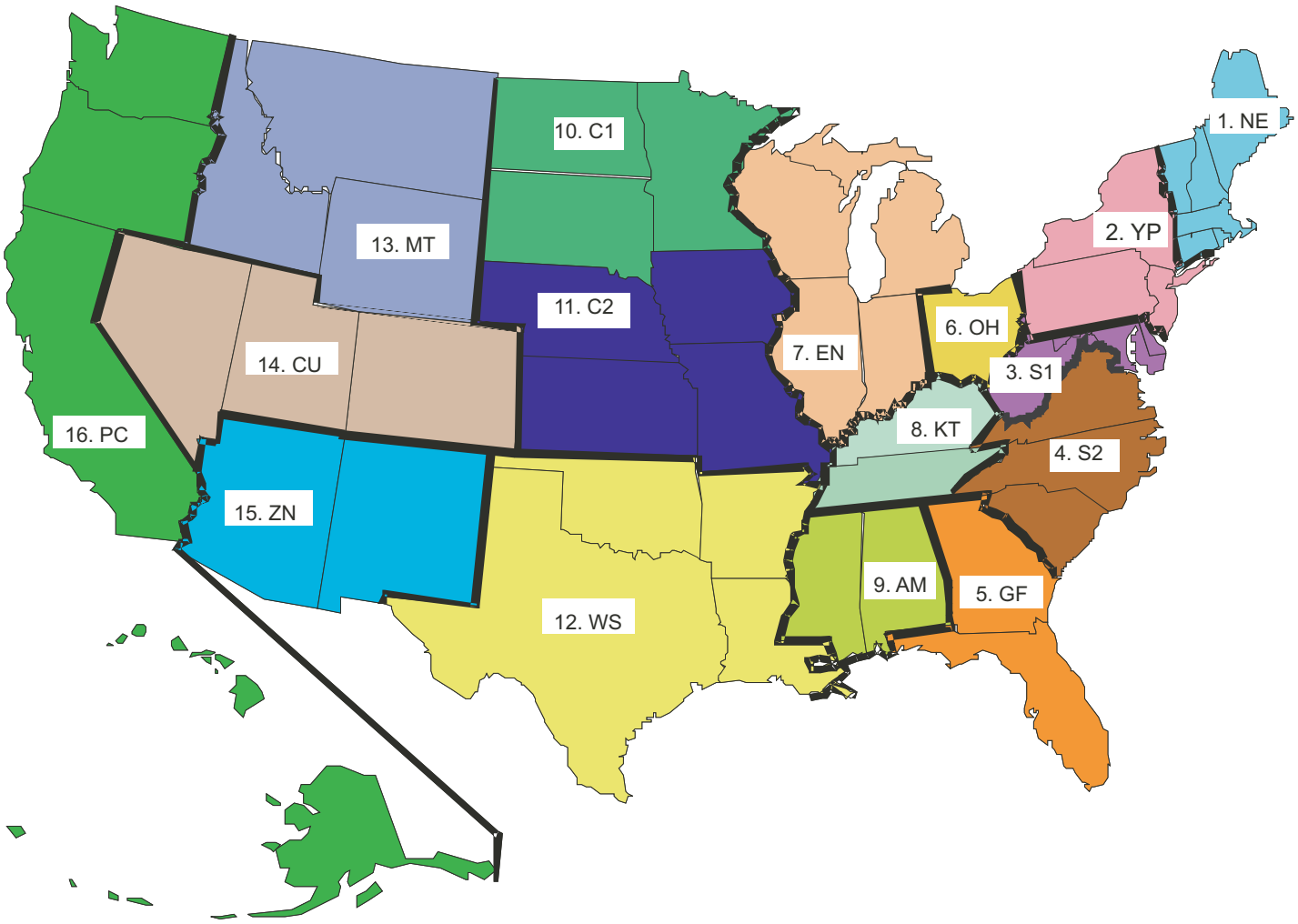
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F6. Coal supply regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F7. Coal demand regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. S1	WV,MD,DC,DE
4. S2	VA,NC,SC
5. GF	GA,FL
6. OH	OH
7. EN	IN,IL,MI,WI
8. KT	KY,TN

Region Code	Region Content
9. AM	AL,MS
10. C1	MN,ND,SD
11. C2	IA,NE,MO,KS
12. WS	TX,LA,OK,AR
13. MT	MT,WY,ID
14. CU	CO,UT,NV
15. ZN	AZ,NM
16. PC	AK,HI,WA,OR,CA

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Appendix G

Conversion factors

Table G1. Heat rates

Fuel	Units	Approximate heat content
Coal[1]		
Production	million Btu per short ton	20.192
Consumption	million Btu per short ton	19.847
Coke plants	million Btu per short ton	26.297
Industrial	million Btu per short ton	20.433
Residential and commercial	million Btu per short ton	21.188
Electric power sector	million Btu per short ton	19.623
Imports	million Btu per short ton	24.719
Exports	million Btu per short ton	25.698
Coal coke	million Btu per short ton	24.800
Crude oil		
Production	million Btu per barrel	5.800
Imports[1]	million Btu per barrel	5.989
Petroleum products and other liquids		
Consumption[1]	million Btu per barrel	5.254
Motor gasoline[1]	million Btu per barrel	5.100
Jet fuel	million Btu per barrel	5.670
Distillate fuel oil[1]	million Btu per barrel	5.771
Diesel fuel[1]	million Btu per barrel	5.762
Residual fuel oil	million Btu per barrel	6.287
Liquefied petroleum gases[1]	million Btu per barrel	3.557
Kerosene	million Btu per barrel	5.670
Petrochemical feedstocks[1]	million Btu per barrel	5.510
Unfinished oils	million Btu per barrel	6.118
Imports[1]	million Btu per barrel	5.337
Exports[1]	million Btu per barrel	5.851
Ethanol	million Btu per barrel	3.561
Biodiesel	million Btu per barrel	5.359
Natural gas plant liquids		
Production[1]	million Btu per barrel	3.674
Natural gas[1]		
Production, dry	Btu per cubic foot	1,024
Consumption	Btu per cubic foot	1,024
End-use sectors	Btu per cubic foot	1,025
Electric power sector	Btu per cubic foot	1,022
Imports	Btu per cubic foot	1,025
Exports	Btu per cubic foot	1,009
Electricity consumption	Btu per kilowatthour	3,412

[1]Conversion factor varies from year to year. The value shown is for 2010.
Btu = British thermal unit.
Sources: U.S. Energy Information Administration (EIA), *Annual Energy Review 2010*, DOE/EIA-0384(2010) (Washington, DC, October 2011), and EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

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http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html
Last updated on Wednesday, October 17, 2012

Clean Energy

Air Emissions

Various Energy Resources

- Air Emissions
- Water Resource Use
- Water Discharges
- Solid Waste Generation
- Land Resource Use

Electricity generation is the dominant industrial source of air emissions in the United States today. Fossil fuel-fired power plants are responsible for 67 percent of the nation's sulfur dioxide emissions, 23 percent of nitrogen oxide emissions, and 40 percent of man-made carbon dioxide emissions. These emissions can lead to smog, acid rain, and haze. In addition, these power plant emissions increase the risk of climate change. Congress is currently considering proposals to require further reductions of emissions from power plants, including the President's Clear Skies Initiative. However, renewable energy is receiving increased attention by environmental policymakers because renewable energy technologies have significantly lower emissions than traditional power generation technologies. To find out more about the air emissions generated by U.S. power plants, you can use EPA's Emissions and Generated Resource Integrated Database, or eGRID. eGRID provides emissions data on virtually every power plant and company that generates electricity in the United States.

The air emissions impacts of electricity generation vary from technology to technology, as described below.

Natural Gas

At the power plant, the burning of natural gas produces nitrogen oxides and carbon dioxide, but in lower quantities than burning coal or oil. Methane, a primary component of natural gas and a greenhouse gas, can also be emitted into the air when natural gas is not burned completely. Similarly, methane can be emitted as the result of leaks and losses during transportation. Emissions of sulfur dioxide and mercury compounds from burning natural gas are negligible.

The average emissions rates in the United States from natural gas-fired generation are: 1135 lbs/MWh of carbon dioxide, 0.1 lbs/MWh of sulfur dioxide, and 1.7 lbs/MWh of nitrogen oxides.[1] Compared to the average air emissions from coal-fired generation, natural gas produces half as much carbon dioxide, less than a third as much nitrogen oxides, and one percent as much sulfur oxides at the power plant. In addition, the process of extraction, treatment, and transport of the natural gas to the power plant generates additional emissions.[2]

Coal

When coal is burned, carbon dioxide, sulfur dioxide, nitrogen oxides, and mercury compounds are released. For that reason, coal-fired boilers are required to have control devices to reduce the amount of emissions that are released.

The average emission rates in the United States from coal-fired generation are: 2,249 lbs/MWh of carbon dioxide, 13 lbs/MWh of sulfur dioxide, and 6 lbs/MWh of nitrogen oxides.[3]

Mining, cleaning, and transporting coal to the power plant generate additional emissions. For example, methane, a potent greenhouse gas that is trapped in the coal, is often vented during these processes to increase safety.

Oil

Burning oil at power plants produces nitrogen oxides, sulfur dioxide, carbon dioxide, methane, and mercury compounds. The amount of sulfur dioxide and mercury compounds can vary greatly depending on the sulfur and mercury content of the oil that is burned.

The average emissions rates in the United States from oil-fired generation are: 1672 lbs/MWh of carbon dioxide, 12 lbs/MWh of sulfur dioxide, and 4 lbs/MWh of nitrogen oxides.[4]

In addition, oil wells and oil collection equipment are a source of emissions of methane, a potent greenhouse gas. The large engines that are used in the oil drilling, production, and transportation processes burn natural gas or diesel that also produce emissions.

Nuclear Energy

Nuclear power plants do not emit carbon dioxide, sulfur dioxide, or nitrogen oxides. However, fossil fuel emissions are associated with the uranium mining and uranium enrichment process as well as the transport of the uranium fuel to the nuclear plant.

Municipal Solid Waste

Although municipal solid waste (MSW) includes renewable resources, its use as a source of energy has been met with controversy. Despite recent toughening of emission standards for MSW combustion, the process creates significant emissions, including trace amounts of hazardous air pollutants.

Burning MSW produces nitrogen oxides and sulfur dioxide as well as trace amounts of toxic pollutants, such as mercury compounds and dioxins. Although MSW power plants do emit carbon dioxide, the primary greenhouse gas, the biomass-derived portion is considered to be part of the Earth's natural carbon cycle. The plants and trees that make up the paper, food, and other biogenic waste remove carbon dioxide from the air while they are growing, which is returned to the air when this material is burned. In contrast, when fossil fuels are burned, they release carbon dioxide that has not been part of the Earth's atmosphere for a very long time (i.e., within a human time scale).

The average air emission rates in the United States from municipal solid waste-fired generation are: 2988 lbs/MWh of carbon dioxide, (it is estimated that the fossil fuel-derived portion of carbon dioxide emissions represent approximately one-third of the total carbon dioxide emissions) 0.8 lbs/MWh of sulfur dioxide, and 5.4 lbs/MWh of nitrogen oxides.[5]

The variation in the composition of MSW raises concerns. For example, if MSW containing batteries and tires are burned, toxic materials are released into the air. A variety of air pollution control technologies are used to reduce most toxic air pollutants from MSW power plants.

If MSW were to be incinerated anyway, little or no environmental impact would be attributable to using the resulting heat to generate electricity. However, there are alternatives to incineration, such as recycling waste, storing waste in landfills, and source reduction.

Hydroelectricity

Hydropower's air emissions are negligible because no fuels are burned. However, if a large amount of vegetation is growing along the riverbed when a dam is built, it can decay in the lake that is created, causing the buildup and release of methane, a potent greenhouse gas.

Non-Hydroelectric Renewable Energy

Solar

Emissions associated with generating electricity from solar technologies are negligible because no fuels are combusted.

Geothermal

Emissions associated with generating electricity from geothermal technologies are negligible because no fuels are combusted.

Biomass

Biomass power plants emit nitrogen oxides and a small amount of sulfur dioxide. The amounts emitted depend on the type of biomass that is burned and the type of generator used. Although the burning of biomass also produces carbon dioxide, the primary greenhouse gas, it is considered to be part of the natural carbon cycle of the earth. The plants take up carbon dioxide from the air while they are growing and then return it to the air when they are burned, thereby causing no net increase. Biomass contains much less sulfur and nitrogen than coal;[6] therefore, when biomass is co-fired with coal, sulfur dioxide and nitrogen oxides emissions are lower than when coal is burned alone.[7] When the role of renewable biomass in the carbon cycle is considered, the carbon dioxide emissions that result from co-firing biomass with coal are lower than those from burning coal alone.[8]

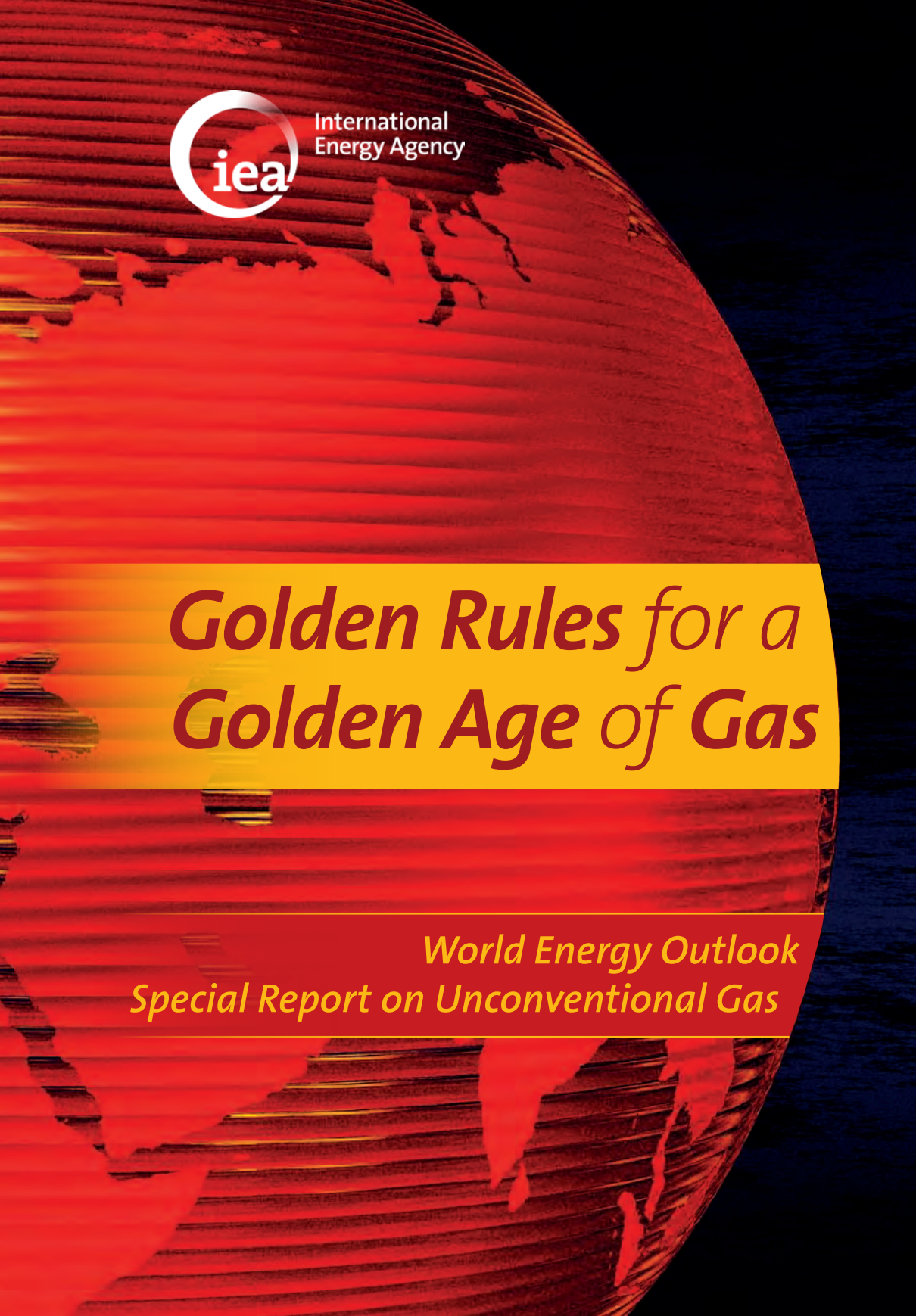
Landfill Gas

Burning landfill gas produces nitrogen oxides emissions as well as trace amounts of toxic materials. The amount of these emissions can vary widely, depending on the waste from which the landfill gas was created. The carbon dioxide released from burning landfill gas is considered to be a part of the natural carbon cycle of the earth. Producing electricity from landfill gas avoids the need to use non-renewable resources to produce the same amount of electricity. In addition, burning landfill gas prevents the release of methane, a potent greenhouse gas, into the atmosphere.

Wind

Emissions associated with generating electricity from wind technology are negligible because no fuels are combusted.

1. U.S. EPA, eGRID 2000.
2. Ibid.
3. Ibid.
4. Ibid.
5. U.S. EPA, Compilation of Air Pollutant Emission Factors (AP-42).
6. U.S. Department of Energy, Energy Efficiency and Renewable Energy Clearinghouse, Biomass Cofiring: A Renewable Alternative for Utilities. June 2000. DOE/GO-102000-1055.
7. Ibid.
8. Ibid.


International
Energy Agency
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Golden Rules for a
Golden Age of Gas
World Energy Outlook
Special Report on Unconventional Gas

Golden Rules for a Golden Age of Gas

World Energy Outlook Special Report on Unconventional Gas

Natural gas is poised to enter a golden age, but this future hinges critically on the successful development of the world's vast unconventional gas resources. North American experience shows unconventional gas – notably shale gas – can be exploited economically. Many countries are lining up to emulate this success.

But some governments are hesitant, or even actively opposed. They are responding to public concerns that production might involve unacceptable environmental and social damage.

This report, in the *World Energy Outlook* series, treats these aspirations and anxieties with equal seriousness. It features two new cases: a Golden Rules Case, in which the highest practicable standards are adopted, gaining industry a "social licence to operate"; and its counterpart, in which the tide turns against unconventional gas as constraints prove too difficult to overcome.

The report:

- Describes the unconventional gas resource and what is involved in exploiting it.
- Identifies the key environmental and social risks and how they can be addressed.
- Suggests the Golden Rules necessary to realise the economic and energy security benefits while meeting public concerns.
- Spells out the implications of compliance with these rules for governments and industry, including on development costs.
- Assesses the impact of the two cases on global gas trade patterns and pricing, energy security and climate change.

For more information, and the free download of this report, please visit: ***www.worldenergyoutlook.org***

WEO-2012 to be released 12 November 2012

International
Energy Agency

Golden Rules for a Golden Age of Gas

World Energy Outlook
Special Report on Unconventional Gas

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

IEA member countries:

Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea (Republic of)
Luxembourg
Netherlands
New Zealand
Norway
Poland
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Slovak Republic
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United States

The European Commission also participates in the work of the IEA.

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Robert Priddle carried editorial responsibility.

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Kamel Bennaceur	Schlumberger
Roberto Bocca	World Economic Forum
Clay Bretches	National Petroleum Council, United States
John Broderick	University of Manchester
Mark Brownstein	Environmental Defense Fund, United States
Carey Bylin	Environmental Protection Agency, United States
Robert Cekuta	Department of State, United States
Xavier Chen	BP, China
Armond Cohen	Clean Air Task Force, United States
John Corben	Schlumberger
Bruno Courme	Total
Randall Cox	Queensland Water Commission, Australia

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John Foran	Natural Resources Canada
Mario Gabriel	Ministry of Energy, Mexico
David Goldwyn	Goldwyn Global Strategies
Sila Guiance	Department of Energy and Climate Change, United Kingdom
John Hanger	Eckert Seamans Cherin & Mellott
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Cal Hill	Energy Resources Conservation Board, Canada
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Idelso Piazza	Petrobras
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Natural gas is poised to enter a golden age, but will do so only if a significant proportion of the world's vast resources of unconventional gas – shale gas, tight gas and coalbed methane – can be developed profitably and in an environmentally acceptable manner. Advances in upstream technology have led to a surge in the production of unconventional gas in North America in recent years, holding out the prospect of further increases in production there and the emergence of a large-scale unconventional gas industry in other parts of the world, where sizeable resources are known to exist. The boost that this would give to gas supply would bring a number of benefits in the form of greater energy diversity and more secure supply in those countries that rely on imports to meet their gas needs, as well as global benefits in the form of reduced energy costs.

Yet a bright future for unconventional gas is far from assured: numerous hurdles need to be overcome, not least the social and environmental concerns associated with its extraction. Producing unconventional gas is an intensive industrial process, generally imposing a larger environmental footprint than conventional gas development. More wells are often needed and techniques such as hydraulic fracturing are usually required to boost the flow of gas from the well. The scale of development can have major implications for local communities, land use and water resources. Serious hazards, including the potential for air pollution and for contamination of surface and groundwater, must be successfully addressed. Greenhouse-gas emissions must be minimised both at the point of production and throughout the entire natural gas supply chain. Improperly addressed, these concerns threaten to curb, if not halt, the development of unconventional resources.

The technologies and know-how exist for unconventional gas to be produced in a way that satisfactorily meets these challenges, but a continuous drive from governments and industry to improve performance is required if public confidence is to be maintained or earned. The industry needs to commit to apply the highest practicable environmental and social standards at all stages of the development process. Governments need to devise appropriate regulatory regimes, based on sound science and high-quality data, with sufficient compliance staff and guaranteed public access to information. Although there is a range of other factors that will affect the development of unconventional gas resources, varying between different countries, our judgement is that there is a critical link between the way that governments and industry respond to these social and environmental challenges and the prospects for unconventional gas production.

We have developed a set of "Golden Rules", suggesting principles that can allow policy-makers, regulators, operators and others to address these environmental and social impacts.[1] We have called them Golden Rules because their application can bring a level of environmental performance and public acceptance that can maintain or earn the industry a "social licence to operate" within a given jurisdiction, paving the way for the widespread development of unconventional gas resources on a large scale, boosting overall gas supply and making the golden age of gas a reality.

The Golden Rules underline that full transparency, measuring and monitoring of environmental impacts and engagement with local communities are critical to addressing public concerns. Careful choice of drilling sites can reduce the above-ground impacts and most effectively target the productive areas, while minimising any risk of earthquakes or of fluids passing between geological strata. Leaks from wells into aquifers can be prevented by high standards of well design, construction and integrity testing. Rigorous assessment and monitoring of water requirements (for shale and tight gas), of the quality of produced water (for coalbed methane) and of waste water for all types of unconventional gas can ensure informed and stringent decisions about water handling and disposal. Production-related emissions of local pollutants and greenhouse-gas emissions can be reduced by investments to eliminate venting and flaring during the well-completion phase.

We estimate that applying the Golden Rules could increase the overall financial cost of development a typical shale-gas well by an estimated 7%. However, for a larger development project with multiple wells, additional investment in measures to mitigate environmental impacts may be offset by lower operating costs.

In our Golden Rules Case, we assume that the conditions are in place, including approaches to unconventional gas development consistent with the Golden Rules, to allow for a continued global expansion of gas supply from unconventional resources, with far-reaching consequences for global energy markets. Greater availability of gas has a strong moderating impact on gas prices and, as a result, global gas demand rises by more than 50% between 2010 and 2035. The increase in demand for gas is equal to the growth coming from coal, oil and nuclear combined, and ahead of the growth in renewables. The share of gas in the global energy mix reaches 25% in 2035, overtaking coal to become the second-largest primary energy source after oil.

1. Consultations with a range of stakeholders when developing these Golden Rules included a high-level workshop held in Warsaw on 7 March 2012, which was organised by the IEA, hosted by the Polish Ministry of Economy and co-hosted by the Mexican Ministry of Energy. In addition to the input received during this workshop, we have drawn upon the extensive work in this area undertaken by many governments, non-governmental and academic organisations, and industry associations.

Production of unconventional gas, primarily shale gas, more than triples in the Golden Rules Case to 1.6 trillion cubic metres in 2035. This accounts for nearly two-thirds of incremental gas supply over the period to 2035, and the share of unconventional gas in total gas output rises from 14% today to 32% in 2035. Most of the increase comes after 2020, reflecting the time needed for new producing countries to establish a commercial industry. The largest producers of unconventional gas over the projection period are the United States, which moves ahead of Russia as the largest global natural gas producer, and China, whose large unconventional resource base allows for very rapid growth in unconventional production starting towards 2020. There are also large increases in Australia, India, Canada and Indonesia. Unconventional gas production in the European Union, led by Poland, is sufficient after 2020 to offset continued decline in conventional output.

Global investment in unconventional production constitutes 40% of the $6.9 trillion (in year-2010 dollars) required for cumulative upstream gas investment in the Golden Rules Case. Countries that were net importers of gas in 2010 (including the United States) account for more than three-quarters of total unconventional upstream investment, gaining the wider economic benefits associated with improved energy trade balances and lower energy prices. The investment reflects the high number of wells required: output at the levels anticipated in the Golden Rules Case would require more than one million new unconventional gas wells worldwide between now and 2035, twice the total number of gas wells currently producing in the United States.

The Golden Rules Case sees gas supply from a more diverse mix of sources of gas in most markets, suggesting growing confidence in the adequacy, reliability and affordability of natural gas. The developments having most impact on global gas markets and security are the increasing levels of unconventional gas production in China and the United States, the former because of the way that it slows the growth in Chinese import needs and the latter because it allows for gas exports from North America. These developments in tandem increase the volume of gas, particularly liquefied natural gas (LNG), looking for markets in the period after 2020, which stimulates the development of more liquid and competitive international markets. The share of Russia and countries in the Middle East in international gas trade declines in the Golden Rules Case from around 45% in 2010 to 35% in 2035, although their gas exports increase by 20% over the same period.

In a Low Unconventional Case, we assume that – primarily because of a lack of public acceptance – only a small share of the unconventional gas resource base is accessible for development. As a result, unconventional gas production in aggregate rises only slightly above current levels by 2035. The competitive position of gas in the global fuel mix deteriorates as a result of lower availability and higher prices, and the share of gas in global energy use increases only slightly, from 21% in 2010 to 22% in 2035, remaining well behind that of coal. The volume of inter-regional trade is higher than in the Golden Rules Case and some patterns of trade are reversed, with North America requiring significant quantities of imported LNG. The Low Unconventional Case reinforces the preeminent position in global supply of the main conventional gas resource-holders.

Energy-related CO_2 emissions are 1.3% higher in the Low Unconventional Case than in the Golden Rules Case. Although the forces driving the Low Unconventional Case are led by environmental concerns, this offsets any claim that a reduction in unconventional gas output brings net environmental gains. Nonetheless, greater reliance on natural gas alone cannot realise the international goal of limiting the long-term increase in the global mean temperature to two degrees Celsius above pre-industrial levels. Achieving this climate target will require a much more substantial shift in global energy use. Anchoring unconventional gas development in a broader energy policy framework that embraces greater improvements in energy efficiency, more concerted efforts to deploy low-carbon energy sources and broad application of new low-carbon technologies, including carbon capture and storage, would help to allay the fear that investment in unconventional gas comes at their expense.

Measure, disclose and engage

- Integrate engagement with local communities, residents and other stakeholders into each phase of a development starting prior to exploration; provide sufficient opportunity for comment on plans, operations and performance; listen to concerns and respond appropriately and promptly.
- Establish baselines for key environmental indicators, such as groundwater quality, prior to commencing activity, with continued monitoring during operations.
- Measure and disclose operational data on water use, on the volumes and characteristics of waste water and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.
- Minimise disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.

Watch where you drill

- Choose well sites so as to minimise impacts on the local community, heritage, existing land use, individual livelihoods and ecology.
- Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.
- Monitor to ensure that hydraulic fractures do not extend beyond the gas-producing formations.

Isolate wells and prevent leaks

- Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.
- Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.
- Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste fluids and solids are disposed of properly.

Treat water responsibly

- Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.
- Store and dispose of produced and waste water safely.
- Minimise use of chemical additives and promote the development and use of more environmentally benign alternatives.

Eliminate venting, minimise flaring and other emissions

- Target zero venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse-gas emissions during the entire productive life of a well.
- Minimise air pollution from vehicles, drilling rig engines, pump engines and compressors.

Be ready to think big

- Seek opportunities for realising the economies of scale and co-ordinated development of local infrastructure that can reduce environmental impacts.
- Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.

Ensure a consistently high level of environmental performance

- Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate levels, sufficient permitting and compliance staff, and reliable public information.
- Find an appropriate balance in policy-making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.
- Ensure that emergency response plans are robust and match the scale of risk.
- Pursue continuous improvement of regulations and operating practices.
- Recognise the case for independent evaluation and verification of environmental performance.

Technology is opening up possibilities for unconventional gas to play a major role in the future global energy mix, a development that would ease concerns about the reliability, affordability and security of energy supply. In North America, production of unconventional gas – notably shale gas – has risen rapidly in recent years and is expected to dominate growth in overall US natural gas production in the coming years and decades. Naturally, there is keen interest in replicating this success in other parts of the world, where sizeable resources of unconventional gas are known to exist. This could give a major boost to gas supply worldwide and help take us into a "Golden Age of Gas" – the subject of a special *WEO* report released last year (IEA, 2011) (Box).

Box ▷ Linking the Golden Rules to a "Golden Age of Gas"

The IEA released an analysis in June 2011 whose title asked the question "Are We Entering a Golden Age of Gas?" (IEA, 2011). How does this report link back to that analysis?

The Golden Age of Gas Scenario (GAS Scenario) in 2011 built a positive outlook for the future role of natural gas on four main pillars: more ambitious assumptions about gas use in China; greater use of natural gas in transportation; an assumption of slower growth in global nuclear power capacity; and a more optimistic outlook for gas supply – primarily though the availability of additional unconventional gas supplies at relatively low cost. In the GAS Scenario, as a result, natural gas increased its role in the future global energy mix from 21% to 25% over the period to 2035.

However, the question mark in the title of this publication was not accidental. It reflected continued uncertainties over the future of natural gas, in particular those connected with the potential for growth in unconventional gas supply. The present analysis zooms in on the environmental impacts of unconventional gas supply, how they are being, and might be, addressed and what the consequences might be. It should therefore be understood as a more detailed examination of a key pre-condition for a golden age of gas.

A range of factors will affect the pace of development of this relatively new industry over the coming decades. In our judgement, a key constraint is that unconventional gas does not yet enjoy, in most places, the degree of societal acceptance that it will require in order to flourish. Without a general, sustained and successful effort from both governments and operators to address the environmental and social concerns that have arisen, it may be impossible to convince the public that, despite the undoubted potential benefits, the impact and risks of unconventional gas development are acceptably small. The IEA offers this special report as a contribution to the solution of this dilemma. The objective is to suggest what might be required to enable the industry to maintain or earn a "social licence to operate".

In Chapter 1 of this special report, we analyse the specific characteristics of each type of unconventional gas development and their environmental and social impacts, examining the technologies and their associated risks, why they have raised public anxiety and why and how they require special attention from policy-makers, regulators and industry. This chapter develops a set of "Golden Rules", the application of which would reduce the impact of unconventional gas developments on land and water use, on the risk of water contamination, and on methane and other air emissions. It also analyses the implications of compliance with the Golden Rules for governments and for industry.

In Chapter 2, we set out the results of two sets of projections of future energy demand, supply and energy-related CO_2 emissions, which explore the potential impact of unconventional gas resources on energy markets. The first of these, to which the main part of this chapter is devoted, is a *Golden Rules Case*, which assumes that the conditions are put in place to allow for a continued expansion of gas supply from unconventional gas resources, including the effective application of the Golden Rules. This situation allows unconventional output to expand not only in North America but also in other countries around the world with major resources. A *Low Unconventional Case*, examined at the end of this chapter, considers the opposite turn of events, in which Golden Rules are not observed, opposition to unconventional gas hardens and the constraints prove too difficult to overcome.

Chapter 3 takes a closer look at unconventional gas in four key regions and countries: North America (United States, Canada and Mexico), China, Europe and Australia. The prospect of increased unconventional gas production is prompting many countries to review their regulatory frameworks to accommodate (or, in some cases, to restrict) the development of these resources. This chapter provides an overview of the main debates and challenges around unconventional production in the selected countries and regions, presented together with our projections for future output.

Addressing environmental risks

Why do we need "Golden Rules"?

Highlights

- Unconventional gas resources are trapped in very tight or low permeability rock and the effort required to extract them is greater than for conventional resources. This means higher intensity of drilling, entailing more industrial activity and disruption above ground. Producing gas from unconventional formations in many cases involves the use of hydraulic fracturing to boost the flow of gas from the well.
- The environmental and social hazards related to these and other features of unconventional gas development have generated keen public anxiety in many places. Means are available to address these concerns. "Golden Rules", as developed here, provide principles that can guide policy-makers, regulators, operators and other stakeholders on how best to reconcile their interests.
- Critical elements are: full transparency, measuring, monitoring and controlling environmental impacts; and early and sustained engagement. Careful choice of drilling sites can reduce the above-ground impacts and most effectively target the productive areas, while minimising any risk of earthquakes or of fluids passing between geological strata.
- Sound management of water resources is at the heart of the Golden Rules. Alongside robust rules on well design, construction, cementing and integrity testing to prevent leaks from the well into aquifers, this requires rigorous assessment, monitoring and handling of water requirements (for shale and tight gas), of the quality of produced water (for coalbed methane) and of waste water (in all cases).
- Unconventional gas has higher production-related greenhouse-gas emissions than conventional gas, but the difference can be reduced and emissions of other pollutants lowered by eliminating venting and minimising flaring during the well completion phase. Releases of methane, wherever they occur in the gas supply chain, are particularly damaging, given its potency as a greenhouse gas.
- The potential environmental impacts and the scale of unconventional gas development make it essential for policy-makers to ensure that effective and balanced regulation is in place, based on sound science and high-quality data, and that adequate resources are available for enforcement.
- Operators have to perform to the highest standards in order to win and retain the "social licence to operate". Application of the Golden Rules does affect costs, with an estimated 7% increase for a typical individual shale gas well. However, when considered across a complete licensing area, additional investment in measures to mitigate environmental impact can be offset in many cases by lower operating costs.

The environmental impact of unconventional gas production

Although known about for decades, the importance of global unconventional gas resources and their full extent has only recently been appreciated. Allowing for the uncertainties in the data, stemming, in part, from difficulties in distinguishing and categorising different types of gas (Box 1.1), we estimate that the remaining technically recoverable resources of unconventional gas worldwide approach the size of remaining conventional resources (which are 420 trillion cubic metres [tcm]). Remaining technically recoverable resources of shale gas are estimated to amount to 208 tcm, tight gas to 76 tcm and coalbed methane to 47 tcm. The economic and political significance of these unconventional resources lies not just in their size but also in their wide geographical distribution, which is in marked contrast to the concentration of conventional resources.[1] Availability of gas from a diverse range of sources would underpin confidence in gas as a secure and reliable source of energy.

Box 1.1 ▷ Unconventional gas resources

Unconventional gas refers to a part of the gas resource base that has traditionally been considered difficult or costly to produce. In this report, we focus on the three main categories of unconventional gas:

- **Shale gas** is natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to flow through the rock than is the case with a conventional reservoir. These formations are often rich in organic matter and, unlike most hydrocarbon reservoirs, are typically the original source of the gas, *i.e.* shale gas is gas that has remained trapped in, or close to, its source rock.
- **Coalbed methane**, also known as coal seam gas in Australia, is natural gas contained in coalbeds. Although extraction of coalbed methane was initially undertaken to make mines safer, it is now typically produced from non-mineable coal seams.
- **Tight gas**[2] is a general term for natural gas found in low permeability formations. Generally, we classify as tight gas those low permeability gas reservoirs that cannot produce economically without the use of technologies to stimulate flow of the gas towards the well, such as hydraulic fracturing.

Although the development cycle for unconventional gas and the technologies used in its production have much in common with those used in other parts of the upstream industry, unconventional gas developments do have some distinctive features and requirements, particularly in relation to the perceived higher risk of environmental damage and adverse

1. The extent and distribution of recoverable resources of unconventional gas is discussed in more detail in Chapter 2.

2. Tight gas is often a poorly defined category with no clear boundary between tight and conventional, nor between tight gas and shale gas.

social impacts. This helps to explain why the issue of unconventional gas exploitation has generated so much controversy.

This chapter addresses these issues by examining in some depth what is involved in exploiting each category of unconventional gas and the associated hazards. It then proposes a set of principles, the "Golden Rules", applicable to future operations in this sector. The objective is to define the conditions which might enable the industry to gain or retain a "social licence to operate". The consequences for the energy sector of securing such an outcome are discussed in Chapters 2 and 3, together with the possible consequences of failing to do so.

The main reason for the potentially larger environmental impact of unconventional gas operations is the nature of the resources themselves: unconventional resources are less concentrated than conventional deposits and do not give themselves up easily. They are difficult to extract because they are trapped in very tight or low permeability rock that impedes their flow. Since the resources are more diffuse and difficult to produce, the scale of the industrial operation required for a given volume of unconventional output is much larger than for conventional production. This means that drilling and production activities can be considerably more invasive, involving a generally larger environmental footprint.

One feature of the greater scale of operations required to extract unconventional gas is the need for more wells. Whereas onshore conventional fields might require less than one well per ten square kilometres, unconventional fields might need more than one well per square kilometre (km^2), significantly intensifying the impact of drilling and completion activities on the environment and local residents.[3] A satellite image from Johnson County in Texas, United States illustrates this point, showing the density of well sites producing from the Barnett shale (Figure 1.1). This image highlights 37 well sites in an area of around 20 km^2, with each well site potentially having more than one well. Another important factor is the need for more complex and intensive preparation for production. While hydraulic fracturing is already used on occasions to stimulate conventional reservoirs, tight gas and shale gas developments almost always require the use of this technique in order to generate adequate flow rates into the well. The same technique is also often used, albeit less frequently, to produce coalbed methane. The associated use and release of water gives rise to a number of environmental concerns, including depletion of freshwater resources and possible contamination of surface water and aquifers.

3. It should be noted that conventional gas fields in mature areas, such as onshore United States or Canada, often have well densities (number of wells per unit area) comparable to those of unconventional gas. However, burgeoning unconventional gas production today tends to replace production that would have come from offshore locations or countries rich in conventional gas, such as Russia or Qatar, in which the well densities are much smaller.

Figure 1.1 ▷ Drilling intensity in Johnson County, Texas

Source: © 2012 Google, DigitalGlobe, GeoEye, Texas Orthoimagery Program, USDA Farm, Farm Service Agency source. Google Maps, http://g.co/maps/j9xws, with well sites highlighted.

The production of unconventional gas also contributes to the atmospheric concentration of greenhouse gases and affects local air quality. In some circumstances, unconventional gas production can result in higher airborne emissions of methane, a potent greenhouse gas, of volatile organic compounds (VOCs) that contribute to smog formation, and of carbon dioxide (CO_2) (from greater use of energy in the production process, compared with conventional production). Just how much greater these risks may be is uncertain: it depends critically on the way operations are carried out. On the other hand, there are potential net benefits from unconventional gas production, to the extent that, having been produced and transported to exacting environmental standards, it leads to greater use of gas instead of more carbon-intensive coal and oil.

In addition to the smaller recoverable hydrocarbon content per unit of land, unconventional developments tend to extend across much larger geographic areas. The Marcellus Shale in the United States covers more than 250 000 km^2, which is about ten times larger than the Hugoton Natural Gas Area in Kansas – the country's largest conventional gas producing zone. Moreover, areas with high unconventional potential are not always those with a strong or recent tradition of oil and gas industry activity; they are not necessarily rich in conventional hydrocarbons and in some cases there may have been little or no recent

hydrocarbon production (and none expected). This tends to exacerbate the problem of public acceptance.

Shale and tight gas developments

Characteristics of the resource

By contrast to conventional gas reservoirs, shale gas reservoirs (Box 1.2) have very low permeability due to the fine-grained nature of the original sediments (gas does not flow easily out of the rock), fairly low porosities (relatively few spaces for the gas to be stored, generally less than 10% of the total volume), and low recovery rates (because the gas can be trapped in disconnected spaces within the rock or stuck to its surface). The last two factors (low porosity and low recovery) are responsible for the fact that the volume of recoverable hydrocarbons per square kilometre of area at the surface is usually an order of magnitude smaller than for conventional gas. Low permeability is responsible for shale gas requiring specific technologies, such as hydraulic fracturing, to achieve commercial flow rates.

Tight gas reservoirs originate in the same way as conventional gas reservoirs: the rock into which the gas migrates after being expelled from the source rock just happens to be of very low permeability. As a result, tight gas reservoirs also require special techniques to achieve commercial flow rates. On the other hand, they tend to have better recovery factors than shale gas deposits and, therefore, higher density of recoverable hydrocarbons per unit of surface area.

Box 1.2 ▷ What are shales and shale gas?

Shales are geological rock formations rich in clays, typically derived from fine sediments, deposited in fairly quiet environments at the bottom of seas or lakes, having then been buried over the course of millions of years. When a significant amount of organic matter has been deposited with the sediments, the shale rock can contain organic solid material called kerogen. If the rock has been heated up to sufficient temperatures during its burial history, part of the kerogen will have been transformed into oil or gas (or a mixture of both), depending on the temperature conditions in the rock. This transformation typically increases pressure within the rock, resulting in part of the oil and gas being expelled from the shale and migrating upwards into other rock formations, where it forms conventional oil and gas reservoirs. The shales are the source rock for the oil and gas found in such conventional reservoirs. Some, or occasionally all, of the oil and gas formed in the shale can remain trapped there, thus forming shale gas or light tight oil reservoirs.[4]

4. Terminology in this area remains to be standardised (see Box 1.1). Previous WEOs have classified light tight oil from shales as conventional oil. Note that the term light tight oil is preferred to that of shale oil, as the latter can bring confusion with oil shales, which are kerogen-rich shales that can be mined and heated to produce oil (IEA, 2010; IEA, 2011a).

Shales are ubiquitous in sedimentary basins: they typically form about 80% of what a well will drill through. As a result, the main organic-rich shales have already been identified in most regions of the world. Their depths vary from near surface to several thousand metres underground, while their thickness varies from just a few metres to several hundred.[5] Often, enough is known about the geological history to infer which shales are likely to contain gas (or oil, or a mixture of both). In that sense there is no real "exploration" required for shale gas. However, the amount of gas present and particularly the amount of gas that can be recovered technically and economically cannot be known until a number of wells have been drilled and tested. Each shale formation has different geological characteristics that affect the way gas can be produced, the technologies needed and the economics of production.[6] Different parts of the (generally large) shale deposits will also have different characteristics: small "sweet spots" or "core areas" may provide much better production than the rest of the play, often because of the presence of natural fractures that enhance permeability. The amount of natural gas liquids (NGLs) present in the gas can also vary considerably, with important implications for the economics of production. While most dry gas plays in the United States are probably uneconomic at the current low natural gas prices, plays with significant liquid content can be produced for the value of the liquids only (the market value of NGLs is correlated with oil prices, rather than gas prices), making gas an essentially free by-product.

Well construction[7]

The drilling phase is the most visible and disruptive in any oil and gas development – particularly so in the case of shale gas or tight gas because of the larger number of wells required. On land, a drilling rig, associated equipment and pits to store drilling fluids and waste typically occupy an area of 100 metres by 100 metres (the well site). Setting up drilling in a new location might involve between 100 and 200 truck movements to deliver all the equipment, while further truck movements will be required to deliver supplies during drilling and completion of the well.

Each well site needs to be chosen taking account not only of the subsurface geology, but also of a range of other concerns, including proximity to populated areas and existing infrastructure, the local ecology, water availability and disposal options, and seasonal restrictions related to climate or wildlife concerns. In North America, there has recently

5. Thin shales are generally considered as not exploitable. Depth can cut both ways: shallower shales require shallower, *i.e.* cheaper, wells, but deeper shales have higher pressures, which increases the areal density of recoverable gas (which is measured at surface conditions, while the gas in the shale is compressed by the formation pressure).

6. For example, horizontal wells with multi-stage hydraulic fracturing have been pivotal to the economic success of shale gas in the United States, while in Argentina, YPF has recently reported successful tests with vertical wells with only three or four hydraulic fractures (YPF, 2012).

7. The construction of a well to access unconventional gas deposits is divided into two phases: the drilling phase, where the hole is drilled to its target depth in sections that are secured with metal casing and cement; and the completion phase, where the cemented casing across the reservoir is perforated and the reservoir stimulated (generally by hydraulic fracturing) in order to start the production of hydrocarbons.

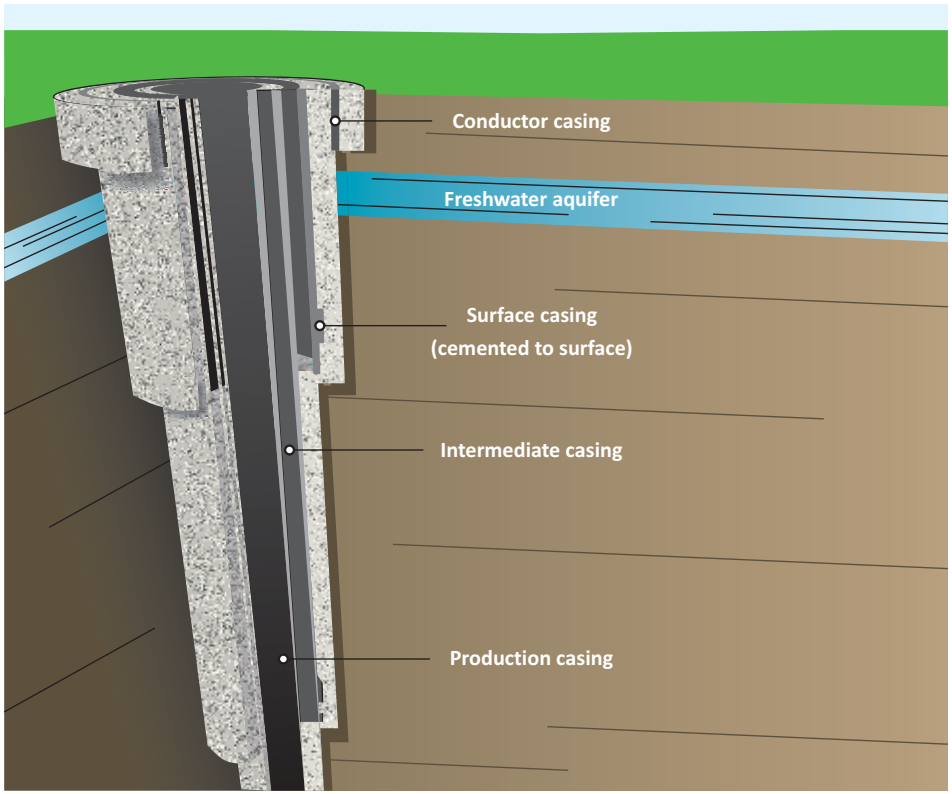
been a move towards drilling multiple wells from a single site, or pad, in order to limit the amount of disruption and thereby the overall environmental impact of well construction.[8] In 2011, according to industry sources, around 30% of all new shale and tight gas wells in the United States and Canada were multiple wells drilled from pads.

Once drilling starts, it is generally a 24-hour-per-day operation, creating noise and fumes from diesel generators, requiring lights at night and creating a regular stream of truck movements during mobilisation/demobilisation periods. Drilling operations can take anything from just a few days to several months, depending on the depth of the well and type of rock encountered. As the drill bit bores through the rock, drilling fluid known as "mud" is circulated through the wellbore in order, among other tasks, to control pressure in the well and remove cuttings created by the drill bit from the well. This lubricating "mud" consists of a base fluid, such as water or oil, mixed with salts and solid particles to increase its density and a variety of chemical additives. Mud is stored either in mobile containers or in open pits which are dug into the ground and lined with impermeable material. The volume of material in the pits needs to be monitored and contained to prevent leaks or spills. A drilling rig might have several hundred tonnes of mud in use at any one time, which creates a large demand for supplies. Once used, the mud must be either recycled or disposed of safely. Rock cuttings recovered from the mud during the drilling process amount to between 100 and 500 tonnes per well, depending on the depth. These, too, need to be disposed of in an environmentally acceptable fashion.

A combination of steel casing and cement in the well (Figure 1.2) provides an essential barrier to ensure that high-pressure gas or liquids from deeper down cannot escape into shallower rock formations or water aquifers. This barrier has to be designed to withstand the cycles of stress it will endure during the subsequent hydraulic fracturing, without suffering any cracks. The design aspects that are most important to ensure a leak-free well include the drilling of the well bore to specification (without additional twists, turns or cavities), the positioning of the casing in the centre of the well bore before it is cemented in place (this is done with centralisers placed at regular intervals along the casing as it is run in the hole, to keep it away from the rock face) and the correct choice of cement. The cement design needs to be studied both for its liquid properties during pumping (to ensure that it gets to the right place) and then for its mechanical strength and flexibility, so that it remains intact. The setting time of the cement is also a critical factor – cement that takes too long to set may have reduced strength; equally, cement that sets before it has been fully pumped into place requires difficult remedial action.

8. Pad drilling has long been used in northern areas, such as Alaska and in Russia, but the introduction of this practice to places such as Texas is relatively new.

Figure 1.2 ▷ Typical well design and cementing



Source: Adapted from ConocoPhillips.

Well completion

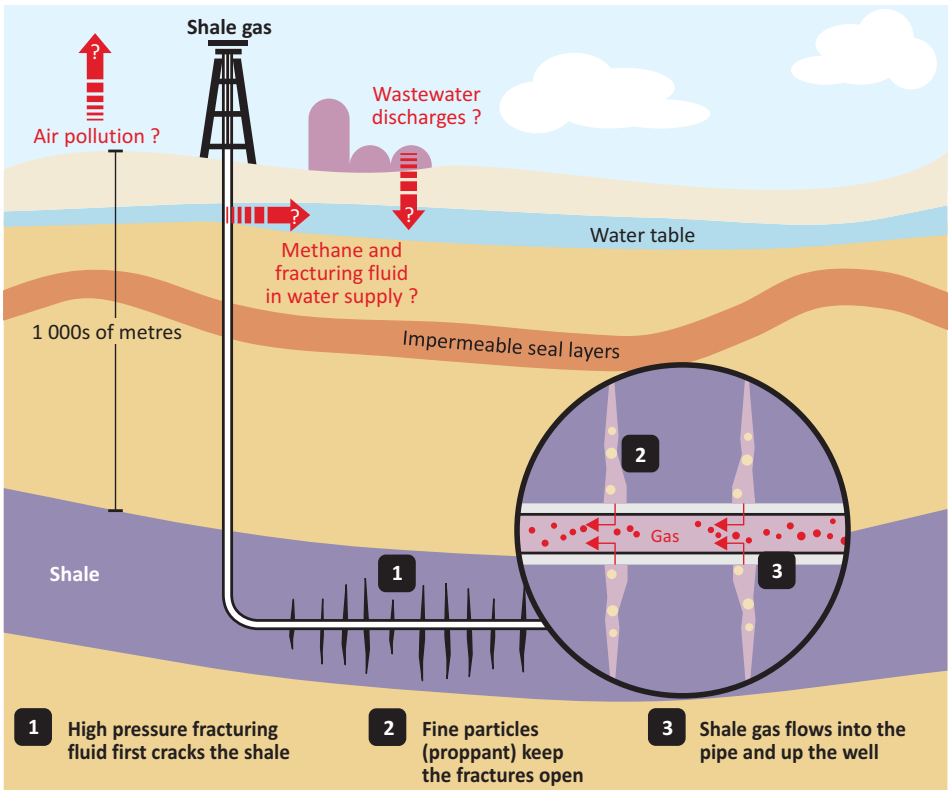
Once the well has been drilled, the final casing cemented in place across the gas-bearing rock has to be perforated in order to establish communication between the rock and the well.[9] The pressure in the well is then lowered so that hydrocarbons can flow from the rock to the well, driven by the pressure differential. With shale and tight gas, the flow will be very low, because of the low permeability of the rock. As the rate of hydrocarbon flow determines directly the cash flow from the well, low flow rates can mean there is insufficient revenue to pay for operating expenses and provide a return on the capital invested. Without additional measures to accelerate the flow of hydrocarbons to the well, the operation is then not economic.

Several technologies have been developed over the years to enhance the flow from low permeability reservoirs. Acid treatment, involving the injection of small amounts of strong acids into the reservoir to dissolve some of the rock minerals and enhance the permeability

9. Some wells are completed "open-hole", in which there is no casing in the final part of the well in the gas-bearing rock; this is not uncommon in horizontal wells.

of the rock near the wellbore, is probably the oldest and is still widely practised, particularly in carbonate reservoirs. Wells with long horizontal or lateral sections (known as horizontal wells) can increase dramatically the contact area between the reservoir rock and the wellbore, and are likewise effective in improving project economics. Hydraulic fracturing, developed initially in the late 1940s, is another effective and commonly-practised technology for low-permeability reservoirs. When rock permeability is extremely low, as in the case of shale gas or light tight oil, it often takes the combination of horizontal wells and hydraulic fracturing to achieve commercial rates of production (Figure 1.3). Advances in the application of these two techniques, in combination, largely explain the surge in shale gas production in the United States since 2005.

Figure 1.3 ▷ Shale gas production techniques and possible environmental hazards



Source: Adapted from Aldhous (2012).

Note: The possible environmental hazards discussed in the text are shown with red arrows. Although the figure illustrates a shale gas well with multi-stage hydraulic fracturing, some similar hazards are present with conventional gas wells, and with tight gas developments.

Hydraulic fracturing involves pumping a fluid – known as fracturing fluid – at high pressure into the well and then, far below the surface, into the surrounding target rock. This creates

fractures or fissures a few millimetres wide in the rock. These fissures can extend tens or, in some cases, even hundreds of metres away from the well bore. Once the pressure is released, these fractures would tend to close again and not produce any lasting improvement in the flow of hydrocarbons. To keep the fractures open, small particles, such as sand or ceramic beads, are added to the pumped fluid to fill the fractures and to act as proppants, *i.e.* they prop open the fractures thus allowing the gas to escape into the well.

Box 1.3 ▷ Unconventional gas production and earthquake risks

There have been instances of earthquakes associated with unconventional gas production, for example the case of the Cuadrilla shale gas operations near Blackpool in the United Kingdom, or a case near Youngstown, Ohio, in the United States, which has been provisionally linked to injection of waste water, an operation that is similar in some respects to hydraulic fracturing. The registered earthquakes were small, of a magnitude of around two on the Richter scale, meaning they were discernible by humans but did not create any surface damage.

Because it creates cracks in rocks deep beneath the surface, hydraulic fracturing always generates small seismic events; these are actually used by petroleum engineers to monitor the process. In general, such events are several orders of magnitude too small to be detected at the surface: special observation wells and very sensitive instruments need to be used to monitor the process. Larger seismic events can be generated when the well or the fractures happen to intersect, and reactivate, an existing fault. This appears to be what happened in the Cuadrilla case.

Hydraulic fracturing is not the only anthropogenic process that can trigger small earthquakes. Any activity that creates underground stresses carries such a risk. Examples linked to construction of large buildings, or dams, have been reported. Geothermal wells in which cold water is circulated underground have been known to create enough thermally-induced stresses to generate earthquakes that can be sensed by humans (Cuenot, 2011). The same applies to deep mining (Redmayne, 1998). What is essential for unconventional gas development is to survey carefully the geology of the area to assess whether deep faults or other geological features present an enhanced risk and to avoid such areas for fracturing. In any case, monitoring is necessary so that operations can be suspended if there are signs of increased seismic activity.[10]

In many cases, a series of fractures is created at set intervals, one after the other, about every 100 metres along the horizontal well bore. This multi-stage fracturing technique has played a key role in unlocking production of shale gas and light tight oil in the United States and promises to do likewise elsewhere in the world. A standard single-stage hydraulic fracturing may pump down several hundred cubic metres of water together with proppant and a mixture of various chemical additives. In shale gas wells, a multi-stage fracturing

10. Detailed recommendations, following analysis of the Cuadrilla event, are under consideration by the United Kingdom Department of Energy and Climate Change (DECC, 2012).

would commonly involve between ten and twenty stages, multiplying the volumes of water and solids by 10 or 20, and hence the total values for water use might reach from a few thousand to up to twenty thousand cubic metres of water per well and volumes of proppant of the order of 1 000 to 4 000 tonnes per well. The repeated stresses on the well from multiple high-pressure procedures increase the premium on good well design and construction to ensure that gas bearing formations are completely isolated from other strata penetrated by the well.

Once the hydraulic fracturing has been completed, some of the fluid injected during the process flows back up the well as part of the produced stream, though typically not all of it – some remains trapped in the treated rock. During this flow-back period, typically over days (for a single-stage fracturing) to weeks (for a multi-stage fracturing), the amount of flow back of fracturing fluid decreases, while the hydrocarbon content of the produced stream increases, until the flow from the well is primarily hydrocarbons.

Best practice during this period is to use a so-called "green completion" or "reduced-emissions completion", whereby the hydrocarbons are separated from the fracturing fluid (and then sold) and the residual flow-back fluid is collected for processing and recycling or disposal. However, while collecting and processing the fluid is standard practice, capturing and selling the gas during this initial flow-back phase requires investment in gas separation and processing facilities, which does not always take place. In these cases, there can be venting of gas to the atmosphere (mostly methane, with a small fraction of VOCs) or flaring (burning) of hydrocarbon or hydrocarbon/water mixtures. Venting and/or flaring of the gas at this stage are the main reasons why shale and tight gas can give rise to higher greenhouse-gas emissions than conventional production (see the later section on methane and other airborne emissions).

Production

Once wells are connected to processing facilities, the main production phase can begin. During production, wells will produce hydrocarbons and waste streams, which have to be managed. But the well site itself is now less visible: a "Christmas tree" of valves, typically one metre high, is left on top of the well, with production being piped to processing facilities that usually serve several wells; the rest of the well site can be reclaimed. In some cases, the operator may decide to repeat the hydraulic fracturing procedure at later times in the life of the producing well, a procedure called re-fracturing. This was more frequent in vertical wells but is currently relatively rare in horizontal wells, occurring in less than 10% of the horizontal shale-gas wells drilled in the United States.

The production phase is the longest phase of the lifecycle. For a conventional well, production might last 30 years or more. For an unconventional development, the productive life of a well is expected to be similar, but shale gas wells typically exhibit a burst of initial production and then a steep decline, followed by a long period of relatively low production. Output typically declines by between 50% and 75% in the first year of production, and most recoverable gas is usually extracted after just a few years (IEA, 2009).

Well abandonment

At the end of their economic life, wells need to be safely abandoned, facilities dismantled and land returned to its natural state or put to new appropriate productive use. Long-term prevention of leaks to aquifers or to the surface is particularly important. Since much of the abandonment will not take place until production has ceased, the regulatory framework needs to ensure that the companies concerned make the necessary financial provisions and maintain technical capacity beyond the field's economic life to ensure that abandonment is completed satisfactorily, and well integrity maintained over the long term.

Coalbed methane developments

Coalbed methane refers to methane (natural gas) held within the solid matrix of coal seams. Some of the methane is stored within the coal as a result of a process called adsorption, whereby a film of methane is created on the surface of the pores inside the coal. Open fractures in the coal may also contain free gas or water. In some cases, methane is present in large volumes in coalbeds and can constitute a serious safety hazard for coal-mining operations. Significant volumes of CO_2 may also be present in the coal.

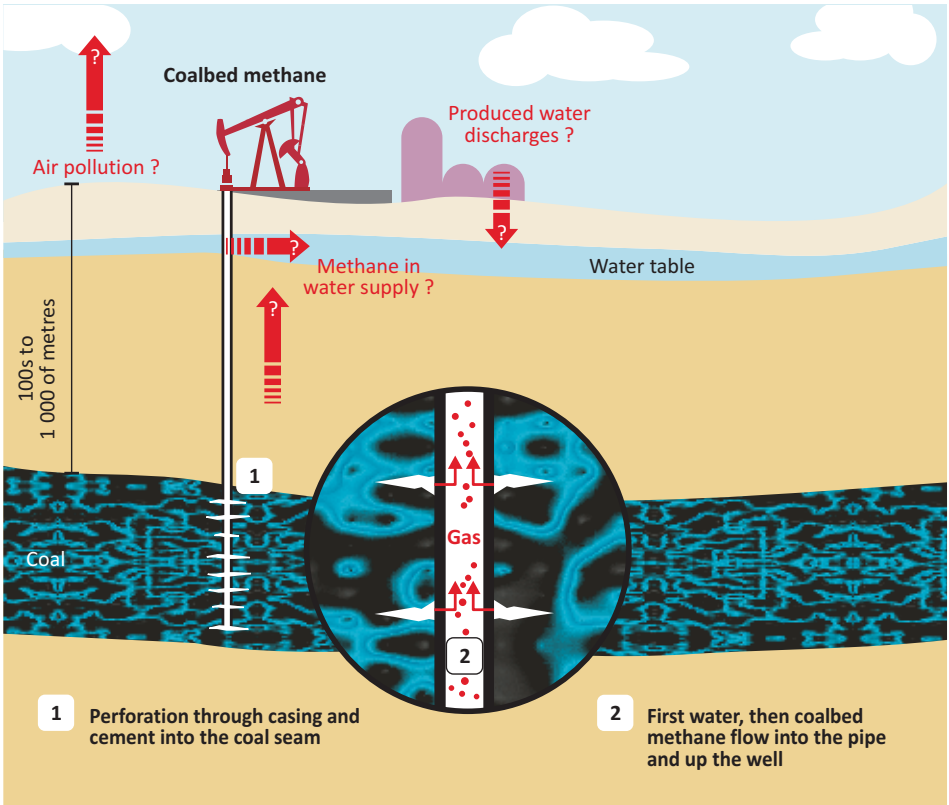
There are both similarities and differences between coalbed methane and the two other main types of unconventional gas discussed, which are linked to the way in which coalbed methane is extracted, the associated costs and the impact on the environment. The main similarity is the low permeability of the gas-bearing reservoir – a critical factor for the technical and economic viability of extraction. Virtually all the permeability of a coalbed is due to fractures, in the form of cleats and joints. These fractures tend to occur naturally so that, within a small part of the seam, methane is able to flow through the coalbed. As with shale and tight gas deposits, there are major variations in the concentration of gas from one area to another within the coal seams. This, together with variations in the thickness of the seam, has a significant impact on potential production rates.

Above ground, coalbed methane production involves disruption to the landscape and local environment through the construction of drilling pads and access roads, and the installation of on-site production equipment, gas processing and transportation facilities. As is often the case with shale gas and tight gas, coalbed methane developments require the drilling of more wells than conventional oil and gas production; as a result, traffic and vehicle noise levels, noise from compressors, air pollution and the potential damage to local ecological systems are generally more of an issue than for conventional gas output.

There are some important differences between coalbed methane and shale or tight gas resources. Coalbed methane deposits can be located at shallow depths (these are predominantly the deposits that have been exploited thus far), whereas shale and tight gas are usually found further below the surface. Water is often present in the coalbed, which needs to be removed to allow the gas to flow to the well. In addition, coalbed methane contains very few heavier liquid hydrocarbons (natural gas liquids or gas condensate), which means the commercial viability of production depends heavily on the price at which

the gas itself can be sold; in the case of shale gas produced together with large volumes of associated natural gas liquids, the price of oil plays a very important role in determining the overall profitability of the development project.

Figure 1.4 ▷ Coalbed methane production techniques and possible environmental hazards



Source: Adapted from Aldhous (2012).

Note: The possible environmental hazards discussed in the text are shown with red arrows.

Considerable progress has been made over the last 25 years in honing techniques to extract coalbed methane on a commercial basis, paving the way to production on a significant scale, initially in North America and, since the mid-1990s, in Australia. Coalbed methane can be produced from vertical or horizontal wells. The latter are becoming increasingly common, though less so than for shale gas. Generally, the thinner the coal seam and the greater the depth of the deposit, the more likely it is that a horizontal well will be drilled. Although a depth of 800 to 1 200 metres is typical, in some cases coalbed methane is located in shallow formations as little as 100 metres below the surface, making it more economical to drill a series of vertical wells, rather than a horizontal well with extended reach along the coal seam. For shallow deposits, wells can often be drilled using

water-well drilling equipment, rather than rigs designed for conventional hydrocarbon extraction, with commensurately cheaper costs (US EPA, 2010). For deeper formations (400 to 1 200 metres), both vertical and horizontal wells are used and custom-built small drilling rigs, capable of handling blow-out risks, have been developed.

Once a well is drilled, the water in the coalbed is extracted, either under natural pressure or by using mechanical pumping equipment – a process known as dewatering (water use and contamination risks are discussed in more detail in the next section). As subsurface pressure drops with dewatering, the flow of natural gas previously held in place by water pressure increases initially as it is released from the natural fractures or cleats within the coalbed. The gas is separated from the water at the surface and is then compressed and injected into a gas-gathering pipeline for onward transportation.

As in the case of shale gas, the rate of production of coalbed methane is often significantly lower than that achieved in conventional gas reservoirs; it also tends to reach a peak quickly as water is extracted, before entering a period of decline as the well pressure drops further. A well's typical lifespan is between five and fifteen years, with maximum gas production often achieved after one to six months of water removal (Horsley & Witten, 2001). In most cases, the low natural permeability of the coal seam means that gas can flow into the well from only a small segment of the coal seam – a characteristic shared with shale and tight gas. As a result, a relatively large number of wells is required over the area of the coalbed, especially if they are drilled vertically.

In some cases, it may also be necessary to use hydraulic fracturing to increase the permeability of the coal seam in order to stimulate the release of water and gas. This is normally practised only in deeper wells, typically at several hundred metres below the ground. The decision to proceed with hydraulic fracturing needs to be made before drilling begins, as the well and surface facilities need to be designed accordingly. The approach is similar to that described above, but in contrast to current practice with shale gas and tight gas wells, fracturing for coalbed methane production is frequently a single-stage process, *i.e.* one fracturing job per well, rather than multi-stage. Since wells are often drilled in batches, the water required for hydraulic fracturing can be sourced from neighbouring wells that are being de-watered. The flow-back fluids recovered from the well are pumped to lined containment pits or tanks for treatment or offsite disposal.

Water use

The extent of water use and the risk of water contamination are key issues for any unconventional gas development and have generated considerable public concern. In the case of a shale gas or tight gas development, though some water is required during the drilling phase, the largest volumes of water are used during the hydraulic fracturing process: each well might need anything between a few thousand and 20 000 cubic metres (between 1 million and 5 million gallons). Efficient use of water during fracturing is essential. Average water use per well completion in the Eagle Ford play in west Texas has

been reduced from 18.5 to 13.6 thousand cubic metres since mid-2010, primarily through increased recycling of waste water from flow-back of fracturing fluid, an important step forward, given that more than 2 800 drilling permits were issued by the Railroad Commission of Texas for Eagle Ford wells in 2011 (RCT, 2012).[11] The amount of water required for shale gas or tight gas developments, calculated per unit of energy produced, is higher than for conventional gas but comparable to the amount used for the production of conventional oil (Table 1.1).

Table 1.1 ▷ Ranges of water use per unit of natural gas and oil produced (cubic metres per terajoule)

	Water consumption	
	Production	Refining
Natural gas		
Conventional gas	0.001 - 0.01	
Conventional gas with fracture stimulation	0.005 - 0.05	
Tight gas	0.1 - 1	
Shale gas	2 - 100	
Oil		
Conventional oil*	0.01 - 50	5 - 15
Conventional oil with fracture stimulation*	0.05 - 50	5 - 15
Light tight oil	5 - 100	5 - 15

Source: IEA analysis.

* The high end of this range is for secondary recovery with water flood; the low end is primary recovery.

Note: Coalbed methane is not included in this table as it tends to produce water, rather than require it for production (but see below for the discussion of waste water disposal).

Water for fracturing can come from surface water sources (such as rivers, lakes or the sea), or from local boreholes (which may draw from shallow or deep aquifers and which may already have been drilled to support production operations), or from further afield (which generally requires trucking). Transportation of water from its source and to disposal locations can be a large-scale activity. If the hydraulic fracturing of a well requires 15 000 cubic metres, this amounts to 500 truck-loads of water, on the basis that a typical truck can hold around 30 cubic metres of water. Such transportation congests local roads, increases wear and tear to roads and bridges and, if not managed safely, can increase road accidents.

In areas of water-scarcity, the extraction of water for drilling and hydraulic fracturing (or even the production of water, in the case of coalbed methane) can have broad and serious environmental effects. It can lower the water table, affect biodiversity and harm the local

11. If these 2 800 wells each require 13.6 thousand cubic metres for well completion, the water requirement of 38 million cubic metres represents 0.2% of annual water consumption of the state of Texas, or 12% of the annual water consumption of the city of Dallas, Texas.

ecosystem. It can also reduce the availability of water for use by local communities and in other productive activities, such as agriculture.

Limited availability of water for hydraulic fracturing could become a significant constraint on the development of tight gas and shale gas in some water-stressed areas. In China, for example, the Tarim Basin in the Xinjiang Uyghur Autonomous Region holds some of the country's largest shale gas deposits, but also suffers from severe water scarcity. Although not on the same scale, in terms of either resource endowment or water stress, a number of other prospective deposits occur in regions that are already experiencing intense competition for water resources. The development of China's shale gas industry has to date focused on the Sichuan basin, in part because water is much more abundant in this region.

Hydraulic fracturing dominates the freshwater requirements for unconventional gas wells and the dominant choice of fracturing fluid for shale gas, "slick-water", which is often available at the lowest cost and in some shale reservoirs may also bring some gas-production benefits, is actually the most demanding in terms of water needs. Much attention has accordingly been given to approaches which might reduce the amount of water used in fracturing. Total pumped volumes (and therefore water volumes required) can be decreased through the use of more traditional, high viscosity, fracturing fluids (using polymers or surfactants), but these require a complex cocktail of chemicals to be added. Foamed fluids, in which water is foamed with nitrogen or CO_2, with the help of surfactants (as used in dish washing liquids), can be attractive, as 90% of the fluid can be gas and this fluid has very good proppant-carrying properties. Water can, indeed, be eliminated altogether by using hydrocarbon-based fracturing fluids, such as propane or gelled hydrocarbons, but their flammability makes them more difficult to handle safely at the well site. The percentage of fracturing fluid that gets back-produced during the flow-back phase varies with the type of fluid used (and the shale characteristics), so the optimum choice of fluid will depend on many factors: the availability of water, whether water recycling is included in the project, the properties of the shale reservoir being tapped, the desire to reduce the usage of chemicals and the economics.

Treatment and disposal of waste water

Waste water from hydraulic fracturing

The treatment and disposal of waste water are critical issues for unconventional gas production – especially in the case of the large amounts of water customarily used for hydraulic fracturing. After being injected into the well, part of the fracturing fluid (which is often almost entirely water) is returned as flow-back in the days and weeks that follow. The total amount of fluid returned depends on the geology; for shale it can run from 20% to 50% of the input, the rest remaining bound to the clays in the shale rock. Flow-back water contains some of the chemicals used in the hydraulic fracturing process, together with metals, minerals and hydrocarbons leached from the reservoir rock. High levels of salinity are quite common and, in some reservoirs, the leached minerals can be weakly radioactive,

requiring specific precautions at the surface.[12] Flow-back returns (like waste water from drilling) requires secure storage on site, preferably fully contained in stable, weather-proof storage facilities as they do pose a potential threat to the local environment unless handled properly (see next section).

Once separated out, there are different options available for dealing with waste water from hydraulic fracturing. The optimal solution is to recycle it for future use and technologies are available to do this, although they do not always provide water ready for re-use for hydraulic fracturing on a cost-effective basis. A second option is to treat waste water at local industrial waste facilities capable of extracting the water and bringing it to a sufficient standard to enable it to be either discharged into local rivers or used in agriculture. Alternatively, where suitable geology exists, waste water can be injected into deep rock layers.

Box 1.4 ▷ What is in a fracturing fluid?

Environmental concerns have focused on the fluid used for hydraulic fracturing and the risk of water contamination through leaks of this fluid into groundwater. Water itself, together with sand or ceramic beads (the "proppant"), makes up over 99% of a typical fracturing fluid, but a mixture of chemical additives is also used to give the fluid the properties that are needed for fracturing. These properties vary according to the type of formation. Additives (not all of which would be used in all fracturing fluids) typically help to accomplish four tasks:

- To keep the proppant suspended in the fluid by gelifying the fluid while it is being pumped into the well and to ensure that the proppant ends up in the fractures being created. Without this effect, the heavier proppant particles would tend to be distributed unevenly in the fluid under the influence of gravity and would, therefore, be less effective. Gelling polymers, such as guar or cellulose (similar to those used in food and cosmetics) are used at a concentration of about 1%. Cross-linking agents, such as borates or metallic salts, are also commonly used at very low concentration to form a stronger gel. They can be toxic at high concentrations, though they are often found at low natural concentrations in mineral water.
- To change the properties of the fluid over time. Characteristics that are needed to deliver the proppant deep into subsurface cracks are not desirable at other stages in the process, so there are additives that give time-dependent properties to the fluid, for example, to make the fluid less viscous after fracturing, so that the hydrocarbons flow more easily along the fractures to the well. Typically, small concentrations of chelants (such as those used to de-scale kettles) are used, as are small concentrations of oxidants or enzymes (used in a range of industrial processes) to break down the gelling polymer at the end of the process.

12. These naturally occurring radioactive materials, or NORMs, are not specific to unconventional resources; some conventional reservoirs are also known to produce them.

- To reduce friction and therefore reduce the power required to inject the fluid into the well. A typical drag-reducing polymer is polyacrylamide (widely used, for example, as an absorbent in baby diapers).
- To reduce the risk that naturally occurring bacteria in the water affect the performance of the fracturing fluid or proliferate in the reservoir, producing hydrogen sulphide; this is often achieved by using a disinfectant (biocide), similar to those commonly used in hospitals or cleaning supplies.

Until recently, the chemical composition of fracturing fluids was considered a trade secret and was not made public. This position has fallen increasingly out of step with public insistence that the community has the right to know what is being injected into the ground. Since 2010, voluntary disclosure has become the norm in most of the United States.[13] The industry is also looking at ways to achieve the desired results without using potentially harmful chemicals. "Slick-water", made up of water, proppant, simple drag-reducing polymers and biocide, has become increasingly popular as a fracturing fluid in the United States, though it needs to be pumped at high rates and can carry only very fine proppant. Attention is also being focused on reducing accidental surface spills, which most experts regard as a more significant risk of contamination to groundwater.

Produced water from coalbed methane production[14]

In the case of coalbed methane, additional water supplies are rarely required for the production process, but the satisfactory disposal of water that has been extracted from the well during the dewatering process is of critical importance. The produced water is usually either re-injected into isolated underground formations, discharged into existing drainage systems, sent to shallow ponds for evaporation or, once properly treated, used for irrigation or other productive uses. The appropriate disposal option depends on several factors, notably the quality of the water. Depending on the geology of the coal deposit and hydrological conditions, produced water can be very salty and sodic (containing high concentrations of sodium, calcium and magnesium) and can contain trace amounts of organic compounds, so it often requires treatment before it can be used for irrigation or other uses. Using saline water for irrigation can inhibit germination and plant growth, while excessively sodic water can change the physical properties of the soil, leading to poor drainage and crusting and adversely affecting crop yields.

The potential cost of water disposal depends on both the extent to which treatment is required and the volume of water produced. In practice, the total amount of water that must be removed from each well to allow gas to be produced varies considerably. It can be very large; for example, an estimated 65 cubic metres of water (17 000 gallons) are

13. See the voluntary disclosure web site FracFocus (www.fracfocus.org).

14. Both conventional gas and other types of unconventional gas production can also be accompanied by produced water, but the flow rates involved are normally much smaller than for coalbed methane.

pumped from each coalbed methane well every day on average in the Powder River Basin in Montana and Wyoming. For the United States as a whole, it is estimated that, in 2008, more than 180 million cubic metres (47 billion gallons) of produced water were pumped out of coal seams (US EPA, 2010), equivalent to the annual direct water consumption of the city of San Francisco. In principle, produced water can be treated to any desired quality. This may be costly, but the treated water may have economic value for productive uses – as long as the cost of transporting the water is not excessive.

The options for treatment and disposal of produced water and the market value of water in the near vicinity are often key factors in the economics of coalbed methane developments. Many of the areas where coalbed methane is produced today, or where prospects for production are good, are arid or semi-arid and could benefit from additional freshwater supplies. For now, evaporation or discharge into drainage systems (in some cases, after treatment) are still the most common methods in North America (reuse of treated water is growing in Australia) because of the high cost of purifying the water for irrigation or reinjection into a deeper layer. In the United States, approximately 85 million cubic metres (22 billion gallons) of produced water, or about 45% of the total, were discharged to surface waters in 2008 with little or no treatment (US EPA, 2010).

There is limited experience of assessing the actual environmental impacts of produced water from coalbed methane production. A recent study by the US National Research Council found that the eventual disposal or use of produced water can have both positive and negative impacts on soil, ecosystems, and the quality and quantity of surface water and groundwater (NRC, 2010). Although the study found no evidence of widespread negative effects, allowance must be made for the fact that the industry is relatively young and that few detailed investigations into local impacts have been carried out yet.

The risk of water contamination

Significant concern has been expressed about the potential for contamination of water supplies, whether surface supplies, such as rivers or shallow freshwater aquifers, or deeper waters, as a result of all types of unconventional gas production. Water supplies can be contaminated from four main sources:

- Accidental spills of fluids or solids (drilling fluids, fracturing fluids, water and produced water, hydrocarbons and solid waste) at the surface.
- Leakage of fracturing fluids, saline water from deeper zones or hydrocarbons into a shallow aquifer through imperfect sealing of the cement column around the casing.
- Leakage of hydrocarbons or chemicals from the producing zone to shallow aquifers through the rock between the two.
- Discharge of insufficiently treated waste water into groundwater or, even, deep underground.

None of these hazards is specific to unconventional resources; they also exist in conventional developments, with or without hydraulic fracturing. However, as noted, unconventional

developments occur at a scale that inevitably increases the risk of incidents occurring. Public concern has focused on the third source of potential contamination, *i.e.* the possibility that hydrocarbons or chemicals might migrate from the produced zone into aquifers through the intervening rock. However, this may actually be the least significant of the hazards, at least in the case of shale gas and tight gas production; in some cases a focus on this risk may have diverted attention, including the time of regulators, away from other more pressing issues.

Box 1.5 ▷ Coalbed methane production and effects on groundwater

There are concerns about the impact of coalbed methane production on groundwater flows and the supply and purity of water in aquifers adjacent to the coal seams being exploited. The extent to which this can occur is very location specific and depends on several factors, the most important of which are the overall volume of water initially in the coalbed and the hydrogeology of the basin; the density of the coalbed methane wells; the rate of water pumping by the operator; the connectivity of the coalbed and aquifer to surrounding water sources and, therefore, the rate of recharge of the aquifer; and the length of time over which pumping takes place.

In the United States, various agencies now monitor water in producing areas in order to learn more about this process. Depletion of aquifers because of coalbed methane production has been well-documented in the Powder River Basin: in the Montana portion of the basin, 65% to 87% recovery of coalbed groundwater levels has occurred after production ceased (NRC, 2010). However, the extent to which water levels in shallow alluvial and water table aquifers have dropped has not been measured (recent legislation in Queensland in Australia now requires such measurements to be performed). There is evidence that groundwater movement provoked by dewatering during coalbed methane production has increased the amount of dissolved salt and other minerals in some areas.

Because productive coal seams are often at shallower depths than tight or shale gas deposits, there is also a greater risk that fracturing fluids might find their way into an aquifer directly or via a fracture system (either a natural system or one that is created through fracturing). This risk is mitigated in part by the fact that, in contrast to shale or tight gas, the dewatering required for production of coalbed methane means that less water may be left in the ground in aquifers near the vicinity of the well, limiting the potential for contamination. As with shale or tight gas production, the flow-back fluids removed from the well after fracturing need to be treated before disposal.

The first hazard – the risk of spills at the surface – can be mitigated through rigorous containment of all fluid and solid streams. Accidents can always happen but good procedures, training of personnel and availability of spill control equipment can ensure they have a limited impact. As discussed below, greater use of pipelines to move liquids can reduce the risks associated with trucking movements.

Controlling the second hazard – leakage into a shallow aquifer behind the well casing – requires use of best practice in well design and well construction, particularly during the cementing process, to ensure a proper seal is in place, systematic verification of the quality of the seal and ensuring the seal does not deteriorate through the life of a well. This is a particular issue for wells in which multi-stage hydraulic fracturing is performed: the repeated cycles of high pressure pumping can apply repeated stress to the casing and to the cement column, potentially weakening them; selection of an appropriate strength of casing is therefore important.

The third hazard – leakage through the rock from the producing zone – is unlikely in the case of shale gas or tight gas because the producing zone is one to several thousand metres below any relevant aquifers and this thickness of rock usually includes one or several very impermeable layers. For example, the deepest potential underground sources of drinking water in the Barnett shale are at a depth of 350 metres, whereas the shale layer is at 2 000 to 2 300 metres. However, the hazard may be encountered if the producing zone is shallower or if there are shallow pockets of naturally occurring methane above the target reservoir. It is also theoretically possible if there are no identified impermeable layers in between or if deep faults are present that can act as a conduit for fluids to move from the deep producing zone towards the surface (such fluid movements are generally slow, but can occur on time scales of tens of years). One particular possibility is that hydraulic fractures may not be contained in the targeted rock layer and may break through important rock barriers or connect to deep faults. This is a rare occurrence because hydraulic fracturing is designed to avoid this (potentially costly) situation[15], but it cannot be completely excluded when the local geology is insufficiently understood.

Appropriate prior studies of the local geology to identify such situations are therefore a must before undertaking significant developments. Indeed, methane seeps to the surface have long been known (for example, the flame that has been burning for centuries in the village of Mrapen in Central Java, Indonesia, or the gas that fuels the "Eternal Flame Falls" in New York State, United States) and they have been used as a way to identify the presence of hydrocarbon deposits underground, showing that perfect rock seals do not always exist. On the other hand, the existence of seeps, and for that matter the presence of methane in many aquifers (Molofsky, 2011), shows that not all contamination is linked to industrial activity; it can also occur as a result of natural geological or biological processes.

15. This would increase losses of fracturing fluid and could mean in turn that the fracturing does not translate into the desired increase in gas production.

Addressing the fourth hazard – discharge of insufficiently treated waste water into groundwater or, even, deep underground – requires a regulatory response including appropriate tracking and documentation of waste water volumes and composition, how they are transported and disposed.

Methane and other air emissions

Shale gas and tight gas have higher production-related greenhouse-gas emissions than conventional gas. This stems from two effects:

- More wells and more hydraulic fracturing are needed per cubic metre of gas produced. These operations use energy, typically coming from diesel motors, leading to higher CO_2 emissions per unit of useful energy produced.
- More venting or flaring during well completion. The flow-back phase after hydraulic fracturing represents a larger percentage of the total recovery per well (because of more hydraulic fracturing, the flow-back takes longer and the total recovery per well is typically smaller due to the low permeability of the rock).

We have previously released estimates of these effects both in the case of flaring and for venting during flow-back, based on EPA data, in order to see what difference these practices make (IEA, 2011b). In the case of flaring, total well-to-burner emissions are estimated to be 3.5% higher than for conventional gas, but this figure rises to 12% if the gas is vented. Eliminating venting, minimising flaring and recovering and selling the gas produced during flow-back, in line with the Golden Rules, would reduce emissions below the lower figure given here.

Similar concerns about emissions attach to coalbed methane production, where significant volumes of methane can be vented into the atmosphere during the transition phase from dewatering to gas production and, where hydraulic fracturing is applied, during the well completion phase. Careful management of drilling, fracturing and production operations is essential to keep such emissions to a minimum.[16] This requires specialised equipment to separate gas from the produced water (and fracturing fluids) before injecting it into a gas-gathering system (or into temporary storage). If this is not possible for technical, logistical or economic reasons, it is preferable that the gas should be flared rather than vented for safety reasons and because the global-warming effect is considerably less.

The general issue of greenhouse-gas emissions from the production, transportation and use of natural gas, as well as the additional emissions from unconventional gas compared with conventional gas, has been the subject of some controversy. Some authors (Howarth, 2011) have argued that emissions from using natural gas as a source of primary energy have been significantly underestimated, particularly for unconventional gas. It has even been argued that full life-cycle emissions from unconventional gas can be higher than from

16. Coalbed methane production can reduce methane emissions if the gas would in any case have been released by subsequent coal-mining activities.

coal. The main issue revolves around methane emissions not only during production, but also during transportation and use of natural gas.

Methane is a more potent greenhouse gas than CO_2 but has a shorter lifetime in the atmosphere – a half-life of about fifteen years, versus more than 150 years for CO_2. As a result, there are different possible ways to compare the effect of methane and CO_2 on global warming. One way is to evaluate the Global Warming Potential (GWP) of methane, compared to CO_2, averaged over 100 years. The 4th Assessment report of the IPCC (IPCC, 2007) gives a value of 25 (on a mass basis) for this 100-years GWP, revised up from their previous estimate of 21. This value is relevant when looking at the long-term relative benefits of eliminating a temporary source of methane emissions versus a CO_2 source.

Averaged over 20 years, the GWP, estimated by the IPCC, is 72. This figure can be argued to be more relevant to the evaluation of the significance of methane emissions in the next two or three decades, which will be the most critical to determine whether the world can still reach the objective of limiting the long-term increase in average surface temperatures to 2 degrees Celsius (°C). Moreover, some scientists have argued that interactions of methane with aerosols reinforce the GWP of methane, possibly bringing it to 33 over 100 years and 105 over 20 years (Shindell, 2009): these recent analyses are under review by the IPCC. Such higher values would, of course, have implications not only for methane emissions from the gas chain but also for all other methane emissions, from livestock, landfills, rice paddies and other agricultural sources, as well as from natural sources (Spotlight).

Methane emissions along the gas value chain (whether conventional or unconventional) come from four main sources:

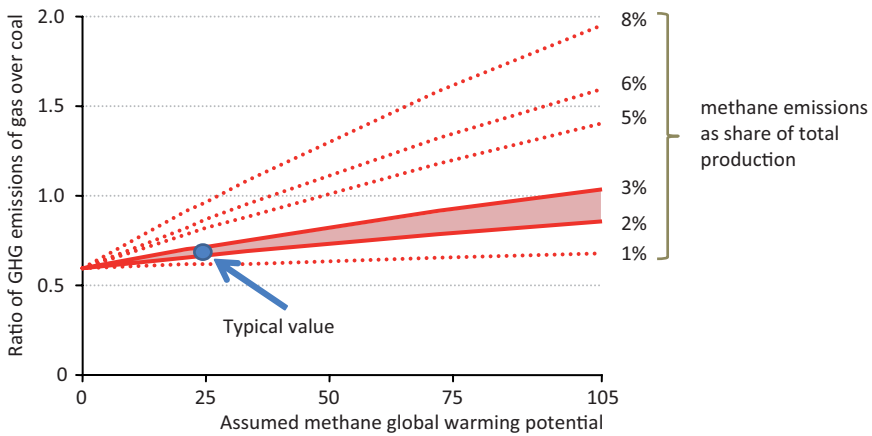
- Intentional venting of gas for safety or economic reasons. Venting during well completions falls into this category, but venting can also take place as part of equipment maintenance operations.
- Fugitive emissions. These might be leaks in pipelines, valves or seals, whether accidental (*e.g*. corrosion in pipelines) or built into the equipment design (*e.g.* rotating seals, open tanks).
- Incidents involving rupture of confining equipment (pipelines, pressurised tanks, well isolation).
- Incomplete burning. The effectiveness of gas burning in gas flares varies according to wind and other conditions and is typically no better than 98%. (A similar effect can be seen when starting a gas stove: it can take a few seconds before a steady flame is established).

By their very nature, these emissions are difficult to quantify. Most estimates are based on emission factors for various parts of the chain (wells, various equipment, pipelines and so on), derived from studies conducted in the United States by the EPA and the Gas Research Institute in the 1990s (US EPA and GRI, 1996). It is by no means clear that these studies give

a good indication for emissions in other parts of the world, or for the possible evolution of methane emissions in the future. Estimates of methane emissions from the gas chain at the global level vary between 1% and 8% of produced natural gas volumes (Howarth, 2011 and references therein; Petron, 2012; Cathles, 2012; Jiang 2011; and Skone 2011). The most comprehensive projections of future emissions, from the EPA (US EPA, 2011), assume no change in emission factors, for want of a better approach, and project a 26% increase in methane emissions from the oil and gas industry between 2010 and 2030.

Different assumptions about the level and impact of methane emissions can have a profound effect on the perception of gas as a "cleaner" fossil fuel. Figure 1.5 shows the well-to-burner emissions of natural gas compared to coal, as a function of various assumptions on GWP and average methane emissions. As seen from this figure, standard values (25 GWP, 2% to 3% methane emissions as a share of total production) substantiate the widely accepted advantage of gas, thanks to its lower combustion CO_2 emissions per unit of energy; but it is clear that more pessimistic assumptions can make gas a worse greenhouse-gas emitter than coal. It is very important that additional scientific work should pinpoint the most relevant GWP value and that efforts are redoubled to measure methane emissions more systematically.[17]

Figure 1.5 ▷ The impact of changing assumptions about methane on comparative well-to-burner greenhouse-gas emissions of natural gas versus coal



Note: Values below 1.0 on the vertical axis show points at which gas has lower well-to-burner emissions than coal. The comparison is for equivalent volumes of primary energy; however, gas also tends to be transformed, into other energy carriers (such as electricity) with higher efficiency than coal, so the ratio can be lower when calculated for the same end-use energy.

17. See, for example, a recent paper included in the Proceedings of the US National Academy of Sciences on methane leakage from natural gas infrastructure (Alvarez *et al.*, 2012)

One advantage attributable to expanded unconventional gas production and use over production and use of conventional gas is the distance to market; in general, unconventional resources are developed closer to the point of consumption, thereby reducing the distance required for transportation. All else being equal, this tends to reduce the level of fugitive emissions, as well as CO_2 emissions from the energy used for transportation.

SPOTLIGHT

How large are global methane emissions?

It is estimated that about 550 million tonnes (Mt) of methane (IPPC, 2007) are released into the atmosphere every year, but data on global methane emissions are poor. Converted into CO_2 equivalent (using the standard IPCC 100-years Global Warming Potential of 25), this amounts to about 14 gigatonnes CO_2-eq, roughly one-fourth of global greenhouse-gas emissions. Natural emissions (not related to man's activities) represent about 40% of total methane emissions. They come from natural seeps, wetlands, animals, such as termites, and vegetation decay. In addition, massive amounts of methane are stored in permafrost in Arctic regions and in underwater methane hydrates deposits. Some of this stored methane is released by natural processes, which are considered likely to accelerate with global warming: there is a risk of natural emissions increasing dramatically over the coming decades.

Non-energy related anthropogenic emissions come mostly from livestock, agriculture, landfills and wastewater. These represent about 38% of total methane emissions (64% of anthropogenic methane emissions). Energy-related methane emissions come from oil, gas and coal production, transportation, distribution and use as well as some biomass combustion: together they are estimated to be 125 Mt per year, about 20% of global methane emissions (36% of anthropogenic methane emissions). The gas and oil industry account for the lion's share of this: 70%, or 90 Mt per year, representing about 15% of total methane emissions (26% of anthropogenic emissions).

If current emissions are poorly known and the numbers above mere estimates, projecting future methane emissions is fraught with even more uncertainties. Natural emissions could be dramatically altered by the evolution of the climate. For anthropogenic emissions, activity levels in the energy and other industries as well as in livestock and agriculture can be projected, based on econometric analysis and assumptions on GDP and population growth, but the evolution of emission factors (volume of methane emitted per unit of activity) is very uncertain.[18] Many mitigation measures are considered to have low or even negative costs: reducing leaks in a gas

18. The IEA model (developed in collaboration with the OECD, using the ENV-linkages OECD model) uses the costs of mitigation measures (as derived from EPA studies; EPA, 2006) and a pseudo-price of carbon (whether coming from taxes, a carbon market or from regulations) to determine the likely evolution of emissions from an economic point of view. EPA has recently released draft updated costs of mitigation (EPA, 2012).

distribution system, for example, can allow more gas to be sold; the gas collected from a landfill can be marketed; changing the feed given to livestock to reduce methane production can allow more of the energy content of the feed to be transformed into marketable meat or milk. On the other hand, because of the very (spatially) distributed nature of most methane emission sources, it is not obvious that economic considerations alone will be sufficient to induce change. To achieve the trajectories of methane emissions consistent with the internationally agreed goal to limit the rise in global mean temperature to 2°C above pre-industrial levels, additional policy measures will be needed.

Golden Rules to address the environmental impacts

The outlook for unconventional gas production around the world depends critically on how the environmental issues described earlier are addressed. Society needs to be adequately convinced that the environmental and social risks will be well enough managed to warrant consent to unconventional gas production, in the interests of the broader economic, social and environmental benefits that the development of unconventional resources can bring. The Golden Rules, which are set out below with some explanatory background, suggest principles that can allow policy-makers, regulators, operators and others to address these environmental and social impacts in order to earn or retain that consent. We have called them Golden Rules because they can pave the way for the widespread and large-scale development of unconventional gas resources, boosting overall natural gas supply so as to realise a Golden Age of Gas (IEA, 2011b).

Abiding by these Golden Rules – or any rules – cannot reduce to zero the impacts on the environment associated with unconventional gas production. In any such undertaking, there are inevitable trade-offs between reducing the risks of environmental damage, on the one hand, and achieving the benefits that can accrue to society from the development of economic resources. In designing an appropriate regulatory framework, policy-makers need to set the highest reasonable social and environmental standards, assessing the cost of any residual risk against the cost of still higher standards (which could include the abandonment of resource exploitation). What is reasonable will evolve over time, as technology and industrial best practice evolve: in this spirit, these are not rigid rules, set in stone, but principles intended to guide regulators and operators. The format of regulation is also critical to achieving the intended result: it may include some specific and inflexible requirements but it should also encourage and reward performance to the highest standards, not supporting the notion that enough has been done if the instructions of others are mechanically observed, however meticulously. Ultimately, operators are responsible for the results of their operations. In framing these Golden Rules, we find that both governments and industry need to intensify their associated work if public confidence in this new industry is to be gained and retained.

Measure, disclose and engage

- ***Integrate engagement with local communities, residents and other stakeholders into each phase of a development, starting prior to exploration; provide sufficient opportunity for comment on plans, operations and performance, listen to concerns and respond appropriately and promptly.*** Simply providing information to the public is not enough; both the industry and the public authorities need to engage with local communities and other stakeholders and seek the informed consent that is often critical for companies to proceed with a development. Operators need to explain openly and honestly their production practices, the environmental, safety, and health risks and how they are addressed. The public needs to gain a clear understanding of the challenges, risks and benefits associated with the development. The primary role of the public authorities in this context is to provide credible, science-based background information that can underpin an informed debate and provide the necessary stimulus for joint endeavour between the stakeholders.
- ***Establish baselines for key environmental indicators, such as groundwater quality, prior to commencing activity, and continue monitoring during operations.*** This is a shared responsibility between the regulatory authorities, industry and other stakeholders. The data gathered needs to be made public and opportunities provided for all stakeholders to address any concerns raised, as an essential part of earning public trust. At a minimum, resource management or regulatory agencies must have groundwater quality information (and, for coalbed methane production, information on groundwater levels) in advance of new drilling activities, so as to provide a baseline against which changes in water level and quality can be compared.
- ***Measure and disclose operational data on water use, on the volumes and characteristics of waste water and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.*** Good data, measurement and transparency are vital to public confidence. For example, effective tracking and documentation of waste water is necessary to incentivise and ensure its proper treatment and disposal. Reluctance to disclose the chemicals used in the hydraulic fracturing process and the volumes involved, though understandable in terms of commercial competition, can quickly breed mistrust among local citizens and environmental groups.
- ***Minimise disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.*** Existing legislation and regulations usually require operators to act in an environmentally and socially responsible manner, but operators need to go beyond minimally satisfying legal requirements in demonstrating their commitment to local development and environmental protection, for example through attention to local concerns about the volume and timing of truck traffic. Particularly in jurisdictions where mineral rights are owned by the state (rather than as in parts of the United States, where surface landowners might also be subsurface mineral rights holders,

entitled to royalty payments), it is essential that tangible benefits are evident at the local level, where production occurs. This can be difficult to achieve in a timely manner, given the delay between the start of a development project and the moment at which revenues start to flow, whether to government, the mineral rights' owner or the operator. Early public commitment by authorities and developers to expand local infrastructure and services in step with exploration and production activities can help. Governments need to be willing to consider using part of the revenues (from taxes, royalties, etc.) to invest in the development of the areas in question.

Watch where you drill

- ***Choose well sites so as to minimise impacts on the local community, heritage, existing land use, individual livelihoods and ecology.*** The choice of well site is a moment when engagement with local stakeholders and regulators needs to be handled with the utmost care. Each well site needs to be chosen based on the subsurface geology, but also taking into consideration populated areas, the natural environment and local ecology, existing infrastructure and access roads, water availability and disposal options and seasonal restrictions caused by climate or wildlife concerns. Sensitivity at this stage to a range of above-ground concerns can do much to mitigate or avoid problems later in a development.
- ***Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.*** Careful planning can greatly improve the productivity and recovery rates of wells, reducing the number of wells that need to be drilled and minimising the intensity of hydraulic fracturing and the associated environmental impact. Although the risk of triggering an earthquake is small, even minor earth tremors can easily undermine public confidence in the safety of drilling operations. A careful study of the geology of the area targeted for drilling is necessary to allow operators to avoid operations in areas where deep faults or other characteristics create higher risks. Producers also need to survey for the presence of old boreholes or naturally occurring methane in shallow pockets above the source rock and adjust drilling sites (or the pathway of the wellbore) to avoid these areas.
- ***Monitor to ensure that hydraulic fractures do not extend beyond the gas-producing formations.*** The risk of leakage of the fracturing fluid used for shale and tight gas production through the rock from the producing zone into aquifers is minimal because the aquifers are located at much shallower depths; but such migration is theoretically possible in certain exceptional circumstances (described in the preceding section). A good understanding of the local geology and the use of micro-seismic (or other) measuring techniques for monitoring fractures is necessary to minimise the residual risk.

Isolate wells and prevent leaks

- ***Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.*** Regulations need to ensure wells are designed, constructed and operated so as to ensure complete isolation. Multiple measures need to be in place to prevent leaks, with an overarching performance standard requiring operators to follow systematically all recommended industry best practices. This applies up to and including the abandonment of the well, *i.e.* through and beyond the lifetime of the development.
- ***Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.*** Alongside measures to ensure that wells are designed, built and cemented to a high standard, the regulator may choose to define an appropriate depth limitation for shale and tight gas wells, based on local geology and any risk of communication with freshwater aquifers, above which hydraulic fracturing is prohibited.
- ***Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste fluids and solids are disposed of properly.*** This requires both stringent regulations and a strong performance commitment by all companies involved in drilling and production-related activities to carry out operations to the highest possible standard. Good procedures, training of personnel and ready availability of spill-control equipment are essential to prevent and limit the impact of accidents if they do occur. Upgrading fluid-disposal systems so that storage and separation tanks replace open pits (closed-loop systems) can reduce the risk of accidental discharge of wastes during drilling.

Treat water responsibly

- ***Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.*** Regulations covering shale and tight gas production (coalbed methane operations are net producers of water) need to be designed to encourage operators to use water efficiently and to reuse and recycle it. The largest volumes of water are required for hydraulic fracturing: where the necessary economies of scale are present, it should be feasible to reuse and recycle significant volumes of the flow-back water from fracturing operations, reducing the issues and costs associated with truck traffic and with securing water supplies and wastewater disposal.
- ***Store and dispose of produced and waste water safely.*** Within an overarching performance framework, rigorous and consistent regulations are needed to cover safe storage of waste water, with measures to ensure the robust construction and lining of open pits or, preferably, the use of storage tanks. Technology exists to treat produced and waste water to any standard, with the cost varying accordingly. It is

the responsibility of regulators to set and enforce appropriate standards based on local factors, including the availability of freshwater supplies and options for disposal, without diminishing the operators' ultimate responsibility for operation in accordance with evolving best practice standards. The least-cost solution for producers may not be the most economically optimal solution, when the potential long-term benefits of using treated water and the wider social and environmental costs of discharges into water courses or evaporation ponds are taken into consideration.

- ***Minimise use of chemical additives and promote the development and use of more environmentally benign alternatives.*** Disclosure of fracturing fluid additives can and should be compatible with continued incentives for innovation. The industry should commit to the development of fluid mixtures that, if they inadvertently migrate or spill, do not impair groundwater quality, or adopt techniques that reduce the need to use chemical additives.

Eliminate venting, minimise flaring and other emissions

- ***Target zero venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse-gas emissions during the entire productive life of a well.*** Best practice is to recover and market gas produced during the completion phase of a well, and public authorities need to consider imposing restrictions on venting and flaring and specific requirements for installing equipment to help minimise emissions. Measures in this area will also lower emissions of conventional pollutants, including VOCs. Operators should consider setting targets on emissions as part of their overall strategic policies to win public confidence that they are acting to minimise the environmental impact of their activities, taking into account the financial benefits of commercialising the gas that would otherwise be vented or flared. The gas industry as a whole, including conventional gas producers and companies operating in the midstream and downstream, needs to demonstrate that they are just as concerned by methane emissions beyond the production stage, for example in transportation and distribution.
- ***Minimise air pollution from vehicles, drilling rig engines, pump engines and compressors.*** Pollution from vehicles and equipment is often controlled by existing environmental and fuel-efficiency standards (it is a responsibility of governments to ensure that appropriate standards are in place). Operators and service providers should consider the advantages of deploying the cleanest vehicles and equipment available, for example, electric vehicles and gas-powered rig engines, to reduce both local air and noise pollution.

Be ready to think big

- ***Seek opportunities for realising the economies of scale and co-ordinated development of local infrastructure that can reduce environmental impacts.*** Investments in infrastructure to reduce environmental impacts that may be commercially impossible to justify for an individual well can be justified for a larger development. Good regulation can help to realise these gains by ensuring appropriate spatial planning of licensing areas and of the associated infrastructure (such as access roads, water resources and disposal facilities, gas processing units, compression stations and pipelines). The concept of utility corridors and multi-use rights of way can be useful to concentrate infrastructure development and so limit the wider environmental impacts. Operators can realise these gains in various ways, for example by drilling multiple wells from a single pad (with horizontal bores tapping different parts of the reservoirs): this may result in greater disruption in the immediate vicinity of the site but can significantly reduce the wider environmental footprint. Another example is the construction of a pipeline network for water that requires upfront investment but obviates the need for many thousands of truck movements over the duration of a project and can lower unit costs.[19] Good project and logistical planning by operators needs to go hand-in-hand with early strategic assessments and timely interventions by public authorities.
- ***Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.*** Development of any hydrocarbon resource involves a large amount of activity to build the necessary infrastructure, bring in supplies, drill wells, extract the resource, process it and transport it to market. This activity is enhanced for unconventional developments, because of the larger number of wells required. As a result, the level of activity that might be tolerable for individual wells, such as volumes of road traffic, land and water use or noise from drilling activity, can increase by orders of magnitude. Regulators need to assess the cumulative impact of these effects and respond appropriately. Assessment on a regional basis is particularly important in the case of water requirements.

19. See the next sub-section for an assessment of the impact of such infrastructure developments on project costs; this is also covered in a recent paper on water management economics for shale gas developments (Robart, 2012).

Ensure a consistently high level of environmental performance

- ***Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate level, sufficient permitting and compliance staff, and reliable public information.*** An important focus for governments should be on ensuring there is a sufficient knowledge base on all environmental and technical aspects of unconventional gas development, that high-quality data are available and that sound science is being applied and promoted. Well-funded, suitably skilled and motivated regulators, in sufficient numbers, are essential to the responsible development of an unconventional resource.
- ***Find an appropriate balance in policy-making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.*** In some areas, detailed rules and checks are indispensable to guarantee environmental performance; but it is not always possible, or desirable, to regulate every aspect of a process in which technology is moving rapidly. Setting performance criteria and allowing operators to find the best way to meet them can often provide a better outcome than a prescriptive approach. Examples of performance criteria might be a mandated minimum level of improvement in water usage or a requirement that a "best-in-class" cement quality measurement is run, the burden being on the operator to prove the use of best-in-class. Whichever approach or combination of methods is chosen, there needs to be strict enforcement and penalties in the case of non-compliance, ultimately including loss of the licence to operate.
- ***Ensure that emergency response plans are robust and match the scale of risk.*** Operators and local emergency services should have robust plans and procedures in place to respond quickly and effectively to any accident, including appropriate training and equipment.
- ***Pursue continuous improvement of regulations and operating practices.*** Technology and best practice are constantly evolving. While respecting the advantages of clarity and stability in regulation, governments must be ready to incorporate lessons learned from experience in a dynamic industrial sector. For industry, following best practice means constant readiness to raise standards and providing the means to meet them.
- ***Recognise the case for independent evaluation and verification of environmental performance***. Credible, third-party certification of industry performance can provide a powerful tool to earn and maintain public acceptance, as well as providing a powerful tool to assist companies to adhere to best practices. These independent assessments should come from institutions that enjoy public trust, whether academic or research institutes or independent regulatory or certification bodies.

Complying with the Golden Rules

Application of these Golden Rules requires action to be taken by both governments and industry. While the ultimate responsibility for sustaining public confidence rests with the industry, it is governments that that need to set the regulatory framework, promulgate the required principles and provide support through many related activities, *e.g.* scientific research. Trying to specify precisely the roles of governments, gas producers and other private sector operators in each area is not practicable on a global scale. Conditions vary from country to country, including the legal, geological, social and political background, farming/land-use practices, water availability and many others.[20] But the general principles are clear and, in the sections that follow which examine the implications of the Golden Rules for governments and for industry, we have included some observations on the allocation of responsibilities between the public authorities and operators.

Implications for governments

Ensuring responsible development of unconventional gas resources, in line with these Golden Rules, puts substantial demands on policy-makers and regulators. First and foremost, the intensive nature of unconventional gas developments – and the scope for rapid growth in unconventional supply discussed in Chapter 2 – means that existing regulatory arrangements may have to be revised and licensing, compliance and enforcement staff reinforced. The need for new regulatory bodies may need to be considered or, more likely, existing ones may require new resources, functions and powers. This reinforcement of capacity needs to anticipate the expansion of industrial activity, so an appropriate regulatory regime is in place in good time. In keeping with regulatory best practice, such regulators will need to be independent of industry (although this certainly does not exclude ongoing consultation with industry), and have the right (often new) skills and funding. Scope exists to secure the necessary funding from industry in advance of development, for example through fees attached to the award of exploration rights.

The overarching challenge for policy-makers, to find the right balance between the need to minimise adverse environmental and social impacts while encouraging the responsible development of resources for the benefit of the local and national economy, will require judgement at the highest political level. Once that judgement is made, operational decisions of considerable weight remain to be made, for example as to the level of detail required in regulating industry operations – detailed or prescriptive provisions may be necessary, but they can also deny legitimate scope for operators to minimise costs and can impose onerous monitoring and enforcement responsibilities on regulators; performance-based regulation can work better in many areas, particularly for an industry in which technology is changing quickly.

20. Examples of regulation and best practice, from different countries, in areas covered by these Golden Rules are available on the IEA website at http://www.worldenergyoutlook.org/goldenrules.

In a number of jurisdictions, significant advances have been made in regulatory arrangements in recent years. However, the situation is very dynamic and industry has the capacity to expand rapidly; governments in resource-rich areas need to act quickly to anticipate future needs and to put the necessary measures in place. The challenge for governments and regulators can be acute in relation to water resources and the risk of water contamination. Rigorous data collection, assessment and monitoring of water requirements (for shale and tight gas), and measurement of the quality of produced water (for coalbed methane) and of waste water (in all cases) are needed to allow informed decisions to be made. Existing users are deeply suspicious that their rights and water availability might be compromised. There is a need, among other things, for transparent, speedy and equitable procedures for compensating existing users who suffer loss.

Box 1.6 ▷ Getting the market setting right

Alongside attention to environmental issues, there are many other policy areas that affect the prospects for unconventional gas development, including: the terms for access to resources; clarity on mineral rights; a consistent fiscal and overall investment framework; the provision of infrastructure; and the structure and regulatory framework in a given market (see also the assumptions underpinning the projections in Chapter 2). Market developments are at varying stages in different countries and regions. North America has well-functioning gas markets and, to take one example, many observers consider reliable third-party access to pipelines has been a pivotal part in its unconventional gas development by giving gas producers confidence that their new gas output will be able to reach market. Other key supportive market or regulatory conditions for gas production (both conventional and unconventional) include: the removal of wellhead price controls; the absence of undue restrictions on trade and export; a competitive upstream environment that encourages innovation; and efficiency and market-based pricing for gas. While these market conditions have been under discussion for many years in most OECD jurisdictions, implementation of the necessary reforms remains at best incomplete; and the challenges are greater in many non OECD countries.

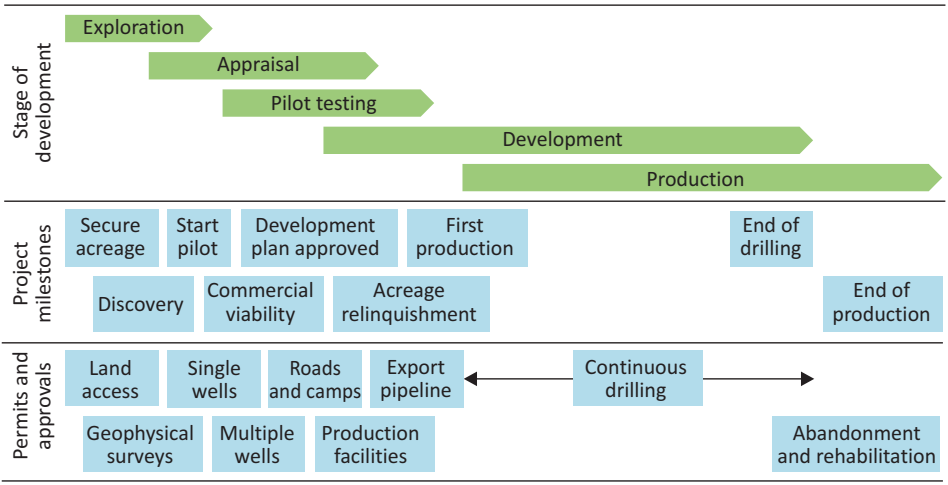
Governments everywhere have a central role in ensuring a sound, scientific, credible, knowledge base is publicly available prior to widespread development. Policy-makers and regulators themselves need access to the necessary expertise in order to understand and mitigate the environmental risks.[21] Baselines for various indicators, water in particular, are critical in this regard, but this requirement also encompasses basic geological and geophysical information. Good quality data are essential, not just as an input to good

21. An example is the decision of the Australian Government in late 2011 to establish an expert Scientific Committee, funded with AUD 150 million ($150 million) over four years, to oversee regional assessments and research on water-related impacts in areas where coalbed methane developments are proposed.

policy-making, but also to make it possible to demonstrate that the regulatory system is functioning effectively and to identify areas where improvements are needed.

Within large federal systems (for example the United States, Canada and Australia) environmental powers are usually exercised at state or provincial level, facilitating approaches that respond to local factors, such as the geology, the chosen technology and specific environmental risk factors. Local social and environmental concerns are often best dealt with at local levels. Clarity is often required as to the division of responsibilities between different levels of government, with the national authorities responsible for ensuring reasonable consistency of regulation and that adequate funding is available for region-wide work (for example, in river systems that cross internal or international boundaries).

Figure 1.6 ▷ Stages in an unconventional gas development



Note: The stages, milestones and permits shown here are not unique to unconventional developments, but the distinctive element is the overlap between stages of development, as opposed to a more sequential pattern for a typical conventional project.

Differences between the way in which conventional and unconventional resources are developed need to be taken into account in designing an effective legal and regulatory system. Conventional oil and gas developments generally follow a fairly well-defined sequence, but the distinctions between the phases of an unconventional development can be much less clear-cut – development generally proceeds in a more incremental fashion (Figure 1.6).[22] At any given time an operator may be exploring or appraising part of a

22. Often, the initial question is not whether the unconventional resource exists but whether the gas or liquids can be produced in a particular location at economic flow rates. Whereas each appraisal well of a conventional reservoir tends to increase knowledge about the overall reservoir structure and its limits, it is much more difficult with an unconventional play to extrapolate the results of individual appraisal wells to the acreage as a whole.

licence area, developing another part and producing from a third, with different regulatory approvals and permits applying at each stage. The blurred lines between the stages of an unconventional resource project development increase the complexity of the interactions between operator and regulators (and between the operator and local communities) throughout the life cycle of the development. For example, the regulatory system in most jurisdictions requires the submission and approval of a detailed field development plan at the end of the exploration phase. However, the longer learning curve for unconventional plays makes it much more difficult to develop comprehensive plans at this stage, with the risk that relatively small subsequent alterations might trigger the need to resubmit and re-approve the entire development plan – a lengthy and burdensome process for both sides.

Beyond their focus on the proper construction of individual wells and installations, regulators also need to take a broader view of the impact of multiple projects and wells over time. This broader scope is essential when it comes to assessments of water use and disposal and of future water requirements, but can be also required in other areas, including land use, air quality, traffic and noise. In general, a regulatory system that focuses primarily on well-by-well approvals rather than project level authorisations, can fail to provide for some environmental risks and miss opportunities to relieve them. For example, there are investments in infrastructure that may not proceed for an individual well but which would serve appreciably to reduce the cumulative environmental impacts of large-scale development, such as centralised water treatment plants or pipeline networks for water supply or removal (see below). One of the ways that a regulatory framework can facilitate this sort of investment is through issuing licences for sufficiently large areas and durations.

Governments are usually instrumental in promoting the co-ordinated and timely expansion of regional infrastructure alongside a gas development, including either directly putting in place alternatives to road transportation or ensuring that the regulatory framework serves to encourage or require the construction of gas transportation capacity or an expansion of local power supply. Either way, strong co-ordination and communication is necessary between different branches and levels of government, as the rapid growth of a new industry puts pressure not only on the local physical infrastructure, but also on local social services.

Implications for industry

All parts of the unconventional gas industry have to contribute to proving to society that the benefits of unconventional gas development more than offset the costs in social and environmental terms. This entails, among other things, demonstrating that environmental and social risks are being properly addressed at all stages of a development: adoption and application in full of these Golden Rules is one way to support and accelerate this process. Elements of these Golden Rules are already being applied today, incorporated into best practice or embodied in regulation. The challenge is to ensure that the highest reasonable standards are in place and are applied and enforced in a consistent and credible way across

the industry. Companies have to convince society that they have both the interest and the incentive to constantly seek ways of improving their performance.

There is a cost entailed. Compliance with these Golden Rules can in many cases increase the overall financial cost of development. How much will vary, depending on the starting point and on how each jurisdiction formulates its rules but, based on our analysis of the impact on the costs of a typical 2011 shale gas well (presented below), the additional costs are likely to be limited. For a single well, application of the Golden Rules can add around 7% to the overall cost of drilling and completion. The increase in costs could be significantly lower when considered across a full development project, as additional upfront capital costs incurred to reduce environmental impacts can, in many cases, be offset by lower operating costs.

Major cost elements in a shale gas well

The major cost elements in the drilling and completion of a shale gas well are the rig and associated drilling services, and the hydraulic fracturing stage of well completion. Well construction costs are primarily influenced by the geographical location, the well depth and, to some extent, reservoir pressure, and by the market and infrastructure conditions in the country or region under consideration. For example, a typical onshore shale gas well in the Barnett shale in Texas may currently cost $4 million to construct, while a similar well in the Haynesville shale costs twice as much, because of the depth and pressure. A similar well in Poland might cost $10 million to $12 million, because the current size of the market means that the drilling and service industry is much less developed in Poland than in the United States.

In general, more technical services are required during drilling and completing a shale or tight gas well than for a similar onshore conventional gas well, which makes it more expensive. The cost of multi-stage hydraulic fracturing can add anything between $1 million and $4 million to the construction costs of a well in the United States, depending on location, depth and the number of stages. In a shale reservoir, when drilling a well with a long lateral section, roughly 40% of the total cost goes toward the drilling and associated hardware and the remaining 60% to well completion, of which multi-stage hydraulic fracturing is the largest component. In a conventional well, the completion cost would be only about 15% of the overall well cost.

Break-even costs of shale-gas production in the United States have fallen sharply in recent years, thanks to an increase in the proportion of horizontal wells, the length of horizontal sections and the number of hydraulic fracturing stages per well, as well as the benefits of ever-better knowledge and experience of the various resource plays. The share of horizontal wells in the total number of shale-gas wells drilled increased from less than 10% in 2 000 to well over 80% today. Over the same period, the average length of the lateral

sections has increased from around 800 metres to well over 1 200 metres and the typical number of hydraulic fracturing stages has risen from single figures to around 20.[23]

Operational costs, similarly, vary with local conditions: for example, just as for drilling, operating costs in Europe are expected to be 30% to 50% higher than in the United States for a similar shale gas operation. Dry gas requires less processing than wet gas (gas containing a small fraction of liquid hydrocarbons), but also has lower market value, particularly in the current context of very high oil-to-gas price ratios in some markets.

It is worth noting that two of the key subsurface drivers of well cost – depth and well pressure – are expected to be higher in many of the areas being explored outside North America. On the other hand, for all unconventional deposits, there is considerable potential for cost savings through organising development so as to exploit economies of scale, learning, and optimising well selection and locations for hydraulic fracturing.

Impact on the cost of a single well

The typical shale gas well that we use as a basis for this analysis is not a "worst case" but rather a well of the type that was regularly drilled in 2011 into deep shale reservoirs (such as the Haynesville and Eagle Ford shale plays) in the United States, taking in many industry best practices that were not always systematically followed in the previous decade. The well is assumed to reach a vertical depth of the order of 3 000 metres, have a horizontal section of around 1 200 metres and be completed with 20 fracture stages using a total of 2 000 tonnes of proppant and 15 000 cubic metres of water (requiring 500 trucks). This type of well would typically be drilled in three sections of successively smaller diameter, each one being lined with steel casing and cemented in place before the next section is drilled.[24] The well considered is a development well rather than an exploratory well.

Such a well might be expected to cost $8 million, take a month to drill and a further month to complete. The hydraulic fracturing process accounts for around 40% of the total well cost – around twice as much as the second most expensive item, the rig itself. By comparison, a typical onshore conventional vertical gas well in the same area would cost around $3 million, with 40% being spent on the rig.

23. Some wells have lateral sections reaching up to 3 000 metres in length, with up to 40 individual geological zones for hydraulic fracturing, carried out one at a time. However, there are practical mechanical limits to the length of horizontal sections and multi-stages due to the pressure and temperature effect on the casing which mean that laterals longer than 1 800 metres or more than 20 fracture stages carry more mechanical risk (Holditch, 2010).

24. Since the well being considered already had two barriers over the shallow aquifer region with hydrocarbons being produced through production tubing, we did not include an additional casing string in our calculation of the additional costs of compliance.

Applying the Golden Rules to this well would be expected to have the following effects on costs, summarising various elements of the Rules under four indicative headings:

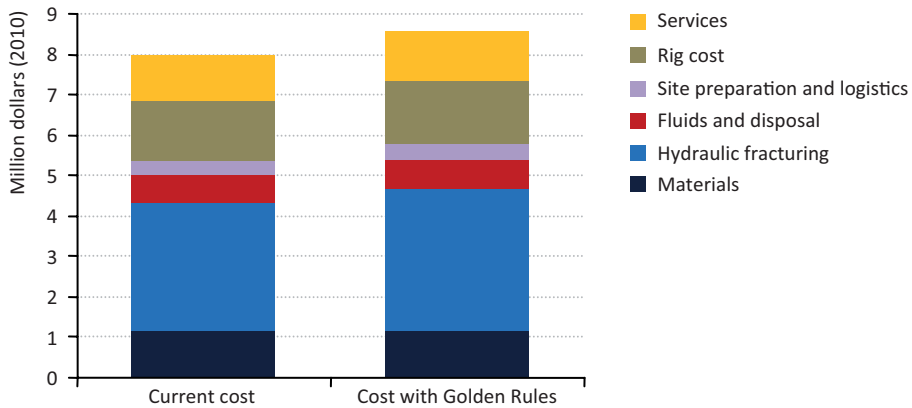
- **Isolate wells and prevent leaks:** measures in this area could include increased spending on cement design, selection and verification, coupled with a slight increase in drilling time to ensure the quality of the well-bore and provide a contingency for remedial cementing, if required. For the purposes of our analysis, we have assumed that the cement would be designed to withstand all expected stresses over the life span of the well, including the stresses induced during the 20 stages of hydraulic fracturing. The well would be drilled with appropriate tools and mud to produce a smooth and regular well-bore, to ensure that the cement bonds tightly with the wall of the well. Flexible cements or cements incorporating other technical advances that give better performance against the design criteria would be used. The cement would be pressure-tested and measurements taken to validate the quality of the cement bond on the exterior casing wall, with a contingency for remedial work if required. The American Petroleum Institute (API) publishes comprehensive standards and best practices pertaining to the construction of wells to ensure their integrity so that they are leak-free. In our analysis, 10% was estimated as the increment to drilling and cementing service costs needed to take account of these measures.
- **Eliminate venting, minimise flaring and other emissions:** this could be achieved by installing separator equipment for the hydrocarbons when they are brought to surface. For the purposes of our analysis, we have estimated a 10% addition to the cost of services required during the flow-back phase (but have not assumed that it is offset by sales of the recovered oil or gas[25]).
- **Treat water responsibly:** measures in this area could involve upgrading of fluid-disposal systems to ensure zero discharge at any stage and maximum re-use of water, as well as the use of green fracturing fluids with minimum chemical additives. In our analysis, 10% has been added to the cost of hydraulic fracturing on this basis, and a further 10% to the cost of rig fluids and disposal.
- **Disclose and engage:** responsiveness to local community concerns might involve reducing the noise from rig operations by cladding the rig with sound-proof material or imposing trucking restrictions at times at which they would otherwise cause greatest local disturbance or risk of accident. $20 000 has been added to the rig cost to cover sound-proofing of the rig and 10% to the logistics cost to cover some trucking restrictions.

In addition to these measures, we have included other actions that would add little to the cost of operations but would increase understanding of the environmental impact of shale-gas operations and facilitate dialogue with stakeholders. Simple measurement of airborne

25. According to the US EPA (EPA, 2011), general adoption of this type of "green completion" could also cut emissions of VOCs from new hydraulically fractured gas wells by 95%. The EPA further estimates that operators could expect to recover the additional cost associated with green completions within 60 days through the sale of captured hydrocarbons.

emissions at well sites in a consistent manner would provide valuable information to narrow the uncertainty around the extent of fugitive emissions of methane. Similarly, tests of local water wells that draw from an aquifer being drilled through would determine if there was contamination from any source. In total, we estimate that all the measures listed above would add around $580 000, or 7%, to the overall cost of drilling and completing this shale-gas well (Figure 1.7).

Figure 1.7 ▷ Impact of the Golden Rules on the cost of a single deep shale-gas well



Notes: Materials include all tangible material that is used in the well construction and remains in the well when it is completed, such as steel casing, valves and plugs.

Services include various services, other than hydraulic fracturing services, that are used in well construction: directional drilling services, cementing services, casing services, wire line and testing services.

Source: IEA analysis.

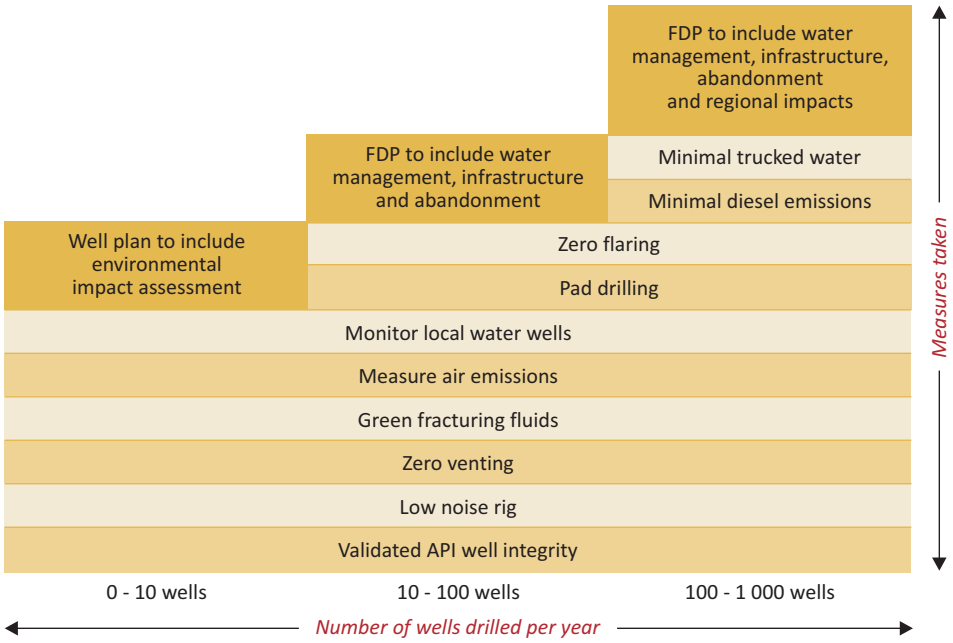
Impact on larger-scale developments

In practice, within a single licensing area, each operator typically drills a large number of wells at different sites. Applying the Golden Rules to entire unconventional gas developments could diminish the impact on overall production costs, because of economies of scale. While many of the environmental impacts discussed earlier in this chapter demand action chiefly where the scale of operations is large, large-scale operations also provide opportunities to minimise or eliminate environmental risks by optimising the process of drilling and completing each well. As the size of a development increases, measures to reduce environmental effects become both necessary and economically feasible (Figure 1.8), in a way that may not be possible for a single well.[26] In the case of gas, water and potentially

26. Many best practices can and should be applied to all wells, regardless of the size of the development. However, practices such as pad drilling, zero flaring and the minimisation of diesel emissions or trucked water involve the installation of infrastructure that, as well as not being cost effective, might even cause more environmental disruption if serving only single wells. For example, the number of truck journeys required to install water pipelines to a single isolated well would probably be more than the number of truck journeys required for the water itself.

electricity networks, greater upfront capital expenditure is required, but operating costs can be reduced, leaving the overall economics of a large-scale development no worse and in some cases improved.

Figure 1.8 ▷ Indicators of best practice as unconventional gas developments grow in size



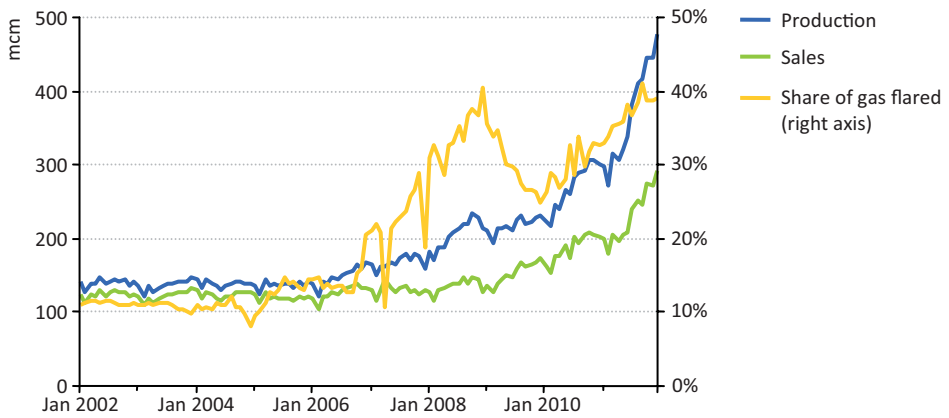
Notes: FDP = Field Development Plan; API = American Petroleum Institute Standards.

A well thought-out field development plan, based on a thorough environmental impact assessment, can help to capture these economies of scale and ensure that the hazards are well identified and that preventative or mitigating measures are in place. A key assumption in our analysis is that operators are able to plan developments optimally, both in space and in time. For this, licensing areas need to be large enough and be held for periods that are long enough for efficient development planning and the sharing of infrastructure. This needs a supportive regulatory framework.[27] Realising these gains also tends to rely on early investment in project infrastructure, often before production comes on stream and revenues start to flow: this can be a constraint for smaller companies, particularly where they are investing in marginal developments.

27. In certain regions of the United States, this is not possible due to smaller acreage blocks and lease expiration acting as a driver for development planning.

Good logistics and project planning is essential, both from the industry and from the public authorities, in view of the envisaged scale of a development. It is particularly important that infrastructure development keeps pace with upstream activity as the consequences of failure to do so can fall on the environment. For example, Figure 1.9 illustrates how the rapid development of light tight oil production in the Bakken shale was accompanied by a rise in the flaring of associated gas, as the necessary increase in gas transport infrastructure did not occur at the same pace as the increase in drilling.

Figure 1.9 ▷ Monthly natural gas production and flaring in North Dakota



Source: North Dakota Mineral Resources Department.

For the purposes of our analysis of the implications of applying the Golden Rules at scale, we considered a development of 120 wells per year.[28] In order to be able to plan and implement the types of measures described in Figure 1.8, the licensing area would need to comprise contiguous blocks and be held for at least a ten-year period, with freedom to develop according to the best environmental plan (rather than drilling to retain leases or avoid relinquishment clauses).

For this scale of development, we envisaged the following:

- **Zero venting or flaring of gas at all stages of operations:** this would require the installation of test equipment and gas-gathering infrastructure before any wells are completed. The scale of operation would mean that it would be economically viable to have this equipment dedicated to the development, although it remains challenging to estimate expected production rates with sufficient accuracy to ensure that the infrastructure is correctly sized. The early installation of gas-gathering infrastructure would bring forward capital expenditure, but would not increase the net cost, as any additional charges, including interest charges, would probably be offset by the value of the gas captured. *Estimated cost impact on a large-scale development: neutral.*

28. We considered ten rigs drilling eight wells from each pad, where the drilling phase of each well lasts 30 days, including the rig move. Thus, each rig would move every eight months to a new pad location.

- **Zero in-field trucking of water within the concession area:** this is an area where regulation and licensing requirements can play an important role. If these facilitate the necessary investment, capital expenditure on building water supply pipelines could be offset over the ten-year period by the reduction in truck movements. *Estimated cost impact: neutral.*
- **Central purpose-built water-treatment facilities:** these facilities, allowing closed-loop recycling of waste water, could be linked by pipeline to each pad location. They would reduce the overall water supply required for operations and minimise the need for off-site disposal, thereby reducing total transportation, water and disposal costs. Based on industry case studies, *we estimate savings at $100 000 to $150 000 per well*.
- **A long-term monitoring program for the development:** this could take different forms but might include performing a 3-D seismic survey over the licensing area before drilling commences to establish a geological baseline for the location of faults and sweet spots, as well as the temporary or permanent installation of micro-seismic monitoring to monitor seismic events and the propagation of fractures, and the installation of equipment to monitor the quality of water in aquifers that are being drilled through. *We estimate the additional cost of these three measures at between $100 000 and $150 000 per well*.
- **Systematic learning about the shale:** this could involve taking the opportunity provided by each well to learn more about the reservoir by capturing data (typically by using down-hole measuring instruments) that will enable the character and behaviour of the shale to be better understood. This understanding is an important contributory factor in improving the operational performance (and therefore the environmental impact per unit of production) of each well drilled and in eliminating wells and fracture stages that do not contribute significantly to production. *We estimate the additional cost at $200 000 per well*.

Most of these measures would involve a marginal increase in the overall cost of a large-scale development. But there is potential for reducing costs through better planning of operations, which would also reduce environmental risks:

- **Exploiting economies of scale:** pad drilling and the associated ability to carry out simultaneous operations on more than one well has been shown to bring significant cost savings as well as reducing the total surface footprint. Typically the drilling phase of a number of wells on the pad would be finished first, enabling the completion phase to be carried out for multiple wells in parallel. “Simultaneous operations” of this sort can allow for more efficient use of equipment for hydraulic fracturing. The US company, Continental Resources, has reported a 10% drop in average well cost in the Bakken Shale, from $7.2 million to $6.5 million, by using such an approach at eight well pads. Other industry sources report savings of up to 30%, due to a combination of economies of scale and improvements in operational efficiency. *On this basis, we have estimated savings of 10% per well.*

- **Optimising the number of fracture stages:** this can achieved by acquiring better information about where the sweet spots are likely to be and fracturing only in those zones, rather than simply fracturing every 100 metres, with no science applied. Industry data from different shale plays in the United States show that, on average, between 30% and 40% of fractures do not contribute any production at all. We have assumed conservatively that at least two hydraulic fracturing stages out of twenty could be saved as a result of better reservoir characterisation by systematically learning about the shale. *This would represent a cost saving of around $400 000 per well or equivalent gains in production for the same number of stages.*
- **Learning from experience:** there is a learning curve associated with the drilling and completion of shale-gas wells that, on a large scale of development, can bring significant cost savings as time goes on: these savings are often quoted in conjunction with economies of scale and the optimisation of fracture stages. *For the purposes of our analysis, we have not added any additional saving related to the learning curve.*

Summing up the effects of the more stringent environmental measures applied to the development and the efficiency savings from better planning yields an overall net cost saving of approximately 5%. Most of these savings come from economies of scale and reduced hydraulic fracturing, which more than offset the additional cost of implementing well-specific measures and monitoring environmental effects.

There is potential for even larger cost savings in large-scale developments by optimising the number and location of wells drilled. Given the enormous variability in geology, there are significant variations in the economics of unconventional gas wells, driven largely by differences in the expected cumulative output of each one (referred to as Estimated Ultimate Recovery [EUR]). The ability of operators to locate sweet spots within an unconventional gas play, where output is particularly high, (or their good fortune in doing so) explains a large part of the difference in EUR between wells. The adoption of advanced technologies in drilling and completing wells can also help to increase EUR.

At present, in the vast majority of shale gas developments wells are drilled and hydraulically fractured "geometrically", that is to say at regular intervals, without regard for the changing geology between those intervals. Some wells give very good initial production and others close to zero. A detailed study of more than 7 000 wells in the Barnett Shale in *WEO-2009* showed that half of the horizontal wells drilled were unprofitable, even at the 2009 gas price of $6 per MBtu, while some others were profitable at much lower prices (IEA, 2009). This reflects differences in the amount of gas produced, itself a reflection of the local geology of the formation, but also of differences in the suitability and effectiveness of the well design and hydraulic fracturing operations. Reservoir characterisation and modelling techniques for shales is applied only in a limited manner at present. It is not unreasonable to expect that, had there been smarter selection of drilling targets, the least profitable 20% of wells in our sample would not have been drilled at all. Better understanding of the science of hydrocarbon flows within unconventional gas reservoirs is needed for improved reservoir characterisation and modelling to be achieved (Box 1.7).

Box 1.7 ▷ The potential benefits of better petroleum science

For all the advances that have been made in shale gas production in the United States in recent years, a large number of wells that prove to be very unproductive are still being drilled. Often, the value of the gas and liquids they yield is insufficient to cover the cost, the losses on such wells generally being offset by other wells that prove to be very productive. In addition, recovery factors for shale gas and light tight oil are very low, compared to conventional reservoirs: estimates in most cases do not exceed 15% of the original oil and gas in place. A better scientific understanding of both the geological structure and hydrocarbon flows within shale and tight gas rock should allow producers to target better and to refine their drilling and well-completion operations, driving down the number of unproductive wells and pushing up the estimated ultimate recovery – a tremendous prize for all stakeholders.

Thus far, improvements in unconventional gas technology have largely been concerned with how, on a cost-effective basis, to pump more fluid into more fracture stages in longer horizontal sections in order to increase reservoir contact, and how to better manage the environmental effects. But while advances in drilling and hydraulic fracturing technology have unlocked unconventional reserves that were previously uneconomic, the science of the behaviour of the reservoirs is still not well understood. This makes it very hard to predict decline rates and the ultimate production potential of each play and individual areas and wells. Traditional methods of computer modelling and simulation of oil and gas reservoirs do not work well in the case of shale gas or light tight oil.

This scientific challenge has attracted a significant research effort from industry experts and academia. Breakthroughs in understanding the behaviour of shale and tight-gas reservoirs are expected and are likely to trigger a shift from the current "brute force" approach to production towards a more scientific one, enabling operators to avoid drilling poor wells and using ineffective well-completion methods. This would allow for more efficient use of water and other resources, minimising the environmental footprint and lowering production costs.

The Golden Rules Case and its counterpart

How might unconventional gas re-shape energy markets?

Highlights

- In a Golden Rules Case, we assume that the conditions are in place, including the application of the Golden Rules, to allow for an accelerated global expansion of gas supply from unconventional resources, with far-reaching consequences for global energy markets. Greater availability of gas supply has a strong moderating impact on gas prices and, as a result, demand for gas grows by more than 50% to 2035 and the share of gas in the global energy mix rises to 25% in 2035, overtaking that of coal.
- Production of unconventional gas, primarily shale gas, more than triples in the Golden Rules Case to 1.6 tcm in 2035. The share of unconventional gas in total gas output rises from 14% today to 32% in 2035. Whereas unconventional gas supply is currently concentrated in North America, in the Golden Rules Case it is developed in many other countries around the world, notably in China, Australia, India, Canada, Indonesia and Poland.
- The Golden Rules Case sees a more diverse mix of sources of gas in most markets, suggesting an environment of growing confidence in the adequacy, reliability and affordability of natural gas supplies. An increased volume of gas, particularly LNG, looking for markets in the period after 2020 stimulates the development of more liquid and competitive international markets. The projected levels of output in the Golden Rules Case would require more than one million new unconventional gas wells to be drilled worldwide between now and 2035.
- In a Low Unconventional Case, we assume that – primarily because of a lack of public acceptance – only a small share of unconventional gas resources is accessible for development and, as a result, global unconventional gas production rises only slightly above 2010 levels by 2035. The competitive position of gas in the global fuel mix deteriorates as a result of lower availability and higher prices, and the share of gas in global energy use remains well behind that of coal. The requirement for imported gas is higher and some patterns of trade are reversed, with North America needing significant quantities of imported LNG, and the preeminent position in global supply of the main conventional gas resource-holders is reinforced.
- Although the forces driving the Low Unconventional Case are led by environmental concerns, it is difficult to make the case that a reduction in unconventional gas output brings net environmental gains. The effect of replacing gas with coal in the Low Unconventional Case is to push up energy-related CO_2 emissions, which are 1.3% higher than in the Golden Rules Case. Reaching the international goal to limit the long-term increase in the global mean temperature to two degrees Celsius would, in either case, require strong additional policy action.

Paths for unconventional gas development

There are factors on both the demand and supply sides pointing to a bright future for natural gas, but the key element in the supply outlook is the growth in production of – and expectations for – unconventional gas resources. For the moment, production of unconventional gas is still overwhelmingly a North American phenomenon: in 2010, 76% of global unconventional gas output came from the United States (360 billion cubic metres [bcm]) and a further 13% from Canada (60 bcm). Outside North America, the largest contribution to unconventional gas production came from China and Australia, producing around 10 bcm and 5 bcm of coalbed methane, respectively.[1] But, in light of the North American experience and with evidence of a large and widely dispersed resource base, there has been a surge of interest from countries all around the world in improving their security of supply and gaining economic benefits from exploitation of domestic unconventional resources.

Box 2.1 ▷ Overview of cases

This chapter sets out projections from two cases, for the period to 2035, which explore the potential impact and implications of different trajectories for unconventional gas development.

- A ***Golden Rules Case***, to which the main part of this chapter is devoted, assumes that the conditions are put in place to allow for a continued global expansion of gas supply from unconventional resources. This allows unconventional gas output to expand not only in North America but also in other countries around the world with major resources.
- A ***Low Unconventional Case*** considers the opposite turn of events, where the tide turns against unconventional gas, as environmental and other constraints prove too difficult to overcome.

These projections are assessed against an updated ***baseline***, which takes as its starting point the central scenario (the New Policies Scenario) from the most recent *World Energy Outlook*, *WEO-2011*. The two main cases test a range of favourable and unfavourable assumptions about the future of unconventional gas. A necessary, but not sufficient, condition of the Golden Rules Case is the effective application of the Golden Rules, in order to earn or maintain the "social licence" for the industry to operate. Neither case is advanced as more probable; they are rather designed to inform the debate about the implications of different policy choices for energy markets, energy security and for climate change and the environment.

1. A proportion of gas production in Russia is classified as unconventional, tight gas.

The potential is there for unconventional gas supply to grow rapidly in the coming decades, but the speed at which this supply will grow is still highly uncertain. Outside North America, the unconventional gas business is in its formative years, with major questions still to be answered about the extent and quality of the resource base and the ability of companies to develop it economically. Moreover, as discussed in Chapter 1, social concerns about the impact of producing unconventional gas, particularly the threat of unacceptable environmental damage, have risen as production has grown. Reports of water contamination, earthquakes, and other disruptions to local communities have given unconventional gas production, and the practice of hydraulic fracturing in particular, a bad name in many countries.

It remains to be seen how this social and environmental debate will play out in different parts of the world. In parts of Canada, the United States and Australia, moratoria have been placed on hydraulic fracturing, pending the results of additional studies on the environmental impact of the technology. Even in advance of any commercial production, similar prohibitions are already in force in parts of Europe. There is a distinct possibility that, if these concerns are not directly and convincingly addressed, then the lack of public acceptance in some countries could mean that unconventional production is slow to take off, or, indeed, falters at the global level.

This chapter examines two scenarios, the Golden Rules Case and the Low Unconventional Case (Box 2.1), in the first of which these challenges are overcome and a second in which they are not successfully addressed. The difference in outcomes between them posits a critical link between the way governments and operators respond to these social and environmental challenges and the prospects for unconventional gas production. The strength of this link differs among countries depending on the ways that public concerns and perceptions of risk affect political decision-making. But the assumptions underlying these cases reflect our judgement that the development of this relatively new industry is contingent, in many places, on a degree of societal consent that in some places has yet to be achieved. Moreover, the perception of the industry as a whole is likely to be cast by the performance of its weakest players, not its strongest. Without a general and sustained effort from both governments and operators, the public may not be convinced that the undoubted benefits outweigh potential risks.

Golden Rules and other policy conditions

The Golden Rules, presented and discussed in Chapter 1, are principles designed to minimise the undesirable effects of unconventional gas production on society and the environment. Implementing such principles is in many cases a question of appropriate regulation; but this is not the whole story. The task for policy-makers and regulators is to find the right equilibrium that deals convincingly with social and environmental concerns without removing the economic incentives for developing an important national resource. This balance will vary from country to country, given differing energy security, economic and environmental priorities.

In the Golden Rules Case, we assume that all resource-rich countries formulate their approach to environmental regulation of unconventional gas production in line with these principles and thereby achieve a level of environmental performance and public acceptance that provides the industry with a "social licence to operate". In that sense, the Golden Rules become a necessary (but not sufficient) condition for a wide expansion of unconventional gas supply.

In the Low Unconventional Case, this balance is not found and the Golden Rules are either not adopted or inadequately applied. Whether in response to new incidents of environmental damage or evidence of poor industry performance, the potential social and environmental threats are deemed to be too significant in some countries or regions, to the extent that there are substantial obstacles to developing the resource. Longer-lasting prohibitions are imposed in some countries on technologies that are essential to unconventional gas development, such as hydraulic fracturing, or exclusion zones are created and tight restrictions applied to drilling locations that restrict access to all or part of the resource. Alternatively, either a combination of very strict and detailed regulation imposes prohibitive compliance costs or fears about future regulatory change deter investment.

The application of these Golden Rules is not sufficient in itself to determine successful resource development in countries with unconventional gas potential. Based on experience in the United States, other key factors include:

- **Access to resources:** these considerations include access to geological data on a reasonable and transparent basis, the size of the area covered by a licence and the duration of the licence, and freedom for companies to engage in upstream activities on a competitive basis.
- **The fiscal and regulatory framework:** some countries have high potential in terms of resources but unattractive overall conditions for investment, such as unpredictable fiscal regimes or weak institutions.
- **Availability of expertise and technology:** not least because unconventional gas production requires a large number of wells, the industry needs a skilled and experienced workforce and a well-developed service sector with access to the necessary equipment.
- **Existing infrastructure:** although there are possibilities for small-scale gas gathering arrangements and direct conversion to power (or liquefied natural gas [LNG]), the density of the gas transport infrastructure in areas targeted for unconventional development is an important consideration, as is the existence of guaranteed access to this infrastructure.
- **Markets and pricing:** gas is relatively expensive to transport (compared with its well-head production costs and also with the cost of transporting oil) so companies will be attracted to resources with reliable, proximate markets that offer the necessary

incentives to develop the gas. The absence of market pricing in the host market can eliminate the commercial case for unconventional gas development.

- **Water availability:** water is essential to the production process for shale gas and tight gas (see Chapter 1), and competition with established users in water-stressed areas may constrain unconventional developments.[2]

Experience in the United States points to additional factors such as the number of entrepreneurial and independent companies willing to take the risk of venturing into a new industrial sector, which is coupled with their ability to mitigate market risk via well-developed financial markets. In the absence of widespread examples outside the United States, it is impossible for the moment to say which of the ingredients listed above are essential for large-scale unconventional gas development, which of them are merely desirable, and which might play only a limited role. What can be said, though, is that the mix of conditions and constraints varies by country: in some, environmental and social issues will be decisive; in others, the quality of the resource, the nature of the upstream supply chain, market conditions and prices, or the overall legal system and investment security, may be more significant.

Our general assumption in the Golden Rules Case is that all of the potential obstacles listed are either overcome or do not prove a serious constraint on unconventional gas development. A major motivation for supportive policies is assumed to be the desire of countries to secure the economic benefits of a valuable indigenous resource and, in many cases, also to improve energy security by reducing dependence on imported gas. The essence of the Golden Rules is that they bolster public confidence in the determination of public authorities and operators alike to overcome the social and environmental hazards, thereby creating a political environment that allows for the enactment of other policies encouraging investment in this sector. In the Low Unconventional Case, weak or absent political support deters the implementation of supportive measures for unconventional gas development, such as attractive fiscal and investment terms.

In the projections for the different cases, which are presented later in this chapter, the results of adopting the Golden Rules, in the Golden Rules Case, and the results of failing to do so, in the Low Unconventional Case, are compared against the outcome in a baseline case. This baseline case uses the central scenario of the *WEO-2011* (the New Policies Scenario) as its starting point, but incorporates more recent data, where these have become available, and certain new assumptions, such as the rate of GDP growth, which are described more fully later in the chapter. The baseline case sees natural gas prices converge towards the levels assumed in the *WEO-2011* New Policies Scenario, whereby prices in the United States reach $8.2 per million British thermal units (MBtu) in 2035 (in year-2010 dollars) and average import prices into Europe and Japan reach $12.2/MBtu and $14.2/MBtu respectively. However, the baseline case excludes the application in full of the

2. The *WEO-2012* will include a dedicated chapter on the links between energy and water use.

Golden Rules and the other supportive policies that generate faster growth in natural gas production in the Golden Rules Case.

Unconventional gas resources

Our projections depend, first, on the size of the available resource. Drawing on data from a variety of sources, we estimate that remaining technically recoverable resources of shale gas amount to 208 trillion cubic metres (tcm), tight gas 76 tcm and coalbed methane 47 tcm (Table 2.1). Russia and countries in the Middle East are the largest holders of conventional gas resources (and Russia has by a distance the largest overall gas resources). However, a large part of the world's remaining recoverable unconventional gas lies in countries or regions that are currently net gas importers and face increasing import dependency, such as China, and the United States, which before the recent boom in unconventional gas in North America was looking at the prospect of rising LNG imports (Figure 2.1). Different assumptions about the terms of access to the unconventional resource base in China and in the United States, and in other unconventional resource-rich countries around the world, are a main determinant of the variations between levels of production in the Golden Rules Case and the Low Unconventional Case.

Table 2.1 ▷ Remaining technically recoverable natural gas resources by type and region, end-2011 (tcm)

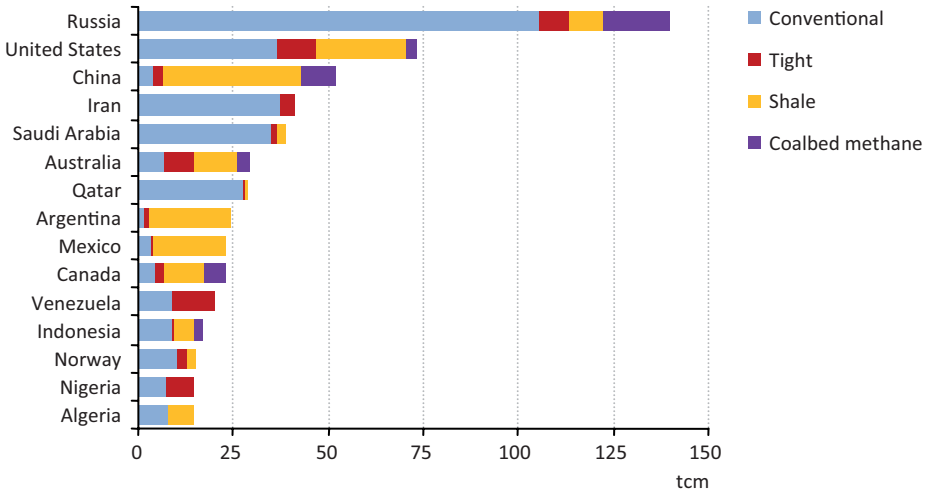
	Total		Unconventional		
	Conventional	Unconventional	Tight Gas	Shale Gas	Coalbed methane
E. Europe/Eurasia	131	43	10	12	20
Middle East	125	12	8	4	-
Asia/Pacific	35	93	20	57	16
OECD Americas	45	77	12	56	9
Africa	37	37	7	30	0
Latin America	23	48	15	33	-
OECD Europe	24	21	3	16	2
World	**421**	**331**	**76**	**208**	**47**

Source: IEA analysis.

Note: The resource estimate for coalbed methane in Eastern Europe and Eurasia replaces a figure given in the *WEO-2011* and in the *Golden Age of Gas* publications (IEA, 2011a and 2011b), which included a "gas-in-place" estimate for Russia instead of the estimate for technically recoverable resources.

Although they are undoubtedly large, unconventional gas resources are still relatively poorly known, both in terms of the extent of the resource in place and judgements about how much might be economically extracted. The industry is still in the learning phase when it comes to many resources outside North America: each unconventional resource play brings with it distinctive challenges and it has not yet been demonstrated that technologies well adapted to existing production areas can unlock the resource potential in all areas.

Figure 2.1 ▷ Remaining recoverable gas resources in the top fifteen countries, end-2011



Source: IEA analysis.

In particular for shale gas, our analysis and projections in this report rely on estimates from the pioneering work of Rogner (Rogner, 1997) and the landmark study from Advanced Resources International (ARI), published by the US Energy Information Administration (EIA) in 2011 (US DOE/EIA, 2011a); these are distinctive in applying consistent standards of evaluation to a large number of countries. On the one hand, resources could easily be even larger than indicated in these studies, as they do not examine all possible shale gas reservoirs around the world. On the other hand, several publications have provided estimates significantly lower than the ARI study: the United States Geological Survey (USGS), whose resource assessments are generally among the most authoritative, has recently published several regional studies indicating lower resources. This is the case, for example, for the Krishna-Godavari shale gas basin in India (USGS, 2012) for which they report a mean estimate of 116 bcm (4.1 trillion cubic feet [tcf]), compared with the ARI estimate of 765 bcm (27 tcf); this much more conservative estimate can be traced back to a smaller estimate for the productive area of the shale and to a smaller mean recovery per well (assuming the same drainage area).[3] Studies by the Polish Geological Institute with support from USGS also give a much lower estimate (a range of 346 bcm to 768 bcm versus the 5.3 tcm given in the ARI study[4]) for shale gas resources in Poland (PGI, 2012). China has

3. The methodologies used for the two studies are different. ARI first estimates gas-in-place and then applies a recovery factor. USGS estimates directly the recoverable resources based on recovery per well and well drainage areas derived by analogy with reservoirs in the United States for which data is available. The methodology used to determine well drainage areas has not been published yet by USGS, making it difficult to compare with industry-accepted values.

4. The different resource estimates can have a substantial impact on the outcome of our projections: see the references to Poland in Chapter 3.

also released new estimates of shale gas resources that are about 20% lower than those given by ARI (MLR, 2012). The much talked-about USGS study of the Marcellus shale in the northeast United States estimated the undiscovered shale resources there at 2.4 tcm (84 tcf), much lower than the 11.6 tcm (410 tcf) recoverable resources reported by the US EIA in 2011 (USGS, 2011).[5] US EIA subsequently reduced their estimate for recoverable gas in the Marcellus to 4 tcm (141 tcf) (US DOE/EIA, 2012).

Estimates of coalbed methane resources are drawn from the German Federal Institute for Geosciences and Natural Resources (BGR, 2011) and US EIA. Tight gas resources are generally poorly defined and known: the exceptions are the United States, Canada and Australia, for which national resource data are used. Tight gas resource estimates for other countries are derived from Rogner.

In the Golden Rules Case, the entire resource base for unconventional gas is assumed to be accessible for development, including in countries and regions where moratoria or other restrictions are currently in place. In the Low Unconventional Case, however, the constraints imposed by the absence of supportive policies (in particular the Golden Rules themselves) and the uncertainties over the size and quality of the resource base were modelled by assuming that only a small part of the ultimately recoverable unconventional resource base is accessible for development. The key assumptions by country or region for the Low Unconventional Case are:

- **United States**: only 65% of tight gas, 45% of coalbed methane and 40% of shale gas resources are accessible. For shale gas, this could, as an example, correspond to excluding all new developments in the northeast United States[6], in California and in the Rocky Mountains, while the more traditional oil and gas producing regions, such as Texas, Oklahoma or the Gulf Coast, would continue to develop their shale resources. Alternatively, restrictions could apply to some parts of the prospective acreage in all regions, such as the more densely populated parts, or those with serious competition in uses for water. For coalbed methane, this could essentially restrict developments to regions that are already producing. Tight gas has been produced for many years in numerous traditional hydrocarbon-producing regions, so tight gas production is not assumed to be restricted as much as the other categories.

5. Strictly speaking, the USGS and US EIA numbers cannot be compared as USGS reports undiscovered gas resources while US EIA reports total recoverable resources, which differ from undiscovered by proven reserves and discovered-but-undeveloped resources. However, neither organisation has provided a breakdown of these three categories. Overall, unconventional gas challenges the usual definitions, as there is no real discovery process (the locations of most gas bearing shales in the world are already known); it is more an appraisal process: the process of establishing that a given shale, and/or what part of the shale, can produce economically. As a result the difference between undiscovered and discovered-but-not-developed is blurred and it is important to clarify the assumption used in various resources estimates.

6. The *World Energy Model* (*WEM*) currently uses the US EIA 2011 resources numbers (US DOE/EIA, 2011b), before their downward revision for the Marcellus shale, pending publication of more details for the background of this revision. So the northeast United States, and the Marcellus shale in particular, represents about half of the estimated resources. Note that *WEM* treats the United States as a single region, so there is no projection of production by basin.

- **China**: only 40% of the coalbed methane and 20% of the shale gas resources are assumed to be accessible. Public acceptance is likely to be a lesser influence in China than in other countries (although we are looking forward 25 years and, if the changes that have occurred in the last 25 years in China are any guide, public sensitivity to environmental issues could become significantly greater during the projection period), but other factors could restrict the ambitious official plans for unconventional gas production (Box 2.4).
- **India**: only 30% of the coalbed methane and 20% of the shale gas resources are assumed to be accessible. The large projected gas import requirements of India make it unlikely that public opposition would force a complete ban. On the other hand, on current estimates, unconventional gas resources in India are not sufficient to make more than a dent in these imports and our assumption is consistent with a political decision to restrict development of all but the less contentious resource areas.
- **Australia**: only 40% of coalbed methane and none of the shale gas resources are assumed to be accessible. Development of both types of resources has already become controversial in Australia. About 5 bcm of coalbed methane was produced in Australia in 2010 and there are three large-scale projects underway to build LNG plants fed by coalbed methane. The restriction to 40% of available resources essentially amounts to no new projects being authorised beyond those announced.
- **Rest of the world**: no new unconventional gas resources are assumed to be developed outside Canada (for which we use percentages about half of those in the United States, to reflect similar dynamics, but the smaller part of the resources so far developed) and Russia (where, in any event, unconventional resources are not expected to play a significant role).[7]

Development and production costs

The costs of developing and producing unconventional gas are made up of several elements: capital costs, operational costs, transportation costs, and taxes and royalties. Capital costs, often called finding and development costs, are usually dominated by the costs of constructing wells. As discussed in Chapter 1 (under "Implications for Industry"), shale gas wells do cost more than conventional gas wells in the same conditions, because of the additional costs of multistage hydraulic fracturing; the same consideration applies to tight gas wells, for the same reason. Coalbed methane wells have so far been relatively cheap, compared with conventional gas wells, because production has been at shallow depths in regions with well-developed markets. Operational costs, also called lifting costs, are those variable costs that are directly linked to the production activity: they may differ according to local conditions (but not necessarily between conventional and

7. This assumption about the rest of the world (with the partial exception of Canada and Russia) has the virtue of simplicity, although it is a little extreme in some countries that are already producing coalbed methane without any controversy; however, the amounts involved are too small to have any impact on prices or energy security.

unconventional gas produced under similar conditions). The cost of bringing gas to market is distance-dependent and is identical for conventional and unconventional gas.

The final element, taxes and royalties, varies greatly between jurisdictions; in addition to a profit tax component, it very often includes fixed or production-related taxes (paid to governments) and/or royalties (paid to the resource owner, which may or may not be governments). Countries or regions that have higher capital and operating costs, due to their geography or market conditions, often create a more attractive fiscal regime in order to attract investment. This can go as far as offering subsidies: China provides subsidies for coalbed methane and shale gas production.

On the basis of these costs, one can estimate a "break-even cost", or "supply cost", the market value required to provide an adequate real return on capital for a new project (normally taken to be 10% for a project categorised as risk-free and rising with incremental risk). This break-even cost does not apply to legacy production from largely depreciated installations. Lifting costs, transport costs, and taxes and royalties are usually directly expressed in US dollars per unit of gas produced. The significance of capital costs is very dependent on the amount of gas recovered per well. This also varies greatly: the best shale gas wells in the United States are reported to have Estimated Ultimate Recovery (EUR) of 150 to 300 million cubic metres (mcm) (5 to 10 billion cubic feet [bcf]); but many shale gas wells have EUR that is 10 or 100 times less. The average EUR varies from one shale to another, but also depends on the experience of the industry in a given shale: with time, the industry optimises the technologies used and extracts more gas from each well. Outside the United States, there is essentially no experience so far, but drilling longer horizontal wells should help improve EUR per well (in many jurisdictions in the United States, horizontal well length is limited by acreage unit size regulations).

It follows from the discussion of costs that the break-even costs for gas can vary greatly from one location to the next, or within a single country (Table 2.2). For example in the United States, break-even costs for dry gas wells probably range from $5/MBtu to $7/MBtu; gas containing liquids has a lower (gas) break-even cost, which can be as low as $3/MBtu, as the liquids add considerable value for a small increase in costs (associated gas from wells producing predominantly oil can have an even lower break-even cost). Since conventional gas resources are already fairly depleted onshore and most future conventional gas production will therefore come from more expensive offshore locations, the range of break-even costs for conventional and unconventional gas in the United States is fairly similar.

In Europe, the costs of production are expected to be about 50% higher, with a range of break-even costs between $5/MBtu and $10/MBtu. Conventional and unconventional gas are expected to be in the same range, as conventional resources are depleted and new projects are moving to the more expensive Norwegian Arctic. China has a cost structure similar to that of the United States, but shale reservoirs there tend to be deeper and more geologically complex; similarly, coalbed methane reservoirs in China tend to be in remote locations, so we estimate the break-even cost range to be intermediate between that of

the United States and that of Europe – from $4/MBtu to $8/MBtu (although there are production subsidies in place that can bring this figure down). This estimate for China applies to both conventional and unconventional gas, as the easy conventional gas is depleting and production is moving to offshore or more remote regions. In countries that have large, relatively easy, remaining conventional gas, such as the Middle East, with break-even costs of less than $2/MBtu, the break-even cost range for unconventional gas is expected to be higher (similar to that for unconventional gas in the United States).

Table 2.2 ▷ Indicative natural gas well-head development and production costs in selected regions (in year-2010 dollars per MBtu)

	Conventional	Shale gas	Coalbed methane
United States	3 - 7	3 - 7	3 - 7
Europe	5 - 9	5 - 10	5 - 9
China	4 - 8	4 - 8	3 - 8
Russia	0 - 2, 3 - 7*	-	3 - 5
Qatar	0 - 2	-	-

* The lower range for Russia represents production from the traditional producing regions of Western Siberia and the Volga-Urals; the higher range is for projects in new onshore regions such as Eastern Siberia, offshore and Arctic developments.

In the Golden Rules Case, the development and production cost assumptions are not increased because of the application of the Golden Rules; as discussed in Chapter 1, the application of the Golden Rules does have some cost impact, but not sufficient to push up the costs of production significantly (and, possibly, not at all). The same starting point is used for development and production costs in the Low Unconventional Case; costs in this case, though, are subject to the general assumption (built into the modelling) that production tends to become more costly as a given resource starts to become scarcer. Since access to unconventional gas resources is limited in this case, the rate of increase in the costs of production is higher than in the Golden Rules Case.

Natural gas prices

The price assumptions in the Golden Rules Case and in the Low Unconventional Case vary substantially, reflecting the different regional and global balances between supply and demand in each case (Table 2.3). The price assumptions in the Golden Rules Case reflect the favourable outlook for unconventional gas supply that results from successfully addressing the potential barriers to its development. Greater availability of gas supply has a strong moderating impact on gas prices. Conversely, lower production of unconventional gas in the Low Unconventional Case means that higher natural gas prices are required to bring the different regional markets into balance.

Table 2.3 ▷ Natural gas price assumptions by case
(in year-2010 dollars per MBtu)

		Golden Rules Case		Low Unconventional Case	
	2010	2020	2035	2020	2035
United States	4.4	5.4	7.1	6.7	10.0
Europe	7.5	10.5	10.8	11.6	13.1
Japan	11.0	12.4	12.6	14.3	15.2

Note: Natural gas prices are expressed on a gross calorific value basis. Prices are for wholesale supplies exclusive of tax. The prices for Europe and Japan are weighted average import prices. The United States price reflects the wholesale price prevailing on the domestic market

North America is the region where the unconventional gas industry has grown most rapidly and, unsurprisingly, is also the region where the impact on markets and prices has thus far been greatest. Historically low prices are being obtained for natural gas, relative to other energy forms such as oil. More surprisingly, given the relative isolation of North American markets from other major gas-using regions, this development has already had profound international impacts. These have arisen because North America has become almost self-sufficient in gas, whereas many LNG investments in the decade 2000 to 2010 were made in the expectation that the North American region would be a substantial net LNG importer. Import infrastructure in excess of 100 bcm was built in the United States alone in this period, with matching LNG supply investments in major producers, such as Qatar. However, in 2011, net LNG imports to North America were less than 20 bcm, out of a total market exceeding 850 bcm: 8 bcm into the United States and 9 bcm into Mexico and Canada. Hence, major quantities of LNG supply became available for other global markets, including Asia and Europe.

Natural gas prices in the United States are assumed to rise from today's historic lows in both cases, but they increase much more quickly in the Low Unconventional Case. The contrasting future roles of North America in global gas trade in the two cases help to explain these different price trajectories. In the Golden Rules Case, the region becomes a significant net LNG exporter, on the back of continued increases in unconventional gas output in the United States and Canada and an expansion in LNG export capacity. Natural gas prices in the United States are assumed to reach a plateau of between $5.5/MBtu and $6.5/MBtu during the 2020s (the levels which we assume are sufficient to support substantial volumes of dry gas production) before rising to $7.1/MBtu in 2035. Exports at the levels anticipated in this case are relatively small, compared with the overall size of the United States' gas market, and do not play a decisive role in domestic price-setting (although they are significant for other markets). By contrast, in the Low Unconventional Case, North America remains a net importer of gas, with imports growing rapidly after 2025. With the region needing to draw its incremental gas supply from international markets, the natural gas price in the United States is pushed up much more quickly than in the Golden Rules Case, reaching $10/MBtu in 2035.

The weighted average import price assumptions for Europe and for Japan are likewise lower in the Golden Rules Case than in the Low Unconventional Case. Within this basic trend, differences between the two markets reflect the different balances between gas supply and demand in each case, as well as the various pricing mechanisms present and how these mechanisms are assumed to evolve. At present, gas prices are set freely in several markets, including North America, the United Kingdom and, to a somewhat lesser extent, Australia, an approach known as gas-to-gas competition. However, much of the gas traded across borders in the Asia-Pacific region is sold under long-term contracts, with linkages to the price of oil or refined products. Prices in continental Europe are predominantly oil-linked, though in recent years a mixture of the two systems (and many variations in between) has emerged, with oil-indexed prices co-existing – often uneasily – with prices set by gas-to-gas competition. We assume that pressure to move away from prices set by oil-indexation and towards those established through gas-to-gas competition is significantly greater in the Golden Rules Case than in the Low Unconventional Case.

In the Golden Rules Case, the United States is expected to play an important role in the evolution of international natural gas pricing mechanisms. Initial contracts for United States LNG exports have been written on the basis of the price at the main domestic natural gas trading hub (Henry Hub), plus liquefaction and transport costs, plus profit, rather than the traditional oil-price indexation prevailing in many of the markets where this gas will be sold. In the Golden Rules Case, this is assumed to put pressure on oil-indexed price formulas for natural gas, moderating gas price increases and provoking a greater degree of convergence in international prices towards those set by gas-to-gas competition. We do not, though, assume that this process of creating a single, liquid or competitive international gas market is completed in the Golden Rules Case (a situation in which natural gas price differentials between regions would reflect only the costs of transportation between them). An important moderating factor in importing regions, especially in Asia, is that most existing natural gas import contracts will continue to remain in force for many years and are based on oil indexation, so average prices cannot be expected to fall dramatically. In addition, some major new export projects (including, for example, from Canadian plants) are greenfield LNG operations, likely to push for traditional pricing arrangements. Hence, while the rise of North American LNG exports in the Golden Rules Case is a major development in global gas markets, we anticipate that wholesale prices in the United States remain at least $5 to $6 below Japanese import prices, with European import prices between these two.

Other assumptions

Both cases include updated assumptions on GDP, compared with the *WEO-2011*, with average annual GDP growth of 3.5% for the period 2012 to 2035, compared with 3.4% in *WEO-2011* for the same period (this allows the global economy in 2035 to reach the same overall size as assumed in *WEO-2011*). World population is assumed to expand from an estimated 7.0 billion in 2012 to 8.6 billion in 2035, as in *WEO-2011*. The projections for natural gas incorporate new demand and supply data by country and region for 2011,

where these are available. Prices for oil, coal and carbon-dioxide (CO_2) are likewise updated to include new data for 2011, but they still converge towards the levels assumed in the central scenario of the *WEO-2011,* the New Policies Scenario. This means that the average IEA crude oil import price – a proxy for international oil prices – reaches $120/barrel in 2035 in year-2010 dollars (a nominal oil price of $212/barrel). The IEA steam coal import price increases to $112/tonne in 2035.

In the Golden Rules Case, to complement the impact on gas demand arising from lower prices that improve the competitive position of gas compared with other fuels, we also assume intervention by governments to foster demand growth in countries experiencing a large rise in indigenous gas production. In the United States, for example, supportive policies are assumed to facilitate increased use of natural gas in the road-transport sector, in particular for the commercial fleet. These additional demand-side policies are not included in the baseline case nor in the Low Unconventional Case, because the motivation for their adoption, *i.e.* higher indigenous production and lower prices, is absent.

Another notable change in policy assumptions, compared with the *WEO-2011*, occurs in Japan, where, pending the outcome of the ongoing review of Japan's Strategic Energy Plan, the future contribution of the nuclear sector to power generation is revised downwards in all cases.

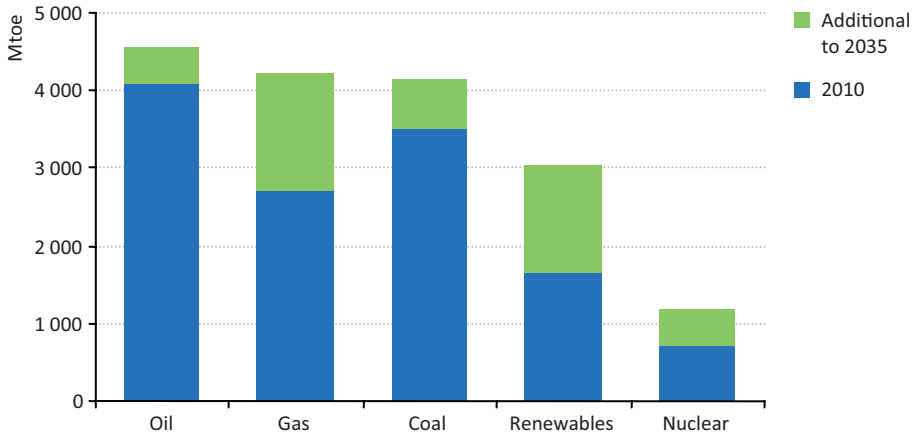
Otherwise, all assumptions remain constant from the New Policies Scenario of the *WEO-2011* (which takes into account policies and declared future intentions as of mid-2011), including the assumption that new measures are introduced to implement announced policy commitments, but only in a relatively cautious manner. These commitments include national pledges to reduce greenhouse-gas emissions and, in certain countries, plans to phase out fossil-fuel subsidies.

The Golden Rules Case

Demand

Global primary energy demand in the Golden Rules Case rises from around 12 700 million tonnes of oil equivalent (Mtoe) in 2010 to 17 150 Mtoe in 2035, an increase of 35%. Natural gas demand increases in the period to 2020 by more than 700 bcm (compared with 2010 levels), the equivalent of adding another United States to the global demand balance, and by a further 1.1 tcm in the period from 2020 to 2035, reaching a total of 5.1 tcm (4 230 Mtoe) in 2035. This is around 300 bcm, or 6%, higher than in the baseline case in 2035, with average annual growth over the projection period of 1.8%, compared with 1.5%. In the Golden Rules Case, gas accounts for about one-third of the overall increase in primary energy demand, a larger contribution than that made by any other fuel and equivalent to the growth in demand for coal, oil and nuclear combined (Figure 2.2). By 2035, natural gas has overtaken coal to become the second most important fuel in the energy mix.

Figure 2.2 ▷ World primary energy demand by fuel in the Golden Rules Case



Different rates of gas demand growth, albeit less pronounced than in the exceptional year of 2011[8], are expected to characterise gas markets in the longer term (Table 2.4). In the Golden Rules Case, 80% of the growth in gas demand comes from outside the OECD; China, India and the countries of the Middle East require an additional 900 bcm of gas in 2035, compared with consumption in 2010. In China and India and other emerging economies, natural gas at present often has a relatively low share of total energy consumption and its use is being specifically promoted as a way to diversify the fuel mix and reap some environmental benefits, often displacing coal as the preferred fuel to supply fast-growing urban areas. While growth in gas demand is healthy even in many of the more mature OECD gas markets – a development that is encouraged by the lower prices for natural gas in the Golden Rules Case – the growth in China alone is more than the anticipated growth in all of the OECD countries put together. Gas demand in China grows over the period 2010 to 2035 by 480 bcm, reaching a total of around 590 bcm in 2035 (larger than current gas demand in the European Union), meaning that developments on both the supply and demand sides in China will continue to have a substantial impact not just in the Asia-Pacific region but – via the wider effects on trade and prices – in markets around the world.

Gas used for generating power and heat is the single largest component of gas demand, accounting for around 40% of total gas consumed. Alongside the lower perceived risk of building gas-fired plants and the lower environmental impact, compared with other fossil fuels, the natural gas prices assumed in the Golden Rules Case improve the competitive

8. Preliminary data suggest that gas consumption in Europe declined by around 11% compared with the previous year, pulled down by warm weather, a sluggish European economy and a weak competitive position in the power sector compared with coal. This was in marked contrast to developments in the Asia-Pacific region: Korea and Japan showed a dramatic upsurge in demand for LNG, the latter linked to reduced output of nuclear energy following Fukushima, and Chinese gas demand continued its meteoric rise, becoming a larger gas consumer than any OECD country except the United States. The United States also saw growth in consumption, of around 2.5%, spurred by low prices that neared $2/MBtu in late 2011.

position of natural gas and push up gas demand for power generation to more than 2 tcm by 2035. The role of gas in power generation increases from 22% to 24%, with coal and oil (the latter a marginal fuel in power generation) ceding share in response. Gas use in buildings and in industry also increases substantially, reaching 1 060 bcm and 970 bcm respectively by the end of the projection period.

Table 2.4 ▷ Natural gas demand by region in the Golden Rules Case (bcm)

	2010	2020	2035	2010-2035*
OECD	**1 601**	**1 756**	**1 982**	**0.9%**
Americas	841	921	1 051	0.9%
United States	*680*	*717*	*787*	*0.6%*
Europe	579	626	692	0.7%
Asia Oceania	180	209	239	1.1%
Japan	*104*	*130*	*137*	*1.1%*
Non-OECD	**1 670**	**2 225**	**3 130**	**2.5%**
E. Europe/Eurasia	662	736	872	1.1%
Russia	*448*	*486*	*560*	*0.9%*
Asia	398	705	1 199	4.5%
China	*110*	*323*	*593*	*7.0%*
India	*63*	*100*	*201*	*4.7%*
Middle East	365	453	641	2.3%
Africa	101	130	166	2.0%
Latin America	144	200	252	2.3%
World	**3 271**	**3 982**	**5 112**	**1.8%**
European Union	*547*	*592*	*644*	*0.7%*

* Compound average annual growth rate

Although volumes are small compared with the other end-use sectors, the Golden Rules Case sees strong growth in gas use in the transport sector. This is encouraged both by lower prices, compared with oil, and also by government policies, for example support for developing the necessary refuelling infrastructure. Use of natural gas for road transportation increases by more than six times in the period to 2035, reaching close to 150 bcm in 2035. For the moment, transport is the only major end-use sector where gas is not widely used: although there are viable natural gas vehicle technologies, there are only a few countries where these are deployed at scale. More than 70% of all natural gas vehicles and half of all fuelling stations are found in just five countries: Pakistan, Iran, Argentina, Brazil and India. In our projections, India and the United States lead the growth in natural gas consumption for transport, primarily in commercial fleets, buses and municipal vehicles that can use central depots for refuelling.

Implications for other fuels

The implications of applying the Golden Rules to unconventional natural gas extend beyond gas to other competing fuels. As the share of gas rises from 21% of global primary energy consumption in 2010 to 25% by 2035 (compared with 23% in the baseline case), growth in demand for oil and coal is constrained and, marginally, also demand for nuclear and renewable energy (Table 2.5).

Table 2.5 ▷ World primary energy demand by fuel in the Golden Rules Case

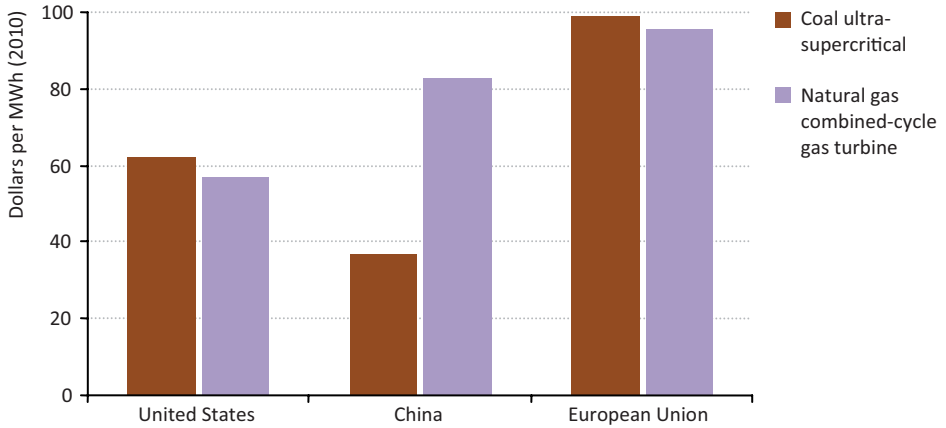
	Demand (Mtoe)			Share		
	2010	2020	2035	2010	2020	2035
Coal	3 519	4 109	4 141	28%	28%	24%
Oil	4 094	4 381	4 548	32%	29%	27%
Gas	2 700	3 291	4 228	21%	22%	25%
Nuclear	719	927	1 181	6%	6%	7%
Hydro	295	376	472	2%	3%	3%
Biomass	1 262	1 496	1 896	10%	10%	11%
Other renewables	110	287	676	1%	2%	4%

Oil continues to be the dominant fuel in the primary energy mix, with demand increasing from about 4 100 Mtoe in 2010 to 4 550 Mtoe in 2035, but its share in the primary energy mix drops from 32% in 2010 to 27% in 2035. Compared with the baseline case, lower gas prices promote substitution for oil in the transport and power sectors, resulting in global oil demand being reduced by some 2 million barrels per day (mb/d) in 2035.

Primary coal consumption in the Golden Rules Case rises until around 2025 and then levels off. Its share in the energy mix declines from 28% in 2010 to 24% in 2035. In that year, coal demand is around 3% lower (115 Mtoe) than in the baseline case, an amount greater than total current European imports of hard coal. Three-quarters of coal demand growth stems from the power sector. Lower gas prices favour gas over coal for new builds in most countries (Figure 2.3). However, in some countries, such as China, coal remains cheaper than gas, in the absence of prices that internalise environmental externalities, such as local pollution or CO_2 emissions. In this situation, Chinese government policies aimed at increasing gas use are crucial to its development. Globally, excluding China, 3.5 units of gas-fired electricity generation are added for each new unit of coal-fired electricity generation.

Over the *Outlook* period, nuclear output grows, but it is marginally below our baseline case in 2035. Gas prices have a direct influence on new nuclear construction in liberalised markets, mostly in OECD countries, where we expect nuclear output to grow 12% less than our baseline. However, most of the global growth in nuclear will occur in non-OECD countries, where specific national plans to expand nuclear capacity are less likely to be affected by changing market conditions.

Figure 2.3 ▷ Electricity generating costs for new coal- and natural gas-fired power plants in selected regions in the Golden Rules Case, 2020



The global outlook for renewable sources of energy is not affected substantially by the increased use of gas in the Golden Rules Case, with volumes and shares of output remaining very close to those in the baseline case. Due to lower gas (and consequently electricity) prices, the growth of electricity output from non-hydro renewables is reduced globally by 5% compared with our baseline. This global average figure hides some larger differences in specific countries, where the impact is stronger, due to the price levels and to the type of support policies in place. This is, for example, the case in the United States, where the growth of electricity from non-hydro renewables is some 10% lower with respect to the baseline.

There are factors working both against, and in favour of, renewables in a world of more abundant gas supplies. Depending on the type of policies in place, an abundance of natural gas might diminish the resolve of governments to support low and zero-carbon sources of energy: lower gas prices (and therefore lower electricity prices) can postpone the moment at which renewable sources of energy become competitive without subsidies and, all else being equal, therefore make renewables more costly in terms of the required levels of support. However, an expansion of gas in the global energy mix can also facilitate greater use of renewable energy, if policies are in place to support its deployment, given that gas-fired power generation can provide effective back-up to variable output from certain renewable sources. Moreover, lower electricity prices can encourage customer acceptance of a higher component of electricity from renewable sources. Ultimately, the way that renewables retain their appeal, in a gas-abundant world, will depend on the resolve of governments. We assume that existing policies and support mechanisms remain in place as part of the efforts by governments to address the threat of a changing climate.

Supply

In the Golden Rules Case, total gas production grows by around 55%, from 3.3 tcm in 2010 to 5.1 tcm in 2035. Over the same period, unconventional gas production increases from around 470 bcm in 2010 to more than 1.6 tcm in 2035. Although unconventional gas output grows relatively slowly in the early part of the projection period, reflecting the time required for new producing countries to develop commercial production, for the projection period as a whole, unconventional gas represents nearly two-thirds of incremental gas supply (Table 2.6).

Table 2.6 ▷ Natural gas production by region in the Golden Rules Case (bcm)

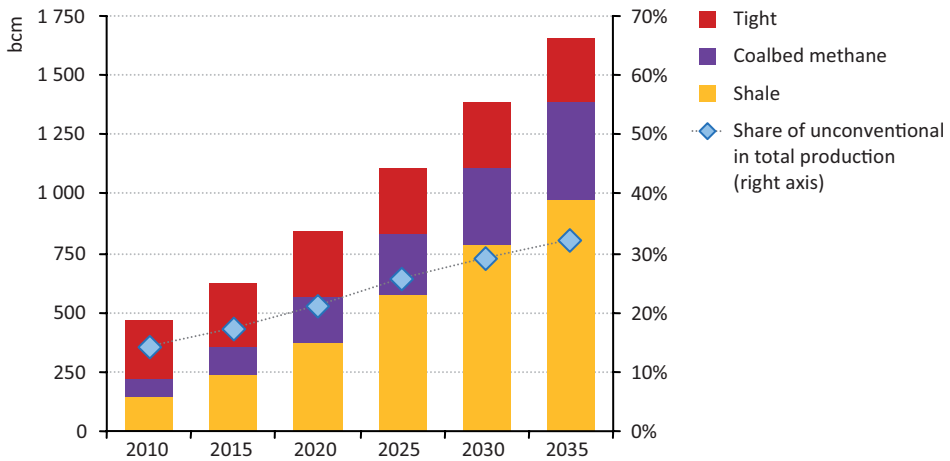
	2010		2020		2035		2010-2035**
	Total	*Share of unconv**	Total	*Share of unconv**	Total	*Share of unconv**	
OECD	**1 183**	**36%**	**1 347**	**49%**	**1 546**	**60%**	**1.1%**
Americas	821	51%	954	62%	1 089	68%	1.1%
Canada	*160*	*39%*	*174*	*57%*	*177*	*67%*	*0.4%*
Mexico	*50*	*3%*	*52*	*12%*	*87*	*43%*	*2.2%*
United States	*609*	*59%*	*726*	*67%*	*821*	*71%*	*1.2%*
Europe	304	0%	272	4%	285	27%	-0.3%
Poland	*6*	*11%*	*9*	*37%*	*34*	*90%*	*7.1%*
Asia Oceania	58	9%	121	49%	172	64%	4.5%
Australia	*49*	*11%*	*115*	*51%*	*170*	*65%*	*5.1%*
Non-OECD	**2 094**	**2%**	**2 635**	**7%**	**3 567**	**20%**	**2.2%**
E. Europe/Eurasia	826	3%	922	3%	1 123	6%	1.2%
Russia	*637*	*3%*	*718*	*4%*	*784*	*6%*	*0.8%*
Asia	431	3%	643	20%	984	56%	3.4%
China	*97*	*12%*	*246*	*45%*	*473*	*83%*	*6.6%*
India	*51*	*2%*	*75*	*21%*	*111*	*80%*	*3.2%*
Indonesia	*88*	-	*106*	*2%*	*153*	*37%*	*2.2%*
Middle East	474	0%	581	1%	776	2%	2.0%
Africa	202	1%	264	1%	397	5%	2.7%
Algeria	*79*	-	*101*	*1%*	*135*	*8%*	*2.2%*
Latin America	159	2%	226	4%	286	22%	2.4%
Argentina	*42*	*9%*	*53*	*9%*	*72*	*48%*	*2.1%*
World	**3 276**	**14%**	**3 982**	**21%**	**5 112**	**32%**	**1.8%**
European Union	*201*	*1%*	*160*	*7%*	*165*	*47%*	*-0.8%*

* Share of unconventional production in total natural gas production.

** Compound average annual growth rate.

The share of unconventional gas in total gas production increases in the Golden Rules Case from 14% in 2010 to 32% in 2035 (Figure 2.4). Of the different sources of unconventional supply, tight gas, at 245 bcm, accounted for just over half of global unconventional production in 2010. However, it is rapidly overtaken in our projections by production of shale gas, which rises from around 145 bcm in 2010 (31% of total unconventional output) to 975 bcm in 2035 (almost 60% of the total). Production of coalbed methane likewise grows rapidly, from 80 bcm in 2010 to nearly 410 bcm in 2035.

Figure 2.4 ▷ Unconventional natural gas production by type in the Golden Rules Case



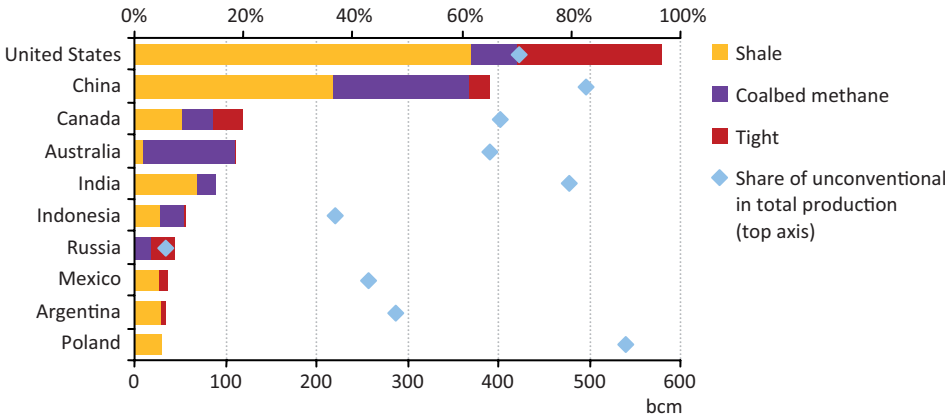
The continued expansion of unconventional gas production in North America means that the United States moves ahead of Russia as the largest global gas producer, with about 820 bcm of total gas production in 2035, compared with 785 bcm in Russia. North American unconventional output, with substantial contributions also from Canada and Mexico, rises to nearly 740 bcm in 2035 in the Golden Rules Case. But increased unconventional production also occurs widely around the world: whereas unconventional gas production in 2010 is dominated by North America, the share of North America in global unconventional production falls to around 70% in 2020 and only 45% in 2035.[9]

China becomes a major gas producer in the Golden Rules Case and the second-largest global producer of unconventional gas, after the United States (Figure 2.5). Progress with developing unconventional gas resources is bolstered by the twin policy commitments of increasing the share of natural gas in the Chinese energy mix and developing, where possible, the domestic resource base so as to mitigate increased reliance upon energy imports. The large resource base for shale gas and coalbed methane allows very rapid growth in unconventional production from around 2017 onwards and total unconventional

9. More detailed discussion of the regulatory issues and production outlooks for North America, China, Europe and Australia are included in Chapter 3 of this report.

production reaches just over 110 bcm in 2020 and 390 bcm in 2035, 83% of total Chinese gas production.

Figure 2.5 ▷ Ten largest unconventional gas producers in the Golden Rules Case, 2035



Similar policy objectives are assumed to drive an expansion in unconventional gas production elsewhere in Asia, notably in India where unconventional gas supply rises to nearly 90 bcm in 2035 (80% of total gas output). The currently known unconventional gas resource base in India can meet only a part of India's incremental needs, given the prospect of strong growth in gas demand, and production growth starts to tail off towards the end of the projection period. In Indonesia, by contrast, resources of both conventional and unconventional gas are very large; some recent conventional discoveries are offshore and relatively expensive to develop, so the onshore unconventional plays, including rich potential for coalbed methane, are attractive by comparison. Unconventional gas production in Indonesia rises to around 55 bcm in 2035 (almost 40% of total output). Australia is another country that has the opportunity to develop both conventional and unconventional resources with a mix of coalbed methane, tight and shale gas. In the Golden Rules Case, unconventional gas makes up about 65% of Australia's 170 bcm of total gas output by 2035.

The expansion of unconventional gas production in China and the United States (and, to a lesser extent, also in Europe) creates strategic challenges for existing gas exporters. This is evident in the projections for Russia, which remains by far the largest producer of conventional gas.[10] Developments in the Golden Rules Case call into question the speed at which Russia will need to develop relatively expensive new fields in the Yamal peninsula, in the Arctic offshore and in Eastern Siberia. In our projections, Russia's total gas production rises to about 785 bcm in 2035, more than 20% above 2010, but below the levels foreseen in

10. A part of Russia's production is classified as tight gas although this is very similar to conventional production in practice; hydraulic fracturing to enhance flow rates is rarely used in gas wells. Russia is, though, projected to expand its output of coalbed methane by 2035.

Russian policy or company outlooks and in our baseline. In the Middle East, an increasingly important challenge for gas producers – with the exception of an export-oriented producer like Qatar – is to meet increasing demand for gas on domestic markets. In our Golden Rules Case projections, this imperative to meet domestic needs leads to small amounts of shale gas being produced, mainly in Saudi Arabia and Oman, but conventional gas continues to predominate. In North Africa, though, unconventional gas plays a slightly more significant role, with Algeria, Tunisia and Morocco starting to produce shale gas in the early 2020s. By the end of the projection period, unconventional gas production reaches around 8% of total output in Algeria; with conventional resources becoming scarcer by this time, unconventional gas helps to maintain consistently high levels of production and export. Overall gas production in Africa is bolstered by expanded conventional output from a traditional producer, Nigeria, but also by output from new conventional producers, such as Mozambique and Angola.

Latin America has large potential for unconventional gas development, with Argentina (primarily shale gas) having the largest resource base, followed by Venezuela (tight gas) and then Brazil (shale gas). Attention in Argentina is focused on the Neuquén Basin in Patagonia, which helps Argentinean unconventional production reach 35 bcm by 2035 in the Golden Rules Case, almost half of the total gas output. Both Venezuela and Brazil have ample conventional resources, which means that there is less need to develop their unconventional potential during the projection period; however, some unconventional gas is produced by 2035 in Bolivia (5 bcm), Peru (5 bcm), Paraguay (3 bcm) and Uruguay (3 bcm).

Implications for other fuels

In the Golden Rules Case, the conditions supportive of unconventional gas production also support increased output of natural gas liquids (NGLs), extracted from liquids-rich shale gas, as well as light tight oil.[11] This oil is analogous in many ways to shale gas, both in terms of its origins – it is oil that has not migrated, or at least not migrated far, from the (shale) source rock – and in terms of the production techniques required to exploit it. Light tight oil is being produced from many of the same basins as unconventional gas in the United States, and, in a price environment combining high oil prices and very low prices for natural gas, there is a strong economic incentive to target plays with higher liquids content. In the Golden Rules Case, we project a strong increase in production of light tight oil in the United States, with the potential for production to spread also to other countries rich in this resource (Box 2.2).

11. Almost all shale gas plays produce some liquids and light tight oil production likewise comes with some associated gas. The distinction between liquids-rich unconventional gas plays and gas-rich light tight oil reservoirs is not clear-cut; it normally depends on the relative energy content of the gas versus the liquids produced, but this can vary over time for a single well.

Box 2.2 ▷ The liquid side of the story – light tight oil

The spectacular rise in oil production from North Dakota and Texas in the United States clearly illustrates the growth potential for light tight oil. The Bakken formation under North Dakota has been known about since the 1950s, but production from this formation remained under 100 thousand barrels per day (kb/d) until only a few years ago, since when it has surged to over 500 kb/d and looks set to continue growing. The Eagle Ford shale in south Texas, adjacent to the Mexican border, also shows considerable promise, with production expected to grow from almost nothing three years ago to around 400 kb/d by the end of 2012. Combined production from the Bakken, the Eagle Ford and other emerging light tight oil plays in the United States is expected to reach 2 mb/d by 2020 in the Golden Rules Case.

United States' NGL production from shales such as the Barnett, Eagle Ford and Marcellus is also increasing rapidly and up to 1 mb/d of new capacity is expected to be added by 2020. The growth in NGL production is creating new opportunities for the petrochemical industry, but action will be required to remove pipeline bottlenecks and provide additional fractionation and storage facilities if the benefits are to be fully realised. The growth in global production of NGLs from shale formations and light tight oil in the period to 2020, predominantly in North America, makes up almost half the incremental growth in oil supply over this period.

Production outside North America of NGLs from shale and of light tight oil is unlikely to make a large contribution to global liquids production before 2020 as much evaluation work still needs to be done. However, the Neuquén basin in Argentina shows promise, YPF announcing potential resources of 7 billion barrels (YPF, 2012), while the extension of the Eagle Ford shale into Mexico is also a focus of attention. Our projections for light tight oil production outside North America remain small even beyond 2020, as we have yet to see sufficient progress in confirming resources, so there is some upside potential. It should be noted, however that on the basis of current knowledge, light tight oil resources are expected to be of less consequence than shale gas resources: whereas the estimated shale gas resources in the United States represent at least 35 years of 2010 domestic gas demand, the known light tight oil resources make up no more than four years of domestic oil demand. This is why we currently project light tight oil production in the United States to peak in the 2020s.

The liquids content of shale gas plays is an important consideration in their economic viability as NGLs are easily transported to world markets, while market opportunities for gas are often only local, at prices that may not be aligned to international prices for reasons of policy or infrastructure. However there is always a degree of uncertainty about the extent of liquids content until new shales have been drilled and tested.

International gas trade, markets and security

In the Golden Rules Case, the developments having the most impact on gas markets and security are the increasing levels of unconventional production in China and in the United States, the former because of the way that it slows the growth in Chinese import needs and the latter because it allows for gas exports from North America. The implication of these two developments in tandem is to increase the volume of gas, particularly LNG, looking for markets in the period after 2020.

China's requirement for imported natural gas in the Golden Rules Case grows from around 15 bcm in 2010 to 80 bcm in 2020 and then to 120 bcm in 2035. These volumes are about half the corresponding imports in the baseline case. Chinese gas imports at the levels projected in the Golden Rules Case could be covered by existing contractual arrangements for LNG and pipeline supplies (from Central Asia and Myanmar) until well into the 2020s, pushing back the need for additional projects aimed at the Chinese market.

With the United States developing as an LNG exporter over the period to 2020 and Canada also starting to export LNG from its west coast, exports from North America reach 35 bcm by 2020, after which they stabilise just above these levels as the opportunities for export start to narrow. The influence of these exports on trade flows and pricing is larger than these volumes suggest. LNG from the United States, if priced at the prices prevailing on the domestic gas trading hub, can compete with oil-indexed gas in both the European and Asia-Pacific markets in the Golden Rules Case, and the mere presence of this source of LNG (more so than the actual level of export) plays an important role in creating a more competitive international market for gas supply.

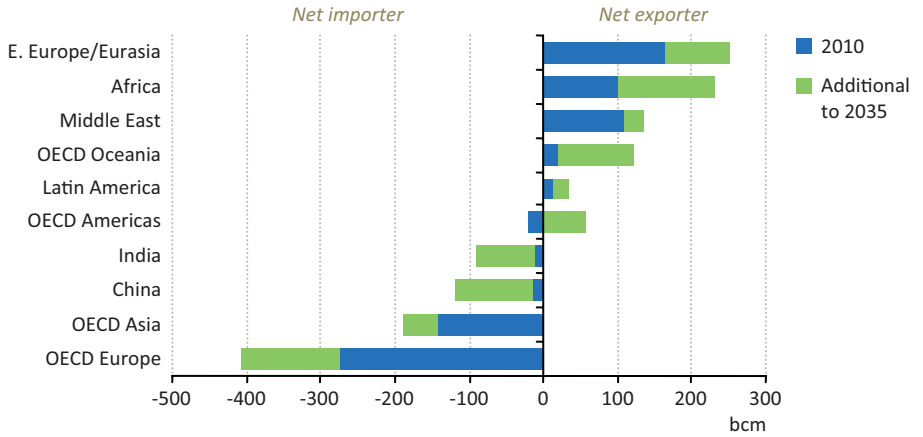
The total volume of gas traded between *WEO* regions[12] in the Golden Rules Case in 2035 is 1 015 bcm. This represents an increase of nearly 50%, compared with the volume of inter-regional trade in 2010 (Figure 2.6), but it is some 15% below the figure for 2035 in our baseline case. The share of inter-regional trade in global supply rises to 22% in 2015, but international market conditions start to ease over the period to 2020 and beyond, as new sources of unconventional gas start to be developed closer to the main areas of consumption. This pick-up in unconventional gas production means that the share of inter-regional trade in global supply plateaus after 2015 before falling to 20% by 2035, reversing the expectation that international trade will play an increasingly important role in meeting global needs.

The European Union's growing requirement for imported gas accounts for 40% of the increase in global inter-regional gas trade in the Golden Rules Case. Here too, the development of indigenous unconventional gas moderates somewhat the growth in imports, so that they reach 480 bcm in 2035, about 135 bcm more than in 2010. Among importing countries in Asia, Japan and Korea (which do not have potential to develop

12. Trade between the 25 regions included in the *WEM*. It does not include trade between countries within a single region.

indigenous production) see imports rise steadily, as does India, whose import requirement rises to nearly 90 bcm from around 10 bcm in 2010.

Figure 2.6 ▷ Natural gas net trade by major region in the Golden Rules Case



Box 2.3 ▷ Implications for prices and pricing mechanisms

In an environment where gas is potentially available from a greater variety of sources, buyers not only in Europe but also in Asia could well insist on greater independence from oil prices in the pricing of gas supplies, particularly when gas is used in the fast-growing power sector in which oil is disappearing as an energy source. The Golden Rules Case is likely to see accelerated movement towards hub-based pricing or a hybrid pricing system in which alternatives to oil-price indexation plays a much larger role in both Europe and across Asia.

The way such a change might play out in practice would depend to a large degree on the reaction of the main traditional exporters, who could confront greater risks in financing expensive upstream developments and transportation projects. Producers such as Russia and Qatar, the largest current exporters of natural gas, have access to ample conventional reserves, with costs that are in most cases substantially lower than those of unconventional gas (and other conventional producers as well). With well-developed export infrastructure, these countries could undercut the prices offered by most other exporters on international markets, retaining or expanding export volumes by offering gas to markets on more attractive terms than others. Alternatively, they could aim to maintain higher prices for their exports, but at the risk of losing market share. In the Golden Rules Case, their strategic choice would have substantial implications for the location of investment and production, including the speed of development of unconventional resources. The net result for gas consumers, however, would be broadly the same: lower prices for imported natural gas.

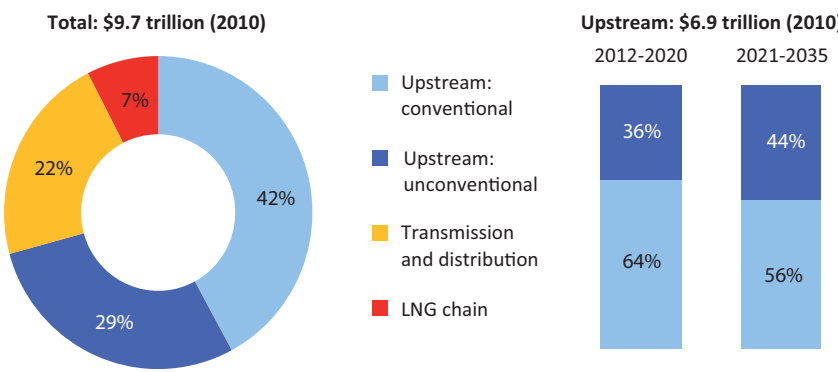
Russia and the Middle East supplied around 45% of inter-regional gas trade in 2010; this declines to 35% in 2035 in the Golden Rules Case, as other players announce or expand their presence in the market, notably Australia, the United States and producers in Africa and Latin America. From around 20 bcm in 2010, Australia's exports rise quickly to 120 bcm in 2035, based on a rapid expansion of LNG capacity, which permits new markets to be captured in the earlier part of the projection period, during which demand for imports remains relatively strong. By around 2020, African exports – based on new conventional projects and LNG, thanks to the large recent discoveries offshore east and west Africa – overtake those from the Middle East.

Overall, the Golden Rules Case presents an improved picture of security of gas supplies. High dependence on imports, in itself, is not necessarily an indicator of insecure supply; but the conditions observed in the Golden Rules Case of a more diverse mix of sources of gas in most markets, including both indigenous output and imports from a range of potential suppliers, suggests an environment of growing confidence in the adequacy, reliability and affordability of natural gas supplies.

Investment and other economic impacts

At the global level, for conventional and unconventional gas together, the Golden Rules Case requires $9.7 trillion in cumulative investment in gas-supply infrastructure in the period 2012 to 2035 (in year-2010 dollars). This represents an increase of $390 billion, compared with the baseline case, reflecting the need to bring on more production to meet higher demand and a slight increase in unit production costs as unconventional resources make up a growing share of production. Spending on gas exploration and development, to find new fields and bring them into production and to maintain output from existing ones, amounts to nearly $6.9 trillion, bolstered by the large number of new wells required (see Spotlight).

Figure 2.7 ▷ Cumulative investment in natural gas-supply infrastructure by type in the Golden Rules Case, 2012-2035 (in year-2010 dollars)



SPOTLIGHT

How many wells? How many rigs?

Expanded unconventional gas production requires a significant increase in the number of unconventional gas wells over the coming decades, though there is a huge range of uncertainty when calculating the extent of the requirement for unconventional gas wells for a projected level of production. Key variables are the average ultimate recovery per well and the average decline rate of production in the early years, both of which vary significantly between shale gas, tight gas and coalbed methane wells.[13]

We estimate that, to meet the global unconventional gas production requirements of the Golden Rules Case, more than one million unconventional gas wells would need to be drilled globally between 2012 and 2035. For comparison, around 700 000 oil and gas wells have been drilled in the United States over the last 25 years and half a million are currently producing gas. At present, global drilling activity for both conventional and unconventional resources is heavily concentrated in the United States, where more than half of the world's drilling rig fleet (around 2 000 active oil and gas drilling rigs, including those used for unconventional gas) is deployed to sustain production of just 9% of the world's oil and 19% of the world's gas.

In the Golden Rules Case, the United States would still account for around 500 000 of the new unconventional gas wells required by 2035, with the yearly drilling requirement rising from around 7 000 wells per year to 25 000 per year by 2035 (and the unconventional gas rig count increasing by the same order of magnitude, given that the efficiency of rig use probably has potential for only modest increases).

China would have a cumulative requirement of some 300 000 unconventional gas wells over the projection period and an annual requirement increasing from around 2 000 in the early years to 20 000 wells nearer 2035. Assuming that drilling becomes more efficient with time, this might correspond to an increase in the number of unconventional gas drilling rigs from around 400 to 2 000, a demanding increase in the rig count. There are an estimated 1 000 rigs in China at present, but only a fraction of these are capable of horizontal drilling.

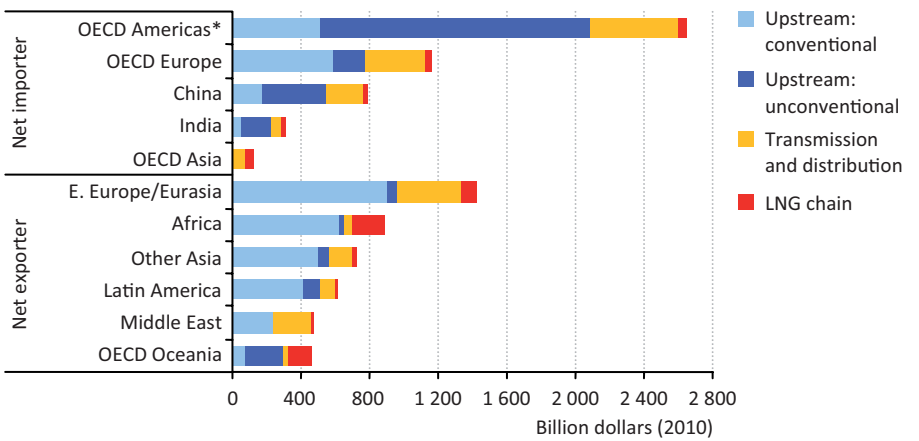
In the European Union, the cumulative number of wells in the projection period is around 50 000, increasing to around 3 000 per year by the 2030s. The number of drilling rigs required is between 500 and 600; there are currently around 50 land rigs in Europe, of which only around half may be capable of horizontal drilling.

13. For the purpose of these calculations, we have used an average EUR of around 1 bcf, assumed that about 50% of EUR is recovered in the first three years of production, and a 15% average decline rate of current unconventional gas production (in the United States). Varying these assumptions within a reasonable range produces very different outcomes in terms of the number of wells.

Unconventional resources attract an increasing share of this upstream investment – about 36% before 2020 and 44% in the subsequent period to 2035 – as prospective areas mature (Figure 2.7). Being geographically well-dispersed and closer to demand centres, unconventional gas diminishes the need for long-distance gas transport infrastructure to some degree. Nevertheless, growing trade in the Golden Rules Case requires additional LNG facilities and new long-haul pipelines. Cumulative investment in the LNG chain is $0.7 trillion and investment in gas transmission and distribution infrastructure, including smaller scale networks to connect end-users, absorbs $2.1 trillion.

The proportion of upstream investment made in countries that hold unconventional resources increases. Spending on exploration and development for unconventional gas in the United States alone is more than double total upstream spending in any other country or region.[14] China also becomes one of the world's leading locations for upstream gas investment, thanks to its huge resource base. Countries that were net importers of gas in 2010 make some of the most significant investments in unconventional gas, accounting for more than three-quarters of total unconventional upstream investment (Figure 2.8). This investment can generate the wider economic benefits associated with improved energy trade balances, lower energy prices and employment, all of which add economic value for unconventional resource holders.

Figure 2.8 ▷ Cumulative investment in natural gas-supply infrastructure by major region and type in the Golden Rules Case, 2012-2035



* OECD Americas become a net exporter of natural gas by 2020 in the Golden Rules Case.

The outlook for energy trade balances improves for unconventional resource holders in the Golden Rules Case. China and the European Union remain large net importers of gas,

14. Because of the rapid decline in production in shale gas wells, maintaining production requires continuous investment in drilling new wells. This explains why the United States needs the lion's share of the investment in unconventional gas: although it does not grow supply as much as China for example, it needs investment just to sustain its already substantial level of unconventional gas production.

but indigenous unconventional gas production tempers their import bills, which stabilise at about 0.2% and 0.7% of GDP, respectively, after 2020. Australia, where production far outstrips domestic gas demand, sees export revenues reach nearly 2% of GDP in 2035. Net exports of gas bring revenues to the United States after it ceases to be a net gas importer; the more substantial impact on energy trade balances in the United States results from light tight oil production and increased NGLs from higher unconventional gas production, which contribute to a considerable reduction in its oil import bill – to 0.8% of GDP in 2035, compared with a peak of 2.8% of GDP in 2008.

Climate change and the environment

Energy-related CO_2 emissions in the Golden Rules Case reach 36.8 gigatonnes (Gt) in 2035, an increase of over 20% compared with 2010 (Table 2.7) but lower than the 2035 baseline projection by 0.5%. At the global level, there are two major effects of the Golden Rules Case on CO_2 emissions, which counteract one another. Lower natural gas prices mean that, in some instances, gas displaces the use of more carbon-intensive fuels, oil and coal, pushing down emissions. At the same time, lower natural gas prices lead to slightly higher overall consumption of energy and, in some instances, to displacement of lower-carbon fuels, such as renewable energy sources and nuclear power. Overall, the projections in the Golden Rules Case involve only a small net shift in anticipated levels of greenhouse-gas emissions.

Table 2.7 ▷ World energy-related CO_2 emissions in the Golden Rules Case (million tonnes)

	2010	2020	2035	2010-2035*
OECD	12 363	12 157	10 716	-0.6%
of which from natural gas	3 034	3 336	3 758	0.9%
Non-OECD	16 960	21 327	24 674	1.5%
of which from natural gas	3 082	4 118	5 781	2.5%
World	**30 336**	**34 648**	**36 795**	**0.8%**

* Compound average annual growth rate.

The Golden Rules Case puts CO_2 emissions on a long-term trajectory consistent with stabilising the atmospheric concentration of greenhouse-gas emissions at around 650 parts per million, a trajectory consistent with a probable temperature rise of more than 3.5 degrees Celsius (°C) in the long term, well above the widely accepted 2°C target. This finding reinforces a central conclusion from the *WEO* special report on a Golden Age of Gas (IEA, 2011b), that, while a greater role for natural gas in the global energy mix does bring environmental benefits where it substitutes for other fossil fuels, natural gas cannot on its own provide the answer to the challenge of climate change. This conclusion could be changed by widespread application of technologies such as carbon capture and storage,

which could reduce considerably the emissions from the consumption of gas (and other fossil fuels); but this is not assumed in the period to 2035.[15]

At country level, the impact of the Golden Rules Case on greenhouse-gas emissions from gas depends to a large degree on the structure of domestic fuel use, in particular for power generation. In countries where the average greenhouse-gas intensity of power generation is already close to that of natural gas, as for example in Europe, the addition of extra natural gas to the fuel mix has relatively little impact on the overall emissions trajectory. By contrast, in countries heavily reliant upon coal for electricity generation, such as China, the increased availability of natural gas has a more substantial impact on CO_2 emissions. Such increased use of gas also reduces emissions of other pollutants; compared with burning coal, combustion of natural gas results in lower emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_x) and gas also emits almost no particulate matter. Local emissions of particulate matter and NO_x are the main causes of low air quality – a particularly important consideration for emerging economies seeking to provide energy for fast-growing urban areas.

Unconventional gas production itself inevitably results in some changes to the land, to surface water and to groundwater systems, particularly given the scale of the production envisaged in the Golden Rules Case. As indicated in the Spotlight, we estimate that production at these levels would require the drilling of over one million new wells in the course of the projection period, over half of which would be in the United States and China. These operations have to be managed strictly in accordance with the Golden Rules, or the associated social and environmental damage will cut short attainment of the Golden Rules Case.

The Low Unconventional Case

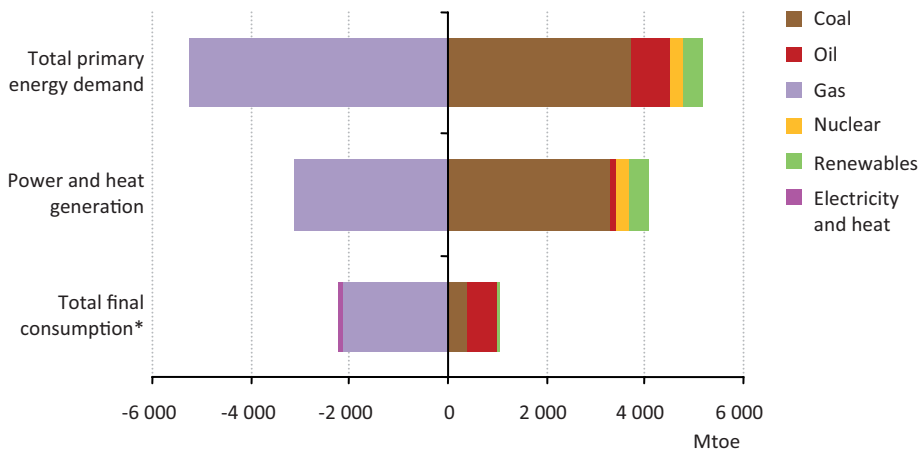
Demand

In the Low Unconventional Case, where the Golden Rules are not applied and environmental and other constraints on unconventional gas development provide too difficult to overcome, the competitive position of gas in the global fuel mix deteriorates, compared with the Golden Rules Case, as a result of lower availability and higher prices. Global demand for gas grows more slowly, reaching 4.6 tcm in 2035. The difference in primary gas demand in 2035 between the Low Unconventional Case and the Golden Rules Case is about 535 bcm, an amount close to total gas demand in the European Union in 2010. In the global energy mix, whereas in the Golden Rules Case gas overtakes coal by 2035, in the Low Unconventional Case the share of gas in the global energy mix increases only slightly, from 21% in 2010 to 22% in 2035, remaining well behind that of coal (whose share decreases from 28% to 26%) and of oil.

15. There is the possibility that the capacities for CO_2 storage might be affected by hydraulic fracturing. A recent study (Elliot and Celia, 2012) estimated that 80% of the potential area to store CO_2 underground in the United States could be prejudiced by shale and tight gas development, although others have argued that, even if the rock seal in one place were to be broken by hydraulic fracturing, other layers of impermeable rock underneath the fractured area would block migration of the CO_2.

The fall in gas demand in the Low Unconventional Case, relative to the Golden Rules Case, is mostly compensated for by increased consumption of coal (Figure 2.9). The cumulative difference in total primary gas demand over the projection period is around 5 200 Mtoe (6.3 tcm); coal accounts for almost three-quarters of the increase in the demand for other fuels, the largest coming in China (accounting for about 40% of the additional coal demand). The total primary energy used for power and heat generation is higher in the Low Unconventional Case because of the substitution of gas-fired generation by coal-fired generation; being less efficient, coal plants require more energy to produce the same amount of electricity. In power generation, around 75% of the fall in gas-fired power is taken up by coal. In total final consumption, the effect is felt primarily through the increase in demand for oil, because gas fails to make the same inroads in the transportation sector.

Figure 2.9 ▷ Cumulative change in energy demand by fuel and sector in the Low Unconventional Case relative to Golden Rules Case, 2010-2035



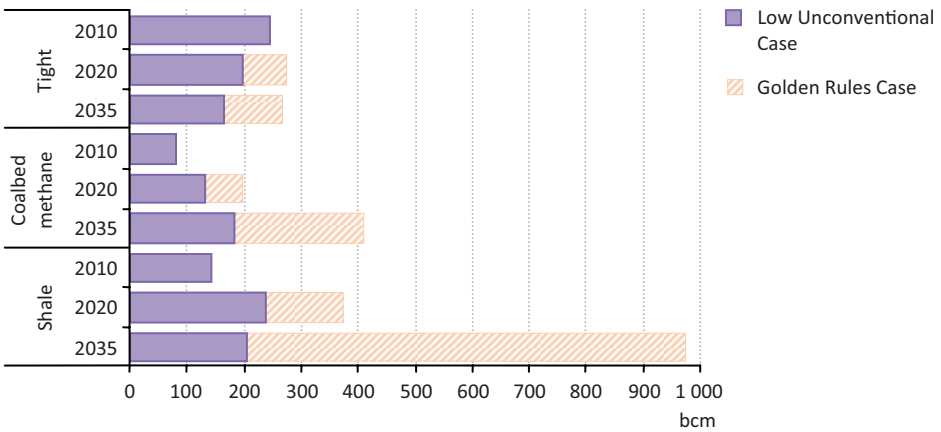
* Total final consumption is the sum of consumption by the end-use sectors industry, transport, buildings (including residential and services) and other (including agriculture and non-energy use).

Supply

In the Low Unconventional Case, total gas supply is lower, at 4.6 tcm, and unconventional production is much lower than in the Golden Rules Case. Unconventional gas production in aggregate rises above 2010 levels of 470 bcm but reaches only 570 bcm in 2020 and falls back to 550 bcm by 2035. Unconventional gas contributes only 6% to global gas production growth over the projection period, meaning that the share of unconventional gas in total gas output falls slightly over time, from 14% in 2010 to 12% in 2035. This is a long way below the 32% share reached by unconventional gas in 2035 in the Golden Rules Case. The difference in unconventional gas production in 2035 between the cases is over 1 tcm, equivalent to 5% of total primary energy supply.

In the Low Unconventional Case, the largest impact is on production of shale gas (Figure 2.10). At a global level, shale gas production increases by 40% over the projection period, reaching just above 200 bcm in 2035, about one-fifth of the level reached in the Golden Rules Case. Tight gas production falls to 165 bcm. Output of coalbed methane is slightly more resilient, rising by two-and-a-half times to around 185 bcm, 45% of the level reached in the Golden Rules Case. This is accounted for by the fact that coalbed methane resources are typically in areas that have existing coal mining operations, in which there is often less resistance to coalbed methane operations than to other types of unconventional gas development – and that the case can be made on environmental grounds that producing the gas is preferable to mining the coal.[16]

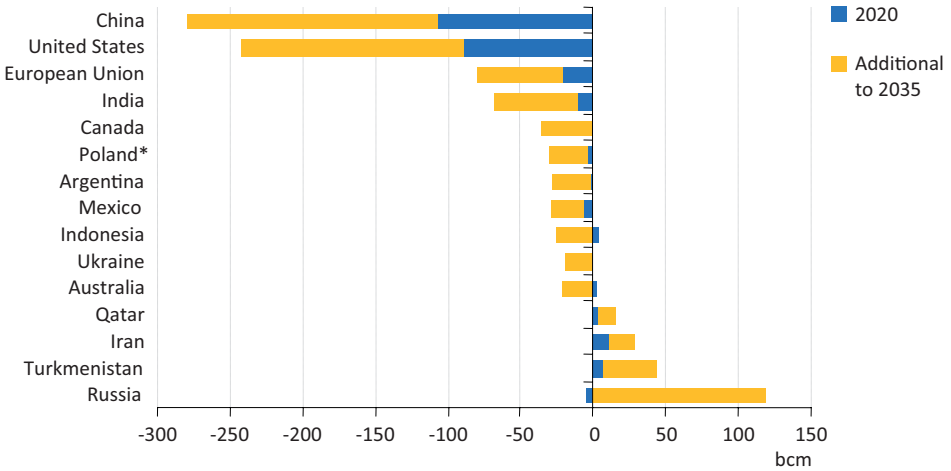
Figure 2.10 ▷ Unconventional gas production by type and case



The reduction in unconventional gas output in the Low Unconventional Case has most impact on China and the United States; their total gas production is lower in 2035 by 280 bcm and 240 bcm, respectively. This represents a 30% reduction in US output, but a much larger fall, 60%, in Chinese production relative to the Golden Rules Case (Figure 2.11 and Box 2.4). There are also major declines in output in the European Union (particularly Poland), India, Canada, Argentina, Mexico, and Indonesia. By contrast, the Low Unconventional Case shores up the preeminent position of the main conventional gas resource-holders. Even though total gas supply is lower than in the Golden Rules Case, Russia (around +115 bcm), Iran (nearly +30 bcm) and Qatar (just over +15 bcm) all post significant increases in their 2035 production, compared to the Golden Rules Case. In the Low Unconventional Case, increased demand from Europe and China for Russian gas means that Russia accounts for 20% of global supply, compared with 15% in the Golden Rules Case.

16. Coalbed methane production can actually reduce methane emissions if the gas would have been released by subsequent coal mining activities (this is sometimes referred to as coal mine methane production).

Figure 2.11 ▷ Change in natural gas production by selected region in the Low Unconventional Case relative to the Golden Rules Case



* The change in Polish output is included also in the figures for the European Union.

Box 2.4 ▷ What could lead to a Low Unconventional Case in China?

The Chinese government has announced ambitious targets for future production of coalbed methane and shale gas: 6.5 bcm of shale gas and 30 bcm of coalbed methane in 2015, and 60 to 100 bcm of shale gas in 2020. These targets are supported by large producer subsidies for both types of resources. Our projections for the Golden Rules Case show a somewhat slower rate of increase before 2020, but are generally in line with official targets. Public opposition to unconventional gas developments is not currently manifest in China; if it were to develop over the projection period without gaining a commensurate regulatory and industry response, including application of the Golden Rules, the result could be production restrictions leading to an output plateau near the level of the 2020 targets, instead of the continuing growth projected in the Golden Rules Case. There are other hurdles which could also hold back the development of unconventional gas in China:

- The resource base could turn out to be much smaller than currently estimated. The current resource estimates are largely extrapolations from a small number of wells.
- Recovery factors or production rates could be lower than thought. In the United States, different gas shale deposits and different coalbed methane deposits yield very different levels of production. Not enough is known yet about the Chinese reservoirs to confirm that the range of productivity will be similar to that observed

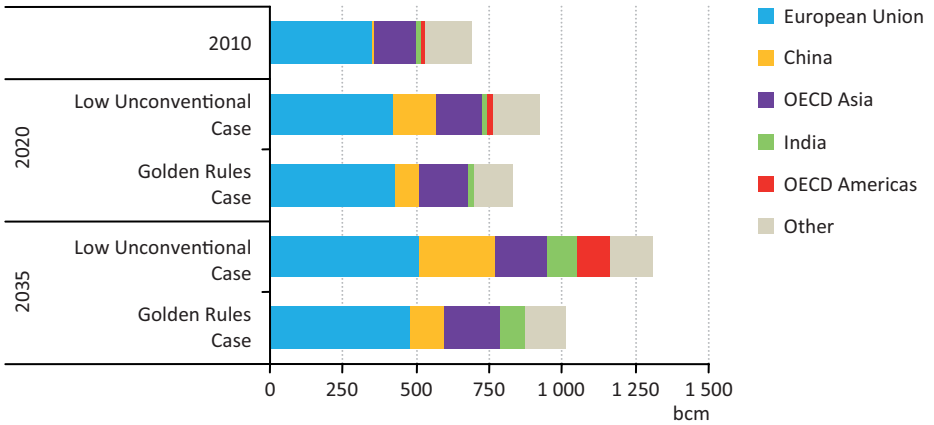
in the United States. On the assumption of similar productivity, the Golden Rules Case will require drilling something like 300 000 new unconventional gas wells in China during the projection period, already a very demanding level of activity. Even modest reductions in productivity would test the limits of the drilling capacity of the country.

- The economics could turn out to be disappointing. Many of the shale gas reservoirs in China are known to be deeper and more complex that those currently exploited in the United States. Both of these factors have a strong influence on the economics. The costs of well construction scale up rapidly with depth. Moreover, most of the coalbed methane resources are located far from large consumption centres: transportation costs make such resources not much more attractive than imports.
- Water availability: a significant part of the shale gas resources is located in regions where either water availability is limited or where competition with agricultural users of the water resources is likely to be a serious issue. This could limit the number of wells and hydraulic fracturing treatments that can be performed in those regions.
- Wavering government support: shale gas and coalbed methane production currently benefit from large subsidies in order to promote their development. When the volumes get large, such subsidies may not be sustainable. Or subsidies to fossil fuels in general may become unacceptable in the later part of the projection period. Loss of subsidies and worsening economics could curb the growth of unconventional gas production from the mid-2020s.

International gas trade, markets and security

The picture of inter-regional trade in the Low Unconventional Case is radically different from that described in the Golden Rules Case. The volume of trade is almost 300 bcm higher in the Low Unconventional Case in 2035, up about 30%, and some patterns of trade are also reversed, with North America requiring large quantities of imported gas to meet its net requirements (Figure 2.12). The United States, a strategically significant gas exporter in the Golden Rules Case, imports nearly 100 bcm by the end of the projection period in the Low Unconventional Case. Despite lower overall gas demand, China's demand for pipeline and LNG imports in 2035 reaches 260 bcm in the Low Unconventional Case, nearly 145 bcm higher than in the Golden Rules Case.

Figure 2.12 ▷ Major natural gas net importers by case



Among the exporters, the share of Russia and the Middle East in global inter-regional trade increases slightly to 46% in 2035 in the Low Unconventional Case, compared with a drop to 35% in the Golden Rules Case. Against a backdrop of rising import dependence in some key gas-consuming regions and a more limited number of potential suppliers, the outlook for customers for gas in the Low Unconventional Case looks less bright. Competition among importers becomes more intense, contributing to tighter markets in Europe and Asia. In North America, with the marginal supply coming from international markets, relatively expensive LNG imports pull up domestic prices in the United States – the opposite effect from the Golden Rules Case, where competitively priced exports have a mitigating effect on prices in export markets.

Box 2.5 ▷ A hybrid case

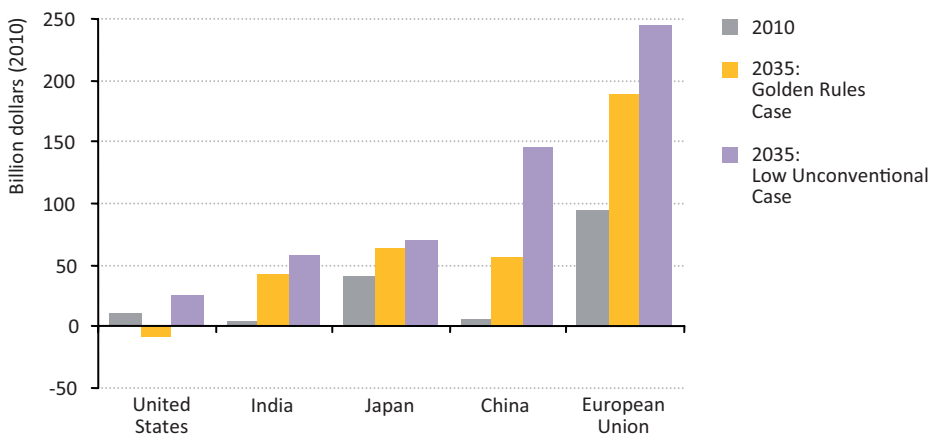
The two cases examined here apply favourable and unfavourable assumptions, respectively and uniformly, to all countries' prospects for unconventional gas development. But it is also possible that some countries follow a path of rapid growth in unconventional resource development along the lines of the Golden Rules Case, while others make slow progress or opt not to develop these resources, as in the Low Unconventional Case. Perhaps the most plausible of these hybrid cases is one in which enhanced attention to environmental issues sustains growth in unconventional output in North America and Australia, while elsewhere – with the partial exception of China – countries fail to realise the regulatory mix that would allow unconventional gas output to grow fast, at least until well into the 2020s. This case is not modelled here, but bears a resemblance to the central scenario of the *WEO-2011* that will be updated in full in this year's *Outlook*, to be published in November 2012.

Investment and other economic impacts

Various constraints in the Low Unconventional Case – moratoria on the use of hydraulic fracturing, overly strict regulation, unreasonably high compliance costs, arbitrary restrictions on drilling locations, less attractive fiscal terms, limitations on water availability and emerging resource limitations – serve to deter upstream investment in unconventional resources. Global cumulative investment in unconventional gas falls by half, to some $1.4 trillion, compared with the investment in the Golden Rules Case, and 60% of investment in unconventional gas is made in the United States. Even so, the share of the United States in global cumulative upstream gas investment declines from 24% to 21%. Limited prospects for unconventional gas prompt $0.7 trillion more cumulative investment in conventional resources. This underscores the relative shift in market power from unconventional resource holders to the major conventional producers, notably in Russia, the Middle East and North Africa.

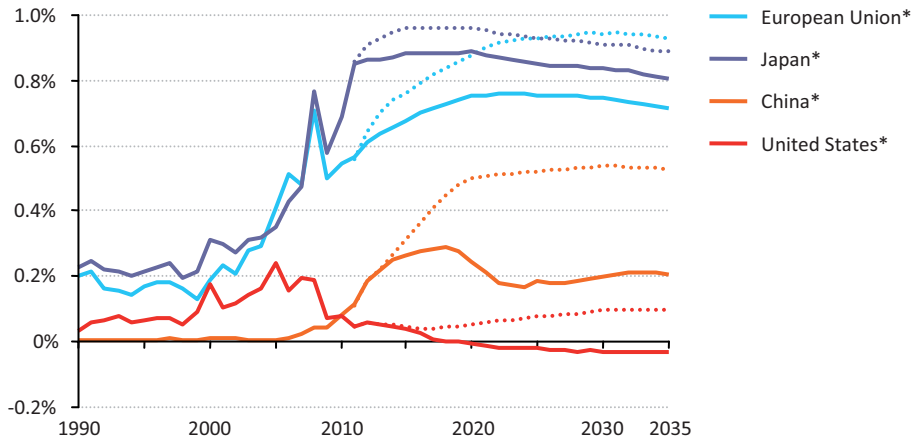
The import bills attached to inter-regional trade rise to $630 billion in 2035 (in year-2010 dollars) in the Low Unconventional Case, nearly 60% higher than in the Golden Rules Case. The proportionate impact on import bills is highest in China and the European Union, but the effect in other countries is also marked (Figure 2.13). China's spending on gas imports in 2035 in the Low Unconventional Case reaches almost $150 billion, or almost three times the level reached in the Golden Rules Case. Gas-import bills in the European Union rise to $245 billion in 2035, 30% above the $190 billion reached in the Golden Rules Case. Spending by the United States on gas imports in 2035 in the Low Unconventional Case totals $25 billion, around double the level of 2010, whereas the United States is a net exporter from 2020 in the Golden Rules Case, with export earnings increasing steadily to around $10 billion in 2035.

Figure 2.13 ▷ Natural gas-import bills by selected region and case



It follows that gas import bills expressed as a share of GDP are also sharply higher in the Low Unconventional Case than in the Golden Rules Case (Figure 2.14). For example, China's import bills stabilise at 0.5% of GDP towards the end of the projection period compared with a plateau of just 0.2% in the Golden Rules Case.

Figure 2.14 ▷ Spending on net-imports of natural gas as a share of real GDP at market exchange rates by case



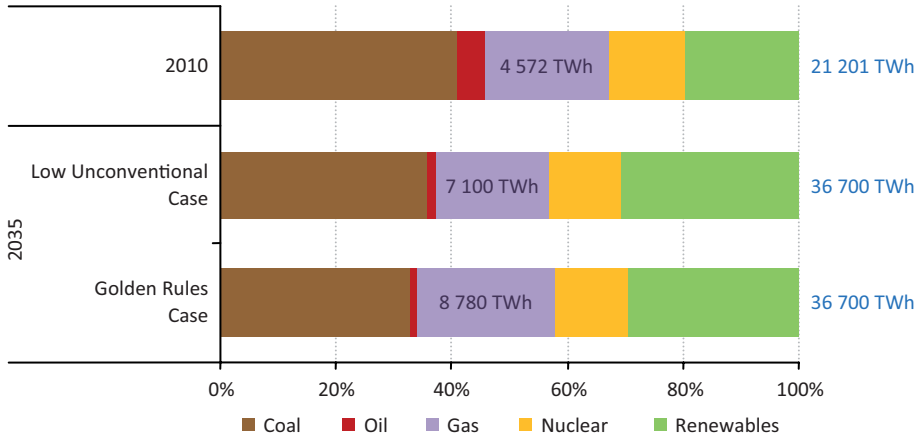
* Solid lines represent the Golden Rules Case; dotted lines represent the Low Unconventional Case.

Climate change and the environment

Although the forces driving the Low Unconventional Case derive in part from environmental concerns, it is difficult to make the case that a reduction in unconventional gas output brings net environmental gains. The effect of replacing gas with coal in the Low Unconventional Case is to push up energy-related CO_2 emissions, which are 1.3% higher than in the Golden Rules Case. The global power generation mix (Figure 2.15) involves a higher share of coal-fired power in the Low Unconventional Case, stemming from the more limited role for natural gas. Additional investment in coal-fired generation locks in additional future emissions, since any new coal-fired power plant has an anticipated operating lifetime in excess of 40 years.

Though many of those concerned with environmental degradation may find it difficult to accept that unconventional gas resources have a place in a sustainable energy policy, a conclusion from this analysis is that, from the perspective of limiting global greenhouse-gas emissions, a Golden Rules Case has some advantages compared with the Low Unconventional Case, while also bringing with it other benefits in terms of the reliability and security of energy supply.

Figure 2.15 ▷ World power generation mix by case



Note: TWh = terawatt-hours.

Nonetheless, reaching the international goal of limiting the long-term increase in the global mean temperature to 2°C above pre-industrial levels cannot be accomplished through greater reliance on natural gas alone. Achieving this climate target will require a much more substantial shift in global energy use, including much greater improvements in energy efficiency, more concerted efforts to deploy low-carbon energy sources and broad application of new low-carbon technologies, including power plants and industrial facilities equipped for carbon capture and storage. Anchoring unconventional gas development in a broader energy policy framework that embraces these elements would help to allay the fear that investment in unconventional gas comes at the expense of investment in lower-carbon alternatives or energy efficiency.

Country and regional outlooks

Are we moving towards a world of Golden Rules?

Highlights

- The United States is the birthplace of the unconventional gas revolution and regulatory developments at both federal and state levels will do much to define the scope and direction of similar debates in other countries. Moves are underway to build on existing regulation and practice, for example by tightening the rules on air emissions, ensuring disclosure of the composition of fracturing fluids and improving public information and co-operation among regulators.
- In North America, both Mexico and Canada also have significant unconventional gas resources and Canada is one of only a handful of countries outside the United States where commercial production is underway. Which way the regulatory debate turns could have a substantial effect on future unconventional supply: in the Golden Rules Case, total production from North America reaches 1 085 bcm in 2035, of which almost 70% is unconventional supply, whereas the equivalent figure in the Low Unconventional Case is only 780 bcm; this makes the difference between the region exporting to, or importing from, global gas markets.
- The prospects for unconventional gas in China are intertwined with the much broader process of gas market and pricing reform, and with open questions about the extent and quality of the resource. Over the longer term, environmental policies and constraints, notably water availability, are also set to play a role. Our projections for the Golden Rules Case are for unconventional output to reach just over 110 bcm in 2020, a very rapid increase but still somewhat lower than ambitious official targets, and 390 bcm in 2035. Unconventional production is some 280 bcm lower in 2035 in the Low Unconventional Case.
- In advance of any substantial unconventional output, the regulatory framework in Europe is under examination at both national and EU levels, with a variety of outcomes ranging from enthusiastic support for unconventional development from Poland to the bans on hydraulic fracturing in place in France and Bulgaria. In our projections in the Golden Rules Case, growth in unconventional supply in the European Union reaches almost 80 bcm in 2035, which is sufficient post-2020 to offset the decline in conventional output.
- New unconventional gas projects in Australia are coming under increased environmental scrutiny, in particular related to the risk of water contamination from coalbed methane projects. This could constrain future unconventional gas output, although Australia has ample conventional resources with which to achieve growth in supply and export; exports of 120 bcm by 2035 in the Golden Rules Case come mainly from unconventional gas developments, whereas a comparable level of export in the Low Unconventional Case is driven by mainly by conventional output.

United States

Resources and production

Until recently, unconventional natural gas production was almost exclusively a US phenomenon. Tight gas production has the longest history, having been expanding steadily for several decades. Commercial production of coalbed methane began in the 1980s, but only took off in the 1990s; it has levelled off in recent years. Shale gas has also been in production for several decades, but started to expand rapidly only in the mid-2000s, growing at more than 45% per year between 2005 and 2010. Unconventional gas production was nearly 60% of total gas production in the United States in 2010. While tight gas and shale gas account for the overwhelming bulk of this, shale gas is expected to remain the main source of growth in overall gas supply in the United States in the coming decades. The United States and Canada still account for virtually all the shale gas produced commercially in the world, though – as discussed in Chapter 2 of this report – many countries are now trying to replicate this experience.

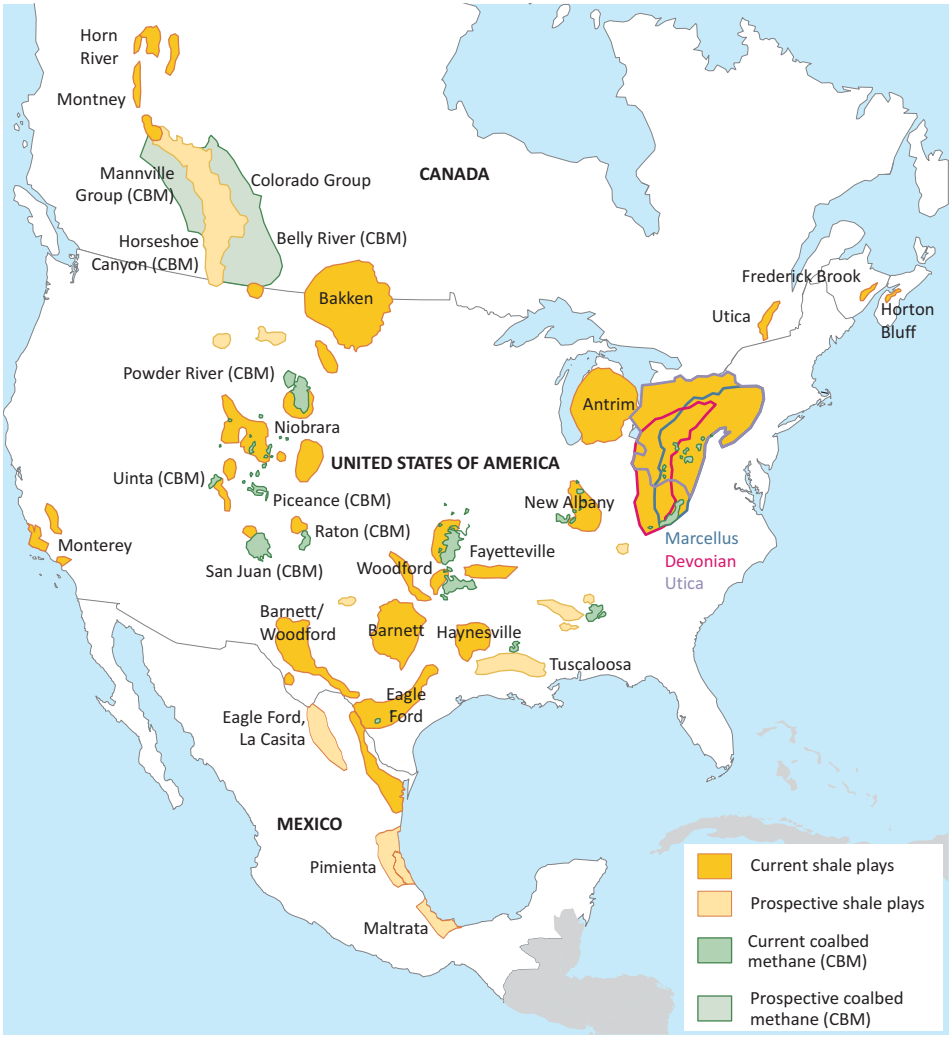
There are large resources of all three types of unconventional gas across the United States. Of the 74 trillion cubic metres (tcm) of remaining recoverable resources of natural gas at end-2011, half are unconventional (Table 3.1); in total, gas resources represent around 110 years of production at 2011 rates. Major unconventional gas deposits in the United States are distributed across much of the country (Figure 3.1). Coalbed methane resources are found principally in the Rocky Mountain states of Wyoming, Utah, New Mexico, Colorado and Montana. Tight gas and shale gas are located in a number of different basins stretching across large parts of the United States, some of which are shared with Canada and Mexico. Two of the largest shale plays that have been identified, the Marcellus and Haynesville formations, taken as single reservoirs are among the largest known gas fields of any type in the world.

Table 3.1 ▷ Remaining recoverable natural gas resources and production by type in the United States

	Recoverable resources (tcm)		Production (bcm)		
	End-2011	Share of total	2005	2010	Share of total (2010)
Unconventional gas	37	50%	224	358	59%
Shale gas	24	32%	21	141	23%
Tight gas	10	13%	154	161	26%
Coalbed methane	3	4%	49	56	9%
Conventional gas	37	50%	288	251	41%
Total	**74**	**100%**	**511**	**609**	**100%**

Sources: IEA analysis and databases.

Figure 3.1 ▷ Major unconventional natural gas resources in North America



This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Regulatory framework

As pioneers of large-scale unconventional gas development, policy-makers, regulators, producers and the general public in the United States have been the first to face the question of how to evaluate and minimise the associated environmental risks. The emergence of unconventional gas production on a large scale has prompted a broad debate, particularly as production has moved out of traditional oil and gas producing areas. It has also led to changes in the regulatory framework and industry practices. As described in Chapter 1, the principal areas of concern are the impact of drilling on land use and water resources

(in particular, the possible contamination of aquifers and surface water) and possible increases in air emissions, particularly of methane and volatile organic compounds.

The legal and regulatory framework for the development of unconventional resources in the United States is a mixture of laws, statutes and regulations at the federal, state, regional and local levels. Most of these rules apply to oil and gas generally and were in place before unconventional resource development took off. They cover virtually all phases of an unconventional resource development, from exploration through to site restoration, and include provisions for environmental protection and management of air, land, waste and water. States carry the primary responsibility for regulation and enforcement on lands outside federal ownership. This approach allows for some regionally specific conditions, such as geology or differing economic or environmental priorities, to be taken into account, with consequential variations in regulatory practices among states. However, on federal lands (extensive in the western United States), the federal government owns the land and mineral resources and directly regulates the extraction process.

Federal laws applicable to unconventional gas resource development are directed mainly at environmental protection. They include the Clean Air Act, Clean Water Act and Safe Drinking Water Act. Certain exemptions from federal rules have been granted; for example, hydraulic fracturing is excluded from the list of regulated activities under the Underground Injection Program authorised by the Safe Drinking Water Act (unless diesel-based fracturing fluids are used). Federal regulations related to community protection and occupational health and safety require that operators make information on certain hazardous chemicals used in drilling operations, including fracturing fluids, available to officials and those responsible for emergency services. Federal rules do not pre-empt additional state-level regulations and public concerns about the risk of pollution have prompted some states to require wider public disclosure about the types and volumes of chemicals used.

State-level regulations relevant to unconventional resources are typically specified in state oil and gas laws; in some cases, these are being updated to respond to public concerns about the environmental impact of unconventional gas development. Typical changes include rules about disclosure of information on fracturing fluids, additional measures to ensure adequate integrity in well casing and cementing, and rules on the treatment and disposal of waste water. Yet regulatory gaps remain in many states, not least because some have limited experience with oil and gas development. The states of New York, New Jersey and Maryland have enacted temporary bans on hydraulic fracturing pending further review of its environmental impacts and the need for changes to regulations; at the time of writing, Vermont also seems set to enact a ban.

Efforts to strengthen the United States' regulatory framework are a public priority, in order to ensure responsible development of unconventional resources and respond to rising public anxiety and pressure. Among the many public organisations focusing on the environmental aspects of unconventional gas development, two are working specifically on improving the quality of regulatory policy: the Ground Water Protection Council and the State Review of Oil and Natural Gas Environmental Regulations (STRONGER). They

have both been advising states on regulatory matters to do with unconventional gas. The industry itself has taken steps to promote best practice, both through industry bodies, such as the American Petroleum Institute and through initiatives such as the creation of the FracFocus website, a voluntary online registry to which companies submit data about chemicals used in hydraulic fracturing operations (API, 2011). The site is managed through a partnership with the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

The United States Environmental Protection Agency has issued federal regulations under the Clean Air Act that aim to reduce emissions of volatile organic compounds from all operations of the oil and gas industry; these will also cut methane emissions. The regulations apply to wells that are hydraulically fractured and will, in essence, enforce the use of "green completions", as already mandated in Colorado and Wyoming. The Bureau of Land Management, responsible for regulation of most energy-related activities on federal land, has proposed new rules that would require companies to disclose the composition of fracturing fluids, seek additional permits and conduct stringent well integrity tests. These initiatives have sparked an intense debate among interested parties as to whether hydraulic fracturing should be regulated at both state and federal level, and whether harmonised regulations on federal lands and on neighbouring leases are required.

At the end of 2011, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued a set of twenty recommendations for short-term and long-term actions by federal and state agencies to reduce the environmental impact and improve the safety of shale gas production (US DOE, 2011). A major study by the National Petroleum Council on the future of oil and gas resources in the United States has also emphasised the need for "prudent development" and concluded that the benefits of the country's oil and gas resources can be realised by ensuring that they are developed and delivered in a safe, responsible and environmentally acceptable manner in all circumstances (NPC, 2011). These studies and recommendations have been important in defining the scope of regulatory change in the United States and setting its direction; by extension, they could be influential in many countries that are seeking to undertake unconventional gas development.

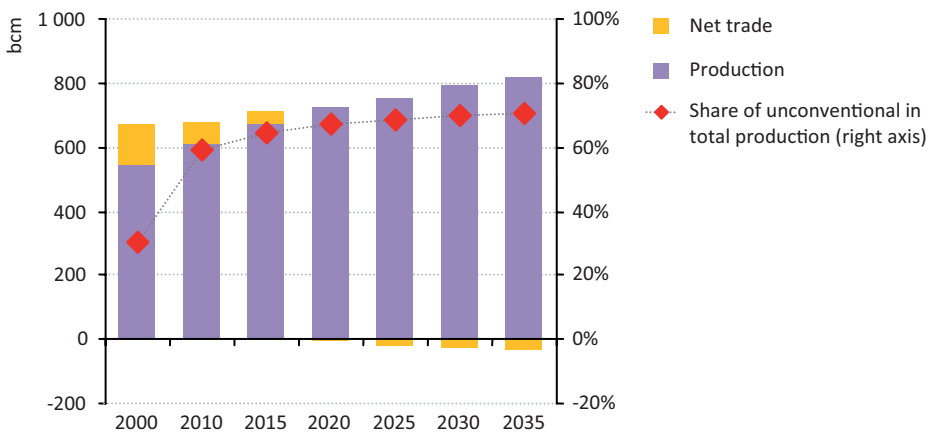
Within this diverse structure, a major challenge is to maintain reasonable consistency of regulation (for example, among the different states), closing regulatory gaps, where necessary, and doing this in a way that encourages best practice and responds to changes in production technology. Unconventional resource production may be well underway in United States, but shale gas development – and hydraulic fracturing in particular – has become an emotive public issue, with strong and well-organised positions taken by many of the parties involved. This has complicated the prospects for constructive engagement, limiting the common ground on which new regulation (at federal or state level) or new projects (at local level) might be based. Given the scale and pace of development in the United States, there is a likelihood that regulation will be driven by events. For example, an environmental incident linked to unconventional gas development could crystallise

public views and prompt new restrictions on unconventional gas production or the use of hydraulic fracturing.

Projections and implications

Assumptions about the regulatory environment have a marked impact on the results of the two cases examined in this report.[1] In the Golden Rules Case, total gas production in the United States grows from around 610 billion cubic metres (bcm) in 2010 to 820 bcm in 2035 (Figure 3.2). Almost all of this increase comes from shale gas production: output of conventional gas, coalbed methane and tight gas remain close to current levels. As a result, the share of shale gas in total gas production rises from 23% in 2010 to 45% in 2035; total unconventional production takes a 71% share of gas output by 2035.

Figure 3.2 ▷ Natural gas balance in the United States in the Golden Rules Case*



* Positive values for net trade denote imports, while negative values represent exports. The sum of production and net trade represents total demand.

In the Low Unconventional Case, total gas production goes into decline after peaking at 660 bcm around 2015, falling to 580 bcm in 2035, 30% less than in the Golden Rules Case (Table 3.2). Production of shale gas in the United States grows until 2017 before limitations on access to resources cause output to fall back to 2010 levels; tight gas and coalbed methane production also decline, to levels seen around 2000 and 1990, respectively. In the Low Unconventional Case, the share of unconventional gas in total supply decreases to only 47% by the end of the *Outlook* period – 23 percentage points less than in the Golden Rules Case. On the other hand, higher gas prices and limited unconventional production in the Low Unconventional Case prompt a mini-renaissance in conventional gas output, with an increase of more than 50 bcm over 2010 production, driven by the investment capital

1. See Chapter 2 for details of assumptions in both cases.

and rigs freed up by the shrinking unconventional sector and the possible opening of more offshore and Arctic acreage as the United States struggles to reduce its imports and the associated bills.

These results point in two very different directions for the United States' domestic consumers of gas and its gas industry and its role in international markets. On the domestic market, although gas prices are set to increase in both cases, the rate of the price increase is moderated in the Golden Rules Case by the availability of domestic unconventional gas. United States gas consumption grows by 0.6% per year in this case, a modest rate of increase by global standards (reflecting the maturity of the gas market), but much more impressive considering that overall energy demand growth in the United States averages 0.1% per year (so gas consumption grows six times faster than overall energy demand[2]). In the United States, IHS Global Insight estimates that the lower gas prices attributable to shale gas production will save households $926 per year between 2012 and 2015 (IHS, 2011). Cheaper gas also stimulates industries – chemicals and fertilisers, in particular – that rely on gas as a key feedstock or source of energy. Several chemical companies have announced expansion plans in the United States (PWC, 2011). In the Low Unconventional Case, gas consumption in the United States grows until 2020 and then declines thereafter, ending almost 15% lower by 2035 than in the Golden Rules Case.

Table 3.2 ▷ Natural gas indicators in the United States by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	609	726	821	637	578	242
Unconventional	358	489	580	383	274	306
Share of unconventional	59%	67%	71%	60%	47%	23%
Cumulative investment in upstream gas, 2012-2035**		1 648		1 293		355
Unconventional		1 308		854		454
Net trade (bcm): net imports (+) / net exports (-)	71	-9	-33	57	97	-131
Imports as a share of demand	10%	n.a.	n.a.	8%	14%	n.a.
Share of gas in the energy mix	25%	26%	28%	25%	24%	4%
Total energy-related CO_2 emissions (million tonnes)	5 343	5 218	4 618	5 173	4 511	108

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

2. This figure for the United States is higher, for example, than the comparable figure for China, where gas demand grows by an average of 7% per year in the Golden Rules Scenario, "only" about four times faster than total energy growth averaging 1.9% per year.

The boom in shale gas thus far has already transformed prospects for gas trade. The future of this unconventional "revolution" will determine whether the United States becomes an influential gas exporter over the coming decades or, alternatively, sees its imports rise from current levels. As recently as 2008, the United States was projected to require increasing imports of liquefied natural gas (LNG) to meet incremental gas demand (US DOE/EIA, 2008). In the Low Unconventional Case, this again becomes a prospect as domestic production declines.

In the expectation of a more favourable outlook for unconventional gas supply, a number of projects have been proposed to convert idle regasification terminals into liquefaction facilities to enable LNG exports (see Chapter 2). The most advanced of these, Sabine Pass on the United States Gulf Coast, cleared the last of its regulatory hurdles in April 2012 and could be exporting as soon as late 2015, with a target throughput of 22 bcm per year. A further seven projects await Department of Energy export approval, totalling in excess of 120 bcm of capacity. While not all these projects will proceed by 2020, even an additional two projects could see United States LNG export capacity exceed 60 bcm by 2020.

The prospect of LNG export has ignited a debate in the United States about the possible impact on price levels, with domestic gas-intensive industrial users expressing concern that they might lose an element of their current competitive advantage. We assume that other LNG export projects besides Sabine Pass are approved to begin operation but, in the Golden Rules Case, because of limited opportunities for export, the additional capacity may not be needed: LNG exports out of North America reach 40 bcm in 2035 but this is split between the United States and Canada. As discussed in Chapter 2, such exports and capacity would nonetheless have significant implications for the structure of international gas markets and for gas security, especially since a part of these exports would be based on a gas-priced formula, derived from the Henry Hub price.

Successfully meeting public concerns by putting in place the regulatory conditions that deal convincingly with environmental risks could be expected to have a significant impact on the pace of development of unconventional gas resources in other parts of the world. The United States has been the testing ground for unconventional gas technology and the place where this technology has been most widely and most productively applied. Just as experience from the United States has prompted both global interest in developing unconventional resources and reservations about their environmental impact, so too will other countries look to the United States for evidence that social and environmental risks can be managed successfully, in part with appropriate regulation.

Canada

Resources and production

Canada is endowed with large unconventional gas resources of all three types and is one of only a handful of countries outside the United States where commercial production is underway. Production of tight gas was around 50 bcm in 2010 and production of coalbed

methane (concentrated in the province of Alberta) close to 8 bcm. Shale gas is believed to have the greatest production potential in the longer term, although commercial production is only 3 bcm. The main Canadian shale gas plays currently being explored and appraised are the Horn River Basin and Montney shales in northeast British Columbia, the Colorado Group in Alberta and Saskatchewan, the Utica Shale in Quebec and the Horton Bluff Shale in New Brunswick and Nova Scotia (Figure 3.1). Remaining recoverable unconventional resources in Canada at end-2011 are estimated to be 18 tcm (11 tcm shale gas, 5 tcm coalbed methane and 2 tcm tight gas), representing around 6% of world unconventional resources. 80% of Canada's total remaining recoverable gas resources are unconventional.

Regulatory framework

Unconventional gas in Canada is subject to a set of federal, provincial and local laws and regulations governing upstream activities, including those relating to environmental impacts. Most oil and gas regulations are provincial, as the resources belong to the provinces (with the exception of those on native lands). The National Energy Board is the federal regulatory body for international and inter-provincial energy issues, while Environment Canada is the federal agency responsible for environmental protection, including the administration and enforcement of federal laws.

The regulatory picture in Canada varies by province, but in response to public pressure and the heightened commercial interest in Canadian unconventional gas opportunities, regulators across the country are paying increasing attention to the potential pollution risks from hydraulic fracturing and to the disposal of waste water from unconventional wells. While each province has its own particular regulations, all jurisdictions have laws to protect fresh water aquifers and to ensure responsible development. In western Canada, gas producers are required by regulation to re-inject produced water into deep saline zones located far below the base of the groundwater, using water disposal wells. In other regions, where no such disposal wells are available, provincial regulations set requirements for treating and disposing of produced water.

Approvals for water use are required from the responsible regulatory agency or government department. Regulators and governments have a variety of control mechanisms available to manage water use and mitigate potential impacts, including the ability to limit the rate at which water is used from any source and to specify aggregate water use limits. There are also regulations aimed at minimising the environmental footprint of drilling and production operations, for example by requiring centralised drilling pads and requiring land restoration after production has ceased.

As in the United States, industry bodies are promulgating and promoting best practices. The Canadian Association of Petroleum Producers has recently issued new guidelines for its members, covering many of the issues in the Golden Rules (CAPP, 2012). The Energy Resources Conservation Board, the regulator for the Province of Alberta, a province with a long history of oil and gas production, has initiated a review of its regulatory framework as

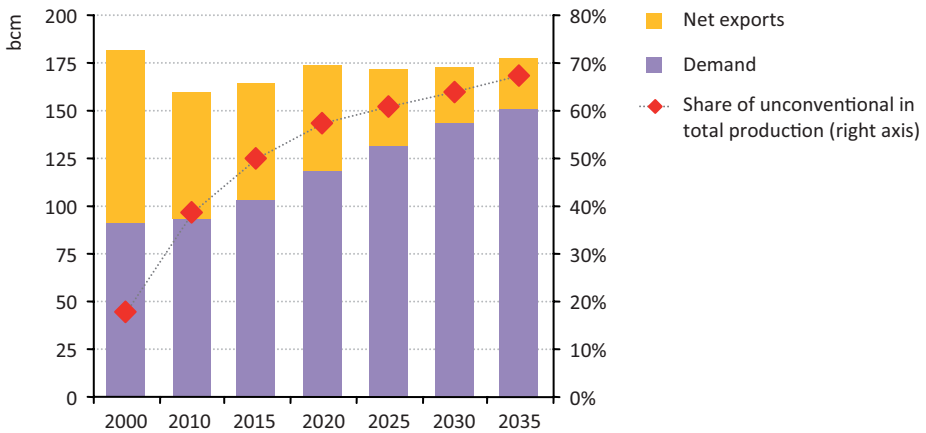
it applies to unconventional gas (ERCB, 2011). Five of Canada's provinces and one territory are associate members of the United States Interstate Oil and Gas Compact Commission.

The prospect of expanded drilling for shale gas has generated some public and political concern; the clearest incidence of this led the provincial government in Quebec to call a halt in 2011 to the use of hydraulic fracturing, pending an environmental review of the impacts of this practice on water supplies. This followed commercial interest in developing the Utica shale which, running near population centres along the St Lawrence River, generated substantial local opposition. The review is expected to report in 2013.

Projections and implications

Unconventional gas in Canada is expected to play an increasingly important role in offsetting a projected decline in conventional gas production and meeting rising domestic demand. In the Golden Rules Case, unconventional gas production rises from 62 bcm in 2010 to about 120 bcm in 2035, its share of total gas output increasing from just under 40% to two-thirds (Figure 3.3). Shale gas and, to a slightly lesser extent, coalbed methane drive this growth. Total gas production increases from 160 bcm to nearly 180 bcm between 2010 and 2035. Canadian gas demand grows even faster, so net exports drop sharply – from around 65 bcm in 2010 to 25 bcm in 2035. The United States has less need – possibly none at all – to import gas from Canada as its own production of unconventional gas is projected to outpace its domestic gas needs. While Canadian LNG exports to Pacific markets commence before 2020, further growth in exports to Asia is limited in the Golden Rules Case by the large increase in domestic production in China, as well as the rise in unconventional production in Indonesia and Australia.

Figure 3.3 ▷ Natural gas balance in Canada in the Golden Rules Case*



* The sum of demand and net exports represents total production.

In the Low Unconventional Case, shale gas production remains relatively robust, even with the assumed limitations on access to resources. It is about the only unconventional gas resource type with room to grow to offset otherwise rising North American demand for imports. However, overall gas production peaks before 2025 and falls back below current levels by the end of the projection period (Table 3.3). The higher prices that result from slower development constrain demand, which reaches around 130 bcm in 2035, 15% lower than in the Golden Rules Case. Although production is lower in the Low Unconventional Case, it is noteworthy that the required upstream investment is at a level similar to that in the Golden Rules Case; this is because of the relative resilience of shale gas production in the Low Unconventional Case and to the assumption (built into the model) that production tends to become more costly as a given resource starts to become more difficult to access. Since access to shale gas resources is limited in this case, the cost of production rises in a way that balances the effect of lower output on the overall investment requirement.

Table 3.3 ▷ Natural gas indicators in Canada by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	160	174	177	173	141	37
Unconventional	62	100	119	82	84	35
Share of unconventional	39%	57%	67%	48%	60%	7%
Cumulative investment in upstream gas, 2012-2035**		292		296		-4
Unconventional		218		207		11
Net exports (bcm)	66	55	26	63	12	14
Share of gas in the energy mix	30%	34%	40%	32%	35%	5%
Total energy-related CO_2 emissions (million tonnes)	523	547	540	533	521	19

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

Mexico

Resources and production

Mexico's large resources make it one of the most promising countries for shale gas development. Its 19 tcm of shale gas is the fourth-largest shale gas resource base in the world after China, the United States and Argentina; this figure represents some 85% of Mexico's remaining recoverable gas resources. While known about for more than two decades, as elsewhere, shale gas was not considered economically viable to produce until recently.

The government is keen to exploit shale gas resources to boost the country's flagging output of conventional oil and gas. In its National Energy Strategy 2012-2026, for the first

time, the Mexican Ministry of Energy has included two scenarios for the development of shale gas: the baseline scenario foresees production of 2 bcm (200 million cubic feet per day [mcf/d]) starting in the Eagle Ford shale play in 2016 and reaching 14 bcm (1 343 mcf/d) in 2026 (Secretaria de Energia, 2012). The "strategy scenario" assumes the additional development of the La Casita shale play, which leads to total shale gas production of 34 bcm (3 279 mcf/d) in 2026.

In line with this strategy, Pemex, the national oil company, is looking in particular at the areas in the north that are extensions of the Eagle Ford shale play (Figure 3.1). Pemex sunk its first shale gas well, Emergente 1, in the Burgos basin in February 2011 and this has been producing at a rate of almost 30 million cubic metres (3 mcf/d). Pemex plans to drill around 175 wells during the period 2011 to 2015 to evaluate reserves and delineate priority areas for development. Pemex also plans to acquire about 10 000 square kilometres of three-dimensional seismic data, which it will use to carry out detailed geological and geochemical modelling studies.

If this exploration effort demonstrates the commercial viability of shale gas production, the large-scale development of these resources would require a huge increase in drilling. Pemex estimates that the development of 8.4 tcm (297 trillion cubic feet) of shale gas – its central estimate of recoverable resources – would call for drilling a total of more than 60 000 wells[3] over the next 50 years, requiring a very large-scale capital investment.

In addition to the need for adequate investment, a number of technical challenges would need to be overcome for this to happen, notably adequate access to water for hydraulic fracturing. Coahuila, where much of the Eagle Ford play is located, is one of Mexico's driest states, with rainfall less than half the national average and all of the surface water rights have already been allocated. Three-quarters of the state's water is used in agriculture for the production of grains and other crops that can survive the desert climate, while the rest is for industrial consumption. Hydraulic fracturing on a large scale would require very careful treatment and recycling of waste water to reduce the need for fresh water. Other hurdles to shale gas development, such as the lack of pipeline infrastructure to deliver gas to market, could complicate operations and make the cost of drilling shale gas wells in Mexico significantly higher than in the United States. A plan to increase the transport and distribution capacity for natural gas is being implemented, including a pipeline that will run close to the main gas-rich areas in the northern parts of the country.

3. Information provided in a presentation by Carlos Morales, Director General, PEMEX Exploration & Production, to the IEA Workshop on Unconventional Gas in Warsaw, 7 March 2012. This appears to be based on an Estimated Ultimate Recovery (EUR) of 5 bcf per well; this is representative of good wells in the United States but could overestimate a likely average EUR per well; if so, the number of wells required to produce this volume of shale gas could be higher.

Regulatory framework

The environmental impact of gas development in Mexico is covered by existing environmental, health and safety laws and regulations. There are no specific national regulations in place yet for shale gas; however, the new National Energy Strategy 2012-2026 recognises that the new targets for shale gas production might require specific regulatory provisions and calls for the future development of an "integrated strategy" for shale gas, addressing environmental, social and financial challenges. This will require not only attention to the regulatory framework, but also the allocation of sufficient resources to regulatory bodies to ensure adequate supervision and enforcement.

Pemex holds monopoly rights over all upstream activities in Mexico and no other company is allowed to own hydrocarbons reserves or undertake exploration or production for its own benefit. A law adopted in 2008 allows Pemex to sign incentive-based development contracts with other companies, though the price paid for services cannot be linked to production: three such contracts for the development of small, mature onshore fields were awarded in August 2011. Larger contracts, which could have a more substantial impact on the country's production, are expected to be offered in future.

The strategy to be developed for shale gas could follow one of a range of possibilities: it could rest heavily on assistance from companies under service contracts, either basic in terms of remuneration or more strongly incentive-based, although it is also possible that Pemex could decide to handle all shale development on its own. The pace of shale gas development will depend in part on the approach chosen; a greater involvement of private firms, beyond the arrangements already provided for in current legislation, could accelerate the process, but may be politically challenging.

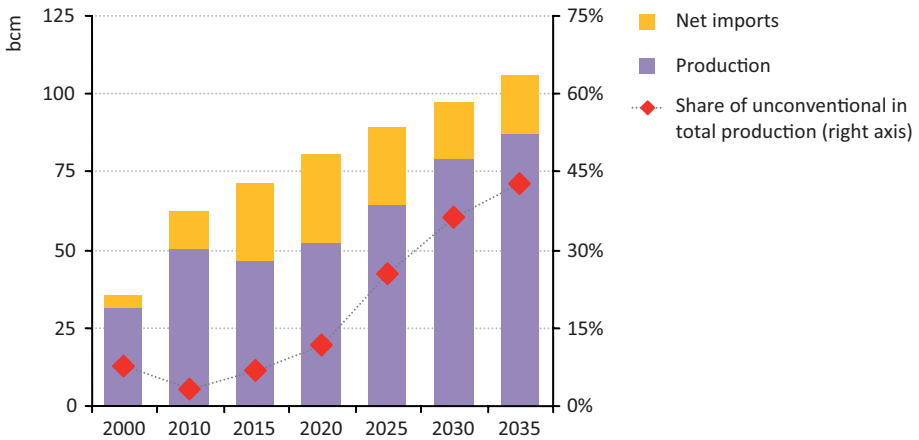
Projections and implications

Shale gas could make a significant contribution to meeting Mexico's gas needs in the longer term, but much will depend on the regulatory regime governing participation by private companies and whether the environmental challenges – notably related to the use and recycling of water for hydraulic fracturing – can be overcome. Development costs will have to be low enough to allow domestic resources to compete with imports from the United States, the price of which recently hit new lows. The alternative – to try and protect the domestic market from cheaper gas imports – is difficult in the context of Mexico's participation in the North American Free Trade Agreement.

In the Golden Rules Case, Mexican gas production grows from 50 bcm in 2010 to almost 90 bcm in 2035, with nearly all of the increase coming from unconventional gas (mostly shale gas, plus some tight gas); conventional gas production grows slightly to around 50 bcm by the end of the projection period, as new fields struggle to compensate for the

continuing decline in output from the Cantarell field and other mature fields.[4] Shale and tight gas production reach about 37 bcm combined in 2035, accounting for close to 45% of total Mexican gas production (Figure 3.4). In the Low Unconventional Case, unconventional gas production remains negligible through to 2035.

Figure 3.4 ▷ Natural gas balance in Mexico in the Golden Rules Case*



* The sum of production and net imports represents total demand.

Rapid growth in unconventional gas would have a major impact on Mexico's overall energy mix, with the lower gas prices encouraging gas use and leading to an increase in gas demand. In the Golden Rules Case, demand rises from around 60 bcm in 2010 to 105 bcm in 2035, the share of gas in total primary energy use increasing from 29% to 35% (Table 3.4). The country's need to import gas varies over time. It currently imports about 20% of its gas needs, by pipeline from the United States and in the form of LNG; these imports rise to nearly 30 bcm by 2020, but then fall back to about 20 bcm by 2035 as gas production outstrips demand growth. Higher gas demand and lower imports promise energy security and economic benefits to Mexico, with the possibility of net environmental benefits. In the Low Unconventional Case, the share of gas in primary energy demand actually drops, to 28% by 2035, leading to higher energy-related carbon-dioxide (CO_2) emissions relative to the Golden Rules Case.

4. In the strategy scenario, or high case, included in Mexico's National Energy Strategy 2012-2026, conventional gas production increases from around 60 bcm in 2011 to almost 85 bcm in 2026. Shale gas production, on its own, contributes around 34 bcm to total natural gas production in 2026.

Table 3.4 ▷ Natural gas indicators in Mexico by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	50	52	87	46	59	28
Unconventional	2	6	37	0	0	37
Share of unconventional	3%	12%	43%	0%	0%	43%
Cumulative investment in upstream gas, 2012-2035**		140		111		29
Unconventional		47		-		47
Net imports (bcm)	12	28	19	25	28	-9
Imports as a share of demand	19%	35%	18%	35%	32%	-14%
Share of gas in the energy mix	29%	32%	35%	29%	28%	7%
Total energy-related CO_2 emissions (million tonnes)	402	449	492	455	511	-19

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

China

Resources and production

The size of unconventional gas resources in China is at an early stage of assessment, but it is undoubtedly large. At end-2011, China's remaining recoverable resources of unconventional gas totalled almost 50 tcm, comprised of 36 tcm of shale gas, 9 tcm of coalbed methane and 3 tcm of tight gas.[5] This is around thirteen times China's remaining recoverable conventional gas resources. China's shale gas resources lie in several large basins spread across the country, with plays in the Sichuan and Tarim Basins believed to have the greatest potential. The main coalbed methane deposits are found in the Ordos, Sichuan and Junggar Basins (Figure 3.5).

Coalbed methane is currently the primary source of unconventional gas produced commercially in China, with output of around 10 bcm in 2010. Most of this output comes from coal producers PetroChina and China United Coal Bed Methane Company. Shale gas exploration activities have increased in recent years under a government-driven programme to evaluate the resource base. Results from several pilot projects, to be completed in 2012, are expected to inform the selection of high potential areas for further exploration. As of early 2012, an estimated 20 shale gas wells had been drilled by Chinese companies. Based on what is known about China's geology at this early stage, shale gas resources may prove more difficult and more expensive to develop than those in North America. Early

5. We use the ARI estimate for shale gas to be consistent with our methodology for other countries. This is higher than the 25 tcm estimated by China's Ministry of Land and Resources for recoverable shale gas resources; however the MLR number does not yet include all provinces (MLR, 2012).

indications are that kerogen quality in the shale plays is relatively poor, resulting in low organic content. This suggests that, for China to achieve a similar output to that of the United States, it would need to drill more wells, with longer reach.

Figure 3.5 ▷ Major unconventional natural gas resources in China

This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

The Chinese government has outlined ambitious plans for boosting unconventional gas exploration and production. These call for coalbed methane production of more than 30 bcm and for shale gas production of 6.5 bcm in 2015; the targets for shale gas output in 2020 are between 60 and 100 bcm. They are accompanied by the goal to add 1 tcm of coalbed methane and 600 bcm of shale gas to proven reserves of unconventional gas by 2015. In support of this effort, China plans to complete a nationwide assessment of shale gas resources and build nineteen exploration and development bases in the Sichuan Basin in the next four years. Efforts are also supported by the international partnerships that Chinese companies have formed in North America to develop shale gas acreage, which will provide valuable development experience.

An initial tender for four blocks of shale gas exploration acreage in the Sichuan Basin was held in June 2011, with participation limited to six eligible state-controlled companies. Of those, Sinopec and Henan Provincial Coal Seam Gas Development and Utilization Company obtained licences. An expanded group of bidders, including privately-owned Chinese

companies (qualified based on sufficient capital, technology and expertise), are expected to participate in a second round of licensing in mid-2012. Foreign firms will not be allowed to participate directly, but may enter into partnerships with eligible companies that submit successful bids. Various major international oil companies have already entered into some form of partnership with state-controlled companies, reflecting their strong interest in pursuing unconventional gas development opportunities in China.

Regulatory framework

China's huge unconventional gas potential and strong policy commitment suggest that these resources will provide an increasingly important share of gas in the longer term, though the pace of development through to 2020 – the key period of learning – remains uncertain. Because of China's highly centralised regulatory and policy-making framework and the high priority placed on industrial and economic development, unconventional gas projects may face fewer hurdles stemming from environmental concerns than those in Europe or the United States. Nonetheless, the regulatory framework is evolving, and different features of it could affect the pace of development in different ways, for example the terms of access, the pace of diffusion of advanced technology, financial incentives, the pricing regime, environmental constraints and infrastructure development.

Strategic policy decisions in China relating to resource management and environmental protection are made nationally, with implementation and enforcement responsibilities often delegated to local authorities. Many aspects of China's legal and regulatory framework for oil and gas development are broadly defined, giving local regulators latitude to consider project-specific circumstances in their decisions (although this can also lead to unpredictable outcomes). Challenges arise from the fragmentation and overlap of responsibilities among various regulating entities, uncertainty about effective co-ordination between them and potentially inconsistent enforcement of regulations.

Domestic petroleum exploration and development has traditionally been the domain of China's state-owned enterprises. Under the Law on Mineral Resources, only state-controlled entities may acquire mineral rights, foreign companies being confined to minority partnerships with state-controlled entities and, in some cases, production-sharing agreements. Although the strategic importance of unconventional gas means that China's national oil companies are likely to be the primary drivers of production growth, there are some changes underway in response to China's ambitious plans for shale gas exploration and development, and the need for the advanced technology and investment that foreign companies can bring. The legal classification of shale gas as a separate "mineral resource" in late 2011 means that the current regulations that give CNPC and SINOPEC exclusive rights for exploration of onshore oil and gas resources do not apply to shale gas, and this step may presage an intention to grant greater access to others. Foreign companies have already been allowed to take a majority stake in coalbed methane projects.

All project promoters must conduct an environmental impact assessment, which must be filed with national and local regulators and approved in advance of submission of a field-development plan. Drilling permits are issued on the basis of the development plan, rather than well-by-well; and any significant changes to the plan, for example related to the density of drilling, require submission of a new environmental impact assessment. Project delays during the early phases of development may occur because of the limited experience of producing unconventional gas in China.

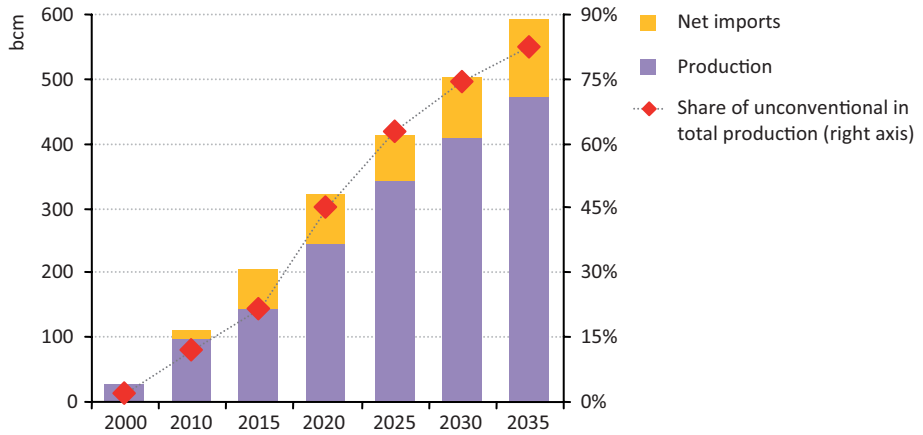
Water availability may prove to be one of the biggest obstacles to unconventional gas development in China, particularly in the north and west, where water is scarce and may be already strained by agricultural or urban needs. Water policies, regulations and plans are determined nationally, though responsibilities for management and enforcement are delegated locally. Many different entities are involved at the national, regional and local levels, which risks limited co-ordination of water resources at the river basin level. National standards establish maximum discharge concentrations for pollutants into water sources and the Circular Water Law promotes reuse and recycling of waste and produced water.

The fiscal regime, gas pricing policies and pipeline access are other regulatory variables that will critically influence the pace of unconventional gas development in China. The 12th Five-Year Plan promises favourable fiscal incentives to producers, namely direct subsidies, preferential tax treatment and priority land use. The domestic coalbed methane industry receives price subsidies of RMB 0.2 ($0.03) per cubic metre for extracted gas and RMB 0.25/m^3 ($0.04) for gas produced for some specific end-users. Shale gas might be expected to attain a similar or higher level of subsidy. According to the 12th Five-Year Plan, the pricing regime for shale gas will be market-based, an important signal that the government is willing to allow higher end-user prices (relative to current controlled prices for natural gas) to encourage development. China's gas pipeline network will necessarily have to expand to reach into unconventional gas production areas in order to avoid becoming a bottleneck as output increases. As major gas pipelines are currently run by national oil companies, making access more available to other producers will be vital.

Projections and implications

Gas is set to play an increasingly important role in meeting China's burgeoning energy needs and the successful development of the country's unconventional resources could accelerate that trend, given effective resource and environmental management. In the Golden Rules Case, unconventional gas production is projected to jump from 12 bcm in 2010 to just over 110 bcm in 2020 and 390 bcm in 2035. Total gas production rises from just under 100 bcm in 2010 to nearly 475 bcm in 2035 (Figure 3.6). Unconventional gas accounts for 83% of total gas production by the end of the projection period. Unconventional gas production in 2035 is predominately from shale gas (56%) and coalbed methane (38%); tight gas (6%) takes a smaller share.

Figure 3.6 ▷ Natural gas balance in China in the Golden Rules Case*



* The sum of production and net imports represents total demand.

Table 3.5 ▷ Natural gas indicators in China by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	97	246	473	139	194	279
Unconventional	12	112	391	37	112	279
Share of unconventional	12%	45%	83%	27%	58%	25%
Cumulative investment in upstream gas, 2012-2035**		554		311		243
Unconventional		374		170		204
Net imports (bcm)	14	77	119	143	262	-143
Imports as a share of demand	12%	24%	20%	51%	57%	-37%
Share of gas in the energy mix	4%	8%	13%	7%	10%	3%
Total energy-related CO_2 emissions (million tonnes)	7 503	9 792	10 449	9 877	10 695	-246

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

In the Low Unconventional Case, output of shale gas and coalbed methane grows much less rapidly, reaching a combined level of less than 115 bcm in 2035 (Table 3.5). The reduced availability of local gas supplies increases the country's dependence on imports at higher average prices. Less ambitious policies to boost demand, coupled with higher prices, lead to slower growth in Chinese gas demand, as the Chinese authorities seek to limit the country's reliance on imports. Demand reaches only 455 bcm by 2035, almost one-quarter lower than in the Golden Rules Case. The share of gas in total primary energy

is correspondingly markedly lower: 10% versus 13% in 2035. This results in increased dependence on coal and, to a lesser extent, on nuclear and renewables.

Rapid growth in unconventional gas would greatly strengthen China's energy security and have major implications for international gas trade. In the Golden Rules Case, imports amount to nearly 120 bcm in 2035, about 20% of the country's gas demand, compared with just over 260 bcm or nearly 60% of demand in the Low Unconventional Case. The overall cost of gas imports is correspondingly much lower, by 60%, in the Golden Rules Case. Lower import volumes would improve China's negotiating position *vis-à-vis* its suppliers, including producers of LNG, existing suppliers by pipeline from Central Asia and Myanmar, and Russia, which has the potential to become a major supplier of gas to China but whose opportunities to do so would be much more limited in the Golden Rules Case. The uncertainty surrounding the prospects for China's unconventional gas industry may favour investment in LNG over pipeline projects (and, in both cases, lessen the attractiveness of large long-duration supply contracts) as China may seek more flexibility to allow for gas-import needs turning out to be smaller than expected.

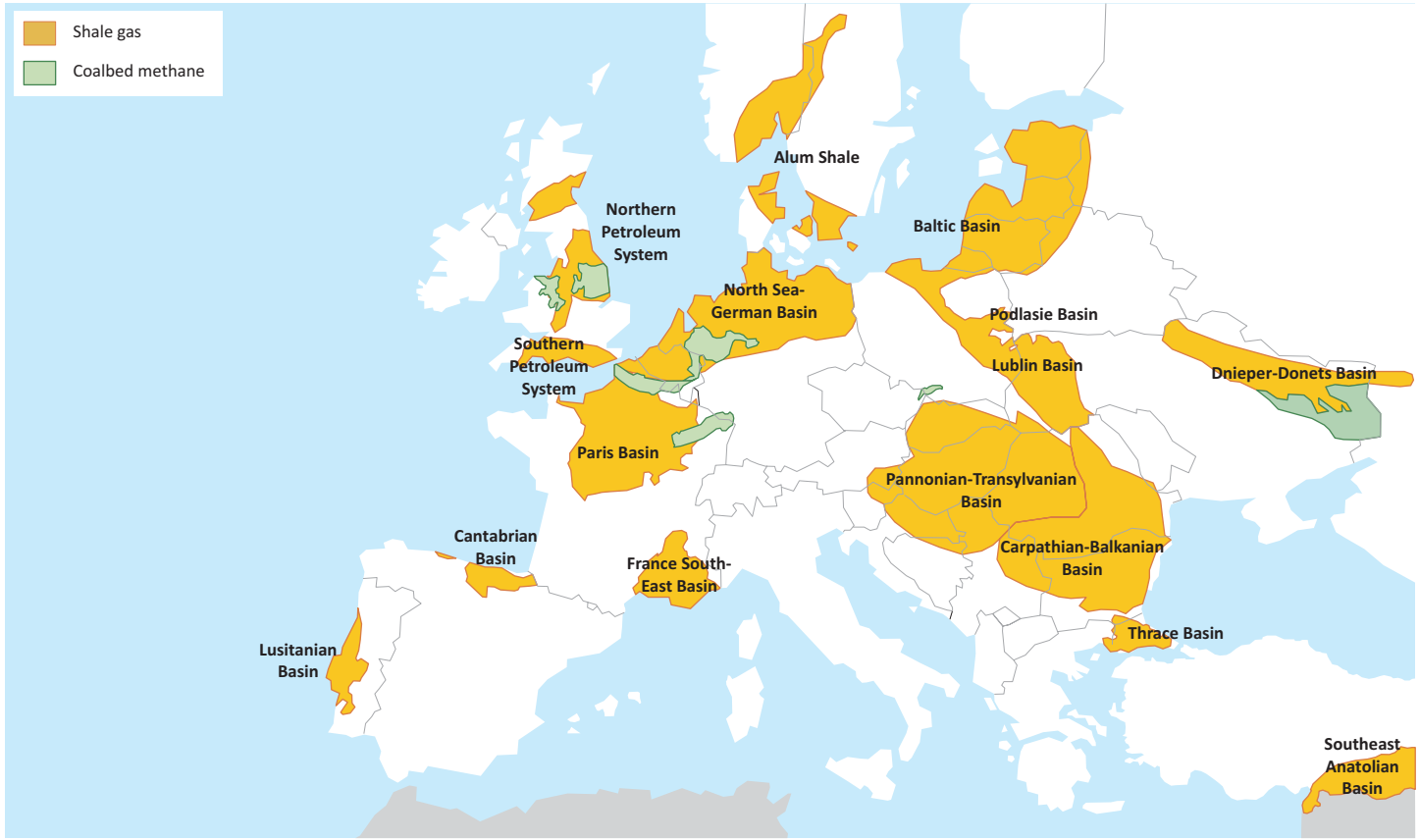
Europe

Resources and production

Europe's unconventional gas resources have attracted considerable interest in the last few years, although in practice the push to develop this resource varies considerably by country, depending on the mix of domestic fuels and imports and perceptions of the risks to energy security and the environment. Attention to unconventional gas focused initially on coalbed methane and tight gas, but has now switched to shale gas. Recoverable resources of shale gas are believed to be large, though how much can be recovered economically remains uncertain.

Europe's shale gas resources are found in three major areas that contain multiple basins, sub-basins and different plays: from eastern Denmark and southern Sweden to northern and eastern Poland (including Alum shales in Sweden and Denmark, and Silurian shales in Poland); from northwest England, through the Netherlands and northwest Germany to southwest Poland; and from southern England through the Paris Basin in France, the Netherlands, northern Germany and Switzerland (Figure 3.7). Poland and France are thought to have the largest shale-gas resources, followed by Norway, Ukraine, Sweden, Denmark and the United Kingdom. Potential coalbed methane resources in Europe are reasonably well established and are significant in some countries, notably in Ukraine, the United Kingdom, Germany, Poland and Turkey.

Figure 3.7 ▷ Major unconventional natural gas resources in Europe



This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

As yet, there is no large-scale production of unconventional gas in Europe. How soon it will begin and how quickly it will grow remain to be seen, though there are several factors favouring development. The European Union is the second-largest regional gas market in the world, with demand amounting to around 550 bcm in 2010, and it is set to become increasingly dependent on imports as indigenous production of conventional gas continues to decline and demand continues to expand. The region has a well-established pipeline and storage network (albeit not as densely developed as in the United States). And, crucially, natural gas prices are high compared with North America, adding to the attractiveness of developing new indigenous gas resources.

But there are above-ground factors that are likely to impede rapid growth in unconventional gas production, the most significant of which is the high population density in many of the prospective areas. This increases the likelihood of opposition from local communities, especially in areas with no tradition of oil and gas drilling. State ownership of oil and gas rights can also reduce the incentives for communities to accept development of local unconventional gas resources, compared with parts of the United States where these rights are held by private land-owners.

The European regulatory framework

Most regulations applicable to upstream oil and gas in the European Union are determined at the national level: member states define their own energy mix and make decisions concerning domestic resource development. At the EU level, there is a common set of rules (under the Hydrocarbons Licensing Directive) to secure transparent and non-discriminatory access to the opportunities for exploration, development and production of hydrocarbons, but the main area in which Europe-wide regulation applies is environmental protection, including:

- Water protection (Water Framework Directive, Groundwater Directive and Mining Waste Directive).
- The use of chemicals (under REACH regulation, administered by the European Chemicals Agency).
- The protection of natural habitats and wildlife.
- Requirements to carry out an environmental impact assessment, under general environmental legislation.
- Liability for upstream operators to incur penalties for environmental damage (under the Environmental Liability Directive and the Mining Waste Directive).

Public concerns about the environmental risks associated with hydraulic fracturing have prompted calls for new regulation on aspects of this practice, often based on the "precautionary principle" that is a statutory requirement in European Union law. A 2011 report commissioned by the Directorate General for Energy of the European Commission found that European environmental legislation applies to all stages of unconventional

gas developments. It also concluded that, both on the European level and at the national level (in the countries studied), there are no significant gaps in the legislative framework when it comes to regulating shale gas activities at the present level of intensity (Philippe & Partners, 2011). However, it did suggest that the situation might change if activities were to expand significantly and did suggest some improvements to national legislation, including procedures to include local citizens at earlier stages in the impact assessment process.

Additional assessments of various aspects of unconventional gas are currently being carried out within the European Commission. These include: a study on the economics of shale gas, by the Joint Research Centre in collaboration with the Directorate General for Energy; a study on methane emissions, by the Directorate General for Climate Action; and an assessment of the adequacy of the current regulatory framework to ensure an appropriate level of protection to the environment and to human health, by the Directorate General for the Environment. On the basis of the results of these assessments, the Commission will decide whether to put forward regulatory proposals specifically related to unconventional gas.

The European Parliament has also taken up the debate about various aspects of shale gas development. An assessment presented to the Committee on Environment, Public Health and Food Safety (European Parliament, 2011a) found that the current regulatory framework concerning hydraulic fracturing has a number of deficiencies, most importantly, the high threshold before an environmental impact assessment is required[6]; it also called for the coverage of the Water Framework Directive to be re-assessed focusing on the possible impacts of hydraulic fracturing on surface water and urged consideration of a ban on the use of toxic chemicals. A draft report to the same committee, prepared by a Polish parliamentarian, is more supportive of unconventional gas development (European Parliament, 2011b), while recognising the need to address concerns about the environmental effects of extraction. A separate draft report, focusing on the energy and industrial implications of shale gas development, is also under consideration by the Parliament's Committee on Industry, Research and Energy (European Parliament, 2012).

Poland

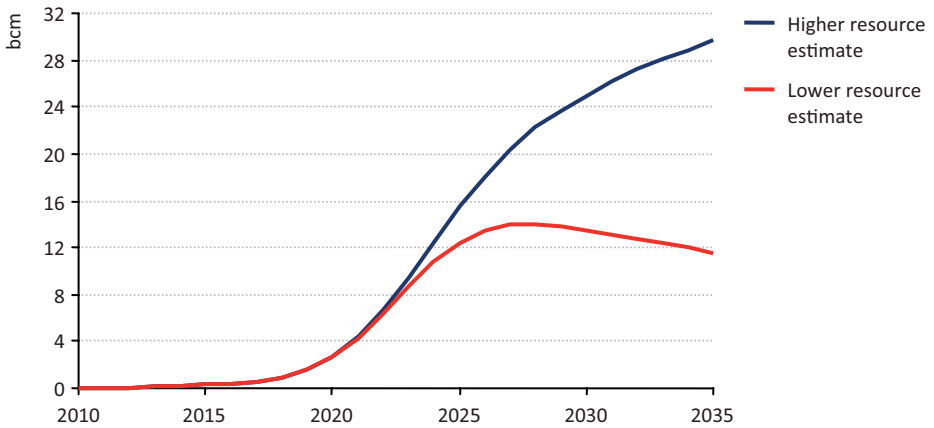
Medium-term prospects for unconventional gas production in Europe appear brightest in Poland, where exploratory drilling for shale gas is most advanced and where above-ground factors are generally less of an obstacle to development than elsewhere. Optimism about Poland's shale gas potential stems from the size of its resources, although these are still subject to considerable uncertainty. The US EIA put technically recoverable resources in Poland at 5.3 tcm (US DOE/EIA, 2011), while an assessment by the Polish Geological Institute (with the support of the United States Geological Survey), studying archive data on the Baltic, Podlasie and Lublin Basins, estimated recoverable resources at 346 bcm to

6. The Environmental Impact Assessment Directive does though include an obligation to screen for possible adverse environmental effects in projects which fall below any relevant thresholds.

768 bcm (PGI, 2012). The large difference is explained primarily by differences in methodologies between the two studies; the range of resource assessments should narrow as more data become available from exploratory drilling.

As described in Chapter 2, the model used for the projections in this report relies on the Rogner and ARI estimates for shale gas resources, which are so far the only assessments that apply a consistent methodology across a large enough number of countries. If actual resources in Poland are significantly lower than assumed, inevitably this would have a considerable impact on our projections, all else being equal. This is illustrated in Figure 3.8, which shows projections for shale gas production in Poland for a higher and lower recoverable resource estimate, respectively, based on the ARI estimate of 5.3 tcm and using a mid-range figure of 0.55 tcm from the Polish Geological Institute estimate.

Figure 3.8 ▷ Impact of different resource assessments on projected shale gas production in Poland



Poland has one of the oldest petroleum industries in the world and has been producing oil and gas from conventional reservoirs since the 1850s, though production has fallen to low levels over recent decades. Interest in shale and tight gas began towards the end of the last decade. A series of exploration licensing rounds has led to a large influx of international companies, with a number of firms that are already active in the United States – including ExxonMobil, Chevron, Eni, Talisman and Marathon – buying up drilling rights, either directly or through joint ventures (although the national oil and gas company, PGNiG, holds the most licences). Over 100 exploration licences, most of which have a duration of five years, have so far been issued, covering most of the prospective shale gas areas.

Early results from exploration drilling have put something of a damper on the initial hopes for a rapid take-off in production. Since PGNiG completed Poland's first shale well in 2009, 18 exploration wells have been drilled, with a further 14 underway and 39 planned (as of March 2012). Flow rates were low in the few wells for which data have been made public, with some reportedly proving unresponsive to normal drilling and well-completion

techniques. ExxonMobil has announced that two wells that it drilled and completed in 2011 are not commercially viable, though it is looking into whether different fluids, proppants or pumping techniques might produce better results. ExxonMobil and other companies continue to drill new wells.

The Polish government has been very supportive of drilling for shale and tight gas, reflecting the potentially large economic and energy security benefits that could be gained from supplementing the country's dwindling resources of conventional gas and reducing its heavy dependence on gas imports from Russia. Gas demand is expected to grow in the coming years, particularly for power generation, as older, low-efficiency coal-fired stations close. Although shale gas production costs are likely to be above those in the United States, high oil-indexed prices for imported gas should make shale developments profitable. Relatively low population density in the main basins as well as a history of oil and gas activities may favour public acceptance.

The regulatory framework applicable to unconventional gas development is changing with the prospect of commercial production. Until the recent arrival of foreign firms, the upstream sector was dominated by PGNiG, which ensured that the government captured a large part of any rent on hydrocarbons production and reduced the need for explicit regulation for that purpose. The legislative system for the upstream is now being adjusted to the reality of many new market entrants and participants, including changes to the licensing system and the fiscal framework for upstream activity.

A new Geological and Mining Law came into force in Poland at the start of 2012, which clarifies some administrative and legal questions regarding the development of Poland's unconventional gas potential. The most significant change was that licences for exploration of hydrocarbons in Poland can now be granted only through tenders (exploration licences issued over the last five years were on a first-come, first-served basis). Since most prospective gas exploration acreage in Poland has already been awarded, the new regulations will become more significant when the first production licences are sought. The new law also modifies the system of mineral rights ownership, more clearly defining the division between state rights and those of landowners, but shale gas, as a strategic mineral, remains the exclusive property of the state.

France

With resources almost as large as those in Poland, France was expected to be one of the first European countries to produce unconventional gas commercially. Shale gas potential is primarily in two major shale basins: the Paris Basin and the Southeast Basin. The Southeast Basin is considered to be the more prospective, in view of the low depth of parts of the basin, possible liquids content and low levels of clay. The government had issued three licences for shale gas exploration drilling in the Southeast Basin but, in May 2011, in the face of a strong public opposition over the potential environmental impacts of hydraulic fracturing, the government announced a moratorium on its use and later prohibited it by

law. Two firms that held licences – France's Total and the US-based Schuepbach Energy – subsequently had their licences cancelled. Schupebach Energy had maintained their intention to use hydraulic fracturing, whereas Total had submitted a report where they committed not to use it. A third company that committed not to use hydraulic fracturing has had its permit maintained.

Public opposition was linked to the fact that part of the prospective basin underlay scenic regions that are heavily dependent on the tourism industry. Resentment was exacerbated by a lack of public consultation: under French mining laws, public consultation is required only at the production stage and not at the exploration stage. Revision of the mining code is under consideration to include earlier public consultation.

A report was commissioned jointly by the Ministry of Ecology and Sustainable Development and the Ministry of Industry, Energy and Economy to provide information on shale gas and light tight oil, the environmental concerns surrounding their development and the applicability of existing hydrocarbon regulation in France to this new potential energy source. A preliminary report recommended some drilling in France, under strict controls, while more information was gathered about the impact of hydraulic fracturing elsewhere in Europe and the United States (Leteurtrois, 2011). However, the final report was not issued because the ban on hydraulic fracturing was voted in the meantime.

In France, as in some other countries, the debate around shale gas developments became a proxy for a much broader question about the approach to sustainable energy policy. In a separate report prepared for the National Assembly, the co-authors did not share a common vision of France's future energy mix, writing two separate conclusions (Gonnot, 2011). One concluded that more study was required to understand the extent of the country's resource and the technologies to safely develop it, with a view to then taking a decision on whether to proceed developing the resources. The second asserted that the development of new hydrocarbon resources has no place in a national energy policy striving to meet agreed climate change objectives.

The Paris Basin has a long history of conventional oil production. In the early 1980s, high hopes were held that significant volumes might be found, but exploration turned out to be disappointing and production has not exceeded a few thousand barrels per day. Production is mostly from the rural Seine et Marne Région, southeast of Paris, where several hundred wells have been drilled. Some geologists have argued recently that the reason large oil fields have not been discovered is that the hydrocarbons have not been expelled from the source rocks. Indeed, there are indications from wells that have intercepted some of the shales that they may be hydrocarbon bearing, probably mostly light tight oil, with some shale gas. Estimates of oil-in-place vary from 1 to 100 billion barrels, though the fraction which might be technically and economically recoverable is not known.

In the Golden Rules Case, we assume a reversal of the ban on hydraulic fracturing. Shale gas production rises after 2020 to reach 8 bcm in 2035, which would allow France to exceed its peak gas production from the end of the 1970s. At the same time, light tight

oil production could reach several tens of thousands of barrels per day. Some of the resources, located in sensitive areas, are likely to remain barred from development but, if productivity can be established, there should be enough resources in other areas to sustain such production.

Other EU member countries

There has been a good deal of discussion about unconventional gas prospects in several other EU member countries, but little exploration activity as yet. Most of the wells that have been drilled are for coalbed methane. There appears to be significant potential for shale gas development in several other EU member countries, notably in Sweden, the United Kingdom and Germany.

Sweden's shale gas resources are located in the Scandinavian Alum shale, which extends from Norway to Estonia and south to Germany and Poland. The Alum shale has been mined for oil shale for many decades in central and southern Sweden (and in Estonia), where it is close to the surface. It has the advantages of high organic content and thermal maturity and is relatively shallow, with depths averaging less than 1 200 metres. But it lacks overpressure and contains a high concentration of uranium, which poses problems for water treatment and recycling. Shell has been most active in assessing the shale, having drilled three exploration wells in the Skåne region of southern Sweden, but it ceased operations when they proved to be dry. Opposition to hydraulic fracturing had delayed the programme and threatens to deter renewed exploration activity.

In the *United Kingdom*, a main shale play is the Bowland shale formation (in the Northern Petroleum System), which is relatively shallow, with an average depth of only 1 600 metres, and with certain areas rich in liquids. Cuadrilla Resources has drilled two exploration wells, one of which encountered gas. It subsequently announced that the formation could hold as much as 5.7 tcm (200 trillion cubic feet) of technically recoverable gas. However, operations have been suspended as a result of two small earthquakes that occurred after hydraulic fracturing was carried out. A report commissioned by Cuadrilla concluded that it is "highly probable" that the fracturing and subsequent earthquakes were linked, although future occurrences should be rare given the unique local geology at the well site (de Pater and Baisch, 2011). The UK Department of Energy and Climate Change commissioned an independent report on the causes of the earthquakes and appropriate means of mitigating seismic risks (Green, Styles and Baptie, 2012). It recommended cautious continuation of Cuadrilla's hydraulic fracturing operations and several safety provisions, including greater use of micro-seismic monitoring and new safeguards that would lead to a suspension of operations in case of seismic activity. At the time of writing, the government was awaiting comments on this report before making any decision regarding additional hydraulic fracturing.

The UK government appears to be supportive of continuing shale gas exploration and development. A parliamentary inquiry in 2011 found no evidence that hydraulic fracturing poses a direct risk to underground water aquifers, provided the drilling well is constructed

properly, and concluded that, on balance, a moratorium on shale gas activity in the United Kingdom is not justified or necessary at present (UK Parliament, 2011). Nonetheless, the inquiry urged the UK Department of Energy and Climate Change to monitor drilling activity extremely closely in its early stages in order to assess its impact on air and water quality.

Germany has shale resources, estimated at 230 bcm, in the large North Sea-German basin, which extends from Belgium to Germany's eastern border along the North Sea coast. Several companies have acquired exploration licences and ExxonMobil has drilled at least three exploratory shale gas wells in Lower Saxony as part of a ten-well programme. Germany has a history of tight gas production with relatively large hydraulic fracturing treatments having been common practice for the last 20 years. As in France, there has been strong opposition to shale gas drilling on environmental grounds, but attention to the need for indigenous energy sources, including unconventional gas, has been intensified by a decision to phase out nuclear power.

Shale gas exploration efforts are advancing elsewhere in the European Union: there are plans by OMV to drill several test wells in *Austria* in the next two years; in *Lithuania*, exploration licences were being tendered at the time of writing. *Bulgaria* and *Romania* have awarded shale gas exploration licences, but these countries have experienced strong public opposition over fears about the environmental impact of hydraulic fracturing and, in Bulgaria, this has led to parliament voting in early 2012 to ban the use of the technique, making it the second country in the European Union to do so.

EU projections and implications

Against a backdrop of declining indigenous production and a policy priority to diversity sources of gas supply, the European Union has reasons to be interested in exploiting its domestic unconventional gas potential. At the same time, environmental concerns could easily delay or derail development. In our projections in the Golden Rules Case, unconventional gas production is slow to take off but accelerates in the longer term, as confidence grows in the effective application of the Golden Rules in the most prospective countries. In our projections, unconventional production in the European Union climbs to just over 10 bcm by 2020, but it grows more rapidly thereafter, reaching almost 80 bcm by 2035 (Table 3.6). Shale gas accounts for the bulk of this output. Unconventional gas contributes almost half of the European Union's total gas production and meets just over 10% of its demand by 2035. As a result, even though there are not dramatic shifts in the trade balance, as seen in the United States, growth in unconventional production offsets continued decline in conventional output from 2020 (Figure 3.9).

Rising unconventional gas production (both in Europe and worldwide) helps to restrain the rise in gas prices in Europe, which – together with additional policies to encourage gas use – drives up gas demand. As a result, the upward trend in net gas imports into the European Union continues throughout the projection period, reaching 480 bcm in 2035, or three-quarters of total demand (compared with 345 bcm, or more than 60%, in 2010). In the Low Unconventional Case, in which there is very little commercial unconventional

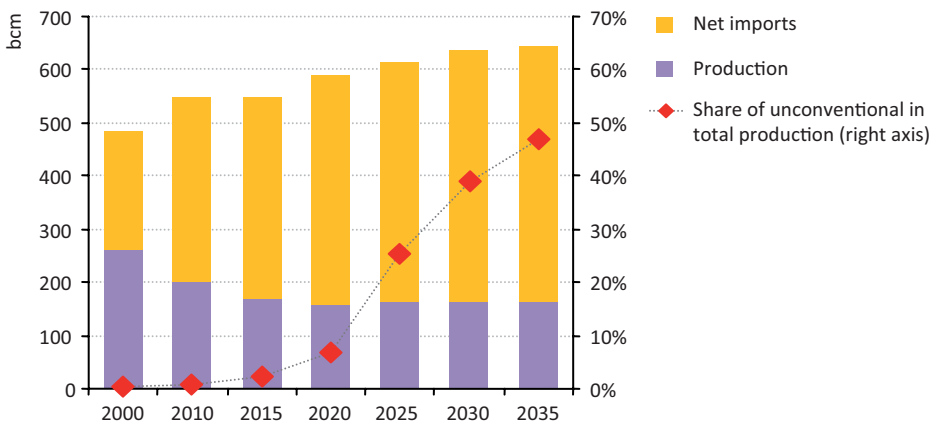
production before 2035, European Union net gas imports are 30 bcm higher in 2035 than in the Golden Rules Case (and gas import prices are higher). Consequently, the cost of those imports reaches about $250 billion in 2035 (in year-2010 dollars) – an additional import bill of almost $60 billion relative to Golden Rules Case.

Table 3.6 ▷ Natural gas indicators in the European Union by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	201	160	165	139	84	81
Unconventional	1	11	77	0	0	77
Share of unconventional	1%	7%	47%	0%	0%	47%
Cumulative investment in upstream gas, 2012-2035**		434		235		199
Unconventional		181		-		181
Net imports (bcm)	346	432	480	423	510	-30
Imports as a share of demand	63%	73%	74%	75%	86%	-11%
Share of gas in the energy mix	26%	28%	30%	26%	28%	2%
Total energy-related CO_2 emissions (million tonnes)	3 633	3 413	2 889	3 414	2 873	16

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

Figure 3.9 ▷ Natural gas balance in the European Union in the Golden Rules Case*



* The sum of production and net imports represents total demand.

Ukraine

Ukraine has considerable unconventional gas potential in the form of coalbed methane in the main coal-mining areas of eastern Ukraine and in two shale gas basins: a portion of the Lublin Basin, which extends across from Poland, and the Dnieper-Donets Basin in the east.

Coalbed methane resources are estimated at close to 3 tcm. Technically recoverable shale gas resources in Ukraine are 1.2 tcm, around one-third less than remaining recoverable resources of conventional gas. The Ukrainian section of the Lublin Basin is large and reportedly has higher average total organic content than the Polish section and lower average depth. The Dnieper-Donets Basin – which currently provides most of the country's conventional oil, gas and coal production – also has high organic content, but is deeper.

The government is keen to develop new sources of gas in order to reduce the country's heavy dependence on imports from Russia – it has set a target of producing 3 to 5 bcm of unconventional gas by 2020. Coalbed methane is the most likely source of unconventional production growth in the short to medium term, but, if the conditions are in place, shale gas also offers considerable promise. A new tender for two large shale gas blocks in both basins is underway, offering foreign companies the opportunity to bid for the right to enter a production-sharing contract. Naftogaz, the state-owned oil and gas company, signed a memorandum of understanding with ExxonMobil in 2011 to co-operate on shale gas exploration; other companies are also interested in Ukraine's potential. An earlier shale gas tender led to some exploration drilling. Hawkley, an independent Australian company, drilled a shale gas well in the Dnieper-Donets basin in 2011. Kulczyk Oil, an international upstream company, announced in November 2011 that it had successfully completed the hydraulic fracturing of a well in a previously non-commercial zone of the Dnieper-Donets basin, yielding 65 thousand cubic metres per day (2.3 mcf/d) of gas and condensates.

In the Golden Rules Case, production of unconventional gas in Ukraine reaches 3 bcm in 2020, before ramping up to around 20 bcm in 2035. The Golden Rules Case assumes, importantly, that supportive measures are adopted to facilitate investment in the gas sector: Ukraine has a poor investment climate and upstream conventional gas output currently stands at around 20 bcm per year.

Australia

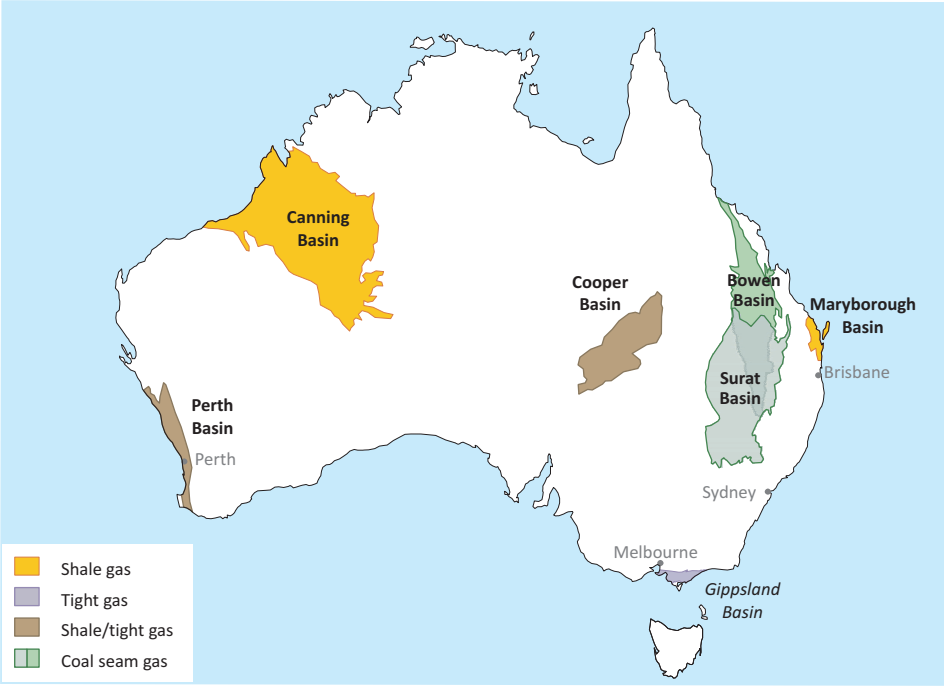
Resources and production

As a sizeable producer of coalbed methane (known as coal seam gas), Australia is one of only a handful of countries already producing commercial volumes of unconventional gas. Its large resources of shale gas, tight gas and coalbed methane hold the promise of continuing strong growth in unconventional gas output in the long term. The attraction of unconventional gas developments is heightened by the fact that Australia's conventional gas resources, while sizeable, tend to be offshore, expensive to develop and far from national markets.

More is known about the size of the country's coalbed methane resources than about the other two categories of unconventional gas. According to official estimates, demonstrated economically recoverable coalbed methane resources were 930 bcm at the end of 2010 (Geoscience Australia, 2012). The estimates of these resources have grown substantially in recent years, as exploration and development has expanded. Nearly all current reserves

are contained in the Surat (69%) and Bowen (23%) basins in central Queensland, with almost all the balance in New South Wales (Figure 3.10).

Figure 3.10 ▷ Major unconventional natural gas resources in Australia



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Commercial production of coalbed methane began in 1996 in eastern Australia and has grown sizeably over the last few years. Output reached 5 bcm in 2010, accounting for about 15% of total Australian gas consumption. Virtually all output comes from the Surat and Bowen basins, with small volumes also now produced from the Sydney Basin. The rapid growth of the unconventional gas industry has been supported by strong demand growth in the eastern Australian market, reflecting in part the Queensland government's energy and climate policies, including a requirement that 13% of power generation in the state be gas-fired by 2005 and 15% by 2010. The abundance of coalbed methane has led to a number of LNG-export projects being proposed in Queensland; and three large plants to be sited at the port of Gladstone are under construction: Queensland Curtis LNG (BG), Gladstone LNG (Santos), and Australia Pacific LNG (Origin and ConocoPhillips), with a fourth – Arrow LNG (Shell/PetroChina) – at an advanced stage of development. Total investment in the three projects underway is projected to be some $40 billion; their capacity of 29 bcm more than doubles current national export capacity. However, policy uncertainty and public reaction to the potential environmental impacts of coalbed methane production has slowed upstream development, particularly in New South Wales.

Remaining recoverable resources of tight gas in Australia are estimated at 8 tcm. The largest resources of these are in low permeability sandstone reservoirs in the Perth, Cooper and Gippsland Basins. Tight gas resources in these established conventional gas-producing basins are located relatively close to existing infrastructure and are currently being considered for commercial exploitation.

Although shale gas exploration is in its infancy in Australia, exploration activity has increased significantly in the last few years. Australia is estimated to contain 11 tcm of remaining recoverable shale gas resources. These are found predominately in the Cooper, Maryborough, Perth and Canning basins. The first vertical wells specifically targeting shale gas were drilled in the Cooper Basin in early 2011 and significant exploration is now underway in this basin and, to a lesser extent, in other promising areas. But a boom in shale gas production is unlikely in the near future because of logistical difficulties and the relatively high cost of labour and hydraulic fracturing.

Regulatory framework

Under the existing regulatory framework governing the upstream hydrocarbons sector in Australia, powers and responsibilities are shared between the federal, state and territory governments and local authorities. The states hold rights over coastal waters from the coast line to the three-mile limit and joint regulatory authority over the federal waters adjacent to each state and the Northern Territory. In addition to various petroleum and pipelines laws, there is an extensive body of legislation governing upstream petroleum activities, covering such aspects as the environment, heritage, development, native title and land rights, and occupational health and safety; most are not specific to the oil and gas sector. A number of bodies across all levels of government have a role in regulating upstream petroleum activities.

Under Australian law, hydrocarbon resources are owned by the state (at federal, state or territory level) on behalf of the community, and governments at all levels have a "stewardship" role in petroleum resource management (AGPC, 2009). Farmers or graziers may hold freehold or leasehold title to land, but generally do not have rights to mineral or petroleum resources – these are subject to petroleum tenure rights granted by the state or territory governments. Underlying native title can coexist with other land title rights. In general, landowners have no right to refuse access to the petroleum tenure holder for petroleum operations; but they do have a claim to compensation for the impact of those operations. Approvals, generally a state or territory responsibility, are required to construct petroleum pipelines and facilities such as LNG trains. Landowners do not have the incentive of ownership of mineral resources to facilitate surface access to unconventional gas projects, but state and territory governments do have an incentive to promote development, as they can benefit from any taxes or royalties levied on production.

Within each jurisdiction, environmental regulation of upstream activities can include hydrocarbon-specific environmental approvals, though there are few rules specific to unconventional gas. The main federal regulations are the Offshore Petroleum and Greenhouse Gas Storage Act 2006 and the Environment Protection and Biodiversity Protection Act 1999 (EPBC Act). Under the EPBC Act, if a project affects matters of national environmental significance, it requires federal approval. LNG projects in Queensland, including their upstream coalbed methane operations, trigger the need for such federal approval. In general, an environmental impact assessment must be carried out in advance of all upstream projects that are likely to have a significant impact on the environment.

The rapid expansion of the coalbed methane industry has led to increased public concern over access issues and the potential environmental risks, particularly the drawdown and contamination of aquifers and groundwater and problems arising from the disposal of produced water. As described in Chapter 1, the techniques used in coalbed methane production differ significantly from those for shale gas; in particular there is a need to remove large amounts of water from the coal formation. This causes concern that those already drawing water from the same formations will be adversely affected and that the disposal of the large water volumes involved in coalbed methane production will not be properly handled. Given the semi-arid conditions in the producing areas, evaporation or discharge of even suitably-treated formation water to existing watercourses may not be appropriate. This has led to delays in issuing approvals for some upstream developments.

The federal government announced in 2011 that all future coalbed methane and other coal projects would come under increased environmental scrutiny. A new, well-resourced and independent scientific committee, established under the EPBC Act, will evaluate most future projects prior to approval to ensure that they do not pose a hazard to underground and surface water sources. Protocols are being developed at federal and state level to determine which projects will be referred to this committee. In Queensland, where most coalbed methane activity is concentrated, new proposals to manage the impact of water extraction on groundwater are being finalised. They provide for cumulative assessment of the impacts on groundwater resources in defined management areas. This work will be based on a major groundwater flow model, designed to predict impacts on aquifers, as well as new monitoring arrangements. A major report, the Surat Underground Water Impact Report, is expected to be published for public consultation by the Queensland Water Commission in mid-2012. A key principle in the regulatory approach is that petroleum operators must make good any impairment of water supply that they cause and that any consequence of underestimating that risk should lie with the operator, not the water source owner or the state government. The upstream industry has argued that the new regulations will hamper the development of the country's nascent unconventional gas sector. In New South Wales, where regulatory activity is less advanced, the state government has introduced a moratorium on hydraulic fracturing while it considers new regulation.

In December 2011, energy and resources ministers at both federal and state levels agreed to develop a nationally harmonised framework for coalbed methane regulation to address the following areas of community concern:

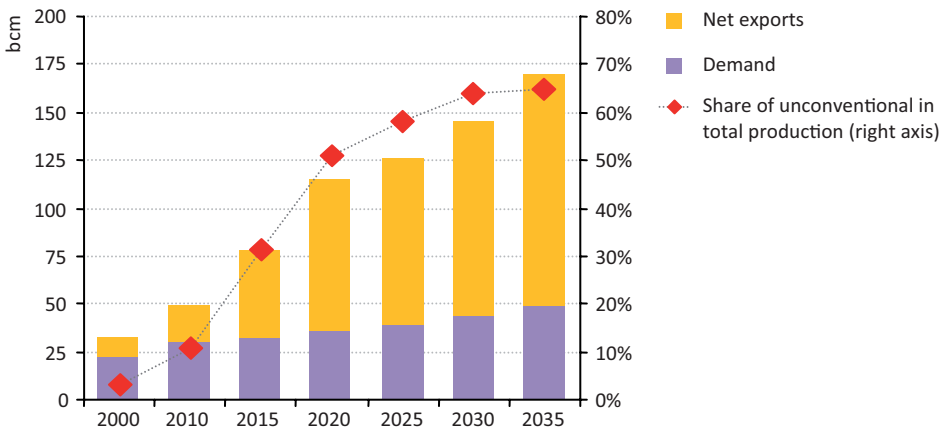
- Water management.
- The need for a multiple land-use framework, meaning measures to reconcile the ability for extraction of coalbed methane with existing and potential agricultural or pastoral uses.
- The application of best practice standards to production activities.
- Minimising environmental and social impacts.

The objective is to achieve measures in these areas which maximise transparency and generate greater public confidence in the effective regulation of the industry while supporting commercial extraction of coalbed methane.

Projections and implications

The prospects for unconventional gas production in Australia hinge to a large degree on whether policy-makers and the industry itself can sustainably manage the associated environmental risks on a basis that retains public confidence in the outcomes. In the Golden Rules Case, this is achieved, with unconventional gas output continuing to expand rapidly, reaching about 60 bcm by 2020 and 110 bcm in 2035. Coalbed methane contributes almost all of this increase, with shale gas production growing more slowly. As a result, total gas production more than triples, with unconventional gas accounting for more than half of gas output after 2020 (Figure 3.11). The projected level of coalbed methane production for 2020 assumes that the four LNG-export projects in Queensland proceed as planned and enter the market before the large increase in unconventional production in other countries, notably China, gains momentum.

Figure 3.11 ▷ Natural gas balance in Australia in the Golden Rules Case*



* The sum of demand and net exports represents total production.

Gas production is driven primarily by exports, based on both conventional and unconventional sources, which rise by 100 bcm in the Golden Rules Case. Exports reach 80 bcm in 2020, based on developments under construction, and continue to grow throughout the projection period. The value of those exports increases seven-fold to just over $55 billion in 2035 (in year-2010 dollars).

In both the Golden Rules and Low Unconventional Cases, east coast Australian domestic prices rise towards the export netback price (the delivered export price less liquefaction and transport costs) from their current very low levels. The high capital costs of Australian LNG plants meaning that these netback levels are likely to be at least $5 to $6/MBtu below the price of LNG delivered to Asian markets. In the Golden Rules Case, Australia's gas consumption nonetheless continues to expand on the back of government policies to encourage switching to gas for environmental reasons (including the recently agreed carbon trading scheme).

In the Low Unconventional Case, coalbed methane production expands at a much slower pace on the assumption of bigger hurdles to development of these resources, while there is no shale gas production at all. In 2035, unconventional gas production falls to around 35 bcm – this is 75 bcm lower than in the Golden Rules Case. The higher international price environment in the Low Unconventional Case means that the upward pull on Australian domestic prices is stronger.

Gas exports still reach more than 110 bcm in the Low Unconventional Case, as investment is shifted to LNG projects based on conventional gas. In this case, the needs of importing countries are much increased and so any gas exporter with the capacity to export has an incentive to do so; this is certainly the case for Australia, with its conventional resources and existing export infrastructure, even if these conventional resources are more costly to develop. Export earnings are even higher in this case, as international gas prices are higher. Unsurprisingly, Australia would stand to benefit from restrictions on unconventional gas developments in other parts of the world, especially in Asia-Pacific, as it is able to expand its own production of conventional and unconventional gas.

Units and conversion factors

This annex provides general information on units and general conversion factors.

Units

Emissions	ppm	parts per million (by volume)
	Gt CO_2-eq	gigatonnes of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases)
	kg CO_2-eq	kilogrammes of carbon-dioxide equivalent
	gCO_2/kWh	grammes of carbon dioxide per kilowatt-hour
Energy	toe	tonne of oil equivalent
	Mtoe	million tonnes of oil equivalent
	Mt LNG	million tonnes of liquefied natural gas
	MBtu	million British thermal units
	MJ	megajoule (1 joule x 10^6)
	GJ	gigajoule (1 joule x 10^9)
	TJ	terajoule (1 joule x 10^{12})
	kWh	kilowatt-hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
Gas	mcm	million cubic metres
	bcm	billion cubic metres
	tcm	trillion cubic metres
	mcf	million cubic feet
	bcf	billion cubic feet
	tcf	trillion cubic feet
Mass	kg	kilogramme (1 000 kg = 1 tonne)
	kt	kilotonnes (1 tonne x 10^3)
	Mt	million tonnes (1 tonne x 10^6)
	Gt	gigatonnes (1 tonne x 10^9)

Monetary	$ million	1 US dollar x 10^6
	$ billion	1 US dollar x 10^9
	$ trillion	1 US dollar x 10^{12}
Oil	b/d	barrels per day
	kb/d	thousand barrels per day
	mb/d	million barrels per day
Power	W	watt (1 joule per second)
	kW	kilowatt (1 watt x 10^3)
	MW	megawatt (1 watt x 10^6)
	GW	gigawatt (1 watt x 10^9)
	TW	terawatt (1 watt x 10^{12})

General conversion factors for energy

Convert to:	bcm	bcf	Mt LNG	TJ	GWh	MBtu	Mtoe
From:	multiply by:						
bcm	1	35.315	0.7350	4.000×10^4	11.11×10^3	3.79×10^7	0.9554
bcf	2.832×10^{-2}	1	2.082×10^{-2}	1.133×10^3	3.146×10^2	1.074×10^6	2.705×10^{-2}
Mt LNG	1.360	48.03	1	54 400	15 110	5.16×10^7	1.299
TJ	2.5×10^{-5}	8.829×10^{-4}	1.838×10^{-5}	1	0.2778	947.8	2.388×10^{-5}
GWh	9.0×10^{-5}	3.178×10^{-3}	6.615×10^{-5}	3.6	1	3 412	8.6×10^{-5}
MBtu	2.638×10^{-8}	9.315×10^{-7}	1.939×10^{-8}	1.0551×10^{-3}	2.931×10^{-4}	1	2.52×10^{-8}
Mtoe	1.047	36.97	0.7693	4.1868×10^4	11 630	3.968×10^7	1

Notes

- Gas volumes are measured at a temperature of 15°C and a pressure of 101.325 kilopascals.
- The Gross Calorific Value (GCV) of gas is defined as 40.0 MJ/cm for conversion purposes in the table above.
- The global average GCV varies with the mix of production over time, in 2009 it was 38.4 MJ/cm.
- 1 Mtoe is equivalent to 10^7 gigacalories.

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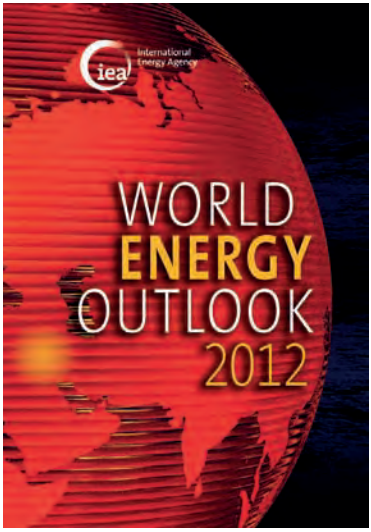

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Natural Gas and the Transformation of the U.S. Energy Sector: Electricity

Jeffrey Logan, Garvin Heath, and Jordan Macknick
National Renewable Energy Laboratory

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University of Colorado Law School

Ken Carlson
Colorado State University

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Technical Report
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Foreword

We are very pleased to present this work on natural gas and the transformation of the United States' power sector. The subject is both highly topical and divisive. Very few people saw the dramatic changes coming that are being witnessed in the U.S. natural gas sector. The critical role of unconventional gas—and specifically, shale gas—has been dramatic. The changes taking place in the U.S. natural gas sector go well beyond the boundaries of traditional energy-sector analysis. They touch on areas as diverse as foreign policy and industrial competitiveness.

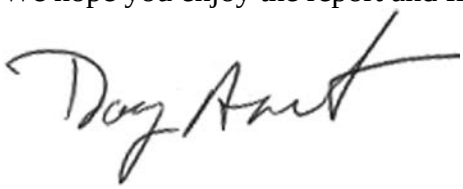
This makes the topic ripe for robust analytical work, which is the role of the Joint Institute for Strategic Energy Analysis (JISEA).

To help inform both the national and international dialogue on this subject, we have focused on a few key areas critical to decision makers. These issues include greenhouse gas emissions, regulatory interventions, water management, and the portfolio of generation in the power sector.

As part of our series of studies on the U.S. energy system, this body of work continues to elucidate details related to life cycle greenhouse gas emissions of shale gas relative to other options for power generation. It also contributes new analysis related to water and regulatory frameworks that are evolving apace. Additionally, we evaluate various pathways for the evolution of the electric sector given a range of options for natural gas, other technologies, and policy.

Although the four principal areas of focus in this report are closely interrelated, each has its own specific needs in terms of analysis, investment risk, and policy design. We have presented detailed consideration of each area, with further appended supporting material, to contribute to the ongoing and increasing national and international dialogue.

We hope you enjoy the report and find the results and discussion useful for your work.



Douglas J. Arent
Executive Director, JISEA

Preface

This report was developed with guidance from a cross-section of natural gas and electricity sector stakeholders. In 2011, JISEA convened a workshop with representatives from these organizations, some of whom also provided financial support for this work. That workshop resulted in identifying several key analytical issues for natural gas in the electric power sector that need to be addressed. Research, analysis, and writing were performed independently by the authors, with editorial oversight by JISEA. This study has been extensively peer reviewed. Findings, content, and conclusions of this study are the sole responsibility of the JISEA study team. JISEA provides objective information so that decision makers can make informed choices, but does not make its own policy recommendations.

Although the sponsoring organizations provided invaluable perspective and advice to the study group, individual members may have different views on one or more matters addressed in the report. The sponsoring organizations were not asked individually or collectively to endorse the report findings nor should any implied endorsement by the sponsoring organizations be assumed.

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This report has been reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise. These reviews serve to make this report as technically sound as possible, and they ensure that the report meets institutional standards for objectivity, evidence, and responsiveness to the study scope.

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Acronyms and Abbreviations

AGR	acid gas removal
bbl	barrels
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BLM	Bureau of Land Management
Btu	British thermal unit(s)
CBM	coal-bed methane
CCS	carbon capture and sequestration
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CES	clean energy standard (also known as clean electricity standard)
cf	cubic feet
CH_4	methane, the primary component of natural gas
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CSP	concentrating solar power
CWTs	centralized waste treatment facilities
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EUR	estimated ultimate recovery
FF	frac flowback (water)
g	gram(s)
GHG	greenhouse gas
GIS	geographic information system
GW	gigawatt(s)
hp	horsepower
hr	hour
kg	kilogram(s)
kWh	kilowatt-hour(s)
lb	pound(s)
LCA	life cycle assessment
LNG	liquefied natural gas
MJ	megajoules
Mcf	thousand cubic feet
MMBtu	million British thermal unit(s)
NG-CC	natural gas combined-cycle
NG-CCS	natural gas generator with carbon capture and sequestration
NG-CT	natural gas combustion turbine
NGLs	natural gas liquids
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
POTWs	publicly owned treatment works
PW	produced water
PV	photovoltaic

RE	renewable energy (also known as renewable electricity)
RE Futures	Renewable Electricity Futures Study
ReEDS	Regional Energy Deployment System
SCC	Source Classification Code
scf	standard cubic foot
SEAB	Secretary of Energy Advisory Board Shale Gas Production
SolarDS	Solar Deployment System
TCEQ	Texas Commission on Environmental Quality
Tcf	trillion cubic feet
Tg	teragram(s), or million metric ton(s)
VOC	volatile organic compound
yr	year

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Executive Summary

Domestic natural gas production was largely stagnant from the mid-1970s until about 2005. Planning had been under way by the early 2000s to construct about 40 liquefied natural gas import terminals along the U.S. coasts to meet anticipated rising demand. However, beginning in the late 1990s, advances linking horizontal drilling techniques with hydraulic fracturing allowed drilling to proceed in shale and other formations at much lower cost. The result was a slow, steady increase in unconventional gas production.

As the technology improved and spread, domestic shale gas output began to increase rapidly, such that by 2008 commentators began to routinely speak of a shale gas "boom." Today, shale gas accounts for about 30% of total U.S. natural gas production—up from only 4% in 2005—helping to make the United States the largest producer of natural gas in the world by 2009. Within a decade, the question of how much more dependent the country would become on natural gas imports had been replaced by how much the U.S. gas supply will affect the economics and geopolitics of energy around the globe.

Although the long-term outcome of the shale gas revolution is far from decided, significant shifts are already apparent in U.S. power markets. In that context, low-price natural gas has had the greatest impact to date on generation by coal power plants. Since 2008, coal's share of annual generation has declined from 48% to 36% as of August 2012. This switch from coal to natural gas, combined with growth of renewable energy generation, has led to a reduction of carbon dioxide emissions in the U.S. power sector of about 300 million tons—equivalent to 13% of total power sector emissions in 2008.

It remains unclear, however, whether natural gas will continue to exert such a dramatic impact on the power sector and the overall U.S. economy. If natural gas prices continue to stay at, or near, historically low levels, then a self-correction in the shale gas boom may occur. Due to price concerns, some companies have shifted away from drilling for dry gas and instead are focusing on plays that provide natural gas liquids. The ongoing debate is about what price is needed for unconventional natural gas production to be more sustainable over the medium term. As an example, analysis from Range Resources indicates that New York Mercantile Exchange prices of $4–$6/MMBtu are needed at the vast majority of plays to generate adequate returns on investment.[1] Other factors—including "use it or lose it" lease terms, reserve filings with the Securities and Exchange Commission, and the amount of natural gas liquids that can be recovered—all play a role in continuing investment decisions. But, for now, natural gas markets are still widely acknowledged as oversupplied, and storage facilities held record high amounts of gas as of mid-2012.

Hydraulic fracturing has received negative attention in many parts of the country—especially those areas not accustomed to the oil and gas industry—due to real and perceived environmental and social concerns. Water use and contamination, air pollution, greenhouse gas (GHG) emissions, and truck traffic are among the concerns that have strained the social license to operate, and they have been the subject of multiple national and international reports and

[1] Specifically, a 12% internal rate of return (IRR). The reference to this analysis appears in Ventura, J., 2012. "Uncovering Tomorrow's Energy Today," presentation at the Goldman Sachs Global Energy Conference 2012. 10 January 2012. Slide 11. Accessed 9 June 2012.

continued dialogue. Field practices associated with unconventional natural gas production have evolved rapidly in some regions, either from new regulatory requirements or voluntary company practices. These field practices are still evolving, can be uneven across regions, and are sometimes controversial. At the same time, consolidation within the industry is shifting production from smaller to larger companies.

The Joint Institute for Strategic Energy Analysis (JISEA) designed this study to address four related key questions, which are a subset from the wider dialogue on natural gas:

1. What are the life cycle greenhouse gas (GHG) emissions associated with shale gas compared to conventional natural gas and other fuels used to generate electricity?
2. What are the existing legal and regulatory frameworks governing unconventional gas development at federal, state, and local levels, and how are they changing in response to the rapid industry growth and public concerns?
3. How are natural gas production companies changing their water-related practices?
4. How might demand for natural gas in the electric sector respond to a variety of policy and technology developments over the next 20 to 40 years?

Major Findings

Although the questions analyzed in this report are interlinked to a certain extent, they have specific requirements in terms of analysis methodologies and associated stakeholders. The key findings are presented very briefly as follows:

- **Greenhouse gas emissions:** Based on analysis of more than 16,000 sources of air-pollutant emissions reported in a state inventory of upstream and midstream natural gas industry, life cycle greenhouse gas emissions associated with electricity generated from Barnett Shale gas extracted in 2009 were found to be very similar to conventional natural gas and less than half those of coal-fired electricity generation.

- **Regulatory trends:** The legal and regulatory frameworks governing shale gas development are changing in response to public concerns and rapid industry changes, particularly in areas that have limited experience with oil and gas development. All of the states examined in this study have updated their regulatory frameworks to address the opportunities and challenges associated with increasing unconventional natural gas production.

- **Water management:** Many regions evaluated in this study are making greater use of innovative water management practices to limit real and perceived risks. However, a lack of reliable, publicly available water usage and management data—such as total water withdrawals, total wells drilled, water-recycling techniques, and wastewater management practices—currently hinders efforts to develop appropriately flexible and adaptive best management practices. Recent studies have documented a number of management practices related to the chemical makeup of fracking fluids, impacts on local freshwater, and on-site wastewater management that may be appropriate in many locations.

However, to date, no public studies have been published on cost-benefit, risk-mitigation potential, or the transferability of practices from one shale play to another.

- **Electric power futures:** A number of different future electric power scenarios were analyzed to evaluate both the implications of shale gas development and use, and various policy and technology changes. These scenarios include power plant retirements, advances in generation technologies, federal policies to reduce greenhouse gas emissions, and variations in natural gas supply and demand. We find that natural gas use for power generation grows strongly in most scenarios.

Life Cycle Greenhouse Gas Emissions from Barnett Shale Gas Using Air-Quality Inventory Data

A national debate over life cycle GHG emissions[2] from shale natural gas erupted in 2011 after a study was released stating that shale gas had equivalent or even greater GHG emissions than coal.[3] Since then, a number of other published, peer-reviewed studies have included contrary findings,[4] although data limitations and methodological variability make conclusive statements problematic about the "real" GHG emission profile.

For Chapter 1, the study team conducted original research on life cycle GHG emissions associated with natural gas production in the Barnett Shale play in Texas. This estimate leverages high-resolution empirical data to a greater extent than previous assessments. The data sources and approach used in this study differ significantly from previous efforts, providing an estimate valuable for its complementary methodological approach to the literature.

The authors used inventories from 2009 that tracked emissions of regulated air pollutants by the natural gas industry in the Barnett Shale play. The Texas Commission on Environmental Quality (TCEQ) collected and screened these inventories. These data cover the characteristics and volatile organic compound (VOC) emissions of more than 16,000 individual sources in shale gas production and processing. Translating estimated emissions of VOCs into estimates of methane and carbon dioxide emissions was accomplished through the novel compilation of spatially heterogeneous gas composition analyses.

Major findings from this analysis of life cycle GHG emissions include:

- Electricity generated using a modern natural gas combined-cycle turbine combusting Barnett Shale gas produced and processed in 2009 has life cycle GHG emissions ranging between 420 and 510 grams carbon dioxide-equivalent emissions per kilowatt-hour (g

[2] GHG emissions considered within a life cycle assessment (LCA) include those from the "fuel cycle" of natural gas, which includes activities from well drilling and completion, through production, processing, and transport to the power plant, as well as from the life cycle of the power plant, which includes construction and decommissioning of the power plant and combustion of the fuel. Results are normalized per unit of electricity generated (kWh). See Figure 7 within Chapter 1 and the surrounding text for further description of the scope of this LCA.
[3] Howarth, R. W., R. Santoro, and A. Ingraffea. 2011. "Methane and the greenhouse gas footprint of natural gas from shale formations." *Climatic Change Letters*, DOI: 10.1007/s10584-011-0061-5 (http://www.springerlink.com/content/e384226wr4160653/fulltext.pdf).
[4] These studies include Burnham et al. 2012; Jiang et al. 2011; Skone et al. 2011; Stephenson et al. 2011; Hultman et al. 2011.

CO_2e/kWh) generated, depending on assumed lifetime production of a well, with a central estimate of about 440 g CO_2e/kWh—similar to levels reported in the literature from conventional natural gas and less than half that typical for coal-fired electricity generation (Figure 1).[5] Comparisons to conventional natural gas and coal are achieved through harmonization of 200 published estimates of life cycle GHG emissions for those two technologies.[6] Harmonization is a meta-analytical process that makes consistent the assumptions and methods between LCAs.

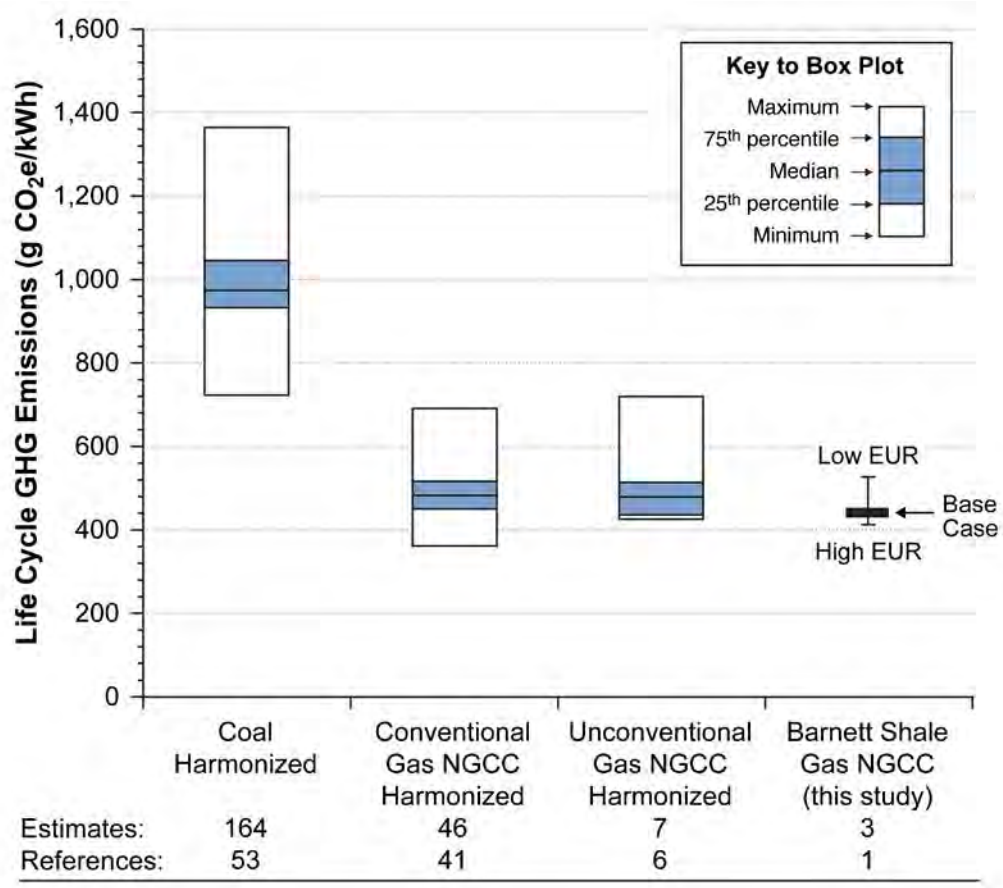

Figure 1. Estimate of life cycle GHG emissions from 2009 Barnett Shale gas combusted to generate electricity in a modern natural gas combined-cycle (NGCC) turbine compared to previously published estimates for unconventional (mostly shale) gas, conventional natural gas, and coal after methodological harmonization.

Notes: EUR = estimated ultimate recovery, or lifetime production; NGCC = natural gas combined-cycle turbine

[5] The results reported here do not include emissions associated with liquids unloading, a process that the natural gas industry recently reported as applicable to both conventional *and* unconventional wells, but without direct evidence for the Barnett Shale play. (See: Shires and Lev-On (2012).)
However, inclusion of these emissions would not qualitatively change our findings.

[6] See Whitaker et al. 2011 and O'Donoughue et al. 2012 for systematic review and harmonization of published estimates of life cycle GHG emissions from coal-fired and conventional natural gas-fired electricity generation, respectively.

- An estimated 7% to 15% of life cycle GHG emissions from electricity generation (mean = 9%) are from methane emissions throughout the fuel cycle of Barnett Shale gas (well pre-production activities through transmission), mostly from venting during completion and workover, and from the natural gas transmission pipeline network.
- GHG emissions result from many sources throughout the production and use of natural gas. Based on our analysis, more than half can be characterized as sources with potentially controllable leakage—for instance, from tanks or vents**.** Another 20% are combustion sources, which also have some emission control opportunities. Remaining sources, called fugitive emissions, are more challenging to control because of their dispersed nature.
- An estimated 1.5% of Barnett Shale produced gas is emitted to the atmosphere before reaching the power plant, much of which is potentially preventable, with an additional 5.6% of produced gas consumed along the process chain as fuel for different types of engines. Based on the estimated methane content of this produced gas and average assumed lifetime production of a well, this equates to a central estimate of leakage rate across the life cycle of 1.3% methane volume per volume of natural gas processed.
- Chemical composition of produced gas varies considerably within the Barnett Shale area such that at the county level, estimates of GHG emissions differ significantly from those based on composition averaged at a higher spatial resolution (play or nation). Variability in gas composition has implications for the understanding of emission sources and the design of regulatory emission control strategies.

A Changing Regulatory Framework for Unconventional Gas Production

Chapter 2 examines the main federal, state, and local regulatory frameworks that govern unconventional natural gas development. Specifically, it focuses on requirements related to water withdrawals used for hydraulic fracturing, disclosure of chemicals used in hydraulic fracturing fluids, setbacks for wells, baseline water monitoring of surface water resources or water wells, well-construction standards, “green” or “reduced emission” completions, storage of waste in closed-loop systems, and the disposal of produced water. It also examines state compliance monitoring and enforcement capabilities, and the efforts by some local governments in key gas-producing states to limit—and, in some cases, ban—unconventional gas development. Major findings include the following:

- There is a trend toward more regulation at all levels of governance, but there has been a corresponding increase in regulatory fragmentation and differentiation at state and local levels. Better coordination and policy alignment among regulators can help to reduce risks to industry and the public of regulatory fragmentation—including uncertainty, delays, gaps, and redundancies across jurisdictions. Improved communication and sharing of information among regulators at all levels of government and across jurisdictions, as well as increased transparency in the form of publicly available data from industry, would help address regulatory fragmentation and inform regulatory development tailored to specific geographic and geologic characteristics.
- Compliance monitoring and enforcement varies across states, with significant implications for the efficacy of regulations, as well as public confidence. Increased public disclosure of voluntary information—as well as public disclosure of violations,

enforcement actions, and company compliance—would increase transparency, offer opportunities to highlight the compliance records of leading companies who have demonstrated a commitment to safe natural gas production, and help address public concerns.

- There is a significant range in the environmental performance of operators in the industry, with some operators performing at a level that goes beyond existing regulations and other operators falling short. There is an evolving portfolio of recommended practices emerging from across the stakeholder community; these practices can complement and supplement regulations.
- The varied state and local approaches to regulation can provide important opportunities for learning and innovation regarding substantive rules, the role of best practices, and compliance and enforcement. Regulators might consider adopting performance-based standards, rather than freezing today's "best management practices" into prescriptive rules that could become outdated.

Management Practices in Shale Gas Production: Focus on Water

Chapter 3 addresses current water usage and water management practices at shale gas development sites and discusses risks to water availability and quality. We evaluated publicly available water usage data from six shale plays throughout the United States. When data were available, we conducted statistical analyses from a randomized sample of wells in each play to gauge current estimates of water usage per well. In addition, data were collected on current wastewater management techniques and volumes associated with managing produced water from wells along with the returned fracking fluids. Lastly, in addition to analyzing current industry practices, we evaluated how water usage, well number, and water management techniques have evolved over time, indicating that water risk and management issues in the future may differ from historical issues. Natural gas exploration and production has significant spatial variability in community and environmental issues, current practices, and regulations. Therefore, JISEA is also publishing the water-related results of this study in a web-based GIS format.

The three primary water impact risks are: regional resource depletion due to use of fresh water during hydraulic fracturing, surface water degradation, and groundwater degradation. Impact risks to water resources vary geographically based on three considerations: 1) where the water comes from, 2) what water use and management practices are followed on site for hydraulic fracturing, and 3) how and where produced water and frac flowback water are treated and/or disposed.

Major findings from this analysis of water impacts include the following:

- Risks to regional freshwater depletion depend on a variety of factors, including water use per well, total number of wells, water recycling rates, and regional water availability. Analysis of use data for four of the six regions from 2007 to 2011 indicated average water use per well ranges from 1.1 to 4.8 million gallons, with a multi-region average of 3.3 million gallons. The total magnitude of water usage depends on the number of wells drilled, which has increased in most regions from 2007 to 2011. In the Eagle Ford play, for example, gas wells increased from 67 in 2009 to 550 in 2011. Total freshwater usage depends on water recycling rates, which may vary greatly depending on location. In

2011, the highest rates of recycling were reported in Pennsylvania, where 37% of produced water and 55% of frac flowback water were recycled, representing nearly 200,000 gallons per well, or 4% of average water use per well in Pennsylvania. Total impacts on regional freshwater resources can be evaluated by comparing total freshwater uses with estimates of regional freshwater availability.

- Wastewater management practices vary regionally and show different trends from 2008 to 2011. In Pennsylvania, 80% of produced water and 54% of frac flowback water was treated through surface water discharge in 2008, whereas in 2011, less than 1% of produced water and frac flowback was treated through surface water discharge. In 2011, centralized disposal facilities and recycling are the primary wastewater management methods, accounting for 80% of produced water volumes and 99% of frac flowback volumes. In Colorado, surface water discharge of both produced water and frac flowback volumes has increased from 2% in 2008 to 11% in 2011. Management of produced water and frac flowback through onsite injection pits and evaporation ponds have remained the dominant practices from 2008 to 2011, representing 72% and 58%, respectively. Treatment at a centralized disposal facility has increased from 26% to 31% from 2008 to 2011. The management and transport of produced water and frac flowback water is considered to be the stage at which spills and leaks are most likely.
- A lack of reliable, publicly available water usage and management data hinders comprehensive analyses of water risks**.** Data are not publicly available for total water withdrawals, total gas wells drilled, flowback volume per well, water recycling techniques, wastewater management, and other management practices for many regions. These data would assist in developing appropriately flexible and adaptive best management practices. Certain resources—such as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and FracFocus—have greatly increased public access to information about risks of hydraulic fracturing; however, further efforts would be beneficial.
- A variety of best management practices are currently being employed in different regions, but there is industry uncertainty over transferability, cost-effectiveness, and risk mitigation potential. Recent studies have documented a number of water-related management practices related to the chemical makeup of fracking fluids (disclosure of additives, minimizing or switching to more benign additives, baseline water quality testing), the impacts on local freshwater (measuring and reporting of volumes, water recycling, use of non-potable or non-water sources), and onsite wastewater management techniques (use of closed-loop drilling systems, elimination of flowback and freshwater mixing in open impoundments, use of protective liners at pad sites) that may be appropriate in many locations. However, to date, there are no publicly available studies that have performed cost-benefit analyses, evaluated the risk-mitigation potential of each strategy, or analyzed practices that could be transferred from one shale play to another.

Modeling U.S. Electric Power Futures Given Shale Gas Dynamics

In Chapter 4, the study evaluates different electric power scenarios that are influenced by natural gas availability and price, as well as other key policy, regulatory, and technology factors. Many of the scenarios examine sensitivities for the estimated ultimate recovery (EUR) of gas fields. High-EUR corresponds to more abundant and inexpensive natural gas compared to Low-EUR.

Major findings from the electric sector analysis include the following:

- Natural gas demand by the power sector would grow rapidly—more than doubling from the 2010 level by 2050—in the Reference, or baseline, scenario.[7] Figure 2 illustrates the range of natural gas power generation in all scenarios. The main Reference scenario suggests that natural gas would replace coal as the predominant fuel for electricity generation. Attributes of this baseline scenario include rising power demand, stable greenhouse gas emissions, and slowly rising electricity prices that reflect natural gas availability and prices. By 2050, in the Reference scenario, gas could represent from 28% to 38% of power-sector generation compared to the 2010 portion of 20%.
- In a coal retirement scenario, natural gas, and wind to a lesser extent, replaces coal-based generation. Our modeling results indicate no impact on power sector reliability from 80 GW of coal retirements by 2025 on an aggregate scale, although additional detailed dispatch modeling is needed to evaluate localized impacts. National average retail electricity prices in the retirement scenario increase by less than 2% in 2030 compared to the baseline.
- Under a clean energy standard (CES) scenario, U.S. power sector carbon dioxide emissions would decrease by 90% between 2010 and 2050, with a corresponding 6%–12% increase in average retail electricity prices, including transmission build-out that ranges from 3 to 6 times more than the Reference scenario (measured in million MW-miles). Among the CES sensitivity scenarios, large quantities of variable renewable energy and flexible gas generation work synergistically to maintain system reliability requirements.

[7] A Reference scenario serves as a point of comparison with other alternative scenarios. The Reference assumes a fairly static view of the future, so it, and all alternative scenarios, should not be considered forecasts or predictions of the future.

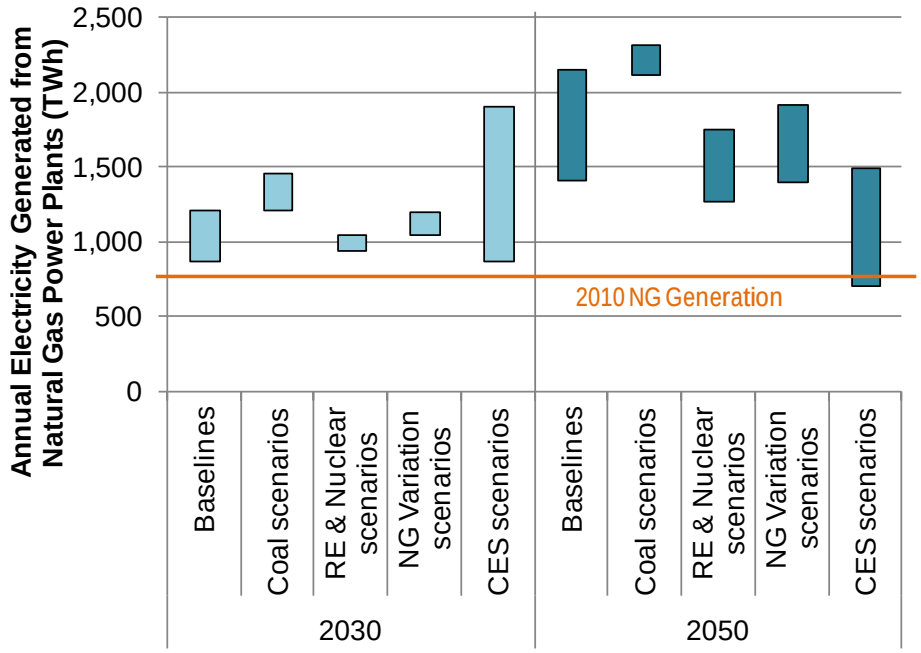

Figure 2. Range of electricity generated from natural gas plants in the scenario analysis

- Advances in generation technologies can have a significant impact on estimated carbon emissions, electricity diversity, and prices. For example, nuclear capital costs would need to decline by half, while gas prices remain relatively high (as simulated in the low-EUR assumption), for the nuclear generating option to compete economically with other options. Wind and solar electricity could more than double by 2050 compared to the Reference scenario with continued improvements in the cost and performance of these technologies. Likewise, continued improvements in production techniques for unconventional natural gas production could enable natural gas to continue to grow market share.
- We consider a range of potential incremental costs associated with operating practices that could better address some of the public concerns in the production of unconventional natural gas. Some of these options include recycling larger amounts of frac flowback water, reducing methane releases to the atmosphere, setting well locations further from potentially sensitive communities, and assuring consistent use of best practices or regulations in well drilling and completions. Sensitivities in incremental costs were evaluated from $0.50/MMBtu to $2/MMBtu. For example, additional costs of $1/MMBtu associated with some or all of these several dozen operating practices would lead to a 17% reduction in gas use for power generation by 2050 compared to the Reference scenario; however, gas-fired generation still more than doubles from the 2010 level.
- A “dash-to-gas” scenario, where other sectors of the economy increase natural gas demand by 12 billion cubic feet per day by 2030, would likely result in higher domestic gas prices and lead to a roughly 20% reduction in power sector natural gas use by 2050 compared to the Reference scenario in that year, but still nearly twice the level used in 2010. Additional research is needed to understand how natural gas prices respond to rising demand in the new natural gas environment.

The rapid expansion of shale gas has created dynamic opportunities and challenges in the U.S. energy sector. How long the ascendancy of natural gas in the electric sector will last will be a function of a wide variety of market and policy factors. The story of unconventional gas is evolving rapidly, and in some cases, unexpectedly. Robust and up-to-date analysis will remain critical to informing the key decisions that must be made by all types of stakeholders in the energy and environmental arenas.

Introduction

This report addresses several aspects of the changing context of natural gas in the U.S. electric power sector. Increasingly plentiful and affordable natural gas has catalyzed major changes in U.S. power generation and has helped to boost U.S. economic recovery. Increased substitution of natural gas for coal in power generation has also cut U.S. GHG emissions. However, processes to produce natural gas—shale gas in particular—have also elevated environmental and safety concerns in certain regions of the country. The rapid rise of natural gas is also beginning to drive more thought on longer-term energy policy issues such as the appropriate level of generation diversity (given the history of volatile prices for natural gas), and trajectories of natural gas use that will still allow GHG mitigation sufficient to address the climate challenge.

This report is intended to help inform those energy policy and investment discussions. This chapter first outlines the current dynamics of natural gas in the power sector and then describes how the remainder of the report addresses selected challenges and opportunities in the use of natural gas to generate electricity.

Natural gas supply and demand are transforming the energy marketplace. Natural gas prices have been relatively volatile over the past 40 years, at least compared to coal (see Figure 3). Today, advances in unconventional gas production, which include a host of technologies and processes beyond horizontal drilling and hydraulic fracturing,[8] have enabled a new market outlook. Shale production grew from less than 3 billion cubic feet per day (bcf/d) in 2006 to about 20 bcf/d by mid-2012.[9] Without this expansion, natural gas prices might be significantly higher because most other sources of domestic natural gas production are in decline.

Given the low-price outlook, many new potential uses for natural gas outside of power generation are being considered and developed—including the export of LNG, the use of compressed natural gas in vehicles, the construction of ethylene plants and other chemical facilities that use natural gas and associated products as a feedstock, and, potentially, investment in gas-to-liquids facilities that convert natural gas into synthetic petroleum products (i.e., diesel) that can be used as a transportation fuel in existing infrastructure. Efforts to further develop the latter may become particularly strong if the price gap shown in Figure 3 remains.

[8] For a description of this technological progress, see Seto (2011).
[9] In 2011, the U.S. power sector consumed about 22 bcf/d and the entire economy consumed about 67 bcf/d (EIA 2012b).

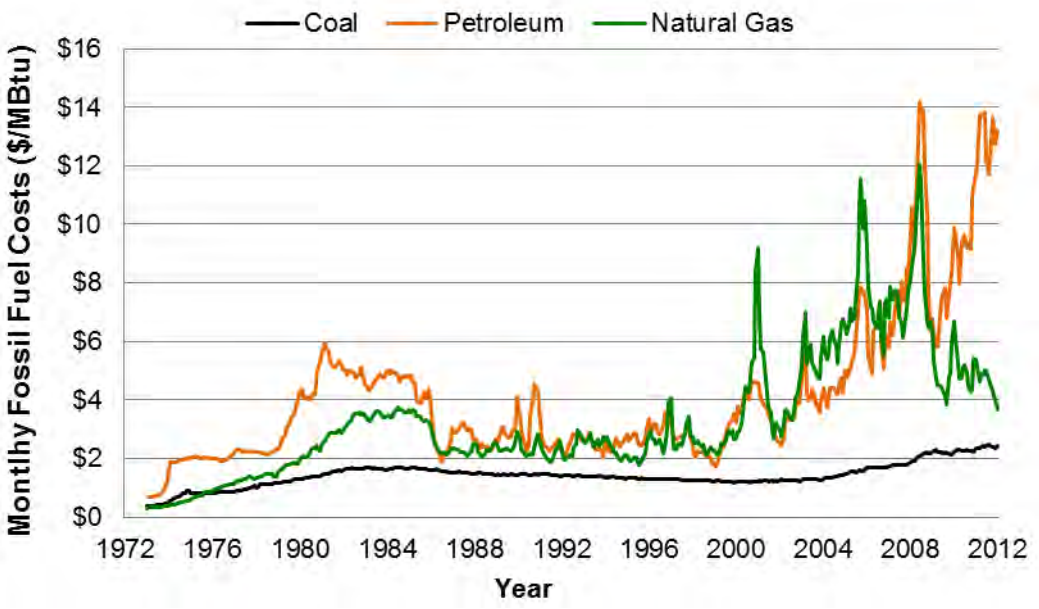

Figure 3. Volatility in fossil fuel costs for power generators

Source: EIA, "Monthly Energy Review," April 27, 2012.

However, given the current low-price environment, many producers have scaled back their plans to drill for dry natural gas, even as they accelerate drilling for wet natural gas (whose natural gas liquids are sold at prices comparable to petroleum products). These cutbacks have contributed to the recent increase in Henry Hub prices, from a low of $1.90/MMBtu in early 2012 to more than $3.60/MMBtu by November 2012. On the other hand, the number of rigs actively developing natural gas has declined sharply since 2009 while production continues to expand, indicating that producers are getting more output with less input (Ebinger et al. 2012). Where prices go next will be influenced by potential new sources of demand noted above, and by supply-side issues, including continued technology improvement, efforts to better protect the environment, and regulatory requirements.

Coal-generated electricity is rapidly declining. Dramatic changes are occurring in the U.S. electric power sector. These changes include a steep reduction in the portion of electric power coming from coal combustion, and a corresponding increase in that provided by natural gas and (to a lesser extent) renewable sources, especially wind power (see Figure 4). Eastern and southern regions are generally experiencing the most rapid shift in generation mix (see Appendix A for more detail). Coal's contribution to total annual U.S. power generation has fallen more rapidly over the past four years than in any time in the history of data collection—from roughly 48% of U.S. generation in 2008 to 36% as of August 2012. Had coal generation remained at the 2008 level, the U.S. power sector would be emitting roughly 300 million tons of additional CO_2 each year.[10]

[10] This is a "burner tip" analysis only and does not consider the full life cycle GHG emissions of coal or natural gas. Data for 2012 are based on a rolling 12-month sum ending in August. The carbon mitigation calculation is based on a 440 TWh reduction in coal generation and corresponding increase in natural gas combined-cycle generation of 310 TWh. Growth in certain renewable generation sources and a reduction in power demand make up the remaining

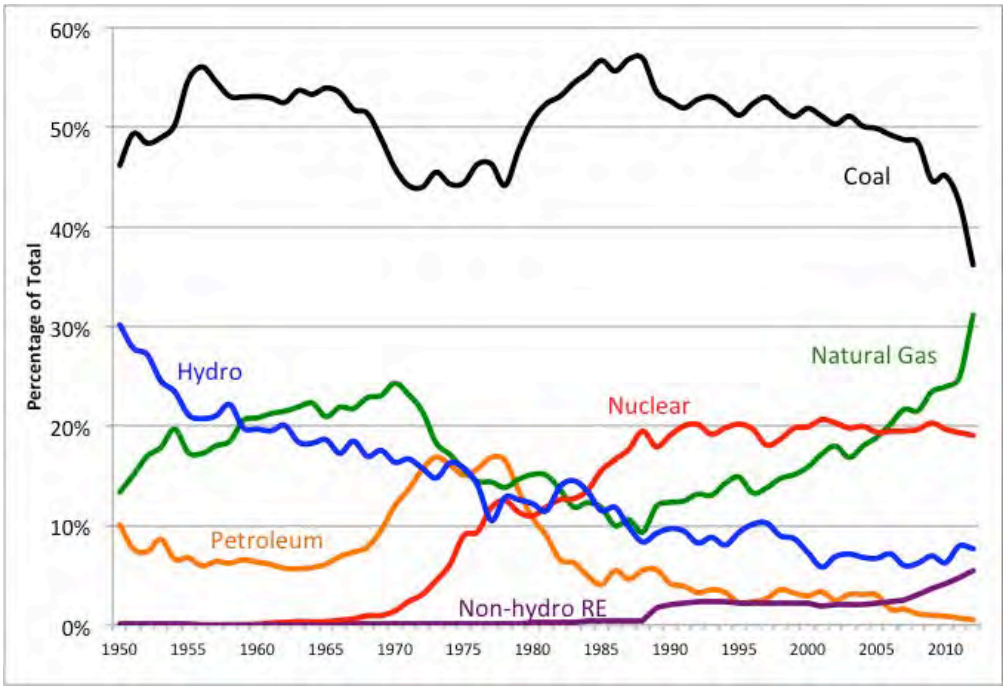

Figure 4. Coal-fired electricity generation is declining rapidly as the use of natural gas and renewable energy expand

Source: EIA, "Annual Energy Review," September 27, 2012; EIA "Electric Power Monthly," October 31, 2012. Data for 2012 includes generation through August only.

The primary drivers of these changes include low-priced natural gas resulting from rapidly growing shale gas production, an unusually warm 2011–2012 winter throughout much of the contiguous United States,[11] and the expectation that EPA will issue new or revised power plant regulations to further protect the environment.[12] It remains to be seen whether this trend of declining coal generation continues, stabilizes, or reverses itself.[13]

Hydraulic fracturing presents opportunities and challenges that are in the headlines daily. These opportunities include additional U.S. jobs, increased economic activity, potentially greater energy diversity (particularly in the transportation sector), and less reliance on imported fossil fuels. Challenges largely center on environmental and social concerns associated with shale gas

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difference. See EIA Electric Power Monthly (October 2012) for more detail. Chapter 1 of this report addresses the issue of life cycle GHG emissions for various electric generating technologies.

[11] The U.S. Department of Energy reported that the number of heating degree days in the first quarter of 2012 were at the lowest level since record keeping began in 1895 (EIA 2012a).

[12] These rules include the Cross-States Air Pollution Rule (recently vacated, but backstopped by somewhat less restrictive requirements), the Mercury and Air Toxics Standard, the Clean Water Act Section 316(b) Water Intake Structures, and the Coal Combustion Residual requirements. Numerous studies attempt to estimate the potential impacts of some or all of these rules after they take effect (see CRS 2011; CERA 2011; and Credit Suisse 2010).

[13] In a May 22, 2012 presentation to investors, for example, ArchCoal stated that half of the coal generation recently lost to low-cost natural gas could be recovered when gas prices rise back above $3/MMBtu (Slone 2012). AEP also noted in an October 24, 2012 news story that it had seen some fuel switching from natural gas back to coal due to rising natural gas prices (Reuters, 2012).

production, especially through hydraulic fracturing.[14] These concerns are acute in some states and increasingly on the docket for federal regulators in several agencies. Current federal regulations to protect surface and underground water resources are less onerous for hydraulically fractured gas production than they are for conventional oil and gas drilling, although many states are passing or updating rules quickly as drilling expands (see Chapter 2, UT 2012, Zoback 2010). Companies are also making greater voluntary efforts to ensure the likelihood that air, water, land, and other resources are protected—at least compared to the early days of hydraulic fracturing—although these efforts are still not practiced universally (see Chapters 2 and 3).

A more general concern for policy makers centers on the role of natural gas versus other sources of electricity in the future: low-priced natural gas could disrupt the development of advanced nuclear or renewable energy technologies, for example, and delay the date when they are cost competitive with traditional energy options. If natural gas prices rose substantially after the power sector had evolved to become more reliant on that fuel, the economy could be vulnerable to an expensive and "locked-in" power sector.

This report focuses on four topics. First, Chapter 1 addresses the full life cycle GHG emissions of shale gas compared to other power generation options. Questions about these "cradle-to-grave" emissions began to appear in 2011 with several reports claiming that shale gas had life cycle GHG emissions as high as, or higher than, coal.[15] Controversy remains over how much methane is released to the atmosphere during the process of producing natural gas, in general, and shale gas, in particular. Chapter 1 uses a new approach to advance the state of knowledge about the life cycle GHG emissions from shale gas based on analysis of highly resolved inventories of air pollutant emissions completely independent of the data sources used in previous research.

Second, Chapter 2 surveys the legal and regulatory trends associated with shale gas production at both the federal and state level. Although federal agencies are taking an active role in ensuring that shale gas is produced safely, Congress has imposed some limitations on what agencies can regulate. The state role in regulating unconventional natural gas production is more pronounced and varied. Chapter 2 summarizes trends in regulatory action at six major unconventional gas plays/basins: Barnett Shale play and Eagle Ford Shale play in Texas, Haynesville Shale play in Texas and Louisiana, Marcellus Shale play in New York and Pennsylvania, North San Juan basin in Colorado, and Upper Green River basin in Wyoming.

Third, Chapter 3 assesses environmental and community risks associated with unconventional natural gas production in the same six regions identified in Chapter 2. It focuses particularly on water issues and company practices that impact water. Public concern over environmental and safety issues has been severe enough in some areas to delay or halt plans to develop unconventional production.

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[14] See, for example, SEAB (2011a and 2011b), MIT (2011), and UT (2012). There is some confusion surrounding hydraulic fracturing and the potential for environmental impact. Those in industry typically use the term in a focused way, referring to the brief period of time that a high-pressure mixture of water, sand, and additives is being injected, and later, partially removed (flowback). The general public often takes a broader view and labels the entire process of producing unconventional gas or oil as hydraulic fracturing. Significant controversy results from the difference in semantics.

[15] See Lustgarten (2011) and Howarth et al. (2011), for example.

A GIS tool was developed to help evaluate:

- Water availability, use, and cost information
- Water flowback and produced water
- Best current practices for management.

Current practices and regulatory oversight need to be evaluated at a deeper level before the overall goal of determining the costs of acceptable practices can be achieved. Chapter 3 describes a comprehensive approach to evaluating risks and following practices so as to support greater public confidence.

In Chapter 4, we report on different U.S. electric power futures based on a variety of potential developments in technology, environmental protection, GHG mitigation, social license to operate, and gas demand outside the power sector. We use the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) to simulate the impact of these different futures, and benchmark information from Chapters 1–3 in the scenario analysis. Chapter 5 synthesizes findings and summarizes potential follow-on research.

1 Life Cycle Greenhouse Gas Emissions from Barnett Shale Gas Used to Generate Electricity

1.1 Introduction

According to the 2010 U.S. Greenhouse Gas Emissions Inventory (EPA 2012a), the natural gas industry[16] represents nearly a third of total methane emissions in the United States in 2010—the largest single category—and is also the fourth largest category of CO_2 emissions.[17] EPA, which produces the U.S. GHG inventory, significantly increased estimates of methane emissions from the natural gas industry for the 2009 inventory year, resulting from a change in its assessment of emissions from four activities, the most important of which were: well venting from liquids unloading (attributed only to conventional[18] wells by EPA); gas well venting during completions; and gas well venting during well workovers[19] (EPA 2011). The sum of these changes more than doubled the estimate of methane emissions from natural gas systems from the 2009 inventory compared to the 2008 inventory. EPA acknowledges what is well understood: the estimates of GHG emissions from the natural gas sector are highly uncertain, with a critical lack of empirical data to support GHG emission assessments (EPA 2011). This is especially acute for production of unconventional gas resources. Data gathering to support re-assessment of the EPA's U.S. GHG inventory and potential regulations is under way.

An emerging literature has attempted to estimate GHG emissions from unconventional natural gas production, based on the limited available information. Measurement of GHGs in the atmosphere, if they could be reliably attributed to specific sources, would be the ideal methodological approach. However, such measurements are expensive, attribution is challenging, and only one pilot study has been published to date based on measurements in one gas field—which, since the time of measurement, has implemented new practices based on changing state regulations (Petron et al. 2012). The state of the practice employs engineering-based modeling, based on as much empirical information as is possible to assemble.

Much of this emerging literature is guided by the methods of life cycle assessment (LCA), which in this context aims to estimate all GHG emissions attributable to natural gas used for a particular function: electricity, transportation, or primary energy content (e.g., heat). Attributable emissions are those from any activity in the process chain of producing the natural gas—from exploration and well pad preparation to drilling and completion—processing it to pipeline quality, transporting it to the location of end use, and combustion. In addition, the construction, operation and maintenance, and end-of-life decommissioning of the end-use technology are also considered.

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[16] For purposes of the GHG Inventory, the natural gas industry includes exploration, production, processing, transmission, storage, and distribution of natural gas to the end user (EPA 2011).

[17] In 2010, total U.S. GHG emissions have been estimated as 6,822 Tg or million metric tons CO_2e (EPA 2012a). Of this total, 84% were from CO_2, with most of the remaining (10%) from methane. Direct emission from the combustion of fuels, including natural gas, for electricity generation contributes 2,258 Tg CO_2, or 33% of total GHG emissions. Natural gas systems contribute 247 Tg of CO_2e, or 3.6% of total emissions, 87% from emissions of methane.

[18] Defined as any non-stimulated well. This report follows EPA (2011) in recognizing "that not all unconventional wells involve hydraulic fracturing, but some conventional wells are hydraulically fractured, which is assumed to balance the over-estimate."

[19] The frequency of which has since been reduced from 10% of wells per year to 1% of wells per year (EPA 2012b).

LCAs are typically performed to compare the results from one system to another.[20] The focus of this chapter is to advance understanding of GHG emissions from the production and use of shale gas in the context of the electric power sector as compared to generation of electricity from conventionally produced natural gas. Natural gas once processed for pipeline transmission to end-use customers is a homogenous product, undifferentiated by source. End-use combustion of the natural gas has, by far, the largest contribution to life cycle GHG emissions (as is true for any fossil-fueled combustion technology); but is not a point of differentiation between conventional and unconventional natural gas. Therefore, this study focuses on the activities associated with production of natural gas because they are the points of potential differentiation between unconventional and conventional natural gas.

We additionally focus on emissions from natural gas processing, given current regulatory and scientific attention to emissions from the natural gas industry and opportunity provided by the unique data sources employed in this study. Furthermore, we rely on the multitude of previously published LCAs of conventionally produced natural gas, updated for recent changes in understanding (EPA 2011; EPA 2012b) and harmonized for methodological inconsistency, as embodied in our publication (O'Donoughue et al. 2012), for comparison to the results of this study. We also compare our results to those for coal-fired electricity generation based on a systematic review and harmonization of that LCA literature, because coal has been the largest source for electricity in the United States over the last 50-plus years (Whitaker et al. 2012).

Prior research comparing life cycle GHG emissions of electricity generated from shale gas to conventional gas has been inconclusive and remains highly uncertain. Both the magnitude and direction of difference reported in these publications vary (Howarth et al. 2011; Burnham et al. 2012; Jiang et al. 2011; Skone et al. 2011; Stephenson et al. 2011; Hultman et al. 2011). This is despite their reliance on very similar data sources (mostly EPA's GHG emission inventory and supporting documentation). Uncertainty in the underlying data sources drives the uncertainty in published results. Furthermore, inconsistent approaches to data use and other assumptions thwart direct comparison of the results of these studies and the development of collective understanding.

Separately, the authors have examined this literature using a meta-analytical technique called harmonization that clarifies the collective results of this emerging literature by adjustment to more consistent methods and assumptions (Heath et al. 2012). In that publication, the authors elucidate differences between previously published estimates of life cycle GHG emissions from combustion of shale gas for power production and key sensitivities identified in this literature. Key sensitivities include EUR and lifetime (years) of wells; emissions and emissions reduction practices from well completion and workover; and emissions and emission reduction practices from well liquids unloading, all of which vary from basin to basin and from operator to operator. A key conclusion from the assessment of previous estimates of unconventional gas life cycle GHG emissions is that given current uncertainties, it is not possible to discern with a high level of confidence whether more GHGs are emitted from the life cycle of shale gas or conventional gas used for electricity generation.

[20] For interested readers, many texts describe LCA principles and methods, such as Horne et al. (2009) and Vigon et al. (1993).

In this chapter, we present results from a new method of estimating life cycle GHG emissions from shale gas that takes advantage of unusually detailed and rarely produced empirical data specific to a shale gas play and year. Our empirical data sources and approach differ significantly from previous efforts. Broadly, we use the methods of air quality engineering, life cycle assessment, and energy analysis to estimate GHG emissions attributable to the generation of electricity from shale gas produced from the Barnett Shale play in Texas in 2009, the latest year with available data. There are several unique aspects of this research as compared to previous natural gas life cycle assessments:

- Highly resolved estimates of GHG emissions from shale gas production and processing developed at site (facility) and source (equipment and practices) levels.
- Use of industry-supplied and regulator quality-assured data regarding equipment, practices, and emissions developed with very high participation rates.
- Development of a publicly available data set of county-level, extended gas composition analyses of produced (raw) gas demonstrating wide variability of methane and VOC content within the Barnett Shale formation.

It is critical to note that the new results reported here are not necessarily applicable to other plays or years. However, they are discussed in the context of other published literature, where the broad outlines of consistency found within this literature increases confidence in the results, albeit still hampered by many areas of uncertainty remaining to be addressed through further research.

Commercial production of shale gas began in the 1980s, starting in the Barnett Shale play in Texas. The Barnett Shale play continues to be a large source of gas, estimated at more than 6% of total U.S. natural gas production (Skone and James 2010). Data on production and processing activities in this 22-county[21] area (Figure 5) are some of the best available for any unconventional gas formation in the United States. For these reasons, the focus of the analysis of this chapter is shale gas produced from the Barnett Shale formation. As illustrated in Figure 5, the highest production occurred within the Dallas-Ft. Worth metropolitan area, which is in non-attainment for the National Ambient Air Quality Standard for ozone (and other pollutants).

[21] The Barnett Shale is sometimes referred to as consisting of 23 or 24 counties. However, this analysis focuses on the 22 counties with non-zero gas production for 2009 (TRRC 2012).

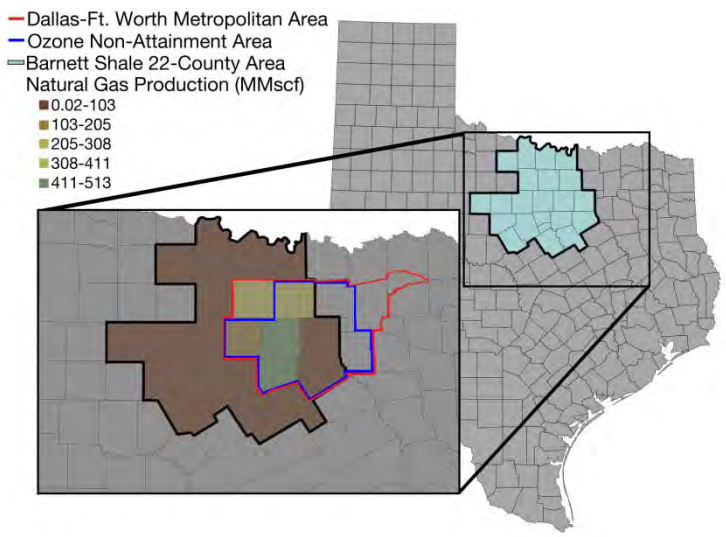


Figure 5. Counties with non-zero gas production from the Barnett Shale formation in 2009, and other demarcations of the Barnett Shale area in Texas (TRRC 2012)

1.2 Methods and Data

There are many different sources of GHG emissions in the natural gas industry (EPA 2011; ENVIRON 2010; API 2009), but the fundamental approach to estimating the magnitude of emission for all of them is:

$$[activity] * [emission\ factor] = [emission]$$

where the emission factor is in units of mass emission per unit activity, and "activities" for the natural gas industry range from counts of drilled wells or pieces of certain equipment to volume of natural gas produced, fuel combusted in an engine, or volume of water produced from a well (e.g., ENVIRON 2010; API 2009; EPA 1995). We call this approach *activity-based emission estimates*.

Different groupings of activity-based emission estimates lead to different types of results. *Inventories* aim to estimate emissions from a given chronological period, representing all activities occurring in that period. Inventories are developed with different foci: geographic, industrial sector, or pollutant. Few GHG emission inventories exist at higher spatial resolution than national, which aggregates industry- and pollutant-specific inventories produced at a national scale.

In contrast, LCAs aim to estimate all emissions attributable to a final product—here, a kilowatt-hour of electricity—scaling all the activities required over time and space to produce that unit of final product. Figure 6 depicts the scope of this LCA of electricity generated with natural gas, which covers all stages in the fuel cycle as well as the power plant's life cycle. As shown, this study combines an original inventory, for stages shown in blue, with best-available literature estimates for the remaining stages. Once co-products are separated from the produced gas, all emissions associated with their storage, processing, transport, and disposal or sale are considered outside of the system boundary for this study (as depicted with dashed lines).

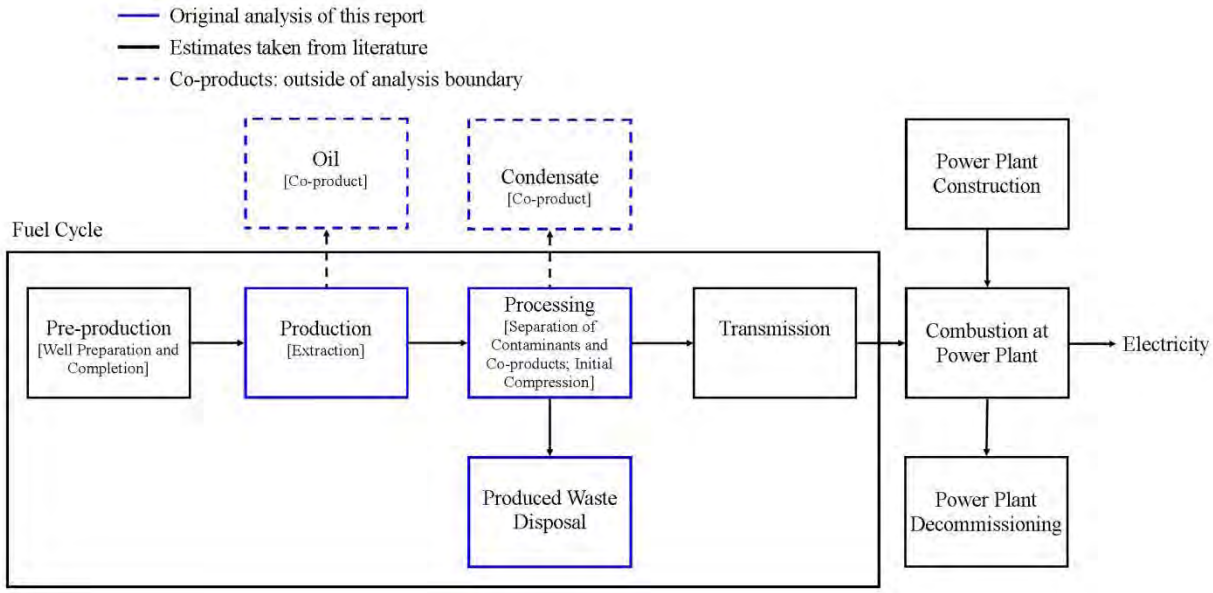


Figure 6. A life cycle assessment of electricity generated from natural gas involves estimating the GHG emissions from each life cycle stage

Because LCAs track the conceptual process chain—rather than the real supply chain—they typically model idealized activities, informed by as much empirical data on real conditions as possible. More than 30 LCAs of conventional natural gas follow this modeling philosophy (O'Donoughue et al. 2012). LCAs on shale gas that follow this approach include one employing a simplified, generic model of the industry (Stephenson et al. 2011); three assessing the U.S. national average or otherwise non-formation-specific conditions (Burnham et al. 2012; Skone et al. 2011; Howarth et al. 2011); and two assessing specific formations—Jiang et al. (2011) on the Marcellus formation and Skone et al. (2011) on the Barnett Shale.

More recently, some LCAs have leveraged EPA's national inventory of the natural gas industry's GHG emissions from a given year to simulate the process chain (Hultman et al. 2011; Venkatesh et al. 2011). These latter assessments benefit from emission estimates meant to be more closely related to actual performance; however, their estimates carry significant uncertainty given the current state of knowledge of activities and emission factors of this industry. In addition, results will change from year to year as the level of activity changes and may not reflect the life cycle of activities for a well (e.g., completions nationally in a given year may contribute a larger fraction of total emissions than what is reflective of their contribution within the life cycle of a single well).

In contrast to such approaches, this study translates estimates of VOC emissions to GHG emissions, capitalizing on a uniquely detailed inventory of VOC emissions and activities collected by the TCEQ. This approach enables a high-resolution GHG inventory for the production and processing of natural gas in the Barnett Shale play, within which individual GHG emissions from all relevant sources are estimated. Then, this annual inventory of the natural gas industry is translated into a longitudinal life cycle assessment for electricity produced from combustion of Barnett Shale gas. A brief summary of the approach is described below, with details provided in Appendix B.

1.2.1 Developing a GHG Emissions Inventory

Inventories of GHG emissions follow a long tradition of inventories for regulated air pollutants such as nitrogen oxides (NO_x) and VOCs that, in combination with sunlight, are precursors of ozone. Because of their role in demonstrating compliance with the National Ambient Air Quality Standard for metropolitan areas, the unit of analysis of these inventories is the county and large, so-called *point sources*. Point-source inventories contain detailed information related to all sources of emissions within specific facilities and are based on activity and characteristics information supplied by those facilities. Smaller, non-mobile sources (called *area sources*) are too numerous for regular, facility-specific information collection efforts and instead are tracked as a class, with emission factors (often simplified) correlating emissions with readily tracked activity data. The natural gas industry has many large point sources (including processing plants, compressor stations, and some production sites); the more numerous, smaller entities (including most production sites and some processing and transmission facilities) are classified as area sources.

Motivated by changing practices in the industry, in 2009, the TCEQ initiated a special inventory to collect detailed information on the activities and characteristics of the smaller entities in the natural gas industry that are normally part of the area-source inventory, similar to what is collected routinely from large point sources (TCEQ 2011). The purpose of the special inventory is to update and improve the TCEQ's estimates of emissions of regulated air pollutants from area sources, focused on the rapidly growing shale gas industry in the Barnett Shale area surrounding the metropolitan area of Dallas-Ft. Worth. The availability of the TCEQ's special inventory, in conjunction with its standard point-source inventory (TCEQ 2010), enables estimates of GHG emissions from activities within this important play at much finer resolution—by geography and entity—than is typically possible.

This study estimates GHG emissions from more than 16,000 individual sources detailed in three different TCEQ emission inventories:[22] the 2009 Point Source Inventory, 2009 Special Inventory, and 2008 Area Source Inventory (Pring et al. 2010). As shown in Figure 7, sources are characterized into profiles, which we further group into three general categories: combustion sources, potentially controllable leakage, and fugitives.[23] We differentiate between *potentially controllable leakage* and *fugitives*, where the former typically involves gas released from an isolatable emission point and therefore is potentially controllable, and the latter comes from more dispersed leaks that are less feasible to control. Many of the individual sources analyzed in this report are potentially controllable, as are many additional emissions in the fuel cycle, which come from completions and workovers, waste disposal, and transmission. For each profile, we estimate emissions with a tiered approach based on the availability of data. In general, primary (most accurate) methods are based on reported volumes, such as fuel combusted or gas emitted, whereas secondary methods are based on reported VOC emissions or average usage conditions. We use primary methods for 83% of sources, secondary for 15%, and profile medians for the remaining 1%.

[22] Detailed inventory data were received through personal communication (TCEQ 2012).

[23] Skone et al. (2011) state that 25% of compressor engines in the Barnett Shale area are electrically powered, which would require the inclusion of emissions attributed to the generation of that electricity as an additional category. However, no electrically powered compressor engines are listed in the TCEQ data provided, and personal communication with the TCEQ (TCEQ 2012) stated that few, if any, such engines exist in the area.

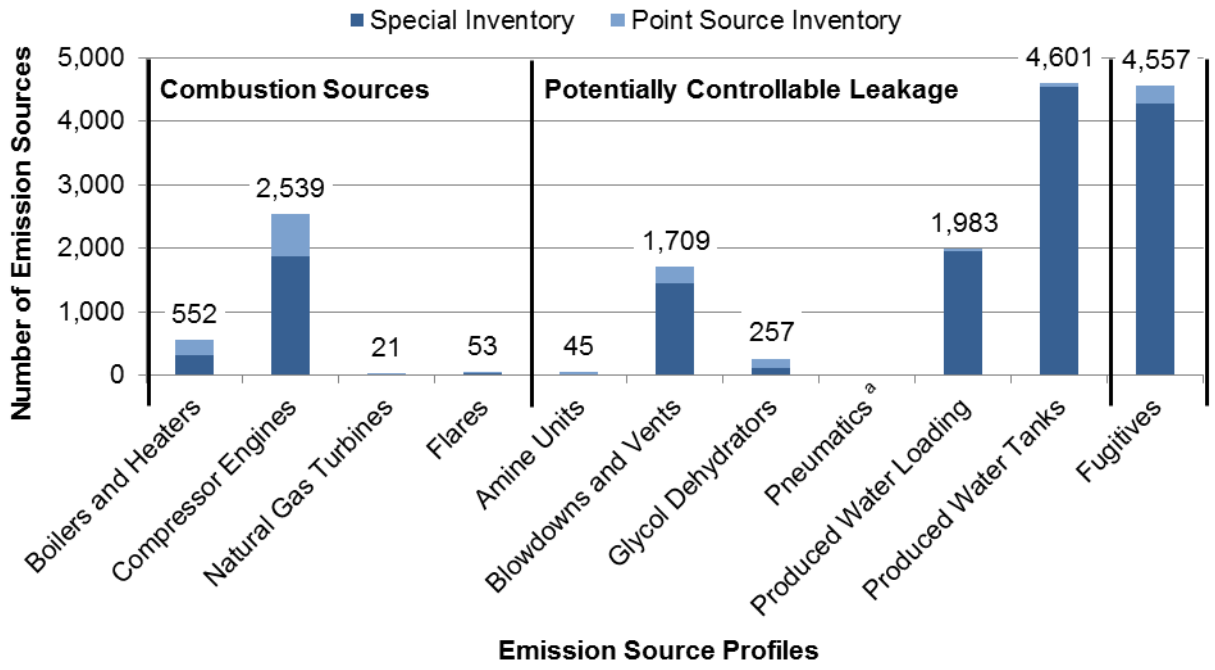


Figure 7. Greenhouse gas sources belonging to the natural gas industry in the 22-county Barnett Shale area; many are potentially controllable

[a]Pneumatics, from the area source inventory, have no count of individual sources

The central principle for translating a VOC emission inventory to one that estimates GHG emissions is the recognition that methane is a VOC,[24] albeit the slowest-acting one (Seinfeld and Pandis 2006). The key to translating VOC emission estimates to methane emissions is the availability of gas composition analyses reporting the proportion of methane, VOCs, and other gases (e.g., CO_2) within a sample. For validation purposes, the TCEQ requested many such gas composition analyses from reporting entities, which have been assembled into the largest known play-specific and publicly available set of gas-composition analyses. Organized by county, this database allows for estimation of methane and CO_2 content in gas emitted through venting and fugitive sources by ratio. It is well understood by geologists, petroleum engineers, investors, and others that gas composition varies within a geologic shale gas basin (e.g., Bullin and Krouskop 2008; Bruner and Smosna 2011); however, this is the first LCA or GHG emissions inventory to explore the implications of this variability.

In addition, other valued hydrocarbon products, such as condensate and oil, are created during the production and processing of natural gas. A principle of LCA research called co-product allocation dictates that the burdens of a system should be shared among all valued products from that system (e.g., Horne et al. 2009). In this study, emissions are allocated with respect to their share of the total energy content of all products from the fuel cycle. In addition to weighting the emissions from each source according to associated condensate and oil production, this means

[24] The VOCs typically tracked in Texas and national (EPA) regulations are non-methane, non-ethane VOCs. Accordingly, this report follows standard convention and refers to the set of non-methane, non-ethane hydrocarbons as VOCs. However, measurements of the composition of a gas sample (a so-called "extended analysis") include methane.

that the 25% of the sources in the TCEQ inventories that are associated only with the storage and handling of these co-products (e.g., condensate tanks) have been omitted.[25]

1.2.2 From Inventory to LCA

The GHG emissions inventory estimated here draws mainly from the TCEQ Special Inventory and Point Source Inventory for sources within natural gas production and processing life cycle stages (see Figure 7) (TCEQ 2010, 2011). Natural gas *production* relates to ongoing activities for the extraction of gas at wellheads. Natural gas *processing* relates to ongoing activities for the conversion of the produced gas to the required quality, composition, and pressure for pipeline transport.[26] In addition, the TCEQ area-source inventory is leveraged to estimate emissions associated with some activities at produced water *disposal* sites (Pring et al. 2010).[27]

Emissions from all sources within a fuel cycle phase are summed and then divided by the energy content of gas produced in that year to estimate an emissions factor in terms of mass of GHG emissions per unit of energy content of gas. Gas production statistics come from the Texas Railroad Commission for the 22-county play (TRRC 2012). Each GHG is weighted by its Intergovernmental Panel on Climate Change (IPCC) 100-year global warming potential according to standard procedure to normalize to units of CO_2e (Forster et al. 2007).[28] However, these emission factors cover only a portion of the natural gas fuel cycle, which itself is a subset of the life cycle of electricity generation from natural gas (Figure 6). Therefore, although the inventory data provide an important addition to the relatively sparse information about GHG emissions from shale gas development, literature sources are relied on for data on other emissions sources and life cycle stages—including sources such as completions, workovers, and liquids unloading—where there is considerable controversy currently about activity factors, emission reduction measures, and the magnitude of emissions.

Additional fuel-cycle stages include pre-production and transmission. *Pre-production* consists of one-time or episodic activities related to the preparation of wells, including the drilling and construction of well pads and wells, hydraulic fracturing to stimulate production, and well-completion activities. Emissions factors for these one-time activities, gathered from open literature (Santoro et al. 2011; EPA 2011; EPA 2012b; Skone et al. 2011), must be amortized over the lifetime production (EUR) of a well. *Transmission*, also estimated from literature data (Skone et al. 2011), involves the transport of processed gas to the power plant.[29]

This study combines fuel cycle emission factors into a full LCA by assuming a standard efficiency of conversion to electricity and adjusting for natural gas losses throughout the fuel cycle due to both leakage to the atmosphere and the use of production gas as fuel. This study

[25] Sources contained within the TCEQ inventories that are considered outside of the system boundary collectively represent 60% of total reported VOC emissions but a much smaller fraction of GHG emissions.
[26] Processing can occur either at wellheads or at separate processing facilities.
[27] Emissions from produced water tanks at produced water disposal sites are tracked by TCEQ; transport of the produced water to the disposal site and operation of engines at these sites are not considered in this analysis.
[28] Global warming potentials (GWP) are also reported by the IPCC for a 20 year horizon and 500 year. The 100-year GWP is used in this study to ensure consistency with the standard practice in LCA and GHG emission inventories. Results based on alternative GWPs or other metrics of climate impact could be developed based on the results reported here.
[29] Following Skone et al. (2011), we consider the final step of processing as initial compression to pipeline pressure.

assumes combustion in a modern natural gas combined-cycle facility with thermal conversion efficiency of 51% (higher heating value) to make the results comparable to the meta-analysis of electricity generated from combustion of conventionally produced natural gas (O'Donoughue et al. 2012). Many natural gas-fired power plants do not operate at this efficiency, and the results reported here can be easily adjusted to apply to alternative conditions. GHG emissions from power plant construction and decommissioning are also considered, amortized over the lifetime generation from the facility (O'Donoughue et al. 2012). Data on emissions from *combustion at power plant*, *power-plant construction*, and *power-plant decommissioning* come from open literature (Skone et al. 2011; Skone and James 2010).

The final estimate of life cycle GHG emissions is calculated as the sum of the estimated emissions from each life cycle stage, adjusted by the thermal efficiency and relevant production losses, as appropriate for each stage and detailed in the appendix. These full life cycle emissions are expressed in units of mass CO_2e per kilowatt-hour generated.

1.3 Results

In this section, we present and discuss key findings. Because of their relevance to the current debate about GHG emissions from natural gas, the full LCA results are presented first, followed by a comparison of these results to other published estimates. Then, the primary research contribution of this chapter is detailed: a high-resolution inventory analysis of the production and processing stages of the natural gas fuel cycle for Barnett Shale gas produced in 2009. Appendix B provides further results, including county-level analysis of production gas composition, allocation of emissions to co-products, and details supporting the presented results.

1.3.1 Life Cycle Emissions

GHG emissions from the natural gas fuel cycle are a focus in the public sphere and of the novel analysis of this study. However, the functional unit of the fuel cycle—a unit of energy content of processed natural gas delivered to the end user—is not easily comparable to that for other fuels for end-uses other than direct heating. Use of natural gas in the electric sector is the focus of this report and is the market for about 30% of natural gas production in 2011 (EIA 2012). Some have argued that future production of unconventional natural gas will only displace dwindling production of conventional natural gas (e.g., Howarth et al. 2012). However, others believe that natural gas could displace existing and new coal as fuel for electricity generation (e.g., Venkatesh et al. 2011; Hultman et al. 2011). Comparisons of the results to both alternatives are provided in the next section.

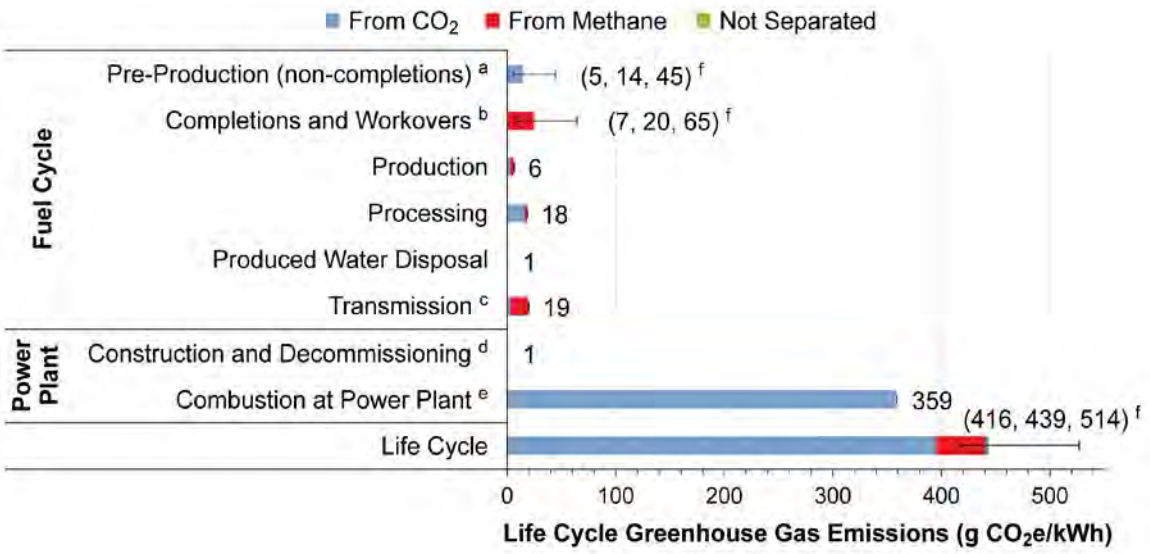
First, it is critical to emphasize the importance of GHG emissions from combustion at the power plant in the life cycle of natural gas electricity generation. The GHG emissions from combustion are primarily determined by the carbon content of the fuel and the efficiency of converting fuel (chemical) energy to electrical energy. Regardless of whether natural gas comes from conventional or unconventional sources, its chemical and thermal properties once processed are indistinguishable. With regard to carbon content of the fuel, coal has about 75% more carbon per unit fuel energy than gas. Regarding efficiency, when considering new power plants, most new natural gas generation assets will likely be natural gas combined-cycle, which has a characteristic higher heating value efficiency of 51% (O'Donoughue et al. 2012). This efficiency, chosen to maintain consistency with other studies for comparison purposes, does not reflect the existing

fleet of natural gas plants, but rather, it is characteristic of a modern, state-of-the-art facility. The existing fleet of coal power plants has an efficiency of close to 34% (Hultman et al. 2011), whereas new plants of either supercritical or integrated gasification combined-cycle designs will reach near 40% (MIT 2007). The efficiency improvement for natural gas combined-cycle plants over old or new coal plants is substantial, especially considering the inherent difference in carbon content of the two fuels (absent any coal decarbonization).

Assuming 51% efficiency for natural gas combined-cycle and 50 g CO_2/MJ carbon intensity of natural gas yields an estimate of nearly 360 g CO_2/kWh from combustion at the power plant. Other stages in the life cycle of the power plant (e.g., construction and decommissioning) add very little (~1 g CO_2e/kWh) to life cycle GHG emissions of electricity generation for fossil-fuel facilities because those emissions are amortized over lifetime generation.

Including the 2009 Barnett Shale fuel cycle emissions compiled in this study, total life cycle GHG emissions from natural gas combined-cycle electricity are estimated to be about 440 g CO_2e/kWh (Figure 8). Of this total, about 18% of life cycle GHG emissions (or 78 g CO_2e/kWh) are embodied in the fuel cycle of Barnett Shale gas, as defined in Figure 7. These fuel cycle emissions from unconventional gas are comparable to those estimated from the fuel cycle of conventional gas, which O'Donoughue et al. (2012) find have a median estimate of about 480 g CO_2e/kWh in the existing literature after methodological harmonization. (See the next section for further discussion and comparisons.) About 10% (or 42 g CO_2e/kWh) of life cycle emissions result from emissions of methane, mostly through venting during completion and workover and from the natural gas transmission pipeline network. These results are calculated assuming a base-case EUR of 1.42 bcf produced over the lifetime of a well, which is the play-average EUR used by the U.S. Energy Information Administration in their National Energy Modeling Systems (NEMS) model (INTEK 2011).

The results are fairly sensitive to alternative estimates of Barnett Shale well EUR, which other studies have found to be one of the most influential parameters on life cycle GHG emissions (Burnham et al. 2012; Stephenson et al. 2011; Skone et al. 2011; Jiang et al. 2011). Adjusting all one-time and episodic emissions by lower- and upper-bound estimates of well-level EUR (INTEK, 2011) yields estimates of life cycle GHG emissions that vary by nearly 100 g CO_2e/kWh. Figure 8 displays the use of reported lower- and upper-bounds of well-level EUR for the Barnett Shale play (INTEK 2011) of 0.45 and 4.26 bcf/well, respectively. Life cycle GHG emissions then range between about 420 and 510 g CO_2e/kWh owing to the tested variability in assumed EUR.



[a] Although lower estimates for this stage have been published, reported emissions increase as the comprehensiveness of processes considered increase. So we use the highest published estimate for this stage that provided results in a form that could be adjusted by EUR (Santoro et al. 2011).
[b] Based on EPA (2011) estimate of 9,175 Mcf natural gas emission/completion, 1% of wells/year workover rate (EPA 2012b), 30-year assumed lifetime (Skone et al. 2011), and 22-county, Barnett Shale average natural gas molecular weight of 20.1 lb/lb-mol and methane mass fraction of 66.2%.
[c] Based on Skone et al. (2011)
[d] Based on Skone and James (2010)
[e] Based on Skone et al. (2011)
[f] Multiple estimates, in parentheses, pertain to high EUR, base-case EUR, and low EUR, respectively. Single estimates pertain to stages without sensitivity to EUR. The error bar is plus or minus the total bar length (life cycle GHG emissions).

Figure 8. Combustion at the power plant contributes the majority of GHG emissions from the life cycle of electricity generated from Barnett Shale gas

1.3.2 Comparisons to Other Studies

There are three important points of comparison for the life cycle GHG emission results presented here:

1. Previous estimates for electricity generated from shale or other unconventional gas
2. Previous estimates for electricity generated from conventional gas
3. Previous estimates for electricity generated from coal.

Direct comparison of the results of LCAs is hindered by the sensitivity of results to alternative assumptions of key parameters and other methodological considerations. Harmonization, which is a meta-analytical approach to enable more direct comparison, has been demonstrated for a wide range of electricity generation technologies (e.g., Burkhardt et al. 2012; Warner and Heath 2012). For coal-fired electricity generation, Whitaker et al. (2012) harmonized 164 estimates from 53 LCAs on four coal generation technologies (i.e., subcritical, supercritical, integrated gasification combined cycle, and fluidized bed). More recently, this approach has been applied to the LCA literature on natural gas-fired electricity generation, where estimates from 42 LCAs on

conventionally produced natural gas (O'Donoughue et al. 2012) and 6 shale gas LCAs (Heath et al. 2012) have been harmonized. Results from these studies are used for comparing results of this report to those in the literature because they ensure fair and consistent comparisons and enable insight useful for broad decision-making.[30] It is important to note that the results of this study were developed using the same key assumptions and system boundaries as in the harmonization of the literature estimates for conventional and shale gas—and, more broadly, with those for coal.

Figure 9 displays the results of this chapter's analysis (base case and EUR sensitivity)—which estimates life cycle GHG emissions from Barnett Shale gas produced in 2009 and combusted to generate electricity in a modern natural gas combined-cycle turbine—compared to other estimates, which are based on a systematic review and harmonization of existing literature. Compared to other estimates for shale gas electricity generation, the base case results of this methodologically independent assessment are near the 25th percentile of harmonized estimates, which is similar for the comparison to harmonized conventional natural gas estimates. High and low EUR scenarios are also within the range of previous estimates for shale and conventional gas life cycle GHG emissions. The results are also found to be considerably lower than those for coal—nearly half of the median estimate of 980 g CO_2e/kWh (Whitaker et al. 2012), even under low EUR conditions.

[30] Estimates of life cycle GHG emissions for specific facilities can legitimately differ from those produced through harmonization. See Heath and Mann (2012) and other harmonization articles in the Special Issue on Meta-Analysis of LCA in the *Journal of Industrial Ecology* (http://jie.yale.edu/LCA-meta-analysis) for further discussion.

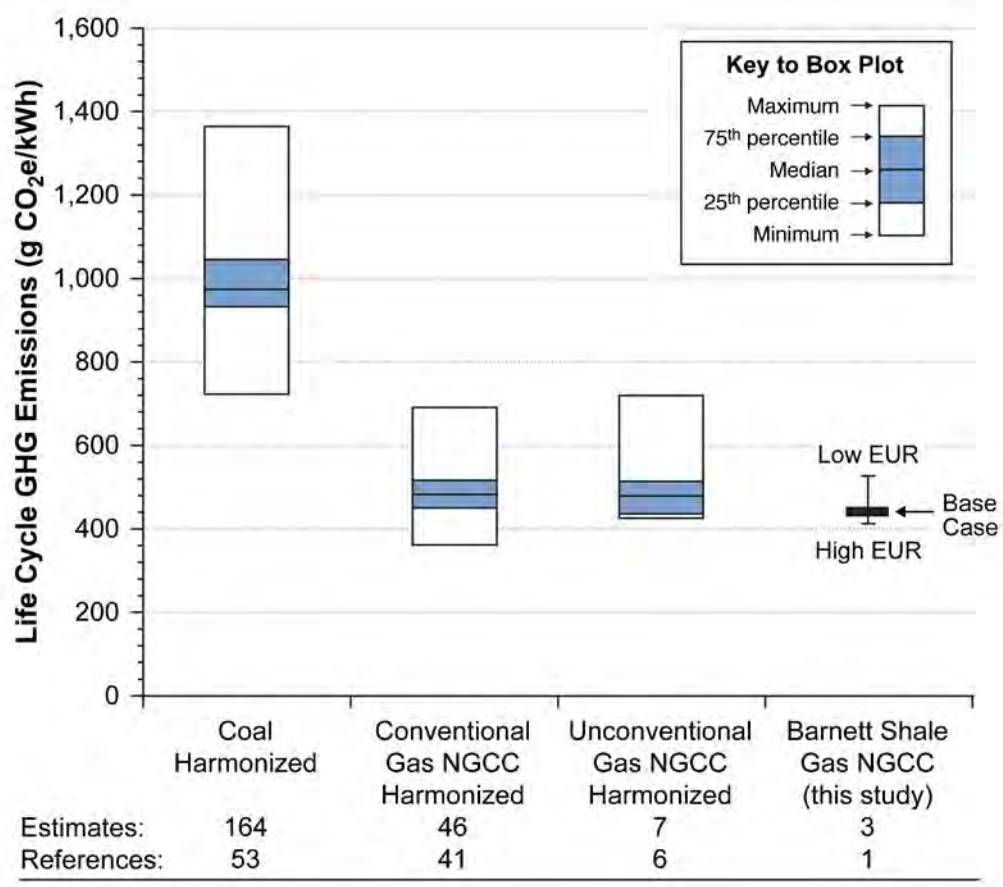


Figure 9. Estimate of life cycle GHG emissions from 2009 Barnett Shale gas combusted to generate electricity in a modern natural gas combined-cycle (NGCC) turbine compared to previously published estimates for unconventional (mostly shale) gas, conventional natural gas, and coal after methodological harmonization. [31]

Notes: EUR = estimated ultimate recovery, or lifetime production; NGCC = natural gas combined-cycle turbine

The rest of this section briefly reviews the key differences that could explain the relationship between the results from this study and those from other shale gas LCA literature. More detailed discussion of each of the existing shale gas life cycle GHG emission estimates can be found in Heath et al. (2012). Differentiating factors that tend to reduce estimates of life cycle GHG emissions for our study compared to some others include: equitably sharing the burdens of natural gas production with valuable co-products; not considering nitrous oxide emissions throughout the life cycle or non-CO_2 emissions from power-plant combustion; not considering embodied GHG emissions of purchased fuels; and not considering transport of produced water to disposal wells. None of the following factors are considered significant points of

[31] See O'Donoughue et al. (2012), Heath et al. (2012) and Whitaker et al (2012) for further description of the review and harmonization of estimates of life cycle GHG emissions from electricity generated from conventional natural gas, unconventional (mostly shale) gas and coal, respectively. The studies reviewed and harmonized in Heath et al. (2012) for unconventional (mostly shale) gas are: Howarth et al. (2011); Burnham et al. (2012); Jiang et al. (2011); Skone et al. (2011); Stephenson et al. (2011); Hultman et al. (2011).

underestimation: negligible impacts found in previous analyses,[32] contributions only to the fuel cycle (which represents 18% of total life cycle emissions), and negligible quantities of relevant sources.[33] Differentiating factors that tend to increase life cycle GHG emission estimates for particular literature estimates compared to ours include: higher natural gas leakage estimates (Howarth et al. 2011; Burnham et al. 2012; Skone et al. 2011; Hultman et al. 2011; Jiang et al. 2011); higher estimate of methane content of produced gas (Jiang et al. 2011; Burnham et al. 2012; Skone et al. 2011; Hultman et al. 2011); and inclusion of natural gas distribution for transport of gas to the power plant[34] (Jiang et al. 2011; Howarth et al. 2011; Hultman et al. 2011). On the other hand, EURs considered in this chapter are considerably lower than for other studies. This is especially true for the sensitivity analyses conducted by this and other studies, where the low-bound case for all other studies is at least twice the lower-bound estimate reported by EIA for the Barnett Shale play (INTEK 2011).[35]

A key distinguishing feature of the practices typically assumed for conventional as compared to unconventional wells is liquids unloading (i.e., periodic removal of liquids and other debris from a well). EPA has found that this practice occurs frequently—31 times per year on average (EPA 2011)—every year in the life of a well. And emissions from this practice, even when amortized over lifetime production of a well as in LCAs, are significant (e.g., Burnham et al. 2012). A recent survey of 91,000 wells by two industry associations suggests that at least for this sample, emissions from liquids unloading are nearly 80% lower than EPA's estimate (Shires and Lev-On 2012). Not only is the magnitude of emissions from liquids unloading controversial, but the same industry survey suggests that liquids unloading is also practiced on unconventional wells, reversing previous assumptions (Shires and Lev-On 2012). If liquids unloading were practiced on Barnett Shale wells,[36] then life cycle GHG emissions under average-EUR conditions would increase between 6 and 28 g CO_2e/kWh depending on the emission rate assumed[37] and potentially as high as 100 g CO_2e/kWh under low EUR conditions.

1.3.3 Fuel Cycle Methane Losses

Throughout each stage of the fuel cycle, a portion of the produced gas is used or lost: gas is used as a fuel for combustion activities, and it is lost when it leaks to the atmosphere either through potentially controllable leakage or fugitive emissions. As a potent GHG, methane emitted to the atmosphere is especially important to understand.

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[32] For example, Skone et al. (2011) find that nitrous oxide contributes 0.04% to the total life-cycle GHG emissions for a natural gas combined-cycle plant. They also found that nitrous oxide and methane contribute 0.001% and 0.004%, respectively, to the GHG emissions from the energy-conversion facility (which primarily consist of fuel combustion emissions) for a natural gas combined-cycle plant.

[33] Fewer than ten engines in the inventory are identified as using purchased fuels (i.e., gasoline or diesel).

[34] To approximate an upper bound for such an omission, consider that even doubling the estimated emissions from transmission adds only 19 g CO_2e/kWh, or about 4%, to the total life-cycle GHG emissions.

[35] Base-case EURs were 3, 3.5, 3, 2.7, and 2 bcf for Howarth et al. (2011) (average of estimates reported in Table 1), Burnham et al. (2012), Skone et al. (2011), Jiang et al. (2011) and Stephenson et al. (2011), respectively. Lower bounds tested were 1.6, 2.1, 2.7, and 1 bcf for Burnham et al. (2012), Skone et al. (2011), Jiang et al. (2011), and Stephenson et al. (2011), respectively.

[36] Assuming 30-year well lifetime (Skone et al. 2011), 1.42 bcf EUR (INTEK, 2011), and 12% emission reductions (Burnham et al. 2012).

[37] The low estimate assumes an emission rate according to Shires and Lev-On (2012), whereas the high estimate assumes an emission rate according to EPA (2011).

This section reports two related metrics, each important for different purposes. The first metric we refer to as *natural gas losses*, which signifies the percentage of produced natural gas either lost or consumed along the fuel cycle, expressed in units of volume natural gas lost per volume natural gas produced.[38] The second metric we refer to as *methane leakage*, which signifies the volume of methane released to the atmosphere in relation to the amount of gas produced, expressed in units of volume methane emitted per volume natural gas produced. A leakage rate reported in these units enables rapid estimation of methane emissions based on a known amount of produced natural gas.

Based on the analysis of TCEQ inventories for natural gas production and processing emissions, as well as published estimates for other fuel cycle phases, this study estimates that 1.5% of produced gas is emitted to the atmosphere before reaching the power plant (see Table 1). Much of this is potentially preventable, with an additional 5.6% of produced gas consumed along the process chain as fuel for different types of engines. Based on the estimated methane content of this produced gas, this equates to a *leakage rate* across the fuel cycle of 1.3% methane volume per volume of natural gas processed, based on the assumed play-average EUR of 1.42 bcf/well. Because of the contribution of one-time emissions to these results, they are sensitive to EUR; low EUR corresponds to an estimated 2.8% methane leakage rate and the loss of 8.9% of produced gas across the fuel cycle, whereas high EUR corresponds to an estimated 0.8% leakage and 6.5% losses.

Table 1. Loss of Produced Gas along the Fuel Cycle[a]

	Completions and Workovers[b]	Production	Processing	Transmission[c]	Total
Extracted from Ground	100.0%				100.0%
Fugitive Losses	–	0.1%	0.0%	0.5%	0.6%
Potentially Controllable Leakage	0.8%	0.1%	0.0%	0.0%	0.9%
Combusted as Fuel	–	0.9%	3.9%	0.8%	5.6%
Delivered to Power Plant					92.9%

[a] Reported as volume of natural gas consumed or lost per volume of natural gas produced
[b] See footnote to Figure 9
[c] From Skone et al. (2011)

1.3.4 Air Pollutant Emissions Inventory-Based GHG Emissions Estimates

This study develops emissions factors for the production and processing stages of shale gas development based on original estimates of GHG emissions from TCEQ inventories and the Texas Railroad Commission's production statistics. These emission factors are shown in Figure using the functional unit of grams CO_2e per mega-joule of natural gas (i.e., g CO_2e/MJ).

[38] Although the use of natural gas in production and transportation processes is for beneficial purpose, it nonetheless represents the loss of a potentially marketable product. For instance, increasing the efficiency of engines at pipeline booster stations would increase the amount of product delivered to the end user. From this perspective, we employ the simplified terminology of "loss" of natural gas to include its use prior to sale to an end user.

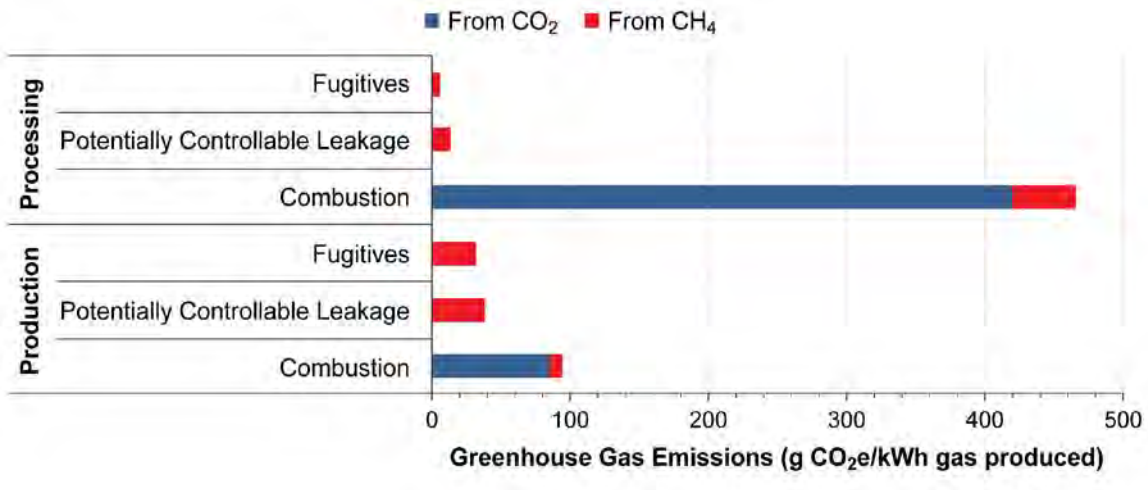

Figure 10. Inventory-based analysis of production and processing fuel cycle stages showing that the majority of GHG emissions are CO_2 resulting from combustion, although the CO_2e from methane emissions is significant

Most noticeably, the majority of GHG (CO_2e) emissions in both of these life cycle stages comes from CO_2 emissions from combustion sources. These emissions represent 53% of the total GHG emissions for the production stage and 87% for the processing stage. In the production stage, 90% of CO_2 emissions come from a large number of four-cycle rich-burn engines, nearly all of which are not normally individually tracked in the point-source inventory. Of the 1,564 compressor engines contributing to CO_2 emissions during natural gas production, only seven are reported to the point-source inventory, with the vast remainder of sources (and 99.9% of the CO_2 emissions) being reported only in the special inventory. Although the point-source inventory is intended to cover major emissions sources, the large number of individually smaller sources that are only captured by the special inventory play an important role in the GHG emissions from natural gas production in the Barnett Shale play. In the processing stage, 49% of CO_2 combustion emissions come from 405 4-cycle, lean-burn engines; 21% from 273 4-cycle, rich burn; 20% from 552 external-combustion boilers and heaters; and the remaining CO_2 emissions come from natural gas turbines, other compression engines, and equipment flares. In contrast to the production stage, 76% of these sources—representing 79% of the CO_2 emissions—are covered by the point-source inventory. Direct emission of CO_2 from fugitives and from processing (to achieve pipeline-quality specifications) is negligible but included for completeness.

Of the remaining GHG emissions, more methane emissions come from potentially controllable gas leakages than from fugitives. Specifically, only 41% of methane released in the production stage comes from fugitives. The 49% of methane coming from potentially controllable leakage in the production stage is dominated by emissions from pneumatic pumps and controls, which are a focus of recent EPA regulations. In the processing stage, fugitives make up an even smaller proportion (10%) of overall methane leakage. Of the 21% of methane emissions in this life cycle stage coming from potentially controllable leakage, more than half comes from emissions from produced water tanks, and almost a third from emissions from glycol dehydrators. Despite only a small proportion of combustion emissions being methane, combustion activities still account for

69% of the total methane emitted in the processing stage as a result of the large numbers of engines.

1.3.5 Sensitivity to Gas Composition Analysis

Because it reflects a key differentiation of this study from previous analyses, this section explores the sensitivity of this study's results to assumptions about the composition of the produced gas. Specifically, this section compares the study's main results—which are based on county-specific gas composition estimates (see Appendix B)—with results based on two alternative assumptions about produced gas composition.

The first alternative calculates emissions using a play-level gas composition estimate, which reflects a production-weighted average of all county estimates with original data. The second alternative uses EPA's reported national average production gas composition (EPA 2011) as the estimated composition for all sources. The national average is used for comparison because most LCAs rely on this gas composition, even for play-specific estimates (e.g., Skone et al. 2011). Table 2 reports the difference in emission estimates for CO_2, methane, and CO_2e using these alternative gas composition analyses compared to this study's spatially explicit approach (main results).

Table 2. Effects of Alternative, Spatially Uniform Estimates of Gas Composition on Inventoried GHG Emissions for the Barnett Shale Play

	Difference from Main Results		
	CO_2	Methane	CO_2e
Production and Processing Combined			
Main Results	–	–	–
Barnett Shale Average	-0.5%	2.6%	0.2%
National Average	-3.5%	5.7%	-1.5%

The overall impact is negligible of using spatially explicit estimates versus the Barnett Shale average, which is a production-weighted average of individual estimates: the effect on the two different GHGs cancel out in terms of CO_2e. The impact of using national average gas composition estimates is larger, but still small. As shown by the difference in Barnett Shale average versus national average results, these impacts come not from shifting to uniform gas compositions, per se, but rather, from using gas composition estimates less reflective of the specific gas analyses obtained from locations within the Barnett Shale region.

However, estimates differ more substantially when looking at a finer scale, as shown in Table 3, which focuses on production-stage emissions estimates for the four top-producing counties in the Barnett Shale. Using Barnett Shale or national average gas composition can lead to estimates one-third lower or higher for Tarrant and Wise counties, respectively, compared to using the county-level average. This variation comes from the substantial difference in estimated gas composition across counties, also shown in the lower portion of Table 3 for the representative gas constituents of VOCs, CO_2, and methane. Note that Tarrant and Wise counties both deviate substantially from the Barnett Shale average, as well as from the national average.

Table 3. Effects of Alternative, Spatially Uniform Estimates of Gas Composition on Estimated Production Emissions at the County-Level

	Denton County[a]	Johnson County[a]	Tarrant County[a]	Wise County[a]	22-County Total	
Barnett Shale average vs. main results	12%	-5%	-33%	29%	1%	
National average vs. main results	15%	-11%	-36%	29%	-3%	
	Denton County[a]	**Johnson County[a]**	**Tarrant County[a]**	**Wise County[a]**	**Barnett Shale play average[b]**	**National average[c]**
Volatile organic compounds content[d]	18%	19%	6%	23%	16%	18%
CO_2 content[d]	2%	2%	1%	3%	2%	2%
Methane content[d]	63%	63%	80%	56%	66%	78%

[a] Only the four top-producing counties in the Barnett Shale play are shown.
[b] Production-weighted average across the 22 counties of the Barnett Shale play
[c] As reported in EPA (2011)
[d] Percentage by mass

These results have implications for developing more accurate GHG emission inventories at sub-national levels and any regulatory system that might seek to identify high emitters within plays. Furthermore, when detailed activity data at the site or source level are developed, these data should be matched by detailed gas-composition analyses for the most accurate outcomes.

1.3.6 Areas for Improvement in Understanding

The estimate of life cycle GHG emissions from gas produced from Barnett Shale in 2009 reported here advances our understanding through rigorous analysis of more than 16,000 sources of emissions and accounts for the known spatial heterogeneity in gas composition within the Barnett Shale play. However, future efforts should explore the sensitivity of the estimates herein to the many contributing parameters and several other aspects because further improvement remains.

Chief among the areas for improvement are a greater number of recent measurements of emission factors and statistically representative surveys of current practices characterizing GHG emissions from the natural gas industry. For instance, there is a critical lack of measurements of emissions for completion and re-completion (workover) activities that account for different physical and operational conditions based on use of reduced-emission completion equipment, variations in gas flow during flowback and initial production, and mud degassing (EPA 2011; Shires and Lev-On 2012; CERA 2011; Burnham et al. 2012). Likewise, better and more recent measurements of fugitive emissions from well and processing equipment, as well as pipelines at all stages—gathering, transmission, and distribution lines—are warranted because the existing data are sparse and old. The prevalence of emission-reduction practices (e.g., flaring) during completion, workover, and other activities is another area of considerable lack of empirical information and variability in current assumptions (Heath et al. 2012) that would improve understanding of life cycle GHG emissions.

Furthermore, if other well-specific information—such as annual and lifetime gas, condensate, oil, and produced water production, and lifetime workovers—were available and could be

matched to the TCEQ emissions inventories, then fuel cycle and life cycle GHG emissions could be estimated at the well level. These results could allow for consideration of well-level variability, with implications for the design of efficient strategies to control emissions. In particular, given the substantial sensitivity of results to EUR (total life cycle GHG emissions differ from base results by -5% or +17% for upper and lower EUR estimates, respectively), better well-specific information on EUR will improve the precision of emissions estimates. However, EUR is neither geographically nor temporally constant; rather, it relates both to physical characteristics of natural gas deposits and to the (constantly evolving) technical and economic feasibility of recovery of that natural gas. An improved and sophisticated understanding of EUR is therefore necessary. Finally, production activity is often planned for a field based on a set of wells; when initial wells decline in production, they could be restimulated and other wells could be drilled within the same area (through new laterals or new surface sites). Considerable knowledge of these dynamics is currently lacking. Yet, it is important to understanding GHG emissions in the context of deployment strategies used by many large players.

We have assembled the largest publicly available database of gas composition analyses for a shale gas play, and the counties with highest production correspond to those with the greatest number of analyses. However, given the sensitivity of the study's county-level results to the gas composition, it appears to be warranted to devote further effort toward improving the availability of production gas composition analyses specific to a region of interest. A random-sampling campaign conducted by a third party would be an ideal match for the methods used in this chapter if they are deemed useful for future analyses. A nearer-term objective could be to simply increase the pool of gas analyses from any entity willing to make such data available. Results of such further investigation could have implications for developing more accurate GHG emission inventories at sub-national levels and any regulatory system that might seek to identify high emitters within plays.

Further investigation of emissions from liquids unloading from unconventional wells is also warranted given the potentially significant GHG emissions from this activity, as described above. An emissions sampling strategy that accounts for variability across geography, gas type, well type, operator size, and operational practices, among other factors, should lead to an improved understanding of the potential for GHG emissions from liquids unloading for conventional and unconventional wells. Additional activity data regarding frequency of unloading and how this might change over the lifetime of a well, proportion of wells requiring unloading, and prevalence and effectiveness of emission-reduction activities are necessary to develop a more complete understanding of the emissions from this practice. Finally, because emissions from this episodic activity are amortized over lifetime production for use in LCAs, more certainty in the estimate of EUR would improve the accuracy of life cycle emission estimates.

Practices in the natural gas industry change over time, as do resource characteristics. Estimates of GHG emissions should be periodically repeated to reflect those changing practices and characteristics, using the most up-to-date and accurate data on emissions, emission-reduction practices, resource characteristics and activities available. Estimates could also be developed for future conditions based on expected changes in practices due to, for instance, full implementation of promulgated regulations. Such estimates could be compared to goals for GHG

emission reduction to highlight whether additional emission reductions are necessary to reach those goals.

Analogously, industry practices and resource characteristics vary by location owing to differences in, for instance, geology, hydrology and state regulations. Estimates of GHG emissions should be developed in other locations using as much geographically specific data and information as possible. Furthermore, GHG emissions will also differ by gas type—not only by broad categories such as conventional and unconventional, but also, by different types of each, e.g., shale, tight, and coal-bed methane for unconventional, and associated, onshore, and offshore for conventional. GHG emissions for each of these types should be characterized so that a more accurate understanding of drivers of variability (if any) by type can inform discussions of opportunities to reduce emissions.

Finally, the bottom-up, engineering-based inventory of emissions should be confirmed through top-down atmospheric measurements. Literature suggests that emissions are typically underestimated through bottom-up approaches compared to concentrations of those same pollutants in the atmosphere (e.g., Townsend-Small et al. 2012; Petron et al. 2012). This effect likely results not only from issues such as non-reported sources, but also from inaccuracies that inherently arise from the use of non-specific methods that depend on average or ideal conditions. Although source attribution is still challenging and these measurements are expensive, they provide a much-needed confirmation of when inventories are accurate and when updates and improvements are necessary to support sound decision-making.

1.4 Conclusions

The aim of this research is to advance the state of knowledge of life cycle GHG emissions from electricity generated from shale gas extracted from a specific play—the Barnett Shale play in north Texas—using data sources independent of those used in previous LCAs of natural gas. We leveraged inventories of regulated air pollutants collected and screened by the Texas Commission on Environmental Quality for a 2009 special inventory of the Barnett Shale gas production, processing, and transportation sectors and their regular point- and area-source inventories in the 22-county Barnett Shale area. We used data supplied by the industry to TCEQ regarding the emissions and characteristics of more than 16,000 individual sources. The TCEQ inventories are used to estimate VOC emissions, a precursor of ozone. VOC emission estimates were translated to methane and CO_2 emissions by using gas composition analyses that report proportions by mass of each constituent. This study compiled a large dataset of such gas composition analyses at the county level, enabling a quantitative accounting of the significant variability that exists within the play of methane, CO_2, and other compounds.

Based on the analysis of TCEQ inventories and the addition of missing life cycle stages not included in those inventories, this study estimates that electricity generated using a modern natural gas combined-cycle turbine combusting Barnett Shale gas produced and processed in 2009 is associated with about 440 g CO_2e/kWh generated, with a sensitivity range based on published high and low EURs of 420 to 510 g CO_2e/kWh. Thus, the life cycle GHG emission result is sensitive to the lifetime production of wells, where additional research would be helpful to more precisely estimate life cycle GHG emissions. Regardless of this uncertainty, however, this chapter's main conclusion is that life cycle GHG emissions from electricity produced from Barnett Shale natural gas lie within the range of previously published estimates for GHG

emissions (after methodological harmonization) from electricity produced by either conventional or unconventional natural gas (O'Donoughue et al. 2012; Heath et al. 2012). Furthermore, this report's estimate of life cycle GHG emissions is less than half of the median of published estimates for coal-fired electricity generation (after methodological harmonization) (Whitaker et al. 2012). It should be noted that the estimate of life cycle GHG emissions developed here is not strictly applicable to other locations or years, and that several important aspects of uncertainty in the methods of this research should be improved through additional research. However, the broad agreement between the estimate developed here and those published independently for both unconventional and conventional gas increases confidence in our understanding of life cycle GHG emissions of natural gas used for electricity generation.

This study found that about 19% of base case life cycle GHG emissions results from the fuel cycle of Barnett Shale gas (pre-production through transmission). About 10% of base case life cycle GHG emissions are methane, mostly vented during completion and workover and released from the natural gas transmission pipeline network. Only 11% of life cycle GHG emissions depend on characteristics of shale gas (e.g., extraction techniques, composition); the vast majority of life cycle emissions are not affected by the type or origin of the gas because they occur after processing that has the function of creating a homogenous product.

With regard to the fuel cycle GHG emissions, which were the focus of the analytical effort of this chapter, the vast majority comes from CO_2—80% or more of which is emitted from combustion sources (mostly engines and turbines) in the production and processing stages. The majority of emissions coming from natural gas production activities is from sources not routinely tracked individually (because they do not meet regulatory thresholds) in a classic example of how important the more numerous small sources can be to total emissions and how challenging quantifying and reducing emissions from the natural gas industry will be for regulators. Only through special inventories, such as the one conducted in 2009 for the Barnett Shale area, is it possible to have the kinds of detailed information necessary to estimate source-specific emissions for the vast majority of production sources within this industry. By contrast, processing sources are typically larger, meeting the threshold for annual emissions reporting under the regular point-source inventory.

We find that methane leakage, though playing a smaller role in life cycle GHG emissions from this analysis of 2009 Barnett Shale gas as compared to others, comes mostly from what we have classified as potentially controllable sources, rather than from fugitives—with implications for the potential for GHG emission reductions in the natural gas industry. In gas production, 40% of methane released comes from fugitive sources; methane emitted from potentially controllable leakage in the production stage comes mostly from pneumatic pumps and controls, which are specifically addressed in recent EPA regulations. In the processing stage, fugitives make up an even smaller proportion (10%) of overall methane emissions. As for potentially controllable leakage in processing, half comes from emissions from produced water tanks and a third from glycol dehydrators.

Our method represents an improvement in accuracy by accounting for spatial differences in gas composition as compared to previous LCAs. For instance, methane content of raw gas from the top four producing counties ranges from 56% to 80%, with implications for how much methane is released in venting or fugitive emissions. Previous research has either used play-level average

gas composition (e.g., Jiang et al. [2011] for the Marcellus) or the national average. For Barnett Shale total emissions, the difference in results between using county-level gas composition compared to a play-wide average composition is relatively small; however, the improvement is more significant compared to using national average composition.

The overall results for the Barnett Shale play are only marginally sensitive to the variability in gas composition across the play because of offsetting differences. But the variability observed in gas composition has implications for accurate estimation of GHG emissions at finer spatial resolution, monitoring programs, and regulatory strategies. This study found differences in GHG emission estimates at the county level compared to estimates using national average figures; furthermore, inventories of the level of detail of the special inventory provide an important piece of the overall story of emissions. Therefore, accurate usage of such detailed information needs to be matched by more detailed input information, notably gas composition analyses. The database assembled for this study is a first step toward developing more robust databases in the Barnett and other natural gas basins around the country.

Improvements can be made to the estimate produced here of life cycle GHG emissions for 2009 Barnett Shale gas used in a modern combined cycle electricity generator. But this study's methodologically independent estimate confirms previous research on shale gas electricity generation. In addition, it is similar to previous estimates for generation using conventionally produced natural gas, and it is less than half of that estimated in other studies for coal. Liquids unloading, which is typically assumed to occur only for conventional wells, accounts for most of the difference between this study's estimate and that developed based on meta-analysis and updating of more than 40 references reporting life cycle GHG emissions for electricity generated from conventionally produced natural gas. However, evidence has emerged suggesting that liquids unloading is also a practice applicable to unconventional wells. If confirmed for Barnett Shale wells in particular, then it means that the estimate reported here should be updated accordingly. The high carbon content and significantly lower thermal efficiencies of coal-fired power plants account for their substantially higher life cycle GHG emissions.

2 Regulatory Framework Governing Unconventional Gas Development

2.1 Introduction

Rapid development of unconventional natural gas in the United States in recent years has raised a number of important environmental concerns, including ground and surface water contamination; disposal practices for frac flowback, produced water, and other associated drilling wastes; impacts on local and regional air quality; methane leakage and venting rates; and increased traffic, noise, and other community impacts. It is clear that regulations have increased at virtually all levels of governance in response to the unconventional gas boom. Various commissions, advocacy groups, and research organizations have weighed in on the pros and cons of additional regulation, including two reports issued by the Secretary of Energy Advisory Board Shale Gas Production Subcommittee ("SEAB Subcommittee").[39] But questions persist regarding the sufficiency of these regulations across differing jurisdictions and the adequacy of compliance monitoring and enforcement in the face of rapid growth.

Because of the "distributed" nature of unconventional gas development and the substantial increase in wells in key basins,[40] local land-use conflicts have erupted in certain areas of the country that have led to restrictions and moratoria on drilling by state, county, and municipal governments, raising questions about the industry's continued social license to operate in specific jurisdictions[41] (Dryden 2012; Middlefield 2012). In response, some states—notably Pennsylvania—have recently enacted legislation to restrict the ability of local governments to

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[39] *See e.g.*, U.S. DOE, *Secretary of Energy Advisory Board Shale Gas Production Subcommittee, Ninety-Day Report*, (Aug. 11, 2011) and *Second Ninety-Day Report* (Nov. 18, 2011), http://www.shalegas.energy.gov/resources/081111_90_day_report.pdf; National Petroleum Council, *Prudent Development Realizing the Potential of North America's Abundant Natural Gas and Oil Resources* (2011), http://www.npc.org/NARD-ExecSummVol.pdf; Cardi Reports, *The Economic Consequences of Marcellus Shale Gas Extraction: Key Issue*s, prepared on behalf of Cornell University (Sept. 2011), http://www.greenchoices.cornell.edu/downloads/development/marcellus/Marcellus_CaRDI.pdf; Thomas Kurth, et al., "American Law and Jurisprudence on Fracing," Haynes and Boone, LLP (2010), http://www.haynesboone.com/files/Publication/3477accb-8147-4dfc-b0b4-380441178123/Presentation/PublicationAttachment/195a3398-5f02-4905-b76d-3858a6959343/American_Law_Jurisprudence_Fracing.pdf ; Bipartisan Policy Center, Energy Project, *Shale Gas: New Opportunities, New Challenges* (Jan. 2012), http://www.scribd.com/doc/95194795/Shale-Gas-New-Opportunities-New-Challenges; Charles G. Groat and Thomas W. Grimshaw, *Fact-Based Regulation for Environmental Protection in Shale Gas*, report prepared for the Energy Institute, University of Texas at Austin (Feb. 2012), http://energy.utexas.edu/images/ei_shale_gas_regulation120215.pdf; Rebecca Hammer, et al, *In Fracking's Wake: New Rules are Needed to Protect Our Health and Environment from Contaminated Wastewate*r, Natural Resources Defense Council (May 2012) http://www.nrdc.org/energy/files/Fracking-Wastewater-FullReport.pdf; International Energy Agency, Golden Rules for a Golden Age of Gas, 9-10 (May 29, 2012), http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/WEO2012_GoldenRulesReport.pdf (discussing the importance of public acceptance for continued expansion of unconventional gas development in the U.S. and abroad).

[40] For a graphic depiction of the rapid increase in shale gas wells in Pennsylvania, see U.S. Energy Information Administration, "Horizontal drilling boosts Pennsylvania's natural gas production," available at http://www.eia.gov/todayinenergy/detail.cfm?id=6390.

[41] Some national governments, including France and Bulgaria, have also banned hydraulic fracturing (BBC News 2012). For a list of current moratoria and bans, see Sierra Club, FRAC Tracker, http://www.sierraclub.org/naturalgas/rulemaking/.

regulate unconventional gas development.[42] Other states, such as Colorado, have engaged in multi-stakeholder processes to strengthen and continue to revise new rules for oil and gas development that have been embraced by multiple constituencies and paved the way for innovative legislation that is re-shaping the electric power sector in the state (COGCC 2008; Xcel 2012). See Textbox 1 for more on Colorado's recent experience. But even in those states, such as Colorado, where oil and gas development has been a feature of the landscape for decades, a number of communities have expressed concerns about the proximity and pace of unconventional gas development and are seeking to impose new restrictions on development.[43]

Text Box 1: Colorado's Clean Air-Clean Jobs Act

In 2010, then Governor of Colorado Bill Ritter introduced landmark legislation that fundamentally altered the energy make-up of the state's electric power sector. The legislation, HB 1365, also known as the "Clean Air-Clean Jobs Act," required regulated utilities to reduce emissions of nitrogen oxides by 70% to 80% or greater from 900 megawatts of coal-fired generation by 2018 and meet certain "reasonably foreseeable" environmental requirements, such as lower ozone standards. To meet these targets, the state's regulated utilities proposed a plan that included retiring aging coal-fired power units, retrofitting others with state-of-the-art clean technology, and expanding capacity for units powered by natural gas and renewable energy sources. The Act had broad support from a number of constituencies including local Front Range governments, local and national non-governmental organizations, Xcel Energy and the natural gas industry (CCC 2010; Xcel 2012). Importantly, much of this support can be tied to the state's decision to first put in place strong rules for the development of its oil and gas resources before introducing legislation that would very likely lead to increased production. Many believe there is still work to be done to ensure that production is done properly statewide, especially in the Front Range, where new production is taking hold that did not exist to the same extent in 2008. However, many point to the Colorado model as an example of collaboration, innovation, and leadership that can be replicated elsewhere.

In short, the regulatory landscape affecting unconventional gas development is complex, dynamic, and multi-layered. Going forward, there is a risk of increased regulatory fragmentation within and among gas-producing basins, as well as a lack of coordination among the different government entities responsible for regulating and ensuring compliance with various aspects of unconventional gas development, leading to additional uncertainty, gaps, redundancies, potential delay for producers, and under-enforcement.[44] At the same time, leading companies continue to

[42] 58 Pa. Cons. Stat. § 3218; see also CO SB 088, introduced unsuccessfully Feb. 16, 2012.

[43] For example, Boulder County, Resolution No. 2012-16 (Feb. 2, 2012); Colorado Springs, Steve Bach, Mayer of Colorado Springs, "Memorandum on Administration of the Use of Regulations Set Forth in Chapter 7, City Code," (Nov. 28, 2011); the City of Erie, Ord. No. 09-2012 (Mar. 7, 2012); and the city of Longmont, Ord. No. O-2012-18 (Dec. 20, 2011)—all enacted temporary moratoria on applications for oil and gas development.

[44] For a recent report that surveys state shale gas regulation and similarly finds significant variations among them, see Resources for the Future, "A Review of Shale Gas Regulations by State," http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx.

develop and elaborate best practices[45] to control and/or mitigate some of the environmental impacts associated with unconventional gas development. Some of these corporate practices go beyond existing regulation and some have served as the basis for new regulations.[46] Although it is impossible to predict the precise mix of future regulation, it is likely that additional regulations will be adopted and implemented as unconventional gas development proceeds. These could affect the costs of producing unconventional gas, but without basin- and company-specific data, it is not possible to determine the amount of additional compliance costs associated with any particular regulatory scenario. This is an important area for future research.

This chapter examines the main federal, state, and local regulatory frameworks that govern unconventional natural gas development.[47] Specifically, this chapter focuses on requirements related to water withdrawals used for hydraulic fracturing, disclosure of chemicals used in hydraulic fracturing fluids, setbacks for wells, baseline water monitoring of surface water resources or water wells, well construction standards, "green" or "reduced emission" completions, storage of waste in closed-loop systems, and the disposal of produced water. It also examines state compliance monitoring and enforcement capabilities. The goal of the research was to identify changes and trends in the governing legal frameworks across the different basins, as well as key challenges going forward. Specific attention is given to regulatory uncertainty, fragmentation, gaps, and redundancies associated with the proliferation of new rules and regulations at multiple levels, as well as the implications of shifting public perception and support for gas development across various jurisdictions.

Due to time constraints, it was not possible to examine all impacts associated with gas development and corresponding regulatory responses. Key areas for future research include, for example, regulations aimed at reducing the risk of surface spills of acids and chemicals used in hydraulic fracturing, storm-water controls, open-pit requirements, and mitigation measures for truck traffic. Beyond the scope of this report is a complete discussion of the environmental and public health risks posed by unconventional gas development and an analysis of the extent to which the current regulatory and statutory regimes reduce such risks, or the extent to which voluntary implementation of best practices fill any gaps remaining.

The chapter focuses on six unconventional U.S. basins: Barnett Shale play and Eagle Ford Shale play in Texas, Haynesville Shale play in Texas and Louisiana, Marcellus Shale play in New York and Pennsylvania, North San Juan basin in Colorado, and Upper Green River basin in Wyoming. As Table 4 illustrates, each of these basins is marked by distinct resource, geologic, and hydro-geologic characteristics, and each has had different historical and contemporary

[45] The term *best practices* used here has the same meaning as that used by the SEAB in that it refers to "improvements in techniques and methods that rely on measurement and field experience" (SEAB 2011a). Best practices are not static, but rather, continuously evolving, as evidenced by the rapid changes in technologies related to stimulation techniques, methane capture, and water recycling.

[46] See, for example, green completions, voluntary disclosure of chemicals used in hydraulic fracturing fluids, and reuse of produced and flowback waters. EPA specifically cited industry's voluntary use of green completions in promulgating recent federal standards to limit air pollution from new and modified stationary sources in the Crude Oil and Natural Gas Production Category (EPA 2012c).

[47] Statutes applying uniquely to federal lands or actions, such as the Federal Lands Policy and Management Act, National Environmental Protection Act, and Endangered Species Act, are not discussed. For a more complete description of the federal framework that applies to unconventional gas development, see EPA 2000 and Kurth 2010.

experiences with oil and gas development. Accordingly, unconventional gas development in each of these basins and jurisdictions poses a distinct set of environmental issues, and it is the subject of a different mix of state and local regulation.

Table 4. Description of Shale Plays and Basins Studied

Primary Designation	Secondary Designation	Hydrocarbon Resources	Interest for Study	Production Characteristics
Barnett Shale Play	District 5, North Texas	Mostly dry gas, shale	Original shale gas basin, history, water stressed, near urban areas	6,000–8,500 feet deep
Eagle Ford Shale Play	Oil Producing Counties, South Texas	Oil, NGLs and gas, shale	High activity, resource diversity, water stressed	Oil 4,000–8,000 feet, NGLs/gas 8,000–12,000 feet deep, average thickness 450 feet
Haynesville Shale Play	DeSoto Parish, Louisiana	Mostly dry gas, shale	Second-largest shale gas reserves in U.S., active production	10,500–13,000 feet deep, high temperature and pressure
Marcellus Shale Play	Susquehanna River Basin, Ohio River Basin, Pennsylvania	Mostly dry gas, shale	Rapidly growing, diverse, area of significant public attention	5,000–7,000 feet deep, 100–500 feet thick, largest shale gas reserves in U.S.
North San Juan Basin	La Plata County, Colorado	Coal-bed methane	Colorado regulations, distinct risks due to CBM production	Fruitland formation, 550–4,000 feet deep
Upper Green River Basin	Jonah Field, Pinedale Anticline Wyoming	Mostly dry gas, tight sands	Active production, ozone nonattainment	Vertical wells, 8,000–11,000 feet deep in tight sands

This chapter also examines recent actions by local governments to ban, delay, or regulate hydraulic fracturing or gas development; responses to such actions by state courts and legislatures; and the implications of these developments for the industry's social license to operate in specific parts of the country.

Lastly, this chapter identifies several important examples where companies have adopted measures that go beyond compliance—namely, "green" completions, voluntary disclosure of chemicals used in hydraulic fracturing fluids, and reuse of produced and flowback waters. In some cases, these best practices have become the basis for new regulations (e.g., "green" completions). In others, they continue as voluntary actions that fill gaps or go beyond existing regulatory frameworks (e.g., reuse of produced and flowback waters).

The major conclusions that emerge from this analysis are as follows:

- Although there is a trend toward more regulation at all levels of governance, there has been a corresponding increase in regulatory fragmentation and differentiation at state and local levels. Better coordination and policy alignment among regulators can help to reduce risks of regulatory fragmentation including uncertainty, delays, gaps, and redundancies across jurisdictions. Improved communication and sharing of information between regulators at all levels of government and across jurisdictions—as well as increased transparency in the form of publicly reported and publicly available data from industry—will help ensure that regulations are coordinated and tailored to specific geographic and geologic characteristics. Appropriately designed regulations that reflect local conditions such as gas composition and geology reduce environmental risks and ensure more efficient resource recovery.
- Compliance monitoring and enforcement actions vary significantly across states, with significant implications for the efficacy of regulations, as well as public confidence in the ability of state regulators to ensure that development proceeds safely. Public disclosure of violations, enforcement actions, and company compliance would bring greater transparency and accountability to an industry that, by its nature, poses unique compliance and enforcement challenges due to the disparate and often remote location of facilities and its rapid development in recent years. It would also provide an opportunity to highlight the compliance records of leading companies that have demonstrated a commitment to safe natural gas production.
- There is a significant range in the environmental performance of operators in the industry, with some operators performing at a level that goes beyond existing regulations and other operators falling short. Ongoing consolidation in the industry could lead to more widespread adoption of best practices across the industry. However, additional implementation of beyond-compliance measures is unlikely to lead to less regulation given limited public acceptance of the concept of self-regulation in the industry. In some instances, the implementation of best practices may serve as the foundation for future regulation (Efstathiou 2012), which, in turn, could serve to level the playing field among producers and may help restore public trust in areas of the country where unconventional gas development has been controversial.
- There is a need for basin- and company-specific data to analyze the extent to which implementing beyond-compliance measures or additional regulation will affect the cost of producing natural gas and, by extension, the supply of gas to the electric power sector.[48] This study was not able to collect such data (see Chapter 4), but this will be a focus of a potential follow-up study.
- Notwithstanding the challenges of regulatory fragmentation, different state and local approaches to regulating unconventional natural gas development provide important opportunities for learning and innovation regarding substantive rules, the role of best practices, and process. Colorado, for example, recently implemented landmark legislation

[48] A recent report estimates that the application of 22 "Golden Rules" for shale gas development could add about 7% to the overall drilling and completion costs on a per well basis (IEA 2012). Assuming today's costs and prices are roughly equivalent, 7% added costs in the U.S. would amount to roughly an additional $0.25/MMBtu produced.

with the support of multiple constituencies, including the natural gas industry and environmental groups, that resulted in a dramatic shift in the state's electric power sector away from coal toward greater use of natural gas and renewable energy (see Chapter 1 for a discussion of the potential climate benefits associated with using natural gas as opposed to coal as a feedstock for electricity generation). This could not have happened absent an initial effort to revise the state's oil and gas laws. New York's decision to undertake a detailed and extensive study of the impacts associated with high-volume hydraulic fracturing has led to development of some of the most comprehensive rules in the country. It remains to be seen whether, if adopted, they alleviate public concerns regarding the risks associated with unconventional gas development .

2.2 Federal Legal Framework

The major federal environmental laws provide the overarching framework for regulating many of the environmental impacts associated with unconventional natural gas development. Some of these laws, however, contain explicit exemptions or definitional exclusions for natural gas development, resulting in a significant role for state regulation in key areas such as waste management, disclosure of chemicals used in hydraulic fracturing and releases, and well construction standards other than for underground-injection disposal wells. This section analyzes the federal regulatory framework governing air, water, and waste issues associated with unconventional gas development. It focuses on the scope of federal regulation, the extent to which state law fills any gaps left open by the federal regulatory scheme, recent legislative proposals and rule-makings, key trends, and the implications of a changing federal regulatory framework for future development.

2.2.1 Overview and Key Trends

Federal laws governing the air, water, and waste impacts associated with the production of unconventional natural gas vary in terms of scope. EPA has broad authority to regulate emissions of air pollutants, including GHGs, direct and indirect discharges of wastewater from point sources, and the injection of produced water into underground injection wells for disposal.[49] The federal government, primarily through the U.S. Department of the Interior, also has authority over the development of natural gas on federal and tribal lands. Federal oversight over the management of hazardous and solid wastes, reporting and disclosure requirements of toxic or hazardous releases, and the process of hydraulic fracturing itself is much more limited—and, in some cases, it is entirely absent given specific exemptions and definitional exclusions under certain federal laws such as the Resource Recovery and Conservation Act; the Comprehensive Environmental Response, Compensation and Liability Act; and the Safe Drinking Water Act.

Some federal exemptions have been the focus of proposed legislation in past and current Congresses,[50] and efforts to repeal or narrow these exemptions are likely to continue. Congress also recently requested that EPA conduct a study evaluating the potential impacts of hydraulic fracturing on drinking water (EPA 2011e). Depending on the results of this study, the first of

[49] An exception to this is section 112(n)(4) of the Clean Air Act, which contains prohibitions on the aggregation of hazardous air pollutant emissions from certain gas wells and other equipment that constrain regulation of such sources (42 U.S.C. § 7412(n)(4)).
[50] See, for example, The Fracturing Responsibility and Awareness Act of 2011, H.R. 1084.

which are due out sometime in 2012 with additional results in 2014, EPA may assume a more active role in regulating hydraulic fracturing—including reconsidering its determination that certain natural gas wastes are not hazardous, and recommending changes to the statutory framework that applies to the process of hydraulic fracturing. In the meantime, the states continue to play an important role in regulating various aspects of hydraulic fracturing. The extent to which states have filled gaps left open by federal regulation is discussed in Section 2.3.

The trend at the federal level is toward more regulation. As discussed in more detail below, a number of federal rules related to gas development have been finalized, proposed, or announced recently in response to increased development, and there have been repeated calls for new legislation. Taken together, these efforts indicate a growing interest in hydraulic fracturing and unconventional gas development at the federal level and the likelihood of additional federal regulation, and possibly legislation regarding the removal of certain exemptions in existing statutes, as has been proposed in the past.

2.2.2 Hydraulic Fracturing

The process of hydraulic fracturing, other than when diesel fuel is used, is expressly excluded from federal regulation under the Safe Drinking Water Act's Underground Injection Control program.[51] Were hydraulic fracturing not specifically excluded from the definition of *underground injection*, the natural gas industry would be required to comply with certain federal well construction, operation, and closure requirements, as well as disclosure requirements. This has been, and likely will continue to be, a source of controversy because numerous bills were introduced in 2009, 2010, and 2011 to bring the process of hydraulic fracturing within EPA's control (Martin et al. 2010).[52] Although prior attempts have all been unsuccessful, it is likely that similar legislation will be introduced in the future (Hammer and VanBriesen 2012). Additional pressure for greater federal regulation could also come as a result of EPA's hydraulic fracturing study if it concludes that the process of injecting fluids underground during hydraulic fracturing increases the risk of groundwater contamination.[53]

EPA recently published draft guidance governing the use of diesel in hydraulic fracturing fluids that includes requirements for diesel fuels used for hydraulic fracturing wells, technical recommendations for permitting, and a description of diesel fuels for EPA underground injection control permitting (EPA 2012b). As proposed, this guidance only applies where the EPA is the permitting authority. States with primacy over the Underground Injection Control program, which include Texas, Louisiana, and Wyoming, are not required to follow the guidance (Figure 11).

[51] 42 U.S.C. § 300h(d)(1)(B)(ii) (2005).
[52] The most recent efforts being The Fracturing Responsibility and Awareness Act of 2011, H.R. 1084.
[53] An area of ongoing controversy and debate is whether or not the process of hydraulic fracturing poses a greater risk of subsurface water contamination than other aspects of development that are common to all types of oil and gas production such as surface spills, impoundment failures, and faulty well construction (Groat and Grimshaw 2012; Hammer and VanBriesen 2012; Jones 2011).

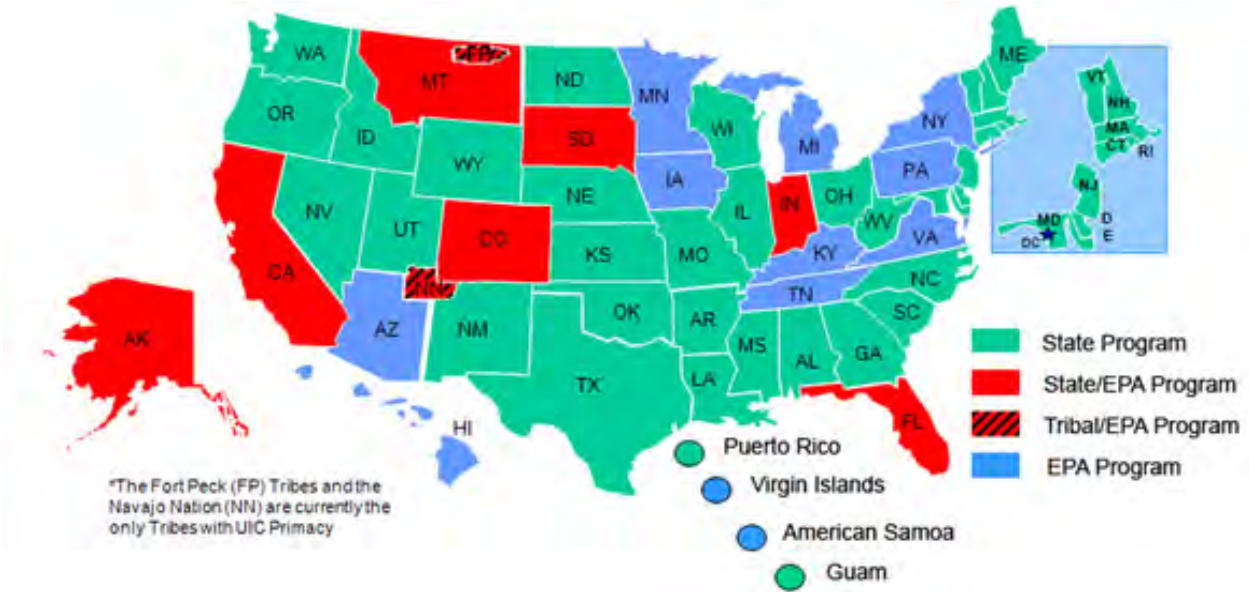

Figure 11. EPA map of Underground Injection Control Program Primacy[54]

Given the limited federal role in this area, states are the primary regulators of well construction standards that apply to the process of hydraulic fracturing (see Section 2.3.3 below).[55] However, with respect to natural gas development on federal lands, the Bureau of Land Management (BLM) recently proposed a rule that would require the use of cement bond logs on surface casing and mechanical integrity testing prior to hydraulic fracturing to improve well integrity (BLM 2012). Both EPA's proposed diesel fuel guidance and BLM's proposed well construction standards help to provide greater regulatory certainty to the production of natural gas. However, state regulations remain central given the limited applicability of the EPA guidance and BLM standards.

2.2.3 Water Quality

As reported in various news media, for the public, some of the most prominent environmental concerns associated with unconventional gas development that have emerged are adverse impacts to groundwater and surface water resources. The major federal statutes protecting water quality—the Clean Water Act and the Safe Drinking Water Act—apply to various aspects of unconventional gas development, with different approaches and experiences in different parts of the country.

The Clean Water Act prohibits the unauthorized discharge of wastewater into the surface waters of the United States from point sources. Discharges may be authorized by permits issued under the National Pollutant Discharge Elimination System, whose permits require industry-specific, technology-based limits and water-quality-based effluent limitations. The latter vary depending

[54] EPA, "UIC Program Primacy," http://water.epa.gov/type/groundwater/uic/Primacy.cfm.
[55] Well integrity is essential not only to reduce risks associated with hydraulic fracturing, but also, with the entire universe of down-hole activities (i.e., wells that are not hydraulically fractured also pose a risk to surface and subsurface water sources if not properly cased, cemented, and monitored).

on local conditions because they are tailored to protect specific designated uses of surface waters.

EPA has established two national effluent limitation guidelines that apply to unconventional gas wells. The first completely prohibits the discharge into navigable waters of natural gas wastewater pollutants, such as produced water, drilling muds, or drill cuttings from any source associated with oil and gas production, field exploration, drilling, well completion, or well treatment, located east of the 98th meridian. [56] The second guideline applies to operators west of the 98th meridian and allows the discharge of produced water only if it may be used beneficially for agricultural or wildlife propagation.[57]

Indirect discharges to publicly owned treatment works (POTWs) and discharges from centralized waste treatment facilities (CWTs) are also subject to the Clean Water Act framework. However, EPA has not promulgated pretreatment standards that apply to the discharge of shale and coal-bed methane (CBM) wastewater to POTWs, leaving a gap in the federal framework that has been the source of considerable controversy. Discharges from CWTs are subject to federal technology-based standards, although these standards do not contain limits for all of the pollutants contained in natural gas wastewater—in particular, bromide or total dissolved solids. [58]

EPA's decision under the CWA to prohibit direct discharges of drilling wastewater to surface waters in states east of the 98th meridian, combined with limited injection well capacity in that part of the country (see Chapter 4, discussing the fact that Pennsylvania has only eight Class II underground disposal wells), has resulted in increased use of indirect discharges to POTWs and CWTs. Many POTWs, however, are not designed or permitted to handle the volumes and types of wastewater produced from the booming shale gas industry (Urbina 2011). In Pennsylvania, insufficient treatment capacity for shale gas wastewater resulted in contamination of state waters—in particular, elevated levels of total dissolved solids, organic chemicals, and metals (EPA 2011c)—prompting the state to request operators to voluntarily cease sending shale gas wastewater to older POTWs and also resulting in new state limits for total dissolved solids and chlorides[59] (EPA 2011b).

EPA has announced its intent to develop pretreatment standards for discharges of CBM and shale wastewater in 2013 and 2014, respectively (EPA 2011a). These standards should bring certainty to this area, reduce the likelihood that treated wastewater discharges from POTWs will contaminate surface waters, and improve public confidence in the ability of natural gas development to be done safely. Depending on how these standards are set, they may also drive the development of technologies to recycle and reuse wastewater. If, for example, EPA adopted a "no discharge" or otherwise stringent limit, operators would need to rely more heavily on other

[56] Onshore Subcategory Guidelines, 40 C.F.R. § 435.30 (2012). The 98th meridian runs through North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. Direct discharges of produced water west of the 98th meridian are permitted provided the water does not exceed specified parameters for oil or grease and can be used for agricultural or wildlife propagation. *Id.* § 435.50.
[57] *Id.* § 435.50. Produced water has an effluent limitation of 35 mg/L of oil and grease. *Id.* § 435.52.
[58] See 33 U.S.C. § 1317 (2012); EPA, "National Recommended Water Quality Criteria," available at http://water.epa.gov/scitech/swguidance/standards/criteria/current/index.cfm.
[59] 25 Pa. Code § 95.10(b)(3)(iv)-(vi).

forms of wastewater disposal such as underground injection or recycling. In parts of the country, such as Pennsylvania, where underground injection wells are limited, a "no discharge" standard could result in significantly more recycling and reuse—especially if doing so is less costly than transporting wastewater out of state for injection.

As noted above, in addition to complying with national effluent limitation guidelines, POTWs and CWTs discharging wastewater must comply with numeric limits on certain pollutants designed to ensure that discharges do not impair the designated uses of surface water bodies. Although EPA has established guidance for water-quality criteria for some natural gas wastewater, it does not cover all pollutants contained in wastewater (Hammer and VanBriesen 2012).[60] Additional guidance from EPA would provide a certain degree of certainty and more uniform protection because states rely on EPA guidance when adopting water-quality criteria, and EPA retains authority to promulgate its own criteria if it determines a state has failed to adopt adequate standards of its own. Notably, EPA recently signaled its intent to update water-quality criteria for chloride, which is arguably outdated because it was established well before the recent shale gas boom (EPA 2011b).

2.2.4 Hazardous and Solid Wastes

2.2.4.1 Management of Waste

Subtitle C of the Resource Conservation and Recovery Act imposes stringent "cradle-to-grave" requirements that apply to the generation, transportation, treatment, storage, and disposal of hazardous waste.[61] Most of the wastes associated with natural gas drilling, however, are exempt from the Resource Conservation and Recovery Act's program for hazardous wastes. Specifically, drilling fluids, produced water, and other wastes "intrinsically related" to the production and development of natural gas are exempt from Subtitle C hazardous waste requirements.[62] As a result, management of these wastes is primarily a matter of state law. Non-exempt wastes, such as unused fracturing fluids, waste solvents, and used hydraulic fluids, are subject to the Resource Conservation and Recovery Act and may be covered under Subtitle C if they exhibit hazardous characteristics or are specifically listed as hazardous wastes. Exempt wastes not regulated as hazardous are subject to state rules because EPA has not promulgated regulations governing the management of oil and gas solid waste (NRLC 2012). Although this allows for regulation to be tailored to local geologic or hydrologic conditions, it also creates greater horizontal fragmentation, uncertainty, and the potential for inadequate state rules. See the discussion in Section 2.3.5.2 and Table 28 in Appendix C comparing state rules for produced water.

[60] The current guideline only applies to certain pollutants such as chloride, oil and grease, suspended solids, turbidity, and nitrates. See EPA, "National Recommended Water Quality Criteria," available at http://water.epa.gov/scitech/swguidance/standards/criteria/current/index.cfm.

[61] 40 C.F.R. pt. 260 et seq. Specifically, generators must ensure and fully document that their hazardous waste is properly identified, managed, and treated prior to recycling and disposal. They must comply with requirements for training and emergency arrangements (including having an emergency coordinator and testing and maintaining emergency equipment) and must track the shipment and receipt of their waste. Additionally, a hazardous waste generator is limited in the amount of waste it can accumulate. A large-quantity hazardous waste generator (one that generates 1,000 kg or more of hazardous waste per month) must move all the waste it generates off site within 90 days; a small-quantity generator must move all its waste off site within 180 days. See EPA, Regulations Governing Hazardous Waste Generators, at III-41-47, http://www.epa.gov/osw/inforesources/pubs/orientat/rom33.pdf.

[62] In addition, EPA has determined that produced water injected for enhanced recovery is not waste subject to the Resource Conservation and Recovery Act and is therefore exempt from regulation under the statute. However, produced water stored in above-ground impoundments is subject to state law (EPA 2000).

Some observers have called for the federal regulation of natural gas waste as hazardous under Subtitle C of the Resource Conservation and Recovery Act (Hammer and VanBriesen 2012). EPA has not signaled its intent to reverse its decision regarding the management of natural gas waste; however, it remains a possibility, and may turn, in part, on the outcome of EPA's study on hydraulic fracturing.

2.2.4.2 Liability for Releases of Hazardous Substances

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as "Superfund," imposes strict liability for releases of hazardous substances on owners and operators of "facilities" (which include natural gas production sites), as well as arrangers and transporters of hazardous substances. The definition of *hazardous substance* under CERCLA, however, is limited in its application to crude oil, petroleum, and natural gas.[63] Specifically, petroleum and crude oil—as well as hazardous substances that are normally mixed with or added to crude oil or crude oil fractions during the refining process—are not considered hazardous substances under the so-called "petroleum exclusion."[64] Also excluded from the definition of hazardous substances are natural gas, natural gas liquids, liquefied natural gas, and synthetic gas usable for fuel.[65] Releases of other hazardous substances from natural gas drilling operations, such as hydraulic fracturing fluids containing hazardous chemicals, are subject to standard CERCLA liability. Thus, federal law provides for some potential CERCLA liability for natural gas operators, but the scope of such liability is narrow. Moreover, even though some states, such as Colorado, Texas, and Pennsylvania, have adopted their own environmental cleanup legislation, these states have all retained the federal definition of hazardous substances.[66]

2.2.4.3 Reporting of Hazardous or Toxic Chemical Releases

Federal law imposes few reporting requirements on operators of natural gas production facilities for the release of hazardous or toxic chemicals. Under CERCLA, operators must report releases of hazardous substances above reportable quantities, although the same definition of hazardous

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[63] 42 U.S.C. § 9601(14).

[64] *Id*. Discharges of oil from certain production facilities may be subject to the Clean Water Act's Oil Pollution Prevention Program, which requires covered facilities to prepare and implement Spill Prevention Control and Countermeasures to prevent oil discharges (EPA 2000).

[65] *Id*. at § 9601(14).

[66] New York has a state law mirroring CERCLA, including a state Superfund to pay for site cleanup when no responsible party can be identified or the responsible party has inadequate funds for the cleanup. The state requires reporting and cleanup of petroleum spills within the state through its spill response program and its Brownfield and Superfund laws. New York's Brownfield regulations still exclude "natural gas, natural gas liquids, liquefied natural gas, synthetic gas usable for fuel, or mixtures of natural gas and such synthetic gas" from the definition of "hazardous waste" and "contaminant," thereby removing natural gas from the law's application. New York Department of Environmental Conservation, *Chemical and Petroleum Spills*, http://www.dec.ny.gov/chemical/8428.html; see also New York General Remedial Program Requirements, N .Y. Comp. Codes R. & Regs. title 6, § 375-1.2(w)(1). Pennsylvania operates within the CERCLA framework, but also has separate state legislation to fill in gaps in CERCLA. Pennsylvania Department of Environmental Protection, *Superfund*, http://www.portal.state.pa.us/portal/server.pt?open=514&objID=589587&mode=2. This state legislation retains the exclusion for natural gas and petroleum from the definition of "hazardous substance" and "hazardous waste." Pennsylvania Hazardous Sites Cleanup Act, 756 Act 1988–108, sec. 103 (definitions of "hazardous substance" and "hazardous waste"). Colorado has a statute on hazardous waste cleanup that essentially authorizes the State to cooperate with the federal government in the implementation of CERCLA. Colorado Hazardous Waste Cleanup Act, C.R.S. § 25-16-101. The Colorado statute adopts the CERCLA definition of hazardous substance, thereby excluding petroleum and natural gas. *Id*.

substance applies here as it does to the statute's liability scheme.[67] Oil and gas operators are not required to report annual releases of toxic chemicals under rules promulgated pursuant to the Emergency Planning and Community Right-to-Know Act's Toxics Release Inventory or to disclose the chemicals used in hydraulic fracturing to members of the public or regulators due to the exemption of hydraulic fracturing under the Safe Drinking Water Act.[68]

Natural gas operators are subject to requirements to report or disclose chemicals stored on-site, although these are limited. Owners and operators of storage facilities holding in excess of 10,000 pounds of any hazardous chemical must submit chemical inventory information to state and local emergency response and fire officials.[69] In addition, under the Emergency Planning and Community Right-to-Know Act and regulations promulgated pursuant to the Occupational Safety and Health Act, natural gas operators using products containing hazardous chemicals must maintain material safety data sheets on site, and must make them available to state and local emergency response and fire officials, subject to trade secret protection.[70]

States are increasingly filling the gap related to public disclosure of the chemicals used in hydraulic fracturing fluids. As discussed in more detail below, there is a clear trend toward public disclosure of all chemicals, not just those listed on material safety data sheets (Table 23 in Appendix C). This trend is evident at the state level and in the recently proposed BLM rule, which would require disclosure for production on federal and tribal lands (BLM 2012).

In terms of other reporting requirements, EPA has announced an intention to gather data on the aggregate amounts of exploration and production chemical substances and mixtures used in hydraulic fracturing. It is unclear to what extent these regulations will fill any of the gaps that remain in federal reporting requirements. But EPA has signaled an intent to avoid vertical fragmentation by framing its proposal as one that "would not duplicate, but instead complement, the well-by-well disclosure programs of states"(EPA 2011d).[71] In addition, states may adopt their own reporting requirements for releases.[72]

2.2.4.4 Disposal of Produced Water

As noted above, states primarily regulate waste disposal. One exception is the disposal of produced water into Class II underground injection wells, which is regulated by EPA's Underground Injection Control program, although states with primacy issue the actual permits.[73] Some states have recently raised concerns regarding the disposal of produced water into Class II wells, in response to evidence linking such disposal to earthquakes (Niquette 2011; Hammer and VanBriesen 2012). For example, nine earthquakes were recorded recently in Youngstown, Ohio,

[67] 42 U.S.C. § 11004 (2012). EPA also requires operators to disclose "the source and analysis of the physical and chemical characteristics" of chemicals used in underground well stimulation permit applications (EPA 2008b).
[68] 42 U.S.C. § 11023(b) (2012) (EPA 2000; Wiseman 2010).
[69] 42 U.S.C. § 11022 (2012).
[70] *Id.*; 29 C.F.R. §1960.34(b)(6) (2012). Disclosure to the public of material safety data sheets is available upon written request.
[71] Letter from Stephen A. Owens, Assistant Administrator to Ms. Deborah Goldberg, Earthjustice re: TSCA Section 21 Petition Concerning Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production, (Nov. 23, 2011), http://www.epa.gov/oppt/chemtest/pubs/EPA_Letter_to_Earthjustice_on_TSCA_Petition.pdf.
[72] See, for example, COGCC R. 906(b)(3) (requiring oil and gas producers to report spills that threaten to impact waters of the state).
[73] 40 C.F.R. § 144.6 (2010).

all of which were located within a half mile of an injection well, and all of which occurred within the first 11 months of injection of produced water into the well (Niquette 2011). Although scientists have yet to determine the cause of recent earthquakes, there have been instances in the past where injection wells used by other industries have been linked to earthquakes. (Holland 2011). This indicates that any causal relationship between underground injection of waste and seismic activity is not an impact unique to the natural gas industry. However, the volume of produced water associated with the significant increase in unconventional gas development across the country may place an increased strain on underground injection well capacity, especially in those areas where other disposal methods are less available. In addition to potentially causing earthquakes, underground injection of large amounts of produced water can increase the risk of subsurface contamination due to leaky wells.[74] Some suggest EPA should require the disposal of produced water into Class I, rather than Class II, wells because the former are subject to more rigorous standards on well construction, operation, and closure (Hammer and VanBriesen 2012). This will likely be an area of continuing public scrutiny and could be subject to additional state or federal regulation in the future.[75]

2.2.5 Air Quality

EPA has broad authority under the Clean Air Act to promulgate rules to reduce air pollution from natural gas sources. The most prominent air-quality issues associated with unconventional gas development include emissions of ozone precursors, VOCs and oxides of nitrogen, various hazardous air pollutants, and methane, all of which are subject to the basic Clean Air Act framework. Concentrated natural gas development has led to elevated ozone levels in rural parts of Wyoming and Utah where little other industrial activity occurs (Fruedenthal 2009; Streater 2010), and has also contributed to ozone pollution in more urban and industrial areas such as the Dallas Fort-Worth metropolitan area (Armendariz 2009). In 2012, the EPA responded to exceedances of the national health-based ambient air quality standards (i.e., National Ambient Air Quality Standards) for ozone in the Upper Green River basin by classifying the basin—for the first time—as in nonattainment with the 2008 8-hour National Ambient Air Quality Standard for ozone. [76] This listing could result in the state adopting more stringent rules to reduce emissions of VOCs and/or NO_x from natural gas sources in the basin to meet its Clean Air Act obligations.

Until recently, EPA has exercised its Clean Air Act authority with respect to natural gas production by focusing on a select number of natural gas production sources such as new and modified gas-processing plants, glycol dehydrators, crude oil and condensate storage vessels, and select engines used in the natural gas supply chain (e.g., engines used to power compressors). Most of these rules were implemented long before the unconventional natural gas boom occurred.

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[74] Personal conversation with Mark Williams, Professor of Geography and Fellow, INSTAAR, University of Colorado-Boulder, April 25, 2012.

[75] Notably, the Ohio Dept. of Natural Resources has enhanced Class II well permitting requirements, requiring seismic tests prior to construction of the well and ongoing monitoring, among other protections. Ohio Dept. of Natural Resources, Class II Disposal Well Reforms/Youngstown Seismic Activity Questions and Answers, http://ohiodnr.com/downloads/northstar/YoungstownFAQ.pdf.

[76] See EPA State Final Designations, April 2012 and May 2012, http://www.epa.gov/ozonedesignations/2008standards/state.htm.

In April 2012, however, EPA issued revised New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) (EPA 2012c)[77] that update existing standards and apply new requirements to previously unregulated sources. Specifically, EPA's new rules add requirements limiting VOCs and hazardous air pollutants emitted from completions and recompletions of hydraulically fractured natural gas wells (known as the "reduced emission completion" or "green completion" requirement), pneumatic devices, storage vessels, compressors, and "small" glycol dehydrators located at major sources of hazardous air pollution (EPA 2012c). Certain of these requirements result in the co-benefit of reducing methane because, in many cases, controlling VOCs also results in methane reductions (EPA 2012c). In addition, EPA updated standards and limits that apply to gas processing plants and large glycol dehydrators located at major sources of air pollution (EPA 2012c).

The revised NSPS and NESHAPS regulations provide a national floor that addresses unevenness in state air requirements. For example, EPA's new green completion requirements impose a level of uniformity across states with respect to control of ozone precursors and methane from unconventional natural gas development, as illustrated in Table 29, Appendix C, which compares green completion requirements. These new requirements implement one of the key recommendations of the SEAB, that EPA "adopt rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations[.]" (SEAB 2011a, 2011b). Prior to EPA's adoption of the reduced emission completion requirement, many operators voluntarily used green completion practices to maximize resource recovery, illustrating how certain best management practices can serve as the foundation for future regulation (Efstathiou 2012, EPA 2012c).

In August 2012, EPA released a rule that requires capture or high-efficiency combustion of associated gas produced from crude oil wells in the Fort Berthold Indian Reservation in North Dakota.[78] The rule applies during well completions and re-completions, the separation phase of oil production, and during production. Specifically, the rule requires that operators control emissions of VOCs by 90% during well completions or re-completions or perform a reduced-emission completion, route all produced gas and gas emissions to a control device capable of at least a 90% control efficiency upon production, and, within 90 days of production, capture all associated gas or route it to a control device capable of 98% control efficiency.

In September 2012, natural gas producers will also begin reporting GHG emissions from facilities subject to EPA's Mandatory Greenhouse Gas Reporting rule. As required by that rule, natural gas facilities that emit 25,000 metric tons of CO_2e or more of GHGs will be required to report GHG emissions (EPA 2010). Operators have been granted a grace period to use less rigorous measurement practices initially, but the data collected will provide much greater certainty regarding actual methane leakage rates. Precise information regarding methane emissions from natural gas systems is essential to resolving discrepancies among life cycle assessments, such as those discussed in Chapter 1.

[77] U.S. E.P.A, Final Rule, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," http://www.epa.gov/airquality/oilandgas/pdfs/20120417finalrule.pdf.

[78] EPA, "Approval and Promulgation of Federal Implementation Plan for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nations), ND" 77 Federal Register 48878 (August 15, 2012).

Despite EPA's broad authority to implement clean air measures, states retain significant room to regulate. States with delegated programs may implement standards more stringent than federal law, unless prohibited by state law from doing so. States retain authority to regulate sources and air pollutants not covered by existing federal rules, and states may also impose more stringent rules than federal to meet National Ambient Air Quality Standards for criteria pollutants.

2.3 State Statutory and Regulatory Frameworks

Against this backdrop of federal environmental regulation, state and local governments have adopted numerous laws and regulations governing unconventional gas development, with considerable variation across different states, especially regarding the handling of waste and wastewater, construction of wells other than underground injection disposal wells, and baseline water-monitoring requirements. States also have exclusive jurisdiction over water withdrawals, other than those occurring on federal lands,[79] and over various land-use controls such as setback requirements and zoning, some of which have been delegated to local governments. As discussed above, although a number of federal rules apply to protecting water and air resources, states also retain authority to develop more stringent standards and to regulate impacts or sources not covered by federal law. Prior to EPA's recent revisions of the NSPS and NESHAPS, some states—notably Colorado and Wyoming—adopted air regulations that went beyond then-existing federal standards [80] (WY DEQ 2010), whereas New York has proposed a number of regulations to protect water sources and ensure safer waste management that go beyond federal and other state rules. Some states have increased inspection capacity to respond to the rapid increase in unconventional gas development; however, there is considerable variation in state inspection capacities and enforcement approaches.

This section analyzes the state regulatory frameworks governing air, water, waste, and compliance and enforcement issues associated with unconventional gas development in Colorado, Wyoming, New York, Texas, Louisiana, and Pennsylvania. It focuses on the extent to which state law fills any gaps left open by the federal regulatory scheme, as well as on key trends, differences in the regulatory frameworks across the different basins, compliance monitoring, and enforcement capabilities and actions.

2.3.1 Overview and Key Trends

The wide variation in state approaches to the regulation of unconventional natural gas development reflects differences in resource characteristics (e.g., dry versus wet gas, deep shale versus shallow CBM), geology, and hydrology, as well as different experiences with oil and gas development and different approaches to and preferences for environmental protection. Across the country, states have responded to hydraulic fracturing in very different ways. Vermont, for example, recently enacted legislation banning hydraulic fracturing in the state.[81] New York, as noted, has imposed a temporary moratorium on drilling as it develops regulations.[82] Recently, the Cuomo administration announced that it will undertake a public health study of the potential impacts of hydraulic fracturing and re-start the rule-making process prior to issuing any new

[79] See, for example, the proposed BLM rule, which requires operators to identify the source of water to be used in fracturing in order for the BLM to determine impacts and mitigation measures, if needed (BLM 2012).
[80] COGCC R. 805(b).
[81] H 464 (enacted May 16, 2012).
[82] 9 N.Y. Comp. Codes R. & Regs. tit. 9, § 7.41.

regulations.[83] A number of states (specifically Colorado, Wyoming, and Pennsylvania) have revised their oil and gas rules extensively—at least once, and in some cases, continue to do so—to respond to the uptick in unconventional resource development; Louisiana and Texas have engaged in much more limited revisions. New York, as noted above, is in the process of revising its regulations. Louisiana, Pennsylvania, and Colorado have all recently submitted their hydraulic fracturing rules to the State Review of Oil and Natural Gas Environmental Regulations for review, whereas Wyoming and Texas have not (and New York has not yet finalized its high-volume hydraulic fracturing regulations) (STRONGER, 2010; STRONGER 2011a; STRONGER 2011b). Pennsylvania and Louisiana significantly increased the number of oil and gas inspectors in response to increased development, whereas resources in other states appear quite limited. Data are limited and more research is needed, but there appears to be very little consistency in the ways that states record, respond to, and enforce against violations—including substantial ranges in penalties and the number of violations that result in enforcement actions. Areas highlighted as meriting additional attention from state regulators are improved transparency regarding compliance monitoring, company compliance histories, and enforcement actions.

Different regulatory approaches by states can lead to uncertainty, gaps, and/or redundancies in mitigating some of the more significant environmental risks associated with unconventional gas development and ensuring overall compliance. But they can also provide a source of policy innovation because different jurisdictions experiment with new approaches to regulating various aspects of shale gas development. An example is New York's proposal to require operators to document that, compared to available alternatives, chemical additives used in hydraulic fracturing fluids exhibit reduced aquatic toxicity and pose a lower potential risk to water resources and the environment.[84] For this reason, it is important that state regulators and policy makers share information and lessons learned with other states. National standards provide a baseline or floor in some areas, such as national effluent limitation guidelines for wastewater discharges and EPA's recent NSPS and National Emission Standards for Hazardous Air Pollutants. However, a permanent feature of the regulatory landscape appears to be the uneven and varied nature of state and local regulation and enforcement regarding most other aspects of shale gas development.

Despite the variety in specific state and local regulations and enforcement, some important trends are evident. All states reviewed here recently revised their oil and gas rules and/or laws to respond specifically to the increase in unconventional resource development. Colorado, New York, Wyoming, and Pennsylvania recently undertook extensive reviews and revisions of their laws and regulations that , in some cases, resulted in considerably more comprehensive—and in many instances, protective—rules than those in Louisiana and Texas. For example, Colorado and Wyoming have been leaders in rules to reduce emissions of ozone precursors, and New York and Pennsylvania are leaders in laws regarding measurement and public disclosure of water sources and waste. See Table 22, Appendix C, for a general description of revisions to state oil and gas laws.

[83] Danny Hakim, "Shift by Cuomo on Gas Drilling Prompts Both Anger and Praise," *New York Times,* Sept. 30, 2012.
[84] N.Y. Comp. Codes R. & Regs. tit. 6, §560. 3.

There is a clear trend in all of the states studied toward greater transparency—such as mandatory public disclosure of chemicals used in hydraulic fracturing and the composition of wastewater, reporting of the amounts and sources of water used in hydraulic fracturing, and more rigorous well-construction standards, including notifications of hydraulic fracturing and well completions. A key recommendation of the SEAB Subcommittee (SEAB 2011a) was greater transparency, in the form of public disclosure of the chemicals, amounts, and sources of water used or produced during hydraulic fracturing, baseline water monitoring measurements, and reduction and measurement of air emissions. These activities have the potential to lead to better public understanding and acceptance of natural gas development.

All states covered in this study have added requirements that providers of fluids used in hydraulic fracturing and/or operators disclose the contents of most chemicals to the public. These requirements are in addition to, and go beyond, federal requirements that require operators to maintain material safety data sheets for certain hazardous chemicals stored on-site in threshold quantities, and to report releases of hazardous chemicals in threshold quantities.[85] In addition, all of the states covered in this study require operators to report the amount and, in most cases, the source of water used in hydraulic fracturing either to the public or state regulators.

Other areas of state regulation or interest include: baseline water-monitoring requirements; use of closed-loop drilling systems to contain waste, rather than open, earthen pits; reporting or reduction of emissions of air pollutants; standards to ensure well integrity; and more active involvement on the parts of local government over drilling activities.

State compliance monitoring and enforcement capacity varies considerably, although significant data limitations across the different states mean that any comparisons should be considered provisional. Based on available data, some states—notably Pennsylvania and Louisiana—recently increased state inspection capabilities to respond to increased development, whereas resources in other states appear quite limited. The methods that states use to track and report violations and enforcement actions also differ substantially—with some states, notably Pennsylvania, making violations and enforcement actions publicly available via online databases; other states, notably Colorado and Wyoming, have been criticized for a lack of transparency and limited public access to such information.[86]

Variation across states in substantive regulations, as well as compliance monitoring and enforcement capacity, can be explained by a number of factors. Some are legal, such as federal effluent limitation guidelines that differ across regions and state statutes limiting the amount of penalties that can be assessed for violations. Others reflect differences in local environmental conditions (e.g., elevated ozone levels in the Upper Green River basin and Denver metropolitan area, respectively, led Wyoming and Colorado to adopt air rules that went beyond then-existing federal requirements, forming the basis for some of EPA's new NSPS rules); geologic and hydro-geologic conditions (e.g., developing shallow CBM resources poses unique risks that deep shale does not)[87]; proximity of drilling to densely populated areas or sensitive environmental

[85] 42 U.S.C. § 11021-11022 (2006); 55 Fed. Reg. 30,632 (July 26, 1990).
[86] See, for example, Earthworks (2012b) and Soraghan (2011).
[87] See, for example, COGCC R. 608(b)(4).

areas (e.g., setback requirements and buffer zones)[88]; historical and contemporary experiences with oil and gas development; and preferences for environmental protection.

2.3.2 Water Acquisition

The regulation of water withdrawals is primarily a matter of state and local, rather than federal, law. The legal framework governing water rights differs from state to state, although there is some consistency along regional lines.[89] There is a clear trend toward requiring operators to identify the sources of water used, report the amount of water used in hydraulic fracturing, and provide for incentives to promote reuse of water used in hydraulic fracturing such as by recycling flowback waters or production fluids. All states require operators to report on the amount of water used for hydraulic fracturing, as does BLM's new proposed rule.[90] In addition, both New York and Pennsylvania require operators to provide for the reuse and recycling of flowback water or production fluids in water management plans or wastewater source reduction strategies. States also have begun to require minimum in-stream flow below points of water withdrawal and other measures to ensure that aquatic wildlife, water quality, and other water users will not be adversely affected.[91]

A handful of local governments also regulate some aspects of water acquisition. For example, Archuleta County, Colorado, requires operators in the North San Juan basin to submit a water management plan that includes a plan for disposal or reuse, projected water use, identification of the water source, and water availability (Archuleta 2010). The City of Fort Worth, Texas, requires operators to describe the water source proposed to be used for drilling in application for permits to drill.[92] As unconventional gas development expands in various parts of the country, it seems likely that more local governments will seek to get involved in regulating aspects of water acquisition.

For more information related to state and local regulation of water withdrawals, see Table 24, Appendix C, Water Acquisition Requirements.

2.3.3 Hydraulic Fracturing and Well Construction Standards

State well-construction standards vary considerably, which to a certain extent can be explained by differences in local geology. However, certain safeguards do not depend on differences in local conditions. Standards that have been recommended to increase well integrity include the use of state-of-the-art cement bond logs, pressure testing of casing, monitoring and recording bradenhead annulus pressure, and assurances that surface casing is run below all known underground aquifers to reduce the risk of drinking water contamination from fluid or gas

[88] See, for example, setback requirements in the Barnett Shale and New York's proposed buffer zones to protect sources of drinking water, Appendix C.
[89] The two most common doctrines governing water rights are the prior appropriation and riparian doctrines. The prior appropriation doctrine provides rights to continued use of water to those who first put water to beneficial use and is the predominant regime in most of the West (CDWR 2012; Groat and Grimshaw 2012). In a riparian water rights system, water rights are tied to the ownership of land adjacent to water resources.
[90] DOI, Bureau of Land Management, Proposed Rule "Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands", May 4, 2012, http://www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&pageid=293916.
[91] See, e.g., 58 Penn. Stat. § 3211(m)(2).
[92] Fort Worth, Tex., Ord. No. 18449-02-2009.

migration (SEAB 2011b). Of the states reviewed, only Colorado and Louisiana require the use of cement bond logs.[93] New York has proposed to require the use of cement bond logs. All states except Wyoming require some kind of pressure testing of casing, although the specifics vary regarding the testing and circumstances requiring testing. Colorado is the only state that requires monitoring of annulus pressure with bradenhead (Texas requires all wells to be equipped with bradenhead, but only requires a pressure test in certain instances). All states require surface casing to be set below known aquifers, although the specific requirements vary. For specific requirements, see Table 25 in Appendix C.

2.3.4 Baseline Water-Quality Monitoring

Requiring operators to conduct baseline monitoring of wells or water resources near gas operations is an important objective for all stakeholders because it results in science-based measurement data that can be used to identify whether or not well activities cause contamination. For example, in Pennsylvania, operators who conduct pre- and post-baseline water monitoring of nearby water sources can overcome a rebuttable presumption that a well operator is responsible for pollution of nearby water resources if the monitoring demonstrates that constituents found in the sampled water sources did not come from the well operator's activities.[94] In Colorado, the Colorado Oil and Gas Association instituted a voluntary baseline monitoring program, with results being submitted to the Colorado Oil and Gas Conservation Commission (COGCC), provided landowner consent.[95] Colorado requires baseline water testing in the North San Juan basin (as well as other parts of the state), in limited circumstances to protect sources of drinking water, resources located near CBM wells, and in the Greater Wattenberg Area.[96] New York has proposed to require operators to make reasonable attempts to sample and test all residential water wells within 1,000 feet of a well pad prior to commencing drilling. If no well is located within 1,000 feet, or the surface owner denies permission, then the operator must sample all wells within a 2,000-foot radius. Monitoring continues at specified intervals as determined by the U.S. Department of Environmental Conservation.[97] For more information related to state baseline monitoring requirements, see Table 26, Appendix C, Baseline Monitoring Requirements.

2.3.5 Storage and Management of Wastes

2.3.5.1 Waste Storage

As noted above, waste storage is largely a matter of state and local law. The onsite storage of waste—such as produced and flowback water, drill cuttings, and fluids—is usually restricted to either storage tanks or open lined or unlined pits. Open pits pose a number of risks, including

[93] We do not include where state regulations refer to logs generally, as opposed to using the specific terminology "cement bond logs."
[94] 58 Pa. Cons. Stat. § 3218. In those instances where an operator is deemed responsible for contaminating or diminishing a private or public water source, he or she must restore or replace the water with an alternate source.
[95] Colorado Oil & Gas Association, "Colorado Oil & Gas Association Voluntary Baseline Groundwater Quality Sampling Program," http://www.coga.org/index.php/BaselineWaterSampling.
[96] Colorado requires baseline sampling of surface waters located downstream of drilling operations conducted near surface waters intended for drinking water and baseline sampling of water wells located near CBM wells. COGCC R. 317.b (2012). The state also recently added a statewide requirement that operators provide notice to surface and adjacent landowners, which must include instructions for the collection baseline water samples. COGCC R. 305.e.1.A (2012). Operators drilling in the Greater Wattenberg Area must also conduct limited baseline water sampling prior to drilling. COGCC R. 318A.
[97] Proposed N.Y. Comp. Codes R. & Regs. tit 6, § 560.5(d).

threats of drowning to migratory birds and wildlife, air pollution caused by the volatilization of hazardous or organic compounds, and soil and water contamination posed by overflowing pits or liner failures (Earthworks 2012, NM OCD 2008). According to the Ground Water Protection Council, "The containment of fluids within a pit is the most critical element in the prevention of shallow ground water contamination" (GWPC 2009). This study did not perform a comprehensive analysis of state pit requirements; however, a preliminary review revealed significant variation among state pit rules in terms of liner, monitoring, fencing, and other construction and operation requirements, which is complicated somewhat by the use of inconsistent nomenclature for pit types.

An alternative to the use of pits is the use of closed-loop or "pitless" drilling systems that require the storage of fluids in tanks, preferably closed tanks, rather than open pits. Closed-loop drilling reduces many of the risks associated with open pits (Earthworks 2012). Closed-loop drilling also "allows for enhanced monitoring of fluid levels and characteristics which allows for more efficient use of drilling fluids, reduces waste, encourages recycling, and reduces potential liability associated with waste management and reduces site closure costs"[98] (TRRC 2012). New York has proposed to require closed-loop drilling for drilling fluids and cuttings associated with high-volume hydraulic fracturing operations. Colorado, Pennsylvania, Wyoming, and Fort Worth (Texas), require the practice in certain situations, such as where drilling occurs in sensitive areas where there is a heightened risk of water contamination from pit failure or the implications of contamination are more severe if contamination does occur. A recent bill introduced in Colorado would have required enhanced use of this practice statewide.[99] BLM's proposed rule for development on public and tribal lands provides for the use of either closed-loop systems or pits (BLM 2012). For a comparison of state and local closed-loop drilling requirements, see Table 27, Appendix C, Closed-Loop or Pitless Drilling Requirements.

2.3.5.2 Produced Water Disposal

State requirements regarding the disposal of produced water also vary considerably. Some of this variation can be explained by local conditions, such as the scarcity of underground injection wells in Pennsylvania, as noted above. However, disparate regulatory requirements also contribute to state-by-state variation.

In general, natural gas operators have a variety of options for disposing of wastewater. These include discharging wastewater directly to surface waters, sending the waste to treatment facilities such as POTWs or CWTs authorized to discharge, disposal via underground injection well, reuse for further hydraulic fracturing, disposal into evaporation ponds or impoundments, or disposal via land application. However, legal and practical constraints can limit some of these options.

Of the states reviewed, Colorado, Wyoming, and Texas allow for direct discharges only in specified circumstances (e.g., if produced water meets national effluent limitation guidelines for agricultural or wildlife propagation). State requirements vary considerably with respect to indirect discharges to POTWs or CWT facilities. All of the states studied except New York allow for disposal or storage of produced water in evaporation or open pits, subject to specific

[98] NY SGEIS, § 7.1.7.4.
[99] SB 12-107 (introduced January 31, 2012).

circumstances where closed-loop systems are required. Similarly, all states except New York and Texas allow for produced water to be disposed of via land application, such as road-spreading or land farming, but the specific requirements and limits for doing so vary considerably. New York has proposed to require operators to demonstrate that all flowback water and production brine will be treated, recycled, or otherwise properly disposed of over the projected life of the well,[100] and also, that operators prepare a waste tracking form for flowback and production brine similar to what is required for medical waste.[101] Operators in Pennsylvania must prepare a wastewater source reduction strategy identifying the methods and procedures operators will use to maximize recycling and reuse of flowback or production fluids, and most states are increasingly encouraging reuse and recycling. Additional requirements to incent or require recycling and reuse of produced and flowback are likely given the heightened interest in reducing the risk of contamination posed by other disposal methods, and reducing impacts to freshwater resources associated with withdrawals. See Table 28, Appendix C, Produced Water Disposal, for specific state disposal requirements for produced water.

2.3.6 Air Quality

As discussed above, EPA and the states exercise joint authority over standards to limit or report amounts of air pollution from unconventional gas activities.

State regulation of air contaminants varies significantly, with Colorado and Wyoming containing some of the most comprehensive and rigorous requirements to reduce emissions statewide and in areas home to significant drilling activity. Some of Colorado's and Wyoming's air rules have been driven by exceedances of the national ambient air-quality standards for ozone. For example, Wyoming adopted more stringent requirements to reduce VOCs from natural gas operations in the Upper Green River basin in response to elevated levels of ozone in the winter, as did Colorado in response to violations of national ambient air-quality standards for ozone in parts of the Denver-Julesburg Basin in the Denver Metropolitan Area. Attainment of national ambient air-quality standards (i.e., National Ambient Air Quality Standards) is determined at regional and local levels (so-called "air quality management regions"); also, states have flexibility under the Clean Air Act in developing state implementation plans under the National Ambient Air Quality Standards program. Therefore, state air pollution requirements and controls vary considerably.

In addition to meeting baseline federal requirements, areas that fail to meet—or are at risk of failing to meet—national ambient air-quality standards may adopt additional measures beyond those that apply statewide in order to improve air quality. Indeed, many of the standards recently adopted by EPA in its recent NSPS—such as those that apply to completions and re-completions of hydraulically fractured wells, storage vessels, and pneumatic devices—are similar to those already required in the Upper Green River basin in Wyoming and in Colorado (WY DEQ 2010, CDPHE 2012, COGCC 2008).[102] A different situation exists for the Barnett Shale, also in an area that fails to meet national ambient air-quality standards for ozone, where the state imposes few limits on the emissions of VOCs and hazardous air pollutants; here, EPA's new rules will add a number of requirements. See Table 29, Appendix C, for a comparison of how EPA's new

[100] Proposed N.Y. Comp. Codes R. & Regs. tit 6, § 750-3.12.
[101] NY SGEIS, § 7.1.7.1.
[102] See also COGCC R. 805.

reduced-emission completion requirement (or "green completion") compares with existing requirements in the basins reviewed.[103]

Despite EPA's enhanced role in regulating air pollution, states retain substantial discretion to regulate uncovered sources or pollutants, or, where permitted under state law, adopt more stringent rules and/or require additional reporting. For example, Pennsylvania recently added a requirement that natural gas operators report annually amounts of air pollutants.[104] New York has also proposed additional clean-air measures, including a requirement that natural gas operators submit plans to reduce GHG emissions.[105] State requirements vary considerably related to the amount of associated natural gas that operators may flare or vent during production. As production increasingly shifts toward liquids and oil-rich formations, this issue is likely to be an area of continuing policy focus because EPA's reduced-emission completion requirement does not apply to associated gas emitted during the production phase of oil wells.[106] EPA's recent Fort Berthold Indian Reservation rule provides one example of how regulators, going forward, may address the problem of associated gas emissions.

A number of recent air studies and reports have raised questions related to the sufficiency of current air regulations to protect the health of local communities from hazardous air pollutants and reduce fugitive and vented methane emissions (McKenzie et al. 2012; Petron 2012). As the industry expands, especially into more densely populated areas, concerns regarding air quality and GHG emissions will likely persist and receive ongoing regulatory attention.

2.3.7 Compliance Monitoring and Enforcement

Compliance is essential if regulations are to serve their purpose of mitigating environmental risks. Significant challenges for compliance monitoring occur due to the unique nature of the unconventional natural gas industry, characterized by dispersed and often remotely located facilities controlled by numerous operators whose practices can vary significantly. On top of this, regulators face a rapidly changing industry as development, technologies, and practices continue to expand in scale and scope.

A number of reports that have addressed the adequacy of state compliance monitoring and enforcement capabilities conclude that state inspection and enforcement capacity varies significantly, as do state processes for recording and disseminating compliance histories to the public (Groat and Grimshaw 2012; Earthworks 2012b; Soraghan 2011). For example, as Table 5 illustrates, Colorado and Wyoming have 15 and 12 inspectors, respectively, dedicated to oil and gas facilities (Earthworks 2012b; Groat and Grimshaw 2012). Pennsylvania, by comparison, quadrupled its enforcement staff in 2010, resulting in 193 enforcement personnel, 65 of whom are inspectors (Earthworks 2012b). Similarly, Texas has 125 inspectors while Louisiana has 38 (Groat and Grimshaw 2012, LDNR 2011). Data for New York were not identified.

[103] Texas air rules are not comparable to EPA's recent rules in overall scope or rigor, with the exception of Fort Worth's "green completion" requirement. See Appendix C for green completion requirements.
[104] Act 13.
[105] NY SGEIS, § 7.6.8.
[106] For a discussion of this issue, see Clifford Kraus, *New York Times*, "In North Dakota, Flames of Wasted Gas Light the Prairie" (September 28, 2011).

As illustrated in Table 5, the number of inspections performed in each state varied considerably as well, although the data demonstrate a correlation between the number of inspectors and number of onsite inspections. Adequate inspection capability is critical to carry out the SEAB recommendation that "regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing" (SEAB 2011a).

Table 5. Compliance Monitoring and Enforcement Capabilities[107]

State	Inspectors (2010–2011)	Field Inspections (2010–2011)	Total Violations (2009–2011)	Percent of total Violations that are Procedural	Percent of Violations that Result in Enforcement[108]
CO	15[109]	16,228[110]	N/A	N/A	N/A
LA	38[111]	363	158	60	70
PA	65[112]	298	2,280	22.4	N/A
TX	125	N/A	35[113]	72[114]	20
WY	12	2	N/A	N/A	N/A

Research conducted by the University of Texas identified significant variation among states in terms of the types of violations found (e.g., pit and tank construction and maintenance are the most common violations in Louisiana, whereas permitting violations are most common in Texas). Despite the variation in violations, it appears that most violations identified are minor or procedural violations. Note, however, that this does not necessarily mean that most environmental impacts associated with gas development are minor, nor that companies comply with more "serious" requirements at higher rates. A number of factors affect the types of violations that inspectors identify, such as the visibility of violations (e.g., special equipment is needed to detect and measure natural gas leaks from equipment), state inspector capacity to respond to complaints or conduct investigations, and types of complaints reported (Groat and Grimshaw 2012).

Enforcement varies considerably among states, as well. Table 5 illustrates that the percent of violations leading to enforcement actions differed significantly among states where data are available (e.g., 70% of violations noted resulted in enforcement actions in Louisiana compared to only 20% in Texas) (Groat and Grimshaw 2012; Soraghan 2011). Penalties also vary significantly across jurisdictions, due in part to statutory constraints limiting the amount of penalties a state may assess for a given violation (e.g., the maximum fine for a violation in Colorado is $1,000 per day, whereas enforcement authorities in Pennsylvania and Texas can issue fines of $5,000 and $10,000 per day, respectively) (Earthworks 2012b). Some have questioned whether monetary penalties are sufficient to deter non-compliance given the

[107] Data taken from Groat and Grimshaw (2012), unless otherwise noted.
[108] Soraghan 2011.
[109] Earthworks 2012b.
[110] *Id*.
[111] LDNR 2011.
[112] Earthworks, 2012b.
[113] See Chapter 4.
[114] These are for 2008–2011, rather than 2009–2011.

resources of some companies (Earthworks 2012; Soraghan 2011). Others posit that orders to cease production may be more likely to lead to compliance (Soraghan 2011).

Lastly, public dissemination regarding violations, enforcement actions, and company compliance histories also varies across states. Of the states reviewed, only Pennsylvania maintains a publicly searchable database of violations and enforcement actions. More complete and publicly available data on the compliance histories of companies are needed to understand the effectiveness of compliance and rules, as is more transparency and consistency in the ways that states record and report violations and impose penalties (SEAB 2011a). As with regulations themselves, unevenness in state compliance monitoring and enforcement capacity can lead to additional uncertainty and gaps as well as delay, because public mistrust of industry and regulators can undermine the industry's social license to operate, resulting in bans or moratoria on drilling.

2.3.8 Summary of State Statutory and Regulatory Framework

States are the primary regulators, inspectors, and enforcers of most impacts associated with unconventional natural gas development. Regulatory requirements, compliance monitoring, and enforcement capabilities vary across states. Some of this variation is reduced by the recent trend toward consistency in requirements related to the public disclosure of fluids and the amount and sources of water used in hydraulic fracturing. Additional regulation is likely in the area of well integrity standards—specifically, greater adoption of requirements to ensure adequate casing and cement jobs such as cement bond logs and pressure testing of casing. In addition, in light of continued public concern regarding adverse air, water, and waste impacts associated with unconventional gas development, states are likely to adopt regulations requiring baseline water-monitoring requirements, air-quality rules, and provisions that encourage or require greater reuse of produced and flowback waters. Some states may need to increase their inspection and enforcement resources to ensure that rules are being followed. Processes that provide greater transparency regarding state methods for identifying violations and bringing enforcement actions would help to improve public understanding of the extent to which additional resources are needed. Additional accountability and public trust are likely to result from self-reporting mechanisms that are publicly available, such as a joint industry non-governmental organization database on company compliance records (see SEAB 2011a).

2.4 Local Regulation and Social License to Operate

Across the country, communities have responded to the increased development of unconventional natural gas with mixed reactions. In half of the states reviewed for this study (Colorado, New York, and Pennsylvania), legislation has recently been proposed or enacted to limit the power of local governments to regulate unconventional gas development, or to make such local authority explicit (see Figure 12). In these states, 30 local governments have banned hydraulic fracturing or oil and gas development altogether, and an additional 73 have issued temporary moratoria pending review and potential revision of local land-use or other ordinances.[115] This section examines three different approaches to the issue of local authority,

[115] A handful of states have also banned or issued moratoria. In addition to New York, New Jersey (see A 3653 (introduced Jan. 6, 2011, http://www.njleg.state.nj.us/2010/Bills/A4000/3653_R1.HTM), and Maryland (see The Marcellus Shale Safe Drilling Act of 2011 H.B. 852 (effective June 1, 2011, http://mlis.state.md.us/2011rs/fnotes/bil_0002/hb0852.pdf) instituted temporary moratoriums on hydraulic fracturing; Vermont recently banned the practice (see H. 464 [enacted May 16, 2012]).

and provides an example of one set of requirements—setback requirements—intended to protect local communities and sensitive resources from adverse drilling impacts to illustrate differing approaches across and among states.

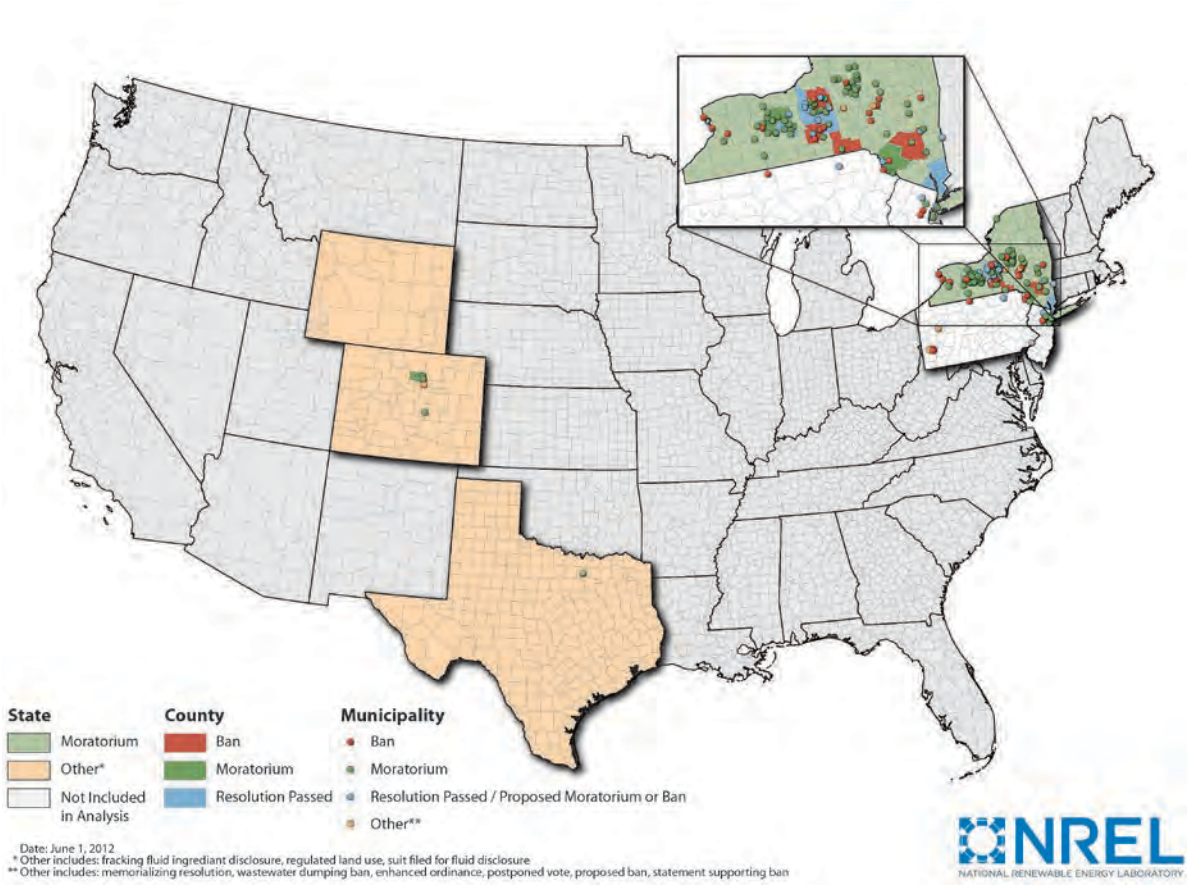

Figure 12. Variation in the rules for six states of rules covering natural gas fracking

States grappling with the issue of local control have adopted very different postures. At one end of the spectrum, Pennsylvania recently enacted legislation that places virtually all control over natural gas development in the hands of the state government.[116] This law, which went into effect April 16, 2012, elicited significant public opposition (Robinson 2012a; Robinson 2012b). A state court judge recently overturned those portions of the law restricting local governments from regulating oil and gas development on the basis that they unconstitutionally violate the substantive due process rights of local governments to enact zoning ordinances that protect the interests of neighboring property owners and neighborhood characteristics (Pellegrini 2012).

[116] Act 13 supersedes all local ordinances purporting to regulate oil and gas operations, other than those adopted pursuant to the Pennsylvania municipalities and planning code and Flood Plain Management Act and provides that "all local ordinances regulating oil and gas operations shall allow for the reasonable development of oil and gas resources." Municipalities must allow "oil and gas operations, other than activities at impoundment areas, compressor stations and processing plants as a permitted use in all zoning districts." The Act allows for the location of well pads within 300 feet of existing buildings, unless the wellhead is less than 500 feet from any existing building. Under the Act, counties may require oil and gas operators to pay impact fees ranging from $40,000 to $60,000 for the first year of production adjusted based on natural gas prices and inflation thereafter. 58 Pa. Cons. Stat. § 3218.

The Corbett Administration filed an appeal of that decision which is set to be heard by the Supreme Court of Pennsylvania on October 17, 2012.[117]

New York's approach to local control represents the other end of the spectrum. In that state, 26 localities have banned natural gas development or hydraulic fracturing altogether, two of which have been upheld as valid exercises of local zoning authority (Dryden 2012; Middlefield 2012). In addition, two bills have been proposed in New York that would allow local governments to enact or enforce laws and ordinances relating to oil, gas, and solution mining.[118]

In Colorado, the issue of local control over oil and gas drilling has become an increasingly prominent subject of discussion. Earlier this year, the Governor formed a multi-stakeholder task force to address the issue. The task force ultimately recommended "coordinated regulation through a collaborative approach…" (CDNR 2012), but what this means in practice remains to be seen. Five bills related to the topic of local control were introduced in the most recent legislative session.[119] In addition, four localities in the Front Range have moved to delay drilling pending a review of their oil and gas, land use, and public health laws; a fifth locality is currently considering a moratorium.[120] To date, the result of these reviews has been one set of final regulations issued by the City of Longmont, draft regulations issued by Boulder County,[121] and one set of operator agreements.[122] The City of Longmont finalized its ordinance in July 2012. The ordinance includes riparian and residential setbacks, disclosure requirements, water testing, wildlife protections, and a ban on drilling in residential areas.[123] Boulder County's draft revisions also contain residential and riparian setbacks, water-testing requirements, emergency response, and other measures intended to protect public health such as air-pollution controls.[124] Shortly after Longmont issued its ordinance, the Colorado Oil and Gas Conservation Commission filed a lawsuit against the City of Longmont alleging that state law preempts a

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[117] Scott Detrow, *StateImpact*, "Corbett Administration Filed Act 13 Appeal with State Supreme Court" (July 27, 2012), http://stateimpact.npr.org/pennsylvania/2012/07/27/corbett-administration-files-act-13-appeal-with-state-supreme-court/.

[118] A8557 (Aug. 24, 2011) (authorizes local governments to address natural gas drilling in their zoning or planning ordinances); A3245 (Jan. 24, 2011) (would allow local governments to enact and enforce local laws/ordinances of general applicability).

[119] SB 088, introduced Feb. 16, 2012 (would have granted COGCC exclusive jurisdiction to regulate oil and gas operations); HB 1173, introduced Feb. 6, 2012 (would have required closed-loop systems for hydraulic fracturing fluid storage/containment); HB 1176, introduced Feb. 6, 2012 (would have mandated setbacks of at least 1000 feet from any school or residence in urban areas); HB 1277, introduced Feb. 20, 2012 (would have stated that oil and gas operators would be subject to the same local government control as for other types of mineral extraction, i.e., a shared state and local approach); SB 107, introduced May 5, 2012 (contained specific requirements, such as closed-loop drilling, water reporting requirements, and the prohibition of the use of carcinogens in hydraulic fracturing fluids).

[120] As noted above, these include Boulder County, Erie, Longmont, and Colorado Springs. At the time this chapter went to publication, the town of Lafayette, Colorado, was considering a temporary ban on oil and natural gas drilling. *NGI's Shale Daily*, "Another Colorado City Considering Drilling Restrictions" (September 6, 2012).

[121] At the time this Chapter went to publication, the Boulder County Planning Commission was considering proposed Land Use Code amendments to address drilling in the County. The City of Longmont finalized its oil and gas revisions to its Municipal Code, Ordinance O-2012-25, on July 17, 2012.

[122] Copies of the agreements are available on the Town of Erie's website, http://www.erieco.gov/CivicAlerts.aspx?AID=487 (last visited September 25, 2012).

[123] City of Longmont Ordinance O-2012-25 (July 17, 2012).

[124] Boulder County, Docket DC-12-0003: Amendments to Oil and Gas Development Regulations, http://www.bouldercounty.org/find/library/build/dc120003stafrecregs20120924.pdf.

number of the purported protections including the riparian and wildlife setbacks, residential well-site ban, disclosure rule, water-testing requirements, a requirement that operators use multi-well sites, and visual mitigation measures.[125] The Oil and Gas Conservation Commission has yet to take an official position on Boulder County's regulations. Nevertheless, the Commission's suit against Longmont may indicate that the approach recommended by the Governor's Task force earlier this year will tilt in favor of state rather than local regulation, with the amount of control retained by the local governments unclear.

Local governments across all states covered in this study are also seeking to impose additional setback requirements, but the governing state law on these requirements varies by jurisdiction. Local setback requirements that are more stringent than state law exist in the Barnett Shale play, Eagle Ford play, Marcellus Shale play in Pennsylvania, and North San Juan basin. There is considerable variety in setback requirements, as well as increasing public interest in this issue. Lack of consensus regarding the appropriate distance required to protect against adverse air, noise, visual, or water pollution may, in part, explain the continuing controversy over setback requirements (CU 2012). For a comparison of specific state and local requirements, see Table 30, Appendix C, Setback Requirements.

2.5 Best Management Practices

Various commissions and reports have stressed the need for continuous improvement in industry practices, as well as industry-led organizations dedicated to developing and disseminating information on best practices (SEAB 2011b; NPC 2011; IEA 2012). Technological innovation in the effort to control and mitigate some of the resource and environmental impacts of unconventional gas development can improve efficiency, reduce environmental risk, and bolster public confidence. As in many industries, leading operators in unconventional gas development have often performed at a level over and above existing regulatory requirements, providing important sources of innovation for new practices and regulations. Notably, a handful of important regulatory developments started as best management practices adopted by leading operators.

For example, as noted above, prior to EPA's adoption of its recent NSPS for the oil and gas sector, leading companies implemented reduced-emission completions ("green completions") to increase profits by maximizing sales of natural gas from the recovery of natural gas otherwise lost to the atmosphere; others voluntarily report chemicals used in hydraulic fracturing fluids to the Groundwater Protection Council's public FracFocus website.[126] Today, a number of companies are developing methods to recycle and reuse flowback and produced waters that reduce operator costs, as well as the risks associated with other forms of disposal.[127] As discussed in the following chapter, documenting such beyond-compliance best practices is an area that merits further study.

[125] Colorado Oil and Gas Conservation Commission v. City of Longmont (filed August 30, 2012 in the Boulder County District Court).
[126] See Ground Water Protection Council Chemical Disclosure Registry, http://fracfocus.org/.
[127] See GIS Mapping Tool in Chapter 4 of this report.

2.6 Conclusion and Key Findings

The combination of hydraulic fracturing and horizontal drilling has been hailed by some as the most important energy innovation of the last century, with dramatic implications for the economics and politics of energy in the United States and throughout the world. This "disruptive" technology has fueled a boom in unconventional gas development in various parts of the United States over the last 10 years. Law and regulation (at multiple levels) have struggled to keep up with the rapid growth of the industry. And the contemporary legal and regulatory landscape that applies to unconventional natural gas development is complex, dynamic, and multi-layered.

The federal government has demonstrated a keen and growing interest in this area, as evident by the prominent role natural gas plays in the current Administration's energy policy (White House 2011), the formation of the SEAB Subcommittee, and the announcement or promulgation of a number of new rules related to air and water quality, data collection regarding the aggregate amounts of chemicals used in fracturing fluids, and development on public lands discussed above. Additional federal regulations and new legislation are also possible. The results of EPA's study on the effects of hydraulic fracturing on drinking water could play a key part in directing any such changes.

States will continue to serve as the major source of regulation, with primary responsibility for well-construction standards, disclosure requirements for hydraulic fracturing fluid chemicals and water used during well stimulation, baseline water-monitoring requirements, waste management, and overall compliance monitoring and enforcement. State and local requirements—other than disclosure requirements regarding chemicals and water usage—vary considerably, and this is likely to continue as more states revise their rules to respond to new development. Greater coordination between regulators at all levels of government could help to reduce uncertainty and fragmentation,[128] as would greater reliance on the expertise contained in organizations such as the State Review of Oil and Natural Gas Environmental Regulation and the Ground Water Protection Council (SEAB 2011a; SEAB 2011b).

State compliance monitoring and enforcement capabilities vary widely. The limited data that have been assembled indicate most violations are minor, but that "enforcement actions are sparse compared to violations noted" (Groat and Grimshaw 2012). Substantially more data and research are needed to understand the extent to which companies are complying with state, local, and federal requirements.

This information gap could begin to be filled by greater reporting, via self-certification requirements that are publicly available, as well as by state databases, searchable by the public, that contain compliance and enforcement records. These activities would also bring greater certainty to this issue.

A number of commissions and industry associations have expressed support for continued development and implementation of beyond-compliance measures (SEAB 2011b; NPC 2011; IEA 2012), and the need for such measures to avoid controversy, delay, and continued

[128] For example, BLM's recent proposed rule notes the importance of consistency in federal and state disclosure requirements and the intent to provide consistency by lining up its requirements with those adopted in leading states.

opposition in certain parts of the country. As discussed in the following chapter, more work is needed to identify and evaluate such measures. Given the rapid pace of unconventional gas development in various parts of the country, best practices will have to complement regulation—and, in some cases, be folded into it. But as the regulatory landscape evolves, it will be important to establish a framework, where possible, that incentivizes the ongoing development and adoption of new state-of-the-art practices and technologies to minimize the risks associated with developing natural gas resources.

3 Key Issues, Challenges, and Best Management Practices Related to Water Availability and Management

3.1 Introduction and Objectives

Shale gas development has several categories of potential risks including air, water, land, and community (Figure 13). Examples of air risks include emissions of GHGs (largely methane) and hazardous air pollutants (e.g., benzene). Land impact risks include ecosystem degradation and land disturbance. Related to water, the risks are either quantity related (regional water depletion) or concerns of quality (surface or groundwater contamination). Community risks include excessive truck traffic and the noise, road damage, and other associated impacts. Induced seismicity is also considered a community issue and the broadest community risk from it could be the loss of the social license to operate (e.g., Energy Institute 2012; Robinson 2012; Zoback et al. 2010.)

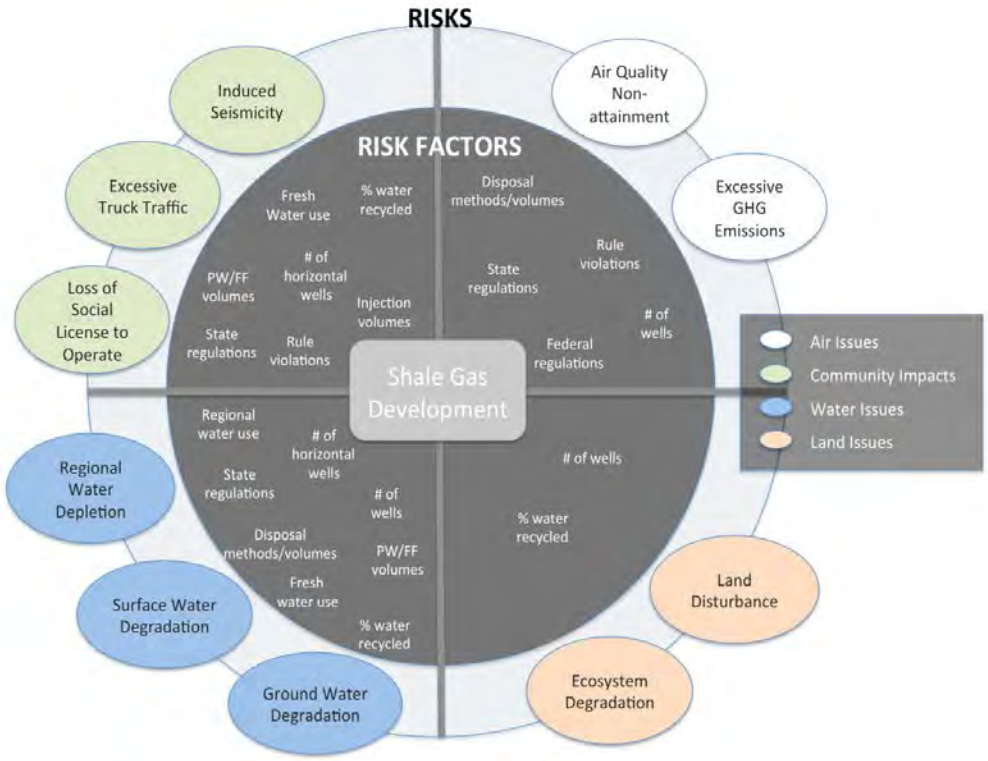

Figure 13. Description of shale gas development risks and characterization metrics

This chapter focuses on the risks and impacts of shale gas development on water resources. Ongoing improvement of the quality and quantity of water resource-related data will inform decisions related to shale gas development. Data collected in this chapter mark the beginning of the risk characterization needed to adequately define best management practices. Specifically, unconventional shale gas development might impact water resources through four major causal routes—one related to water quantity and three related to water quality.

- Water Quantity:
    - Regional water depletion due to large volumes of freshwater use for hydraulic fracturing
- Water Quality:
    - Surface and groundwater degradation resulting from inadequate construction practices and well integrity
    - Surface and groundwater degradation resulting from inadequate onsite management of chemicals used in hydraulic fracturing
    - Surface and groundwater degradation resulting from inadequate wastewater management practices

To better understand the risks to water resources from shale gas production, the variety of risk factors related to water need to be further defined and a thorough spatial and temporal characterization should be completed. The science regarding risks and impacts of the shale gas industry is relatively new and still in a state of flux (EDF 2012; IEA 2012). For this project, we approached the topic by using available literature studies, public databases, and industry interactions.

We established the following objectives to assess the risks to water resources:

- Understand the quantities of water currently being used in six shale plays in the United States as they relate to current estimates of water availability and existing water uses
- Understand the quantities of flowback and produced water for each shale play and the wastewater management techniques employed
- Identify Best Management Practices, including quantity and quality impacts and costs

To accomplish these objectives, we studied six unique natural gas producing regions of the country (as identified in Chapter 2) to capture the spatial variability of water use, water availability, and wastewater management (see Table 8). The six regions include a coalbed methane (CBM) basin (North San Juan); a vertically fractured tight sand basin (Upper Green River); three primarily dry gas shale formations (Barnett, Haynesville, and Marcellus); and one shale formation that is producing condensates and oil along with natural gas (Eagle Ford).

3.2 Importance of Water for Shale Gas Development

The recent expansion of shale gas development is, in part, due to advances in horizontal drilling and hydraulic fracturing. As shale gas development continues to grow rapidly across the U.S., the demand for water used during site operations is also expected to increase (COGCC 2012b). Drilling and fracking operations involved in shale gas development require millions of gallons of water per well that must be acquired and transported to sites to fracture the shale formations (EPA 2011). Hydraulic fracturing is essential for tight formations such as shale because the

geological structure does not have the necessary permeability to allow natural gas to flow freely through the formation and into a wellbore (Arthur 2011). The current development of unconventional shale gas would not be economically viable without hydraulic fracturing, making it important to have an adequate, dependable supply of water to support fracking operations. Equally important is preventing fracking operations from negatively affecting a region's water resources, both in terms of quantity and quality.

Water used in hydraulic fracturing comes from several sources including surface water, groundwater, municipal potable water supplies, or reused water from other water sources (Veil 2010). To date, freshwater has been used for most hydraulic fracturing operations in most regions (Nicot 2012). Surface water, such as streams, rivers, creeks, and lakes, are the largest source of fresh water for operators in the Eastern United States. Groundwater can be a feasible source of water, but only when sufficient amounts are available. In Texas, groundwater is more commonly used than surface water. Public water supply might be an alternative in some regions, because permits for surface and groundwater can take more time to secure.

The impact of water usage will depend on the availability of local water resources, which can vary regionally depending on the geographic location of the shale play, ground and/or surface water sources, and competing demands for water from other users. In locations vulnerable to droughts, operational water needs could adversely impact the viability of gas production from tight formations (Vail 2010). Droughts, particularly in water-stressed regions (such as the arid Southwest), can limit the amount of available water, increasing the competition for water between potable water supplies, water for agriculture, and water for fuel.

3.3 Assessment of Risks to Water Quantity and Water Quality

Shale gas development may incur risks to both regional water quantity and quality. Quantity-related risks depend on the number of wells drilled, water use per well, amount of recycling or non-potable water use that occurs to offset freshwater demands, and local water availability. Quality-related risks depend on onsite construction techniques, onsite chemical management practices, and wastewater management practices. Risks may vary for any given shale gas development site. In many cases, risks to water resources extend beyond the location of the well being drilled, depending on the source location of the water and where wastewater is treated. Figure 14 shows the various risks to water resources that can result from hydraulic fracturing operations.

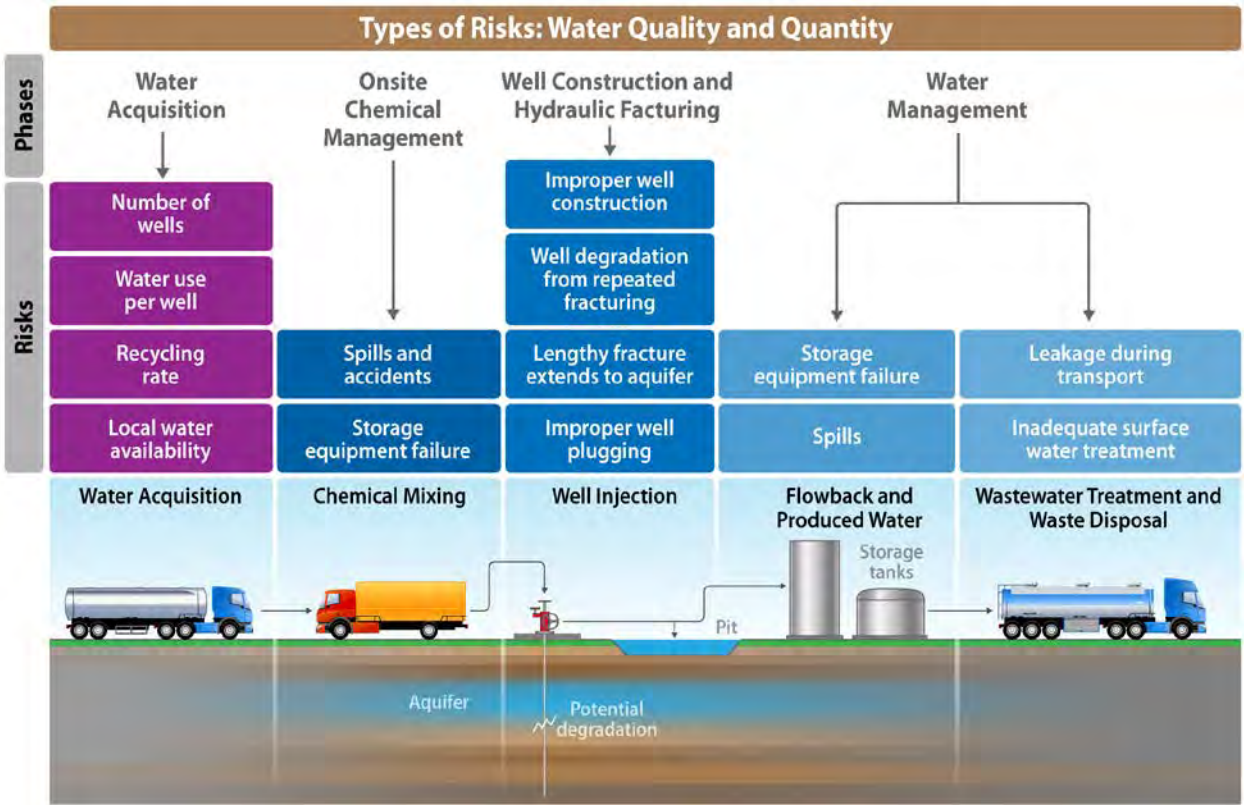

Figure 14. Water quality risks by phase of natural gas production.[129]

3.3.1 Risks to Water Quantity

3.3.1.1 Current Industry Activities Affecting Water Use

A crucial component of hydraulic fracturing is securing a sufficient amount of water for operations. Water may not always be available on the lease site; therefore, developers may have to obtain access to water from a different location and transport water to the site. In such cases, the risks to water resource quantities are assessed with respect to the water's source location, not to where it is eventually used. Where operators source their water depends on several factors, such as location, availability, timing, and cost. The closer a water source is to a well, the lower are the operational costs, whether it be pumping or transporting the water by truck.[130] In many cases, the total amount of water required for multiple operating wells (and the permits required) will be greater than local daily flows. For example, in Pennsylvania, the Susquehanna River Basin Committee (SRBC), which oversees all water source permits in the basin, has approved permits totaling 108 MGD (million gallons per day) at 151 locations (as of September 1, 2011), whereas the estimated peak daily withdrawal of those locations is only around 30 MGD. This means that freshwater impoundments might need to be constructed to collect and store water over a period of time to eventually be used to supply water for drilling and developing multiple wells (SRBC 2012).

[129] Graphic adapted from (EPA, 2011).
[130] Trucks can often have an impact on rural roads, both in terms of increased traffic and increased wear on roads. Analysis of these impacts is beyond the scope of this paper.

Total water use at a shale gas development site depends on the number of wells drilled, water use per well, and amount of recycling that occurs. The term water "use" is used in this chapter, which, in part, reflects the ambiguity of whether the water usage reported in publicly available sources represents freshwater withdrawals, use of freshwater along with recycled water, water consumption, or a combination of these categories. Future research could clarify the definitions of water usage reported by industry.

Number of wells

In the areas for which data are available, the number of producing wells drilled each year has been increasing since 2009 (Figure 15).

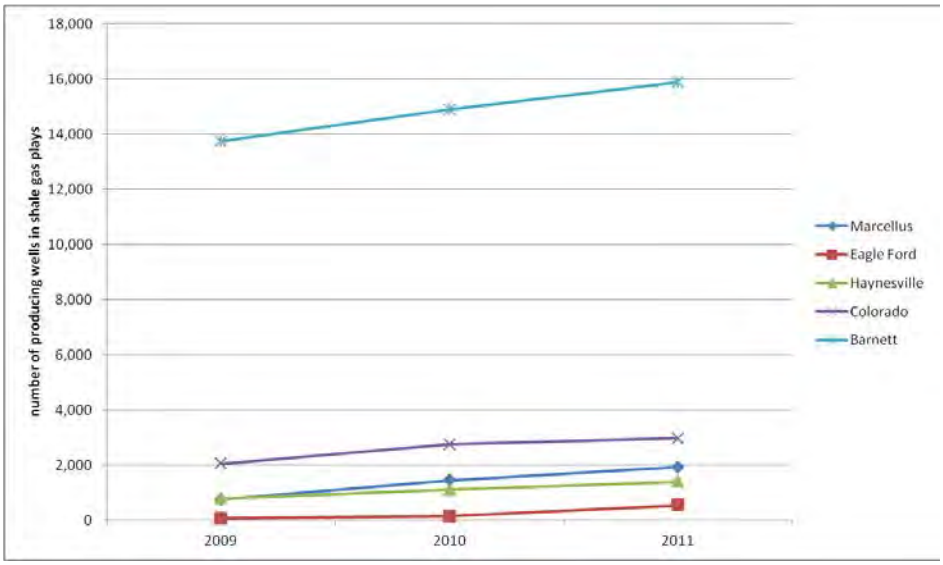

Figure 15. Total number of producing wells in shale gas plays, 2009–2011 (TRRC 2012c; COGCC 2012b; LADNR 2012; PA DEP 2012a; Eagle Ford Shale 2012).

The greatest number of wells is in the Barnett Shale formation, increasing 16% from 2009 to 2011, with nearly 16,000 producing wells (TRRC 2012c). In the other formations considered in this study, the total numbers of wells are smaller, but have been increasing faster. From 2009 to 2011, the total number of wells increased by 45% in Colorado (COGCC 2012b), 76% in the Haynesville formation (LADNR 2012), 154% in the Marcellus formation (PA DEP, 2012a), and 721% in the Eagle Ford formation (Eagle Ford Shale 2012). In all of these formations, well drilling applications have continued to increase each year, indicating a continued trend for the near future.

Water use per well

Data on the water usage per well were available for five of the six regions considered here. Data from about 100 nominal wells were randomly collected for four regions (Marcellus, Barnett, Eagle Ford, and Haynesville) from www.fracfocus.org, a voluntary online chemical disclosure registry of the water used for fracturing. FracFocus provides statewide and county-wide data. Well data are classified according to their API number, county, fracture date, operator name, well name, well type (Oil/Gas), latitude, longitude, datum, and total water use (including fresh water, produced water, and/or recycled water). Water use statistics are compiled and are displayed in Appendix D.

Average water use from the 100-well study in the five regions ranges from 1.1 to 4.8 million gallons per well, with a multi-region average of 3.3 million gallons per well (Figure 16).

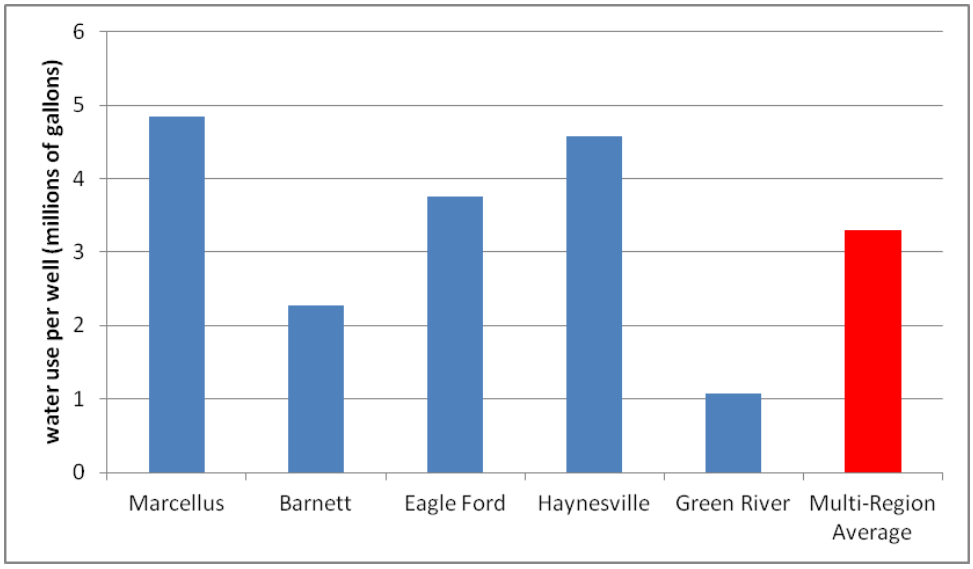

Figure 16. Average water use per well (in millions of gallons) for five regions (2011) (Fracfocus.org).

The Barnett, Eagle Ford, and Green River formations had average water uses of less than 4 million gallons per well, and the Marcellus formation had the highest average water use of 4.8 million gallons per well. Furthermore, considerable variation in water use per well within each formation is shown in Figure 17.

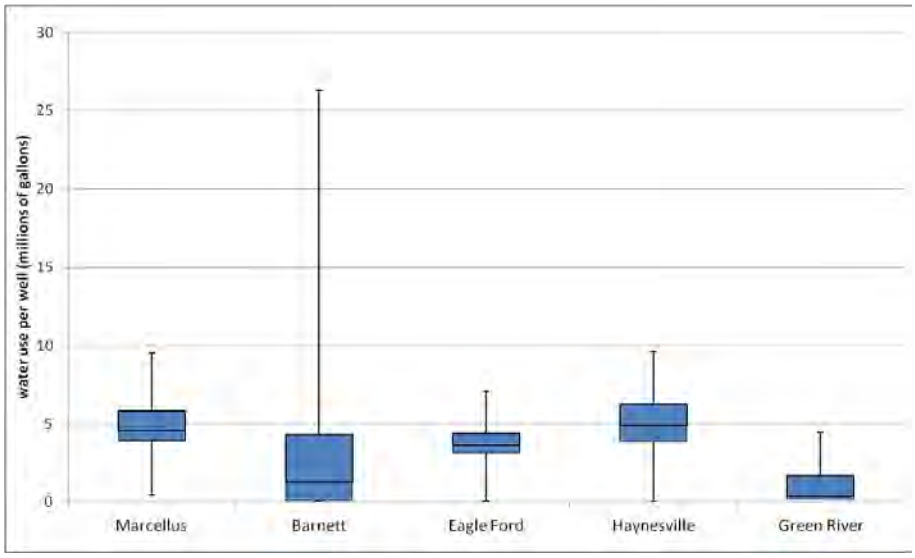

Figure 17. Water use per well for four formations, in millions of gallons. (fracfocus.org)

Note: Low and high error bars represent minimum and maximum reported water usage per wells, respectively. Upper and lower ends of boxes represent 75th and 25th percentile, respectively. Horizontal lines in boxes represent medians.

Results of the 100 well analyses indicate that water usage per well can vary by up to three orders of magnitude (29,000 gallons to 26 million gallons per well in the Barnett formation) depending on geology, type of well and drilling techniques, and industry practices. Median estimates of water usage per well are around five million gallons for the Marcellus, Eagle Ford, and Haynesville formations, yet individual wells can vary greatly. The Barnett formation has the second lowest median value of 2.3 million gallons per well, yet also the highest individual well value of 26 million gallons per well. These statistics do not indicate whether a portion of the water utilized for hydraulic fracturing includes recycled water.

Recycling rates

The impacts on local freshwater resources can be reduced by recycling produced water and frac flowback water. To use wastewater, a series of steps are commonly employed (Mantell, 2011). The water must often be stored in onsite holding tanks before treatment and is filtered or transported to another storage tank to test its remaining constituents. The water is then pumped or otherwise transported to another well location for reuse. Currently, only Pennsylvania tracks the amount of produced water and frac flowback water being recycled for reuse for drilling and hydraulic fracturing operations. Other states considered in this analysis do not have recycling or reuse as a category in their annual reporting forms, yet recycling may be occurring. In Pennsylvania, recycling of produced water has increased from 9% in 2008 to 37% in 2011 (PA DEP 2012b). In general, recycling of frac flowback water has increased from 2% in 2008 to 55% in 2011. In 2011, based on data reported, this recycling led to the reuse of about 65,000 gallons of produced water per well and 120,000 gallons of frac flowback water per well (Figure 18).

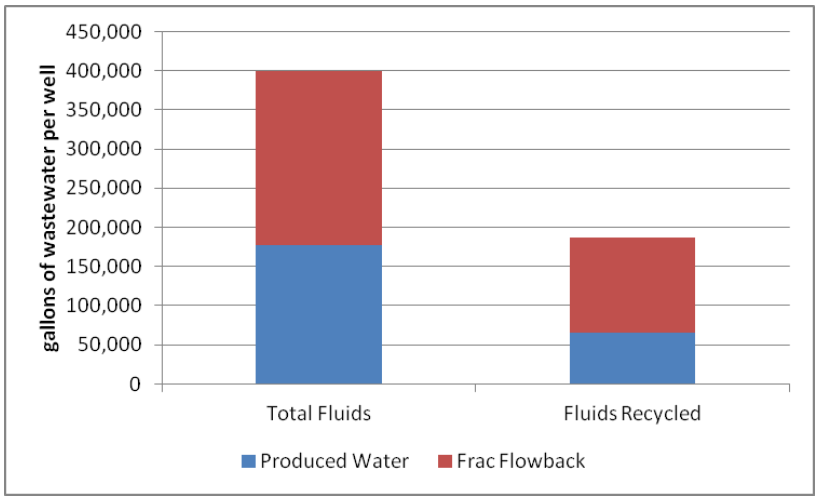

Figure 18. Wastewater production and total recycling at shale gas operations in Pennsylvania in 2011 (PA DEP 2012b)

Although data are not available for recycling rates in other formations, certain state organizations actively encourage recycling practices. The Railroad Commission (RRC) of Texas has provided authorization for seven recycling projects in the Barnett formation, five of which are still active (TRRC 2012d). No recycling authorizations have been given for the Eagle Ford or Haynesville formations to date. The Colorado Oil and Gas Conservation Commission (COGCC) actively

encourages reuse and recycling of water used in well construction as well as produced water. Although there are no data of quantities, the COGCC notes that several operators in the Piceance Basin have constructed infrastructure for reusing water for drilling and completing new wells (COGCC, 2012b).

The feasibility of recycling and reusing produced water and frac flowback depends, in part, on how much and how quickly water returns to the surface. In the Marcellus and Barnett shale formations, Chesapeake Energy reports that about 500,000 to 600,000 gallons per well will return to the surface in the first 10 days, compared to about 250,000 gallons per well in the Haynesville formation (Mantell, 2011). How much of the produced water can be recycled depends on the chemical composition of the water, including its total dissolved solids (TDS), total suspended solids (TSS), and its concentration of chlorides, calcium, and magnesium. High TDS can increase unwanted friction in the fracking process. High TSS can plug wells and decrease the effectiveness of biocides. High concentrations of other elements can lead to high risks associated with scaling.

Recycling produced water and frac flowback can partially reduce the demand for freshwater sources for new hydraulic fracturing operations. The reduction in freshwater demand is limited by the amount of water that is returned to the surface. In general, the amount of water returned to the surface—and thus, the amount of water that could be recycled—is on the order of 10% of the freshwater requirements for developing a well with hydraulic fracturing. The volumes of produced water may vary widely from well to well, making it difficult to predict how much water is produced and how much recycling potential there is for each well.

Water availability

Local water availability conditions in the six study regions can vary greatly. Further information of each shale region can be found in Appendix D. An overview of the six regions is shown in Figure 19.

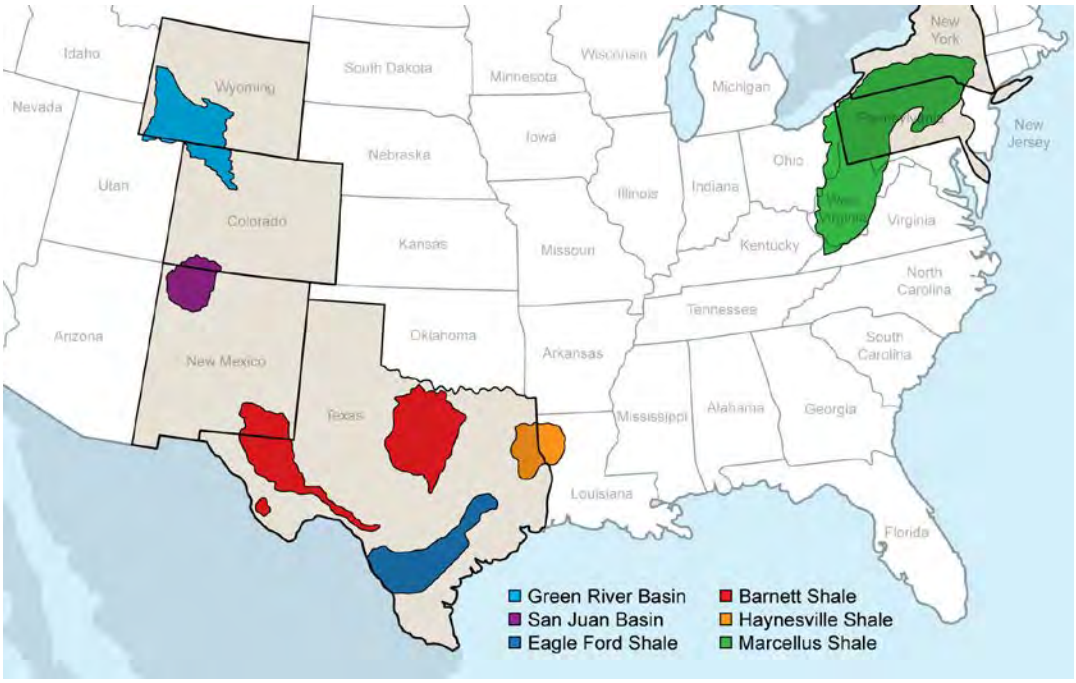

Figure 19. Six shale plays considered in this study.

Marcellus Shale, PA

The Marcellus Shale is located within or nearby highly populated areas of the northeast U.S. occupying the states of New York, Pennsylvania, Maryland, West Virginia, and Ohio. Competition for water might be challenging for shale gas development. However, the area overlying the Marcellus Shale formation has abundant precipitation, making water readily available (Arthur 2010). Three major watershed basins overlie the formation: the Susquehanna, Delaware, and Ohio River Basins are the main suppliers of water for shale gas development. The Marcellus Shale is overlain by about 72% of the Susquehanna River Basin (SRB), 36% of the Delaware River Basin, and about 10% of the Ohio River Basin (Arthur 2010). The SRB drains 27,510 square miles, covering about half the land area of Pennsylvania and portions of Maryland and New York (Arthur 2010). Major streams and rivers in the SRB are potential surface water withdrawals for shale gas development.

Texas water

Texas has dominated shale gas production in the U.S. over the past decade. The Barnett Shale was the sole producer in the early 2000s and accounted for about 66% of the U.S. shale gas production from 2007 to 2009 (Nicot 2012). Texas is subject to drought and wet period cycles that might become extreme with climate change and impact the water available. Water requirements are reported to the RRC of Texas. Surface water is owned and managed by the State and requires a water-right permit for diversions. Groundwater is owned mostly by landowners, but is generally managed by legislatively authorized groundwater conservation districts (Nicot 2012). Groundwater is generally available in each of the shale gas plays, and unlike surface water, groundwater is located close to production wells.

Barnett Shale, TX

The Barnett Shale is located in central Texas around the Dallas-Ft. Worth area. Precipitation is variable across the state of Texas. The mean annual precipitation in the Barnett area is about 790 mm per year (Nicot 2012). About 60% of the water used in hydraulic fracturing operations in the Barnett Shale play comes from groundwater sources, specifically the Trinity and Woodbine aquifers in North Central Texas (Andrew et al. 2009). The Trinity Aquifer extends from south-central Texas to southeastern Oklahoma, and groundwater use varies across the Barnett Shale development area. For example, groundwater provides about 85% of total water supply in Cooke County, but only 1% for Dallas County (Andrew et al. 2009). Extensive development of the Trinity Aquifer in the Dallas-Ft Worth metropolitan area had caused groundwater levels to drop more than 500 feet in some areas (Andrew et al. 2009). For many rural areas, groundwater from the Trinity Aquifer remains the sole water source. Water use can vary widely from county to county depending on the pace of shale gas development. Municipal water use is dominant (greater than 85%) in the footprint of the Barnett Shale play in Denton and Tarrant counties; elsewhere, water use is mixed with some irrigation and manufacturing (Nicot 2012). Surface water is available in the Barnett Shale area, including major rivers and reservoirs; however, population growth is expected to increase demand for water resources and cause increasing competition. It is predicted that the net water use for shale gas production in the Barnet Shale play will increase from 1%–40% at the county level for selected counties (Nicot 2012).

Eagle Ford Shale, TX

The Eagle Ford Shale play is located in South Texas. The mean annual precipitation in the Eagle Ford Shale is about 740 mm per year (Nicot 2012). Surface water in the Eagle Ford Shale region is not as readily available and abundant as the northeast sections of Texas. A small portion of the Rio Grande River at the Mexican border is used, and several streams are ephemeral and recharge underlying aquifers. However, even when surface water is available, it is often not located adjacent to sites; therefore, trucking and piping of water is often required. Operators rely mostly on groundwater from the Carrizo Aquifer, though groundwater has already been partially depleted for irrigation in the Winter Garden region of South Texas (Nicot 2012). Over-extraction of groundwater for irrigation in the past limits water availability for current and future shale gas production (Nicot 2012). Water used in south Texas is variable; municipal water use is dominant (greater than 85%) in the footprint of the Eagle Ford in Web County (Nicot 2012). It is predicted that during the peak years of production, the net water use for shale gas production in the Eagle Ford Shale region will increase from 5% to 89% at the county level for selected counties (Nicot 2012).

Haynesville Shale, LA

The Haynesville Shale is located in East Texas and western Louisiana. The eastern part of Texas has high precipitation, with a mean annual precipitation of 1,320 mm per year, resulting in a widespread and abundant supply of surface water (Nicot 2012). The region also hosts large aquifers, specifically, the Carrizo Wilcox and Queen City/Sparta Aquifers. Shale gas production in Louisiana relies heavily on local groundwater from the Carrizo Aquifer and currently derives about 75% of the water from surface water or lesser-quality shallow groundwater (Nicot 2012). The groundwater is more readily available in East Texas, with the only competition for water use being industrial and municipal demands (Nicot 2012). Furthermore, it is predicted that during the

peak years of production, the net water use for shale gas production in the Haynesville Shale region will increase from 7% to 136% at the county level for selected counties (Nicot 2012).

San Juan Basin, CO

The San Juan Basin is located in the arid Southwest U.S., occupying the Four Corners area of Colorado, New Mexico, Arizona, and Utah. The basin is characterized by a wide range of topographic settings that include valleys, canyons, badlands, uplands, mesas, and buttes (Haerer 2009). Precipitation in the San Juan Basin varies regionally. Annual precipitation in the high mountain areas in Colorado can receive as much as 1,020 mm per year, whereas annual precipitation in lower altitudes of the central basin in New Mexico can receive less than 200 mm per year (Levings 1996). Runoff water from snow and precipitation, which flows into rivers such as the San Juan River, makes up a large portion of the surface water. However, because of high evaporation rates and the hot and dry climate of the Southwest, surface water in the basin is limited and has already been fully appropriated.

Thus, groundwater resources tend to be the only source of water in most of the basin, and they are used mainly for municipal, industrial, domestic, and stock purposes (Levings 1996). The San Juan structural basin is a major oil and gas producing area, and groundwater is produced as a byproduct of these operations (Levings 1996). Several major aquifers exist in the basin; most are unconfined and located within the Tertiary formations (Haerer 2009). The amount of available water varies, depending on the underlying geological rock formations. For example, the Fruitland Formation and Pictured Cliffs Sandstone are aquifers that are sources of drinking water along the northern margin of the basin and act as a single hydrologic unit. The Ojo Alamo Sandstone is the primary aquifer for the southern margins and is a possible source of groundwater (EPA 2004). Groundwater levels in the Fruitland Formation have declined significantly due to the development of energy resources in the San Juan Basin (Levings 1996).

Green River Basin, WY

The Green River Basin is located in the southwest corner of Wyoming, northwest Colorado, and northeast Utah. The basin drains to the Green River, a major tributary to the Colorado River. On average, the basin receives about 250–400 mm of precipitation annually and less than 13% of the basin receives more than 500 mm (WWDC 2010). Precipitation is highest during the months of April and May and the least in December and February. There are four regional aquifer systems in the Wyoming side of the Green River Basin. The Cenozoic, Mesozoic, Paleozoic, and Precambrian aquifer systems range from the youngest and most heavily used to the oldest and least used, respectively (WWDC 2010). There has been relatively little development of groundwater resources in the Green River Basin, and the recent increase in shale oil and gas development has relied on groundwater resources as the primary supply to the industry. In Wyoming, irrigated agriculture is the largest water consumer. However, the energy and mineral sectors have historically added volatility in water use and allocation, requiring large amounts of water (WWDC 2010). Groundwater in the basin is used for domestic and pubic supplies, and industrial uses including mining and irrigation. Oil and gas development has increased substantially in the Green River Basin and accounts for a large part of the increase in groundwater use (WWDC 2010).

3.3.1.2 Current Water Quantity Risks Resulting from Industry Activities

Risks to water quantity resulting from industry practices in shale gas development include reductions in both available surface water and groundwater. These risks occur in the areas from which water resources are sourced, not necessarily the hydraulic fracturing site. In areas where the levels of the groundwater table are already affected by multiple sectors' uses (e.g., agriculture, municipal water supply), large increases in use by any sector might affect water availability or the cost of pumping for all other users.

The water quantity risk to any given water basin depends on how much water is used and on the local water availability. Water usage in shale gas development, as described above, depends on the total number of wells, water use per well, and recycling rate. Water availability depends on local geologic and climatic conditions and on competing users of water. In the study regions, the total number of producing wells has been increasing steadily since 2008. With the exception of Pennsylvania, there are no data indicating a substantial increase in the recycling rate of wastewaters, and the total quantities of freshwater used for hydraulic fracturing have been increasing. The impact of recycling on reducing freshwater demands is limited by the amount of flowback and brine produced from each well. The use of non-freshwater sources, such as shallow brackish waters, could alleviate demands on freshwater; but there are no readily available data on availability or current usage of these water sources for shale gas operations.

Values of total water available physically and legally can be difficult to quantify, but our report analyzes the water usage of oil, gas, and mining activities as a percentage of all other existing water uses. On a state level, the amount of water currently withdrawn for hydraulic fracturing is a relatively minor fraction of total water withdrawals. In Colorado for example, total water diversions for hydraulic fracturing represent only 0.1% of all water diversions in the state (COGCC 2012b). In Texas, mining activities, which include hydraulic development, accounted for just 2% of total water withdrawals in 2011 (TDWB 2012).In Texas and Colorado, irrigation accounts for more than 55% and 85%, respectively, of total water withdrawals (COGCC 2012b; TDWB 2012).

Greater insights into risks to water resources can be gained by analysis on a geospatial scale smaller than the states, such as the county level. In many counties where shale gas development sites are located, mining activities already account for a substantial percentage of existing water usage (Figure 20) (Kenny et al. 2009).

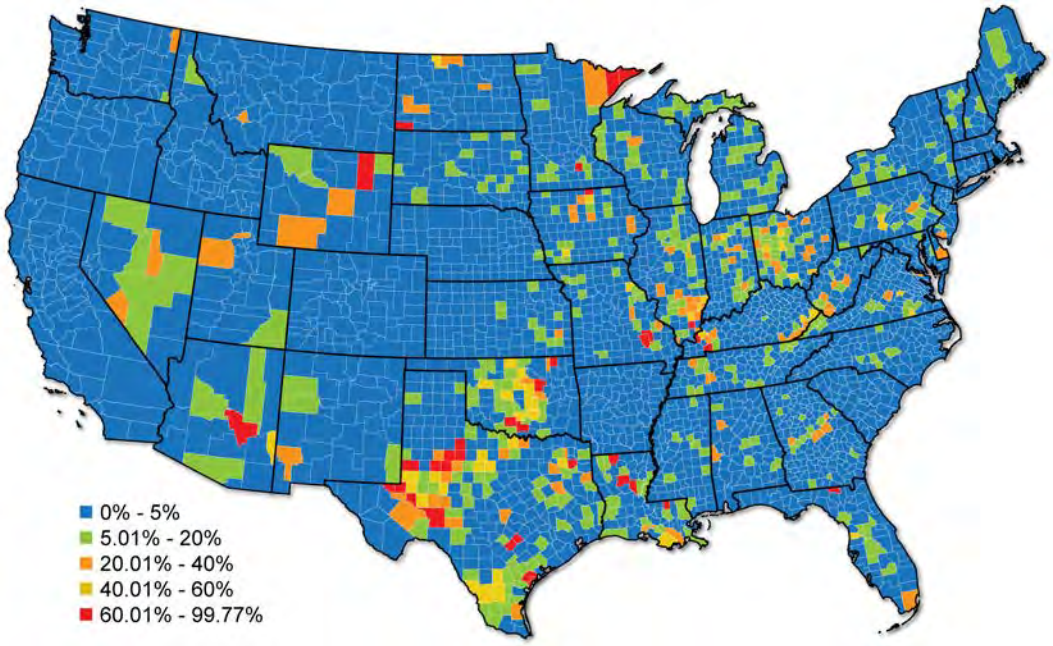

Figure 20. Mining water withdrawals as a percent of total water withdrawals, 2005 (Kenny 2009).

In 2005, mining activities in Texas counties that overlapped with the Barnett, Eagle Ford, and Haynesville formations accounted for a large percentage of total water withdrawals. Similarly, counties in Louisiana overlapping with the Haynesville formation, counties in New Mexico overlapping with the Barnett and San Juan formations, and counties in Wyoming overlapping with the Green River formation show that mining activities account for water withdrawals representing 5% to over 60% of total withdrawals in that county. Thus, water use for mining activities already represents a substantial portion of total water usage in the regions where shale gas development is occurring. Rapid expansion of water required for hydraulic fracturing could impact local water availability, depending on water resources in each region. Further research is needed to evaluate the impact that the current and projected water use for mining activities, including hydraulic fracturing, could have on the water resources and other water demands in these regions.

3.3.2 Risks to Water Quality

3.3.2.1 Current Industry Activities Affecting Water Quality

Risks to water resources depend on well and drilling construction practices, handling of chemicals on site, and wastewater management. Risks to water quality can occur at both the location of hydraulic fracturing and where water is stored or treated.

Onsite well-construction and hydraulic fracturing practices

In terms of risk to water resources, well design and construction phase is a crucial component of the hydraulic fracturing process. Proper well construction can separate the production operations from drinking water resources. Well construction involves drilling, casing, and cementing—all of which are repeated multiple times until a well is completed. Drilling is conducted with a drill bit, drill collars, drill pipe, and drilling fluid such as compressed air or a water- or oil-based liquid (EPA 2011). Water-based liquids typically contain a mixture of water, barite, clay, and

chemical additives (OilGasGlossary.com 2010). Once removed from the well, drilling liquids and cuttings must be treated, recycled, and/or disposed of.

Casing is steel pipe that separates the geologic formation from the materials and equipment in the well, and that also provides structural support. The casing is designed to withstand the external and internal pressures during the installation, cementing, fracturing, and operation of the well. Some operators might forego casing, in what is called an open-hole completion, if the geologic formation is considered strong enough structurally to not collapse upon itself. Casing standards vary regionally and are set by state regulations. Once the casing is in place, a cement slurry is pumped down the inside of the casing and forced between the formation and the casing exterior. The cement serves as a barrier to migration of fluids up the wellbore behind the casing, as well as a structural support for the casing. The cement sheath around the casing and the effectiveness of the cement in preventing fluid movement are the major factors in establishing and maintaining the mechanical integrity of the well; however, even a properly constructed well can fail over time due to stresses and corrosion (Bellabarba et al. 2008). For a given well, there may be multiple levels of drilling, casing, and cementing to prevent contamination of local water resources (Figure 21).

Once the well is constructed, the formation is hydraulically fractured. The hydraulic fracturing occurs over selected intervals where the well is designed to permit fluids to enter the formation. Hydraulic fracturing fluids, by volume, are mostly water and propping agents such as sand, designed to facilitate the fracturing and keep the new fractures open.

The chemicals present in hydraulic fracturing fluids can react with naturally occurring substances in the subsurface, causing these substances to be liberated from the formation (Falk et al. 2006; Long and Angino 1982). These naturally occurring substances include formation fluids (brine), gases (natural gas, carbon dioxide, hydrogen sulfide, nitrogen, helium), trace elements (mercury, lead, arsenic), radioactive materials (radium, thorium, uranium), and organic materials (organic acids, hydrocarbons, volatile organic compounds).

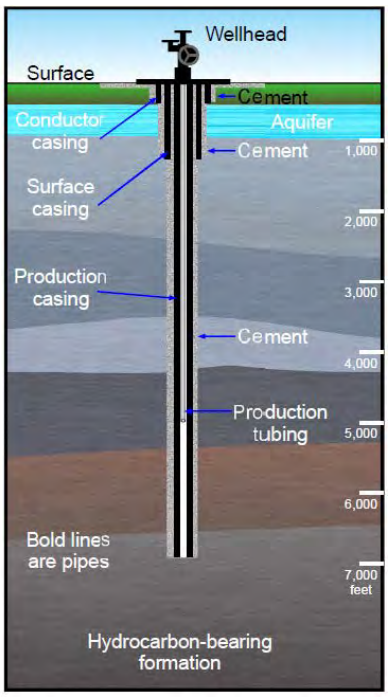

Figure 21. Schematic of well that includes several strings of casing and layers of cement (EPA 2011)

Once a well is no longer producing gas economically, it can either be re-fractured or plugged, to prevent possible fluid migration that could contaminate soils or waters (API 2009). A surface plug is used to prevent surface water from seeping into the wellbore and migrating into groundwater resources.

Onsite handling of chemicals

The chemicals used in fracking fluids are often mixed together on site with the propping agent (usually sand) and water. The types of chemicals and their volumes might vary from site to site and from developer to developer, depending on formation properties and developer common practices. Chemicals are stored on site in tanks before mixing and hydraulic fracturing operations begin. In general, 0.5% to 2% of the total volume of fracking fluid is made up of chemicals (GWPC and ALL Consulting 2009). The composition and relative amounts of chemicals might change from site to site. Table 6 provides an example of the variety and amounts of chemicals that comprise fracking fluid, where chemicals contribute 0.5% of the volume.

Table 6. Example Composition of Hydraulic Fracturing Fluids (GWPC and ALL Consulting 2009; API 2010)

Component	Example Compounds	Purpose	Percent Composition (by Volume)	Volume of Component (Gallons)[131]
Water		Deliver proppant	90	2,970,000
Proppant	Silica, quartz sand	Keep fractures open to allow gas flow out	9.51	313,830

[131] Based on the average water use per well identified in this study, 3.3 million gallons

Component	Example Compounds	Purpose	Percent Composition (by Volume)	Volume of Component (Gallons)[131]
Acid	Hydrochloric acid	Dissolve minerals, initiate cracks in rock	0.123	4,059
Friction Reducer	Polyacrylamide, mineral oil	Minimize friction between fluid and pipe	0.088	2,904
Surfactant	Isopropanol	Increase viscosity of fluid	0.085	2,805
Potassium Chloride		Create a brine carrier fluid	0.06	1,980
Gelling Agent	Guar gum, hydroxyethyl cellulose	Thicken fluid to suspend proppant	0.056	1,848
Scale Inhibitor	Ethylene glycol	Prevent scale deposits in pipe	0.043	1,419
pH Adjusting Agent	Sodium carbonate, potassium carbonate	Maintain effectiveness of other components	0.011	363
Breaker	Ammonium persulfate	Allow delayed breakdown of gel	0.01	330
Crosslinker	Borate salts	Maintain fluid viscosity as temperature increases	0.007	231
Iron Control	Citric acid	Prevent precipitation of metal oxides	0.004	132
Corrosion Inhibitor	N,N-dimethyl formamide	Prevent pipe corrosion	0.002	66
Biocide	Glutaraldehyde	Eliminate bacteria	0.001	33

In this example, we consider the average water use per well as identified in this study to be 3.3 million gallons. Therefore, the total volume of chemicals used—0.5% of the fracking fluid volume—is about 16,500 gallons per well. The total average volume of chemicals used in hydraulic fracturing fluids ranges from 5,500 to 96,000 gallons per well, given the wide range of water use per well, in addition to the chemical composition (Table 7).

Table 7. Estimates of Total Gallons of Chemicals Used per Well

	4.6 million gallons per well (average estimate)	2.3 million gallons per well (low estimate)	7.3 million gallons per well (high estimate)
Lower bound of chemical composition (0.5% of volume)	16,500 gallons	5,500 gallons	24,000 gallons
Upper bound of chemical composition (2.0% of volume)	66,000 gallons	22,000 gallons	96,000 gallons

Wastewater management practices

After hydraulic fracturing operations, pressure decreases and fluids return to the surface before the well begins formal gas production. Although there are no standardized definitions, the used fracking fluids (frac flowback) and naturally occurring water resources (produced water) both return to the surface. In general, the frac flowback returns first at high rates (e.g., ~100,000 gallons per day) for a few days; then produced water surfaces at lower rates for the remainder of the well's lifetime (e.g., ~50 gallons per day). The rates of production and total volumes of frac flowback and produced water vary greatly within and between shale plays—ranging from 10% of original fracking fluid volume to as high as 75% (EPA 2011). Frac flowback and produced water both contain naturally occurring substances, including oil, gas, radionuclides, volatile organic compounds, and other compounds that could contaminate local water resources.

Frac flowback and produced water are stored on site in storage tanks or impoundment pits prior to treatment, recycling, and/or disposal (GWPC 2009).Onsite impoundments can be designed for short-term use (for storage purposes) or for long-term use (evaporation pits), and impoundment regulations and requirements can vary greatly by location.

Operators have a variety of options for managing wastewaters, including recycling and reusing, onsite evaporation in impoundments, onsite injection into wells, disposal at a centralized facility through evaporation or underground injection, and treatment through surface water treatment plants. Overall, national disposal methods are dominated by underground injection (EPA 2011). Current industry practices might vary from state to state, and have shown different trends from 2008 to 2011. For example, Colorado (Figure 22) and Pennsylvania (Figure 23) show stark differences and trends.

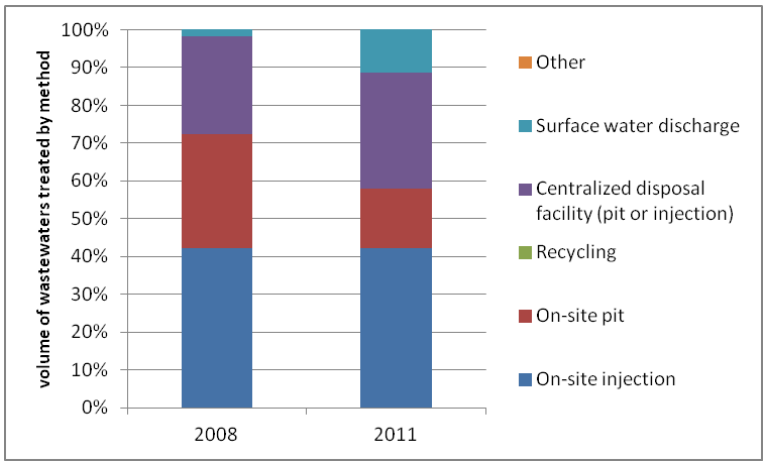

Figure 22. Colorado wastewater treatment methods, 2008–2011 (COGCC 2012a)

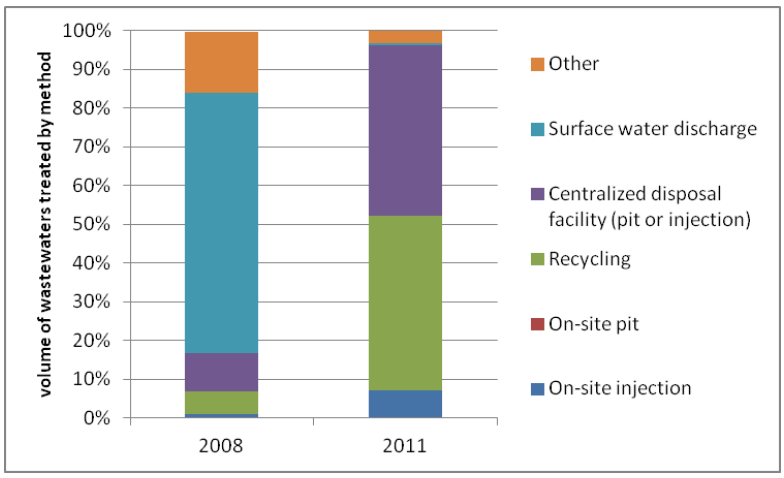

Figure 23. Pennsylvania wastewater treatment methods, 2008–2011 (PA DEP 2012b)

In Pennsylvania, surface water treatment decreased from 67% of total wastewater volumes in 2008 to less than 1% in 2011 (PA DEP 2012b). In contrast, in Colorado, surface water treatment increased from 2% of total wastewater volumes in 2008 to 11% in 2011 (COGCC 2012a). In Pennsylvania, recycling increased from 6% of total wastewater volumes in 2008 to 45% in 2011, whereas there are no data indicating any recycling occurring in Colorado. The dominant disposal method in Colorado remains injecting or evaporating wastewater fluids on site. Onsite disposal methods decreased in Colorado, managing 72% of total wastewater volumes in 2008 to 58% in 2011. In Pennsylvania, onsite well injection increased from 1% of total wastewater volumes in 2008 to 7% in 2011. Both states increased their use of centralized industrial disposal facilities between 2008 and 2011. In Pennsylvania, the use of centralized disposal facilities increased from 10% of total wastewater volumes in 2008 to 44% in 2011. In Colorado, the use of centralized disposal facilities increased from 26% of total wastewater volumes in 2008 to 31% in 2011.

Water disposal methods can change from year to year due to evolving regulations and industry experience. Data from 2008 showed a high percentage of surface water discharge for wastewaters in Pennsylvania; after 2008, there was a sharp decline. This is due to the changes to the Pennsylvania Department of Environmental Protection's (DEP) 25 Pa Code Chapter 95 Wastewater Treatment Requirements. These requirements were changed on April 11, 2009, after total dissolved solids levels were measured far above environmentally healthy levels in 2008 and 2009 (STRONGER, 2010). The high TDS was above drinking water standards in the Monongahela River. The TDS also promoted golden algae growth, resulting in higher toxicity levels in Drunkard Creek, killing over 30 different species of aquatic life. The new regulations required a maximum TDS discharge of 500 mg/L (STRONGER, 2010). This new regulation makes it uneconomical to use municipal water treatment in Pennsylvania because wastewaters can reach up to 360,000 mg/L TDS (USGS 2002b). In addition, injection has remained relatively unfavorable in Pennsylvania because the state has only eight Class II underground injection wells, three of which are commercially owned. The other injection wells are privately owned and only service the companies that own them (Phillips 2011).

Recycling operations can be more expensive than other waste management options. Recycling and reuse of water involves energy for treatment, and costs associated with storing water, transport of water, and transport and disposal of the solid wastes removed from the treated water.

In contrast, injecting wastewater into wells only involves the transport of water to an injection well and fees for the disposal. Recycling options can also be limited by high concentrations of materials that make recycling uneconomic.

3.3.2.2 Current Water-Quality Risks Resulting from Industry Activities

Risks to public water quality resulting from industry practices include risks to both surface water and groundwater sources, and they are not limited to the location of the hydraulic fracturing operation. Risks to surface and groundwater resources exist at each stage of development—well construction and hydraulic fracturing operations, chemical handling, and wastewater management.

Improper well construction or improperly plugged wells are one source of risk by which groundwater contamination can occur (PA DEP 2010b; McMahon et al. 2011). In addition to risks associated with construction integrity, risks are also associated with well durability for wells that are repeatedly hydraulically fractured. The potential exists for fracking fluids, as well as other naturally occurring substances, to reach groundwater sources if well construction or plugging operations are inadequate. The degree of risk will be dependent upon local geology, the composition of the chemicals and naturally occurring substances, and the mobility of the substances within the formation.

Another source of risk during the hydraulic fracturing operation in coalbed methane (CBM) reservoirs is the potential for the fractures to extend into aquifers or into pre-existing faults or fractures (natural or man-made) that might directly extend into aquifers. Currently, it is difficult to predict and control fracture location and lengths, and the overall risk will depend on the local geology and fracking practices used. In shale gas formations, decreasing pressure gradients and natural barriers in the rock strata serve as seals for the gas in the formation and also block the vertical migration of frack fluids (GWPC and ALL Consulting 2009). In contrast, CBM reservoirs, such as the North San Juan considered here, are mostly shallow and may also be co-located with drinking water resources. In CBM areas, hydraulic fracturing operations near a drinking water source might raise the risk of contamination of shallow water resources from hydraulic fracturing fluids (Pashin 2007; EPA 2011).

Another risk to water quality is the handling and mixing of chemicals on site. Risks include spills or leaks that might result from equipment failure, operational error, or accidents. Leaked chemicals could be released into bodies of surface water or could infiltrate groundwater resources. There have been reports of surface spills of hydraulic fracturing fluids; however, little is known about the frequency, severity, and causes of these spills (Lustgarten 2009; Lee 2011; Williams 2011). The risks to local water resources will depend on the proximity to water bodies, the local geology, quantity and toxicity of the chemicals, and how quickly and effectively clean-up operations occur.

Wastewater management practices have risks to water quality that potentially affect water resources both on and off site of the location of the shale gas development operations. Considering risks on site, spills of frac flowback or produced water could contaminate local surface and/or groundwater resources. In addition, there could be equipment failures (e.g., poorly constructed impoundments) during onsite wastewater storage prior to treatment. Potential offsite risks include spills or leakage that might occur during the transport of wastewaters to the location

where they will be treated. If surface water treatment is used, there is a risk of the surface water treatment plant not having the capabilities to fully treat the wastewater before it is released back into the hydrologic cycle (Puko 2010; Ward Jr. 2010; Hopey 2011).

From 2009 to 2011, Pennsylvania had 337 reported violations that were classified as “minor effect” or “substantial effect” (NEPA 2012). Violations of these types include the release of wastes or produced water on site in amounts less than 10 barrels (420 gallons). From 2009 to 2011, Texas had 14 reported “minor effect” or “substantial effect” violations, and one reported “major effect” violation. “Major effect” violations include large spills or improperly disposed of wastes greater than 10 barrels (420 gallons), small to large spills that were moved off site and impacted a resource such as a drainage ditch or wetland, and any spill of fracturing fluid greater than 1 barrel (42 gallons). For Colorado, the only publicly accessible statistics related to violations are Notices of Alleged Violations (NOAVs). The number of NOAVs does not represent the number of violations because violations do not necessarily lead to the issuance of NOAVs. Also, when NOAVs are issued, they may cite violations of more than one rule, order, or permit condition. Colorado violations could not be acquired, and data for violations in other states were not available. More detailed information about violations in states where data are available is listed in Appendix D. Further research is needed to fully determine the severity and cause of the reported violations.

3.4 Data Availability and Gaps

Substantial gaps in data availability prevent a full assessment of risks to water resources resulting from shale gas operations. Only certain statistics are publicly available for each region, and in some regions that cross state boundaries, information is only available for the part of a play that is in one state (Table 8.)

Table 8. Overview of Data Availability

		CO	NM	PA	NY	TX	TX	LA	WY
	Risk Factor or Analysis Metric	**North San Juan**	**North San Juan**	**Marcellus**	**Marcellus**	**Barnett**	**Eagle Ford**	**Haynesville**	**Upper Green River**
1	Disposal methods/volumes	◊		◊	◊				^
1a	Fraction of water recycled	◊		◊					
2	Fresh water use	^	^	◊		^	^	◊	^
2a	*Fracturing water*	◊		◊		◊	◊	◊	◊
2b	*Source permitting*	^		◊		^	^	^	^
3	PW/FF volumes	◊		◊		^	^	^	
3a	*Injected volumes*	◊				^	^	◊	◊
4	State regulations					◊			
4a	*Rule violations*			◊					
5	Regional water use			◊					
6	Total wells			◊		^	◊		
6a	*% Horizontal*			◊			◊		
Key									
◊	Data available								
^	Partial data available								

Comprehensive analyses of water risks are hindered by a lack of reliable, publicly available water usage and management data. Data are not publicly available for many regions for total water withdrawals, total wells drilled, water recycling techniques, wastewater management, and other management practices. These data would assist in developing appropriately flexible and adaptive best management practices. Certain resources—such as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and FracFocus—have greatly increased public access to information about risks of hydraulic fracturing; but further efforts are desired. Data collection and availability could improve with further collaboration and interaction with industry stakeholders, as well as other stakeholders.

3.5 Best Management Practices (BMP)

Various attempts have been made to define best practices for water management (e.g., IEA 2012; Energy Institute 2012; ASRPG 2012; Chief O&G 2012; SEAB 2011; API 2010). Based on these reports, the following are best practices that are generally accepted to be important for understanding and minimizing risks related to water quantity and quality:

3.5.1 Monitoring and Reporting

- *Measure and publicly report the composition of water stocks and flow throughout the fracturing and cleanup process.* There is little information on the management of fracturing water from acquisition to disposal or recycle, both in terms of quality and quantity.

- *Adopt requirements for baseline water-quality testing.* Background testing is recognized for its value, but is often not standardized. Better guidance is needed for statistically defensible testing.
- *Fully disclose hydraulic fracturing fluid additives.* Disclosure of fracturing fluid chemicals on fracfocus.org is now in place in Colorado, Wyoming, and Texas and is being considered in several other states.

3.5.2 Water Quantity

- *Recycle wastewaters.* Freshwater demand can be minimized by treatment and reuse of produced water and frac flowback. Flowback water produced in the hydraulic fracturing process is returned at relatively high flows and might contain more chemicals of concern than produced water. Optimized handling of this fluid is important for mitigating risks to water quality and quantity because it can lessen the need for transport and wastewater disposal.

3.5.3 Water Quality

- *Use a closed-loop drilling system.* In closed-loop drilling processes, contaminated water is not exposed to air or pits where it could leak, thus eliminating the storage of discarded drilling fluids in open pits at the drilling site.
- *Eliminate flowback water mixing with fresh water in open impoundments.* Disposing of untreated flowback water in reservoirs containing fresh water to be used for hydraulic fracturing increases the risk of harmful spills or leaks.
- *Use protective liners at pad sites.* The use of liners or other protective devices at pad sites can contain minor spills and prevent environmental contamination. Proper collection and disposal equipment is also important to have on site.
- *Minimize use of chemical additives and promote the development and use of more environmentally benign alternatives.* "Green" hydraulic fracturing fluid has been developed—based on fluid mixtures from the food industry—that do not impair groundwater quality in the case of an inadvertent leak or spill.

A next step in developing BMPs for reducing risks to water resources in shale gas development is to evaluate the efficacy of each of the above BMPs (Kemp 2012; Energy Collective 2012). Currently, little or no data exist that analyze the effectiveness or cost-benefit tradeoffs of these BMPs. Further examination of BMPs could assist developers in evaluating important water management questions—such as whether installing protective liners at pad sites or reducing use of chemical additives would have a greater impact on reducing risks to water resources in their regions. A first step in this direction would be to develop a methodology for quantifying and comparing current water-management practices with potential risks.

In many cases, BMPs might be more appropriate or cost-effective for certain geological conditions than others. A further area of needed research is to evaluate the extent to which certain BMPs are applicable or effective across multiple types of formations. To better address this question, researchers could engage a variety of stakeholders—including industry, regulators, researchers, environmental groups, and the public—to understand what practices are currently in use, how effective they are at reducing the risk of water impacts, and where improvements are needed.

A major challenge facing some of these BMPs is that there are no national or state-level disclosure initiatives to track or evaluate the success of their implementation. For example, it is difficult to determine how many operators are currently employing (and with what success) the widely discussed BMP to use closed-loop drilling practices because operators are not required to report this information. Absent such reporting, data collection efforts would likely require close collaboration with multiple industry partners operating in a variety of locations, and this could be time-intensive.

3.6 Summary

We used publicly available datasets to provide an initial evaluation of water risks associated with hydraulic fracturing in six natural gas plays in the United States. Data were limited in every region; continued efforts to catalogue and publish water data will improve future analyses.

Hydraulic fracturing operations have the potential to impact water resources. One of the impact risks associated with water is regional resource depletion due to the use of fresh water during hydraulic fracturing. Water-use data were collected for five of the six regions with average use per well ranging from 1.1 to 5.8 million gallons, with a multi-region average of 3.3 million gallons per well. Total water usage can be estimated by determining the average water use per well, number of wells, and recycling rate; this total freshwater demand value can be compared with estimates of local water availability. Hydraulic fracturing demands are a small fraction of total state water demands, but they can be a substantial portion of water demands in the counties in which the hydraulic fracturing operations are active. If water must be transported from off site to a hydraulic fracturing site, water quantity risks might extend to counties where hydraulic fracturing is not occurring. In all regions considered, the number of wells drilled for hydraulic fracturing has increased each year since 2009. Recycling rates have increased significantly in Pennsylvania since 2009, when the state issued new regulations regarding the treatment of wastewaters.

A second impact risk associated with water is degradation of surface and groundwater quality. Water-quality impacts are a risk during the well construction, hydraulic fracturing, mixing of chemicals, and the wastewater management of shale gas development. As noted above, hundreds of substantial or major violations have been reported that have resulted in spills of produced water, frack fluids, or chemicals. However, it is not clear if water resources have been contaminated—and if so, to what extent—or by which pathway the spills occurred.

A better understanding of the potential contamination pathways (listed here) and their impacts to water resources could assist in identifying and evaluating the phases of operation that have the highest risk of impacting water quality. Potential contamination pathways during well construction and hydraulic fracturing are improper well construction, well degradation from repeated use, lengthy fractures, and improper well plugging. Potential contamination pathways during the mixing of chemicals phase are spills, accidents, and storage equipment failures. Potential contamination pathways at the hydraulic fracturing site during the management of wastewaters are onsite storage equipment failures and spills. Additional contamination pathways and risks occur during the transport of wastewaters to disposal facilities and the potential stress put on surface water treatment plants that might not be capable of treating the types of wastes produced from hydraulic fracturing operations.

Currently, a variety of BMPs are being employed in different regions to minimize risks to water resources. However, there is uncertainty in the industry concerning BMP transferability, cost-effectiveness, and risk mitigation potential. In addition, it is unclear to what extent these BMPs are being employed by different operators. Recycling of frac flowback and produced water is an accepted recommended practice, but limited information exists regarding prevalence, methods, and costs. Except for Pennsylvania, recycling data are not available from public databases, so it is difficult to estimate how much water is being reused in these regions.

3.7 Conclusions and Next Steps

Prior efforts, in addition to with this study, have identified the variety of water-related risks and potential contamination pathways resulting from shale gas development. However, existing publicly available data are not sufficient to perform a full risk assessment on a national or regional scale. A comprehensive and actionable risk assessment would require additional analyses, including the following:

- Quantitatively assess the magnitude of the impacts of the contamination pathways discussed in this report.
- Quantitatively assess the probability that the risks discussed will occur, based on existing industry practices.
- Identify the contamination pathways and risks that, at present, are adequately or inadequately addressed by current industry practices.
- Evaluate BMPs in terms of risk mitigation potential, cost-effectiveness, regional transferability, and industry prevalence.
- Evaluate in detail the wastewater recycling practices, including estimates of current recycling rates, estimates of total potential freshwater savings resulting from recycling, and a life cycle assessment (in terms of energy inputs, emissions, and costs) to identify thresholds for deciding whether to dispose of or recycle wastewaters.

The application of systematically developed BMPs could increase the transparency and consistency by which shale gas development occurs, providing benefits to industry and interested stakeholders. Effective BMPs follow from a defined prioritization of risks in the context of other risks. Risk prioritization would be facilitated by greater availability of industry data and current practices. Further collaboration and interaction with industry, and other stakeholders could improve data collection efforts and are a first step in achieving the analysis objectives above. Lastly, water resources are just one category of risk resulting from shale gas development. Future efforts could evaluate water-related risks and BMPs alongside other risks to air, land, and community.

4 Natural Gas Scenarios in the U.S. Power Sector

4.1 Overview of Power Sector Futures

This chapter summarizes results from modeling different U.S. power sector futures. These futures assess key questions affecting today's natural gas and electric power markets, including the impacts of:

- Forthcoming EPA rules on power plants
- Decarbonization options such as a clean energy standard (CES)
- Potential improvements in key generation technologies
- Higher costs for natural gas production assumed to arise from more robust environmental and safety practices in the field
- Expanded use of natural gas outside of the power generation sector.

The simulations were done using NREL's ReEDS model, incorporating findings from Chapters 1, 2, and 3, as applicable, and looking out to the year 2050.

ReEDS is a capacity expansion model that determines the least-cost combination of generation options that fulfill a variety of user-defined constraints such as projected load, capacity reserve margins, emissions limitations, and operating lifetimes. The model has a relatively rich representation of geographic and temporal detail so that it more accurately captures the unique nature of many generation options, as well as overall transmission and grid requirements. It is a power-sector-only model, so special steps were taken to consider the feedback effects of natural gas demand in other sectors of the economy. These steps, along with additional details about the model, are more fully described in Appendix E of this report.[132]

The scenario analysis presented here is not a prediction of how the U.S. electricity sector will evolve in the future—rather, it is an exercise to compare the relative impacts of different scenarios. Three Reference scenario cases are used as points of comparison for other scenarios based on policy, business, or technology change:

1. Baseline – Mid-EUR
2. Baseline – Low-EUR, and
3. Baseline – Low-Demand.

The modeling team explored four potential policy scenarios in addition to the Reference scenario:

1. A *Coal scenario*, driven by a combination of forthcoming EPA rules, low-cost natural gas, and the age of existing coal generators. Specifically, this scenario addresses the

[132] A full description of the model is also available at: http://www.nrel.gov/analysis/reeds/pdfs/reeds_documentation.pdf.

question of what new capacity will need to be built if and when coal plants retire, and what impacts would result from proposed NSPS.

4. A *CES scenario* with carbon mitigation sufficient for the U.S. power sector to contribute its share in lowering emissions to a level that many scientists report is necessary to address the climate challenge (IPCC 2007; C2ES 2011). This simulates a CES similar to that proposed by Senator Jeff Bingaman, but analyzes impacts through 2050 (EIA 2012a).
5. An *Advanced Technology scenario* where several different generation options—nuclear, solar, and wind—achieve cheaper and thus more widespread deployment; and
6. A *Natural Gas Supply-Demand Variation scenario* for natural gas, aimed to simulate the impact of (1) steps taken to incrementally address environmental and safety concerns associated with unconventional gas production, and (2) significant growth in natural gas demand outside the power sector (Dash-to-Gas). In both cases, the incremental cost of securing natural gas for power generation results in different power sector futures over the long term.

The family of scenarios is summarized in Figure 24.

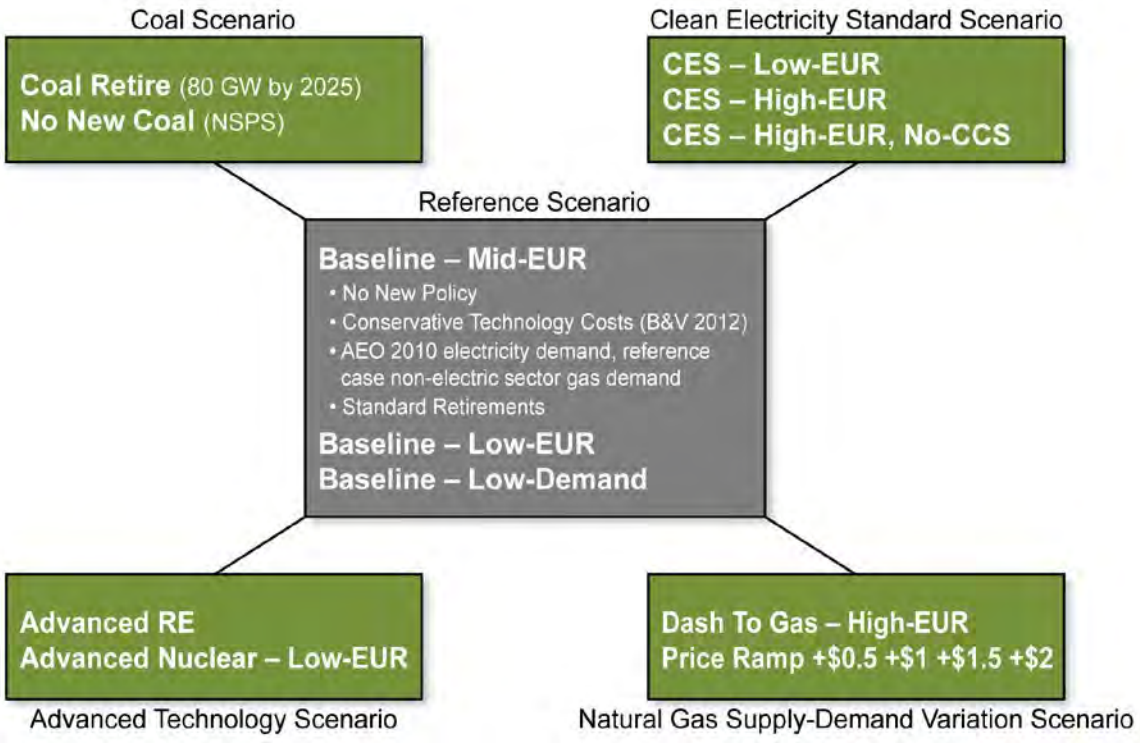

Figure 24. Scenarios evaluated in the power sector futures

4.2 Assumptions and Limitations

Technology cost and performance metrics used in ReEDS are presented in Appendix E. All costs in this study are listed in 2010 dollars unless otherwise noted.

Supply curves were developed to represent natural gas cost to the power sector and the response of this cost to increased power sector demand. The supply curves were developed based on linear regression analyses from multiple scenarios developed by the Energy Information Administration in the Annual Energy Outlook 2011 (EIA 2011).[133] The supply curves represent the price of fossil fuel to the power generators as a function of overall electric sector consumption of the fuel. In particular, as electric sector consumption increases, the marginal fossil fuel price to power generators (and all consumers of the fossil fuel) would increase. Within each year of the ReEDS optimization, the model sees this price response to demand through the linear supply curves. Three sets of supply curves were developed, representing different levels EUR[134] of natural gas. Additional detail on these supply curves is also outlined in Appendix E.

Current renewable tax incentives and state renewable portfolio standards are represented in the ReEDS model. Tax incentives include the modified accelerated cost recovery system for tax depreciation, the production tax credit for utility-scale wind technologies, and the investment tax credit for solar and geothermal technologies.[135] The tax credits are assumed to expire at their legislative end date and not be renewed. In particular, the wind production tax credit expires at the end of 2012, and the solar ITC declines from 30% to 10% in 2016. Although the solar and geothermal investment tax credits have no legislative end date, they are assumed to expire in 2030 as to not influence the long-term expansion decision of the model.

All scenarios evaluated here assume that 30 GW of coal-fired capacity will retire by 2025. The Coal scenario in Section 4.4 considers a higher level of coal retirement and has more detail on the assumed distribution of coal retirements.

ReEDS determines when new high-voltage electricity transmission infrastructure is required and tracks the costs associated with its deployment. It does not track the need to build new natural gas pipeline infrastructure, so those costs are not included in this analysis.

ReEDS is not designed to account for distributed generation; therefore, the penetration of distributed (residential and commercial) rooftop PV capacity was input exogenously into ReEDS from NREL's Solar Deployment Systems (SolarDS) model (Denholm et al. 2009). SolarDS is a market penetration model for commercial and residential rooftop PV, which takes as inputs rooftop PV technology costs, regional retail electricity rates, regional solar resource quality, and rooftop availability. In all cases, except in the Advanced Technology scenario, 85 GW of rooftop PV was assumed to come on line by 2050. This assumption was based on some of the Renewable Electricity Futures (RE Futures) Report 80%-by-2050 renewable electricity scenarios (NREL 2012).

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[133] (EIA 2011). Annual Energy Outlook 2011 scenarios are projections out to the year 2035, and these results are extrapolated to 2050 for use in the ReEDS model. A separate supply curve was developed for each year to represent changes in projected supply and demand interactions as estimated in the multiple Annual Energy Outlook 2011 scenarios. The modeling team had already commenced work by the time the 2012 edition of the Annual Energy Outlook was released, so it could not take advantage of those newer data.

[134] EUR is the amount of natural gas (or petroleum) that analysts expect to be economically recovered from a reservoir over its full lifetime. Three potential measures of EUR are used throughout this study (High, Mid, and Low) to reflect the ranges of optimism and uncertainty over unconventional natural gas availability and price.

[135] Detailed information on these tax incentives can be found on the Database of State Incentives for Renewables and Efficiency at: http://www.dsireusa.org/.

4.3 Reference Scenario

Three different baseline cases were evaluated in the Reference scenario:

- Baseline – Mid-Estimated Ultimate Recovery (Mid-EUR) case, with average power demand growth and a moderate outlook for natural gas prices
- Baseline – Low-EUR case reflecting the potential for more limited—and hence, more expensive—natural gas
- Baseline – Low-Demand case with Mid-EUR expectations. Low demand for electricity could be the result of continued economic stagnation (low gross domestic product [GDP] growth) or successful efforts to curb energy demand through energy efficiency, demand response, smart grid, and other programs to reduce the need for new electricity supply.

A Baseline – High-EUR case was not considered in this family in order to keep the number of results manageable. As noted previously, the Reference scenario is not a prediction of the future U.S. electricity mix *per se*, but instead, it serves as a point of comparison for the other scenarios. Each baseline case in the Reference scenario is summarized in Table 9.

Table 9. Description of Reference Scenario

Case Name	Assumption for Future Electricity Demand	Assumption for Estimated Ultimate Recovery (EUR)
Baseline – Low-EUR	Standard Growth (EIA 2010)	Low-level
Baseline – Mid-EUR	Standard Growth (EIA 2010)	Mid-level
Baseline – Low-Demand	Low Growth (NREL 2012)	Mid-level

Figure 25 and Figure 26 present the projected growth of electric generating capacity and generation for each of the three baseline cases. In the Baseline – Mid-EUR case, total capacity grows from roughly 1,000 GW in 2010 to just over 1,400 GW in 2050. While nuclear and coal capacity decrease as a result of net aged-based retirements, natural gas combined-cycle and natural gas combustion-turbine capacities nearly double, with especially strong growth expected after 2030 when nuclear and coal retirements accelerate. On-shore wind capacity grows steadily from roughly 40 GW in 2010 to nearly 160 GW in 2050, representing about 3 GW of new additions each year on average over the period—a significant reduction from deployment in recent years. In all three baseline cases, oil and gas steam-turbine capacity is fully retired by roughly 2035 due to their low efficiency. Nuclear capacity also declines in all three baseline cases beginning around 2030 as plants reach the end of their operational lifetime and licensing arrangements, and no new plants are built due to uncompetitive economics. As noted above, rooftop PV is not endogenously calculated by ReEDS, but was exogenously assumed for each of the scenarios and baseline cases. Under the technology cost assumptions used, utility-scale PV showed more limited growth compared to natural gas and wind, reaching roughly 10 GW by 2030 and 20 GW by 2050.

The Baseline – Low-EUR case considers a future in which natural gas is less abundant, and thus more expensive, than the Baseline – Mid-EUR case. The primary impact in such a future is less

natural gas capacity and more coal and wind. For example, in this baseline case, the cumulative installed wind capacity reaches about 200 GW by 2050.

In the final Baseline – Low-Demand case, growth in natural gas capacity is affected the most, although wind and coal also see little to no growth.

Considering the associated generation futures in these three baseline cases may be more instructive because capacity alone does not indicate how power plants are operated. Generation from natural gas combined-cycle plants doubles over the 40-year period, growing especially rapidly starting around 2030 because it is used to make up for the retired nuclear and coal generation (see Figure 26). Generation from natural gas combustion-turbine is almost too small to see in these charts, but plays an important role in meeting peak load needs. In the Baseline – Low-EUR case, new coal capacity is added and its generation plays a growing role in meeting power demand after 2030. This new coal is not needed in a low-demand future, and little new wind or other renewable energy generation is needed either.

Figure 27 presents four key metrics for the baseline family of cases. First, natural gas consumption rises 2.5-fold from 2010 to 2050 in the Baseline – Mid-EUR case, but still nearly doubles in the other two cases. Second, average real natural gas prices that generators pay are expected to nearly double by 2050 in the Baseline – Mid-EUR case,[136] while the Baseline – Low-EUR case would see higher prices throughout the period. A Baseline – Low-Demand future will put far less pressure on natural gas prices because they peak at just over $8/MMBtu in 2050. Third, CO_2 emissions from the power sector are expected to remain relatively flat throughout the period. In the Baseline – Low-Demand case, emissions decline significantly as existing coal is replaced with natural gas. Finally, average real prices paid for retail electricity grow steadily through 2050 to roughly $130/MWh in the Baseline – Mid-EUR and Baseline – Low-EUR cases, but are about $15/MWh cheaper in the Baseline – Low-Demand case.

[136] Prices to power generators are higher than well head prices by approximately $1/MMBtu, but vary by region.

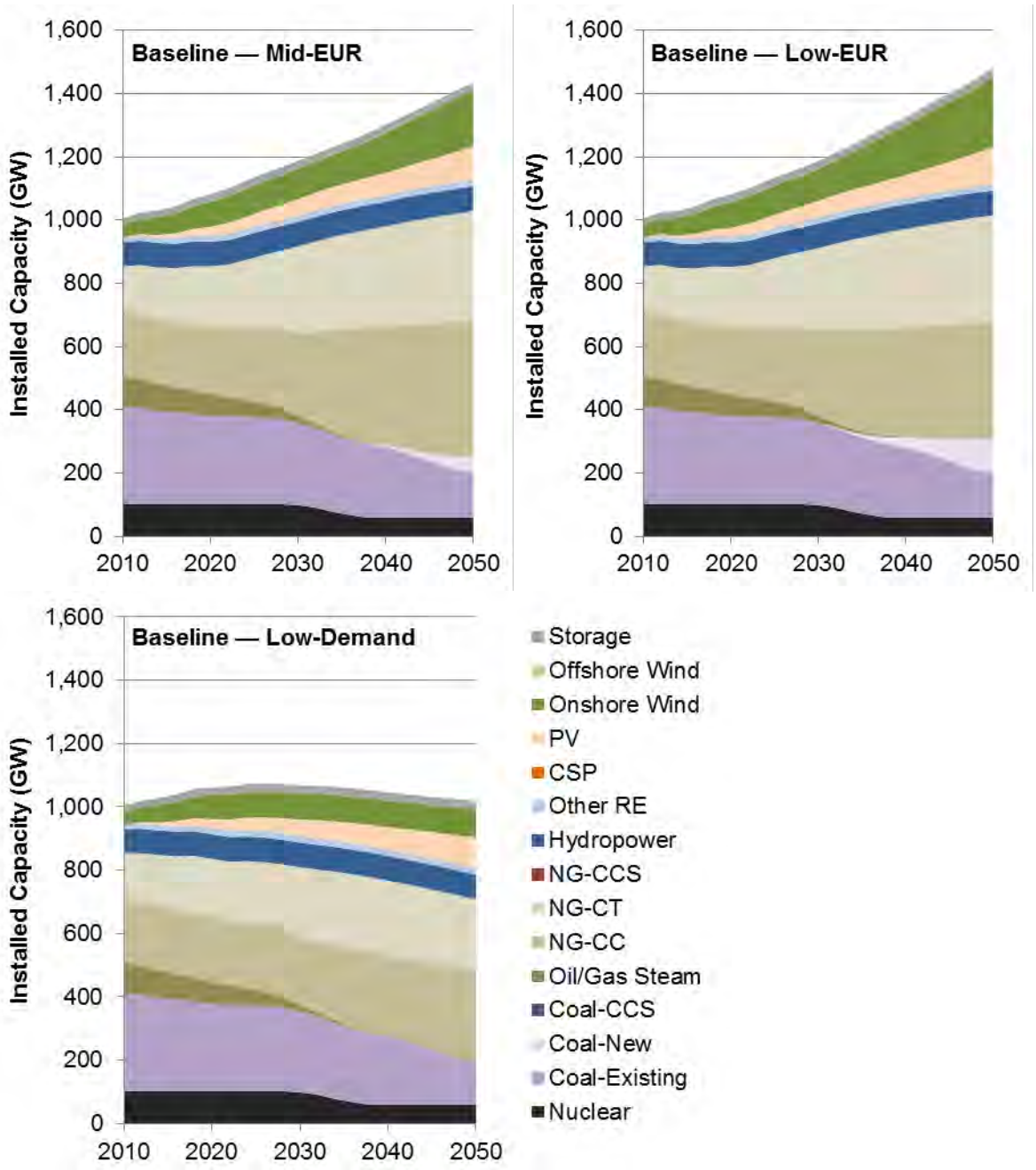


Figure 25. Projected capacity in the Reference scenario, 2010–2050, for Baseline – Mid-EUR, Baseline – Low-EUR, and Baseline – Low-Demand cases

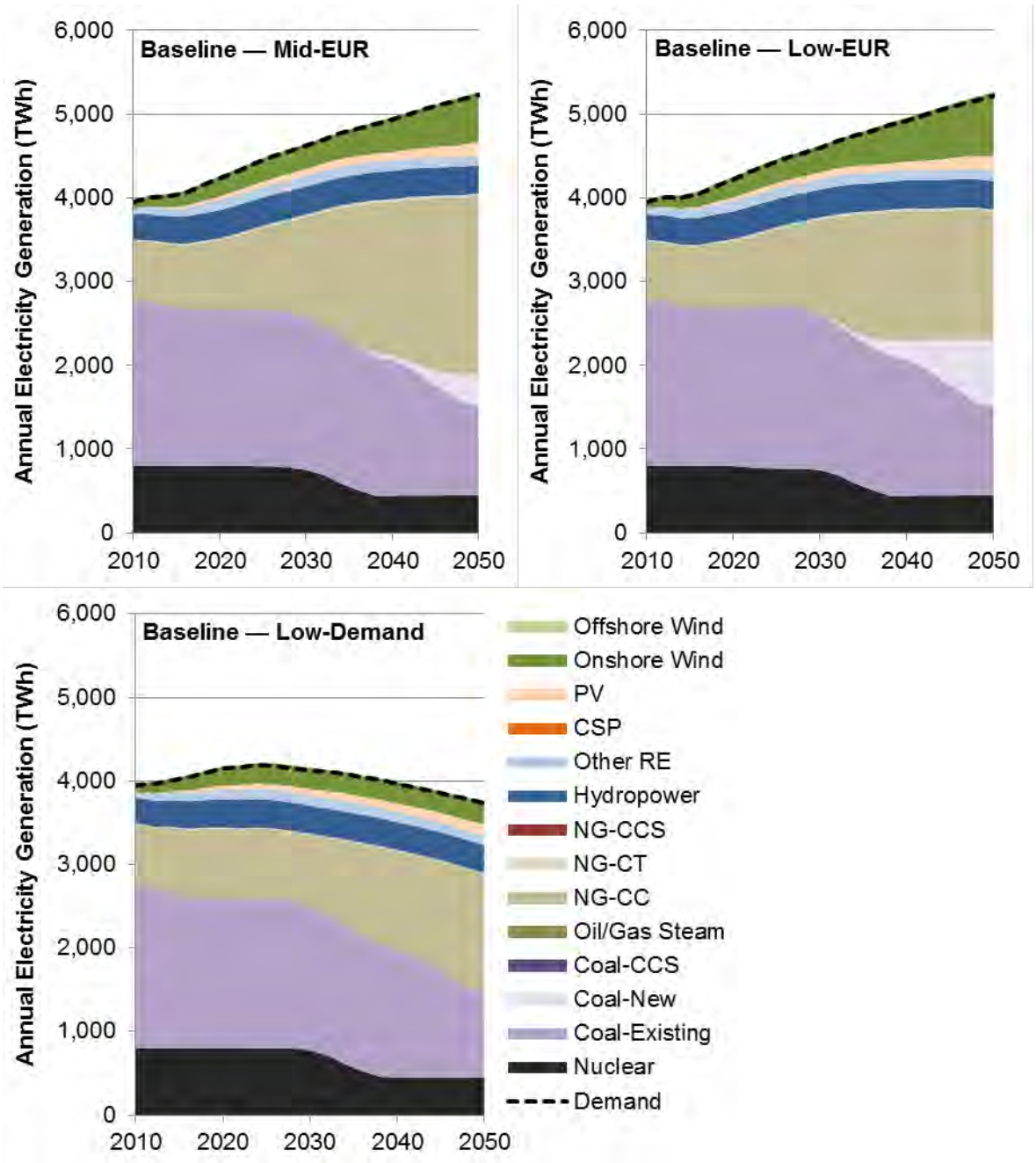


Figure 26. Projected generation in Reference scenario, 2010–2050, for Baseline – Mid-EUR, Baseline – Low-EUR, and Baseline – Low-Demand cases

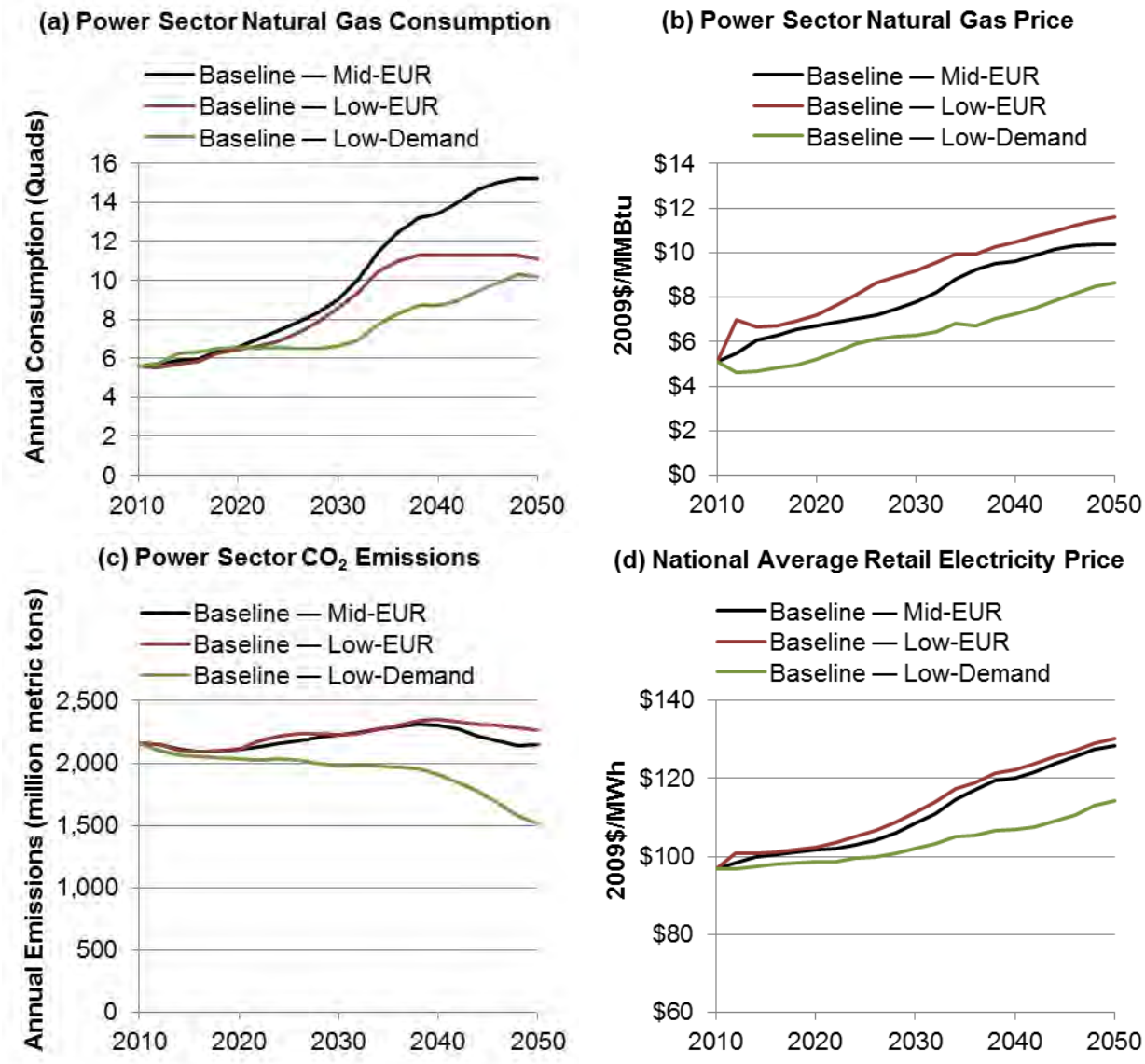


Figure 27. Selected metrics for the Reference scenario, 2010–2050

4.3.1 Implications of Reference Scenario

An electric power future as envisioned in the Baseline – Mid-EUR case would include rapid growth in natural gas generation and less reliance on coal and nuclear power. In effect, natural gas and coal swap positions compared to their historical levels. One concern in such a future is that if volatility returns to natural gas prices after additional new capacity is built—and coal plants are already retired—the economy will be more directly exposed to fluctuating electricity prices. Careful consideration of the benefits and costs of such a shift in generation diversity is warranted.

Although CO_2 emissions do not grow signficantly in such a future, they also do not begin to transition to a trajectory that many scientists believe is necessary to avoid dangerous impacts from climate change. GHG emission reductions of up to 80% by 2050 (compared to 2000 levels)

are considered necessary by most climate scientists to stabilize atmospheric concentrations of GHG and prevent the most serious impacts from a changing climate (IPCC 2007). The Reference scenario results do not put the U.S. power sector on a trajectory to meet this target.

A low power demand future, consistent with recently observed trends,[137] may provide greater generator diversity and prevent a potential over-reliance on natural gas. This Baseline – Low-Demand case also has lower emissions and price impacts, although growth in low-carbon energy deployment slows significantly.

4.4 Coal Scenario

This scenario considers two cases:

- *Coal Plant Retirements case:* The impact of retiring an aggregate 80 GW of coal-fired generation by 2025
- *No New Coal without CCS case:* The impact of not allowing any new coal-fired generating capacity to be built unless it is equipped with CCS technology, which is similar to the proposed EPA New Source Performance Standard rule[138]

As noted previously, the baseline in all scenarios assumes that 30 GW of coal will retire by 2025 due to endogenous age-based rules, plus additional retirements of other aging non-coal-fired plants. Many studies have been published that estimate the potential impact of the forthcoming EPA rules—and increasingly, low-priced natural gas—that are assumed to drive the decision to retire existing plants (Macedonia et al. 2011). A more fundamental reason for retirement may be that about two-thirds of the U.S. coal fleet was built in the 1970s or before (SNL 2011). The two cases evaluated in the Coal scenario are summarized in Table 10. Text Box 2 provides additional information on the EPA rules.

Table 10. Description of Coal Scenario

Case Name	Coal Capacity Retired by 2025 (GW)	Assumption for natural gas Estimated Ultimate Recovery (EUR)
Coal Plant Retirements	80	Mid-level
No New Coal without CCS	30 (same as Reference)	Mid-level

As noted previously, there are two forthcoming EPA rules that are likely to cause many older coal-fired plants to consider either costly retrofits to control pollution or retirement as a more economic solution: the Cross-States Air Pollution Rule and the Mercury and Air Toxics Standard. Two other EPA rules are under development that would attempt to address concerns about (1) water intake structures for cooling purposes at most power plants (the 316(b) rule) and (2) disposal of coal combustion residuals, also known as the coal ash rule.

[137] Total net power generation in the U.S. peaked in 2007, according to EIA statistics, and has not yet returned to pre-recession levels (EIA 2012c).
[138] For additional background on the proposed NSPS ruling, see http://epa.gov/carbonpollutionstandard/.

Text Box 2: Coal Plant Retirements, EPA Rules, and Low-Price Natural Gas

Over the past few years, power sector analysts have debated the impact of new and forthcoming EPA rules on coal plant retirements. These rules include, but are not limited to, the following:

- Cross-States Air Pollution Rule
- Mercury and Air Toxics Standard
- Clean Water Act Section 316(b) cooling water intake structure ruling
- Coal Combustion Residual Rule.

Selected highlights of the rules include:

Cross-States Air Pollution Rule: Limits fine particulate emissions and ozone *transport* in many eastern state power plants by reducing SO_x and NO_x emissions. Compliance options include the installation of low-NO_x burners, catalytic reduction, and scrubbers. The U.S. Court of Appeals struck down this rule in August 2012, and an earlier version known as the Clean Air Interstate Rule will be enforced in its place until EPA redesigns it.

Mercury and Air Toxics Standard: Reduces mercury, acid gases, trace metals and organics emissions at power plants by requiring maximum achievable control technology. Compliance options include scrubbers, filters, and activated carbon injection. Final rule released, and a 3-year compliance period is under way, although legal challenges are also mounting.

316(b): Protects fish and aquatic life from entrapment or entrainment in cooling-water intake structures at power plants. Compliance options include screens, barriers, nets, or cooling towers. The date for issuing the final rule was recently pushed back from July 2012 to June 2013.

Coal Combustion Residual Rule: Establishes standards to manage risk of post-combustion coal waste from power plants. There are two regulatory options under consideration by EPA with different ramifications on power generation cost and impact.

Dozens of studies have been conducted to estimate the impact of these rules on power generators, although most were conducted before the rules were finalized and natural gas prices plummeted in early 2012. Relatively straight-forward financial analysis can be used to determine if it is better to retrofit a power plant so that it can comply with the new rule or retire it. However, real-world decision-making depends on a host of other factors—including future market outlook and plans, portfolio risk management, potential carbon regulations, and reliability assessments.

Some studies anticipated relatively minor impacts from plant retirements (5–20 GW by 2020) (EIA 2011; BPC 2011), whereas others forecast major potential impact and reliability concerns (30–75 GW by 2020) (EEI 2011; CERA 2011; NERA 2011). As of early 2012, about 35 GW of coal-fired generators had already announced that they would retire before 2020. At the same time, as natural gas prices plummeted through 2011 and 2012, generators ramped up operation of natural gas combined-cycle units and scaled back on use of coal generation.

The fuel switching that has already occurred primarily due to low gas prices is equivalent to about 60 GW of coal-fired capacity, although this calculation assumes the coal plants are operated infrequently (32% capacity factor). Most of the oldest coal generators in the U.S. fleet are operated infrequently and have fewer pollution controls. Although fuel switching is a voluntary decision by power generators—and hence, optimized to maximize profits in most cases—the impact of the forthcoming EPA rules will apply different decision-making criteria on top of the inexpensive natural gas driver. Thus, many of the studies conducted to assess the impact of coal plant retirements may need to be redone to account for both drivers of changing generation.

Although most existing studies have anticipated anywhere from 20 to 70 GW of coal retirements by 2020 due to these rules, natural gas price forecasts have fallen below levels that many of the studies used to evaluate the retrofit-retirement decision. The level chosen for this study, 80 GW, is based on these lower natural gas prices and a longer time horizon (2025). *Where* the retirements occur is another important assumption because it will impact whether or not new plants or transmission lines need to be built to replace the lost generation, or if existing natural gas combined-cycle plants can be operated more frequently to meet the load. The retirement distribution chosen was based mainly on the age of existing coal plants and the degree to which they had already installed pollution control devices such as activated-carbon injection and flue-gas desulfurization. Figure 28 displays where existing coal plants were retired, and shows the percentage of coal capacity that is assumed to shut down in each balancing area.

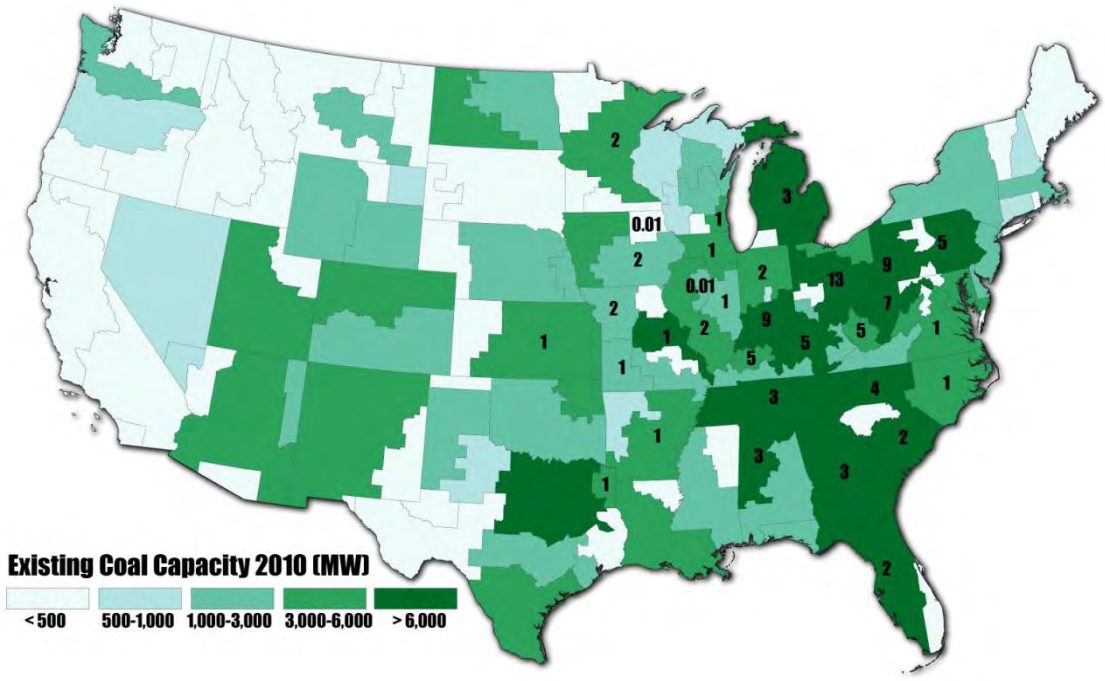


Figure 28. Assumed distribution of retirements in the Coal scenario by percentage of total coal capacity retired in 2025 in each balancing area of ReEDS

The impacts of the two coal cases are summarized in Figure 29 for the years 2030 and 2050. In the Coal Plant Retirements case (where a net 50 GW of additional retirements are seen, compared to the baseline in 2025), most of the retired coal in 2030 is replaced with natural gas combined-cycle, although some additional new wind generation is also added. In the No New Coal without CCS case, there is no difference from the Baseline – Mid-EUR through 2030 because no new coal plants were built by then in the baseline. Cumulative CO_2 emission savings are significant in the Coal Plant Retirements case: 3,300 million tons of CO_2 between 2011 and 2050, even if annual reductions are more modest (see Figure 30). The impact of retirements on average real electricity prices is also modest.

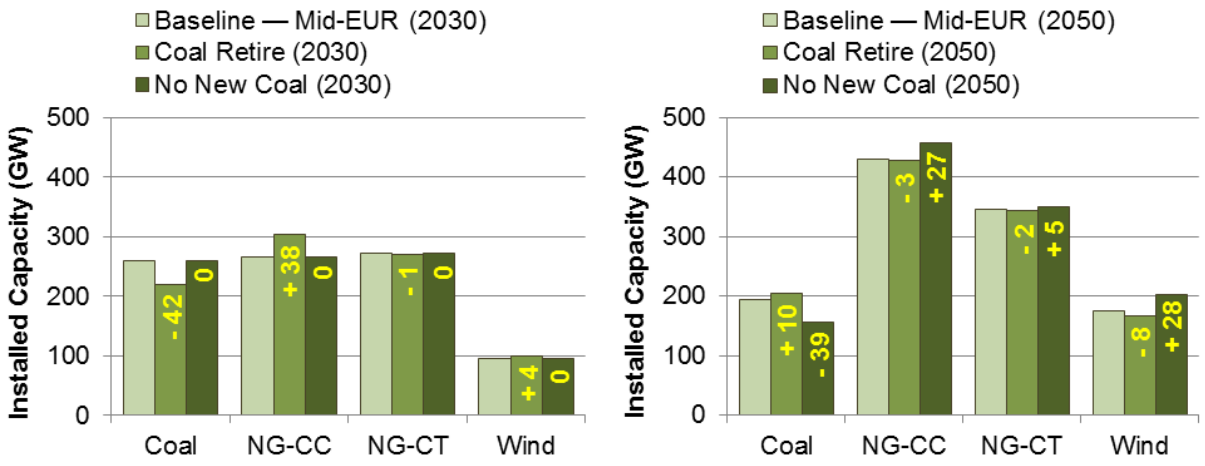


Figure 29. Impacts of coal plant retirements and no new coal without CCS compared to the baseline for 2030 and 2050

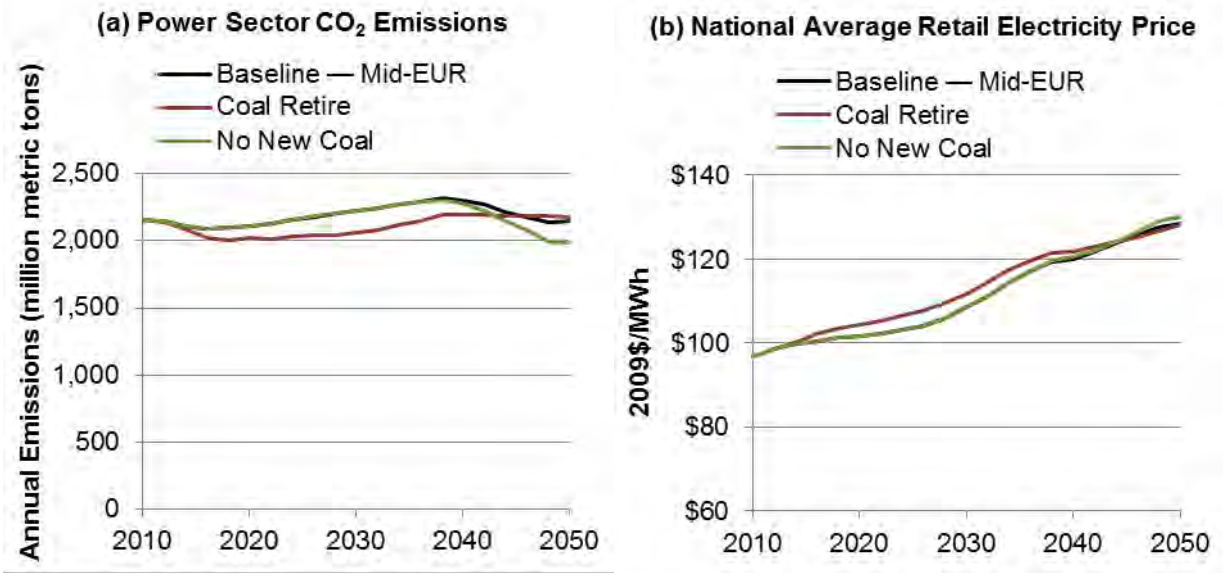


Figure 30. Selected metrics for the Coal cases, 2010–2050

4.4.1 Implications of Coal Scenario Findings

Coal retirements are replaced on a nearly one-to-one basis with natural gas, although wind plays a small role in the early years. In later years, more new coal is built, compared to the baseline, and less wind. In aggregate, however, coal retirements lead to a notable reduction in cumulative CO_2 emissions at relatively modest cost. Initial statistically based analysis does not indicate any difficulty in maintaining adequate reserve margins needed for reliability purposes, although this evaluation is done at a relatively coarse level. A more detailed dispatch model would be required for realistic evaluation of grid reliability issues in such a coal retirement case.

The No New Coal without CCS case, intended to simulate the NSPS, has little impact in early years, but does prevent the construction of new coal after 2030. Compared to the Reference scenario, where new coal does come on line after 2030, the No New Coal without CCS case does

not have any new coal coming on line through 2050 because CCS is not an economic option. In this case, natural gas combined-cycle and wind contribute equally to replace what coal would have been built in the baseline.

4.5 Clean Energy Standard Scenario

After cap-and-trade legislation failed to pass the U.S. Senate in 2010, CES became the preferred vehicle for those decision makers seeking to mitigate GHG emissions in the U.S. power sector.[139] A CES sets targets for the sale of qualifying clean energy generation over time, similar to a renewable portfolio standard,[140] but awards credits roughly based on the relative carbon weighting of emissions compared to standard coal-fired generation (EIA 2012a). In this analysis, new nuclear and renewable generators receive 100% crediting because they have no burner-tip emissions; natural gas combined-cycle generation receives 50% crediting when used without CCS and 95% crediting with CCS; and coal receives 90% crediting, but only with CCS. This analysis follows the current CES legislation under discussion in Congress[141] calling for an 80% clean energy target in 2035, but extends the target to reach 95% by 2050.

Full life cycle GHG emission values could be used in the CES crediting, rather than the current burner-tip estimates, to provide a more representative picture of climate impacts. As discussed in Chapter 1, the current understanding of the full life cycle emissions of unconventional gas is not significantly different from the values noted above; therefore, this analysis does not attempt to use them. As additional information becomes available, however, follow-on research could evaluate the impacts of different crediting values on the long-run evolution of the U.S. power sector.

Three separate CES cases are considered here:

- CES – High-EUR case
- CES – High-EUR case where CCS is not available, either for technical, economic, or social reasons
- CES – Low-EUR case.

Table 11 summarizes the three cases evaluated in the CES scenario.

Table 11. Description of CES Scenario

Case Name	Is Carbon Capture and Sequestration Available/Economic?	Assumption for Estimated Ultimate Recovery (EUR)
CES – High-EUR	Yes	High-level
CES – High-EUR, without CCS	No	Mid-level
CES – Low-EUR	Yes	Mid-level

[139] Three Senate leaders have put forth CES legislation since then: Senator Lindsay Graham (SC), Senator Dick Lugar (IN), and Senator Jeff Bingaman (NM).
[140] For more background on renewable portfolio standards and clean energy standards, see (C2ES 2012).
[141] On March 1, 2012, Senator Jeff Bingaman introduced the Clean Energy Standard Act of 2012. More information on the bill is available at: http://www.energy.senate.gov/public/index.cfm/democratic-news?ID=67e21415-e501-42c3-a1fb-c0768242a2aa.

Figure 31 presents the impacts of the three CES cases on generation through 2050. In the early years before 2030, natural gas replacing coal is the primary contributor to meeting the rising CES targets. Beginning around 2030, however, natural gas is no longer able to contribute to meeting the target without CCS because it receives only 50% crediting toward the target. Instead, coal with CCS, wind, and natural gas with CCS are the next-cheapest options in the CES – High-EUR case. If CCS is not available (CES – without CCS), wind generation is the next-cheapest alternative to take its place. In such a case, renewable energy sources contribute about 80% of total generation by 2050.[142]

A CES power future with more costly natural gas (CES – Low-EUR) would result in less natural gas generation, more solar and wind, and reliance on coal CCS rather than gas CCS compared to the CES – High-EUR case.

[142] NREL recently published the RE Futures study that evaluates many of the technical issues and challenges of operating the grid with such high percentages of renewable energy. See NREL (2012) for more detail.

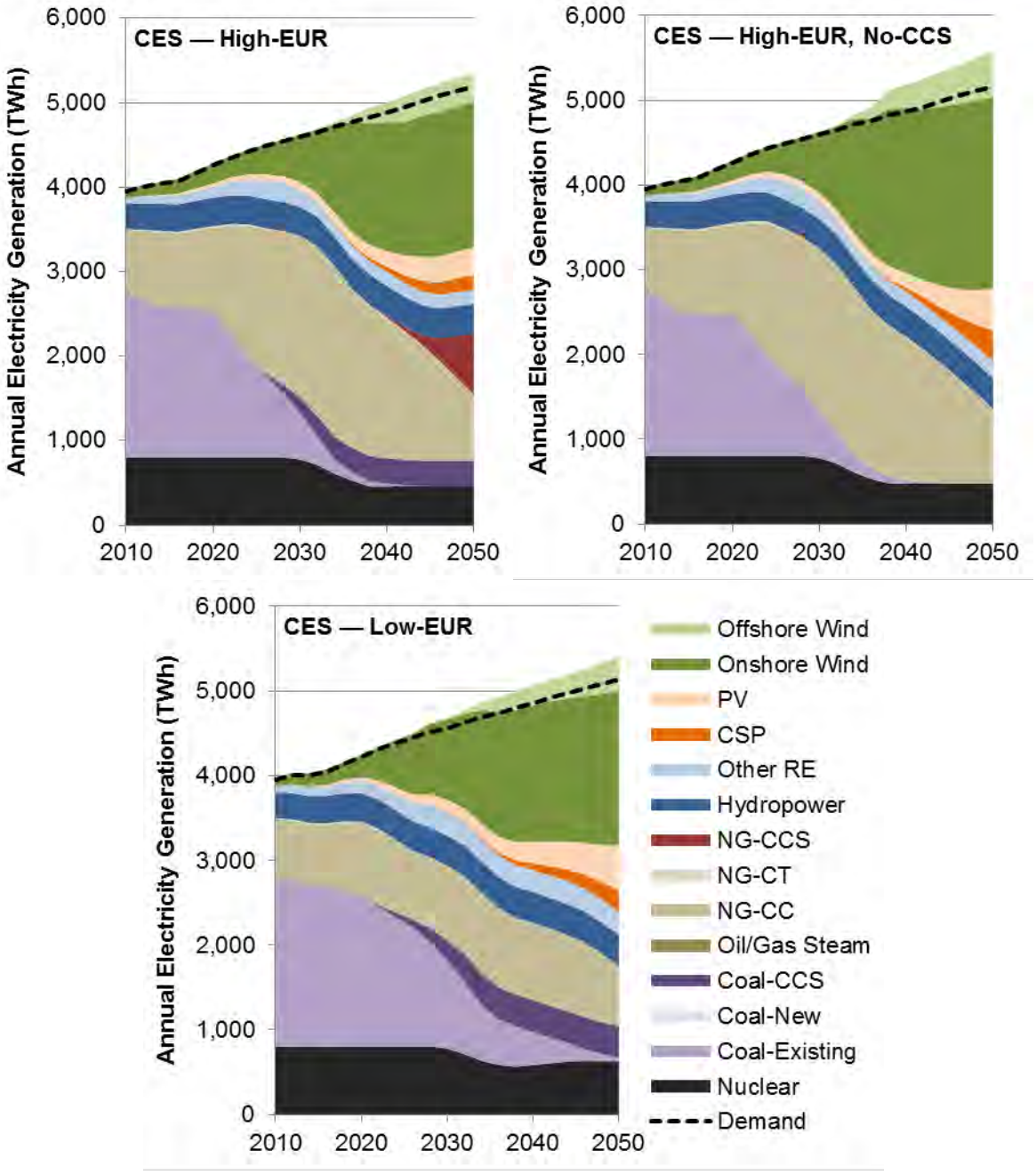


Figure 31. Projected generation in CES scenario, 2010–2050 for CES – High-EUR, CES – High-EUR, without CCS; and CES – Low-EUR cases

The amount of natural gas used in the CES scenario varies significantly by case, as shown in Figure 32. In all cases, however, it peaks around 2030, and prices remain lower than the Baseline – Mid-EUR case through 2050. Power sector gas demand temporarily falls after 2030 in the CES – High-EUR case, but begins to climb again around 2040 as natural gas CCS becomes an economic contributor to the CES target. When CCS is not available, natural gas consumption continues to decline and is back at 2010 levels by 2050. In the CES – Low-EUR case, natural gas usage remains muted throughout the scenario lifetime as other options meet the target more economically. Average real electricity prices would increase compared to the Baseline – Mid-EUR case beginning in roughly 2020 and settle at levels between 6% and 12% higher by 2050.

By 2050, CO_2 emissions from the U.S. power sector decline by more than 80% in all CES cases compared to the baseline. Coal generation without CCS has disappeared by that time in all cases. The power sector would be on a trajectory in all CES cases to achieve that sector's contribution to carbon mitigation commensurate with levels the Intergovernmental Panel on Climate Change deems necessary to stabilize atmospheric concentrations of greenhouse gases (IPCC 2007) at a level that could avoid the most dangerous aspects of climate change.

Because the CES cases project a very large build-out of wind power, ReEDS tracks the amount of new transmission lines needed to deliver power from where it is generated to where it is used. The estimated costs of building this new transmission infrastructure are included in the capacity analysis. Figure 33 presents a geospatial map of where new transmission lines would be required through 2050. The vast majority of this new wind generation would be constructed in the Midwestern states for use throughout the Eastern Interconnect. Smaller quantities would be built in the Western and Electric Reliability Council of Texas (ERCOT) Interconnects. The greatest amount of transmission is needed when CCS is not available, and wind must play an even larger role. In this case, more than twice the amount of transmission, as measured in million megawatt-miles of capacity, would be needed compared to the CES – High-EUR case in 2050 (or six-times the amount as the Baseline – Mid-EUR case).

4.5.1 Implications of CES Scenario

The CES options analyzed here indicate that the U.S. power sector could achieve significant decarbonization by 2050 at relatively modest economic costs, although barriers to building sufficient transmission may be formidable (NREL 2012). About six times more transmission is needed in the CES – without CCS case than in the Baseline – Mid-EUR case by 2050, and three times as much in the CES – High-EUR case. A greater diversity of power generation is achieved when CCS is available and economic for use on coal or gas plants. Heavy reliance on the need for transmission is also lessened when CCS is available. Additional research should be considered to evaluate potential natural gas infrastructure barriers in such a scenario of high variable renewable energy generation.

In all CES cases, large quantities of variable renewable energy are supported and firmed by flexible natural gas generators. Natural gas generators help enable a power generation mix that relies heavily on variable renewable technologies such as wind and solar.

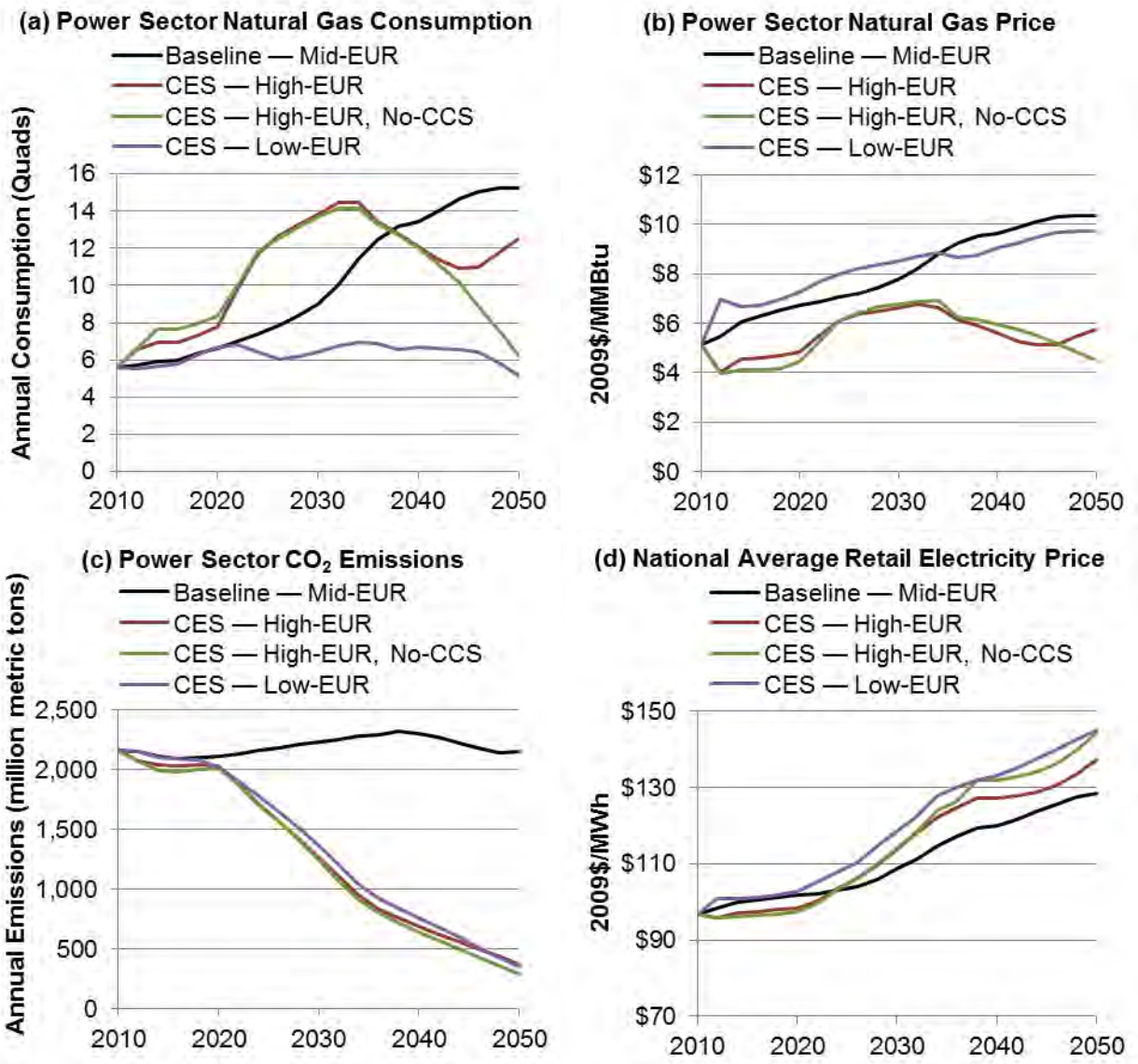
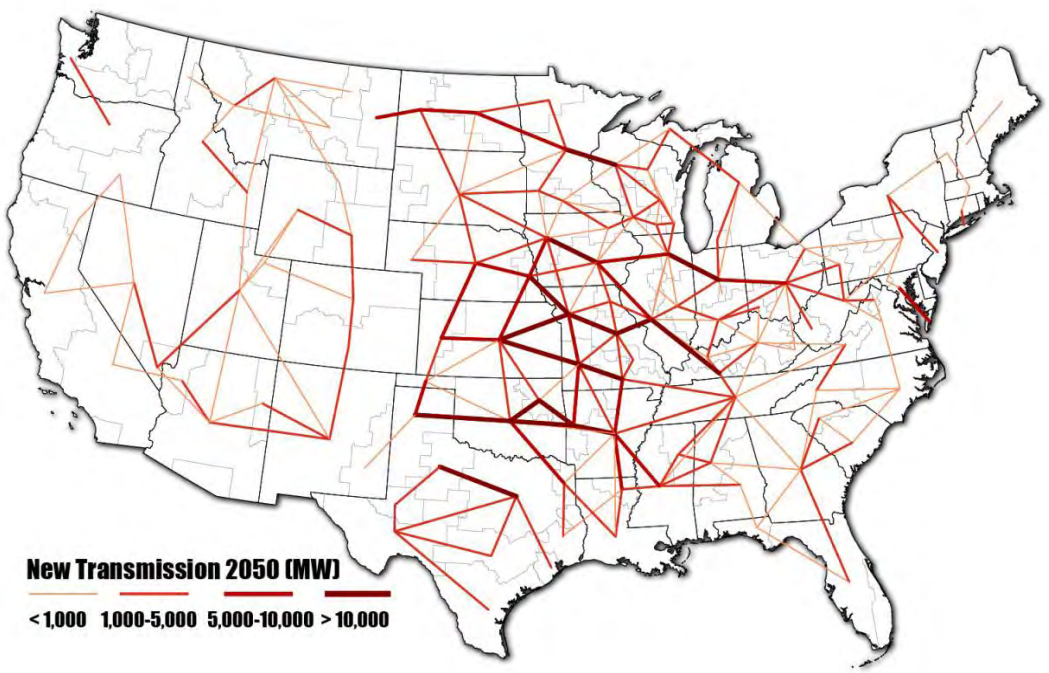


Figure 32. Selected metrics for the CES scenario, 2010–2050



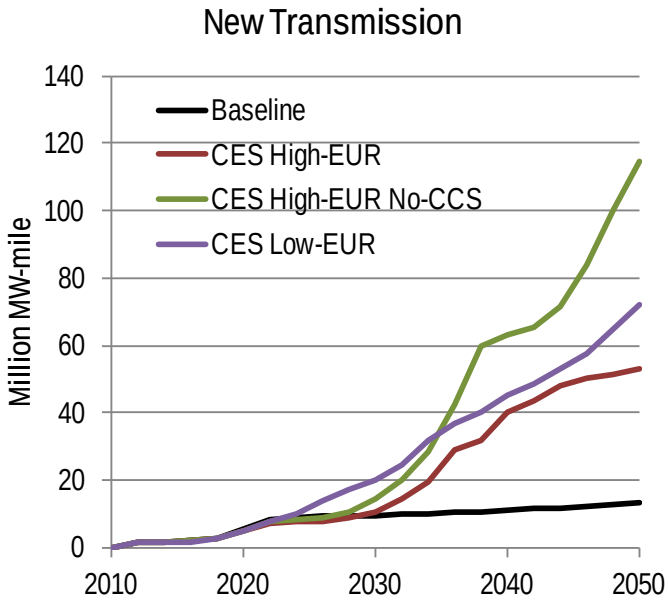


Figure 33. Map of new transmission required by 2050 in the CES – High-EUR case, and measures of new transmission needed in all cases, 2010–2050

4.6 Advanced Technology Scenario

The Advanced Technology scenario considers additional progress in the evolution of cost and performance metrics of certain generation options compared to the Baseline – Mid-EUR case. Two cases are considered here:

- *Advanced Nuclear:* A 50% reduction in the capital costs of nuclear generation by 2020. This scenario also uses a Low-EUR assumption for natural gas.
- *Advanced Renewable Electricity (RE):*[143] Capital costs for utility-scale solar PV, concentrating solar power (CSP) with thermal storage, and wind are assumed to decline, as shown in Table 12. In addition, improvements in performance of advanced RE technologies are assumed to be more significant, as shown in Table 13 (e.g., in 2050, Class 5 wind is assumed to have an annual capacity factor of 46% compared with 43% in the baseline). CSP is assumed to have the same performance as in the baseline, but with towers available at an earlier time (2015 instead of 2025), resulting in higher performance earlier. Furthermore, distributed PV was exogenously input and assumed to reach 240 GW of capacity by 2050,[144] compared to 85 GW in the baseline. This case uses a Mid-EUR natural gas assumption.

Table 12. Assumed Reductions in Capital Costs for the Advanced Technology Scenario

	2020 ($/kW)	2050 ($/kW)
Advanced Nuclear	6,200 → 3,100	6,200 → 3,100
Advanced On-shore Wind	2,012 → 1,964	2,012 → 1,805
Advanced PV	2,550 → 2,213	2,058 → 1,854
Advanced CSP	6,638 → 4,077	4,778 → 2,982

Table 13. Assumed On-shore Wind Improvements in Capacity Factors for the Advanced Technology Scenario

	Class 3	Class 4	Class 5	Class 6	Class 7
2020	0.33 → 0.38	0.37 → 0.42	0.42 → 0.45	0.44 → 0.48	0.46 → 0.52
2050	0.35 → 0.38	0.38 → 0.43	0.43 → 0.46	0.45 → 0.49	0.46 → 0.53

Table 14 summarizes the major assumptions used in the Advanced Technology scenario.

[143] Advanced RE capital costs and performance improvements were taken from the RE Futures report (NREL 2012), evolutionary technology improvement (RE-ITI) cost projection.
[144] This projection is based on the SunShot Vision Report (DOE 2012).

Table 14. Description of Advanced Technology Scenario

Case Name	Cost Assumption	Assumption for Estimated Ultimate Recovery (EUR)
Advanced Nuclear	Nuclear capital costs decline by 50% in 2020 compared to the baseline scenario.	Low-level
Advanced RE	Wind, PV, and CSP capital costs decline as shown in Table 12. Performance improvements as described above and shown in Appendix E.	Mid-level

The impact of potential improvements in these two categories of technology is shown in Figure 34. The primary impact in the Advanced Nuclear case is that enough new nuclear generation is built to offset the decline in age-based retirements by the end of the modeling period.[145] Additionally, because this case assumes a Low-EUR for natural gas (and thus, higher prices), some new coal plants are also built beginning in 2030 to meet load. The new coal plants largely offset the carbon abatement that otherwise would have occurred due to the new nuclear generation. Retail prices are also higher during most of the reporting period because the Low-EUR assumption was made (see Figure 35).

In the Advanced RE case, wind and solar generation expands considerably compared to the Reference scenario. In the case of wind, this illustrates the sensitivity of potential expansion because the assumed cost reductions and performance improvements were relatively modest. Growth in utility-scale PV capacity is substantial in this case, while actual generation increases more modestly due to the relatively low capacity factor that solar achieves. By 2050, CO_2 emissions decline by a little more than one-quarter compared to the baseline, while retail electricity prices are also slightly lower due to the assumed reduction in cost for RE technologies (Figure 35).

4.6.1 Implications of the Advanced Technology Scenario Findings

Under the assumptions used in this analysis, nuclear generation does not become cost competitive with other options until capital costs decline by roughly one-half from today's level and natural gas prices are assumed to be relatively high (Low-EUR). Even under the cost assumptions used in the Advanced Nuclear case, new coal was still competitive with the cheaper nuclear, offsetting some of the carbon advantages of nuclear. Despite these apparently high hurdles, breakthroughs in advanced nuclear designs are possible (OECD 2011; Martin 2012) and could contribute meaningfully to a more diverse and energy-secure power future in the United States.

Even modest reductions in capital costs for renewable energy technologies can have significant impact on their competitiveness compared to baseline assumptions. Wind power appears particularly sensitive to assumed reductions in capital cost and performance improvements, expanding nearly 100% compared to the baseline with capital cost reductions of about 10%. Similar reductions in utility PV capital costs lead to near-identical impacts in the deployment of that technology, whereas a greater reduction in CSP capital costs would be needed to see a large expansion in the role of that technology.

[145] This case was also evaluated under High-EUR and Mid-EUR gas futures, but nuclear was not competitive in that environment, so only the Low-EUR results are shown here.

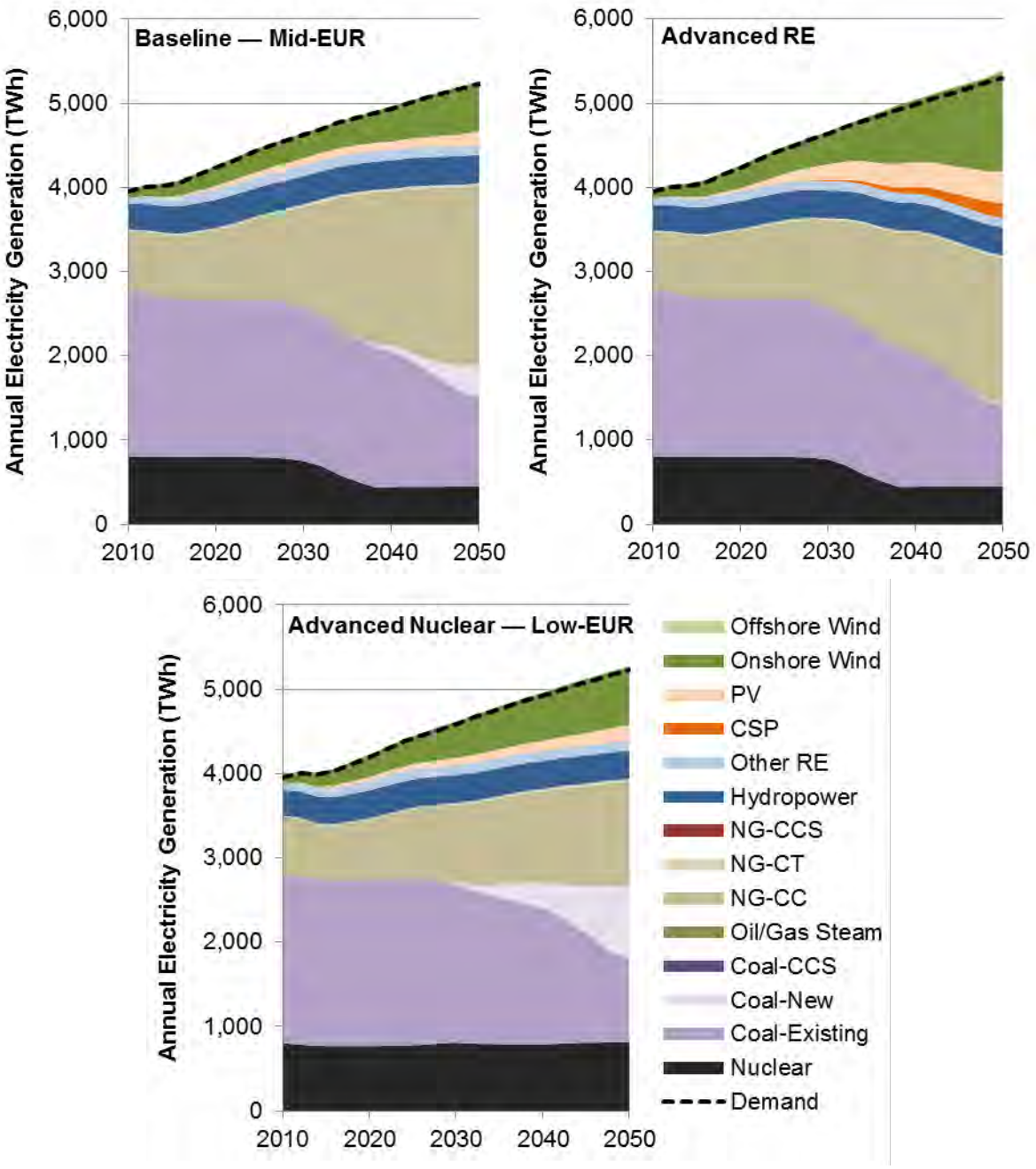


Figure 34. Generation in the Advanced Technology scenario, 2010–2050

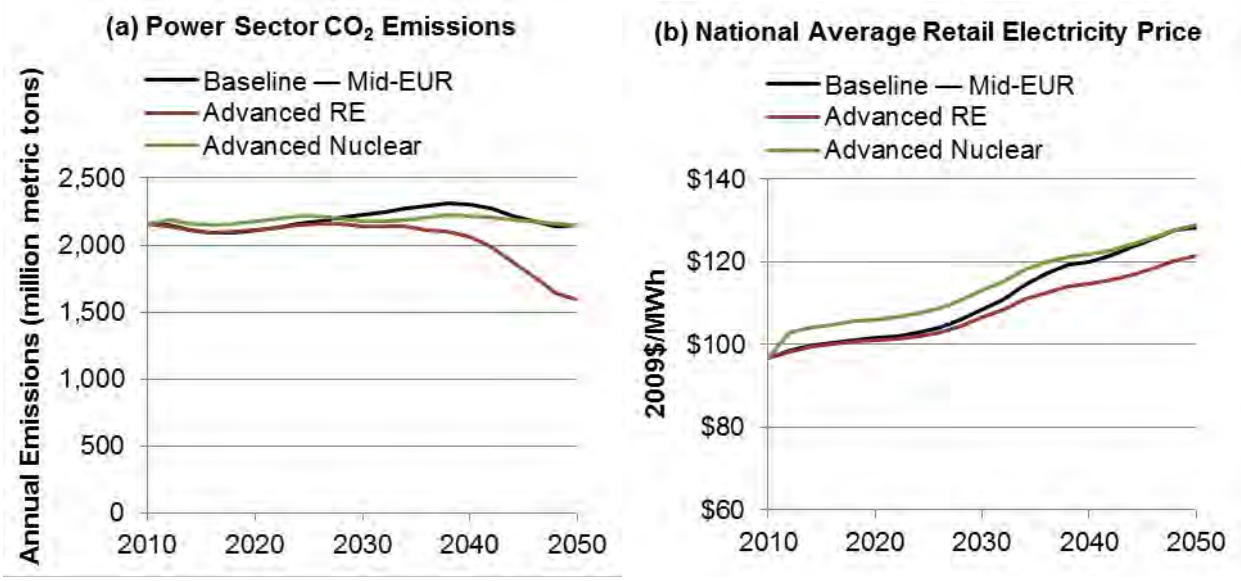


Figure 35. Selected metrics for the Advanced Technology scenario, 2010–2050

4.7 Natural Gas Supply and Demand Variations Scenario

Two separate cases are considered here:

- *Natural Gas Supply Cost Variations:* Variations in natural gas supply costs that could result either from additional state or federal regulations, or from more costly field practices that suppliers follow to better protect the environment. The impact of these incremental natural gas costs on the power sector over the longer-term are simulated using ReEDS. This analysis covers a broad range of potential incremental costs associated with producing natural gas in a way that commands stronger public support yet is still feasible for producers and consumers. Chapters 2 and 3 of this study discuss practices that could result in this more secure outcome on the supply side, but does not arrive at actual estimates of incremental cost impacts in $/MMBtu terms. The values used here could still be helpful to those who know what their incremental costs are, or to a broader audience in the future when cost estimates are available.
- *Natural Gas Demand Variations:* Variations in demand for natural gas outside the power sector that could result from a "dash-to-gas" across the larger economy. This dash-to-gas could occur in the export of LNG, greater use of natural gas in vehicles (either as compressed natural gas throughout the fleet, or as LNG in heavy-duty vehicles). Under a dash-to-gas case, natural gas prices rise due to the greater demand and make it more expensive for power generators to use natural gas generation.

Table 15 summarizes key assumptions used in the Supply and Demand Variations scenario.

Table 15. Description of Natural Gas Supply and Demand Variations Scenario

Case Name	Focus	Assumption for Estimated Ultimate Recovery
Natural Gas Supply Cost Variations	Evaluate impact to power sector as incremental natural gas production costs increase from $0.50/MMBtu to $2/MMBtu	Mid-level
Natural Gas Demand Variations (Dash-to-Gas)	Evaluate impact to power sector as natural gas demand in other sectors increases by 12 bcf/d by 2026	High-level

4.7.1 Natural Gas Supply Cost Variations

Figure 36 illustrates adjustments to the natural gas supply curves that could result when additional measures are taken to protect the environment when producing natural gas. These measures could be the result of new regulations or different practices in the field. Examples of these added costs might include the following:

- Activities such as recycling or treating a greater quantity of water supply used in hydraulic fracturing
- Minimizing the amount of methane that is released to the atmosphere before, during, and after fracturing a well
- Casing wells in a more robust and consistent way
- Practicing more robust techniques of cement bond logging
- Substituting more environmentally benign options for traditional hydraulic fracturing additives
- Engaging local stakeholders in dialogues in advance of drilling to ensure their concerns are heard and addressed
- Enforcing larger setbacks from potentially sensitive communities
- Disposing of or treating flowback water in improved ways.

Few publicly available studies estimate what these specific costs might be and how they vary by region. The International Energy Agency (IEA) recently published Golden Rules for a Golden Age of Natural Gas (IEA 2012), a very general statement of 22 steps that should be considered when producing natural gas. The IEA report stated that, “We estimate that applying the Golden Rules could increase the overall financial cost of development a typical shale-gas well by an estimated 7%.”[sic] (IEA 2012). Therefore, if it normally costs $3.00/MMBtu to develop shale gas, the Golden Rules cost would be $0.21/MMBtu higher at a typical play. This is nominally consistent with, although lower than, recent estimates of the costs of complying with pending federal rules—including the new EPA air regulations for oil and gas producers, which might cost between $0.32 and $0.78/MMBtu, according to one analyst (Book 2012). Informal consultations associated with this study suggest that maximizing water recycling might result in $0.25/MMBtu in added costs. The additional costs that could result from enhanced environmental and safety practices in the field, noted in Chapters 2 and 3, were unable to be quantified. However, it is clear that these costs will vary by region and that many additional safeguards could be practiced at less than an incremental cost of $1/MMBtu. A 2009 study funded by the American Petroleum

Institute anticipated much higher costs if new federal regulations were imposed on natural gas producers (IHS 2009).

To assess the potential impacts of these incremental supply costs, this study considers a range of additional costs—starting from $0.50/MMBtu and going up to $2/MMBtu in increments of $0.50/MMBtu—and evaluates the impacts on the long-range evolution of the power sector when these costs are applied. Figure 36 shows the reduction in natural gas use in the power sector as incremental costs are increasingly applied. At the upper limit, natural gas consumption for power generation declines from roughly 15 quads[146] in the Baseline – Mid-EUR case to 10 quads (incremental $2/MMBtu added) by 2050. With a $0.50/MMBtu added cost of gas production, the long-term impacts are far more modest—resulting in a reduction of gas use for power generation in 2050 of less than 2 quads. Coal—and wind, to a lesser extent—replaces the generation lost by the more expensive gas. Other impacts associated with these assumed incremental costs appear relatively modest.

[146] To roughly convert from quads to bcf/d, multiply by 2.6. Thus, 15 quads per year equal about 38.5 bcf/d.

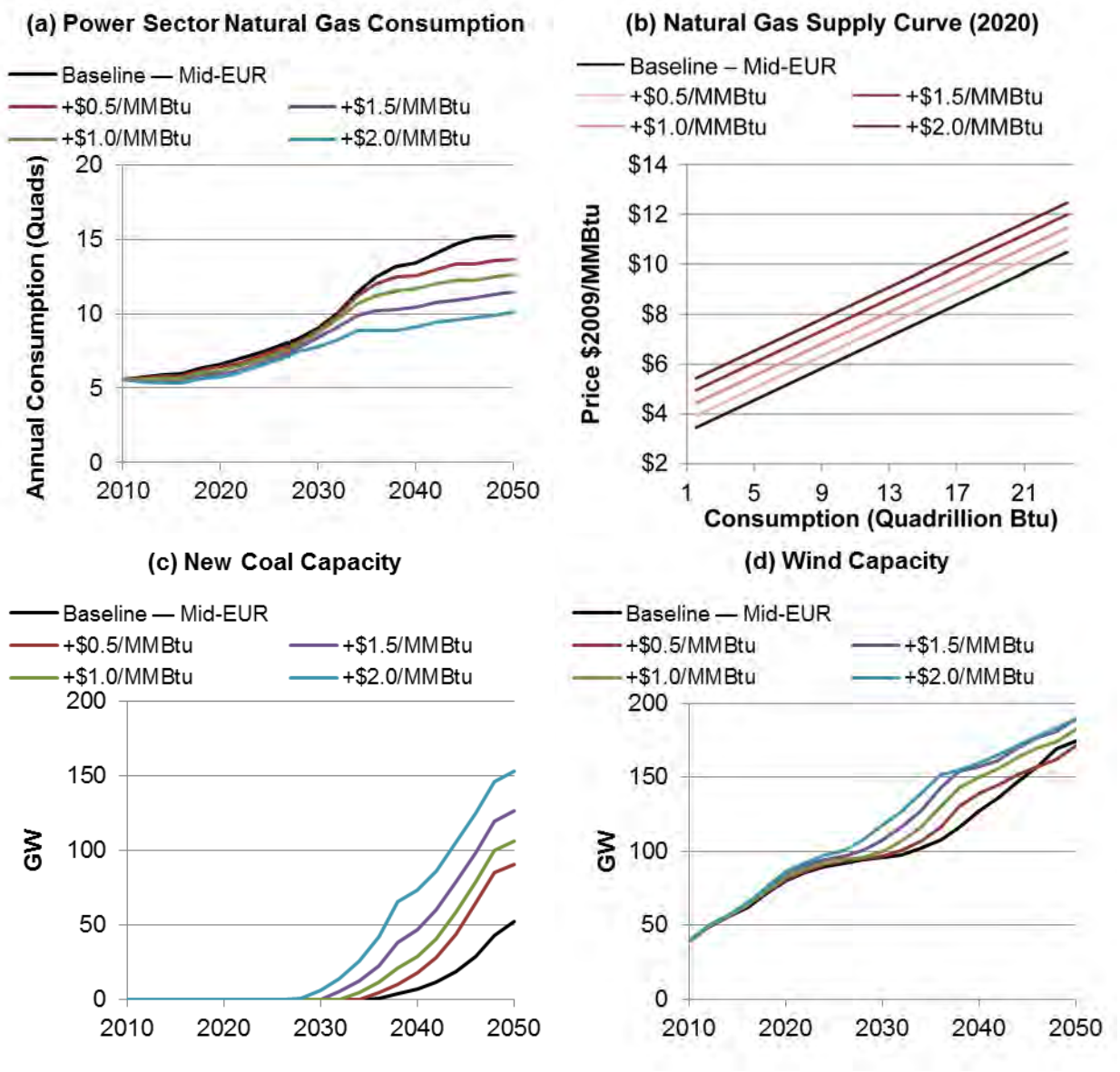


Figure 36. Selected metrics for the Natural Gas Supply Cost Variation case, 2010–2050

4.7.2 Natural Gas Demand Variations (Dash-to-Gas)

The Natural Gas Demand Variations case considers the impact to potential expansion of natural gas generation if a significant shift to natural gas occurs in other sectors of the economy. Specifically, it looks at the combined potential of new LNG exports, natural gas vehicle deployment (both compressed natural gas and LNG in heavy-duty trucking), and use in industrial and chemical applications and any other sector that in aggregate reaches 12 bcf/d by 2026.

A growing number of studies analyze the impact of LNG exports on domestic natural gas prices (EIA 2012b; Pickering 2010; Deloitte 2011; Ebinger et al. 2012). Estimates vary considerably depending on methodology used, location, and assumptions about overall gas availability. The case examined here uses the methodology in the EIA LNG exports scenario as a basis for the full

economy "dash-to-gas."[147] Thus, it takes the "high and slow" EIA-derived price impact of exporting 12 bcf/d of LNG by 2026 and uses it to represent the impact of a combined 12 bcf/d in the total economy, distributed among LNG exports, vehicle use, industrial use, and any other applications (see Figure 37 and Table 16).

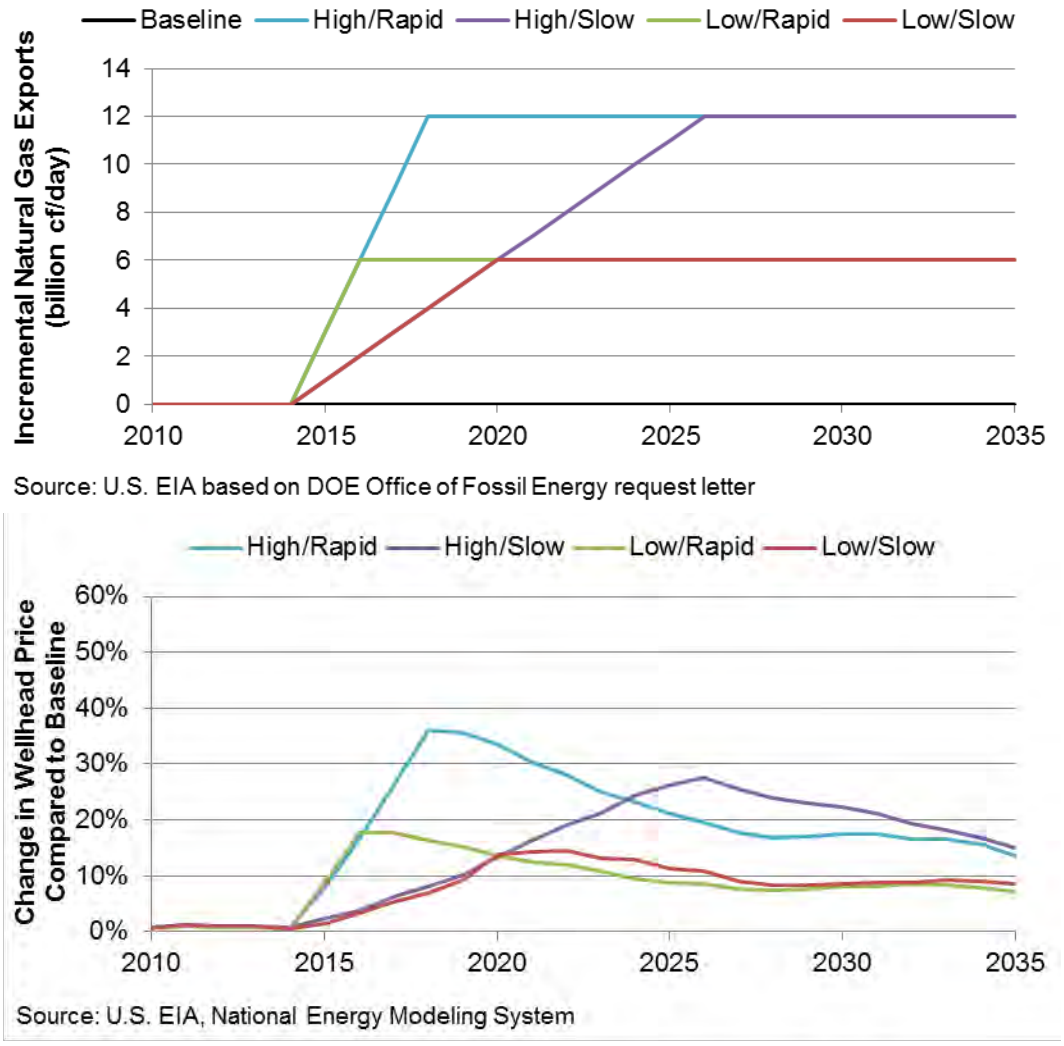


Figure 37. EIA LNG export scenarios and their projected impacts on domestic natural gas prices, 2010–2035

[147] The upper limits (i.e., high/rapid scenario) of the EIA study have been criticized by some (Ebinger et al. 2012) as too extreme and not representative of how LNG exports might really occur. Although the study in this report uses the second-most extreme (high/slow) LNG export scenario considered by the EIA, the scenario is constructed to capture a wider range of potential natural gas end-uses than just LNG exports.

Table 16. Non-Power Sector Natural Gas Demand Assumptions in the Natural Gas Demand Variations Case

	2010	2020	2030	2040	2050
	(billions of cubic feet per day)				
LNG Exports	0	5.0	7.3	5.0	0
Vehicles[148]	0	1.5	2.7	3.0	0
Industry/Other	0	1.5	2.0	1.5	0
Subtotal	0	8.0	12.0	9.5	0

In the Natural Gas Demand Variations (dash-to-gas) case, gas prices rise by a maximum of 29% above the Reference scenario value in 2026 before re-equilibrating. The power sector mix is similar to the Baseline – Low-EUR case (compare Figure 38 with Figure 26), although still slightly more reliant on natural gas generation. A dash-to-gas future, then, would restrict gas generation to less than doubling by 2050 compared to the 2010 level. The larger macroeconomic impacts associated with this future were not evaluated; however, overall gas demand declines by about 3 quads by 2050 (Figure 39) compared to the baseline. The price of natural gas for power generators rises by a maximum of $2/MMBtu above the baseline value in the early 2020s before returning to the baseline level in 2050, when the other sectors are assumed to terminate their extra reliance on natural gas (see Figure 39).

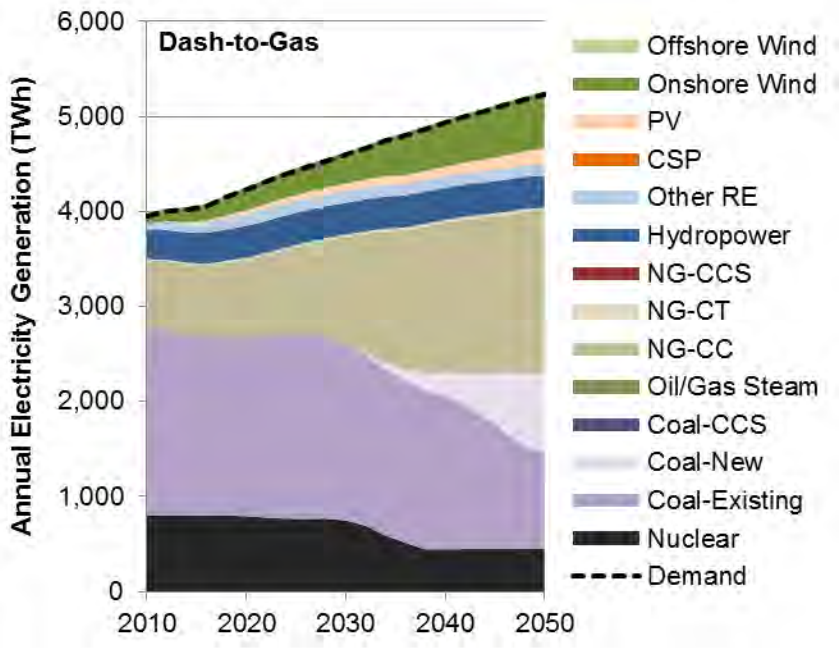


Figure 38. Power generation mix in the Dash-to-Gas case

[148] These estimates for compressed natural gas use in vehicles are proposed by Wellkamp and Weiss (2010).

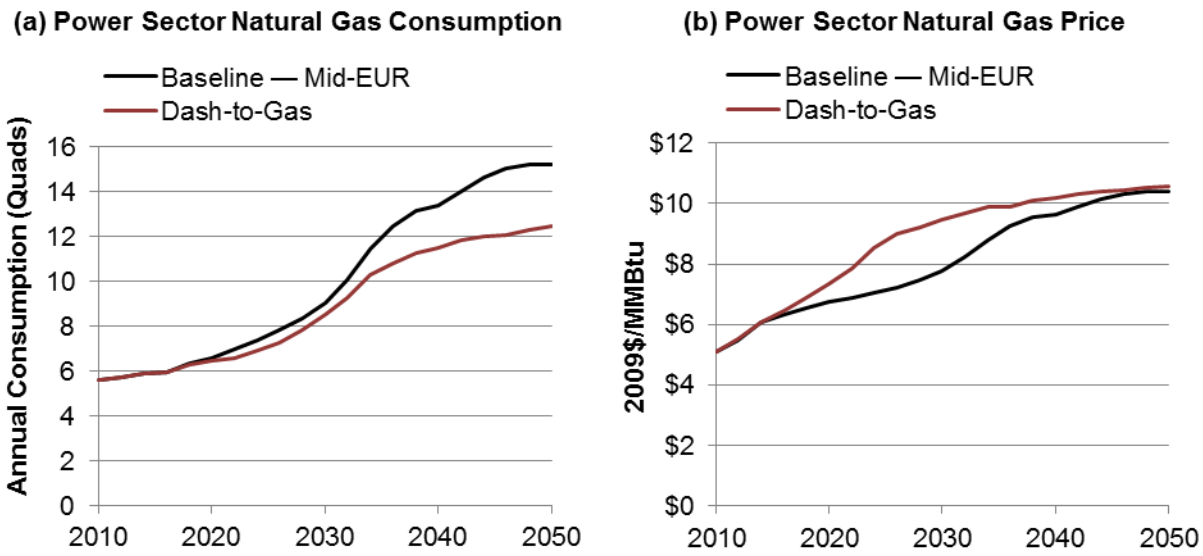


Figure 39. Selected metrics for the Dash-to-Gas case, 2010–2050

4.7.3 Implications of the Natural Gas Supply and Demand Variations Findings

Many additional measures could be taken by producers to address the real and perceived risks associated with unconventional natural gas production at a modest impact to the evolution of the power sector. If total costs from a long list of potential practices reached $1.00/MMBtu, natural gas usage in the 2050 power sector might be expected to decline from 2.5 times the 2010 level in the Baseline to 2 times in the Supply Variation case. Costs associated with ensuring stronger public support of unconventional gas and oil production would vary by region and producer. Technologies associated with unconventional natural gas production are under rapid development, so the cost impacts will be changing dynamically. Follow-on research should attempt to gather additional data from producers to better estimate what the real cost would be of addressing issues of social license to operate on a basin-by-basin level. The question for industry might then be: Are these added costs worth absorbing—and an acceptable price to pay—to ensure both greater public and utility-sector confidence in the production practice over the longer term?

Understanding the price impacts of a Dash-to-Gas case is still poorly characterized due to the newness of the recent change in natural gas supply outlook. Based on currently available estimates, a fairly strong dash-to-gas in other sectors of the economy would have a visible, although still marginal, impact on the evolution of the electric power sector—with natural gas use declining somewhat due to the higher prices and other forms of generation increasing to take its place. As additional experience and estimates of this elasticity become available, follow-on research should re-examine the impacts.

4.8 Conclusions for Power Sector Modeling

The role of natural gas in the U.S. power sector is sensitive to assumptions about EUR. More research is needed to better understand how much gas will ultimately be recovered from unconventional plays.

Coal retirements and fuel switching are already occurring ahead of the rollout of EPA rules. The modeling results indicate that any new plants needed to replace retiring coal would mostly be fired by natural gas and that on an aggregate level, reliability standards are maintained without an unusual level of new construction. This analysis did not attempt to evaluate location-specific reliability impacts associated with coal-plant retirements; more granular dispatch models would be needed to investigate those questions with more certainty.

The CES modeling results indicate that substantial reductions in CO_2 emissions are achievable at modest cost, although transmission barriers could stand in the way. When CCS is not available under a CES, generation options decline, the need for new transmission expands significantly, and the power mix becomes less diverse. Therefore, CCS is an important option for a low-carbon power sector, but may not be essential.

Continued focus on technology research, development, and deployment is needed to bring down costs and ensure a diverse power mix in the future. Even modest reductions in renewable energy capital costs and improvements in performance may have a meaningful impact on their continued deployment in the future. Continued advancements in technologies used to find and produce unconventional gas could also have a strong impact on improving the social license to operate at an acceptable price, and thus, should be pursued at all levels.

Finally, increased costs associated with potential changes in field practices of natural gas producers were evaluated over a fairly broad range. If these costs turn out to be less than an incremental $1/MMBtu, then the long-term impact on natural gas in the power sector is not significantly different from the baseline conclusions: gas demand for power generation declines by about 17% while CO_2 emissions increase marginally. An important outcome of this study—and a potential question for follow-on research and discussion—would be whether these additional costs associated with protecting the environment, improving safety, and commanding public confidence are worthwhile to society and gas producers.

Natural gas appears plentiful and at historically low price levels for the foreseeable future, but going forward, decision makers may want to pay special attention to generation diversity. An undesirable outcome would result if a major shift to natural gas generation occurred before a substantial rise in natural gas prices—due, for example, to mischaracterizations of EUR, a failure to earn the social license to operate, or some other reason that may currently be considered "unlikely." Continuing research, development, and deployment over a wide variety of generation and gas production options can help prevent such an outcome. It would also provide greater flexibility in addressing the threat of climate change.

5 Conclusions and Follow-On Research Priorities

5.1 Conclusions

Major, high-level findings derived from the research conducted in this study include:

- Life cycle greenhouse gas emissions associated with electricity generated from the Barnett Shale play gas in 2009 were found to be very similar to conventional natural gas and less than half of those associated with coal-fired power generation.
- Low-priced natural gas has led to more than 300 terawatt-hours of fuel switching from coal to gas in the U.S. power sector between 2008 and 2012. This switching, in combination with rapid growth in certain renewable energy generation sources, has led to a reduction in power-sector carbon dioxide emissions of about 300 million tons—about 13% of the sector's total. This fuel switching may stop or reverse itself if natural gas prices rise relative to coal. Natural gas can play an important role in greenhouse gas mitigation over the short- to mid-term, but if policymakers pursue an 80% mitigation target by 2050, carbon capture and sequestration may need to be commercially viable by 2030 for natural gas power generation to continue growing.
- The legal and regulatory frameworks governing shale gas development are changing in response to public concerns, particularly in regions that have less experience with oil and gas development. All of the states examined in this study have updated their regulatory frameworks to address the opportunities and challenges associated with greater unconventional natural gas production. Better coordination and information sharing among regulators may help ensure efficient and safe production, while greater availability of transparent and objective data may help address some of the public's concerns.
- States and natural gas producers are developing additional, often voluntary, field practices to ensure that shale gas can be produced with high standards of environmental protection—although these standards are not always uniformly followed. Continued advances in technologies and practices could help address public concern over unconventional gas production. Some data, such as the amount of water used per well in hydraulic fracturing, are readily available and can be analyzed on a regional basis. However, a lack of publicly available information on industry practices limits a full-scale assessment of water risks associated with shale gas operations. Further collaboration and interaction with industry partners could help improve data collection efforts.
- A suite of different future electric power scenarios was evaluated to test the implications of different policy and technology changes. These scenarios include power plant retirements, advances in generation technologies, federal policies to reduce greenhouse gases, and variations in natural gas supply and demand. The study found that natural gas use grows robustly in nearly all scenarios over the next two decades. Over the longer term, natural gas demand for electricity generation faces greater uncertainty, leading to larger ranges of change in gas demand—including the case where demand in 2050 is roughly the same as that in 2010 in the event a clean energy standard is pursued and carbon capture and sequestration is not commercially available (see Figure 32).

Readers should consult corresponding chapters to view more comprehensive findings and ensure that the appropriate context is conveyed with each finding.

5.2 Follow-on Research

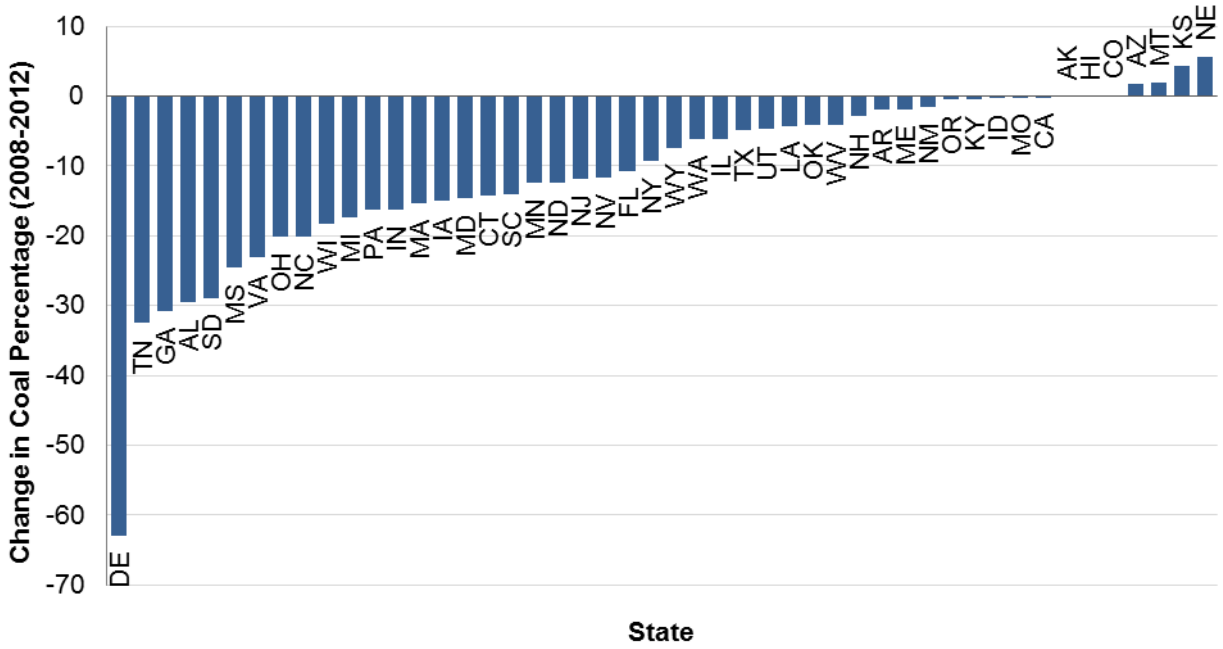
Because of time and budget constraints, the research team could not investigate some issues as fully as warranted. Each chapter identifies areas where additional research would likely lead to improved understanding on certain issues. Selected follow-on research taken from this larger list is presented below. Please refer to the main chapters for a more comprehensive discussion on these follow-on research topics.

- More field-measurement-based research on methane leakage and mitigation options at unconventional gas production facilities (outside of the Barnett Shale play) considering geographic and operational variability at well, play, and national scales.
- More industry- and basin-specific research to estimate the incremental costs associated with various regulatory scenarios, including more robust environmental standards in unconventional gas production. Additional social research to understand how improved standards might impact public perception of gas production and the social license to operate. Additional economic research to understand how higher costs would impact producers, and the degree to which they might be able to pass costs on directly to consumers.
- More comprehensive evaluation of risks in shale gas production and how they can be best addressed using new technologies and field practices. Increased quantitative understanding of the magnitude and probability of risks to water resources that result from current industry practices and proposed best management practices. More comprehensive evaluation of the regional diversity of risks, costs, and effective industry practices inherent in shale gas development.
- Greater understanding of the impact of additional natural gas demand, especially liquefied natural gas exports, on domestic and international prices. In general, greater certainty and understanding of natural gas price volatility and estimated ultimate recovery in the relatively new abundant natural gas environment would also be beneficial.
- Finally, this study did not use a modeling tool that simulated operation and expansion of natural gas pipelines. Follow-on work that included such capabilities might identify additional opportunities and barriers to growth in electric power natural gas use.

Appendix A: Shifting Coal Generation in U.S. States

This appendix summarizes recent data on changes in coal-fired electricity generation published by the Energy Information Administration (EIA) of the U.S. Department of Energy. Many of these changes are due to some combination of low-priced natural gas, aging coal generators, and impending regulations from EPA. However, some changes—especially in small states—could be unrelated. Using data at the state level—rather than the larger boundaries of regional transmission organizations or independent system operators—is somewhat artificial when showing changes in electricity generation. Nevertheless, state-level data are convenient, and important trends can be seen in the grouping of some states.

Figure 41 presents a snapshot of the change in coal-fired generation percentage between 2008 and the first 2 months of 2012 for most states. The charts that follow provide additional information on how changes in generation mix have occurred in the first 15 states shown in Figure 41.



Data: U.S. Energy Information Administration, Electric Power Monthly, data through February 2012.
Note: DC, RI, and VT are not included.

Figure 41. Changes in coal percentage of total net generation at the state level, 2008–2012

Figure 42 through Figure 56 show how generation mix has changed between 2005 and early 2012 for the 15 states with the largest drop in coal percentage as a percent of total net generation. The data for all of these figures come from the U.S. Energy Information Administration, "Electric Power Monthly." The data are through February 2012, and the 2012 data include only January and February net generation. Some seasonal effect is reflected in the 2012 year-to-date data points.

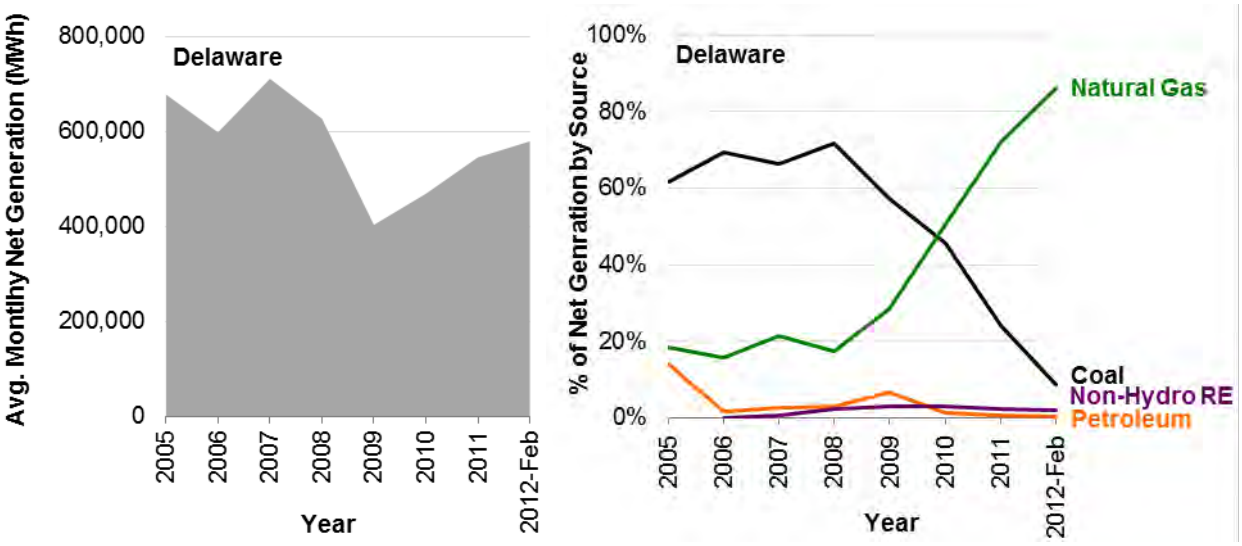


Figure 42. Changes in generation mix in Delaware; 2005–early 2012

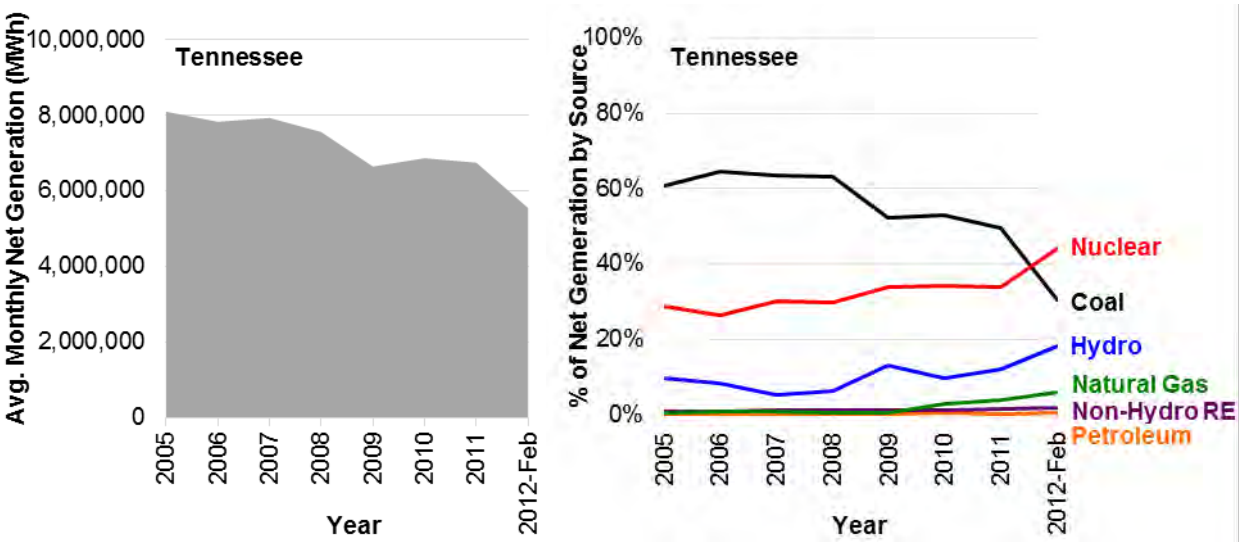


Figure 43. Changes in generation mix in Tennessee; 2005–early 2012

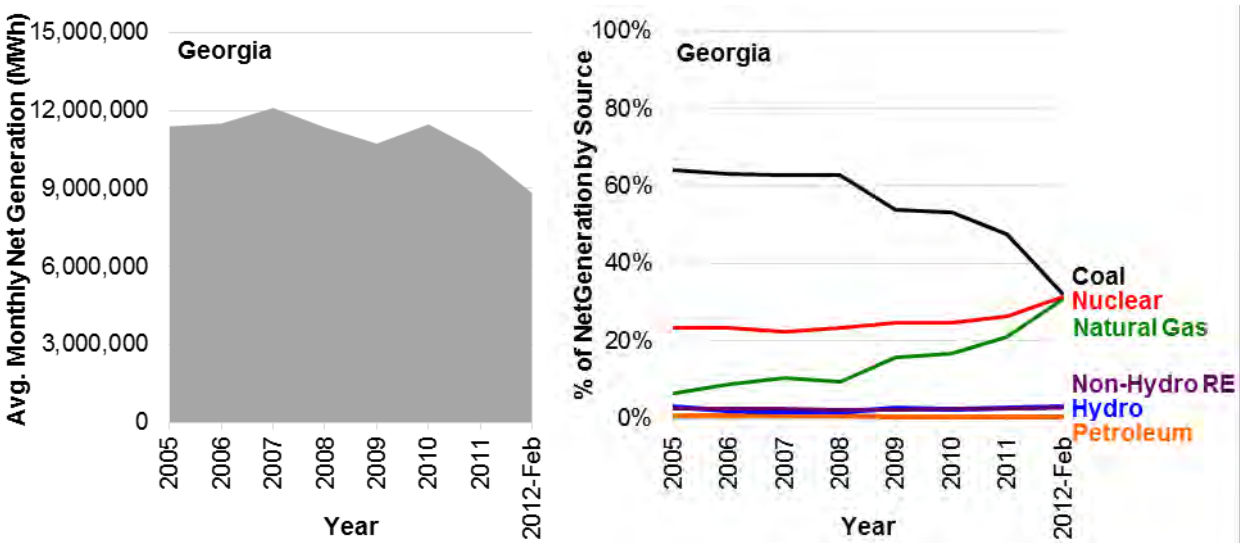


Figure 44. Changes in generation mix in Georgia; 2005–early 2012

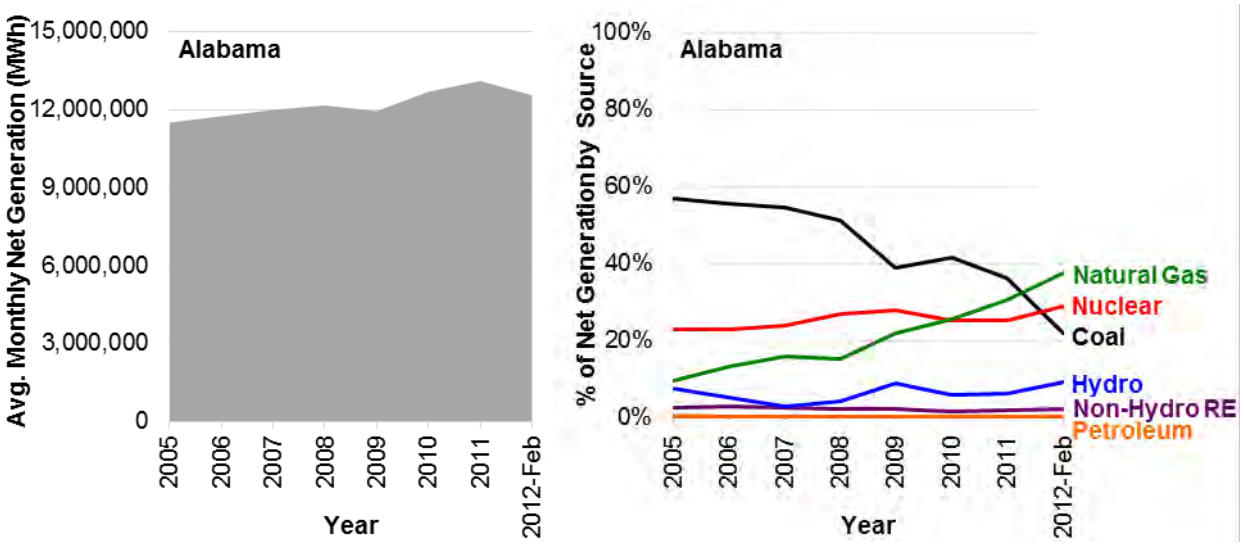


Figure 45. Changes in generation mix in Alabama; 2005–early 2012

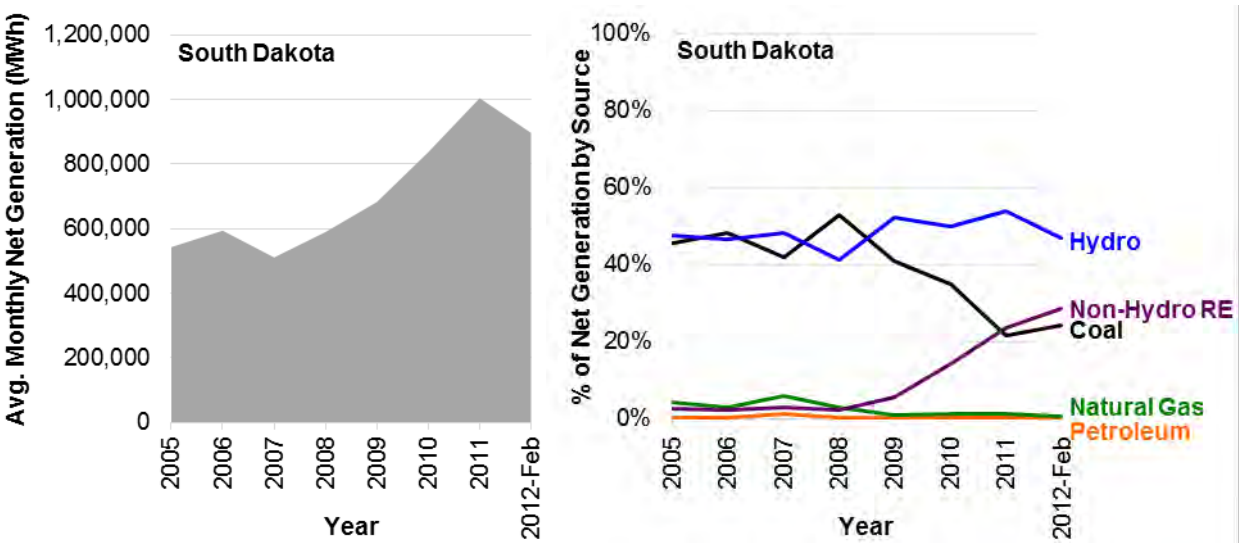


Figure 46. Changes in generation mix in South Dakota; 2005–early 2012

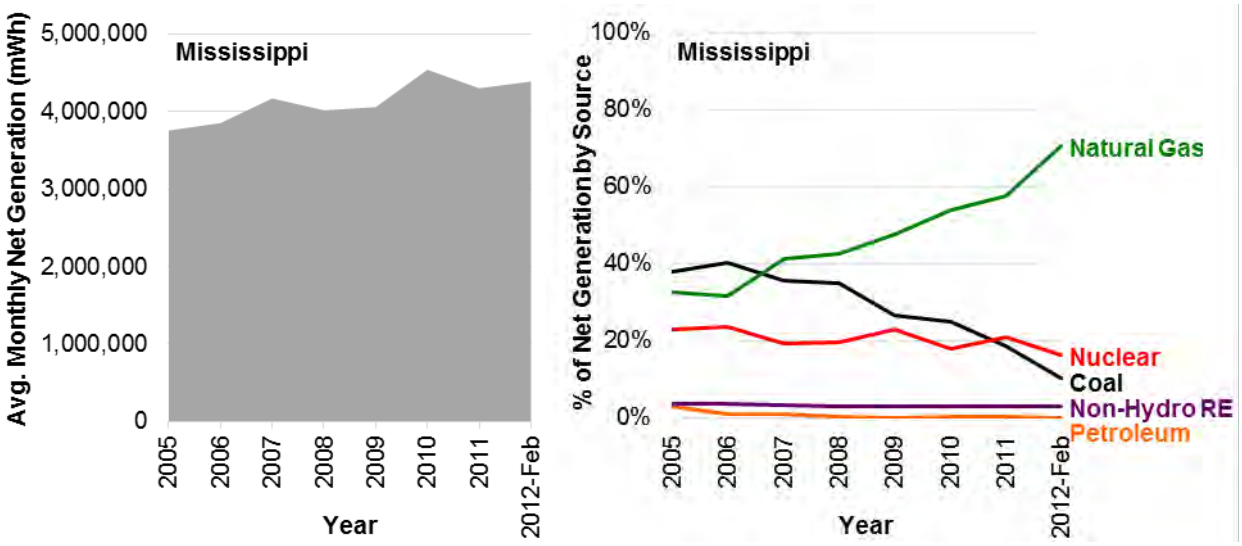


Figure 47. Changes in generation mix in Mississippi; 2005–early 2012

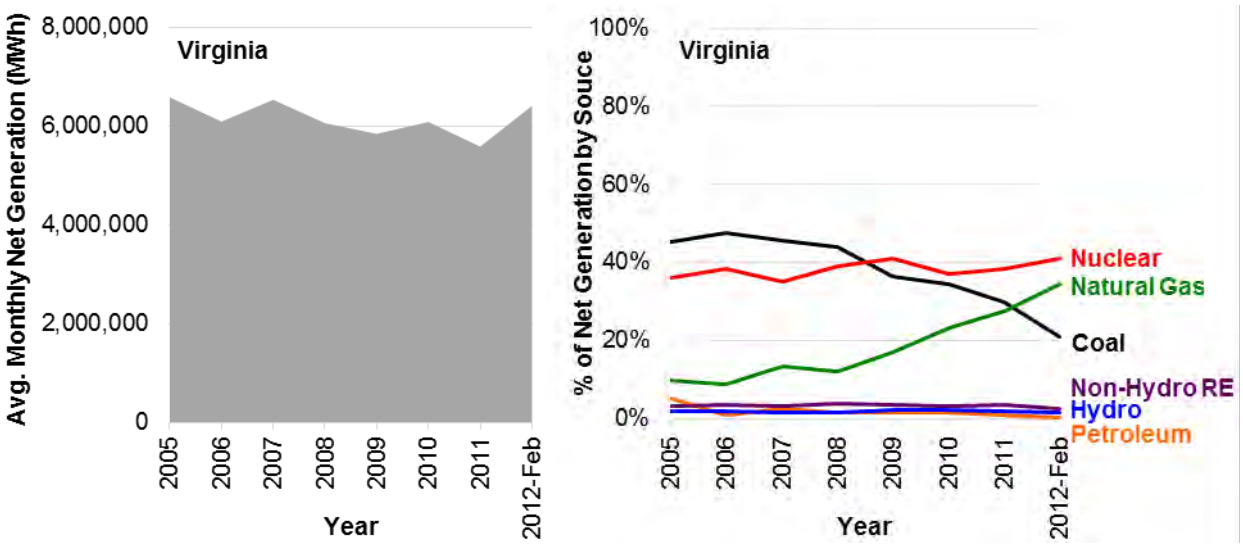


Figure 48. Changes in generation mix in Virginia; 2005–early 2012

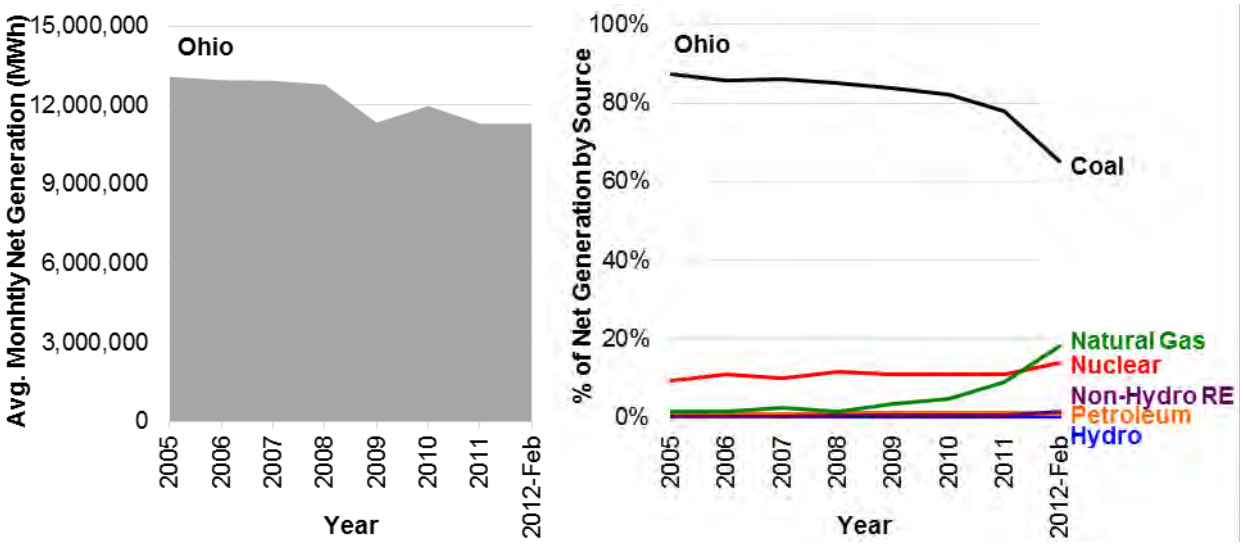


Figure 49. Changes in generation mix in Ohio; 2005–early 2012

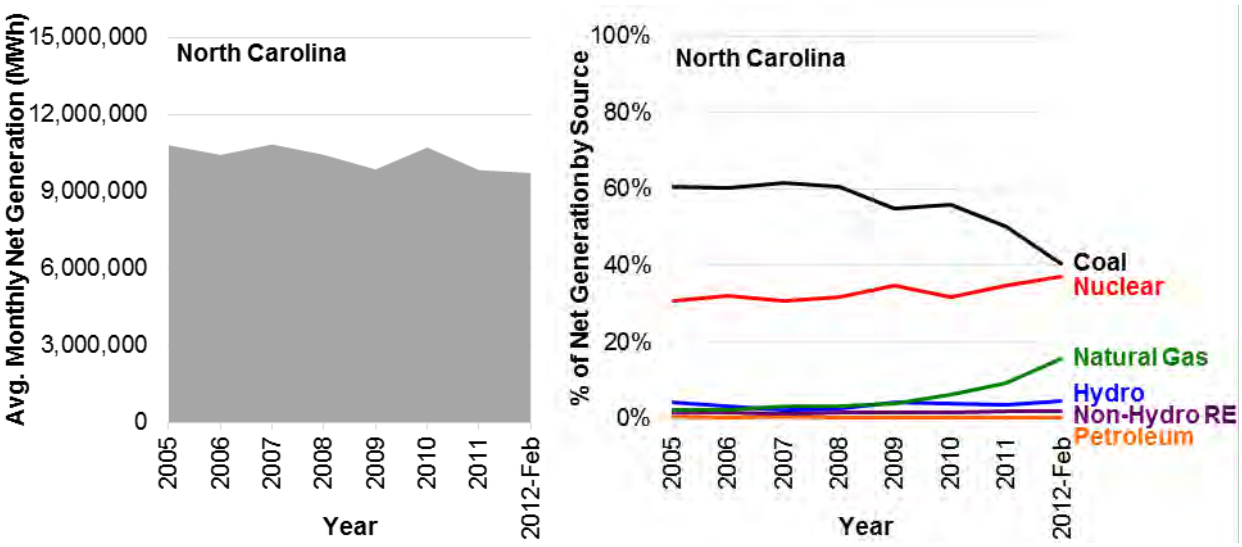


Figure 50. Changes in generation mix in North Carolina; 2005–early 2012

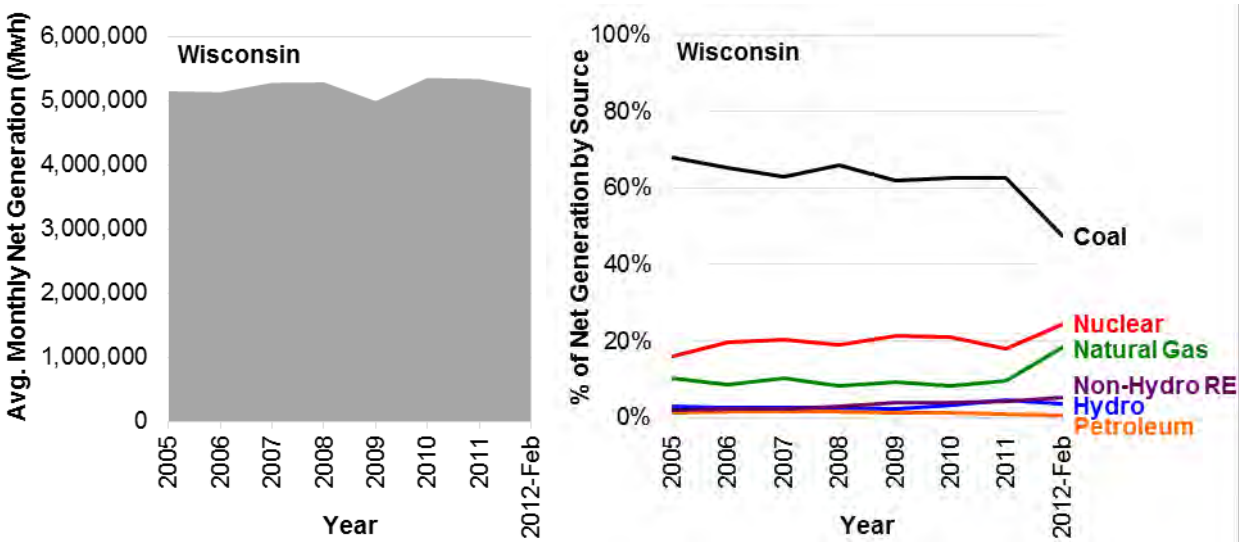


Figure 51. Changes in generation mix in Wisconsin; 2005–early 2012

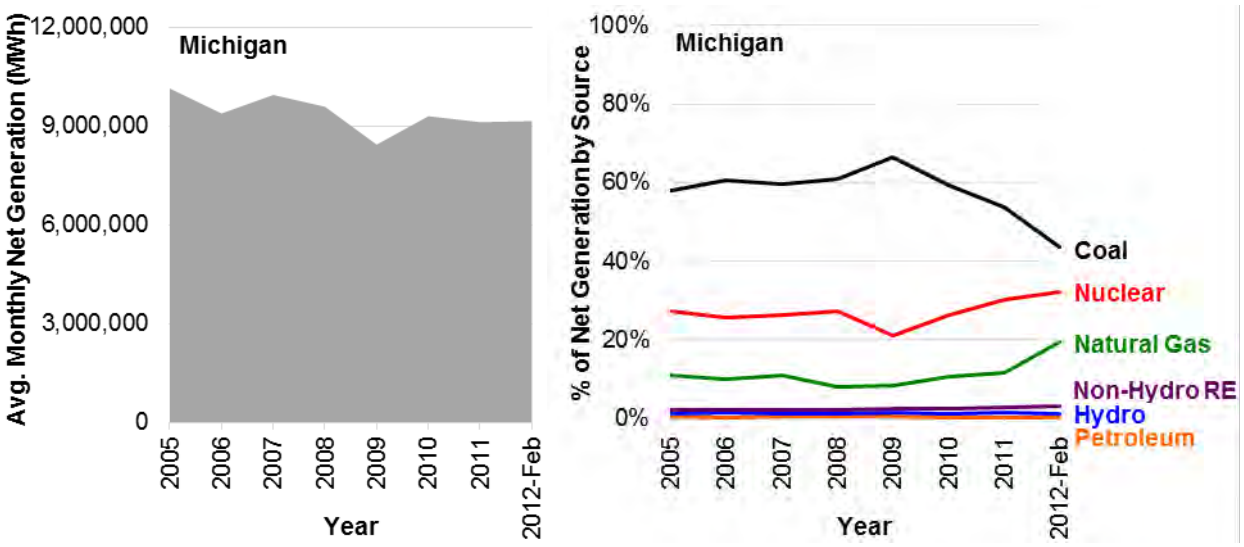


Figure 52. Changes in generation mix in Michigan; 2005–early 2012

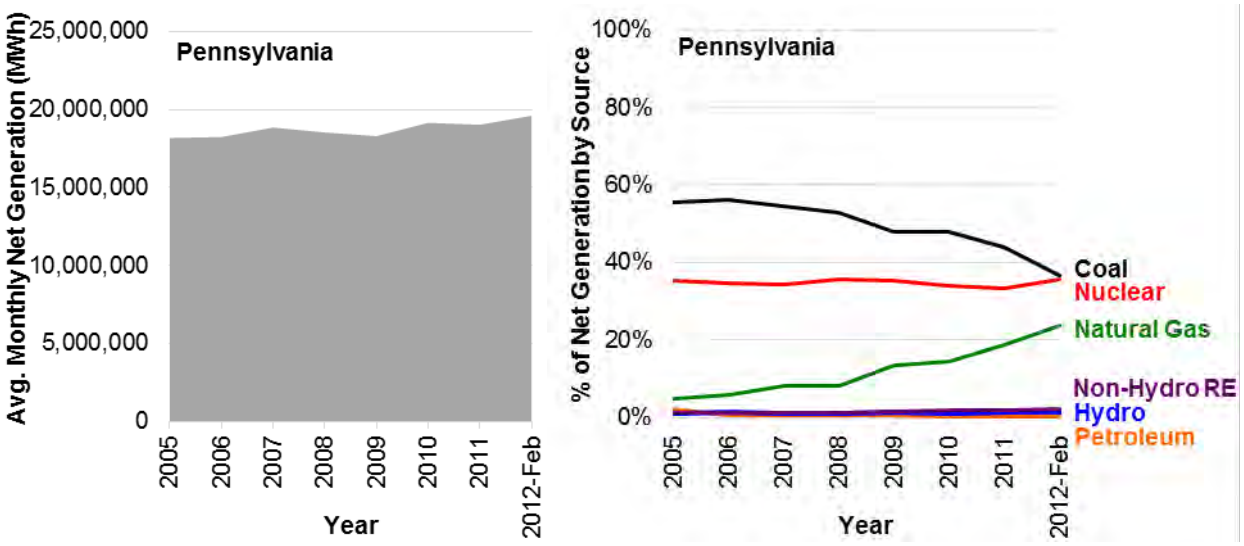


Figure 53. Changes in generation mix in Pennsylvania; 2005–early 2012

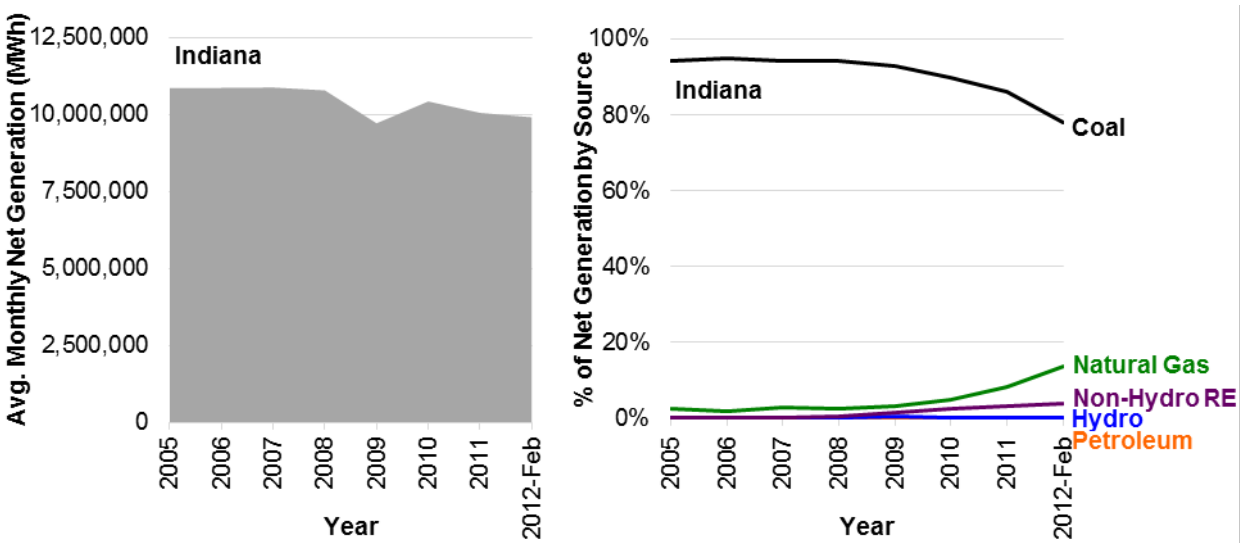


Figure 54. Changes in generation mix in Indiana; 2005–early 2012

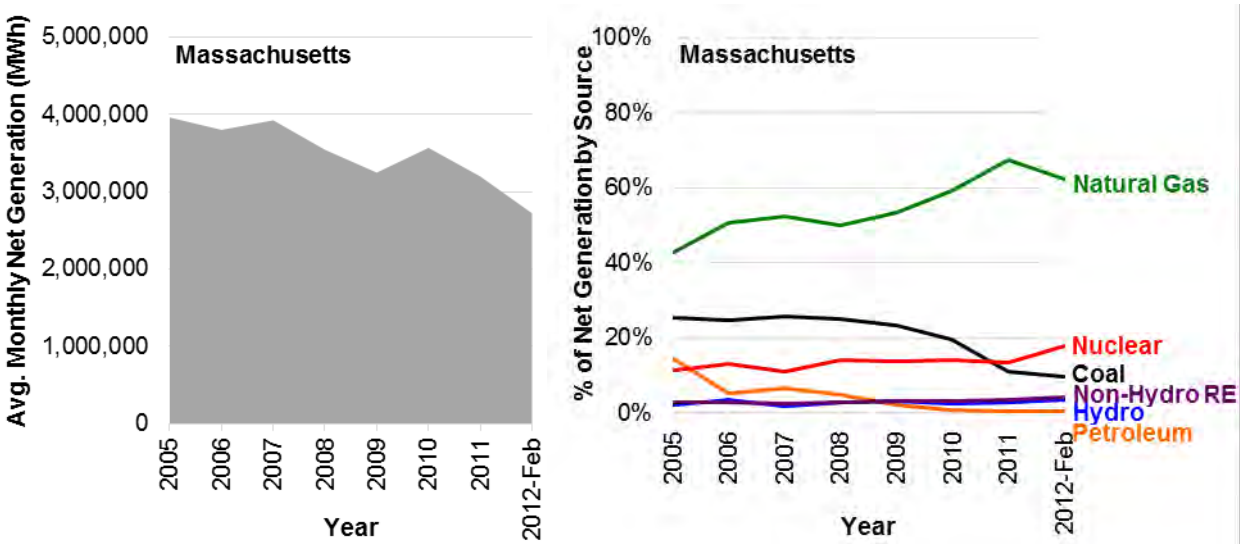


Figure 55. Changes in generation mix in Massachusetts; 2005–early 2012

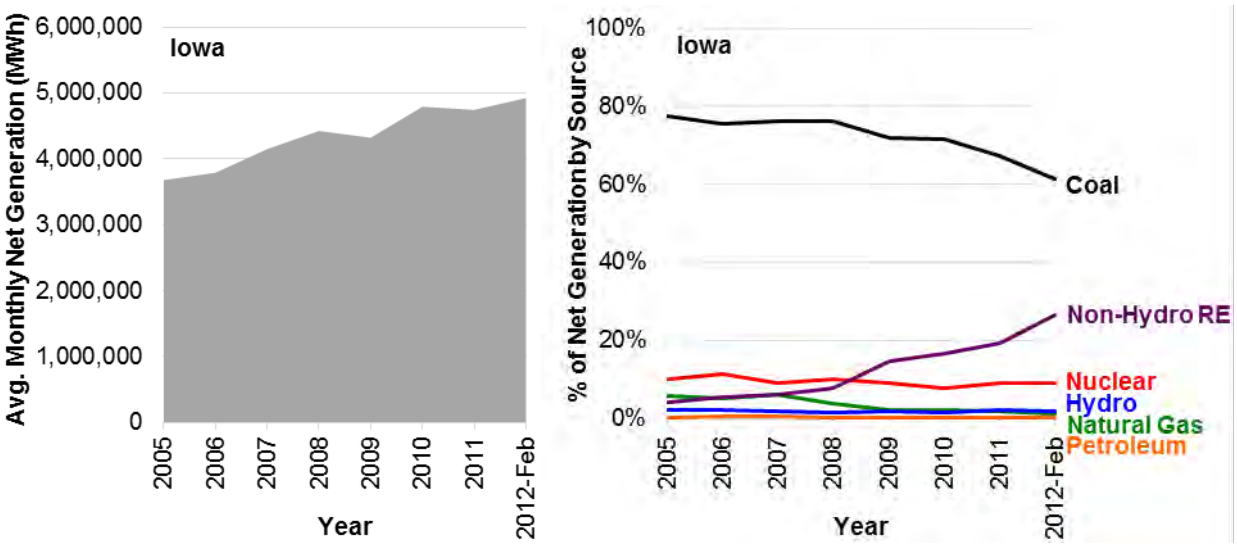


Figure 56. Changes in generation mix in Iowa; 2005–early 2012

Appendix B: Details and Considerations of Methods

This appendix offers details of data, methods, and results for Chapter 1. First, we define several terms relevant to estimating GHG emission factors from the TCEQ inventories.

The *basin* refers to 22 counties under which the Barnett Shale is being developed. Therefore, production in the basin includes production from the Barnett Shale as well as a small amount of additional production from other geological formations contained within the 22 counties.

As defined by the TCEQ (2010: p.23), "any source capable of generating emissions (for example, an engine or a sandblasting area) is called a facility. Thus, facility and emissions source, or 'source' for short, are synonymous." To avoid confusion, we use the term *source* to refer to any individual such facility.

Sources can be characterized into common types called *profiles*. Common examples of profiles include engines, turbines, fugitives, and tanks. Profiles are designated such that the emissions from sources with the same profile can all be estimated with a common method.

The term *site* refers to a physical location for which data are reported to the inventories, where each site consists of multiple different emissions sources. Each site is associated with a unique TCEQ account number and site name. Common examples of types of sites include wells, compressor stations, and gas processing plants. In the Special Inventory, sites are referred to as *leases*.

Production gas refers to the raw, unprocessed gas captured through development activities, and *pipeline gas* refers to the saleable final natural gas product. *Emissions* refer to tons of the specified pollutant(s) emitted per year, whereas *emission factors* refer to the amount of emissions associated with a unit of gas production. This report follows the EPA and TCEQ convention of referring to the set of non-methane, non-ethane hydrocarbons as *VOCs*.

TCEQ Inventory Data

The TCEQ collects an annual, statewide emissions inventory for sources classified as point sources per 30 Texas Administrative Code §101.10. For this study, data were obtained for any sources within this inventory with Standard Industrial Classification (SIC) codes pertaining to the production and processing of natural gas. From the point-source inventory data, GHG emissions are estimated from amine units, boilers, compressor engines, flares, fugitives, glycol dehydrators, heaters, produced-water loadings, produced-water tanks, natural gas turbines, and vents.

To complement the point-source inventory, the TCEQ performs an Area Source Inventory every three years. Data were obtained from the 2008 Area Source Inventory on VOC emissions from pneumatics and produced-water disposal activities, which were not available in the other inventories. These data are reported only at the county level. To combine emissions estimated from pneumatics with those estimated from other inventories, these profile's emissions are adjusted by a factor equal to the change in gas production between 2008 and 2009, at the county level, as shown:

$$Adjustment = \frac{Q_{GWgas,2009}}{Q_{GWgas,2008}}$$

where:

$Adjustment$ = the county-level adjustment from 2008 to 2009 emissions estimates (unitless)

$Q_{GWgas,2008}$ = volume of gas-well gas produced in 2008 (Mcf)

$Q_{GWgas,b,2009}$ = volume of gas-well gas produced in 2009 (Mcf).

In 2009, the TCEQ performed a Special Inventory, for which it requested detailed equipment and production information for stationary emissions sources associated with Barnett Shale oil and gas production, transmission, processing, and related activities. The Special Inventory data cover only stationary emissions sources on site for more than 6 months that were not reported to the 2009 Point Source Inventory. These sources are used in this study to estimate GHG emissions from amine units, boilers, heaters, compressor engines, flares, fugitives, glycol dehydrators, produced-water loadings, produced-water tanks, and vents.

Some emissions sources are not reported to the Special Inventory that nonetheless contribute to the reported site-level total in that inventory. These sources are likely omitted because their emissions are below thresholds for reporting requirements for that inventory. However, although they may be individually negligible, their collective impact is significant—with the sum of the VOC emissions reported for all individual sources equaling only 93% of the sum of all site-level totals reported, across the entire inventory. To account for this underreporting, emissions estimated from Special Inventory data are scaled at the site-level by the inverse of the percentage of site VOCs accounted for by the individual sources reported at each site, as follows:

$$Correction_{site} = \frac{1}{\left[\frac{\sum_{k \in K_n} VOC_k}{VOC_n}\right]} = \frac{VOC_n}{\sum_{k \in K_n} VOC_k} \geq 1$$

where:

$Correction_{site}$ = the site-level correction for non-reported sources (unitless)

VOC_k = the mass of VOCs emitted from source k annually, where $k \in K_n$ is the set of reported sources at site n (tonne/year)

VOC_n = the reported total mass of VOCs emitted from site n annually (tonne/year).

In addition, to account for a stated 98% level of completion for the Special Inventory, all emissions estimated from the inventory's data by the inverse of that completion rate are also adjusted by the inverse of this estimate, as follows:

$$Correction_{inventory} = \frac{1}{98\%} = 1.0204$$

Stages of the Natural Gas Life Cycle

Emissions factors are compiled from the profiles associated with each life cycle stage.

Pre-Production Stage

The pre-production process stage consists of episodic activities related to the preparation of wells. Activities in this stage include the drilling and construction of wells, hydraulic fracturing of shale to stimulate production, and various well-completion activities, which specifically involve the following:

- *Drilling rigs* are used for drilling an oil or gas well. For the purpose of estimating emissions, rigs consist of a collection of diesel-powered engines, which are associated with combustion-generated GHG emissions.
- *Hydraulic fracturing* involves complex liquids, pumps, and trucks for transporting equipment and fluids, which are associated both with combustion-generated GHG emissions and with emissions from off-gassing and fugitives.
- *Well-construction activities* are associated with combustion-generated GHG emissions due to the use of heavy construction equipment.
- *Well-completion activities* involve the release of natural gas from a well before and during the installation of the equipment necessary for recovery of that gas.

Natural Gas Production Stage

The production process stage consists of ongoing activities related to the extraction of natural gas at a gas well. Emissions sources include the following:

- *Compressor engines* are used to maintain well pressure and for other processes at the wellhead. These engines, which typically burn the production gas being extracted, are associated with combustion-generated GHG emissions.
- *Fugitives* occur from the unintentional release of production gas through leaks from equipment and connections throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found.
- *Vents and blowdowns* refer to the intentional release of gas from equipment throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found.
- *Pneumatics devices* are used to open and close valves and other control systems during natural gas extraction. These sources are associated with gas release emissions, which depend on the composition of their identified contents.
- *Miscellaneous material loading and tanks* refer to sources at production sites that are associated with any materials not expected to be co-products of natural gas processing, such as gasoline, diesel, or lubricating oil. These sources are associated with gas release emissions, which depend on the composition of their identified contents.
- *Condensate and crude-oil-related sources*, including loading areas and storage tanks, are associated with substantial VOCs but occur in the process chain only after the co-products have been separated from the natural gas process chain. Therefore, although these emissions sources sometimes are reported in natural gas emission inventories, they are outside the boundary of this analysis.

Natural Gas Processing Stage

The processing process stage consists of ongoing activities related to converting the extraction production gas to the required quality, composition, and compression of pipeline gas. Activities in this stage include separating the condensate co-product from the gas, removing naturally occurring acid gases such as CO_2, lowering the moisture content of the gas, and pressurizing and heating the gas. These activities can occur at either the wellhead or at separate processing facilities, and they are associated with the following emissions sources:

- *Compressor engines and natural gas turbines* are used to pressurize the gas and power other processing activities. These engines, which typically burn the production gas being processed, are associated with combustion-generated GHG emissions.
- *Boilers and heaters*, which typically burn the production gas being processed, are used for processing activities, including the separation of condensate from natural gas and the reduction of ice crystals in the gas stream. Boilers and heaters are associated with combustion-generated GHG emissions.
- *Amine units*, also known as acid gas removal (AGR) units, remove acid gases, such as CO_2, from the production gas to help bring the gas composition to that required for pipeline gas. Amine units are associated with the release of GHGs through venting.
- *Glycol dehydrators* remove water from the production gas to help bring the gas composition to that required for pipeline gas. Dehydrators are associated with the release of GHGs through venting.
- *Fugitives* occur from the unintentional release of production gas through leaks from equipment and connections throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found. Because the precise composition of the fugitive gas cannot be identified, it is assumed that all fugitives consist of production gas.
- *Vents and blowdowns* refer to the intentional release of gas from equipment throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found. Because the precise composition of the vented gas cannot be identified, it is assumed that assume all vents and blowdowns consist of production gas.
- *Produced water handling*, including loading areas and storage tanks, is associated with gas release emissions, which are assumed identical in composition to water flash gas.
- *Flares* are combustion-based emission control devices used to convert methane from gas-release emissions into CO_2 from combustion emissions. Flares are used as controls on a variety of gas-release emission sources, including produced-water tanks, condensate tanks, and glycol dehydrators.
- *Miscellaneous material loading and tanks* refer to sources at processing sites that are associated with any materials not expected to be co-products of natural gas processing, such as gasoline, diesel, or lubricating oil. These sources are associated with gas-release emissions, which depend on the composition of their identified contents.

- *Separators* are used for processing oil and natural gas; however, only separators at oil sites vent to the atmosphere. Therefore, separators at sites producing only natural gas and not oil should be associated with no VOC emissions. Although these emissions sources sometimes are reported in natural gas emission inventories, they are outside the boundary of this analysis.
- *Thermal oxidizers* are used for processing natural gas, but only a negligible number are reported in the inventories used because of prohibitive capital costs. Therefore, although these emissions sources sometimes are reported in natural gas emission inventories, they are outside the boundary of this analysis.

Waste Disposal Stage

Natural gas production and processing generates the byproduct of produced water, which must be disposed of because of its high level of contaminants, including salt, hydrocarbons, and various pollutants. Although these activities are associated with stationary and mobile emissions sources, the only tracked emission source for this category is that pertaining to tanks that store the produced water at disposal sites.

Identification of Source Profiles and Attribution to Process Stages

This study identifies the process stage (e.g., production, processing, or transport) to which each source belongs using the provided site names in both inventories. To attribute sources to process stages, the profile associated with each source must first be identified. In the Special Inventory, each source is explicitly identified with the profile under which it was reported to the TCEQ. For the sources in the Point Source Inventory, however, the profile of each source is identified using additional provided information.

The primary source of information for this profile identification is the Source Classification Code (SCC). As described by the TCEQ (2010: p. 90), "A facility's SCC is an eight-digit EPA-developed code that associates emissions determinations with identifiable industrial processes. The TCEQ uses a facility's SCC for modeling, rulemaking, and SIP-related activities; therefore, a facility's SCC must be as accurate as possible. The EPA maintains a current list of SCCs under the 'EIS Code Tables (including SIC)' link at www.epa.gov/ttn/chief/eiinformation.html."

Despite the regulatory importance of the SCC classification, the SCCs provided in the Point Source Inventory do not identify the associated source's profile to the detail necessary for 254 (or 12%) of the 2,177 sources within the 22 counties of the basin. The remaining sources rely on the additional information within characteristics files provided by the TCEQ for specific profiles, such as tanks and engines, and by consistent coding schemes within the Facility Identification Number, which is self-designated by the respondents to the emissions inventory surveys. The study identifies 43 (or 2%) of the sources by characteristics files and 211 (or 10%) by the Facility Identification Number, which represent 1.4% and 2.0%, respectively, of the total VOCs reported for all reported sources within the 22 counties of the basin.

For those source categories that can exist at multiple types of process stages, the default assumption is that a location is a production facility (i.e., a well site), unless the site name ("Lease Name" in the Special Inventory and "Site Name" in the Point Source Inventory) is identifiable as belonging to a facility type associated with the processing stage, such as a

processing plant or a compressor station, or with the disposal stage, such as salt-water disposal sites. In addition, four sites identified as disposal by this method are reassigned to production due to non-zero gas-well gas production statistics, which means all sources at those four sites are assigned to production, although some presumably relate to water-disposal activities instead. To the extent that this allocation method introduces an error, that error is not the omissions of emissions from the overall estimates, but rather, the incorrect allocation of total emissions across different process stages.

TCEQ inventory data are available for some pre-production processes, but such data cannot be used for original analysis because it incompletely covers the life cycle stage. Also, literature estimates available for supplementing the original analysis do not segregate between different processes as would be necessary for incorporation with the original analysis.

This study uses site-level allocation to select sources into the processing stage. The same site name in both the Point Source Inventory and the Special Inventory is used to positively identify processing sites, with the default stage for the remaining sites being production. Of the processing sites, following the recommendation of the TCEQ,[149] those that do not have any processing-related sources are designated as transmission sites, and accordingly, are considered outside the boundary of this analysis.

After site-level identification, processing-type sources at production sites are associated with the processing life cycle stage. Such equipment includes heaters, boilers, amine units, and dehydrators. In addition, following Stephenson et al. (2011), this study assumes that all tanks—and therefore, also all loading (which occurs after tanks in the process chain)—belong to the processing stage and not the production stage, regardless of where the tanks are physically located.

To avoid double counting with third-party emission factors for transmission, transmission sites (identified as non-well facilities without any processing equipment) are omitted from the analysis of TCEQ inventory data. Specifically, 833 sources are omitted from the special inventory and point-source inventory analyses as pertaining to transmission. This represents 5% of the total sources from these inventories, or about 10% of the CO_2 and the CH_4 emissions from these inventories.

Spatially Explicit Estimation of Production Gas Composition

An important differentiation of this study's estimation approach from similar studies is that this study attempts to estimate the composition of production gas in a specific area. The methods used in this study improve upon the use of a general gas composition developed from national-level averages by 1) developing a novel gas composition estimate that is specific to a region of interest, but also by (2) further recognizing the spatial heterogeneity of this composition within the 22-county basin. Specifically, this method collects data on speciation of production gas and the flash gas from produced water to calculate the CO_2 and CH_4 emissions from numerous sources in the TCEQ Special Inventory using spatially explicit estimates of gas composition. The following factors come from this speciation:

[149] Personal communication (TCEQ 2012).

f_C == the fraction of carbon in the production gas by mass (unitless)

f_{CO_2} = the fraction of CO_2 in the production gas by mass (unitless)

f_{CH_4} = the fraction of CH_4 in the production gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless)

MW_{gas} = the molecular weight of the production gas (lb/lb-mole)

HHV = the higher heating value of the production gas (Btu/scf).

These data are collected from supplementary files from the TCEQ's Barnett Shale Phase Two Special Inventory. As part of the quality assurance procedures of this Special Inventory, the TCEQ requested supplementary files from respondents. These files consist of a record of the written correspondence between the respondent and TCEQ, which varies considerably in content and form across different respondents. To estimate gas composition across the Barnett Shale region, this analysis focuses on included reports from independent laboratory analyses of the gas compositions, identifiable as pertaining to relevant samples of either production gas or of leaked gas in the form of vents or gaseous fugitives. Due to the nature and the origin of these files, the inclusion and reporting of such gas content analyses are not consistent across different files. Detailed supporting information—such as the specific origin of the sample tested, both with respect to process and geographic location—is not consistently available; therefore, it cannot be confirmed in many cases.

Given the disparate nature of these files and the inconsistent reporting of identifying information, these analyses therefore omit many reported composition analyses due to a lack of clarity regarding the geographical or process-source of the analyzed sample. Instead, those analyses are retained that can be assigned a location and content type with a reasonable level of confidence. The creation of these supplementary files and selection of a subset of them for obtaining gas composition analyses is neither random nor intended to be representative; therefore, such elimination does not introduce selection bias created by such omissions. The randomness of the errors will lead to attenuation bias of the analytical results, which is typical in cases of measurement error where there is no reasonably expected consistent bias to the error. In this context, measurement error should reduce the impact of calculating the spatial variation in gas content versus using the central estimate of gas content across the entire region.

In a related limitation of this method, we identified a substantial number of duplicate analyses in these records associated with different lease locations and even across different counties, based on identifying identical laboratory-assigned sample numbers and identical compositions to the reported level of precision provided by the same company. We attempted to identify and remove duplicate analyses; but misspecification in the dataset is possible because it is unclear in some cases which analysis is the original source.

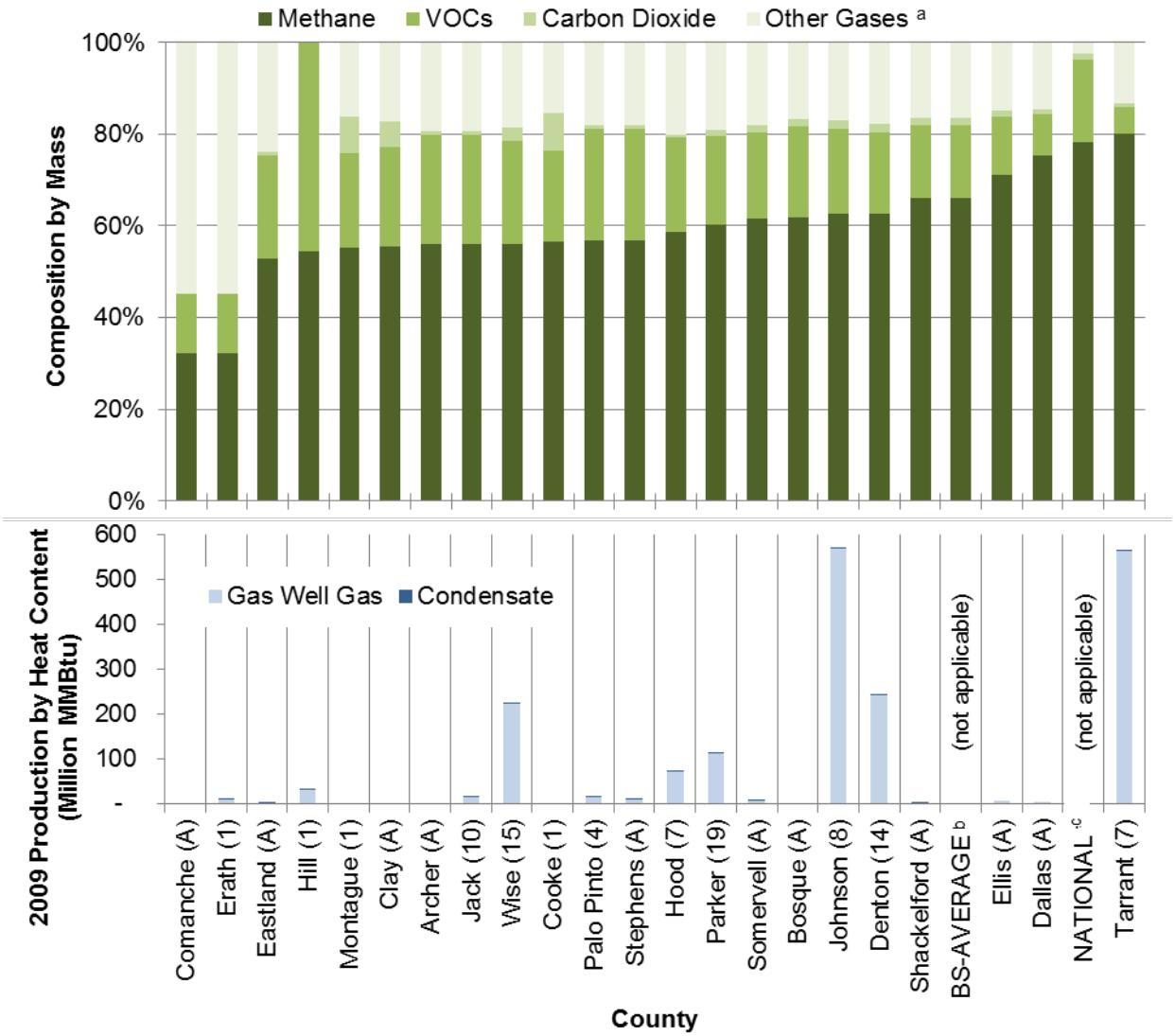
From these data, county-level estimates of gas composition are developed separately for production gas, condensate flash, oil flash, and produced-water flash. Counties with one or more available composition analyses are assigned the composition analysis with the median level percentage-by-weight of methane in the reported composition analyses. In addition to providing a central estimate of gas composition for each county, this estimation of central tendency buffers the results against the impact of misspecifications of location described above.

We used a production-weighted average of the median adjacent counties' estimates with reported composition analyses for counties with no reported composition analyses. A production-weighted average of all reported composition analyses across the Barnett Shale region is used for the few counties with no reported composition analyses either for that county or for all adjacent counties.

In addition to attempting to err on the side of caution in including gas composition analyses, we estimated the sensitivity of the analysis to the gas composition by comparing results of this study's method—which uses the county-level gas composition estimates as described above for emissions estimates—to results using the same emissions estimation calculations with two different sets of alternative gas compositions: one reflecting the production-weighted average of this study's gas analyses from the TCEQ Special Inventory supplementary files and another reflecting standard assumptions of gas composition identified in the literature. Given the imperfect source of information and the assumptions on which this study's analysis depends, substantial variation between these different methods makes a compelling case for the importance of using geographically appropriate gas compositions that are accurate to a reasonably fine scale when estimating GHG emissions from natural gas extraction and production. This study's approach provides the best-available approximation, using the best-available data, of a spatially explicit definition of gas compositions relevant to estimating GHG emissions. To improve on this analysis, future data collection efforts should emphasize the measurement and reporting of spatially explicit gas compositions.

Estimated Composition of Production Gas

The top panel of the Figure 57 presents the estimates of the main components of production gas from each of the 22 counties of the Barnett Shale play, as well as the Barnett Shale production-weighted average and the national average commonly used in the literature. Key parameters and production statistics for each county are also presented in Table 17 and Table 18. Components, which are shown in their mass percentage within the production gas, include methane, VOCs (as defined above to include all non-methane and non-ethane hydrocarbons), CO_2, and other gases. Primary gas species represented in the "other" category are nitrogen and ethane. The lower panel of Figure 57 depicts, for reference, the production volume for each county. Shown after each county's name is the number of unique analyses collected for that county—with counties estimated by a weighted average of adjacent county's compositions designated with an "A," rather than a number.



[a] "Other" gas include nitrogen, ethane, and any other non-methane, -VOC, or -carbon dioxide gases reported
[b] BS-AVERAGE refers to the production-weighted average gas composition in the 22-county Barnett Shale basin
[c] NATIONAL refers to the national average composition commonly used in the literature (EPA 2011)

Figure 57. Composition of production gas by county

NOTE: number of gas composition samples is reported in parentheses following each county name, where "A" denotes counties with no samples such that samples from adjacent counties were substituted.

The gas composition estimates for the six counties that represent the vast majority of production volumes are supported by high numbers of estimates. However, reflecting this study's non-random, targeted strategy for seeking these estimates, many of the estimates for the remaining counties come from either a small number of estimates or the weighted average of adjacent counties. Specifically, no usable estimates were found for 10 of the 22 counties.

The uncertainty inherent to this approach for obtaining gas analyses is highlighted by the difference in gas composition in Comanche County and Erath County versus the majority of the

counties. These compositions, which are both estimated by a single analysis from Erath County, show an abnormally large presence of nitrogen—and thus, are suspect of contamination with ambient air. However, the available information offers no verifiable support of such suspicion. The presence of such uncertainty emphasizes the need for better documentation of gas composition if this factor is to be used in further analysis or other factors, such as implementing regulations. However, it is important to note that the very low production volumes associated with these two counties means that their analyses have a nearly negligible impact on the overall results.

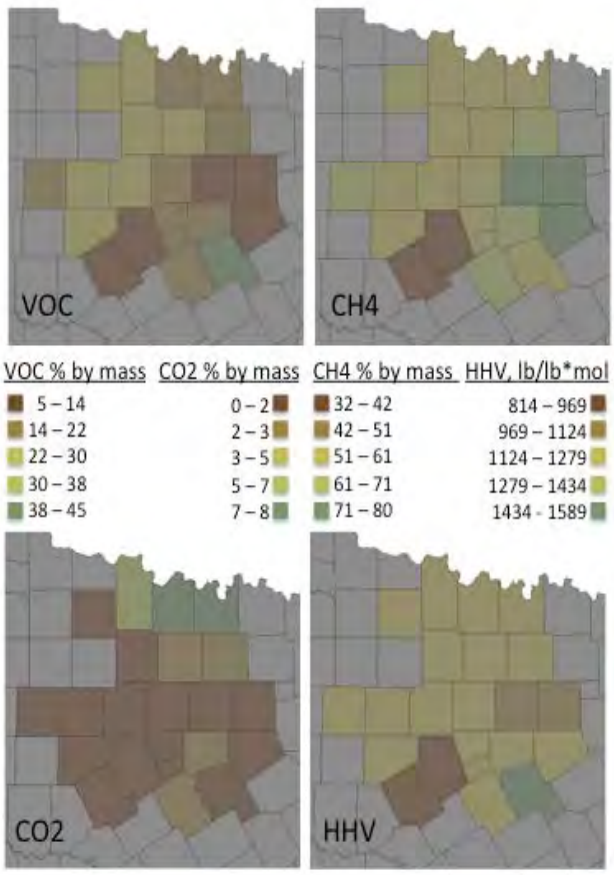


Figure 58. Variation among gas compositions across the 22 counties of the Barnett Shale play

The variation among gas compositions is demonstrated as being patterned across the 22 counties of the Barnett Shale play differently for different key parameters, as shown Figure 58. Such patterned distribution is to be expected if the observed variation reflects geological heterogeneity rather than simply uncertainty in the sampling methodology. The counties represented by weighted averages are located primarily on the western and eastern periphery of the region; therefore, the central north-south corridor represents both the majority of production and the estimates supported by larger samples. Along this corridor, parameters can be observed to vary relatively smoothly, although the differentiation between different parameters demonstrates the complexity of the variation in gas composition. In other words, this map demonstrates that gas composition varies across space, but also, it suggests that the complexity of this variation might extend to finer scales than the county level.

Table 17. Composition of Production Gas and Produced-Water Flash Gas in Barnett Shale Counties

	Production Gas						Produced-Water Flash Gas		
County	**Molecular Weight (lb/lb-mole)**	**Higher Heating Value (Btu/scf)**	**Carbon Content (% by mass)**	**Methane (% by mass)**	**VOCs (% by mass)**	**Carbon Dioxide (% by mass)**	**Methane (% by mass)**	**VOCs (% by mass)**	**CO_2 (% by mass)**
Comanche	23.86	813.78	43.6	32.2	12.9	0.2	33.5	24.8	31.1
Erath	23.86	813.78	43.6	32.2	12.9	0.2	43.1	34.8	7.8
Eastland	22.07	1,188.04	69.3	52.8	22.4	0.7	27.7	52.0	6.4
Hill	26.92	1,589.66	79.2	54.5	45.6	0.0	38.3	5.8	54.8
Montague	21.99	1,216.13	72.6	55.1	20.7	8.1	53.3	17.4	13.0
Clay	21.86	1,229.52	73.2	55.4	21.8	5.5	26.7	6.2	61.1
Archer	21.63	1,253.47	74.2	55.9	23.8	1.0	26.7	6.2	61.1
Jack	21.63	1,253.47	74.2	55.9	23.8	1.0	26.7	6.2	61.1
Wise	21.79	1,274.01	75.5	56.0	22.6	2.9	59.5	19.9	1.9
Cooke	21.76	1,199.75	72.2	56.5	20.0	8.1	46.8	17.2	18.0
Palo Pinto	21.72	1,261.53	74.3	56.9	24.3	0.8	27.7	52.0	6.4
Stephens	21.72	1,261.53	74.3	56.9	24.3	0.8	27.7	52.0	6.4
Hood	21.19	1,248.33	75.2	58.5	20.8	0.6	48.2	29.1	8.2
Parker	20.85	1,242.78	75.9	60.3	19.3	1.2	16.3	52.4	1.1
Somervell	20.71	1,224.89	75.3	61.5	19.0	1.6	40.1	10.0	46.4
Bosque	20.89	1,236.59	75.5	61.7	19.8	1.7	38.3	5.8	54.8
Johnson	20.57	1,226.04	75.8	62.5	18.7	1.8	38.3	5.8	54.8
Denton	20.54	1,218.65	75.4	62.5	17.9	1.9	34.8	14.5	33.3
Shackelford	20.12	1,191.89	74.8	66.2	15.9	1.6	33.5	24.8	31.1
Ellis	19.41	1,159.09	74.6	71.0	12.9	1.3	32.5	19.4	43.2
Dallas	18.63	1,112.74	73.9	75.4	9.0	1.1	23.9	39.5	23.1
Tarrant	17.92	1,072.83	73.3	80.2	5.6	0.9	20.7	46.7	20.1
Barnett Shale Average[a]	20.12	1,191.89	74.8	66.2	15.9	1.6	33.5	24.8	31.1
National Average[b]	17.40	1,027.00	75.0	78.3	17.8	1.5			

[a] Barnett Shale average is a production-weighted average of counties for which original gas compositions could be obtained

[b] National average production gas reported in EPA (2011)

Table 18. 2009 Production Volumes from Barnett Shale Counties

Heat Content (MMBtu)

County	Oil	Condensate	Casinghead Gas	Gas-Well Gas	Combined Gas	County Total
Archer	6,018,590	737	458,853	21,351	480,205	6,499,532
Bosque	0	98	0	354,480	354,480	354,578
Clay	3,514,046	37,503	494,346	351,615	845,961	4,397,511
Comanche	31,946	8,046	54,996	513,967	568,963	608,955
Cooke	11,740,372	43,729	4,394,033	485,521	4,879,554	16,663,655
Dallas	0	0	0	4,923,785	4,923,785	4,923,785
Denton	486,574	2,516,461	1,023,276	241,825,407	242,848,683	245,851,717
Eastland	1,491,957	314,574	834,641	3,916,728	4,751,369	6,557,901
Ellis	6,125	0	0	7,552,672	7,552,672	7,558,797
Erath	34,829	218,806	123,445	10,657,734	10,781,179	11,034,814
Hill	7,267	471	0	31,983,129	31,983,129	31,990,868
Hood	16,553	2,660,894	156,109	72,781,121	72,937,230	75,614,677
Jack	3,999,135	878,025	2,261,462	16,294,739	18,556,202	23,433,361
Johnson	0	318,855	0	570,667,212	570,667,212	570,986,067
Montague	11,979,935	34,090	9,682,791	350,290	10,033,081	22,047,106
Palo Pinto	3,232,091	525,481	6,957,154	16,076,018	23,033,172	26,790,743
Parker	73,886	1,672,455	730,069	112,696,107	113,426,176	115,172,517
Shackelford	4,108,140	66,203	849,166	2,234,492	3,083,658	7,258,000
Somervell	0	65,812	0	7,485,891	7,485,891	7,551,704
Stephens	12,811,777	291,120	3,525,626	11,751,922	15,277,548	28,380,445
Tarrant	0	241,264	0	563,514,077	563,514,077	563,755,341
Wise	2,400,875	5,017,491	6,426,006	222,654,526	229,080,532	236,498,898
Basin Total	**61,954,098**	**14,912,113**	**37,971,973**	**1,899,092,788**	**1,937,064,761**	**2,013,930,972**

Co-Product Allocations

In addition to natural gas, the sources reported in the TCEQ inventories are associated with the marketed products of condensate and, in some cases, oil. In fact, gas companies are focusing all of their new investment in areas with wet gas, which has a higher VOC content, for its higher value. The principle of co-product allocation is that when there are multiple valued products from a single system, the burdens of that system should be shared among all products. This study uses energy-based co-product allocation, which weights the burdens (i.e., emissions) of each process by the ratio of energy contained in all co-products that is embodied in the product of interest.

The factor that is applied depends on the relevant life cycle stage of a source. For production sources, we use the finest grain of spatial resolution available. Specifically, emissions for all production sources in the Special Inventory are allocated among condensate, oil, and natural gas products at the *site level* using site-level production statistics, as follows:

$$Allocation_{site} = \frac{\left(Q_{GWgas,s}\right) * HHV_{pipe\ gas}}{\left(Q_{GWgas,s} + Q_{Cgas,s}\right) * HHV_{pipe\ gas} + Q_{oil,s} * HHV_{oil} + Q_{cond,s} * HHV_{cond}}$$

where:

$Allocation_{site}$ = the site-level, energy-basis co-product factor for gas produced by gas wells (unitless)

$Q_{GWgas,s}$ = the volume of gas-well gas produced at the site annually (Mcf)

$Q_{Cgas,s}$ = the volume of casinghead gas produced at the site annually[150] (Mcf)

$Q_{oil,s}$ = the volume of oil produced at the site annually (bbl)

$Q_{cond,s}$ = the volume of condensate produced at the site annually (bbl)

$HHV_{pipe\ gas}$ = the energy content of natural gas product (i.e., pipeline gas)

- 1,027,000 Btu/Mcf for pipeline-quality gas

HHV_{oil} = the energy content of oil

- 5,800,000 Btu/bbl for crude oil[151]

HHV_{cond} = the energy content of condensate

- 5,418,000 Btu/bbl for plant condensate.[152]

As Figure 59 depicts, the majority of these site-level co-product allocation factors are at or close to 1—reflecting the fact that the majority of production within these counties is natural gas. However, Figure 59 also shows that 15% of the sites included within the Special Inventory produce no gas-well gas and, accordingly, the emissions from these sites do not contribute to the total emissions allocated to natural gas.

[150] Note that casinghead gas is a natural gas that is a co-product of oil production (produced by oil wells).
[151] API (2009), Table 3-8
[152] EIA (2011), Appendix A

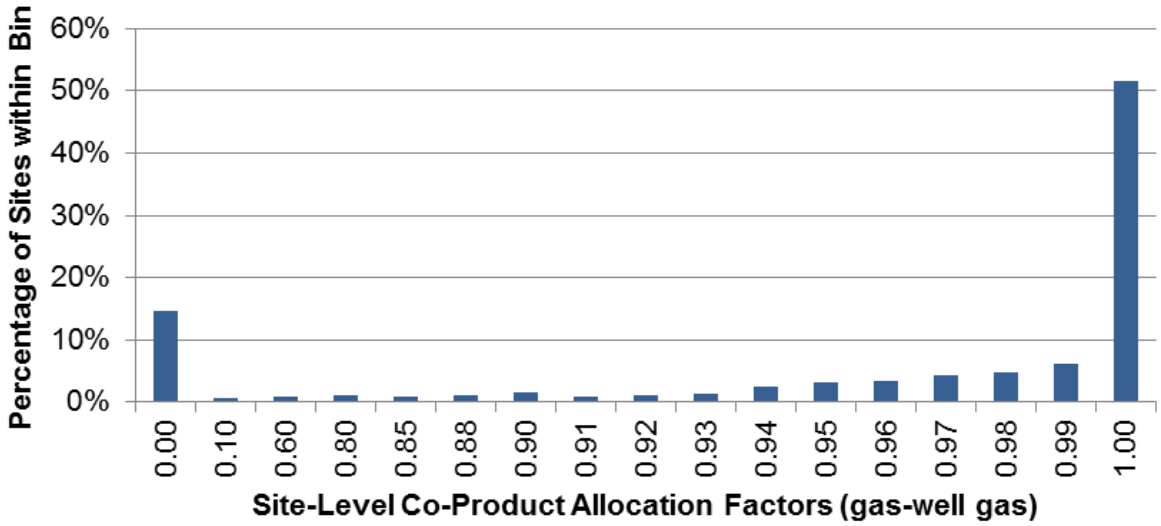


Figure 59. Distribution of site-level emissions allocated to gas

Site-level production statistics are not available for sites in the Point Source Inventory, and relevant counties have negligible oil production, lowering the chance that production-stage point sources emissions are associated with oil production. Therefore, emissions are allocated for all production sources in the Point Source Inventory among condensate and natural gas products at the *county level* using county-level production statistics (Figure 60). Similarly, Area Source Inventory data are available only at the county-level; so they are most appropriately allocated among co-products at this scale. This allocation is calculated as follows:

$$Allocation_{county} = \frac{Q_{GW\ gas,c} * HHV_{pipe\ gas}}{Q_{GW\ gas,c} * HHV_{pipe\ gas} + Q_{cond,c} * HHV_{cond}}$$

where:

$Allocation_{county}$ = the county-level, energy-basis co-product factor for gas (unitless)

$Q_{GWgas,c}$ = the volume of gas-well gas produced in the county annually (Mcf)

$Q_{cond,c}$ = the volume of condensate produced in the county annually (bbl)

$HHV_{pipe\ gas}$ = the energy content of natural gas product (i.e., pipeline gas) (Btu/Mcf)

HHV_{cond} = the energy content of condensate (Btu/bbl).

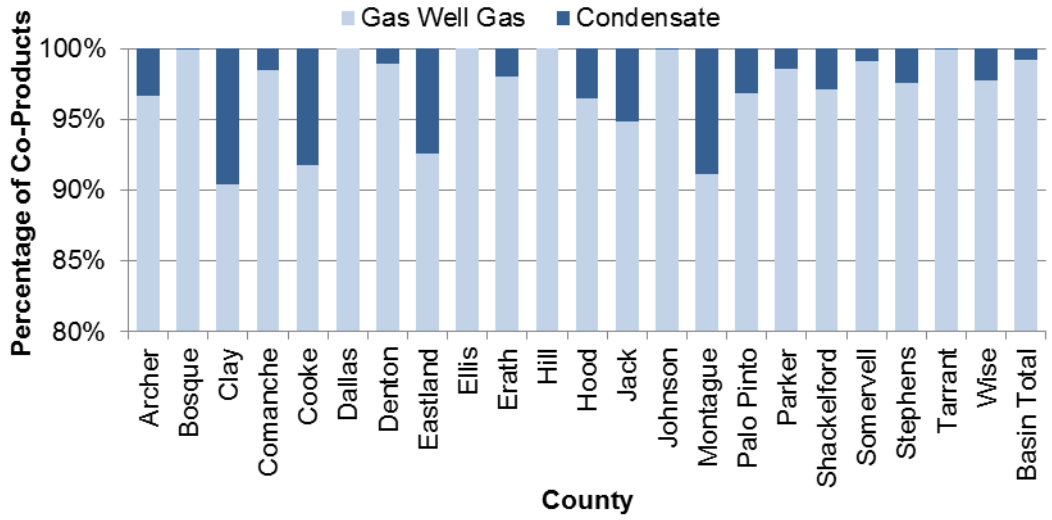


Figure 60. County-level gas production co-products by heat content

Regardless of the inventory in which the sources are described, emissions from processing sources are allocated at the *basin level* using basin-level production statistics. The relevant co-product allocation includes casinghead gas volumes as well as gas-well gas volumes because all natural gas—regardless of whether the production source is a gas or oil well—is processed at these sites. Some of these processing steps might occur after the condensate is separated, but the order of processing steps varies by site and is not identifiable in the data of the TCEQ inventories. Therefore, co-products are allocated as follows:

$$Allocation_{basin} = \frac{\left(Q_{GW\ gas,b} + Q_{Cgas,b}\right) * HHV_{pipe\ gas}}{\left(Q_{GW\ gas,b} + Q_{Cgas,b}\right) * HHV_{pipe\ gas} + Q_{cond,b} * HHV_{cond}}$$

where:

$Allocation_{basin}$ = the basin-level, energy-basis co-product factor for gas (unitless)

$Q_{GWgas,b}$ = the volume of gas-well gas produced in the basin annually (Mcf)

$Q_{Cgas,s}$ = the volume of casinghead gas produced in the basin annually (Mcf)

Q_{cond}, b = the volume of condensate produced in the basin annually (bbl)

$HHV_{pipe\ gas}$ = the energy content of natural gas product (i.e., pipeline gas) (Btu/Mcf)

HHV_{cond} = the energy content of condensate (Btu/bbl).

Note that some processing profiles pertain to processes that might occur after the condensate is separated from the process stream and, therefore, should not be partially allocated to that co-product. However, the specific order of processing steps is not readily identifiable in the data. In addition, the impact of neglecting this is small because condensate contributes less than 1% to the denominator of the allocation factor (Figure 61).

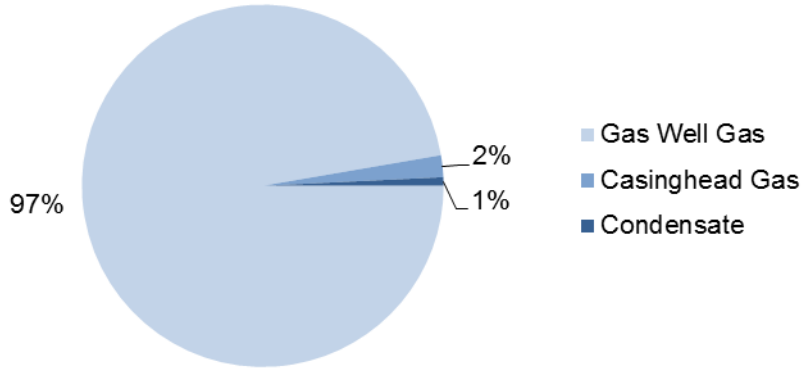


Figure 61. Basin-level gas processing co-products by heat content

In addition, because condensate and crude oil are separately marketable products, co-product allocation means that the substantial VOCs in the TCEQ Inventories corresponding to the storage and handling of these co-products—once separated from the natural gas stream—are outside the boundary of natural gas production and processing. Therefore, this study omits about 25% of the individual sources reported in the two inventories, which collectively represent 60% of the total reported VOC emissions, because they are associated only with the production and processing of the co-products of crude oil and condensate.

Regarding the co-production of oil within the counties of the basin, note that the 84 sites identified as production sites in the Point Source Inventory are all located within the 7 counties listed below—which include their respective percentage of the co-product energy associated with oil production:

- Denton: 0.2% from oil
- Hood: 0.0% from oil
- Johnson: 0.0% from oil
- Palo Pinto: 12.1% from oil
- Parker: 0.1% from oil
- Tarrant: 0.0% from oil
- Wise: 1.0% from oil.

With the exception of Palo Pinto County, these values suggest the co-production of oil represents a negligible amount, and the sole production site in Palo Pinto County identified in the Point Source Inventory is a gas well, associated with zero oil production, as verified through an online query of the Texas Railroad Commission's production statistics database. Therefore, this study does not attribute any production-related emissions from the Point Source Inventory to a co-product of oil.

Overall, 1% of the estimated GHG emissions are allocated to condensate instead of natural gas. For comparison, note that Skone et al. (2011) base their co-product allocation on their reported

12% non-methane VOC whereas Stephenson et al. (2011) report 16.4% allocation to condensate, ethane, and liquid petroleum gas. However, this proportion varies substantially across the 22 counties of the Barnett Shale play, as shown in Figure 62. Even among top-producing counties, which are shown by the larger bars in the lower panel of the figure, significant portions of GHGs are attributed to condensate instead of natural gas—ranging from 0.5% condensate for Johnson County and Tarrant County to 1.7% for Wise County. More strikingly, only 91.7% and 92.7% of emissions in Montague County and Cooke County, respectively, are associated with the natural gas product.

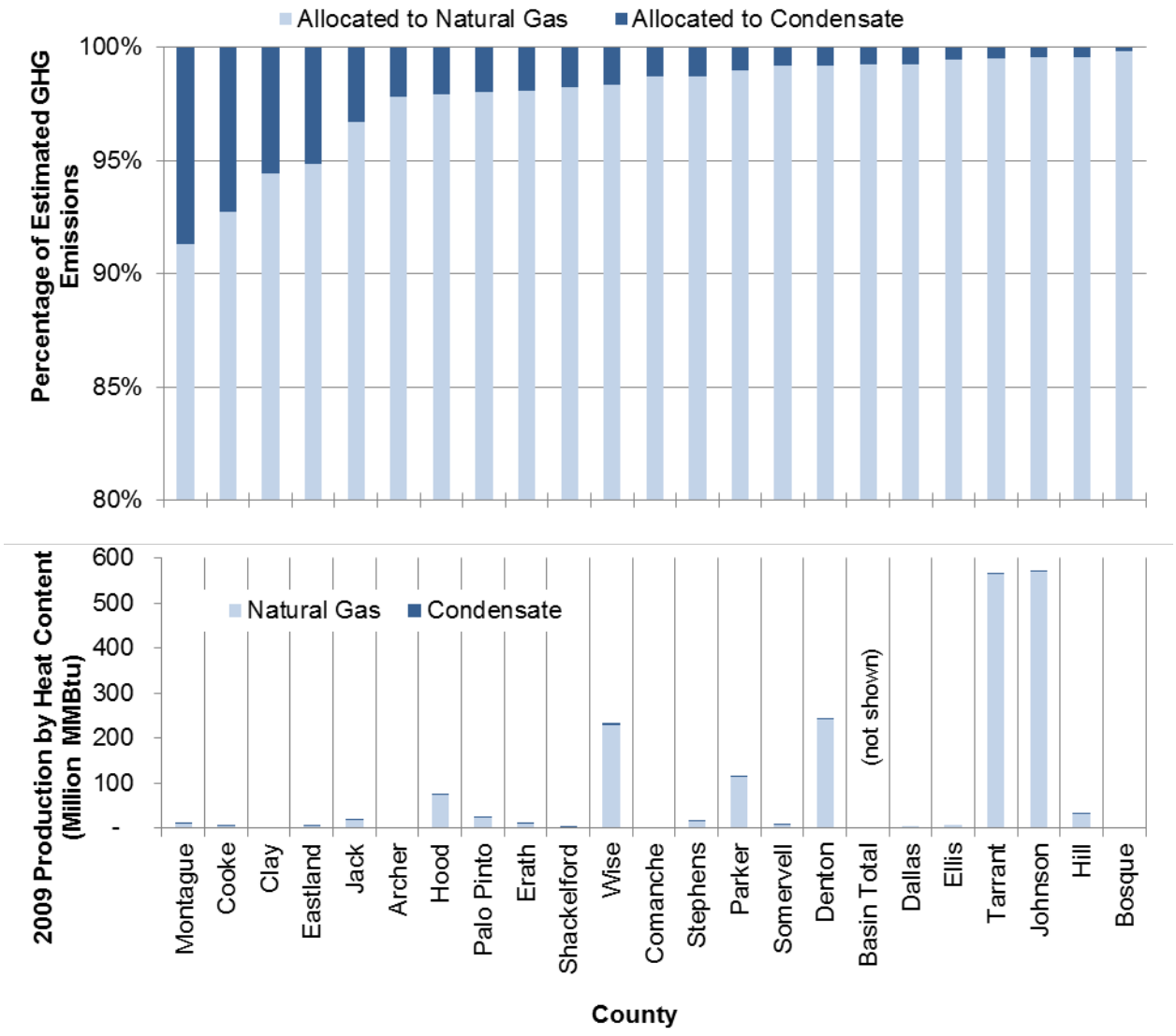


Figure 62. Proportion of GHG emissions associated with co-products

Estimation of Emissions by Source Profile

Emissions estimations generally use a "black box" approach, where a profile is associated with a life cycle stage by the purpose it serves rather than by its physical location. However, for those profiles possibly related to multiple stages, such as compressor engines and fugitives, each source is associated with the life cycle stage by the categorization of the site at which the source is found.

In general, emission sources can be categorized into two broad types of profiles: *combustion sources* and *gas-release sources*, with certain unique characteristics of certain processing activities leading to a third category. A tiered approach is used to calculate emissions, in which secondary calculation methods are applied when the data requirements for preferred methods are not met for an individual source. If neither method is possible with the available data, median estimates from other sources of the same profile are used. Overall, preferred methods were used for 79% of sources, secondary for 18%, and tertiary for the remaining 2%. The following paragraphs introduce the main categories and methodologies, which are adapted from the methodologies presented by ENVIRON (2010), API (2009), and EPA (1995), as appropriate. These emissions estimates include both routine and non-routine emissions estimates for 2009.

Combustion sources include compressor engines, boilers, heaters, and turbines. In these profiles, CO_2 emissions primarily come from chemical reactions during combustion, and methane emissions primarily come from the incomplete combustion of the combusted fuel. The composition of the fuel gas therefore influences the emissions, as do source characteristics and details of the level of usage of the source. This study's preferred methodology for calculating emissions from combustion sources is based on the quantity of fuel combusted and the composition of the fuel gas—as determined by a county-level estimation of production gas composition, assuming that the natural gas fuel used in all cases is the production gas at that site.

Gas leakage sources include both intentional and unintentional releases of gas. Within this category, there is a differentiation between *potentially controllable leakage* and *fugitives*, where the former typically involves gas released from an isolatable emission point and therefore is potentially controllable, and the latter comes from dispersed leaks and therefore is less feasible to control. This study's preferred methodology for calculating GHG emissions from gas-release sources therefore is based on the reported emissions of total VOCs and the ratio of CO_2 and CH_4 to VOCs in the released gas, which means it depends on the speciation of the released gas. Estimating these emissions assumes that production gas is the released gas in all cases, except when the profile is associated specifically with produced water handling; in this case, the released gas is assumed to be equivalent to the produced-water flash gas.

In addition, some processing sources require specialized estimation methods. For example, AGR units specifically remove CO_2 from the production gas. Therefore, this study's method for estimating CO_2 emissions from AGR differs substantially from that used for other profiles. Specifically, AGR units are associated with CO_2 emissions equal to the difference in CO_2 contained within the production gas and that in the final pipeline-quality gas.

The estimation of GHG emissions for different profiles consistently assumes that the speciation of production gas varies spatially based on the geology of the Barnett Shale. This variation can be reasonably represented by variation at the county level, as spatially interpolated from the

sample of gas composition analyses collected from supplementary Special Inventory files provided by the TCEQ.

Similarly, all natural gas represented in the following methodologies is assumed to be the production gas, except where explicitly noted (as in the AGR profile calculations). The speciation of this production gas is spatially explicit to the county level for production sources and the basin average composition for processing sources.

In addition, many profiles rely on standardized emission factors, which represent industry-level averages across the specifics of individual equipment. The majority of these emission factors are obtained from the EPA's AP-42, Compilation of Air Pollutant Emission Factors (EPA 1995). Factors applied are shown in Table 19.

Table 19. EPA's AP-42 Compilation of Air Pollutant Emission Factors

Profile	CO_2 Emission Factor	CH_4 Emission Factor	VOC Emission Factor
External Combustion, Natural Gas[a]	118 lb/MMBtu	2.25e-3 lb/MMBtu	5.39e-3 lb/MMBtu
External Combustion, Diesel[b,c]	2710 $kg/10^3m^3$	0.0062 $kg/10^3m^3$	0.0240 $kg/10^3m^3$
Internal Combustion, Natural Gas: 2-Stroke Lean-Burn[d]	110 lb/MMBtu	1.45 lb/MMBtu	1.20e-01 lb/MMBtu
Internal Combustion, Natural Gas: 4-Stroke Lean-Burn[e]	110 lb/MMBtu	1.25 lb/MMBtu	1.18e-01 lb/MMBtu
Internal Combustion, Natural Gas: 4-Stroke Rich-Burn[f]	110 lb/MMBtu	2.30e-01 lb/MMBtu	2.96e-02 lb/MMBtu
Internal Combustion, Diesel	164 lb/MMBtu[g]	3.15e-02 lb/MMBtu[h]	3.19e-01 lb/MMBtu[h]
Internal Combustion, Gasoline	154 lb/MMBtu[g]	1.89e-01 lb/MMBtu[h]	1.911e00 lb/MMBtu[h]
Natural Gas Turbine[I]	110 lb/MMBtu	8.60e-03 lb/MMBtu	2.10e-03 lb/MMBtu
Stationary Large-Bore Diesel Engines[j]	2745 $kg/10^3m^3$	0.1548 $kg/10^3m^3$	1.7415 $kg/10^3m^3$

[a] EPA (1995), Table 1.4-2
[b] Diesel fuel is also used as a proxy for crude oil.
[c] EPA (1995)
[d] EPA (1995), Table 3.2-1
[e] EPA (1995), Table 3.2-2
[f] EPA (1995), Table 3.2-3
[g] EPA (1995), Table 3.3-1
[h] EPA (1995), Table 3.3-1, where total organic compounds from Exhaust = 2.1 for gasoline and total organic compounds from Exhaust = 0.35 for diesel, and Table 3.4-1, which states that total organic compounds by weight is 9% CH_4 and 91% non-CH_4 for the one diesel engine measured
[I] EPA (1995), Table 3.1-2a
[j] EPA (1995)

Tiered Methods Counts

This study applies a tiered approach to the estimation of GHG emissions, in which preferred methods are applied when available data allow, and secondary methods otherwise. For those sources unable to use either method, we apply a tertiary method of assigning the median estimate for that profile. Table 20 demonstrates the count of the usability of each method across the two main inventories.

Table 20. Count of Usability for each GHG Emissions Estimation Method for CO_2 and Methane

	CO_2			Methane		
	Method 1	**Method 2**	**Method 3**	**Method 1**	**Method 2**	**Method 3**
Amine Units	n/a	–	–	4	–	–
Blowdowns and Vents	1,366	68	10	1,366	68	10
Boilers and Heaters	277	–	32	277	–	32
Engines	1,467	364	35	708	1,133	25
Flares	21	–	15	n/a	–	–
Fugitives	4,247	–	24	4,247	–	24
Glycol Dehydrator	79	21	14	79	21	14
Produced-Water Loading	1,948	–	11	1,948	–	11
Produced-Water Tanks	4,429	–	106	4,429	–	106
Special Inventory Total	13,834	453	247	13,058	1,222	222
Engines	–	673	–	–	673	–
Flares	–	17	–	n/a	–	–
Other combustion	–	264	–	–	264	–
Gas Leakage Sources	–	735	–	–	735	–
Produced-Water Tanks	90	–	–	90	–	–
Point-Source Inventory Total	90	1,689	0	90	1,672	0
Combined Total	13,924	2,142	247	13,148	2,894	222

General Leakage Profiles

General leakage profiles include *blowdowns*, *fugitives*, *pneumatics*, and *vents*. Data on blowdowns, fugitives, and vents are obtained from both the Point Source Inventory and the Special Inventory, and data on pneumatics are obtained from the Area Source Inventory. Although these different sources have different causes, they are calculated by similar methods. Because these profiles occur at both production and processing sites, sources are assigned to the stage to which the site belongs.

The primary methods for estimating CO_2 and methane emissions use the reported volume of gas released and this study's estimate of the composition of that gas. Where data are not available on volume of gas released, the secondary method uses the reported volume of VOC emissions and a ratio of the GHG to VOCs in the gas composition. These methods for calculating CO_2 and methane emissions for leakage sources are adapted from ENVIRON's (2010) discussion of leakage sources, including well-completion venting, well blowdowns, permitted fugitives, and unpermitted fugitives.

Note that unlike most profiles, inventory data on pneumatics come from the Area Source Inventory, which provides county-level data without individual source counts. Therefore, although emissions from pneumatics are calculated using methods analogous to other leakage profiles, such calculation occurs at the county level based on aggregated, county-level emissions reported in the inventory.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = Q_{vented} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_{CO_2} * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{vented} = the total annual volume of gas emitted through the leakage source (scf/year)

MW_{vented} = the molecular weight of the vented gas (lb/lb-mole)

f_{CO_2} = the fraction of CO_2 in the leaked gas by mass (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = E_{VOC} * \frac{f_{CO_2}}{f_{VOC}}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{CO_2} = the fraction of CO_2 in the production gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless).

Methane Emissions: Primary Method

$$E_{CH_4} = Q_{vented} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_{CH_4} * \frac{1tonne}{2204.62lb}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

Q_{vented} = the total annual volume of gas emitted through the leakage source (tonne/year)

MW_{vented} = the molecular weight of the vented gas (lb/lb-mole)

f_{CH_4} = the fraction of CH_4 in the leaked gas by mass (unitless).

Methane Emissions: Secondary Method

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{CO_2} = the fraction of CO_2 in the production gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless).

Compression Engines Profile

Data on compressor engines are obtained from the Special Inventory and the Point Source Inventory. Because these profiles occur at both production and processing sites, the sources are assigned to the stage to which the site belongs.

The primary methods for estimating CO_2 and methane emissions use the reported volume of fuel combusted and this study's estimate of the composition of that fuel, as well as the engine characteristics in the case of methane. Where the volume of fuel combusted is not available, the secondary method for CO_2 emissions uses engine characteristics and operations data, some of which is based on standard assumptions; the secondary method for methane emissions uses the reported volume of VOC emissions and a ratio of the GHG-to-VOCs-related, profile-specific emission factors.

In addition to data availability, the secondary method is preferred for sources that failed a simple data-consistency screen, or "ratio test," based on the ratio of reported fuel consumption to an expected gas usage value, calculated as:

$$ratio = \frac{Q_{fuel}}{EFU} = \frac{Q_{fuel}}{MDC * \frac{t_{annual}}{HHV}}$$

where:

$ratio$ = the test value, where any ratio within a factor of 10 of matching (i.e., between 10% and 1000%) is accepted (unitless)

Q_{fuel} = the total annual amount of fuel combusted (MMscf/year)

EFU = the expected fuel usage (MMscf/year)

MDC = the reported maximum design capacity of the engine (MMBtu/hour)

t_{annual} = the annual hours of usage of the engine (hour/year)

HHV = a standardized higher heating value of the fuel, assumed to be 1,150 (Btu/scf).

A final criterion for using the primary method for methane emissions is the reported absence of emissions controls installed on the engine. Ideally, the primary method should be weighted by methane-control efficiency. However, the reported data on VOC control efficiency demonstrate substantial inconsistency, and standardized methane control ratings for engines are not readily available. So, this study assumes that any controls applied affect methane and VOCs equivalently and therefore applies our secondary method for all engines that report the presence of controls. Because the Point Source Inventory does not include information on controls, the

secondary method is used, which accounts for the possibility of emissions controls, for all engines in that inventory.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = Q_{fuel} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g-CO_2}{12g-C}\right) * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

MW_{gas} = the molecular weight of the combusted gas (lb/lb-mole)

f_C = the fraction of carbon in the combusted fuel by mass (unitless)

f_O = the fraction of fuel carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = HP * LF * f_e * EF_{CO_2} * t_{annual}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

HP = the engine rating (hp)

LF = the load factor of the engine (unitless)

f_e = the energy-basis conversion factor for the engine (Btu/hp-hr)

EF_{CO_2} = the emissions factor of CO_2 on an energy basis (tonne/Btu)

t_{annual} = the annual hours of usage of the engine (hr/year).

Methane Emissions: Primary Method

$$E_{CH_4} = Q_{fuel} * HHV * EF_{CH_4}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

HHV = the higher heating value of the fuel (Btu/scf)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu).

Methane Emissions: Secondary Method

$$E_{CH_4} = E_{VOC} * \frac{EF_{CH_4}}{EF_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu)

EF_{VOC} = the emissions factor of VOCs on an energy basis (tonne/Btu).

In addition to the standard assumptions described above, these methods depend on the following assumptions:

- The load factor (LF) is assumed to be 0.8 for compressor engines with an engine rating greater than 500 hp and 0.7 otherwise, based on the results of a 2005 study of compressor engines in Texas performed by the TCEQ.[153]
- The energy-basis conversion factor (f_e) for all natural gas internal combustion engines is 7858 Btu/hp-hr.[154]
- The annual hours of usage of the engine (t_{annual}) are 8,760 hr/year for engines without specific usage data, which includes all engines in the Point Source Inventory.
- Any reduction in CO_2 released from the engine related to emissions controls is negligible.

Boilers, Heaters, and Turbines

Data on boilers and heaters are obtained from the Special Inventory, and data on boilers, heaters, and turbines are obtained from the Point Source Inventory. Although turbines substantially differ from boilers and heaters, estimation of emissions follows equivalent methods for all three profiles in the Point Source Inventory. Also, although boilers and heaters can occur at both production and processing sites, they are associated with natural gas processing; therefore, boilers and heaters are assigned to the processing stage.

The primary methods for estimating CO_2 and methane emissions use the reported volume of fuel combusted and this study's estimate of the composition of that fuel. Where the volume of fuel combusted is not available, the secondary method for estimating emissions uses the reported volume of VOC emissions and a ratio of the GHG-to-VOCs-related, profile-specific emission factors.

[153] Personal communication with TCEQ (TCEQ 2012)
[154] ENVIRON (2010), p.84

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = Q_{fuel} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g-CO_2}{12g-C}\right) * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

MW_{gas} = the molecular weight of the combusted gas (lb/lb-mole)

f_C = the fraction of carbon in the combusted fuel by mass (unitless)

f_O = the fraction of fuel carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = E_{VOC} * \frac{f_{CO_2}}{f_{VOC}}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{CO_2} = the emissions factor of CO_2 on an energy basis (tonne/Btu)

EF_{VOC} = the emissions factor of VOCs on an energy basis (tonne/Btu).

Methane Emissions: Primary Method

$$E_{CH_4} = Q_{fuel} * HHV * EF_{CH_4}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

HHV = the higher heating value of the fuel (Btu/scf)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu).

Methane Emissions: Secondary Method

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/yr)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu)

EF_{VOC} = the emissions factor of VOCs on an energy basis (tonne/Btu).

Amine Units / Acid Gas Removal

AGR, such as by amine units, removes CO_2 from the production gas. Therefore, this study's method for estimating CO_2 emissions from AGR differs substantially from that used for other profiles. AGR units are associated with CO_2 emissions equal to the difference in CO_2 contained within the production gas and that in the final pipeline-quality gas. Unlike other emissions sources, the CO_2 emissions from amine units are calculated as a single, aggregated basin-wide estimate that does not depend on the number of sources in the inventories.

Specifically, the estimated emissions are estimated as follows:

$$E_{CO_2} = \left[MW_{prod} * f_{CO_2 prod} - MW_{pipe} * f_{CO_2 pipe}\right] * Q_{prod} * \frac{1lb - mole}{379.3\ scf}$$

where:

E_{CO_2} = mass of CO_2 emitted by all AGR sources in the basin annually (tonne/year)

MW_{prod} = the average molecular weight of production gas within the basin (lb/lb-mole)

$f_{CO_2 prod}$ = the average percentage CO_2, by mass, in the production gas (unitless)

MW_{pipe} = the molecular weight of pipeline-quality natural gas[155] (lb/lb-mole)

$f_{CO_2 prod}$ = the average percentage CO_2, by mass, in pipeline gas[156] (unitless)

Q_{prod} = the volume of natural gas produced within the basin annually (scf).

In contrast, methane emissions from AGR are estimated using calculation methods equivalent to those provided in that of General Leakage Sources, as previously discussed.

Dehydrators

GHG emissions from dehydrators are calculated using separate emissions factors depending on the life cycle stage of the site at which the source sites. In the Point Source Inventory, all dehydrators are all at processing sites; but in the Special Inventory, dehydrators exist at both production and processing sites. Therefore, following API (2009), this study uses an emission factor of 275.57 scf/MMscf gas processed for production sites, adjusting the CH_4 content from the 78.8 molar percentage assumed in that reference. Alternatively, if a dehydrator is identified at a processing site, this study uses an emission factor of 121.55 scf/MMscf gas processed and adjusts the molar CH_4 content from 86.8%.

[155] Set to 17.4 lb/lb-mole, as provided by EPA (1995) and used by ENVIRON (2010)

[156] Set to 0.47%, as per EPA (2011). To the extent that this value overestimates the CO_2 content in pipeline-quality gas, it underestimates CO_2 emissions from acid gas removal, and vice versa.

For those dehydrators identified as having a control present in the Special Inventory, and assuming that all dehydrators in the Point Source Inventory have emission controls, this study assumes a 98% control efficiency for methane and a 0% efficiency for CO_2. Otherwise, this study assumes 0% efficiency of control for both emissions types. The 98% efficiency assumption is supported by standard efficiency assumptions for flares, as well as a reported 97% efficiency for separator-condensers (Schievelbein 1997), an alternative method of control for dehydrators.

Primary Methods

For dehydrators at production sites:

$$E_{CH_4} = P * 0.0052859 * \left[\frac{f_{CH_4,county} * MW_{gas,county}}{16}\right] * \left[\frac{1}{0.788}\right] * (1 - CE)$$

$$E_{CO_2} = P * 0.0052859 * \left[\frac{f_{CH_4,county} * MW_{gas,county}}{16}\right] * \left[\frac{1}{0.788}\right] * \frac{f_{CO_2,county}}{f_{CH_4,county}}$$

and for Dehydrators at Processing sites:

$$E_{CH_4} = P * 0.0023315 * \left[\frac{f_{CH_4,basin} * MW_{gas,basin}}{16}\right] * \left[\frac{1}{0.868}\right] * (1 - CE)$$

$$E_{CO_2} = P * 0.0023315 * \left[\frac{f_{CH_4,basin} * MW_{gas,basin}}{16}\right] * \left[\frac{1}{0.868}\right] * \frac{f_{CO_2,basin}}{f_{CH_4,basin}}$$

where CE = 0.98 if controlled, 0 otherwise, and P is the volume of gas processed. Controls do not affect CO_2 emissions, which are weighted by the ratio of CO_2 to CH_4 (by weight) in the production gas, by county.

Secondary Methods

For Dehydrators without P (which includes all Point Source Inventory dehydrators), the secondary method is based on VOC emissions:

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

$$E_{CO_2} = E_{VOC} * \left(\frac{1}{1-CE}\right) * \frac{f_{CO_2}}{f_{VOC}}$$

Flares

Due to a lack of sufficient information for identifying the specific source to which each flare is associated, this study identifies a flare's process stage by the type of site at which it is found and assumes that all flares combust production gas. This approach will likely overestimate natural gas process-chain emissions due to some of the flares controlling emissions from condensate and crude oil tanks, which should be omitted through co-product allocation; but the overestimation is expected to be small because total flare emissions are small. Only those that can be identified as emissions control for condensate tanks are removed; those that can be identified as combined emissions control for an included profile and condensate tanks are kept. Although this leads to a

likely overestimation of emissions from flaring, flares only account for a small proportion of overall emissions, so this overestimation is expected to be small.

For CO_2 emissions, the primary method, which depends on knowing the amount of gas combusted, treats flares equivalently to other combustion sources. The secondary method uses reported VOC emissions and an assumed 98% efficiency to back-calculate the volume of gas combusted. Methane emissions are assumed to be attributed to the original source that is controlled by the flares and therefore are neither calculated nor assigned to this profile.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = (Q_{waste} + Q_{pilot}) * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g-CO_2}{12g-C}\right) * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{waste} = the total annual amount of waste gas combusted (scf/year)

Q_{pilot} = the total annual amount of pilot gas combusted (scf/year)

MW_{gas} = the molecular weight of the combusted gas (lb/lb-mole)

f_C = the fraction of carbon in the combusted fuel by mass (unitless)

f_O = the fraction of fuel carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = E_{VOC} * \left(\frac{1}{f_{VOC}}\right) * \left(\frac{1}{1-CE}\right) * f_C * f_O * CE$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{VOC} = the fraction of VOCs in the combusted gas by mass (unitless)

CE = the assumed control efficiency of the flare, 98% (unitless)

f_C = the fraction of carbon in the combusted gas by mass (unitless)

f_O = the fraction of combusted gas carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Loading and Tanks

For produced-water loading and produced-water tanks, GHG emissions are calculated from VOC emissions and the ratio of VOCs to GHGs in the water flash gas.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = E_{VOC} * \frac{f_{CO_2}}{f_{VOC}}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{CO_2} = the fraction of CO_2 in the produced-water flash gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the produced-water flash gas by mass (unitless).

Methane Emissions: Primary Method

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/yr)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/yr)

f_{CO_2} = the fraction of CO_2 in the produced-water flash gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the produced-water flash gas by mass (unitless).

Calculations of Gas Losses from Production and Processing

Gas Release Sources

Profiles reporting gas release sources include amine units, blowdowns, fugitives, glycol dehydrators, and vents.

Natural Gas Lost, Method 1: From Reported Vented Volume

When the volume of gas vented is listed (only for some vents in the Special Inventory), the only calculation is a simple unit conversion, as follows:

$$Q_{NG,lost} = Q_{vented} * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

Q_{vented} = the total annual volume of gas emitted from the source (scf/year).

Natural Gas Lost, Method 2: From Reported VOC Emissions

For most gas leakage sources, the volume of gas released is not directly reported. For these, the volume of gas released can be calculated from the amount of VOC emissions, as follows:

$$Q_{NG,lost} = E_{VOC} * \frac{1}{f_{VOC}} * \left(\frac{2204.62lb}{1tonne}\right) * \left(\frac{1}{MW_{gas}}\right) * \left(\frac{379.3scf}{1.0lb-mole}\right) * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless)

MW_{gas} = the molecular weight of the production gas (lb/lb-mole).

Engines

Engines and other combustion sources (i.e., boilers and heaters) both sometimes include a direct report of the volume of fuel used. But only engines report the characteristics used for the ratio test, described in the section above on compressor engine emissions, and Method 2. Therefore, these combustion sources are calculated differently.

Natural Gas Lost, Method 1: From Reported Volume of Fuel Used

When the volume of gas combusted is listed (only relevant for some Special Inventory sources) and passes this study's Ratio Test for data entry issues, the value can be used directly, as follows:

$$Q_{NG,lost} = Q_{fuel}$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/yr)

Q_{fuel} = the total annual volume of fuel combusted by the source (MMscf/year).

Natural Gas Lost, Method 2: Using Engine Characteristics

The secondary method uses engine characteristics to estimate the amount of fuel used, which is equivalent to the natural gas lost for these sources.

$$Q_{NG,lost} = HP * LF * f_e * \frac{1}{HHV} * t_{anuual} * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

HP = the engine rating (hp)

LF = the load factor of the engine (0.8 or 0.7, depending on horsepower)

f_e = the energy-basis conversion factor for the engine (Btu/hp-hr)

HHV = the higher heating value of the fuel (Btu/scf)

t_{annual} = the annual hours of usage of the engine (hr/year).

Non-Engine Combustion

Engines and other combustion sources (i.e., boilers and heaters) both sometimes include direct report of the volume of fuel used. But only engines have the characteristics used both for the Ratio Test and Method 2. Therefore, these combustion sources are calculated differently.

Natural Gas Lost, Method 1: From Reported Volume of Fuel Used

When the volume of gas combusted is listed (which is only relevant for some Special Inventory sources), the value can be used directly, as follows:

$$Q_{NG,lost} = Q_{fuel}$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

Q_{fuel} = the total annual volume of fuel combusted by the source (MMscf/year)

Natural Gas Lost, Method 2: From Reported VOC Emissions

This alternative method only applies to Point Source Inventory non-engine combustion sources:

$$Q_{NG,lost} = E_{VOC} * \frac{1}{EF_{VOC}} * \left(\frac{2204.62lb}{1tonne}\right) * \left(\frac{1}{HHV}\right) * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{VOC} = the VOC emission factor for the source (lb/MMBtu)

HHV = the higher heating value of the fuel (Btu/scf).

Methane Lost, for All Sources: Convert from Natural Gas Lost

For all sources, the conversion from estimated natural gas lost to estimated methane lost is completed as shown:

$$Q_{CH_4,lost} = Q_{NG,lost} * \frac{MW_{gas}}{MW_{CH_4}} * f_{CH_4}$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

$Q_{CH_4,lost}$ = the volume of CH_4 lost or used by the source annually (MMscf/year)

f_{CH_4} = the fraction of CH_4 in the production gas by mass (unitless)

MW_{gas} = the molecular weight of the production gas (lb/lb-mole)

MW_{CH_4} = the molecular weight of CH_4 (16.0 lb/lb-mole).

Summary of Adjustments to Estimated Emissions

Emissions from production sources in the Point Source Inventory are adjusted by allocation across co-products at the county-level, as follows:

$$E_{final} = [E_{raw}] * [Allocation_{county}]$$

where:

E_{raw} = the unadjusted emissions estimate, e.g.,

$$E_{CO_2} = Q_{fuel} * \left(\frac{1.0lb - mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g - CO_2}{12g - C}\right) * \frac{1tonne}{2204.62lb}$$

$Allocation_{county}$ = the county-level allocation of emissions across co-products.

Emissions from production sources in the Area Source Inventory are adjusted by allocation across co-products at the county level and the adjustment for changes in production volumes, as follows:

$$E_{final} = [E_{raw}] * [Allocation_{county}] * [Adjustment_{county}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Allocation_{county}$ = the county-level allocation of emissions across co-products

$Adjustment_{county}$ = the county-level adjustment of emissions from 2008 to 2009 estimates.

Adjustments to emissions from production sources in the Special Inventory differ from this by (1) allocation across co-products at the site-level, rather than at the county-level, (2) requiring site-level and inventory-level corrections, and (3) not requiring the production volume adjustment, as follows:

$$E_{final} = [E_{raw}] * [Correction_{site}] * [Correction_{inventory}] * [Allocation_{site}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Correction_{site}$ = the site-level adjustment factor that accounts for the non-report of sources at the site that are below the reporting threshold for the Special Inventory

$Correction_{inventory}$ = the adjustment factor to all Special Inventory results that accounts for the "98% completion rate" of the inventory reported by the TCEQ

$Allocation_{site}$ = the site-level allocation of emissions across co-products.

Emissions from processing sources in the Point Source Inventory are adjusted by allocation across co-products at the basin-level, as follows:

$$E_{final} = [E_{raw}] * [Allocation_{basin}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Allocation_{basin}$ = the basin-level allocation of emissions across co-products.

Finally, emissions from processing sources in the Special Inventory are adjusted by the inventory-level and site-level corrections and by allocation across co-products at the basin level, as follows:

$$E_{final} = [E_{raw}] * [Correction_{site}] * [Correction_{inventory}] * [Allocation_{basin}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Correction_{site}$ = the site-level adjustment factor that accounts for the non-report of sources at the site that are below the reporting threshold for the Special Inventory

$Correction_{inventory}$ = the adjustment factor to all Special Inventory results that accounts for the "98% completion rate" of the inventory reported by the TCEQ

$Allocation_{basin}$ = the basin-level allocation of emissions across co-products.

Greenhouse Gas Emission Factors

To create emissions factors for process stages, the sum of estimated emissions for sources in each stage is divided by the production volume of gas associated with those emissions. The relevant statistics exist at the county level for production sources and at the basin level for processing sources.

For sources in the production stage, emissions and production can be associated at the county level. This emission factor focuses only on natural gas production from gas wells, omitting the

casinghead gas produced as a co-product from oil wells. Specifically, for CH_4 emissions associated with production (and where CO_2 is calculated analogously):

$$EF_{CH_4,prod,i} = \frac{\sum_{n \in N_{prod,i}} E_{CH_4,n}}{Q_{GWgas,i}}$$

where:

$EF_{CH_4,prod,i}$ = the CH_4 emission factor for production in county *i* (tonne/Mcf)

$E_{CH_4,n}$ = the mass of CH_4 emitted from source *n* annually (tonne/year)

$N_{prod,i}$ = the set of production sources in county *i*

$Q_{GWgas,i}$ = the volume of gas produced from gas wells in county *i* annually (Mcf/year).

For sources in the processing stage, however, emissions and production can only be associated at the basin level because centralized processing sites likely process Barnett Shale gas produced in neighboring counties. In addition, the gas processed by these facilities includes gas produced both from gas wells and oil wells (i.e., casinghead gas), and the denominator includes the sum of these two volumes, accordingly. Specifically, for CH_4 emissions associated with processing (and where CO_2 is calculated analogously):

$$EF_{CH_4,proc} = \frac{\sum_{n \in N_{proc}} E_{CH_4,n}}{Q_{GWgas} + Q_{Cgas}}$$

where:

$EF_{CH_4,proc}$ = the CH_4 emission factor for processing in the basin (tonne/Mcf)

$E_{CH_4,n}$ = the mass of CH_4 emitted from source *n* annually (tonne/year)

N_{proc} = the set of processing sources in the basin

Q_{GWgas} = the volume of gas-well gas produced in the basin annually (Mcf/year)

Q_{Cgas} = the volume of casinghead gas produced in the basin annually (Mcf/year).

The estimation strategy for the processing stage is exposed to a risk of leakage of production volumes both into and out of the basin, where the former corresponds to emissions caused by the processing of gas not accounted for in the basin's production statistics and the latter to gas included in the production statistics that is not accounted for in the processing emissions because such processing occurs outside the basin. The potential for bias from leakage is expected to be small because of the costs incurred in shipping unprocessed gas unnecessarily, as well as the relatively small amount of production in neighboring counties (the sum of which is only 8% the sum of gas production within the basin). Further, the potential for leakage in both directions increases the likelihood that any bias introduced by one direction of leakage will be cancelled by that in the other direction. But if not completely cancelling, the small scale of production outside the basin suggests that the sum of leakage would be out of the basin, meaning the estimates will underestimate emission factors.

From Inventory to LCA

The final estimate of life cycle GHG emissions is calculated as:

$$EF_{LifeCycle} = \left(\frac{1}{TE}\right) * \left[\frac{EF_{PreProduction}}{L_1} + \frac{EF_{Production}}{L_2} + \frac{EF_{Processing}}{L_3} + \frac{EF_{Transmission}}{L_4} + \frac{EF_{Disposal}}{L_2}\right] + EF_{Combustion} + EF_{Construction} + EF_{Decommissioning}$$

where:

$EF_{LifeCycle}$ = the emission factor for the entire life cycle (g GHG/kWh generated)

TE = the thermal efficiency of the power plant (kWh-equivalent input/kWh generated)

$EF_{PreProduction}$ = the emission factor for all pre-production processes, including completions and workovers, amortized by the lifetime EUR (g GHG/kWh-equivalent extracted)

$EF_{Production}$ = the emission factor for all production processes (g GHG/kWh-equivalent produced)

$EF_{Processing}$ = the emission factor for all gas processing processes (g GHG/kWh-equivalent processed)

$EF_{Transmission}$ = the emission factor for all processed gas transmission processes (g GHG/kWh-equivalent transmitted)

$EF_{Disposal}$ = the emission factor for all produced-water disposal processes (g GHG/kWh-equivalent produced)

$EF_{Combustion}$ = the emission factor for combustion at the power plant, based on the assumed TE (g GHG/kWh generated)

$EF_{Construction}$ = the emission factor for all power-plant construction processes, amortized over the lifetime production of the power plant (g GHG/kWh generated)

$EF_{Decommissioning}$ = the emission factor for all power-plant decommissioning processes, amortized over the lifetime production of the power plant (g GHG/kWh generated)

L_1 = a loss factor representing the portion of gas extracted that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent extracted/kWh-equivalent input)

L_2 = a loss factor representing the portion of gas produced that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent produced/kWh-equivalent input)

L_3 = a loss factor representing the portion of gas processed that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent processed/kWh-equivalent input)

L_4 = a loss factor representing the portion of gas transmitted that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent transmitted/kWh-equivalent input).

Using this formula, life cycle GHG emissions are estimated as shown in Table 21.

Table 21. Life Cycle GHG Emissions Values (g CO_2e/kWh,100-yr)

		Not Separated	From CO_2	From Methane	Sum Base-EUR	Sum High-EUR	Sum Low-EUR
	EUR (bcf)				1.42	4.26	0.45
Fuel Cycle	Pre-Production (non-completions)[a]		13.9		13.9	4.6	44.6
	Completions and Workovers[b]			20.2	20.2	6.7	65.0
	Production		3.3	3.0	6.3	6.3	6.3
	Processing		15.6	2.4	18.0	18.0	18.0
	Produced Water Disposal		0.0	0.7	0.7	0.7	0.7
	Transmission[c]		3.2	16.2	19.4	19.4	19.4
Power Plant	Construction and Decommissioning[d]	1.2			1.2	1.2	1.2
	Combustion at Power Plant[e]		359.0		359.0	359.0	359.0
Overall	Life Cycle	1.2	395.0	42.4	438.6	415.8	514.1

[a] Although lower estimates for this stage have been published, reported emissions increase as the comprehensiveness of processes considered increase. So we use the highest published estimate for this stage that provided results in a form that could be adjusted by EUR (Santoro et al., 2011).

[b] Based on EPA (2011) estimate of 9,175 Mcf natural gas emission/completion, 1% of wells/year workover rate (EPA 2012b), 30-year assumed lifetime (Skone et al. 2011), and 22-county, Barnett Shale average natural gas molecular weight of 20.1 lb/lb-mol and 66.2% methane by mass.

[c] Based on Skone et al. (2011)

[d] Based on Skone and James (2010)

[e] Based on Skone et al. (2011)

Appendix C: Requirements, Standards, and Reporting

Table 22. State Revisions to Oil and Gas Laws

PA	Updated regulations in 2010. Particular emphasis on well construction, disclosure, handling and disposal of recovered fluids. New 2012 legislation also created new setbacks, environmental impact analysis requirements, new fees, floodplain drilling restrictions, restoration requirements, general containment requirements, public disclosure requirements, restricted local control.
NY	Proposed major overhaul of regulations in 2011 specifically to address high-volume hydraulic fracturing. Some of the most comprehensive rules in the nation. Added new subpart 560 containing definitions specific to high-volume hydraulic fracturing, setback, reporting, well construction, and reclamation standards.
CO	Major overhaul of regulations in 2009. In 2011, revised disclosure rule, added a requirement that operators must notify Commission within 48 hours of intention to fracture and provide landowners within 500 feet of proposed oil and gas location information regarding fracturing and how to collect baseline monitoring.
WY	Updated regulations in 2010. Revised disclosure and pit requirements; strengthened presumptive Best Available Control Technology requirements for air emissions (green completions in Jonah Pinedale Anticline Area and Concentrated Development Areas).
TX	Updated air rules and implemented disclosure rule in January 2012.
LA	Finalized new disclosure rule in October 2011.

Table 23. Fracking Fluid Disclosure Requirements

	Colorado	Louisiana	New York	Pennsylvania	Texas	Wyoming
State Code	COGCC Rule 205A	La. Admin Code. tit. 43, pt. XIX, § 118	Draft SGEIS 8.2.1.1	Act 13, §3222, 3222.1	16 Tex. Admin Code § 3.29	WOGCC Rules, Ch. 3 § 45
Takes Effect	February 1, 2012	October 20, 2011	Proposed 2011	April 16, 2012[157]	February 1, 2012	October 17, 2011
Duty to Report?	Yes. Names of products in fracking fluids, chemicals in fracking fluids, associated chemical abstract numbers.	Yes. Names of products in fracking fluid, chemical ingredients in fracking fluid, chemical concentrations of hazardous chemicals.	Yes. Fracking fluid additive products and material safety data sheets	Yes. Names of products in fracking fluid, chemicals in fracking fluid, associated chemical abstract service numbers.	Yes. Names of products in fracking fluid, chemicals in fracking fluid, associated chemical abstract numbers, volume of fracking fluid.	Yes. Names of products in fracking fluid, chemicals present in fluid, associated chemical abstract service numbers, volume of fracking fluid.
To Whom?	Yes, to Frac Focus provided public can search information by company, chemical ingredient, geographic area, and other criteria by Jan. 1, 2013. If not, COGCC will build its own searchable database. Must also provide landowners within 500 feet of the well with information regarding fracking and baseline water sampling.[158]	Office of Conservation, district manager or Frac Focus	NY Department of Environmental Conservation for public disclosure	PA Department of Environmental Protection or Frac Focus. Similar requirement to CO that Frac Focus must be searchable by Jan. 1, 2013, or DEP may require other form of public disclosure.	Yes, to Frac Focus.	Yes to WOGCC website.

[157] Note, however, that Act is enjoined pending resolution of legal challenge to its constitutionality on other grounds.
[158] 2 CCR 404-1, R. 305.e.(1).A. (2012).

	Colorado	Louisiana	New York	Pennsylvania	Texas	Wyoming
When?	No later than 60 days after completion of fracking operation or no later than 120 days after commencement of fracking operation.	Within 20 days after operations are complete.	Prior to drilling.	Within 60 days of completion of well completion	On or before date operator submits Well Completion Report; operator must also upload required information to Disclosure Registry.	Before fracking begins (APD) and after operation is complete (Well Completion Report Form).
Trade Secret Exemption?	Yes, for chemicals but not for chemical family name.	Yes, for chemicals but not for chemical family.	Yes, but must still disclose information regarding properties and effects of hazardous chemical.	Yes, for chemicals but not for chemical family. Claims governed by PA's "Right to Know" law, which requires companies submit trade secret information to the DEP. Citizens may challenge information.	Yes, for chemicals but not for chemical family.[159]	Yes, operator can make a request to WOGCC to keep proprietary information confidential.
Trade Secret Disclosure?	Yes, trade secrets must be disclosed to medical professional in event of medical emergency, to Commission to respond to a spill, release or complaint or if needed for diagnosis or treatment of exposed individual. Disclosure must be kept confidential.	Yes, if required to be provided to a health care professional, doctor, or nurse.	Yes to health professionals, employees and designated representatives.	Yes, if required to be provided to a health care professional in event of an emergency. Disclosure must be kept confidential.	Yes, to health professionals and emergency responders to diagnose, treat, or otherwise respond to an emergency. Disclosure must be kept confidential.	No.

[159] The Texas law contains provisions that allow landowners on whose property operations are taking place, landowners with adjacent property to operations, or state departments and agencies with jurisdiction over matters relevant to trade secret information to challenge a claim of trade secret.

Table 24. Water Acquisition Requirements

Play/Basin	Permit for Withdrawal	Reporting	Other Requirements	Recycling
North San Juan (Colorado)	Permit for groundwater withdrawal outside designated ground water basin.[160]	Must report total volume of water used in fracking job to Frac Focus.[161]	Local requirements apply.[162]	None.[163]
Upper Green River (Wyoming)	Yes[164]	Yes, limited to amount, not source.[165]	None identified.	None.
Marcellus (New York)	Yes[166]	Operator must identify source of water in permit and report annually on aggregate amounts withdrawn or purchased.[167]	Monitoring and other requirements to ensure no degradation to water quality and quantity.[168]	Must develop a wastewater source reduction strategy identifying the methods and procedures operators will use to maximize recycling and reuse of flow back or production fluid either to fracture other wells or for approved beneficial uses.[169]

[160] C.R.S. §§ 37-90-137, 37-92-308 (2011). See also http://cogcc.state.co.us/Library/Oil_and_Gas_Water_Sources_Fact_Sheet.pdf. The Colorado Ground Water Commission may define and alter designated groundwater basins within the state based on adequate factual information. See C.R.S. §37-90-106 (2012).
[161] COGCC R. 205A(b)(2)(A)(viii) (2012).
[162] See, for example, Archuleta County Land Use Code Section 9.2: Archuleta County's Oil and Gas Development Permit Provisions (Amended Dec. 2010) http://www.archuletacounty.org/Planning/Section%209%20-%20Mining%20December%202010.pdf.
[163] *See* Response of the Colorado Oil and Gas Conservation Commission to the STRONGER Hydraulic Fracturing Questionnaire, 32, http://cogcc.state.co.us/Library/HydroFracStronger/COGCC_Response_To_STRONGER_06132011.pdf (noting that R. 907(a)(3) encourages recycling by encouraging operators to submit waste management plans that may provide for reuse of waste water. Rules 903 and 907 encourage recycling by providing for multi-well pits. R. 902.e and 903.a.(4) creates new pit classification for multi-well pits. "These pits are often centrally located in the oil or gas field, are used to store fluids from multiple wells, and may include treatment areas where fracturing flowback fluids and produced water can be brought up to specifications. COGCC is also working with several operators on waste sharing plans that will facilitate the reuse and recycling of fracturing fluids and produced water."
[164] National Conference of State Legislatures, "State Water Withdrawal Regulations," http://www.ncsl.org/issues-research/env-res/state-water-withdrawal-regulations.aspx.
[165] Conversation with Rick Marvel, engineer, WOGCC, May 29, 2012.
[166] NYSGEIS § 7.1.1.1. Withdrawal permits will include conditions to monitor and enforce water quality and quantity standards and requirements. If withdrawing from within 500 feet of wetlands, must require monitoring during pump test. Lowering groundwater levels at or below wetlands is a significant impact triggering site-specific State Environmental Quality Review Act review. Withdrawals from groundwater within 500 feet of private wells also trigger site-specific State Environmental Quality Review Act reviews.
[167] *Id*.
[168] See *Id* (discussing various standards such as passby flow requirements, water conservation practices, and protections for aquatic life that may be included by permit).
[169] NYSGEIS § 5.12.

Play/Basin	Permit for Withdrawal	Reporting	Other Requirements	Recycling
Marcellus (Pennsylvania)	Cannot withdraw without approved water management plan.[170]	Report list of water sources used under approved water management plan and volume of water.[171]	Water management plan that includes plan for reuse of fluids.[172]	Water management plan must include plan for reuse of fluids used to fracture wells.[173] Well completion report must include total volume of water recycled.[174]
Haynesville (Louisiana)	None identified.	Must report water source and volumes after completion or recompletion.[175]	None.	Regulations recognize processing of E&P waste into reusable materials as alternative to other means of disposal and authorizes commercial facilities for the purpose of generating reusable material.[176]
Eagle Ford (Texas)	Yes.[177]	Report total volume of water used in fracking to Frac Focus.[178]	None identified.	None.
Barnett (Texas)	Yes.	Report total volume of water used in fracking to Frac Focus.[179]	None identified.	None.

[170] 58 PA Con. Stat. ch. 32, § 3211(m). Condition of all permits to hydraulically fracture natural gas wells in unconventional formations.
[171] *Id.* § 3222(b.1)(1)(vi) (2012).
[172] 58 PA Con. Stat. ch. 32, § 3211(m). Operators must develop water management plan, which must be approved by DEP, governing withdrawals or use of water. Approval of plan is contingent on determination that withdrawal/use will not adversely affect quantity or quality of water, will protect and maintain designated and existing uses of water supply, will not cause adverse impact to water quality in watershed and will include a reuse plan for fluids for hydraulically fractured wells. If plan is operated in accord with conditions established by the Susquehanna River Basin Commission, the Delaware River Basin Commission or the Great Lakes Commission, it is presumed to meet above conditions.
[173] 58 PA Con. Stat. ch. 32, §. 3211(m)(2)(iv).
[174] *Id.* § 3222(b.1)(1)(vi) (2012).
[175] Well History and Work Resume Report, Form WH-1, Louisiana Hydraulic Fracturing State Review, 5 (March 2011), http://www.strongerinc.org/documents/Final%20Louisiana%20HF%20Review%203-2011.pdf.
[176] La. Admin. Code tit. 43:XIX, § 565 (2010).
[177] Tex. Water Code, tit. 2, ch. 11. *See also* http://www.rrc.state.tx.us/barnettshale/wateruse.php Short-term permits issued by Texas Commission on Environmental Quality Regional Offices and permits for more than 10 acre-feet of water or for a term lasting more than 1 year are issued by the Commission's Water Rights Permitting Team.
[178] 16 Tex. Admin. Code § 3.29(c)(2)(A)(viii) (2011).
[179] *Id.*

Table 25. Well Construction Standards

Play/Basin/ Jurisdiction	Cement Bond Log	Minimum Surface Casing Depth	Pressure Tests for Casing	Monitor Bradenhead Annulus Pressure
Federal Lands[180]	Yes.	None.	Yes. Mechanical integrity test required before each well stimulation operation.	No. But must continuously monitor and record pressure during well stimulation and notify if annulus pressure increases by more than 500 lbs per square inch.
North San Juan (Colorado)	Yes. Required on all production casing, or in the case of production liner, the intermediate casing.[181]	None specified in rules, but OGCC requires casing be set at least 50 feet below aquifer to ground surface.	Yes. Must test production casing during completion and production. [182]	Must monitor and record bradenhead annulus pressure during fracking and notify COGCC of conditions indicating fracking fluids have escaped producing reservoir.[183]
Upper Green River (Wyoming)	No specific requirement.[184]	None specified but casing must be run below known or reasonably estimated utilizable fresh water levels.[185]	No. Mechanical integrity tests may be required but not mandatory.[186]	No
Barnett (Texas)	No.	None specified but all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm.[187]	All casing must be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to max. pressure to which pipe will be subjected in the well	All wells must be equipped with a bradenhead. Must notify district office when pressure develops between any two strings of casing. Must perform a pressure test with bradenhead if well shows pressure on the bradenhead.[188]

[180] BLM (2012). "Proposed Rule: Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands," Department of Interior, May 4, 2012, http://www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&pageid=293916.
[181] COGCC R. 317(o).
[182] *Id*. at 317(j).
[183] *Id*. at 341.
[184] WOGCC Rules, ch. 3, §§ 12, 21, requires submission of well logs, which includes "electrical, radioactive, or other similar log runs," which may, but does not necessarily, include cement bond logs.
[185] *Id.* § 22(a)(i).
[186] *Id.* § 45.
[187] 16 Tex. Admin. Code § 3.13.
[188] *Id.* § 3.17.

Play/Basin/ Jurisdiction	Cement Bond Log	Minimum Surface Casing Depth	Pressure Tests for Casing	Monitor Bradenhead Annulus Pressure
Eagle Ford (Texas)	No.	None specified but all usable-quality water zones must be isolated and sealed off to effectively prevent contamination or harm.[189]	All casing must be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which pipe will be subjected in the well.	All wells must be equipped with a bradenhead. Must notify district office when pressure develops between any two strings of casing. Must perform a pressure test with bradenhead if well shows pressure on the bradenhead.[190]
Haynesville (Louisiana)	Yes, operator must run cement bond log, temperature survey, X-ray log, density log, or other acceptable test.[191]	None.[192]	Surface, intermediate, and producing casing must be tested depending on their depth.[193]	No.
Marcellus (New York)	Department may require a cement bond long or other measures to ensure adequacy of the bond.[194]	Must be set to at least 75 feet beyond deepest fresh water zone or bedrock, whichever is deeper.	No.[195]	No.
Marcellus (Pennsylvania)	In response to a potential natural gas migration incident, the department may require operator to evaluate adjacent oil and gas wells with different measures, including cement bond logs.[196]	Must be set 50 feet below deepest fresh groundwater or at least 50 feet into consolidated rock, whichever is deeper.[197]	Yes. New casing must have an internal pressure rating that is at least 20% greater than anticipated maximum pressure to which casing will be exposed. Used casing must be pressure tested after cementing and before continuation of drilling.[198]	No.

[189] *Id.* § 3.13.
[190] *Id.* § 3.17.
[191] La. Admin. Code, tit. 43, pt. XIX, §419(A)(3).
[192] *Id*. § 109.
[193] *Id*.
[194] N.Y. Comp. Codes R. & Regs. tit. 6, ch. V, §559.6(d)(2).
[195] *Id*. § 557.2.
[196] 25 Pa. Code § 78.89.
[197] *Id*. § 78.83.
[198] *Id*. § 78.84.

Table 26. Baseline Monitoring Requirements

Play/Basin	Requirement
North San Juan (Colorado)	Operators drilling within 301–2,640 feet of surface water intended to be used for drinking water must collect baseline water samples from the surface water prior to drilling and 3 months after the conclusion of drilling or completion.[199] Operators must collect water well samples from nearby wells prior to drilling, as well as 1, 3, and 6 years after completion.[200] Operators must provide landowners within 500 feet of proposed oil and gas location with instruction as to how to collect baseline water samples.[201]
Marcellus (New York)	Operator must make reasonable attempt to sample and test all residential water wells within 1,000 feet of a wellpad; must be sampled prior to commencing drilling. If no well is located within 1,000 feet, or the surface owner denies permission, then the operator must sample all wells within a 2,000-foot radius. Monitoring continues at specified intervals as determined by the DEC.[202]
Marcellus (Pennsylvania)	PA law provides for a rebuttable presumption that a well operator is responsible for pollution of a private or public water supply if the supply is within 2,500 feet of an unconventional well and the pollution occurred within 12 months of the later of the completion, drilling, stimulation or alteration of the well. Operators can overcome this presumption by undertaking a pre-drilling or pre-alteration survey that demonstrates pre-existing contamination or if landowner or water purveyor refuses to allow the operator to test.[203]

[199] 2 Colo. Code Regs. § 404-1; COGCC R. 317B(d)(e). Samples must be tested for BTEX, TDS, metals, and other specified parameters in the rules.
[200] Various Commission Orders. *See* COGCC Response to STRONGER, 4, available at http://cogcc.state.co.us/Library/HydroFracStronger/COGCC_Response_To_STRONGER_06132011.pdf. R. 608 extends the requirements set forth in Commission Orders to other parts of the state with CBM wells and requires operators to identify all plugged and abandoned wells within ¼ mile of proposed CBM well, assess the risk of leaking gas or water, make a reasonable good-faith effort to conduct pre-production soil gas survey of all plugged and abandoned wells within ¼ mile of proposed CBM well and post-production survey 1 and every 3 years after production has commenced, and sample water wells located within ¼ or ½ mile from proposed CBM well and within 1, 3, and 6 years thereafter.
[201] 2 Colo. Code Regs. § 404-1; COGCC R. 305.e.(1).A. (2012).
[202] N .Y. Comp. Codes R. & Regs. tit 6, § 560.5(d).
[203] 58 Pa. Cons. Stat § 3218(c).

Table 27. Closed-Loop or Pitless Drilling Requirements

Play/Basin	Requirement	Date Adopted
North San Juan (Colorado)	Pitless drilling within 301–500 feet of surface water intended to be used for drinking water. Pitless drilling or containment of all flowback and stimulation fluids in liner pits within 501–2,640 feet of surface water intended to be used for drinking water unless operator can demonstrate pit will not adversely affect waters.[204]	2008
Upper Green River (Wyoming)	Closed system required where groundwater is less than 20 feet below surface.[205]	2010
Marcellus (New York)	Closed-loop tank system for drilling fluids and cuttings produced from horizontal drilling unless an acid rock drainage mitigation plan for on-site burial of such cuttings is approved by department.[206] Cuttings contaminated with oil-based mud or polymer-based mud must be contained and managed in a closed-loop tank system.[207]	Proposed 2011
Marcellus (Pennsylvania)	Prohibits storage and disposal of production fluids and brine in pits unless permitted under Clean Streams Law.[208]	2010
Barnett (Texas)	Closed-loop mud system required for all drilling and reworking operations unless operations located on open space of at least 25 acres and not within 1,000 feet of residence or certain public places.[209]	2009

[204] COGCC R. 317B(d)(1), (e)(1); R. 904. Colorado does not define pitless drilling. The definition of *pit* is a "natural or man-made depression in the ground used for oil or gas exploration or production purposes. Pit does not include steel, fiberglass, concrete or other similar vessels which do not release their contents to surrounding soils." COGCC R. 100.

[205] WY ADC Oil Gen. ch. 4, § 1(u). Commission has authority to require closed system in other instances to protect surface and ground water, human beings, wildlife and livestock. *Id*. Closed system "includes, but is not limited to, the use of a combination of solids control equipment (e.g., unconventional shakers, flow line cleaners, desanders, desilters, mud cleaners, centrifuges, agitators, and necessary pumps and piping) incorporated in a series on the rig's steel mud tanks, or a self-contained unit that eliminates the need for a reserve pit for the purpose of dumping and dilution of drilling fluids for the removal of entrained drilling solids. A closed system for the purpose of the Commission's rules does not automatically include the use of a small pit, even to receive cuttings." WY ADC Oil Gen. ch.1, § 2(k).

[206] NY Dept. of Envtl Conservation Proposed Rules, 6 N.Y. Comp. Codes R. & Regs. § 560.6. Closed-loop drilling system means a pitless drilling system where all drilling fluids and cuttings are contained at the surface within piping, separation equipment and tanks. 6 N.Y. Comp. Codes R. & Regs. § 750-3.2.

[207] New York Department of Environmental Conservation Proposed Rules, 6 N.Y. Comp. Codes R. & Regs. § 560.7.

[208] PA Office of Oil and Gas Mgmt. Rules, ch. 78.57.

[209] Fort Worth, Tex. Ordinance, § 15-42(A)(3), (A)(38)(b) (2009).

Table 28. Produced Water Disposal

State	Direct	Indirect	Underground Injection Control	Ponds	Land	Reuse
CO	Yes, if water meets criteria for wildlife or agricultural propagation. CBM discharges via permit.[210]	Yes	Yes	Yes	Yes, water must meet state water-quality standard for agricultural/livestock use.[211]	Encouraged[212]
WY	Yes, if water meets criteria for wildlife or livestock watering or other agricultural uses.[213]	Yes	Yes	Yes	Yes, with permission.[214]	Encouraged[215]
TX	Yes[216]	No[217]	Yes	Yes, with permit.[218]	No[219]	No provisions
PA	No	Yes, for new and expanded discharges meeting standards.	Yes	Yes	Yes[220]	Yes[221]
NY	No	Yes operator must analyze POTW capacity and create contingency plan if the primary wastewater disposal is at POTW.	Yes[222]	No	Only with permission.[223]	Encouraged[224]

[210] Colorado follows national effluent limitations. 2 Colo. Code Regs. §404-1; COGCC R. 907.
[211] 2 Colo. Code Regs. §404-1, COGCC R. 907. Standard is 3,500 mg/l.
[212] No specific requirements but COGCC R. 907(a)(3) encourages recycling by encouraging operators to submit waste management plans which may provide for reuse of waste water, see http://cogcc.state.co.us/Library/HydroFracStronger/COGCC_Response_To_STRONGER_06132011.pdf
[213] WY Water Quality Rules & Regs, ch. 2, appendix H. *See also* WOGCC Rules, ch. 4 §1 (ee).
[214] WOGCC Rules, ch. 4 §1 (mm)
[215] *Id.* § 1(z). No specific requirements although "Commission encourages the recycling of drilling fluids and by administrative action approves the transfer of drilling fluids intended for recycling.
[216] Personal communication with John Becker, Texas Railroad Commission.
[217] Based on conversation with Phillip Urbany, engineer, TX Commission on Environmental Quality, May 29, 2012.
[218] 16 Tex. Admin. Code §3.8(d)(2).
[219] Our research did not identify any prohibition on land application but also no clear authorization.
[220] 25 Pa. Code §78.63.
[221] AB 13, Sec. 3211(m).

State	Direct	Indirect	Underground Injection Control	Ponds	Land	Reuse
LA	No[225]	Discharge to a POTW is not a permissible disposal method for produced water in Louisiana.[226]	Yes	Yes	Yes[227]	No provisions

[222] N.Y. Comp. Codes R. & Regs. tit. 6, §750-1.24. *See also* 40 C.F.R. 144 & 146.
[223] Revised SGEIS at 7-60: Those wanting to road spread production brine must petition for a beneficial use determination. NORM concentrations in Marcellus Shale likely won't allow road spreading of brine, but "[a]s more data becomes available, it is anticipated that petitions for such use will be evaluated by the Department."
[224] Proposed N.Y. Comp. Codes R. & Regs., tit. 6, §560.7. Removed pit fluids must be disposed, recycled or reused as described in approved fluid disposal plan. Operator must submit fluid disposal plan (see regs at 750. 3.12).
[225] EPA National effluent limitation, *see* 40 CFR ch. I, subch. N; see also http://www.deq.louisiana.gov/portal/Portals/0/planning/Permits%20Docs/Timeline022912mcm-Version%204.pdf (discharges prohibited onto vegetated areas, soil, intermittently exposed sediment surface, lakes, rivers, streams, bayous, canals, or other surface waters regionally characterized as upland, freshwater swamps, freshwater marshes, natural or manmade water bodies bounded by freshwater swamp/marsh).
[226] *See* La. Admin Code titl. 43, pt. XIX, §313.
[227] *Id*. §313(D).

Table 29. Green Completion Requirements

Play/Basin/Jurisdiction	Requirement	Flaring/Venting Allowed	Local
Federal[228]	Hydraulically fractured gas production wells must capture and route all saleable gas to a sales line during flowback starting in 2015. Exception for low-pressure wells. Does not apply to exploratory or delineation wells.	Pit flaring allowed until 2015 and thereafter allowed for non-recoverable gas. Venting allowed where flaring presents safety hazard or if flowback is noncombustible.	N/A
North San Juan (Colorado)[229]	Must use green completion practices to route saleable gas to sales line as soon as practicable. Does not apply to low-pressure or wells with less than 500 MCFD of naturally flowing gas. Exception for exploratory wells and wells not sufficiently proximate to sales lines.	Gaseous phase of non-flammable effluent may be flared or vented until flammable gas is encountered for safety reasons. During upset conditions. If variance granted.	Cannot vent or flare well directly to atmosphere without first going to separation equipment or portable tank.[230]
Upper Green River (Wyoming)[231]	Must eliminate VOCs and hazardous air pollutants to the extent practicable by routing liquids to tanks and gas to sales line or collection system. Does not apply to exploratory wells.	Permitted when required by specific operational events or circumstances.	None

[228] U.S. EPA, Final Rule, Oil and Natural Gas Sector: "New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," (2012).
[229] COGCC R. 805(b)(3).
[230] Archuleta County Land Use Code Sec. 9.2.6.3: Archuleta County's Oil and Gas Development Permit Provisions (Amended Dec. 2010) http://www.archuletacounty.org/DocumentView.aspx?DID=295.
[231] Wyoming Oil and Gas Production Facilities, ch. 6, § 2 Permitting Guidance (March 2010), http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf.

Play/Basin/Jurisdiction	Requirement	Flaring/Venting Allowed	Local
Barnett (Texas)	None	N/A	All wells that have a sales line must use techniques or methods that minimize the release of natural gas and vapors to the environment during flowback except wells permitted prior to July 1, 2009, or the first well on a pad site.[232]
Marcellus (New York) *– Proposed*	REC whenever sales line available.[233]	Yes, if no sales line available.	None identified

[232] Fort Worth, Tex., Ordinance No. 18449-02-2009, § 15-42(A)(28).

[233] Proposed mitigation requirement via permit condition. New York Department of Environmental Compliance, Revised Draft SGEIS, §7.6.8.

Table 30. Setback Requirements

Play/Basin	State-Distance from home	State-Distance from Private Water Well	State-Distance from source of drinking water	Local	Vertical fragmentation?
Barnett (Texas)	200 feet[234]	None	None	600 feet from home, 200 feet to fresh water well[235]	Yes
Eagle Ford (Texas)	200 feet	None	None	500 feet from home,[236] 200 feet from home[237]	Yes
Haynesville (Louisiana)	500 feet[238]	None	None	None	No
Marcellus (Pennsylvania)	500 feet[239]	500 feet[240]	1,000 feet[241]	200 feet from home or water well[242]	Yes, under current law[243]
Marcellus (New York)	None	500 feet[244]	500 feet[245]	N/A[246]	Yes, in that localities have banned development altogether, and if the state moratorium is lifted, it seems likely localities will attempt to regulate this area

[234] Tex. Local Gov't Code 253.005(c).
[235] Fort Worth, Tex.; Ordinance No. 18449-02-2009.
[236] City of Burleson, Tex., Ordinance B-790-09.
[237] Fayette County, Tex., Ordinance. Local zoning ordinance provides for the same 200-foot setback limit from residential homes but ordinance notes "Zoning Hearing Board may attach additional conditions to protect the public's health, safety, and welfare, including increased setbacks."
[238] State of La. Office of Conservation, Order No. U-HS (Aug. 1, 2009),http://dnr.louisiana.gov/assets/docs/news/2009/U-HS.pdf. *See also Louisiana Hydraulic Fracturing State Review*, (Mar. 2011), 5.
[239] Act 13, § 3215(a) (Unconventional wells cannot be drilled within 500 ft. of building or water well, without the consent of the owner of the building or well).
[240] *Id*. DEP shall grant a variance from specified setback requirements if the restriction deprives the owner of the oil and gas rights of the right to produce or share in the oil or gas underlying the surface tract. Note, the statute also provides for a 300-foot setback from streams, springs, other bodies of water identified on a U.S. Geological Survey map, or wetlands, although these "shall" also be waived upon submission of a plan containing additional measures to protect waters. *Id.* § 3215(b).
[241] *Id*.
[242] South Franklin Township, Pa.; Ordinance No. 4-2008 (Wells may not be drilled within 200 feet from an existing habitable structure or existing water well without express written consent of the owner).
[243] Act 13 supersedes all local ordinances purporting to regulate oil and gas operations, other than those adopted pursuant to Pennsylvania municipalities and planning code and Flood Plain Management Act. However, implementation of this provision of the law has been enjoined pending resolution of a legal challenge brought by a number of local governments.
[244] Proposed 6 N.Y. Comp. Codes R. & Regs. 560.4(a)(1) (Well pad must be at least 500 ft. from a private water well unless waived by water well owner).
[245] *Id*. at 560.4(a)(2) (Well pads may not be located within 500 feet of the boundary of a primary aquifer). In addition, NY prohibits well pads within a primary aquifer, 100-year floodplain, and within 2,000 ft. of any public

Play/Basin	State-Distance from home	State-Distance from Private Water Well	State-Distance from source of drinking water	Local	Vertical fragmentation?
North San Juan (Colorado)	150 feet[247]	None	Buffer Zones to protect surface water intended for drinking water	450 from home without consent[248]	Yes
Upper Green River (Wyoming)	350 feet[249]	None	None	None	No

water supply well, reservoir, natural lake or man-made impoundment except those constructed for fresh water storage associated with hydraulic fracturing, and river or stream intakes. *Id.* at 560.4(a)(2)-(4).

[246] Our research did not identify any local laws directly regulating unconventional gas development in NY.

[247] COGCC R. 603(a). In high-density areas, wellheads must be at least 350 ft. from buildings. *Id*. at 603.e(2).

[248] Chapter 90 – La Plata County's Oil and Gas regulations, § 90-122: http://co.laplata.co.us/sites/default/files/departments/planning/chapter_90_adopted_12_7_2010.pdf ; Archuleta County Land Use Code Section 9.2.6.2: Archuleta County's Oil and Gas Development Permit Provisions (Amended Dec. 2010) http://www.archuletacounty.org/DocumentCenter/Home/View/295.

[249] Pits, wellheads, pumping units, tanks and treaters shall be located no closer than 350 ft. from designated public places. Supervisor may extend setbacks or grant exceptions for good cause. WY ADC Oil Gen. ch. 3, § 22(b).

Appendix D: Risk Factor Data

This appendix provides more detailed information on the six selected shale plays considered in this study. For each play, where data are available, we provide 1) an overview of the shale play geology and resource potential, 2) trend data on the number of wells being drilled, 3) information about water usage per well, 4) information on produced water volumes and wastewater management practices, 5) issues associated with freshwater acquisition, and 6) reported data on violations. In addition, this appendix provides more information about the severity index used for water violations (D.7).

Marcellus Shale Play, Pennsylvania

Overview

The Marcellus Shale formation extends across 600 miles within four states, covering an area of about 54,000 square miles. The thickness of the formation varies, but is typically thicker in the east (up to 250 feet) and thins toward the west (Sumi 2008). The Marcellus Shale is the middle Devonian layer between the upper Middle Devonian Mahantango and underlying Middle Devonian Onodaga Limestone formation (USGS 2011). Estimates of the total economically recoverable natural gas in the basin have changed significantly over the years—from an initial estimate of 1.9 trillion cubic feet (Tcf) in 2002 to 168–516 Tcf in 2008 (UM 2010). The U.S. Geological Survey recently estimated mean undiscovered resources for natural gas liquids of 3,379 million barrels and for natural gas of 84,198 billion cubic feet (USGS 2011).

Figure 63 shows the extent and approximate depth of the Macellus formation, which underlies New York, Pennsylvania, Maryland, West Virginia, and Ohio.

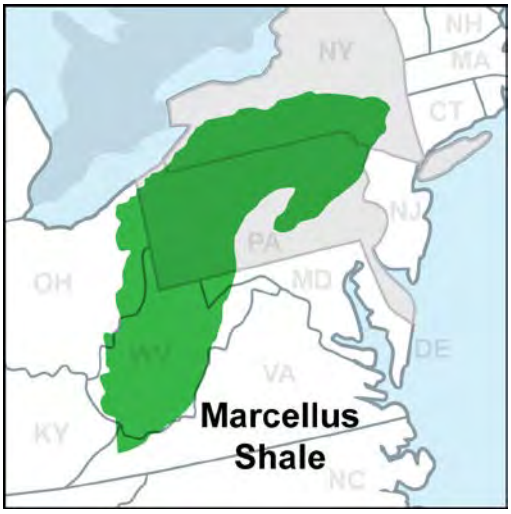


Figure 63. Extent of Marcellus Shale

Number of Wells

As of December 15, 2011, the Marcellus Shale Basin had 88 active operators. More than 9,600 permits have been submitted, with 9,328 issued. Only 36 permits have been denied since 2005 (PA DEP 2011a).The operators with the most permits in the Marcellus Shale include Chesapeake

Appalachia LLC with 1,614 drilling permits, Range Resources Appalachia LLC with 917 permits, and Talisman Energy USA Inc., with 896 permits (PA DEP 2012e).

However, the number of permits does not necessarily reflect the number of wells drilled. Only 44% of the permits resulted in a drilled well (PA DEP 2011b). Figure 64 shows the total number of permits vs. wells drilled in 2010. Figure 65 shows the total number of wells drilled in 2011.

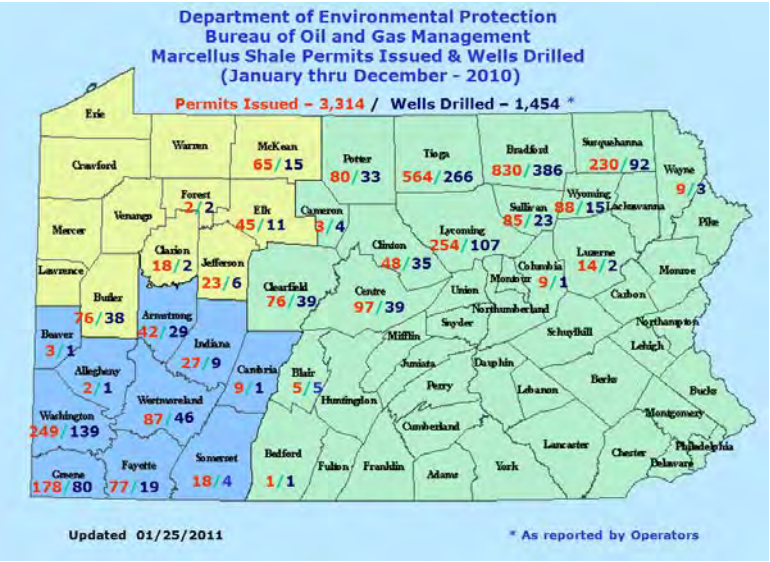


Figure 64. Marcellus Shale permits issued vs. number of wells drilled (PA DEP 2011b)

Water Usage per Well

Some 102 wells in the Marcellus Shale of Pennsylvania were randomly selected for an analysis of water usage per well. The total volume of water per well was acquired through fracfocus.org, and all other information (e.g., latitude, longitude, spud date) was gathered from the fractracker.com data set, "All Wells Marcellus," a compilation of data from the Pennsylvania Department of Environmental Protection (DEP). API numbers and well location files were cross checked between the fractracker and fracfocus data sets. Reporting to fracfocus is voluntary, causing some data to not match official API numbers and latitude/longitude found in regulated DEP data. If discrepancies occurred, then fracfocus data were discarded and a new well was chosen. Table 31 shows results for the 102 wells in Pennsylvania.

Table 31. Analysis of Water Usage per Well (gallons) for 102 Marcellus Wells (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
4,842,070	9,548,784	430,584	9,118,200	1,690,457
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
4,567,320	5,802,941	3,912,996	1,889,945	0.4422

As seen in Table 31, the average volume per well was about 4,842,000 gallons. It is important to note the large range of values—with a minimum of 430,584 gallons and a maximum of 9,548,784 gallons. A histogram (Figure 66) displaying the total volume of water was created by evenly distributing the range of values into twenty bins and then counting the total number of wells for each bin.

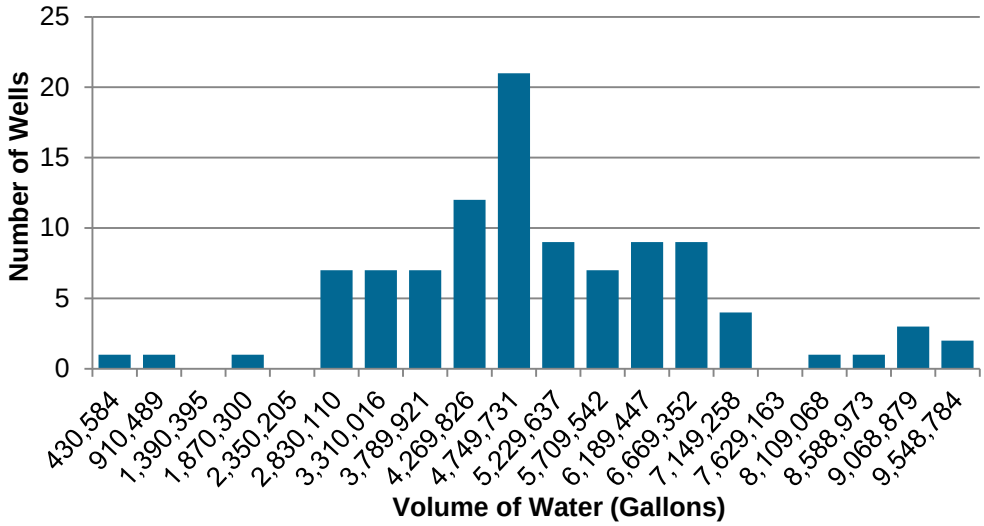


Figure 66. Histogram for 100 wells of total volumes (gallons) (fracfocus.org)

Table 32. Average Water Volume per Well by Well Type (gallons) (fracfocus.org)

Well Type	Vertical	Horizontal
Average	5,431,035	4,756,042
Sample Size	13	89

The effect of a small sample size can be seen in the comparison of average water used by type in vertical and horizontal wells in Table 32. In general, horizontal wells use much more water than vertical wells—a vertical well typically uses 0.5 to 1 million gallons of water, whereas a horizontal well uses between 4 to 8 million gallons of water (Natural Gas 2010). Further data collection is needed to provide a better comparison of vertical and horizontal wells.

Produced Water

The DEP has official production and waste reporting data on its Oil and Gas Reporting website (PA DEP 2012b). The website contains statewide data that can be downloaded on production and waste on a yearly basis. Each waste data set contains the total waste for each well per year, with the waste described by quantity, waste type, and disposal method. Before 2010, waste reports were not well organized, and an online reporting system had not yet been created, causing many wells to be excluded from the data sets. Furthermore, a server malfunction caused the loss of any relevant 2007 data. Since 2010, all waste produced by all wells in Pennsylvania have been

accurately reported. However, reporting period dates have changed to biannual, rather than annual.

Brine production and fracking fluid flowback were analyzed. Although the DEP does not have an official definition of flowback and brine, flowback can be considered the water produced before the well is put into production on a gas line.

For our analysis, natural gas wells in the Marcellus Basin were filtered out from DEP data. We observed that portions of a well's waste were reported multiple times if the waste was taken to more than one treatment facility. The duplicate data were removed from the analysis.

Brine and fracking fluid wastes were divided and analyzed separately. The results can be seen in Tables 33 and 34, along with Figures 67 and 68, with all units in gallons.

Table 33. Summary of Brine Produced (thousands of gallons) (PA DEP 2012b)

				Disposal Method						
Year	**Total Wells**	**Total Volume**	**Average Volume Per Well**	**Brine/ Industrial Water Treatment Plant**	**Injection Disposal Well**	**Municipal Sewage Treatment Plant**	**Other**	**Reuse Other Than Road Spreading**	**Road Spreading**	**Landfill**
2006	14	160.4	14.2	124.9	0	30.6	0	0	4.8	0
2008	204	50,211.0	246.1	1,345.1	775.9	40,067.1	3,457.8	4,501.9	63.0	0
2009	445	231,316.3	519.7	169,860.5	4,707.5	36,402.4	16,466.8	3,875.8	3.1	0
July 2010-June 2011	1,614	287,088.1	177.8	123,623.9	35,541.3	2,711.6	19,931.4	105,248.4	7.8	23.3

Table 34. Summary of Fracking Fluid Produced (thousands of gallons) (PA DEP 2012b)

				Disposal Method						
Year	**Total Wells**	**Total Volume**	**Average Volume Per Well**	**Brine/ Industrial Water Treatment Plant**	**Injection Disposal Well**	**Municipal Sewage Treatment Plant**	**Other**	**Reuse Other Than Road Spreading**	**Road Spreading**	**Landfill**
2006	2	255.4	127.7	255.4	0	0	0	0	0	0
2008	106	46,881.9	442.3	8,792.4	0	25,238.7	11,717.3	1,133.3	0	0
2009	225	105,869.6	470.5	24,505.2	610.2	46,570.4	26,371.2	7,812.4	0	0
July 2010-June2011	1,128	249,336.3	221.0	110,377.0	945.1	284.9	646.1	137,009.5	138.1	73.4

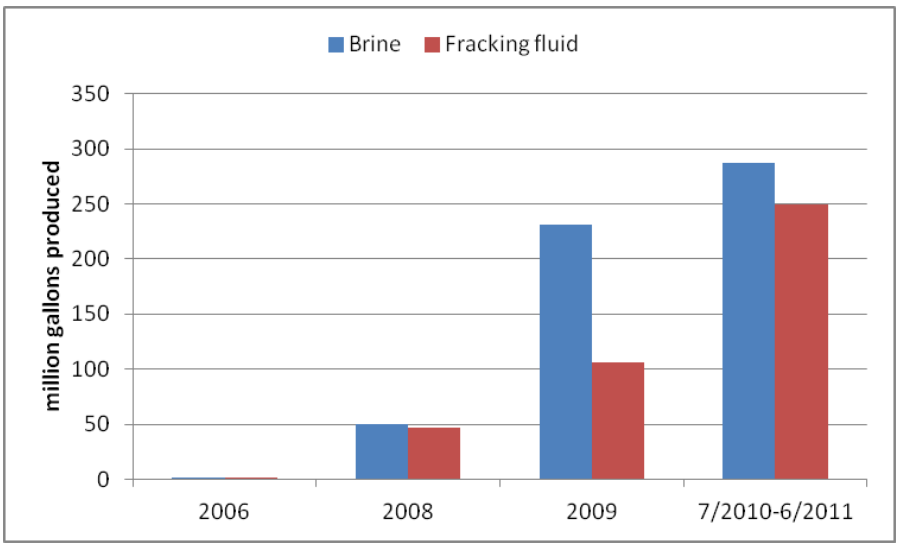


Figure 67. Total volume of produced water, 2006–2011 (PA DEP 2012b)

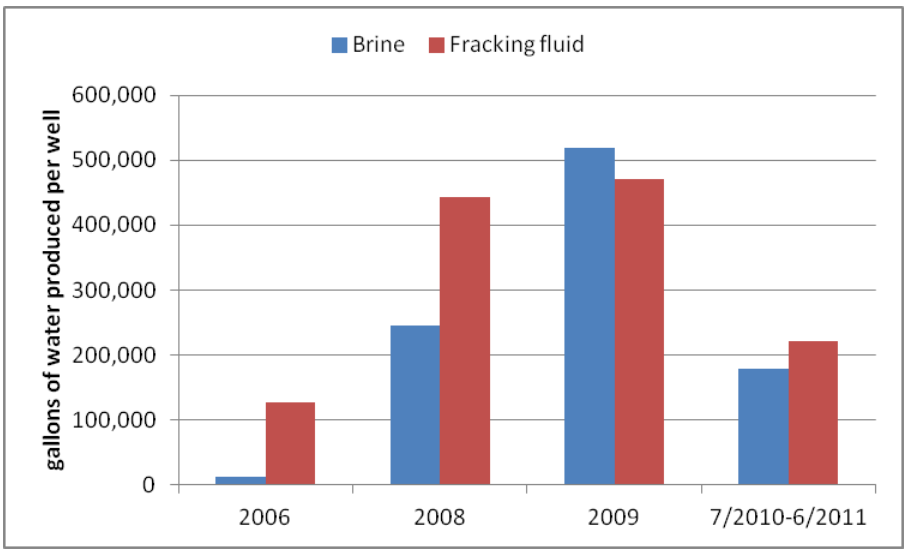


Figure 68. Average volume of produced water per well, 2006–2011 (PA DEP 2012b)

Based on Figure 67, the quantity of both produced brine and fracking fluid are clearly increasing each year—due to the increasing number of wells drilled each year. The final reporting period (July 2010–June 2011) had 1,614 wells producing brine, which is 1,169 more wells than the 2009 period (PA DEP 2012b). As seen in Figure 68, the increase in total brine and fracking fluid does not correlate with average produced brine and fracking fluid per well. There is no recognizable trend in produced water per well, as 2009 had a higher average than any other year.

Water Acquisition

Water withdrawal permit information for the Marcellus in this study focused on the Susquehanna River Basin (SRB). The Marcellus formation underlies 72% of the SRB, covering most of Pennsylvania and part of New York (Arthur 2010). The Susquehanna River Basin Commission

(SRBC) has been the forerunner in determining water usage regulations, monitoring, and permits. The SRBC actively regulates water withdrawal by oil and gas operators; all water withdrawal outside of the SRB is regulated by the DEP.

SRBC issues a report on all approved water sources for natural gas development in the SRB (SRBC 2012a). These permits include the fresh-water source, as well as the maximum allowed uptake per day. These uptakes are rarely at capacity and, according to the SRBC, many sources are used for redundancy due to passby flow conditions when water levels are low (SRBC, 2012a). It is possible to source where operators obtain their water. For example, SWEPI, LP has three different public water suppliers in three different counties. Public water supply does not have a maximum allowed daily uptake, whereas all other supplies do. SWEPI only has one docket approval for a fresh-water source—the Allegheny River in Warren County. This permit allows up to 3 million gallons per day (mgd) of water to be used. SWEPI sources the rest of its water from other drilling companies who share their water permits. Overall, SWEPI has eight different water sources, ranging from 0.217 to 3 mgd. Additional information is available regarding percentage of ground-water to surface-water permits and amounts of water used (SRBC 2011a).

Cost of Acquisition

Fees are associated with fresh-water withdrawal permits. The schedule includes a breakdown of a tiered fee system based on withdrawal amount, as well as consumptive vs. non-consumptive use (SRBC 2011a). Consumptive use is defined in 18 CFR § 806.3 as, "The loss of water transferred through a manmade conveyance system or any integral part thereof… injection of water or wastewater into a subsurface formation from which it would not reasonably be available for future use in the basin, diversion from the basin, or any other process by which the water is not returned to the waters of the basin undiminished in quantity (e-CFR 2012)."

On a per gallon basis, the SRBC fees range from $0.00685–0.1425/gallon for consumptive use, and $0.0030–0.07475/gallon for non-consumptive withdrawals (SRBC 2011a).

Considering SWEPI, LP, it can be seen that a typical docket of 0.250 mgd of surface water would cost $9,975 if the water was not used consumptively. If the use is consumptive, then $1,000 is added as an annual compliance and monitoring fee. There will also be a consumptive-use mitigation fee if the company wishes to use the fee as a method of compliance with 18 CFR §806.22(b). This section states that during low flow periods, several steps may be taken to mitigate consumptive use. One option is to reduce water withdrawal from a source equal to the consumptive use of the operator. Another option is to take water from another approved source. If these or the other provided options are not chosen, the company may choose to pay a fee of $0.29 per 1,000 gallons of water consumed. In the case of SWEPI, this may be an additional cost of $72.50. Companies pay for metering systems and report to the SRBC on a daily basis for each well on its water use.

Another source of fresh water is public supply. The cost of this source varies from utility to utility, but most rates can be found on utility websites. Rates vary significantly from supplier to supplier, and oftentimes unique deals are made between supplier and operator. The deal between East Resources Management, LLC and Morningside Heights Water District approves up to 400,000 gallons per day at a rate of $0.0145 per gallon (Pressconnects 2010). This is 60% greater

than water supplier P.A. American Water, which charges $0.008979 per gallon (American Water 2012).

The above costs refer to obtaining water and do not cover the price of transporting the water. Most water is transported by either pumping or trucking. PSU estimates average trucking costs of $0.2 per gallon (Pressconnects 2010). Further analysis of water-supply distances to wells would need to be studied using GIS to assess the actual cost of water transportation.

Violations

The majority of the violations reported from 2009–2011 fall under the category of "minor - no effect" (Figure 69 and Table 35) (NEPA 2012). "Procedural" violations account for about 20%, and "minor effect" and "substantial" account for about 10%. Also, it should be noted that there are no "major" violations. This data set includes all of the violations from 2009–2011 (NEPA 2012). Further information on violations can be found in D.7 of this appendix.

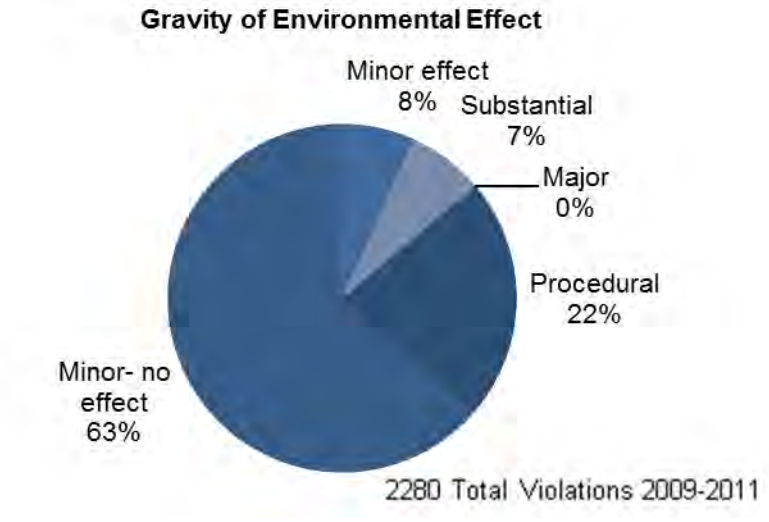


Figure 69. Pennsylvania violations (NEPA 2012)

Table 35. Pennsylvania Violations (NEPA 2012)

Procedural	510	22.4%
Minor - no effect	1433	62.9%
Minor effect	173	7.6%
Substantial	164	7.2%
Major	0	0.0%
Total	2280	

Barnett Shale Play, Texas

Overview

In the early 1900s, geological mapping noted a thick, black, organic-rich shale in an outcrop near the Barnett stream (TRRC 2012e). The Barnett Shale formation exists under extensive areas in Texas and crops out on the flanks of the Llano Uplift, 150 miles to the south of the core area (Figure 70). Current boundaries of the formation are due primarily to erosion (TDWB 2007). The Fort Worth Basin is bounded by tectonic features to the east—notably, the Ouachita Overthrust, an eroded, buried mountain range—and to the north by the uplifted Muenster and Red River Arches. The Barnett Shale dips gently toward the core area and the Muenster Arch from the south where it crops out and thins considerably to the west; its base reaches a maximum depth of ~8,500 ft (subsea) in the northeast. The depth to the top of the Barnett ranges from ~4,500 ft in northwestern Jack County, to ~2,500 ft in southwest Palo Pinto County, to ~3,500 ft in northern Hamilton County, to ~6,000 ft in western McLennan County, to ~7,000 to 8,000 ft in the Dallas-Fort Worth area. Further west in Throckmorton, Shackelford, and Callahan Counties, the depth to the Barnett ranges between ~4,000 and 2,000 ft (TDWB 2007).

The U.S. Geological Survey (USGS) estimated the mean gas resources at 26.7 Tcf (USGS 2004).

Figure 70. Extent of Barnett Shale

Figure 70 shows the extent of the Barnett Shale in Texas. The formation is actually considered to be a hydrocarbon source, reservoir, and trap, all at the same time. As a reservoir, it is known as a "tight" gas reservoir, indicating that the gas is not easily extracted. However, hydraulic fracturing technology has made it possible to extract the gas (TRRC, 2012d). For the Barnett Shale, permeability ranges from microdarcies to nanodarcies, porosity ranges from 0.5% to 6%, and water saturation is below 50%.

Future development will be hampered, in part, because major portions of the field are in urban areas, including the rapidly growing Dallas-Fort Worth Metroplex. Some local governments are researching means by which they can drill on existing public land (e.g., parks) without disrupting

other activities so they may obtain royalties on any minerals found. Others are seeking compensation from drilling companies for roads damaged by overweight vehicles, because many of the roads are rural and not designed for use by heavy equipment. In addition, drilling and exploration have generated significant controversy (TRRC, 2012d).

Number of Wells

The Barnett Shale has experienced substantial development over the last decade, as evidenced by the number of wells (Figure 71) and estimates of total gas production (Figure 72).

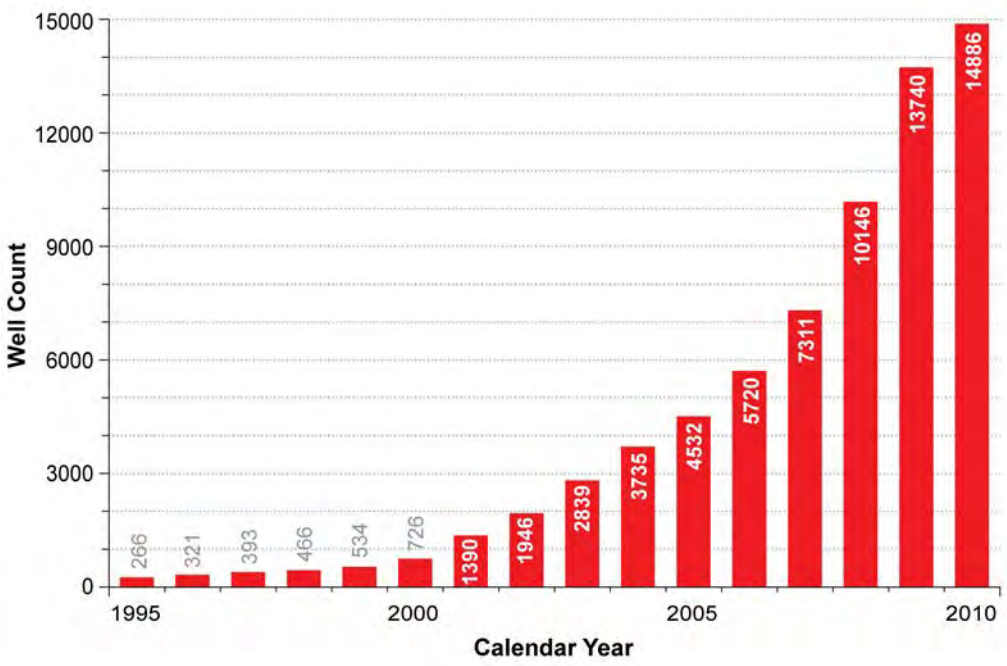


Figure 71. Wells in Barnett Shale, 1995-2010 (TRRC, 2012c)

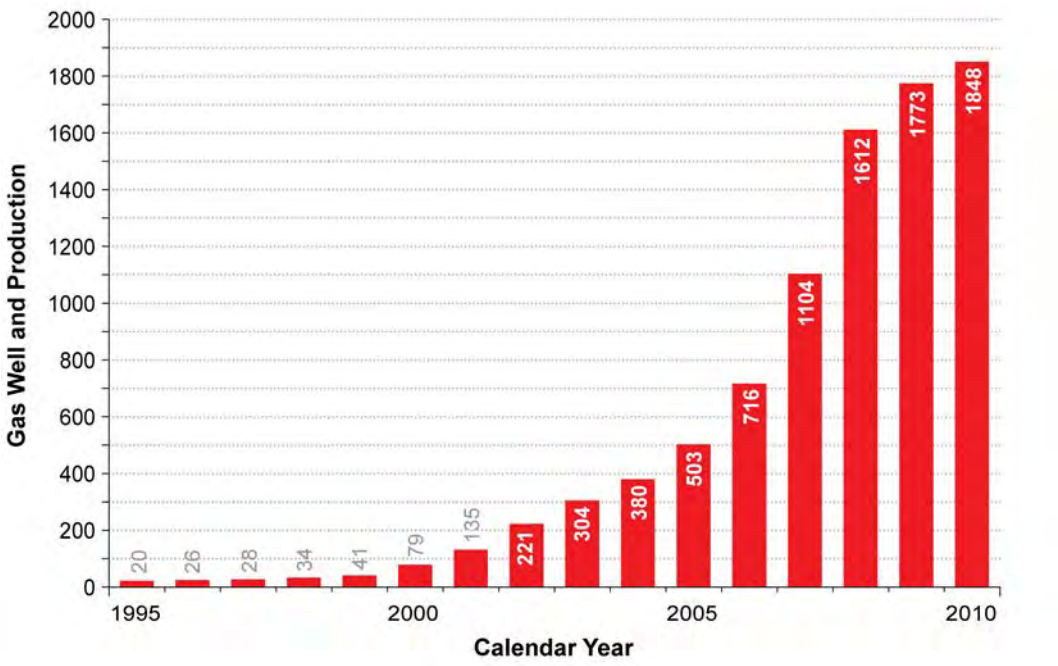


Figure 72. Gas production in the Barnett Shale (bcf), 1995-2010 (TRRC, 2012e)

Water Usage per Well

Table 36 shows the analysis results on 100 Barnett Shale wells selected randomly from fracfocus.org.

Table 36. Statistics of Water Use (Gallons) (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
2,537,853.848	26,315,125	29,186	26,285,939	3,512,472.559
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
1,293,306	4,298,286	86,751	4,211,535	3.500964058

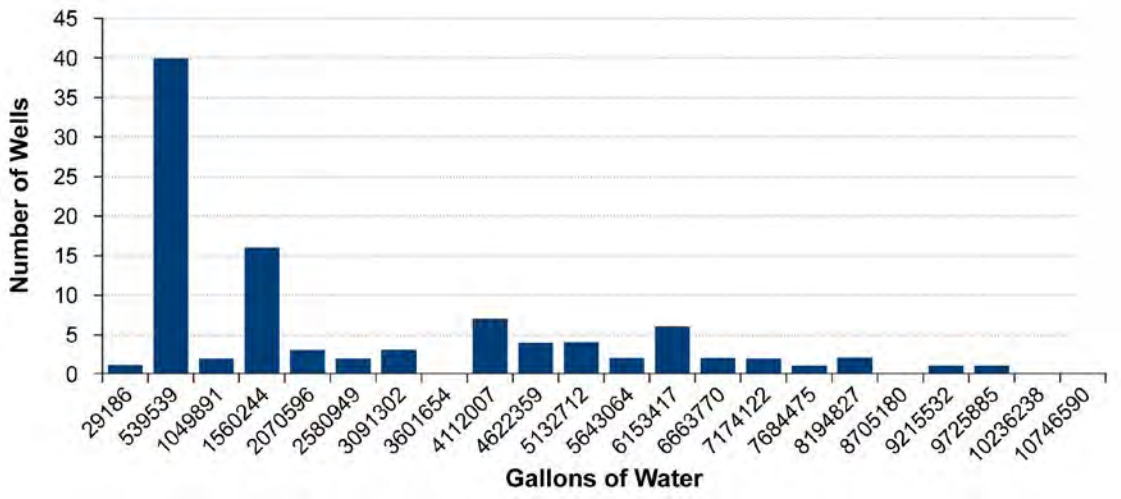


Figure 73. Histogram of 100 wells for total water volume (gallons) (fracfocus.org)

As seen in Table 36, the average volume per well was 2,537,853 gallons, with values ranging from 29,186 gallons to 26,315,125 gallons (fracfocus.org). Figure 73 is a histogram displaying the total volume of water, created by evenly distributing the range of values into twenty bins and then counting the total number of wells for each bin.

Produced Water

No produced water data are available for Barnett shale. However, the Railroad Commission (RRC) of Texas requires every operator to report—into a query system—how much water is disposed. The current method used for disposal in the Barnett Shale is deep-well injected. The Injection Volume Query from the RRC database was used and monthly county-wide or operator-wide injected volumes can be obtained (TRRC 2011).

Violations

Figure 74 expresses the violations from 2009–2011 in Texas according to the severity of environmental effect (Wiseman 2012). Of the 35 total violations (Table 37), 35% of the violations are “minor - no effect” and “substantial.” “Procedural” account for about 20%, and “major” and “minor effect” account for 3%. It should be noted that these violations only include wells for which formal compliance or administrative orders were issued. Therefore, these data are not comprehensive and do not represent the total number of violations. Further information on violations can be found in D.7 of this appendix.

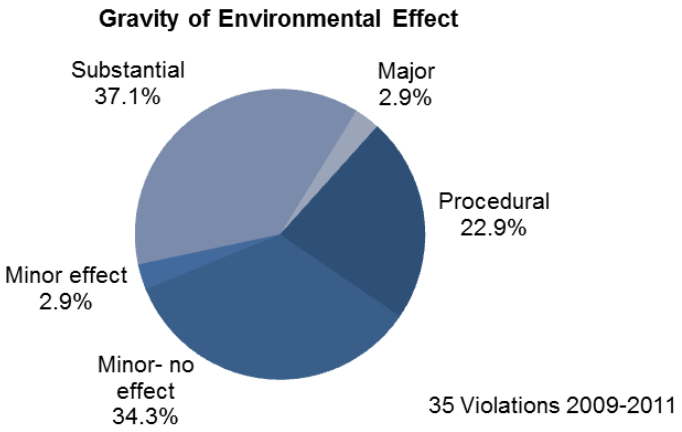


Figure 74. Texas violations (Wiseman 2012)

Table 37. Texas Violations (Wiseman 2012)

Texas		
Procedural	8	22.9%
Minor - no effect	12	34.3%
Minor effect	1	2.9%
Substantial	13	37.1%
Major	1	2.9%
Total	35	

Eagle Ford Shale Play, Texas

Overview

The Eagle Ford Shale play extends across 23 counties, covering an area of 20,000 square miles (Figure 75). The Eagle Ford Shale has an average thickness of 250 feet and contains an estimated 21 Tcf of shale gas and 3 billion barrels of shale oil (EIA 2011).

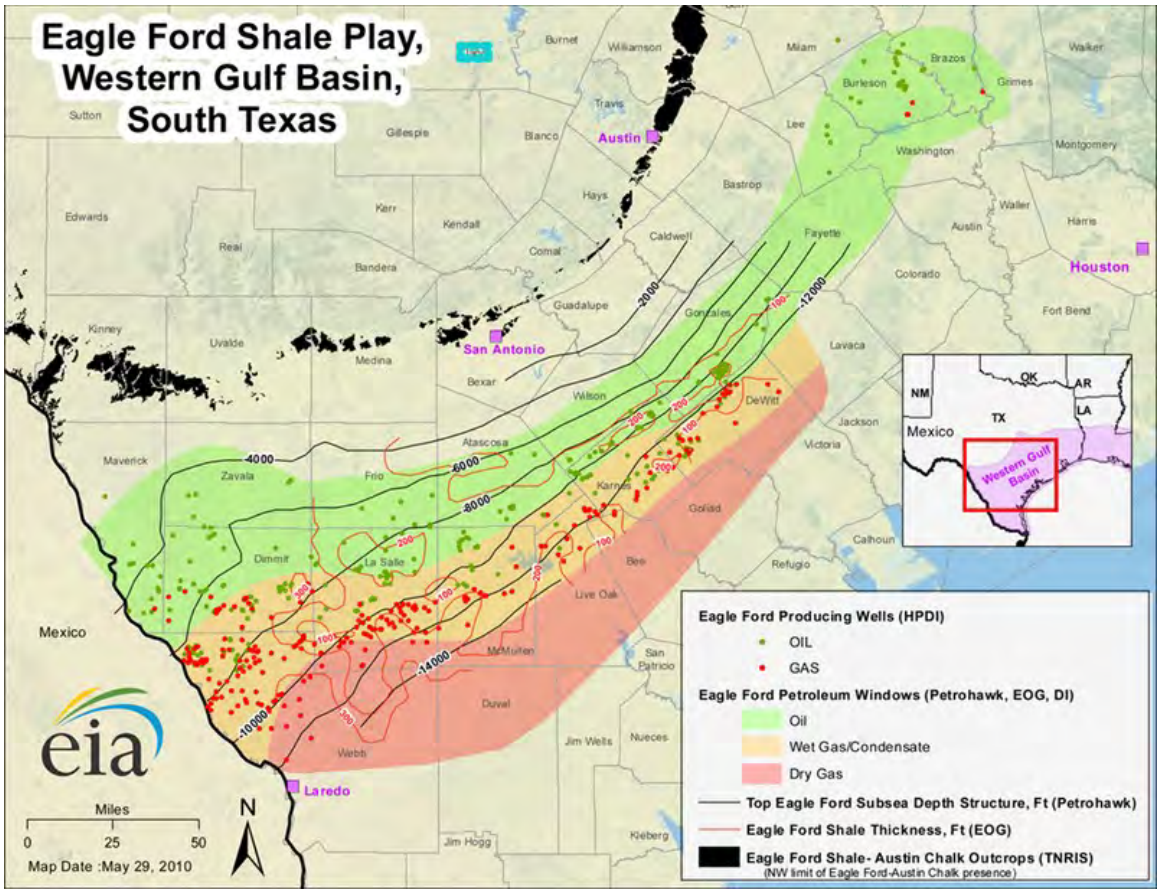


Figure 75. Extent of Eagle Ford Shale play (Eagle Ford Shale 2012)

Number of Wells

In 2008, Petrohawk drilled the first well in the Eagle Ford Shale, and since then, gas production has more than doubled—from 108 bcf in 2010 to 287 bcf in 2011. Oil production increased from more than 4 million barrels in 2010 to more than 36 million barrels in 2011 (TRRC 2012a). Increased production reflects the increases in drilling permits issued and in the number of oil and gas wells. Figure 76 shows the total number of producing oil and gas wells over the past three years.

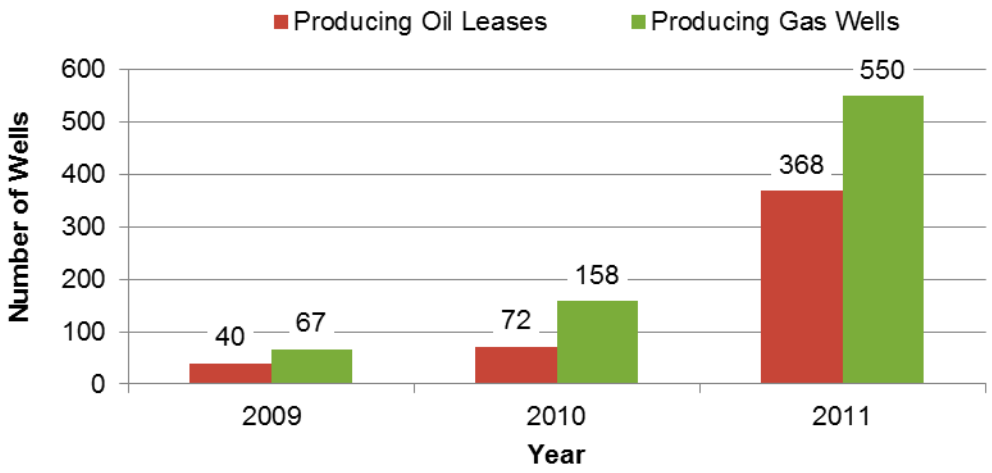


Figure 76. Number of producing oil and gas wells in Eagle Ford (Eagle Ford Shale 2012)

With 2,826 issued drilling permits in 2011 alone, the well count in Eagle Ford may steadily increase (Eagle Ford Shale 2012).

Water Usage per Well

Wells in the Eagle Ford Shale were randomly selected from fracfocus.org. Figure 77 shows a histogram of the water used per well, and Table 38 shows the average, maximum, and minimum water used per well.

Table 38. Fresh Water Use in Eagle Ford (in gallons) (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
3,751,751	7,084,098	77,658	7,006,440	1,276,506
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
3,608,905	4,386,965	3,116,039	1,270,927	-0.079

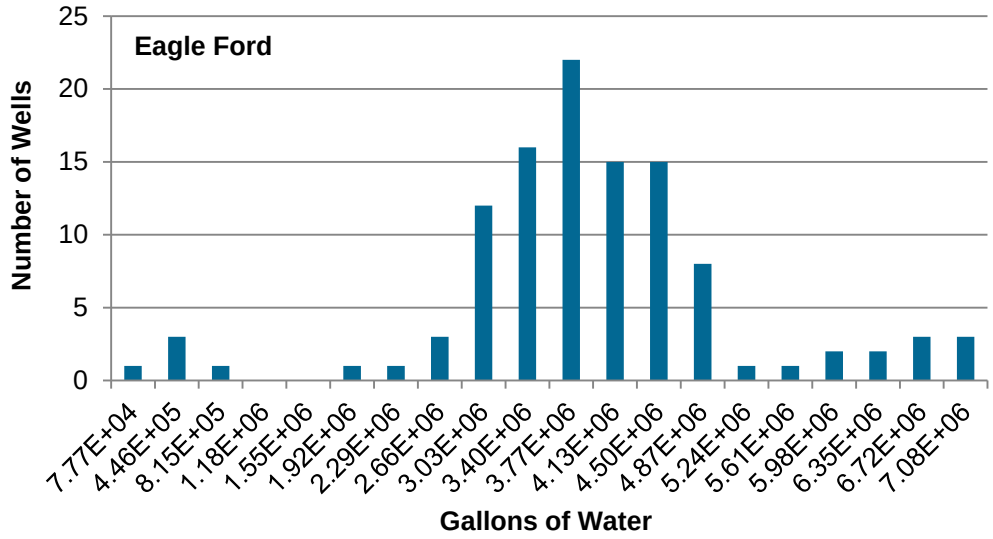


Figure 77. Fresh-water use in Eagle Ford per well (fracfocus.org)

The Texas Commission of Environmental Quality monitors surface water use in Texas. Surface water rights are issued to operators, and withdrawal amounts can be found on the TCEQ website (http://www.tceq.texas.gov/). However, withdrawal information is based on water-right number and is not shown on a well-to-well basis (TCEQ 2012).

Haynesville Shale Play, Louisiana

Overview

The Haynesville Shale extends over large sections of southwestern Arkansas, northwest Louisiana, and East Texas (Figure 19). It is up to 10,500 to 13,000 feet below the surface, with an average thickness of about 200–300 feet, and overs an area of about 9,000 square miles (TRRC 2012f).

Haynesville Shale is an important shale gas play in East Texas and Louisiana. Estimated recoverable reserves are as much as 60 Tcf, with each well producing 6.5 bcf on average (Hammes 2009). The formation came into prominence in 2008 as a potentially major shale gas resource, and production has boomed since late March 2008 (TRRC 2011). Producing natural gas from the Haynesville Shale requires drilling wells from 10,000 to 13,000 feet deep, with the formation being deeper nearer the Gulf of Mexico. The Haynesville Shale has recently been estimated to be the largest natural gas field in the contiguous 48 states, with an estimated 250 Tcf of recoverable gas (Nossiter 2008).

Figure 78. Extent of Haynesville Shale

The Haynesville Shale is lithologically heterogeneous, but is often an organic-rich mudstone. The composition varies greatly according to the geographic location and stratigraphic position of the mudstones—from calcareous mudstone near the ancient carbonate platforms and islands, to argillaceous mudstone in areas where submarine fans prograded into the basin and diluted organic matter. The Haynesville formation was deposited about 150 million years ago in a shallow offshore environment (Geology.com, 2012b).

Number of Wells

The State of Louisiana, Department of Natural Resources, provides information on monthly well counts. Well counts (Figure 79) have varied from 2009–2011 as old wells are abandoned and new wells are drilled and leased. However, total gas production (Figure 80) has increased from 2009–2011.

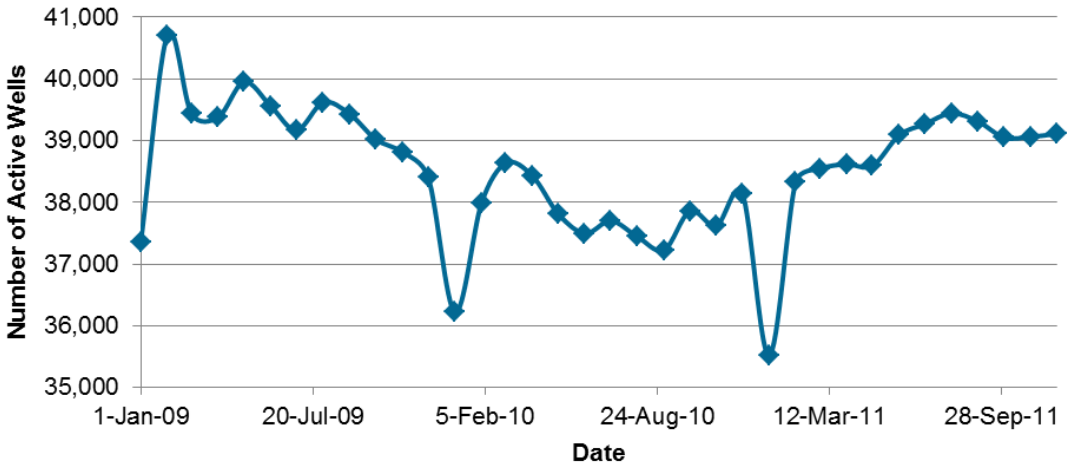


Figure 79. Monthly well count (2006–2011) (LADNR 2012b)

The total number of wells shows a significant drop at the end of 2010, after some natural fractures were seen in the formation cores extracted during test drilling. These fractures suggest

the risk of anthropogenic faulting of the surrounding land; however, drilling continued after these problems were resolved.

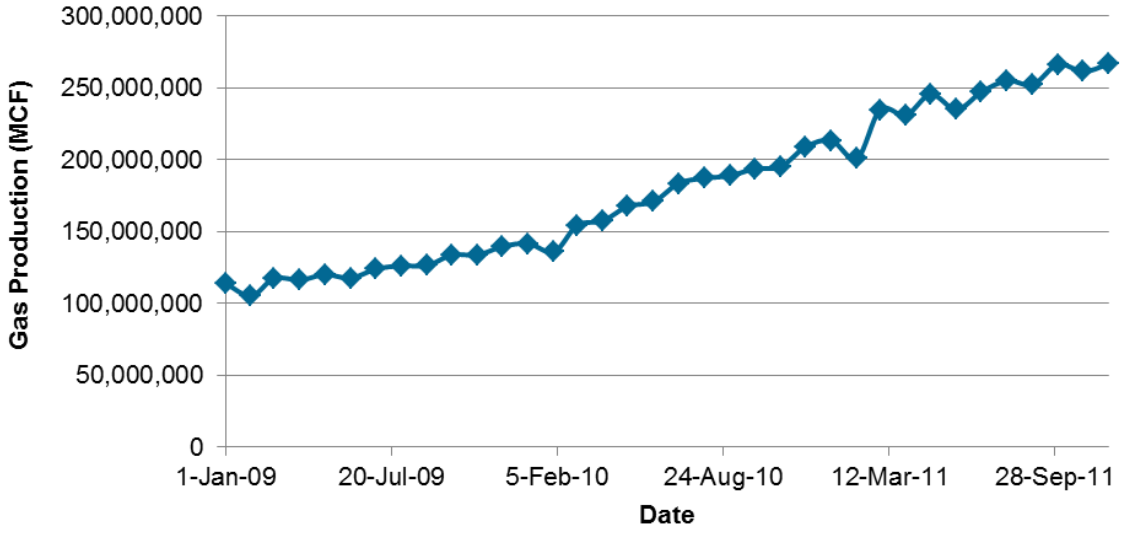


Figure 80. Monthly gas production (2009–2011) (EIA 2011)

Production is increasing almost linearly, despite a drop in well count. At the end of 2011, production was twice that in 2009.

Water Usage per Well

One hundred wells in the Haynesville Shale were randomly selected. Table 39 gives statistics on water usage, and Figure 81 is a histogram of the distribution of water usage distributed evenly into twenty bins.

Table 39. Analysis of Water Usage for 100 Haynesville Shale Wells (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
4,568,683	9,567,936	8,736	9,559,200	2,243,797
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
4,925,256	6,255,663	3,875,203	2,380,460	-0.578

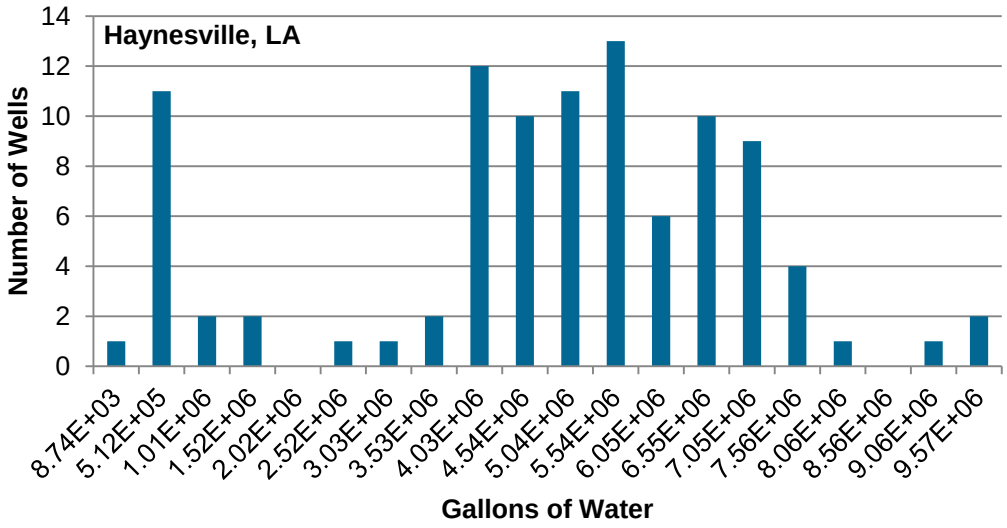


Figure 81. Fresh-water use for 100-well sample (fracfocus.org)

Violations

Figure 82 expresses the violations from 2008–2011 in Louisiana according to the severity of environmental effect. A majority of the violations are in the "procedural" category (Table 40). "Minor - no effect" violations make up about 30%, and "minor effect," "substantial," and "major" account for less than 10% (Wiseman 2012). These data include mostly Haynesville wells with compliance orders from January 1, 2008 through July 14, 2011. About 83 additional well incidents had insufficient information to be categorized. Further information on violations can be found in D.7 of this appendix.

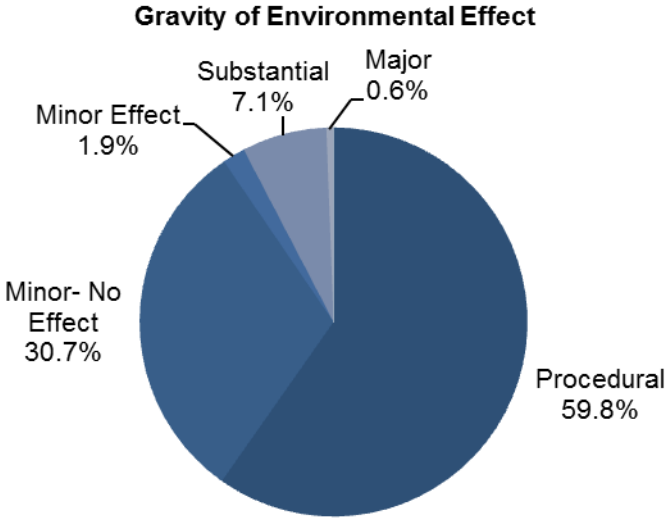


Figure 82. Louisiana violations (Wiseman 2012)

Table 40. Louisiana Violations (Wiseman 2012)

Procedural	95	59.8%
Minor - no effect	49	30.7%
Minor effect	3	1.9%
Substantial	11	7.1%
Major	1	0.6%
Total	158	

Upper San Juan Basin, Colorado, New Mexico

Overview

The San Juan Basin covers an area of about 7,500 square miles across the Colorado and New Mexico border in the Four Corners region (Figure 83). It spans about 100 miles north-south in length and 90 miles east-west in width. In the San Juan Basin, the total thickness of all coalbeds ranges from 20 to more than 80 feet. Coalbed methane production occurs primarily in coals of the Fruitland Formation, but some coalbed methane is trapped within the underlying and adjacent Pictured Cliffs Sandstone; many wells are present in both zones (EPA 2004).

Figure 83. Extent of the San Juan Basin (USGS 2002a)

The Fruitland Formation is the primary coal-bearing unit of the San Juan Basin, as well as the target of most coalbed methane production. The Fruitland coals are thick and have individual beds up to 80 feet thick. The formation is composed of interbedded sandstone, siltstone, shale,

and coal. Some of the most important natural-gas-producing formations include the Fruitland, Pictured Cliffs, Mesaverde, Dakota, and Paradox formations and are located in La Plata County. Early development of natural gas began here in the 1920s. In La Plata County, coalbed methane production began in the late 1970s. Traditional natural gas reserves have been—and continue to be—developed at a steady pace (USGS 2002a).

Two types of natural gas wells exist within La Plata County: conventional and coalbed. Conventional gas wells are usually deeper—3,500 to 10,000 feet—and extract gas and oil from sandstone formations such as the Mesaverde and Dakota (La Plata Energy Council 2012). The shallower coalbed gas wells generally range from 1,000 to 4,000 feet deep and extract gas from coal-bearing formations (EPA 2004). The Fruitland formation is La Plata County's methane-rich coalbed formation.

Produced Water

Conventional wells initially produce large volumes of gas and very little water. Over time, gas production declines and water increases. Coalbed wells are just the opposite, producing large quantities of water and low gas quantities at the beginning; later, water production declines and gas production increases. Table 41 shows oil, gas, and water production from 2007–2011.

Table 41. Oil, Gas, and Water Production in La Plata County (COGCC 2012a)

Year	Oil Production (bbl)	Gas Production (Mcf)	Water Production (bbl)
2007	35,883	412,488,324	24,032,308
2008	38,038	425,541,599	20,154,062
2009	33,975	425,439,680	24,177,214
2010	33,396	422,450,451	31,942,703
2011	26,747	373,116,167	21,231,213

Based on the database provided by the Colorado Oil and Gas Conservation Commission (COGCC), five methods are used to dispose of water in La Plata County: disposal in a central pit well, injection on lease, disposal at a commercial disposal facility, evaporation in an onsite pit, and through surface discharge (COGCC 2012a). Table 42 and Figure 84 show disposal methods in La Plata County from 2007 to 2011.

Table 42. Produced Water and Disposal Method in La Plata County (Million Gallons) (COGCC 2012a)

Disposal Method	2011	2010	2009	2008	2007	Average
Central Disposal Pit Well	637	1,213	726	646	736	791
Injected on Lease	350	362	175	201	179	253
Commercial Disposal Facility	47	60	61	53	37	52
Onsite Pit	2	2	1	2	1	1
Surface Discharge	NON	NON	NON	NON	NON	
SUM	1,036	1,638	963	901	953	1,098
Percentage	60%	61%	51%	48%	57%	55%
Estimation	1,725	2,697	1,876	1,872	1,674	1,969

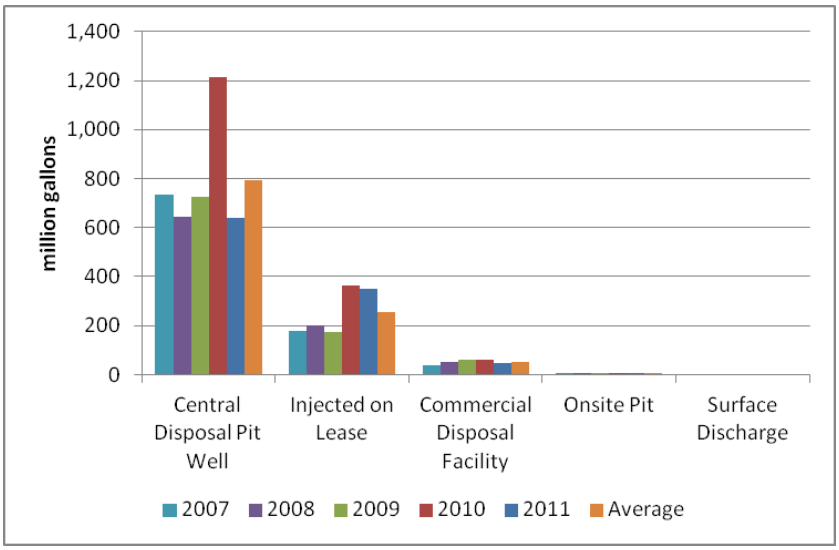


Figure 84. Water disposal volumes and methods in La Plata County (million gallons) (COGCC 2012a)

There is no surface discharge in La Plata County and minimal use of onsite pits. The most widely used method of disposal in La Plata County is a central disposal pit well. Some 70% of produced water is disposed in a central disposal pit well, 23% of produced water is injected on the lease, and 4.7% goes to a commercial disposal facility. Trends in the state of Colorado (Table 43) differ from those in La Plata County (Table 42).

Table 43. Produced Water and Disposal Method in the State of Colorado (Million Gallons) (COGCC 2012a)

Disposal Method	2011	2010	2009	2008	2007	Average
Central Disposal Pit Well	4,609	3,314	3,237	3,135	3,678	3,595
Injected on Lease	8,095	11,243	6,715	7,194	11,666	8,983
Commercial Disposal Facility	1,248	2,266	1,665	1,303	962	1,489
Onsite Pit	3,001	2,962	3,213	5,128	3,588	3,579
Surface Discharge	2,191	1,218	1,219	283	677	1,117
Sum	19,144	21,003	16,049	17,042	20,572	18,762

Violations

For the state of Colorado, the only publicly accessible statistics related to violations are Notices of Alleged Violations (NOAVs). The number of NOAVs does not represent the number of violations because violations do not necessarily lead to the issuance of NOAVs. Additionally, when NOAVs are issued, they may cite violations of more than one rule, order, or permit condition. Colorado violations could not be acquired.

Green River Basin, Wyoming

Overview

The Green River Basin Oil Shale Field, as seen in Figure 85, is located in Wyoming, Utah, and Colorado, on the western flank of the Rocky Mountains. The main part of the Green River Basin Formation is located in the southwest portion of Wyoming. The Colorado oil shale is expected to hold the largest amount of oil from shale. Specifically, the Piceance Creek Basin is the large producer for oil shale in the Green River Formation (Oil Shale Gas 2012).

The estimates of the oil resource within the Green River Formation range from 1.3 to 2.0 trillion barrels. Because not all resources are recoverable, a moderate estimate of recoverable oil is about 800 billion barrels (Oil Shale Gas 2012).

Figure 85. Extent of Green River Formation

The Jonah Field is located in the northern part of the Green River Basin and has produced more than 1.0 Tcf of gas since production commenced in 1992 (Oil Shale Gas 2012). Development of this field resulted from applying advanced fracture stimulation techniques. The field has undergone several iterations of development, with some sections of the field currently being developed on 10-acre well spacing; the current well spacing is around 20 acres. The field produces from a series of stacked reservoirs within the Cretaceous Mesaverde and Lance Formations. The field is bounded between two faults forming a wedge-shaped field.

Water usage per well

One hundred wells in the Green River Formation were randomly selected. Table 44 gives statistics about water usage, and Figure 86 is a histogram of water usage distributed evenly into twenty bins.

Table 44. Analysis of Water Usage for 100 Green River Formation Wells (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
1,076,417	4,451,034	14,467	4,436,567	1,230,306
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
367,522	1,665,741	201,280	1,464,461	1.40

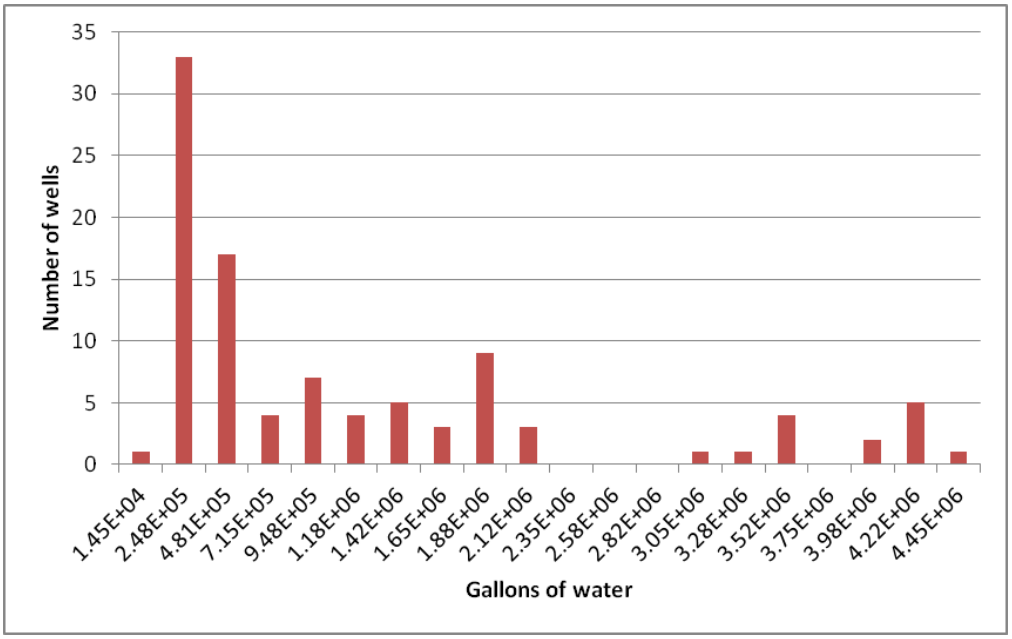


Figure 86. Fresh-water use for 100-well sample (fracfocus.org)

Figure 87 shows the volumes of hydraulic fracturing fluids used in Wyoming by county.

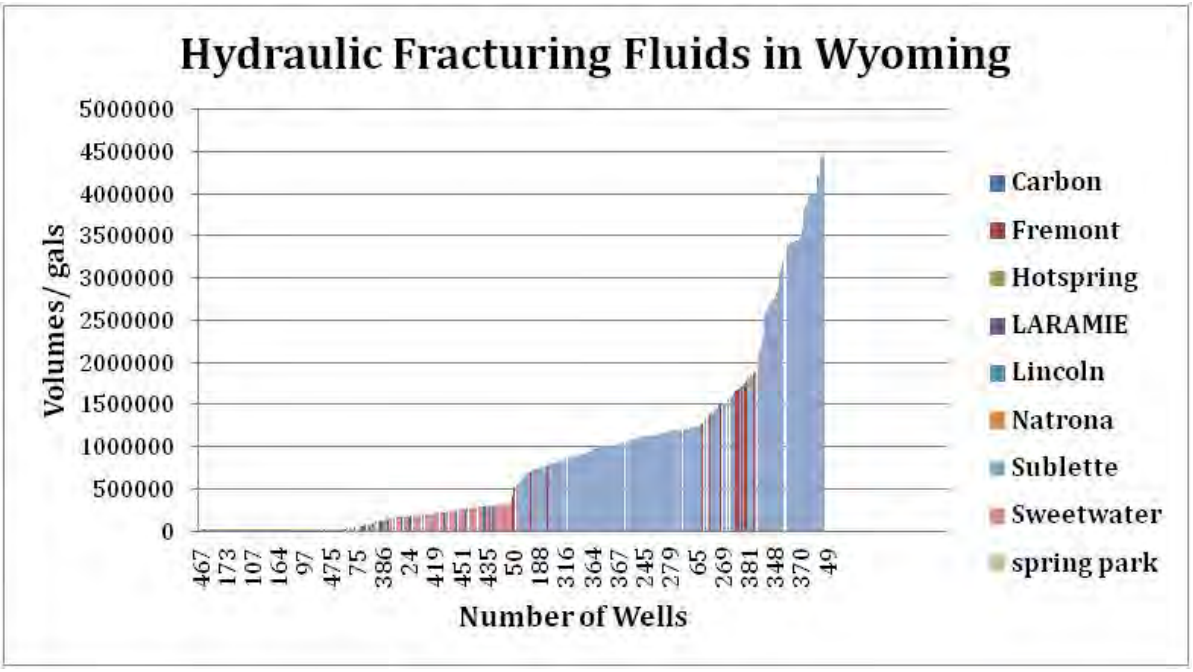


Figure 87. Volumes of hydraulic fracturing water (fracfocus.org)

Produced Water

Table 45 expresses the total oil, gas, and water produced within the Green River Basin from 2007–2011.

Table 45. Production of Oil, Gas, and Water in Green River Basin (WOGCC 2012)

Year	Oil Production (barrels)	Gas Production (Mcf)	Water Production (Barrels)
2007	15,491,483	1,218,888,397	125,613,453
2008	15,824,924	1,371,741,392	150,830,391
2009	15,925,806	1,428,200,434	158,560,401
2010	20,544,588	1,418,379,334	169,901,204
2011	15,385,222	1,347,348,632	177,151,681

Table 46 provides injection volumes by field, although not all fields are represented.

Table 46. Injection Volumes (WOGCC 2012)

Field	2007 (bbl)	2008 (bbl)	2009 (bbl)	2010 (bbl)	2011 (bbl)
Big Piney	577,239	167,646	189,178	70,354	40,247
Bison Basin	1,989,960	2,564,857	2,223,756	2,354,332	2,296,464
Brady	4,419,146	2,612,544	1,943,879	2,003,854	4,688,163
Cow Creek	4,406,339	8,174,082	4,635,125	5,517,186	6,288,081
Fontenelle	111,267	117,390	115,376	110,948	102,167
Green River Bend	592,890	381,857	549,775	616,873	432,311
Jonah	1,367,707	2,010,190	1,588,080	1,991,187	2,703,926

Field	2007 (bbl)	2008 (bbl)	2009 (bbl)	2010 (bbl)	2011 (bbl)
LaBarge	167,441	1,653,772	1,752,291	2,079,953	1,344,187
Lost Soldier	23,577,864	25,017,789	32,557,565	29,490,274	37,367,198
Mahoney Dome	926,644	721,983	1,188,006	1,085,123	1,111,673
McDonald Draw	535,996	494,630	414,810	388,833	377,482
Patrick Draw	1,551,255	4,012,343	1,196,017	1,020,284	1,179,744
Pinedale	954,458	6,749,055	11,951,930	12,027,080	11,482,543
Saddle Ridge	221,413	206,610	227,843	231,330	208,498
Star Corral	288,567	221,015	172,686	190,853	175,222
Tierney	1,083,636	1,813,532	1,660,262	1,831,283	1,004,778
Tip Top	455,781	548,822	427,670	387,878	389,175
WC	16,900,921	33,853,193	31,456,801	24,984,327	12,428,968
Wertz	20,610,169	25,384,888	1,953,919	24,188,672	30,240,574

Severity of Environmental Impact Matrix

Table 47 shows the categorization of environmental impacts for shale gas operations.

Table 47. Severity of Environmental Impact (Wiseman 2012)

Severity of environmental effect	Activity for which violation occurred	Enforcement action	Environmental factors
Procedural	- Permitting - Reporting - Testing - Financial assurance	"All ranges (violation noted" through notice of violation and/or administrative order)	No indication in violation/field notes that failure to obtain permit, report, conduct a test, or provide financial guarantee resulted in environmental damage
Minor - no effect	- Equipment failures - Pit construction, operation, and maintenance - Failure to prevent oil and gas waste - Commingling oil and gas - Site maintenance, such as moving weeds - Sign posting and hazard labels	"All ranges (violation noted" through notice of violation and/or administrative order)	No indication in field notes that violation resulted in any environmental damage
Minor effect	- Equipment failures that led to release - Pit construction, operation, and maintenance that led to release - Air pollution - Spills - Disposal	Violation noted, or NOV/administrative order paired with very small environmental effect	Small spills and improperly disposed wastes (typically less than 5 barrels of produced water or oil) that did not move offsite or otherwise suggest substantial environmental damage. Small quantities of air emissions (e.g., slightly over the daily limit).
Substantial	- Equipment failures that led to release - Pit construction, operation, and maintenance that led to release - Failure to plug well twelve months after abandonment or inactivity - Air pollution - Spills - Disposal	Violation noted, or NOV/administrative order + substantial environmental effect; remediation order	Medium spills and improperly disposed wastes (typically more than 5 barrels and less than 10 for produced water or oil that stayed on site). For fracturing fluid spills, any spill more than 1 barrel was considered major.
Major	- Equipment failures that led to release - Pit construction, operation, and maintenance that led to release - Air pollution - Spills - Disposal	Violation noted, or NOV/administrative order + > substantial environmental effect (or high penalty + substantial environmental effect); remediation order + major environmental effect	Large spills or improperly disposed of wastes (typically 10 or more barrels, small to large spills that moved off site and impacted a resource (e.g., drainage ditch, wetland). Any spill of fracturing fluid > 1 barrel.

Appendix E: Assumptions Used in ReEDS

What is ReEDS?[250]

The Regional Energy Deployment System is an optimization model used to assess the deployment of electric power generation technologies and transmission infrastructure throughout the contiguous United States into the future. The model, developed by NREL, is designed to analyze critical energy issues in the electric sector, especially with respect to the effect of potential energy policies such as clean energy and renewable energy standards or carbon restrictions.

ReEDS provides a detailed treatment of electricity-generating and electrical storage technologies, and specifically addresses a variety of issues related to renewable energy technologies—including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal generation profiles, variability of wind and solar power, and the influence of variability on the reliability of the electrical grid. ReEDS addresses these issues through a highly discretized regional structure, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary services requirements and costs.

Qualitative Model Description

To assess competition among the many electricity generation, storage, and transmission options throughout the contiguous United States, ReEDS chooses the cost-optimal mix of technologies that meet all regional electric power demand requirements, based on grid reliability (reserve) requirements, technology resource constraints, and policy constraints. This cost-minimization routine is performed for each of twenty 2-year periods from 2010 to 2050. The major outputs of ReEDS include the amount of generator capacity and annual generation from each technology, storage capacity expansion, transmission capacity expansion, total electric sector costs, electricity price, fuel prices, and CO_2 emissions. Time in ReEDS is subdivided within each 2-year period, with each year divided into four seasons with a representative day for each season, which is further divided into four diurnal time slices. Also, there is one additional summer-peak time slice. These 17 annual time slices enable ReEDS to capture the intricacies of meeting electric loads that vary throughout the day and year—with both conventional and renewable generators.

Although ReEDS includes all major generator types, it has been designed primarily to address the market issues that are of the greatest significance to renewable energy technologies. As a result, renewable and carbon-free energy technologies and barriers to their adoption are a focus. Diffuse resources such as wind and solar power come with concerns that conventional dispatchable power plants do not have, particularly regarding transmission and variability. The ReEDS model examines these issues primarily by using a much greater level of geographic disaggregation than do other long-term, large-scale, capacity expansion models. ReEDS uses 356 different resource regions in the continental United States. These 356 resource supply regions are grouped into four levels of larger regional groupings—balancing areas, reserve-sharing groups,

[250] "What is ReEDS?" is taken from the 2011 detailed documentation for the ReEDS model.
Short, W., et al., Regional Energy Deployment System (ReEDS). NREL Technical report NREL/TP-6A20-46534, August 2011. http://www.nrel.gov/analysis/reeds/.

North American Electric Reliability Council regions,[251] and interconnects. States are also represented for the inclusion of state policies.

Many of the data inputs in ReEDS are tied to these regions and derived from a detailed GIS model/database of the wind and solar resource, transmission grid, and existing plant data. The geographic disaggregation of renewable resources enables ReEDS to calculate transmission distances, as well as the benefits of dispersed wind farms, PV arrays, or CSP plants supplying power to a demand region. Offshore wind is distinguished from onshore wind both in terms of technology cost/performance and resources. The wind and CSP supply curves are subdivided into five resource classes based on the quality of the resource—strength and dependability of wind or solar isolation.

Regarding resource variability and grid reliability, ReEDS also allows electric and thermal storage systems to be built and used for load shifting, resource firming, and ancillary services. Four varieties of storage are supported: pumped hydropower, batteries, compressed air energy storage, and thermal storage in buildings.

Along with wind and solar power data, ReEDS provides supply curves for hydropower, biomass, and geothermal resources in each of the 134 balancing areas. The geothermal and hydropower supply curves are in megawatts of recoverable capacity, and the biomass supply curve is in million British thermal units of annual feedstock production. In addition, other carbon-reducing options are considered. Nuclear power is an option, as is CCS on some coal and natural gas plants. CCS is treated simply, with only an additional capital cost for new coal and gas-fired power plants for the extra equipment and an efficiency penalty to account for the parasitic loads of the separation and sequestration process. Also, a limited set of existing coal plants can choose to retrofit to CCS for an associated cost, as well as a performance, penalty. The major conventional electricity-generating technologies considered in ReEDS include hydropower, simple- and combined-cycle natural gas, several varieties of coal, oil/gas steam, and nuclear. These technologies are characterized in ReEDS by the following:

- Capital cost ($/MW)
- Fixed and variable operating costs ($/MWh)
- Fuel costs ($/MMBtu)
- Heat rate (MMBtu/MWh)
- Construction period (years)
- Equipment lifetime (years)
- Financing costs (such as nominal interest rate, loan period, debt fraction, debt-service-coverage ratio)
- Tax credits (investment or production)

[251] North American Electric Reliability Corporation, October 2010. "2010 Long-Term Reliability Assessment." http://www.nerc.com/files/2010%20LTRA.pdf. Accessed November 2, 2011.

- Minimum turndown ratio (%)
- Quick-start capability and cost (%, $/MW)
- Spinning reserve capability
- Planned and unplanned outage rates (%).

Renewable and storage technologies are governed by similar parameters—accounting for fundamental differences. For instance, heat rate is replaced with round-trip efficiency in pure storage technologies, and the dispatchability parameters—such as fuel cost, heat rate, turndown ratio, and operating reserve capability—are not used for non-dispatchable wind and solar technologies. These variable generation technologies are further characterized by changes in generation levels over the course of a year.

The model includes consideration of distinguishing characteristics of each conventional generating technology. There are several types of coal-fired power plants within ReEDS, including pulverized coal with and without sulfur dioxide scrubbers, advanced pulverized coal, integrated gasification combined cycle, biomass co-firing, and integrated gasification combined cycle with CCS options. Coal-plant generation is discouraged from daily cycling via a cost penalty, which represents a combination of additional fuel burned, heat rate drop-off, and mechanical wear-and-tear. Natural gas plants represented in ReEDS include simple-cycle combustion turbines, combined-cycle plants, and combined-cycle with CCS plants. Combined-cycle natural gas plants can provide some spinning reserve and quick-start capability, and simple-cycle gas plants can be used cheaply and easily for quick-start power. Nuclear power is represented as one technology in ReEDS and is considered to be baseload.

Retirement of conventional generation and hydropower can be modeled through exogenous specification of planned retirements or based on usage characteristics of the plants. All retiring non-hydro renewable plants are assumed to be refurbished or replaced immediately because the site is already developed and has transmission access and other infrastructure.

ReEDS tracks emissions of carbon and sulfur dioxide from both generators and storage technologies. Caps can be imposed at the national level for these emissions, and constraints can also be applied to impose caps at state or regional levels. There is another option of applying a carbon tax instead of a cap; the tax level and ramp-in pattern can be defined exogenously. In addition, ReEDS can impose clean energy or renewable energy standards at the regional or national level.

Annual electric loads and fuel price supply curves are exogenously specified to define the system boundaries for each period of the optimization. To allow for the evaluation of scenarios that might depart significantly from the Reference scenario, price elasticity of demand is integrated into the model: the exogenously defined demand projection can be adjusted up or down based on a comparison of an estimated business-as-usual electricity price path and a calculation of electricity price within the model for each of the twenty 2-year periods. For coal and natural gas

pricing, supply curves based on the Annual Energy Outlook[252] have been developed and used in ReEDS.

Natural Gas Supply Curve Background and Development

The EIA's Annual Energy Outlook 2011 has two specific scenarios that attempt to model the effects of high or low abundance of natural gas supply: High-EUR and Low-EUR. The High-EUR scenario increases the total unproved technically recoverable shale gas resource from 827 Tcf in the Mid-EUR baseline scenario to 1,230 Tcf. In addition, the ultimate recovery per shale gas well is 50% higher than in the baseline scenario. Low-EUR reduces recoverable shale gas resource to 423 Tcf and 50% lower ultimate recovery per shale gas well than in the Mid-EUR baseline scenario.

Deriving the coefficients for this study relied on assuming a linear regression model and employing an ordinary least-squares method. Linear regression is a statistical technique that examines the relationship between one dependent variable (Y) and multiple explanatory variables, or regressors (X), taking the linear form:

$$Y_i = \beta_0 + \beta_1 * X_1 + \beta_2 * X_2 + \cdots \beta_n * X_n + \varepsilon_i$$

The estimated coefficients represent the marginal impact of a 1-unit change in each independent variable $\mathbf{X_i}$ on Y. Linear regression is often used for prediction or forecasting.[253]

In this case, because the objective was to develop a model to closely model the relationship between natural gas in the electric sector and consumption in the electric sector in different scenarios, the electric-sector price was modeled based on the following predictors: electric-sector consumption, economy-wide consumption, year (2012–2035), and the natural gas scenario case.[254] Each electric-sector price for each of the Annual Energy Outlook scenarios from 2012–2035 was treated as an independent observation used to estimate coefficients in the following model:

$$\begin{aligned} &Electric\ Sector\ Price_i \\ &\quad = \beta_0 + \beta_1 * Electric\ Sector\ Consumption_i + \beta_2 \\ &\quad * Economy - wide\ Consumption_i \\ &\quad + \sum_{j=1}^{12} \beta_j * Year + \sum_{k=1}^{4} \beta_k * Natural\ Gas\ Scenario + \quad \varepsilon_i \end{aligned}$$

Observations that occurred in High-EUR and Low-EUR were coded accordingly, creating two additional intercept shifter "dummy" variables. The year, rather than coded as continuous, was coded as a dummy variable to capture non-linear variation from year to year. To account for the

[252] Annual Energy Outlook 2011. DOE/EIA-0383. Washington, DC: U.S. Energy Information Administration.
[253] Damodar, Gujarati. Basic Econometrics (5th edition). McGraw Hill, 2007.
[254] Data for 2008–2011 as well as outlier scenarios (polmax0314a, polmaxlco20321a, polmaxlp0316a, lgbama050218a, lgbama200218a, aeo2010r1118a, oghtec110209a, ogltec110209a, hilng110209a, lolng110209a) were removed when running the model.

predictor influence of economy-wide consumption, the average value for the year and the scenario for each data point were multiplied by β_2 (the derived electric-sector consumption coefficient). As a result, the intercept varied by year and by scenario, while the slope remained the same across year and scenario. The intercept and shifter for the years 2036–2050 was held constant with model results in 2035.

The following tables summarize the assumptions used in ReEDS for: technology costs and performance (Table 48), wind performance (Table 49), CSP performance (Table 50), and utility-scale PV performance (Table 51).

Table 48. Technology Cost ($2010) and Performance Assumptions Used in ReEDS

	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (MMBtu/MWh)
Coal Integrated Gasification Combined-Cycle CCS				
2010	4,075	7	32	9.0
2020	4,075	7	32	9.0
2030	4,075	7	32	7.9
2040	4,075	7	32	7.9
2050	4,075	7	32	7.9
CSP				
2010	7,179 (8,217)[a]	NA	50 (80)	NA
2020	6,639 (4,077)	NA	50 (66)	NA
2030	5,398 (2,983)	NA	50 (51)	NA
2040	4,778 (2,983)	NA	50 (47)	NA
2050	4,778 (2,983)	NA	50 (45)	NA
Combined-Cycle Plants				
2010	1,250	4	6	7.5
2020	1,250	4	6	6.7
2030	1,250	4	6	6.7
2040	1,250	4	6	6.7
2050	1,250	4	6	6.7
Combined-Cycle Plants CCS				
2010	3,348	10	19	10.0
2020	3,267	10	19	10.0
2030	3,267	10	19	10.0
2040	3,267	10	19	10.0
2050	3,267	10	19	10.0
Simple-Cycle Combustion Turbines				
2010	661	30	5	12.5
2020	661	30	5	10.3
2030	661	30	5	10.3
2040	661	30	5	10.3
2050	661	30	5	10.3

		Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (MMBtu/MWh)
New Coal					
	2010	2,937	4	23	10.4
	2020	2,937	4	23	9.4
	2030	2,937	4	23	9.0
	2040	2,937	4	23	9.0
	2050	2,937	4	23	9.0
Nuclear					
	2010	6,199 (3,100)	NA	129	9.7
	2020	6,199 (3,100)	NA	129	9.7
	2030	6,199 (3,100)	NA	129	9.7
	2040	6,199 (3,100)	NA	129	9.7
	2050	6,199 (3,100)	NA	129	9.7
Utility-Scale PV					
	2010	4,067 (4,067)	NA	51 (21)	NA
	2020	2,560 (2,013)	NA	46 (20)	NA
	2030	2,351 (1,912)	NA	42 (15)	NA
	2040	2,191 (1,797)	NA	38 (13)	NA
	2050	2,058 (1,720)	NA	33 (9)	NA
Wind Offshore					
	2010	3,702 (3,702)	0 (23)	101 (16)	NA
	2020	3,355 (3,284)	0 (17)	101 (16)	NA
	2030	3,042 (2,912)	0 (14)	101 (16)	NA
	2040	3,042 (2,744)	0 (12)	101 (16)	NA
	2050	3,042 (2,744)	0 (12)	101 (16)	NA
Wind Onshore					
	2010	2,012 (2,012)	0 (8)	60 (12)	NA
	2020	2,012 (1,964)	0 (5)	60 (12)	NA
	2030	2,012 (1,865)	0 (5)	60 (12)	NA
	2040	2,012 (1,805)	0 (5)	60 (12)	NA
	2050	2,012 (1,805)	0 (5)	60 (12)	NA

[a] Advanced RE Scenario assumptions displayed in parentheses

Table 49. Wind Performance Assumptions

	Wind Power Class	On-Shore Wind	Off-Shore Wind
2010			
	Class 3	0.32 (0.35)[a]	0.36 (0.37)
	Class 4	0.36 (0.39)	0.39 (0.41)
	Class 5	0.42 (0.43)	0.45 (0.44)
	Class 6	0.44 (0.46)	0.48 (0.48)
	Class 7	0.46 (0.50)	0.50 (0.52)

	Wind Power Class	On-Shore Wind	Off-Shore Wind
2020			
	Class 3	0.33 (0.38)	0.37 (0.39)
	Class 4	0.37 (0.42)	0.39 (0.44)
	Class 5	0.42 (0.45)	0.45 (0.47)
	Class 6	0.44 (0.48)	0.48 (0.51)
	Class 7	0.46 (0.52)	0.50 (0.55)
2030			
	Class 3	0.35 (0.38)	0.38 (0.40)
	Class 4	0.38 (0.43)	0.40 (0.45)
	Class 5	0.43 (0.46)	0.45 (0.48)
	Class 6	0.45 (0.49)	0.48 (0.51)
	Class 7	0.46 (0.53)	0.50 (0.55)
2040			
	Class 3	0.35 (0.38)	0.38 (0.40)
	Class 4	0.38 (0.43)	0.40 (0.45)
	Class 5	0.43 (0.46)	0.45 (0.48)
	Class 6	0.45 (0.49)	0.48 (0.51)
	Class 7	0.46 (0.53)	0.50 (0.55)
2050			
	Class 3	0.35 (0.38)	0.38 (0.40)
	Class 4	0.38 (0.43)	0.40 (0.45)
	Class 5	0.43 (0.46)	0.45 (0.48)
	Class 6	0.45 (0.49)	0.48 (0.51)
	Class 7	0.46 (0.53)	0.50 (0.55)

[a] Advanced RE Scenario assumptions displayed in parentheses

Table 50. CSP Performance Assumptions

	Wind Power Class	Capacity Factor
2010		
	Class 1	0.28 (0.28)[a]
	Class 2	0.37 (0.37)
	Class 3	0.42 (0.42)
	Class 4	0.44 (0.44)
	Class 5	0.46 (0.46)
2020		
	Class 1	0.28 (0.37)
	Class 2	0.37 (0.47)
	Class 3	0.42 (0.52)
	Class 4	0.44 (0.54)
	Class 5	0.46 (0.56)
2030		
	Class 1	0.37 (0.37)

Wind Power Class	Capacity Factor
Class 2	0.47 (0.47)
Class 3	0.52 (0.52)
Class 4	0.54 (0.54)
Class 5	0.56 (0.56)
2040	
Class 1	0.37 (0.37)
Class 2	0.47 (0.47)
Class 3	0.52 (0.52)
Class 4	0.54 (0.54)
Class 5	0.56 (0.56)
2050	
Class 1	0.37 (0.37)
Class 2	0.47 (0.47)
Class 3	0.52 (0.52)
Class 4	0.54 (0.54)
Class 5	0.56 (0.56)

[a] Advanced RE Scenario assumptions displayed in parentheses

Table 51. Utility-Scale PV Performance Assumptions

Year	Capacity Factor
2010	0.16–0.27
2020	0.16–0.27
2030	0.16–0.27
2040	0.16–0.27
2050	0.16–0.27

Treating Plant Retirement in ReEDS[255]

Assumptions about the retirement of conventional-generating units can have considerable cost implications. Considerations that go into the decision-making process on whether or not an individual plant should be retired involve a number of factors—specifically, the economics of plant operations and maintenance. Projecting these economic considerations into the future given the uncertainties involved is beyond the scope of ReEDS. Instead, ReEDS uses the following three retirement options that are not strictly economic:

- *Scheduled lifetimes for existing coal, gas, and oil.* These retirements are based on lifetime estimate data for power plants from Ventyx (2010). Near-term retirements are based on the officially reported retirement date as reported by EIA 860, EIA 411, or Ventyx unit research (Ventyx 2010). If there is no officially reported retirement date, a lifetime-based

[255] This section was taken from existing documentation of the ReEDS model.
Short, W. et al. (2011). "Regional Energy Deployment System (ReEDS)," NREL Technical report NREL/TP-6A20-46534, August 2011. http://www.nrel.gov/analysis/reeds/.

retirement is estimated based on the unit's commercial online date and the following lifetimes:

  - Coal units (< 100 MW) = 65 years
  - Coal units (> 100 MW) = 75 years
  - Natural gas combined-cycle unit = 55 years
  - Oil-gas-steam unit = 55 years

- *Usage-based retirements of coal.* In addition to scheduled retirements, coal technologies, including co-fired coal with biomass, can retire based on proxies for economic considerations. Any capacity that remains unused for energy generation or operating reserves for 4 consecutive years is assumed to retire. Coal capacity is also retired by requiring a minimum annual capacity factor; after every 2-year investment period, if a coal unit has a capacity factor of less than this minimum capacity factor during the 2-year period, an amount of coal capacity is retired such that the capacity factor increases to this minimum threshold (10% in 2030, 20% in 2040, and 30% in 2050). Coal plants are not retired under this algorithm until after 2020.
- *Scheduled nuclear license-based retirements.* Nuclear power plants are retired based on the age of the plant. Under default assumptions, older nuclear plants that are on line before 1980 are assumed to retire after 60 years (one re-licensing renewal), whereas newer plants (on line during or after 1980) are assumed to retire after 80 years (two relicensing renewals). Other options can be implemented, such as assuming 60- or 80-year lifetimes for all nuclear plants.

Glossary

annulus	The space between two concentric lengths of pipe or between pipe and the hole in which it is located.
associated gas	Natural gas that occurs with crude oil reservoirs, either as free gas or dissolved in solution. It is usually produced with crude oil.
basin	A petroleum geology term that refers to a dip in the Earth's crust usually filled or being filled with sediment. Basins are usually relatively large areas where oil and gas can be found.
billion cubic feet (bcf)	Unit used to measure large quantities of gas, approximately equal to 1 trillion British thermal units.
billion cubic feet per day (bcf/d)	Unit used to measure the daily volume of gas produced, stored, transported, or consumed.
bradenhead	A device that is used during inner-string grouting or pressure grouting operations. The bradenhead is situated at the top of the well casing, where it allows a drill pipe to be extended into the well while the well head is sealed and the annulus between the well casing and drill pipe is pressurized. Also termed casing head, cement head, or largen head.
British thermal unit (Btu)	An energy unit equivalent to the amount of energy needed to raise the temperature of 1 pound of water 1°F from 58.5°F to 59.5°F under standard pressure of 30 inches of mercury. Commonly used for measuring gas and other energy sales quantities.
burner tip	The point of end-use consumption of a particular fuel.
cement bond log	A representation of the integrity of the cement job, especially whether the cement is adhering solidly to the outside of the casing. The log is typically obtained from one of a variety of sonic-type tools.
coal-bed methane (CBM)	Natural gas, primarily methane, generated during coal formation and recovered by pumping water from coal seams, allowing gas to escape through shallow wells. It is generally referred to as one type of unconventional gas.
closed-loop drilling	Drilling and fracturing operation that contains all fluids in tanks and other closed-to-the-atmosphere equipment. Closed-loop drilling does not use open pits and therefore can reduce the risks of leaks and spills.
Combined-cycle	An electric generating technology in which conventional gas combustion turbines are combined with heat-recovery, steam-powered generation units, increasing the overall efficiency of the generating facility. Electricity is produced from both the feed gas, as well as from otherwise lost waste heat exiting gas turbines. In a conventional steam power generating facility, electricity is generated only from the feed gas.
completion	Preparing a newly drilled well for production; usually involves setting casing (pipe that lines the interior of a well to prevent caving and protect against ground-water contamination) and perforating the casing to establish communication with the producing formation.
compressed natural gas	Highly compressed natural gas stored and transported in high-pressure containers, typically greater than 3,000 pounds per square inch (200 bar); commonly used for transport fuel.
condensates	Light hydrocarbon compounds that condense into liquid at surface temperatures and pressures. They are generally produced with natural gas.
cubic feet (cf)	Common unit of measurement of gas volume equivalent to the amount of gas required to fill a volume of 1 cubic foot under given temperature and pressure conditions.

deep-well injection	Technique for disposal of frac flowback or produced water in deep formations isolated from producing zones and fresh-water aquifers.
dry gas	Natural gas, mainly methane, that remains after liquid hydrocarbon components have been removed, making it suitable for pipeline shipping, liquefied natural gas processing, or industrial usage.
ethane (C_2H_6)	A normally gaseous natural gas liquid hydrocarbon extracted from natural gas or refinery gas streams.
flaring	The process of disposing uncommercial or otherwise unwanted gas by burning. Operators often flare associated gas in regions with limited gas markets.
formation	Refers to either a certain layer of the Earth's crust, or a certain area of a layer; often refers to the area of rock where a petroleum or natural gas reservoir is located.
fracturing (or fracking)	See hydraulic fracturing.
frac flowback	Fluids that are returned to the surface immediately following hydraulic fracturing that include mostly the injected water, sand, and chemicals used for the fracturing.
geographic information system (GIS)	Integrated hardware, software, and data used for capturing, managing, analyzing, and displaying all forms of geographically referenced information.
gas-to-liquids process	A process that converts natural gas into synthetic liquid petroleum products, such as diesel fuel and blending feedstock.
glycol dehydrators	Facilities in which a glycol-based process removes water from produced natural gas, often in the field and before processing. The removal of water is needed to prevent corrosion and water freezing in pipelines.
green completion	Using technology to recover gas that may otherwise be vented or flared during the completion phase of a natural gas well. Also known as reduced emission completions.
harmonization	A meta-analytical procedure for adjusting published estimates from life cycle assessment to develop a set of directly comparable estimates. Harmonization clarifies a body of published estimates in ways useful to decision-making and future analyses. See nrel.gov/harmonization for further description and resources.
hydraulic fracturing (or hydrofracking)	The process of creating fractures in non-porous rock using specially formulated, water-based solutions forced into wells at extremely high pressure; the cracks in the rock allow for the release and collection of the natural gas. Fracking can be done in vertical or horizontal wells.
induced seismicity	Seismic activity (e.g., earthquakes) that is caused by injection of fluids into deep formations in proximity to natural faults.
life cycle assessment (LCA)	A technique to assess environmental impacts associated with all stages of a product's life from "cradle to grave" (i.e., from raw material extraction through materials processing, manufacture, distribution, use, repair and maintenance, and disposal or decommissioning). LCAs can be applied to water, energy, greenhouse gas emissions, or other metrics of interest.
liquefied natural gas (LNG)	Natural gas, mainly methane, that has been cooled to very low temperature (-259°F) so that it will condense into a transportable colorless and odorless liquid.
methane (CH_4)	The lightest and most abundant of the hydrocarbon gases, it is the principal component of natural gas and LNG.
natural gas	Naturally occurring mixture of hydrocarbon gases from underground sources composed mainly of methane (more than 85% in some cases), ethane, propane, butane, pentane, and impurities including carbon dioxide, helium, nitrogen, and hydrogen sulfide.

natural gas liquids	Natural gas components—including ethane, propane, butane, pentane, and condensates—that are liquid at surface conditions. It does not include methane, which remains in gaseous phase at surface conditions.
New York Mercantile Exchange	The first U.S. exchange to trade natural gas futures contracts; the New York Mercantile Exchange has contracts with major delivery points.
play (shale play, shale gas play)	A geographic area that has been targeted for exploration due to favorable geoseismic survey results, well logs, or production results from a new well in the area. An area comes into play when it is generally recognized that there is an economic quantity of oil or gas to be found.
primacy (primary enforcement responsibility)	The authority to implement the Underground Injection Control Program. To receive primacy, a state, territory, or tribe must demonstrate to EPA that its Underground Injection Control Program is at least as stringent as the federal standards; the state, territory, or tribal Underground Injection Control requirements may be more stringent than the federal requirements. EPA may grant primacy for all or part of the Underground Injection Control Program (e.g., for certain classes of injection wells).
produced water	Water that is extracted with the oil and gas from the producing formation. Produced water is usually highly saline and not usable without treatment.
quad	A unit of energy equal to 10^{15} Btu, roughly equal to 1 Tcf.
reserves	Volumes of hydrocarbons that have a chance of being economically and technically producible.
reservoir	A subsurface rock or formation having sufficient porosity and permeability to store and transmit fluids such as gas, oil, and water. Reservoirs are typically composed of sedimentary rocks with an overlying or adjoining impermeable seal or cap rock.
shale gas	Shale gas is defined as a natural gas produced from shale rock. Shale has low matrix permeability; therefore, gas production in commercial quantities requires fracturing or other stimulation to improve permeability.
social license to operate	A project that has the ongoing approval within the local community and other stakeholders, ongoing approval or broad social acceptance, and, most frequently, as ongoing acceptance.
trillion cubic feet (Tcf)	Unit used to measure large quantities of gas, typically reserve sizes. Approximately equal to 1 quad of energy.
unconventional gas	Unconventional gas refers to gas produced from coal seams (coal-bed methane), shale rocks (shale gas), and rocks with low permeability (tight gas). Once gas is produced from these reservoirs, it has the same properties of gas produced from conventional (i.e., sedimentary reservoirs with high porosity and permeability) sources. Unconventional gas may have high levels of natural gas liquids (an exception is coal-seam gas, which tends to be very dry with high proportion of methane versus natural gas liquids) and may have low or high levels of carbon dioxide and high and low levels of sulfur (sour or sweet). Because unconventional reservoirs have low permeability, artificial methods to increase gas flows, such as mechanical or chemical fracking, is often required before the wells are able to produce commercial quantities of gas.

Underground Injection Control Program	The program that EPA, or an approved state, is authorized to implement under the Safe Drinking Water Act that is responsible for regulating the underground injection of fluids. This includes setting the minimum federal requirements for construction, operation, permitting, and closure of underground injection wells. There are six categories of wells regulated under the Underground Injection Control ranging from Class I to Class VI. Class I wells are the most technologically sophisticated and are used to inject wastes into deep, isolated rock formations below the lowermost underground source of drinking water. Class I wells may inject hazardous waste, non-hazardous industrial waste, or municipal wastewater. Class II wells are typically used by the oil and gas industry to inject brines and other fluids associated with oil and gas production, or storage of hydrocarbons.
volatile organic compound (VOC)	Gases and vapors, such as benzene, released by petroleum refineries, natural gas drilling, petrochemical plants, plastics manufacturing, and the distribution and use of gasoline. VOCs include carcinogens and chemicals that react with sunlight and nitrogen oxides to form ground-level ozone, a component of smog.
water recycling	Collection of frac flowback or produced water and treating the fluid for beneficial use that include hydraulic fracturing, agriculture, or release to streams.
well completion	Well completion incorporates the steps taken to transform a drilled well into a producing one. These steps usually include casing, cementing, perforating, gravel packing, and installing a production tree.
well head	The assembly of fittings and valve equipment used for producing a well and maintaining surface control of a well.
wet gas	Natural gas with significant natural gas liquid components. Also sometimes called rich gas.
workover	Work performed in a well after its completion in an effort to secure production where there has been none, restore production that has ceased, or increase production. Workovers for unconventional wells involve re-fracturing (re-stimulation).

References

Introduction

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Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation

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The U.S. Department of Energy (DOE) estimates that in the coming decades the United States' natural gas (NG) demand for electricity generation will increase. Estimates also suggest that NG supply will increasingly come from imported liquefied natural gas (LNG). Additional supplies of NG could come domestically from the production of synthetic natural gas (SNG) via coal gasification−methanation. The objective of this study is to compare greenhouse gas (GHG), SO_x, and NO_x life-cycle emissions of electricity generated with NG/LNG/SNG and coal. This life-cycle comparison of air emissions from different fuels can help us better understand the advantages and disadvantages of using coal versus globally sourced NG for electricity generation. Our estimates suggest that with the current fleet of power plants, a mix of domestic NG, LNG, and SNG would have lower GHG emissions than coal. If advanced technologies with carbon capture and sequestration (CCS) are used, however, coal and a mix of domestic NG, LNG, and SNG would have very similar life-cycle GHG emissions. For SO_x and NO_x we find there are significant emissions in the upstream stages of the NG/LNG life-cycles, which contribute to a larger range in SO_x and NO_x emissions for NG/LNG than for coal and SNG.

1. Introduction

Natural gas currently provides 24% of the energy used by United States homes (*1*). It is an important feedstock for the chemical and fertilizer industry. Low wellhead gas prices (less than $3/thousand cubic feet (Mcf) (*2*)) spurred a surge in construction of natural-gas-fired power plants: between 1992 and 2003, while coal-fired capacity increased only from 309 to 313 GW, natural-gas-fired capacity more than tripled, from 60 to 208 GW (*3*). Adding to this was the Energy Information Agency's (EIA) prediction of continued low natural gas prices (around $4/Mcf) through 2020 (*4*), lower capital costs, shorter construction times, and generally lower air emissions for natural-gas-fired plants that allowed power generators to meet the clean air standards (*5*). However, instead of remaining near projected levels, the average wellhead price of natural gas peaked at $11/Mcf in October 2005 (*6*). This price increase made natural gas uneconomical as a feedstock, so most natural-gas-fired plants are operating below capacity (*7*). Despite these trends, natural gas consumption is expected to increase by 20% of 2003 levels by 2030. Demand from electricity generators is projected to grow the fastest. At the same time, natural gas production in the United States and pipeline imports from Canada and Mexico are expected to remain fairly constant (*8*). The gap between North American supply and U.S. demand can only be met with alternative sources of natural gas, such as imported liquefied natural gas (LNG) or synthetic natural gas (SNG) produced from coal. Current projections by EIA estimate that LNG imports will increase to 16% of the total U.S. natural gas supply by 2030 (*8*). Alternatively, Rosenberg et al. call for congress to promote gasification technologies that use coal to produce SNG. This National Gasification Strategy calls for the United States to produce 1.5 trillion cubic feet (tcf) of synthetic natural gas per year within the next 10 years (*7*), equivalent to 5% of expected 2030 demand.

The natural gas system is one of the largest sources of greenhouse gas emissions in the United States, generating around 132 million tons of CO_2 equivalents annually (*1*). Significant emissions of criteria air pollutants also come from upstream combustion life-cycle stages of the gas. Emissions from the emerging LNG life-cycle stages or from the production of SNG have not been studied in detail. If larger percentages of the U.S. supply of natural gas will come from these alternative sources, then LNG or SNG supply chain emissions become an important part of understanding overall natural gas life-cycle emissions. Also, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate. The objective of this study is to perform a life-cycle analysis (*9*, *10*) of natural gas, LNG, and SNG. Direct air emissions from the processes during the life-cycle will be considered, as well as air emissions from the combustion of fuels and electricity used to run the process. A comparison with coal life-cycle air emissions will be presented, in order to have a better understanding of the advantages and disadvantages of using coal versus natural gas for electricity generation.

2. Fuel Life-Cycles

The natural gas life-cycle starts with the production of natural gas and ends at the combustion plant. Natural gas is extracted from wells and sent to processing plants where water, carbon dioxide, sulfur, and other hydrocarbons are removed. The produced natural gas then enters the transmission system. The U.S. transmission system also includes some storage of natural gas in underground facilities such as reconditioned depleted gas reservoirs, aquifers, or salt caverns to meet seasonal and/or sudden short-term demand. From the transmission and storage system, some natural gas goes directly to large-scale consumers, like electric power generators, which is modeled here. The rest goes into local distribution systems that deliver it to residential and commercial consumers via low-pressure, small-diameter pipelines.

The use of liquefied natural gas (LNG) adds three additional life-cycle stages to the natural gas life-cycle described above. Natural gas is produced and processed to remove contaminants and transported by pipeline relatively short distances to be liquefied. In the liquefaction process, natural gas is cooled and pressurized (*11*). Liquefaction plants are generally located in coastal areas of LNG exporting countries and dedicated LNG ocean tankers transport LNG

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to the United States. Upon arriving, the LNG tankers offload their cargo and the LNG is regasified. At this point the regasified LNG enters the U.S. natural gas transmission system.

The coal life-cycle is conceptually simpler than the natural gas life-cycle, consisting of three major steps: coal mining and processing, transportation, and use/combustion.

U.S. coal is produced from surface mines (67%), or underground mines (33%) (*1*). Mined coal is processed to remove impurities. Coal is then transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (*12*). More than 90% of the coal used in the United States is used by the electric power sector, which is modeled here (*8*).

The life-cycle of SNG is a combination of some stages from the coal life-cycle and some stages of the natural gas life-cycle. Coal is mined, processed, and transported, as in the coal life-cycle, to the SNG production plant. At this plant, syngas, a mixture of carbon monoxide (CO) and hydrogen (H_2), is produced by gasification and converted, via methanation, to methane and water. The SNG is then sent to the natural gas transmission system, described above, and on to the electric power generator.

3. Methods for Calculating Life-Cycle Air Emissions

In our study we investigate the life-cycle air emissions from coal, natural gas, LNG, and SNG use. All fossil fuel options are used to produce electricity and combustion emissions are included as a component of the each life-cycle. For GHG, the emissions factors at power plants used are 120 lb CO_2 equiv/MMBtu of natural gas and 205 lb CO_2 equiv/MMBtu of coal. The SO_x and NO_x emissions at power plants are presented in the results section and in the Supporting Information

3.1. Life-Cycle Air Emissions from Natural Gas produced in North America. In 2003, the total consumption of natural gas in the United States was over 27 trillion cubic feet (tcf). Of this, 26.5 tcf were produced in North America (U.S., Canada, and Mexico) (*13*). According to the Environmental Protection Agency (EPA), 1.07% of the natural gas produced is lost in its production, processing, transmission, and storage (*14*). Total methane emissions were calculated using the percentage of natural gas lost. It was also assumed that natural gas has an average heat content of 1030 Btu/ft^3 (*13*), and that 96% of the natural gas lost is methane, which has a density of 0.0424 lb/ ft^3 (*14*).

In 1993 the U.S. EPA established the Natural Gas STAR program to reduce methane emissions from the natural gas industry. Data from this program for the reductions in methane lost in the natural gas system, as described in the Supporting Information, were combined with the data described above to develop a range of methane emissions factors for the North American natural gas life-cycle stages.

Carbon dioxide emissions are produced from the combustion of natural gas used during various life-cycle stages and from the production of electricity consumed during transport. EIA provides annual estimates of the amount of natural gas used for the production, processing, and transport of natural gas. In 2003, approximately 1900 billion cubic feet of natural gas were consumed during these stages of the natural gas life-cycle (*13*). Total carbon dioxide emissions were calculated using a carbon content in natural gas of 31.90 lb C/MMBtu and an oxidation fraction of 0.995 (*1*). According to the Transportation Energy Data Book, 3 billion kWh were used for natural gas pipeline transport in 2003 (*15*). The average GHG emission factor from the generation of this electricity is 1400 lb CO_2 equiv/MWh (*16*). These CO_2 emissions were added to methane emissions to obtain the upstream combustion GHG emission factors for North American natural gas.

SO_x and NO_x emissions from the natural gas upstream stages of the life-cycle come from the combustion of the fuels used to produce the energy that runs the system, as given in the Supporting Information. Total emissions from flared gas were calculated using the AP 42 Emission Factors for natural gas boilers (*17*). A range of emissions from the combustion of the natural gas used during the upstream stages of the life-cycle was developed using the AP 42 Emissions Factors for reciprocating engines and for natural gas turbines (*17*). Emissions from generating the electricity used during natural gas pipeline operations were estimated using the most current average emission factors given by EGRID: 6.04 lb SO_2/MWh and 2.96 lb NO_x/MWh (*16*). Note that EGRID reports emissions of SO_2 only. Other references used in this paper report total SO_x emission. For this paper, sulfur emission will be reported in terms of SO_x emissions.

In addition to emissions from the energy used during the life-cycle of natural gas, SO_x emissions are produced in the processing stage of the life-cycle, when hydrogen sulfide (H_2S) is removed from the sour natural gas to meet pipeline requirements. A range of SO_x emissions from this processing of natural gas was developed using the AP 42 emissions factors for natural gas processing and for sulfur recovery (*17*). To use the AP 42 emission factors for sulfur recovery, we found that in 2003 1945 thousand tons of sulfur were recovered from 14.7 trillion cubic feet of natural gas resulting in a calculated average natural gas H_2S mole percentage of 0.0226. This was then used with the AP 42 emission factors for natural gas processing.

3.2. Air Emissions from the LNG Life-Cycle. In 2003, 500 billion cubic feet of natural gas were imported in the form of LNG (*13*). In 2003, 75% of the LNG imported to the United States came from Trinidad and Tobago, but this percentage is expected to decrease as more imports come from Russia, the Middle East, and Southeast Asia (*13*). According to EIA, the LNG tanker world fleet capacity should have reached 890 million cubic feet of liquid (equivalent to 527 billion cubic feet of natural gas) by the end of 2006 (*18*). There are currently 5 LNG terminals in operation in the United States, with a combined base load capacity of 5.3 billion cubic feet per day (about 2 trillion cubic feet per year). In addition to these terminals, there are 45 proposed facilities in North America, 18 of which have already been approved by the Federal Energy Regulatory Commission (FERC) (*19*).

Due to unavailability of data for emissions from natural gas production in other countries, it is assumed that natural gas imported to the United States in the form of LNG produces the same emissions from the production and processing life-cycle stages as North American natural gas. Those stages are incorporated for LNG. Most of the natural gas converted to LNG is produced from modern fields developed and operated by multinational oil and gas companies, so they are assumed to be operated in a similar way to those in the United States.

It is expected that transportation of natural gas from the production field to the liquefaction plant would have emissions similar to those of pipeline transport of domestic natural gas. But the emission factor for the U.S. system (which is included in the LNG life-cycle) is based on total pipeline distances of over 200 000 miles (*20*). Because LNG facilities are closely paired with gas fields, it is expected that the average distance from production field to a LNG facility would be much smaller than 200 000 miles. Also, because there were no reliable data for the myriad of fields and facilities and suspected impact on the overall life cycle would be minimal, this transport from the fields to the liquefaction terminals was ignored. This would slightly underestimate the emissions from the LNG life cycle.

Additional emission factors were developed for the liquefaction, transport, and regasification life-cycle stages of LNG. Tamura et al. have reported emission factors for the

liquefaction stage in the range of 11−31 lb CO_2 equiv/MMBtu (*21*). The sources of these emissions are outlined in the Supporting Information.

LNG is shipped to the United States via LNG tankers. LNG tankers are the last ship type to use steam turbine technology in their engines. This technology allows for easy use of boil-off gas (BOG) in a gas boiler. Boil-off rates in LNG tankers range between 0.15% and 0.25% per day when loaded (*22*, *23*). When there is not enough BOG available, a fuel oil boiler is used to produce the steam. In addition to this benefit, steam turbines require less maintenance than diesel engines, which is beneficial to these tankers that have to be readily available to leave a terminal in case of emergency (*22*).

Most LNG tankers currently in operation have a capacity to carry between 4.2 and 5.3 million cubic feet of LNG (2.6 and 3.2 billion cubic feet of gas). There are smaller tankers available, but they are not widely used for transoceanic transport. There is also discussion about building larger tankers (8.8 million cubic feet), however none of the current U.S. terminals can handle tankers of this size (*18*).

The rated power of the LNG tankers ranges between 20 and 30 MW, and they operate under this capacity around 75% of the time during a trip (*24*, *25*). The energy required to power this engine is 11.6 MMBtu/MWh (*26*). As previously mentioned, some of this energy is provided by BOG and the rest is provided by fuel oil. A loaded tanker with a rated power of 20 MW, and 0.12% daily boil-off rate would consume 3.88 million cubic feet of gas per day and 4.4 tons of fuel oil per day. The same tanker would consume 115 tons of fuel oil per day on they way back to the exporting country operating under ballast conditions. A loaded tanker with a rated power of 30 MW, and a 0.25% daily boil-off rate would get all its energy from the BOG, with some excess gas being combusted to reduce risks of explosion (*22*). Under ballast conditions, the same tanker would consume 172 tons of fuel oil per day.

For LNG imported in 2003 the average travel distance to the Everett, MA LNG terminal was 2700 nautical miles (*13*, *27*). In the future LNG could travel as far as far as 11 700 nautical miles (the distance between Australia and the Lake Charles, LA LNG terminal (*27*)). This range of distances is representative of distances from LNG countries to U.S. terminals that could be located on either the East or West coasts. To estimate the number of days LNG would travel (at a tanker speed of 20 knots (*22*)), these distances were used. This trip length can then be multiplied by the fuel consumption of the tanker to estimate total trip fuel consumption and emissions, and these can then be divided by the average tanker capacity to obtain a range of emission factors for LNG tanker transport between 2 and 17 lb CO_2 equiv/MMBtu.

Regasification emissions were reported by Tamura et al. to be 0.85 lb CO_2 equiv/MMBtu (*21*). Ruether et al. report an emission factor of 3.75 lb of CO_2 equiv/MMBtu for this stage of the LNG life-cycle by assuming that 3% of the gas is used to run the regasification equipment (*28*). The emission reported by Tamura et al. differs because they assumed only 0.15% of the gas is used to run the regasification terminal, while electricity, which may be generated with cleaner energy sources, provides the additional energy requirements. These values were used as lower and upper bounds of the range of emissions from regasification of LNG.

As done for the carbon emissions, natural gas produced in other countries and imported to the United States in the form of LNG is assumed to have the same SO_x and NO_x emissions in the production, processing, and transmission stages of the life-cycle as for natural gas produced in North America. Emission ranges for the liquefaction and regasification of natural gas were calculated using the AP 42 emission factors for reciprocating engines and natural gas turbines (*17*). It is assumed that 8.8% of natural gas is used in the liquefaction plant (*21*) and 3% is used in the regasification plants (*28*). Emissions of SO_x, and NO_x from transporting the LNG via tanker were calculated using the AP 42 emission factor for natural gas boilers and diesel boilers, as well as the tanker fuel consumption previously described.

3.3. Air Emissions from the Coal Life-Cycle. Greenhouse gas emissions from the mining life-cycle stage were developed from methane releases and from combustion of fuels used at the mines. EPA estimates that methane emissions from coal mines in 1997 were 75 million tons of CO_2 equivalents, of which 63 million tons came from underground mines and 12 million tons came from surface mines (*1*). CO_2 is also emitted from mines through the combustion of the fuels that provide the energy for operation. The U.S. Census Bureau provides fuel consumption data for mines in 1997 (*29*). These data are available in the Supporting Information. Fuel consumption data were converted to GHG emissions using the carbon content and heat content of each fuel and an oxidation fraction given in EPA's Inventory of U.S. Greenhouse Gas Emissions Sources and Sinks (*1*) (see Supporting Information). Emissions from the generation of the electricity consumed were calculated using an average 1997 emission factor of 1400 lb CO_2 equiv/MWh (*16*). These total emissions were then converted to an emission factor using the amount of coal produced in 1997 and the average heat content of this coal.

Emissions from the transportation of coal were calculated using the EIO-LCA tool developed at Carnegie Mellon University (*30*). To use this tool, economic values for coal transportation were needed. In 1997, the latest year for which the EIO-LCA tool has data, 84% of coal was transported via rail, 11% via barge, and 5% via truck. The cost for rail transport, barge, and truck transport was 13.9, 9.5, and 142.7 mills/ton-mile respectively (*12*). For a million ton-miles of coal transported, EIO-LCA estimates that 43.6 tons of CO_2 equivalents are emitted from rail transportation, 5.89 tons of CO_2 equivalents from water transportation, and 69 tons of CO_2 equivalents from truck transportation (*30*). These emissions were then converted to an emission factor by using the average travel distance of coal in each mode (796, 337, and 38 miles by rail, barge, and truck, respectively), the weighted average U.S. coal heat content of 10 520 Btu/lb (*31*) and the coal production data for 1997 (see Supporting Information).

The energy consumption data used to develop carbon emissions from the mining life-cycle stage were used to develop SO_x and NO_x emission factors for coal. AP 42 emissions factors for off-road vehicles, natural gas turbines, reciprocating engines, light duty gasoline trucks, large stationary diesel engines, and gasoline engines were used to develop this range of emission factors (*17*, *32*). In addition, the average emission factors from electricity generation in 1997 (3.92 lb NO_x/MWh and 7.86 lb SO_2/MWh (*16*)) were used to include the emissions from the electricity used in mines.

SO_x and NO_x emissions for coal transportation were again calculated using EIO-LCA (*30*). EIO-LCA estimates that a million ton-miles of coal transported via rail results in emissions of 0.02 tons of SO_x and 0.4 tons of NO_x. A million ton-miles of coal transported via water would emit 0.07 tons of SO_x, and 0.36 tons of NO_x. Finally, a million ton-miles of coal transported via truck would emit 0.06 tons of SO_x, and 1.42 tons of NO_x (*30*). These data were added to emissions from mines to find the total SO_x and NO_x emission factors for the upstream stages of the coal life-cycle.

3.4. Air Emissions from the SNG Life-Cycle. Performance characteristics for two SNG plants are given in the Supporting Information. These plants have a higher heating value efficiency between 57% and 60% (*33*, *34*). Using these efficiencies, emissions from coal mining, processing, and

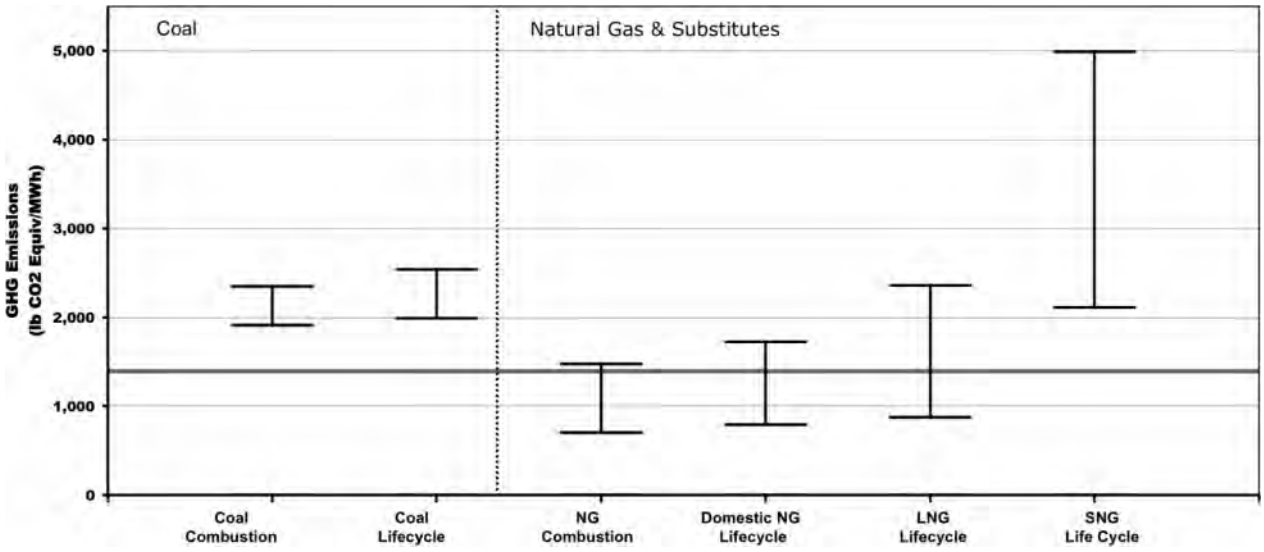

FIGURE 1. Fuel Combustion and Life-Cycle GHG Emissions for Current Power Plants.

transportation previously obtained were converted to pounds of CO_2 equiv/MMBtu of SNG. The data were also used to calculate the emissions at the gasification−methanation plant using a coal carbon content of 0.029 tons/MMBtu and a calculated SNG storage fraction of 37% (*1*). Finally, the emissions from transmission, storage, distribution, and combustion of SNG are the same as those for all other natural gas.

To develop the SO_x and NO_x emissions from the life-cycle of SNG, the emissions from coal mining and transport developed in the previous section in pounds per MMBtu of coal were converted to pounds per MMBtu of SNG using the efficiencies previously discussed. In addition, the emissions from natural gas transmission and storage were assumed to represent emissions from these life-cycle stages of SNG. The emissions from the gasification−methanation plant were taken from emission data for an Integrated Coal Gasification Combine Cycle (IGCC) plant, which operates with a similar process. Bergerson (*35*) reports SO_x emissions factors from IGCC between 0.023 and 0.15 lb/MMBtu coal (0.026−0.17 lb/MMBtu of coal if there is carbon capture), and a NO_x emission factor of 0.0226 lb/MMBtu coal (0.0228 lb/MMBtu of coal if there is carbon capture). These were converted to lb/MMBtu of SNG using the same coal-to-SNG efficiencies previously described.

4. Results

4.1. Comparing Fuel Life-Cycle Emissions for Fuels Used at Currently Operating Power Plants. Emission factors for the fuel life-cycles were calculated as pounds of pollutants per MMBtu of fuel produced, as presented in the Supporting Information. Since coal and natural gas power plants have different efficiencies, 1 MMBtu of coal does not generate the same amount of electricity as 1 MMBtu of natural gas/LNG/SNG. For this reason, emission factors given in Table 10S and Table 11S in the Supporting Information were converted to pounds of pollutant per MWh of electricity generated. This conversion is done using the efficiency of natural gas and coal power plants. According to the U.S. Department of Energy (DOE), currently operating coal power plants have efficiencies ranging from 30% to 37%, while currently operating natural gas power plants have efficiencies ranging from 28% to 58% (*36*). The life-cycle GHG emissions factors of natural gas, LNG, coal, and SNG described in the Supporting Information were converted to a lower and upper bound emission factor from coal and natural gas power plants using these efficiency ranges. Figure 1 shows the final bounds for the emission factors for each fuel cycle. The life-cycle for each fuel use includes fuel combustion at a power plant. The combustion-only emissions for each fuel are shown for comparison. The solid horizontal line shown represents the current average GHG emission factor for U.S. electricity generation: 1400 lb CO_2 equiv/MWh (*16*). Note that in this graph no carbon capture and storage (CCS) is performed at any stage of the life-cycle. CCS is a process by which carbon emissions are separated from other combustion products and injected into underground geologic formations such as saline formations or depleted oil/gas fields. A scenario in which CCS is performed at power plants as well as in gasification−methanation plants will be discussed in the following section.

It can be seen that combustion emissions from coal-fired power plants are higher than those from natural gas: the midpoint between the lower and upper bound emission factors for coal combustion is approximately 2100 lb CO_2 equiv/MWh, while the midpoint for natural gas combustions is approximately 1100 lb CO_2 equiv/MWh. This reflects the known environmental advantages from combustion of natural gas over coal. Figure 1 also shows that the life-cycle GHG emissions of electricity generated with coal are dominated by combustion, and adding the upstream life-cycle stages does not change the emission factor significantly, with the midpoint between the lower and upper bound life-cycle emission factors being 2270 lb CO_2 equiv/MWh. For natural-gas-fired power plants the emissions from the upstream stages of the natural gas life-cycle are more significant, especially if the natural gas used is synthetically produced from coal (SNG). The midpoint life-cycle emission factor for domestic natural gas is 1250 lb CO_2 equiv/MWh; for LNG and SNG it is 1600 lb CO_2 equiv/MWh and 3550 lb CO_2 equiv/MWh, respectively. SNG has much higher emission factors than the other fuels because of efficiency losses throughout the system. It is also interesting to note that the range of life-cycle GHG emissions of electricity generated with LNG is significantly closer to the range of emissions from coal than the life-cycle emissions of natural gas produced in North America. The upper bound life-cycle emission factor for LNG is 2400 lb CO_2 equiv/MWh, while the upper bound life-cycle emission factor for coal is 2550 lb CO_2 equiv/MWh.

To compare emissions of SO_x and NO_x from all life-cycles, the upstream emission factors and the power plant efficiencies from the Supporting Information are used. Emissions of these pollutants from coal and natural gas power plants in operation in 2003 were obtained from EGRID (*37*). Table 1

TABLE 1. SO_x and NO_x Combustion and Life-Cycle Emission Factors for Current Power Plants

fuel		SO_x (lb/MWh)		NO_x (lb/MWh)	
		min	max	min	max
current electricity mix		6.04		2.96	
coal	combustion	1.54	25.5	2.56	9.08
	life-cycle	1.60	25.8	2.83	9.69
natural gas	combustion	0.00	1.13	0.12	5.20
	life-cycle	0.04	1.49	0.17	9.40
LNG	life-cycle	0.094	2.93	0.25	15.4
SNG	life-cycle	0.30	3.88	0.65	8.08

shows life-cycle emissions for each fuel obtained by adding the combustion emissions from EGRID to the transformed upstream emissions. The current average SO_x and NO_x emission factors for electricity generated in the United States are also shown (*16*).

It can be seen that coal has significantly larger SO_x emissions than natural gas, LNG, or SNG. This is expected since the sulfur content of coal is much higher than the sulfur content of other fuels. SNG, which is produced from coal, does not have high sulfur emissions because the sulfur from coal must be removed before the methanation process.

For NO_x, it can be seen that the upstream stages of domestic natural gas, LNG, and even SNG make a significant contribution to the total life-cycle emissions. These upstream NO_x emissions come from the combustion of fuels used to run the natural gas system: for domestic natural gas, production is the largest contributor to these emissions; for LNG most NO_x upstream emissions come from the liquefaction plant; finally, for SNG most upstream NO_x emissions come from the gasification−methanation plant.

4.2. Comparing Fuel Life-Cycle Emissions for Fuels Used with Advanced Technologies. According to the DOE, by 2025 65 GW of inefficient facilities will be retired, while 347 GW of new capacity will be installed (*8*). Advanced pulverized coal (PC), integrated coal gasification combined cycle (IGCC), and natural gas combined cycle (NGCC) power plants could be installed. PC, IGCC, and NGCC plants are generally more efficient (average efficiencies of 39%, 38%, and 50%, respectively (*38*)) than the current fleet of power plants. In addition, CCS could be performed with these newer technologies. Experts believe that sequestration of 90% of the carbon will be technologically and economically feasible in the next 20 years (*5*, *38*). Having CCS at PC, IGCC, and NGCC plants decreases the efficiency of the plants to average of 30%, 33%, and 43%, respectively (*38*).

Figure 2 was developed using the revised efficiencies for advanced technologies and the GHG emission factors (in lb/MMBtu) described in the Supporting Information. This figure represents total life-cycle emissions for electricity generated with each fuel. Notice that emissions are shown with and without CCS. In the case of SNG with CCS, capture is performed at both the gasification−methanation plant and at the power plant. The solid horizontal line shown represents the current average GHG emission factor for electricity generation in the United States (1400 lb CO_2 equiv/MWh) (*16*). The upper and lower bound emissions in this figure are closer together than the upper and lower bounds in Figure 1, because only one power plant efficiency value is used, while for Figure 1 the upper and lower bound efficiency from all currently operating power plants was used (this is especially obvious for the domestic natural gas (NGCC) cases). It can be seen that, in general, life-cycle GHG emissions of electricity generated with the fuels without CCS would decrease slightly compared to emissions from current power plants that use the same fuel (due to efficiency gains). The most efficient natural gas plant currently in operation, however, could have slightly lower emissions than the lower bound for NGCC, LNGG, and SNGCC, due to efficiency differences. Three of the cases, however (PC, IGCC, and SNGCC), would still have higher emissions than the current average emissions from power plants. If CCS were used, however, there would be a significant reduction in emissions for all cases. In addition the midpoints between upper and lower bound emissions from all fuels are closer together, as can be seen in Figure 3. This figure also shows how the upstream from combustion emissions of fuels become significant contributors to the life-cycle emission factors when CCS is used.

Table 2 was developed using the upstream SO_x and NO_x emission factors obtained in this study and the combustion emissions reported by Bergerson (*35*) for PC and IGCC plants and by Rubin et al. for NGCC plants (*38*). These reported combustion emissions can be seen in the Table 12S in the Supporting Information.

As can be seen from Table 2, if advanced technologies are used there could be a significant reduction of NO_x and SO_x emissions, even if CCS is not available. It is interesting also to note that a PC plant with CCS could have lower life-cycle emissions than an IGCC plant with CCS. In the PC case all sulfur is removed through flue gas desulfurization. The removed sulfur compounds are then solidified and disposed of or sold as gypsum. In an IGCC plant with CCS, sulfur is removed from the syngas before combustion. In these plants, however, instead of solidifying the sulfur compounds removed and disposing them, the elemental sulfur is recovered in a process that generates some additional SO_x emissions (*35*). For NO_x, only LNG has higher life-cycle emissions than the average generated at current power plants.

5. Discussion

Natural gas is an important energy source for the residential, commercial, and industrial sectors. In the 1990s, the surge in demand by electricity generators and relatively constant natural gas production in North America caused prices to increase, so that in 2005 these sectors paid 58 billion dollars more than they would have paid if 2000 prices remained constant. Cumulative additional costs of higher natural gas prices for residential, commercial, and industrial consumers between 2000 and 2005 were calculated to be around 120 billion dollars. LNG has been identified as a source of natural gas that might help reduce prices, but even with an increasing supply of LNG, EIA still projects average delivered natural gas prices above $6.5/Mcf in the next 25 years. This is higher than the $4.5 /Mcf average projected price in earlier reports before the natural-gas-fired plant construction boom (*4*).

In addition to LNG, SNG has been proposed as an alternative source to add to the natural gas mix. The decision to follow the path of increased LNG imports or SNG production should be examined in light of more than just economic considerations. In this paper, we analyzed the effects of the additional air emissions from the LNG/SNG life-cycle on the overall emissions from electricity generation in the United States. We found that with current electricity generation technologies, natural gas life-cycle GHG emissions are generally lower than coal life-cycle emissions, even when increased LNG imports are included. However LNG imports decrease the difference between GHG emissions from coal and natural gas. SNG has higher life-cycle GHG emission than coal, domestic natural gas, or LNG. It is also important to note that upstream GHG emissions of NG/LNG/SNG have a higher impact in the total life-cycle emissions than upstream coal emissions. This is a significant point when considering a carbon-constrained future in which combustion emissions are reduced.

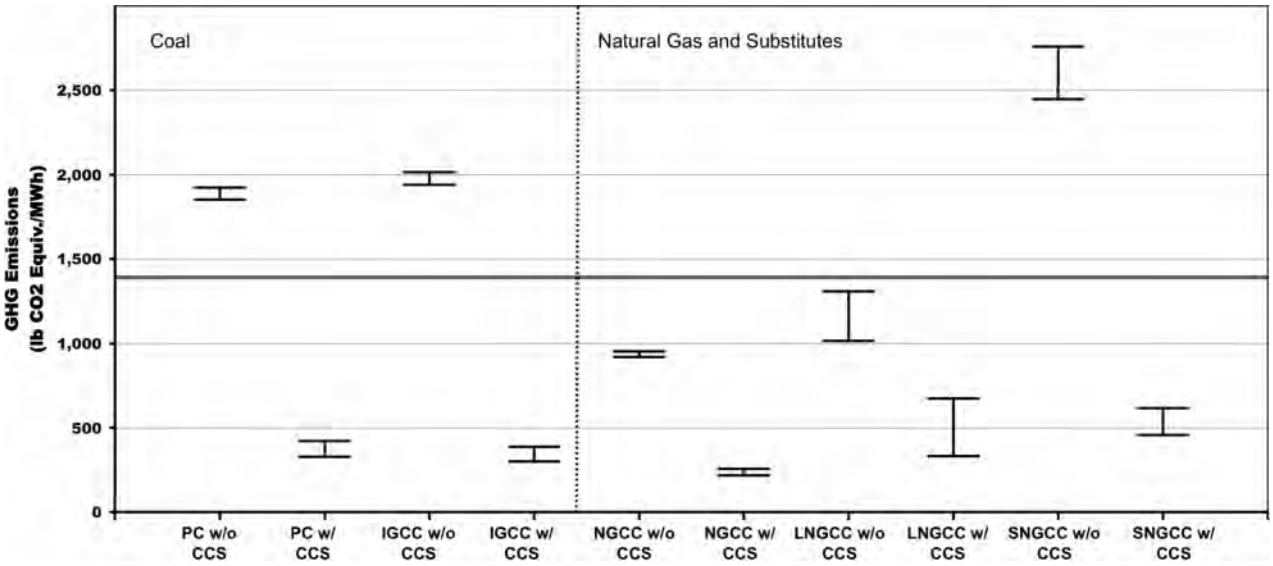

FIGURE 2. Fuel GHG Life-Cycle Emissions Using Advanced Technologies.

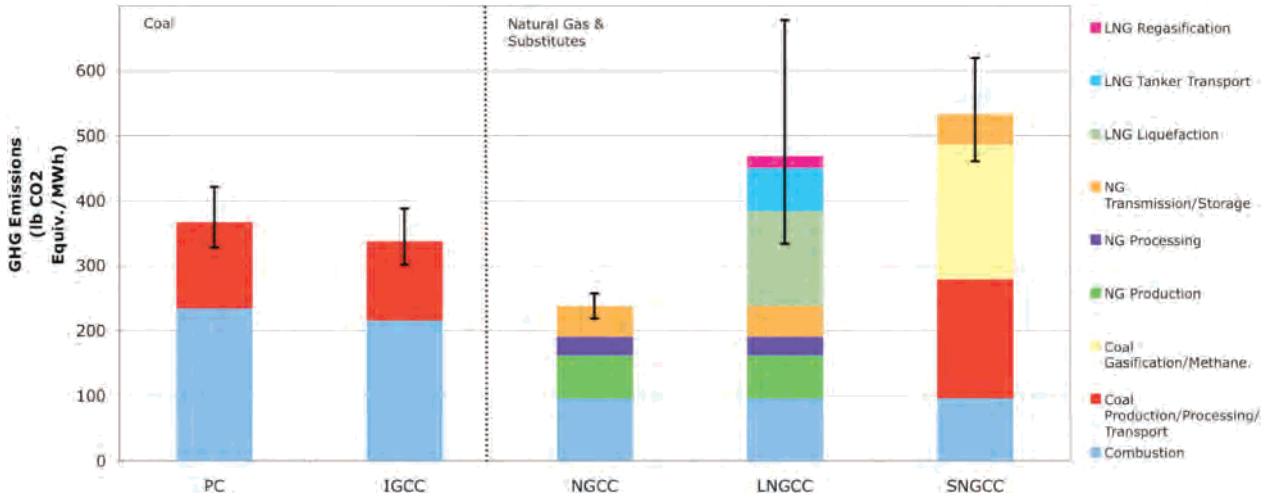

FIGURE 3. Midpoint Life-Cycle GHG Emissions Using Advanced Technologies with CCS.

TABLE 2. SO_x and NO_x Life-Cycle Emission Factors for Advanced Technologies

fuel		SO_x (lb/MWh)		NO_x (lb/MWh)	
		min	max	min	max
current electricity mix		6.04		2.96	
coal	PC w/o CCS	0.24	1.54	1.42	2.46
	PC w/ CCS	0.08	0.34	1.90	3.61
	IGCC w/o CCS	0.27	1.57	0.47	0.70
	IGCC w/ CCS	0.32	1.83	0.54	0.78
natural gas	NGCC w/o CCS	0.04	0.20	0.30	2.57
	NGCC w/ CCS	0.05	0.24	0.36	3.01
LNG	NGCC w/o CCS	0.25	1.04	0.39	5.89
	NGCC w/ CCS	0.30	1.23	0.46	6.91
SNG	NGCC w/o CCS	0.35	2.15	0.88	1.85
	NGCC w/ CCS	0.45	2.80	1.03	2.18

For emissions of SO_x, we found that with current electricity generation technologies, coal has significantly higher life-cycle emissions than any other fuel due to very high emissions at current power plants. For NO_x, however, this pattern is different. We find that with current electricity generation technologies, LNG could have the highest life-cycle NO_x emissions (since emissions from liquefaction and regasification are significant), and that even natural gas produced in North America could have life-cycle NO_x emissions very similar to those of coal. It is important to note that while GHG emissions contribute to a global problem, SO_x and NO_x are local pollutants and U.S. policy makers may not give much weight to emissions of these pollutants in other countries.

In the future, as newer generation technologies and CCS are installed, the overall life-cycle GHG emissions from electricity generated with coal, domestic natural gas, LNG, or SNG could be similar. Most important is that all fuels with advanced combustion technologies and CCS have lower life-cycle GHG emission factors than the current average emission factor from electricity generation. For SO_x we found that coal and SNG would have the largest life-cycle emissions, but all fuels have lower life-cycle SO_x emissions than the current average emissions from electricity generation. For NO_x, LNG would have the highest life-cycle emissions and would be the only fuel that could have higher emissions than the current average emission factor from electricity generation, even with advanced power plant design.

We suggest that advanced technologies are important and should be taken into account when examining the possibility of doing major investments in LNG or SNG infrastructure. Power generators hope that the price of natural gas will decrease as alternative sources of natural gas are added to the U.S. mix, so they can recover the investment made in

natural gas plants that are currently producing well under capacity. We suggest that these investments should be viewed as sunk costs. Thus, it is important to re-evaluate whether investing billions of dollars in LNG/SNG infrastructure will lock us into an undesirable energy path that could make future energy decisions costlier than ever expected and increase the environmental burden from our energy infrastructure.

Acknowledgments

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Supporting Information Available

Graphical representation of the fuel life-cycles, emissions calculation information, summary of emissions from fuel life-cycles, power plant efficiency information, emissions from advanced technologies, and references, This material is available free of charge via the Internet at http://pubs.acs.org.

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Comparative Life-cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation

Supporting Information

1. Graphical Representation of the Fuel Life-cycles

Figure 1S and Figure 2S below, show the life-cycle stages on natural gas used by electric power generators, including the stages from the LNG life-cycle. Notice that local distribution of natural gas falls outside our analysis boundary.

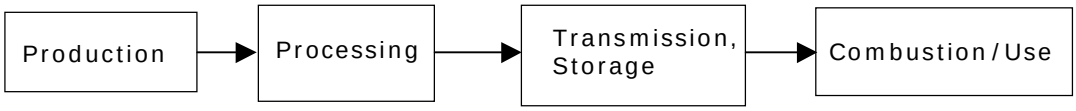

Figure 1S: Domestic Natural Gas Life-cycle.

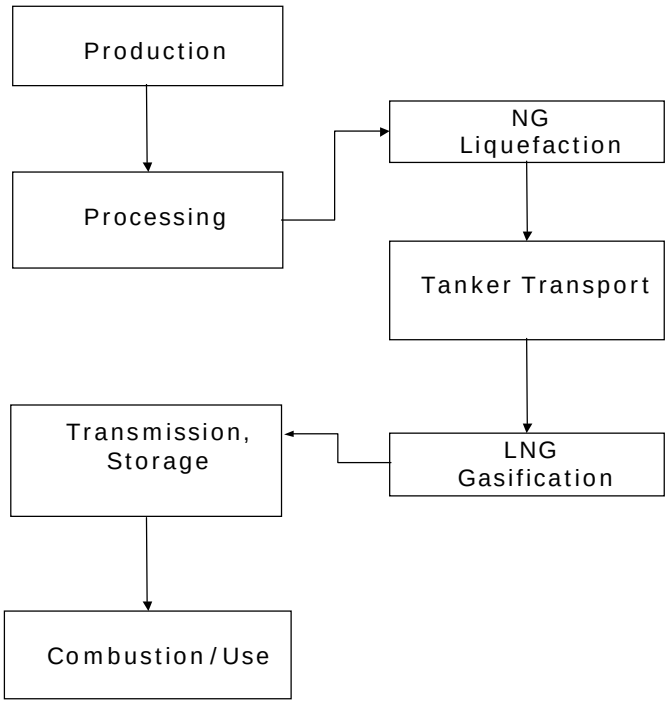

Figure 2S: LNG Life-cycle.

Figure 3S and Figure 4S show the life-cycle of coal and synthetic natural gas (SNG) derived from coal.

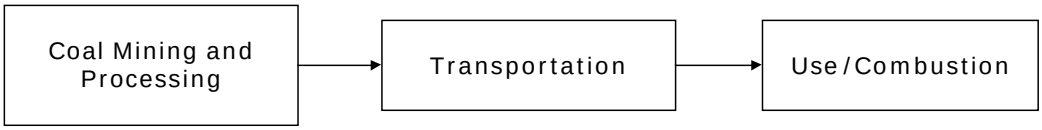

Figure 3S: Coal Life-cycle.

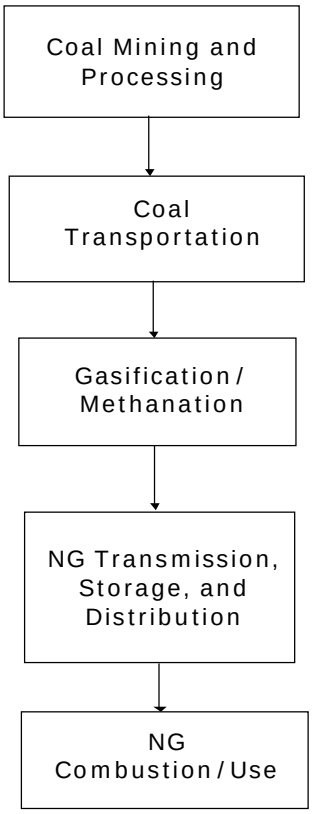

Figure 4S: SNG Life-cycle.

2. Calculating Emissions from the Domestic Natural Gas Life-cycle

During the late 1980s and early 1990s the U.S. Environmental Protection Agency (EPA) conducted a study to determine methane emissions from the natural gas industry (1). This comprehensive study developed hundreds of activity and emissions factors from all areas of the natural gas industry. These factors were developed using data collected from

different sectors of the industry as well as from data collected in field measurements. Methane emissions from the U.S. natural gas system given as a percentage of natural gas produced can be seen in Table 1S. This data was used to develop methane emission factors, as described in the main document. Notice, that Table 1S includes an estimate for natural gas losses in the local distribution system. This estimate is given here for reference, but it was not included in our calculation of emissions of natural gas used to generate electricity.

In addition data from the EPA Natural Gas STAR program was used. The program is a voluntary partnership with the goal of encouraging the natural gas industry to adopt practices that increase efficiency and reduce emissions (for example by reducing natural gas leaks in the pipeline system). Consequently, since 1993, a cumulative total of 338 billion cubic feet of methane emissions have been eliminated. In 2003 alone, 52,900 million cubic feet of methane emissions were eliminated, a 9% reduction over projected emissions for that year without improved practices (2).

Table 1S: Methane Emissions from North American Gas Life-cycle as a Percentage of Natural Gas Produced (1).

Lifecycle Segment	Emissions as a Percentage of Gas Produced
Production	0.38%
Processing	0.16%
Transmission and Storage	0.53%
Distribution	0.35%

Carbon dioxide emissions from the different natural gas life-cycle stages were also calculated. These emissions were calculated using data on the amount of natural gas used to run the processes, as given in Table 2S, as well as an estimated 3 billion KWh of electricity used for pipeline transport. These data were also used to calculate SO_x and NO_x emissions from the life-cycle, as described in the main document. It should be mentioned that the pipeline fuel presented in Table 2S includes fuel used by the transmission system and the local distribution system. As previously described, natural gas used by electricity generators is bought directly from the transmission system, so that emissions from the distribution system are not included in our analysis. Due to data limitations, we were not able to disaggregate pipeline fuel and electricity consumption between the two systems. To deal with this issue, we use a range of emissions. The minimum value assumes that none of this fuel is consumed in the transmission system and the maximum value assumes that all is consumed in the transmission system.

Table 2S: Natural Gas Used During the Natural Gas Life-cycle. (3).

Use (as defined by EIA)	NG Life-cycle Stage	Amount (million ft^3)
Flared Gas	Production	98,000
Lease Fuel	Production	760,000
Pipeline Use	Transmission/Distribution	665,000
Plant Fuel	Processing	365,000

3. Calculating Emissions from the LNG Life-cycle

As mentioned in the main paper, Tamura et al (4) provide GHG emissions for liquefaction plants. Table 3S presents the sources of these emissions.

Table 3S: Liquefaction Emission Factors (Adapted from Tamura et al (4)).

Liquefaction	Emission Factors (lb CO_2 Equivalent/MMBtu)		
	Minimum	Average	Maximum
CO_2 from fuel combustion	11	12	13
CO_2 from flare combustion	0.00	0.77	1.5
CH_4 from vent	0.09	1.3	9.8
CO_2 in raw gas	0.09	4.0	6.6

Table 4S provides the distance from LNG exporting countries to two U.S. LNG terminals and the amount of LNG brought from each country in 2003. These two terminals were chosen because they are two of the largest terminals in the United States and they represent longest and shortest tanker travel distances for which route information is available. In addition, the range of distances provided is also representative of distances LNG would have to travel if a LNG terminal was located in the U.S. West Coast. Figure 5S shows the emission factors for LNG Tanker transport from each country to each of these terminals, obtained using the tanker information given in the main document. Emissions from tanker transport range between 2 and 17 pounds of CO_2 Equivalent per MMBtu of natural gas. These data was also used to calculate the SO_x and NO_x emission factors for tanker transport.

Table 4S: LNG Exporting Countries in 2003.

Exporting Country	Distance to Lake Charles Facility (nautical miles) (5)	Distance to Everett, MA Facility (nautical miles) (5)	2003 US Imports (million cubic feet NG) (3)
Algeria	5,000	3,300	53,000
Australia	12,000	11,000	0
Brunei	12,000	11,000	0
Indonesia	12,000	11,000	0
Malaysia	12,000	11,000	2,700
Nigeria	6,100	5,000	50,000
Oman	8,900	7,500	8,600
Qatar	9,700	8,000	14,000
Trinidad	2,200	2,000	380,000
UAE	9,600	7,959	0
Russia	9,600	11,000	0

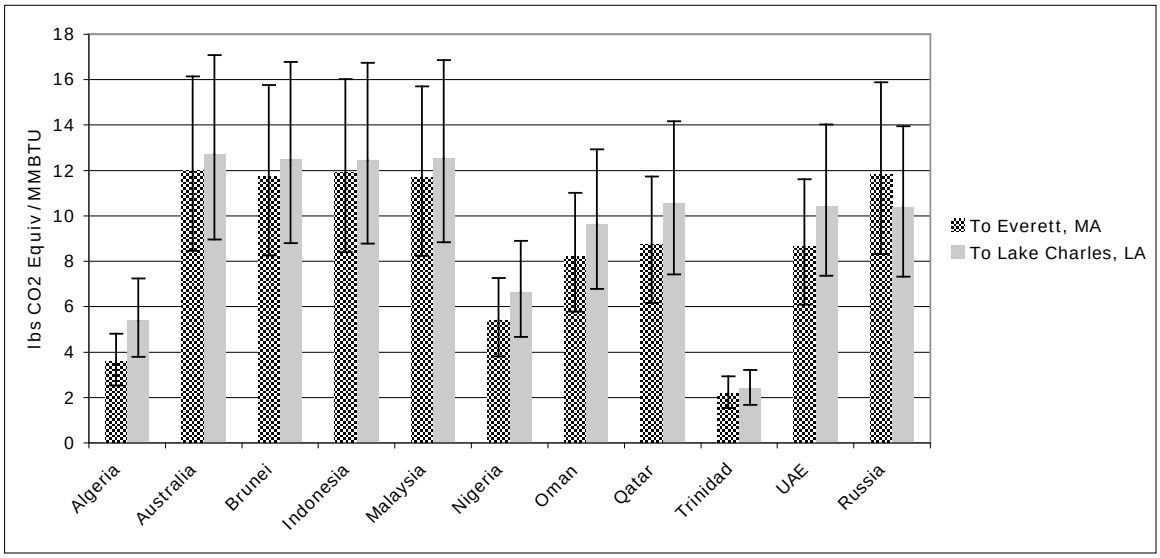

Figure 5S: Tanker Emission Factors from Each Country.

4. Calculating Emissions from the Coal Life-cycle

Table 5S presents fuel consumption data for coal mines in the U.S., and Table 6S presents carbon content, heat content of these fuels. These data was used to calculate GHG emissions factors for coal mines.

Table 5S: 1997 Fuel Consumption at Coal Mines (6)

Mine Type	Fuel Oil (1000 bbl)			Gas (10^9 ft^3)	Gasoline (10^6 gal)	Electricity (10^6 KWh)
	Total	Distillate	Residual			
Surface	8,280	7,524	756	0.7	30	42,474
Underground	801	656	145	0.5	4	7,123

Table 6S: Carbon Content, and Heat Content of Different Fuels (7).

Fuel Type	Carbon Content of Fuel lb/MMBtu Fuel	Heat Content of Fuel (MMBtu/bbl - MMBtu/MMcf)	Fraction Oxidized
Distillate	43.98	5.825	0.99
Residual	47.38	6.287	0.99
Gas	31.90	1,030	0.995
Gasoline	42.66	5.253	0.99

Table 7S: 1997 Coal Production Data (8).

Mine Type	Coal Produced (1000 tons)	Heat Content of Coal (BTU/lb)
Surface	669,273	9,626
Underground	420,657	11,944
Total	1,089,930	10,520

As described in the main document, EIO-LCA was used to estimate emission factors from coal transportation. Table 8S summarizes the emissions resulting from transporting one million ton-miles of coal via each transportation mode.

Table 8S: EIO-LCA GHG Emission Data for a Million Ton-Miles of Coal Transported (9).

Sector	Total GHG Emissions (tons CO_2 Equivalent)	Total SO_x Emissions (tons SO_x)	Total NO_x Emissions (tons NO_x)
Rail Transportation	43.6	0.02	0.40
Water Transportation	5.89	0.07	0.36
Truck Transportation	69.0	0.06	1.42

5. Calculating Emissions from the SNG Life-cycle

In order to calculate air emissions from the SNG life-cycle, the emissions from coal production, processing and transport were converted from pounds per MMBtu of coal used to pounds per MMBtu of SNG produced using the performance characteristics of two SNG plants given in Table 9S. The emissions from SNG transport, storage and use are the same as those from natural gas. The efficiency for the CCS case was obtained assuming an energy penalty of 16% as described for and IGCC plant by Rubin et al (10).

Table 9S: SNG Plant Performance Characteristics

	Case 1 (11)	**Case 2 (12)**
SNG Output (1. mcf/day and 2. MMBtu/hr)	250	1,739
Efficiency without CCS (HHV)	57%	60%
Efficiency with CCS (HHV)	50%	52%

6. Summary of Emissions from Fuel Life-cycles

Table 10S summarizes GHG emission factors for all fuels. The emission factors presented in this section are the average emission rate relative to units of fuel produced, without considering the efficiency of using these fuels. These emission factors can later be used to develop total inventories of GHG emissions from the annual consumption of each fuel. Allocation of these emissions for each life-cycle stage can be seen in Figure 6S through Figure 8S. Note that there are two different emission factors for SNG. In one case, no carbon capture and sequestration (CCS) is performed at the gasification-methanation stage. When CCS is performed at the gasification-methanation plant, an energy penalty is incurred. It was assumed that the energy penalty observed at IGCC plants with CCS (16%) is representative of the energy penalty at the SNG gasification-methanation plant (10). CCS could also be performed at power plants, as discussed in the main document.

It is also very important to note that the emission factors shown in Table 10**S** (and the emission factors given in Table 11S) are not comparable to each other, since one Btu of coal does not generate the same amount of electricity as one Btu of natural gas or SNG. These emission factors can be transformed to comparable units, namely lbs/MWh of electricity produced, by taking into consideration the efficiency of electricity generation.

Table 10S: Life-cycle GHG Emission Factors

(units: lbs/MMBtu of Fuel Produced)

Life-cycle Stages	North American NG		LNG		Coal		SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Upstream	15.3	20.1	29.6	72.3	8.2	16.4	240	286	45.2	65.2
Combustion (no CCS)	120	120	120	120	205	205	120	120	120	120
Combustion (with CCS)	12	12	12	12	20.5	20.5	12	12	12	12

SO_x and NO_x emission factors for the upstream stages of electricity generation for the fuel life-cycles can be seen in Table 11S. SO_x and NO_x emissions from the combustion of fuel at power plants are very dependent on specific plant characteristics, so it was not possible to transform these power plant emissions (given in lbs/MWh) to the same units as the emissions from the upstream stages of the life-cycle (lbs/MMBtu) by simply using the efficiency of the power plants.

Table 11S: Upstream SO_x and NO_x Emission Factors (units: lbs/MMBtu of Fuel Produced)

Pollutant	North American Natural Gas		LNG		Coal		SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
SO_x	0.006	0.030	0.016	0.145	0.007	0.029	0.051	0.316	0.064	0.400
NO_x	0.009	0.342	0.022	0.831	0.030	0.535	0.090	0.234	0.104	0.253

7. GHG Emissions Allocated to Fuel Life-cycle Stages

Figure 6S through Figure 8S show how the GHG emissions reported in Table 10S are allocated among the different life-cycle stages.

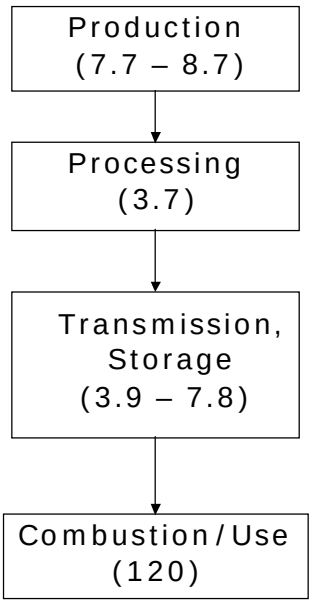

Figure 6S: North American Gas Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

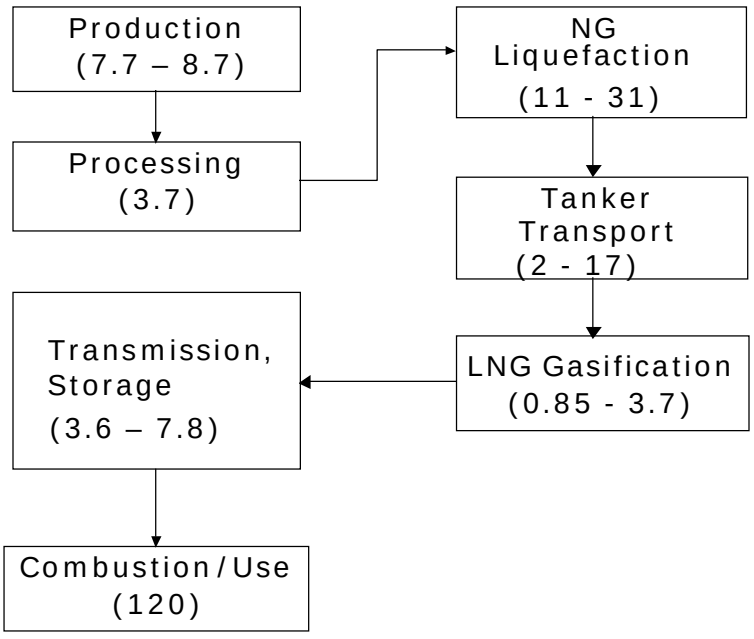

Figure 7S: LNG Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

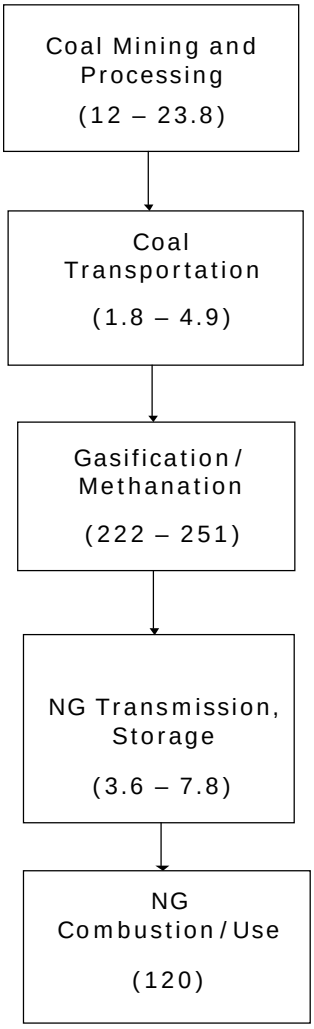

Figure 8S: SNG Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

8. Efficiencies of Currently Operating Power Plants

Figure 9S shows the distribution of the efficiencies of currently operating power plants, obtained using the cumulative distribution function of EIA 2003 electricity generation data for all utility plants (13). As illustrated in Figure 9S, the median efficiency for natural gas plants is higher than the median efficiency for coal plants. These efficiencies were used to convert the emission factors previously presented (in lbs/ MMBtu of fuel) to lbs/MWh.

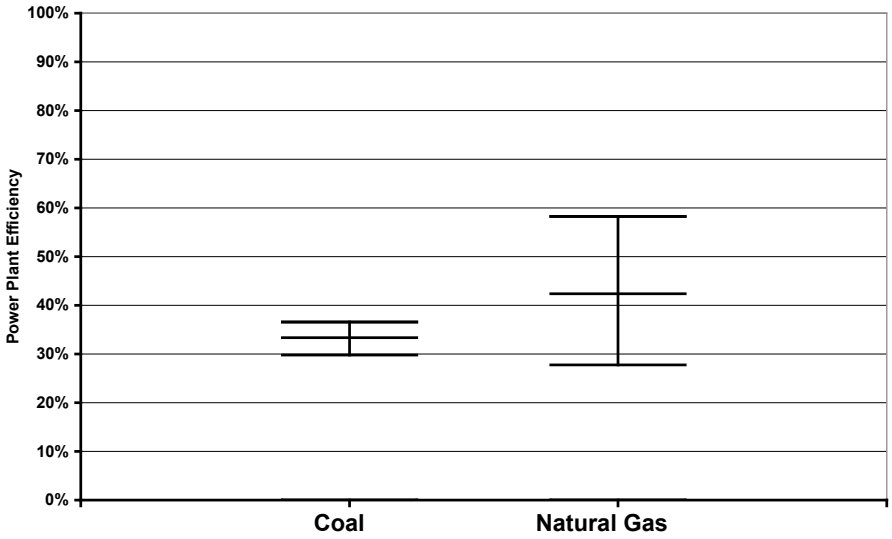

Figure 9S: Efficiencies of Natural Gas and Coal Plants (13).

9. Combustion Emissions from Advance Technologies

Table 12S reports combustion emissions from advanced power plant technologies. The emission factors from PC and IGCC plants were reported Bergerson (14) for PC and IGCC plants. Rubin et al reported the emissions for NGCC plants (10).

Table 12S: Combustion Emissions from Advanced Power Plants.

Fuel/Pollutant	SO_x (lbs/MWh)		NO_x (lbs/MWh)	
	Min	Max	Min	Max
PC w/o CCS	0.17	1.28	1.16	2.00
PC w/ CCS	0.00	0.01	1.56	3.00
IGCC w/o CCS	0.20	1.30	0.20	0.20
IGCC w/ CCS	0.24	1.52	0.20	0.20
NGCC w/o CCS	0.00	0.00	0.24	0.24
NGCC w/ CCS	0.00	0.00	0.29	0.29

10. References

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Comparative Life Cycle Carbon Emissions of LNG Versus Coal and Gas for Electricity Generation

Paulina Jaramillo, W. Michael Griffin, H. Scott Matthews

Introduction

Natural gas currently provides 24% of the energy used by homes and businesses in the US (1). It is also an important feedstock for the chemical and fertilizer industry. In the early 1990's the price of natural gas was low (around \$3/1000 ft^3) and as a result there was a surge in construction of natural gas plants (2). Today, the Henry Hub price of natural gas is around \$15/1000 ft^3 (3), and most of these plants are operating below capacity. However, natural gas consumption is expected to increase 41% by 2025 (to 30 trillion cubic feet), with demand from electricity generators growing the fastest (increasing 90% by 2025). At the same time natural gas production in North America is expected to remain fairly constant at around 24 trillion cubic feet, so that demand of imported liquefied natural gas (LNG) will increase to around 6 trillion cubic feet or 20% of the total supply by 2025 (3).

The natural gas system is the second largest source of greenhouse gas emissions in the US, generating around 132 million tons of CO_2 Equivalents (1). Several studies have performed emission inventories for the natural gas lifecycle from production to distribution. Usually these analyses have been performed for domestic natural gas, so that emissions from the LNG lifecycle stages have been ignored. If, as the DOE estimates suggest, larger percentages of the supply of natural gas will come from these imports, emissions from these steps in the lifecycle could influence the total natural gas lifecycle emissions. Thus, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate. The objective of this study is to perform an analysis of the natural gas lifecycle greenhouse gas emissions taking the emissions from LNG into consideration. Different scenarios for the percentage of natural gas as LNG are analyzed. Moreover, a comparison with the coal fuel cycle greenhouse gas emissions will be presented, in order to have a better understanding of the advantages and disadvantages of using coal versus natural gas for electricity generation.

The Natural Gas Life Cycle

The natural gas life cycle starts with the production of natural gas and ends at the combustion plant. NaturalGas.org has a very detailed description of this life cycle. Readers are encouraged to visit this website if they need more information about the topic.

Geological surveys and seismic studies are used to determine the location of natural gas deposits. After these sites have been identified, wells are constructed. There are two types of well for the extraction of natural gas: oil wells and natural gas wells. Oil wells are

drilled primarily to extract oil, but natural gas can also be obtained. Natural gas wells are specifically drilled to extract natural gas.

After natural gas is extracted through the wells, it has to be processed to meet the characteristics of the natural gas used by consumers. Consumer natural gas is composed primarily of methane. However, when natural gas is extracted, it exists with other hydrocarbons such as propane and ethane. In addition, the extracted natural gas contains impurities such as water vapor and carbon dioxide that must be removed. Natural gas processing plants are usually constructed in gas producing regions. The natural gas is transported from the extraction sites to these plants through a system of low-diameter, low-pressure pipelines. At the plant, water vapor is first removed from the gas by using absorption or adsorption methods. Glycol Dehydration is an example of absorption, in which glycol, which has a chemical affinity to water, is used to absorb the vapor. Solid-Desiccant Dehydration is an example of adsorption. In this process the natural gas passes through towers that contain activated alumina or other solid desiccants. As the gas is passed through these towers, the water particles are retained on the surface of the solids.

As previously mentioned, natural gas is extracted with other hydrocarbons that must be removed. The removal of these hydrocarbons, called Natural Gas Liquids (NGL), is done with the absorption method or the cryogenic expander process. The absorption method is similar to the water absorption method, but instead of glycol, absorbing oil is used. The cryogenic expansion method consists of dropping the temperatures of the gas causing the hydrocarbons to condense so that they can be separated from the natural gas. The absorption method is used to remove heavier hydrocarbons, while lighter hydrocarbons are removed using the cryogenic expansion process.

The final step in the processing of natural gas is the removal of sulfur and carbon dioxide. Often, natural gas from the wells contains high amounts of these two compounds, and it is called sour gas. Sulfur must be removed from the gas because it is a potentially lethal chemical if breathed. In addition, sour gas can be corrosive for the transmissions and distribution pipelines. The process of removing sulfur and carbon dioxide from the gas is similar to the absorption processes previously described.

After the natural gas is processed it enters the transmission system. In the US, this transmission system is the interstate natural gas pipeline network, which consists of thousands of miles of high-pressure pipelines that transport the gas from producing areas to high demand areas. In addition to the pipes, this pipeline system has compressor stations along the way, usually placed in 40 to 100 mile intervals. These compressor stations use a turbine or an engine to compress the natural gas and maintain the high pressure required in the pipeline. The turbines and engines generally run with a small amount of the gas from the pipeline. In addition to compressor stations, metering stations are also placed along the system to allow companies to better monitor and manage the natural gas in the pipes. Moreover valves can be found through the entire length of the pipelines to regulate flow.

Natural gas can be stored to meet seasonal demand increases or to meet sudden, short-term demand increases. Natural gas is usually stored in underground facilities. Such facilities could be built in reconditioned depleted gas reservoirs, aquifers or salt caverns. According to the Energy Information Administration (EIA), in 2003 the total storage capacity in the United States was 8.2 billion cubic feet. 82% of this capacity was in depleted gas fields, 15% in depleted aquifers, and 3% in salt caverns. Moreover during that year, withdrawals from storage added to 3.1 billion cubic feet while injections totaled 3.3 billion cubic feet (4). It is important to note that some gas injected into underground storage becomes physically unrecoverable gas. This gas is known as base gas.

Distribution is the final step before natural gas is delivered to consumers. Local Distribution Companies transport natural gas from delivery points along the transmission system to local consumers via a low-pressure, small-diameter pipeline system. Natural gas that arrives to a city gate through the transmission system is depressurized, and filtered to remove any moisture or particulate content. In addition, Mercaptan is added to the gas to create the distinctive smell that allows leaks to be detected. Small compressors are used in the distribution system to maintain the pressure required.

When Liquefied Natural Gas (LNG) is added to the mix of natural gas, three additional lifecycle stages are created: liquefaction, tanker transport, and regasification. Figure 1 shows the total life cycle of natural gas including the LNG stages.

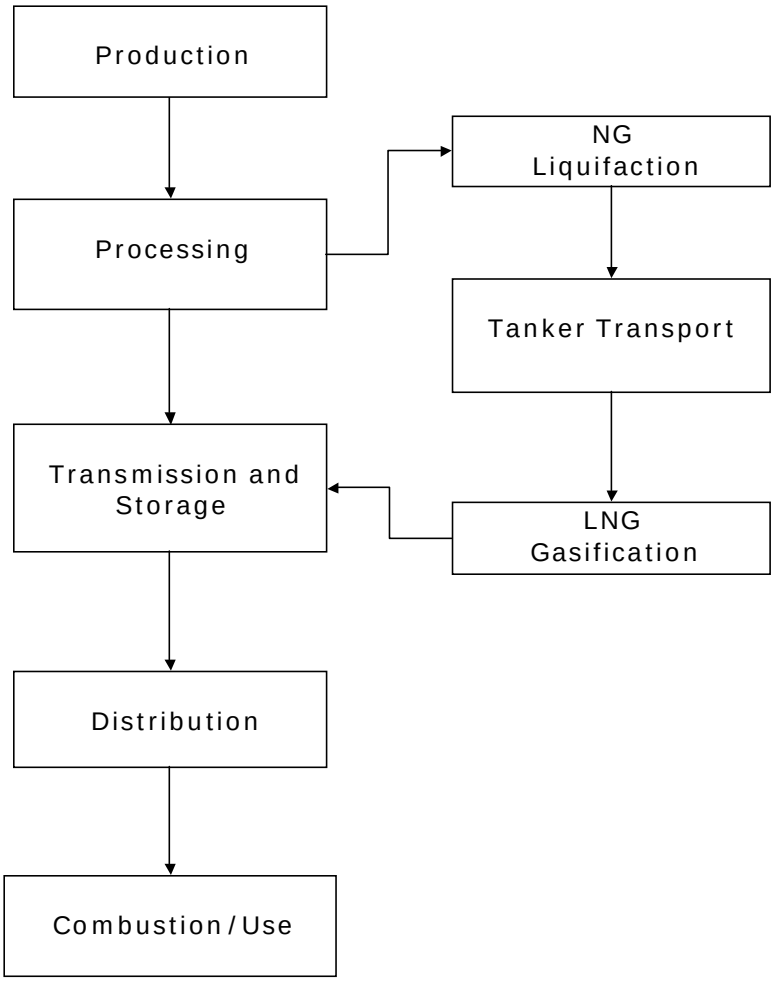

Figure 1: Natural Gas Life Cycle Including LNG.

In the liquefaction process, natural gas is cooled and pressurized to convert it to liquid form, reducing its volume by a factor of 610 (5). These liquefaction plants are generally located in coastal areas of LNG export countries. Currently 75% of the LNG imported to the US comes from Trinidad, but this percentage is expected to decrease as more imports come from Russia, the middle east, and southeast Asia (4). LNG tankers bring this gas to the US. According to EIA, there were 151 LNG tankers in operation worldwide as of October 2003. The majority of these tankers have the capacity to carry more than 120,000 cubic meters of liquefied natural gas (equivalent to 2.59 billion cubic feet of natural gas, enough gas to supply an average of 31,500 residences for a year (4)) and the total fleet capacity is 17.4 million cubic meters of liquid (equivalent to 366 billion cubic feet of natural gas). There are currently fifty-five ships under construction that will increase total fleet capacity to 25.1 million cubic meters of liquid (equivalent to 527 billion cubic feet of natural gas) in 2006 (6).

Regasification facilities are the last step LNG must pass through before going into the US pipeline system. Regasification facilities are LNG marine terminals where LNG tankers unload their gas. These facilities consist of storage tanks and vaporization equipment that warms the LNG to return it to the gaseous state. There are currently 5 LNG terminals in operation in the US: Lake Charles, Louisiana; Elba Island, Georgia; Cove Point, Maryland; Everett, Massachusetts; and a recently opened offshore terminal in the Gulf of Mexico. These terminals have a combined base load capacity of 3.05 billion cubic feet per day (about 1 trillion cubic feet per year). In addition to these there are over fifty proposed facilities for a total proposed capacity of 62 billion cubic feet per day (23 trillion cubic feet per year). Figure 2 shows the proposed location of these facilities (6).

As shown in Figure 1, natural gas combustion is the last stage in the natural gas lifecycle. In the US, natural gas is used for electricity generation, heating, and several industrial processes. Approximately 24% of the electricity generated comes from natural gas (1). Natural gas plants have heat rates that range from 5,800 BTU/kWh to 12,300 BTU/kWh (7).

US Natural Gas Industry in 2003

In 2003, the total supply of natural gas in the US was over 27 trillion cubic feet. Of this, 26.5 trillion cubic feet were produced in North America (US, Canada, and Mexico), and 0.5 trillion cubic feet were imported in the form of LNG. 75% of LNG came from Trinidad and Tobago. Other exporting countries included Algeria, Malaysia, Nigeria, Qatar, and Oman (4). Table 1 shows more detailed statistics about the state of the US natural gas industry in 2003. Numbers may not add up due to rounding.

Table 1: 2003 Natural Gas Industry Statistics (All units in million cubic feet) (4)

Gross Withdrawals	24,000,000
Total Dry Production	19,000,000
Total Supply	27,000,000
Total Consumption	22,500,000
Total Imports	4,000,000
Pipeline Imports	3,500,000
LNG Imports	505,000

Greenhouse gas emissions from Natural Gas produced in North America

During the late 1980's and early 1990's the US Environmental Protection Agency (EPA) conducted a study to determine methane emissions from the natural gas industry. This very comprehensive study developed hundreds of activity and emissions factors from all the areas of the natural industry. These factors were developed using data collected from the different sectors of the industry as well as from data collected in field measurements. Table 2 presents the percentage of produced natural gas that is emitted to the atmosphere

during the lifecycle according to the results of the previously described study, as well as the source of these emissions.

Table 2: Methane Emissions from North American Gas Life Cycle as a Percentage of Natural Gas Produced (8).

Lifecycle Segment	Emission Sources	Emissions as a Percentage of Gas Produced
Production	Pneumatic Devices	0.38%
	Fugitive Emissions	
	Underground Pipeline Leaks	
	Blow and Purge	
	Compressor	
	Glycol Dehydrator	
Processing	Fugitive Emissions	0.16%
	Compressor	
	Blow and Purge	
Transmission and Storage	Fugitive Emissions	0.53%
	Blow and Purge	
	Pneumatic Devices	
	Compressor	
Distribution	Underground Pipeline Leaks	0.35%
	Meter and Pressure Stations	
	Costumer Meter	

Based on the statistics presented in Table 1, 26.5 billion cubic feet of natural gas were produced in North America in 2003. Using the percentages of natural gas emitted, an average heat content of 1,030 BTU/ft^3, and the assumption that 100% of the natural gas lost is methane (density 19.23 gr/ ft^3) which may result in a slight overestimate of emissions given that the real percentage of methane in natural gas varies between 94% and 98%; total methane emission were calculated to develop the emission factors shown in Figure 4.

In addition to methane, carbon dioxide emissions are produced from the combustion of natural gas used during the lifecycle stages previously described. The Energy Information Administration maintains records of the amount of natural gas used during the production, processing, transmission, storage, and distribution of natural gas. This data for 2003 can be seen in Table 3. Assuming that 100% of this gas is methane, total carbon dioxide emissions were found using thermodynamic calculations. These emissions were then added to methane emissions to obtain the total emission factors shown in Figure 3.

Table 3: Natural Gas Used During Natural Gas Life Cycle. (All units in million cubic feet) (4).

Flared Gas	98,000
Lease Fuel	760,000
Pipeline and Distribution Use	665,000
Plant Fuel	365,000

In 1993 the Natural Gas STAR program was established by the EPA to reduce methane emissions from the natural gas industry. The program is a voluntary partnership with the goal of encouraging industries to adopt practices that increase efficiency and reduce emissions. Since 1993, 338 billion cubic feet of methane have been eliminated. In 2003, 52,900 million cubic feet of methane emissions were eliminated, a 9% reduction over projected emissions for that year without improved practices (9). This data was used to develop a range of emission factors for the North American natural gas industry. Figure 2 shows the total range of emission factors for the North American natural gas lifecycle. It can be seen that total lifecycle emission for natural gas produced in North America are approximately 140 lbs CO_2/MMBTU, an amount dominated by combustion emissions for natural gas plants currently in operation in the US of an average 120 lbs CO_2/MMBTU (10)

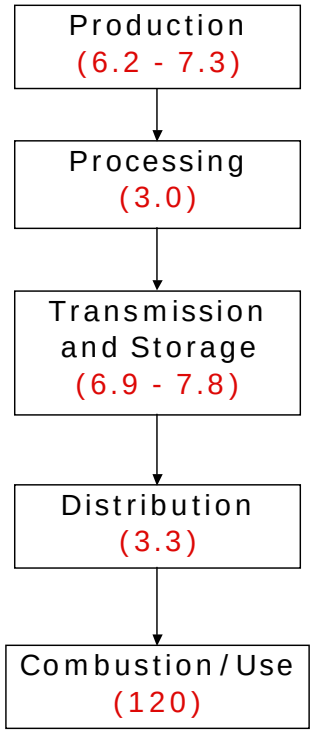

Figure 2: Carbon Dioxide Equivalent Emission Factors from North American Gas Lifecycle (All Units in lbs CO_2/MMBTU).

Greenhouse gas emissions from LNG lifecycle

As shown in Figure 1, the addition of liquefied natural gas (LNG) into the North American gas system introduces three additional stages into the lifecycle of natural gas: liquefaction, tanker transport, and regasification. It is assumed that natural gas produced in other countries and imported to the US in the form of LNG produces the same emissions in the production, processing, transmission, and distribution stages of the lifecycle as if the natural gas were produced in North America. Additional emission factors needed to be developed for the three additional lifecycle stages of LNG. Tamura et-al (11) has reported emission factors for the liquefaction stage in the range of 1.32 to 3,67 gr-C/MJ. Using these results, the emission factors for liquefaction were found in units of pounds of CO_2 per million BTUs, as shown in Table 4.

Table 4: Liquefaction Emission Factors.

Liquefaction	Emission Factors (lb CO_2/MMBTU)		
	Min	Average	Max
CO_2 from fuel combustion	11	12	13
CO_2 from flare combustion	0.00	0.77	1.5
CH_4 from vent	0.09	1.3	9.8
CO_2 in raw gas	0.09	4.0	6.6

Emissions from tanker transport of LNG were calculated using Equation 1.

$$EmissionFactor = \frac{(EF)\sum_{x}\left[\left(2 \times roundup\left(\frac{LNG_x}{TC}\right)\right) \times \frac{D_x}{TS} \times FC \times \frac{1}{24}\right]}{LNG_T}$$

Equation 1: Tanker Emission Factor.

Where EF is the tanker emission factor of 3,200 kg CO_2/ ton of fuel consumed; 2 is the number of trips each tanker does for every load (one bringing the LNG and one going back empty); LNG_x is the amount of natural gas (in cubic feet) brought from each country; TC is the tanker capacity in cubic feet of natural gas, assumed to be 120,000 cubic meters of LNG (1 m^3 LNG = 21,537 ft^3 NG); Dx is the distance from each country to US LNG facilities; TS is the tanker speed of 14 Knots; FC is a fuel consumption of 41 tons of fuel per day; and 24 is hours per day (12).

Exporting countries, their distances to the LNG facilities at Lake Charles, LA and Everett, MA, and the 2003 US imports can be seen in Table 5.

Table 5: LNG Exporting Countries in 2003 (4).

Exporting Country	Distance to Lake Charles Facility (nautical miles)	Distance to Everett, MA Facility (nautical miles)	2003 US Imports (million cubic feet NG)
Algeria	5,000	3,300	53,000
Australia	12,000	11,000	0
Brunei	12,000	11,000	0
Indonesia	12,000	11,000	0
Malaysia	12,000	11,000	2,700
Nigeria	6,100	5,000	50,000
Oman	8,900	7,500	8,600
Qatar	9,700	8,000	14,000
Trinidad	2,200	2,000	380,000
UAE	9,600	7,959	0
Russia	9,600	11,000	0

Emission factors for tanker transport from each country to both US facilities can be seen in Figure 3.

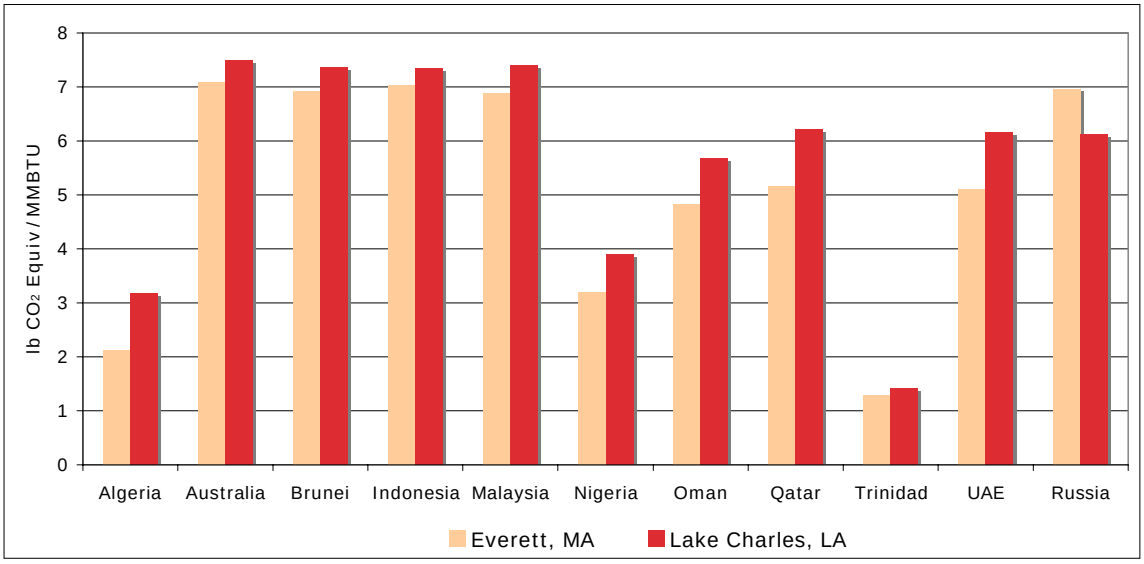

Figure 3: Tanker Emission Factors from Each Country

Since most of the LNG in 2003 was brought from Trinidad, the weighted average emission factor calculated for trips from each country to the Everett, MA facility is considered to be the a lower bound. An upper bound was obtained by assuming that all LNG was brought from Indonesia to the Lake Charles facility, and an average was obtained assuming all LNG was brought from Oman to the Lake Charles, LA facility. These resulting numbers can be seen in Table 6.

Table 6: Tanker Transport Emission Factors.

Emission Factors (lb CO_2/MMBTU)	
Min	1.8
Average	5.7
Max	7.3

Regasification emissions were reported by Tamura et-al to be 0.1 gr C/ MJ (0.85 lb CO_2/MMBTU) (11). Ruether et-al reports an emission factor of 1.6 gr CO_2/MJ (3.75 lb CO_2/MMBTU) for this stage of the LNG lifecycle by assuming that 3% of the gas is used to run the regasification equipment (13). These values were used as the lower and upper bounds of the range of emission from regasification of LNG. Total LNG lifecycle emissions are shown in Figure 4. They range between 154 and 184 lbs CO_2/MMBTU

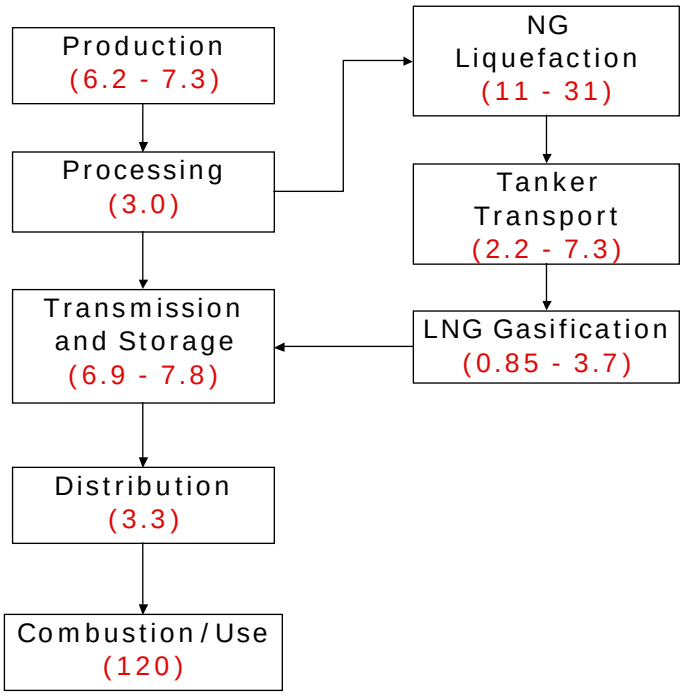

Figure 4: LNG Lifecycle Emission Factors (All Units in lbs CO_2/MMBTU).

Coal Lifecycle and its Greenhouse Gas Emissions for Electricity Generation

The coal lifecycle is conceptually simpler than the natural gas lifecycle, consisting of only three steps, as shown in Figure 5.

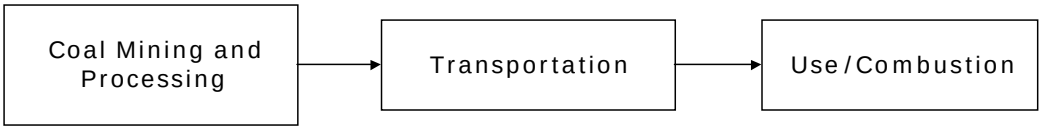

Figure 5: Coal Lifecycle.

In the US, 67% of the coal produced is mined in surface mines, while the remaining 33% is extracted from underground mines (1). Mined coal is then processed to remove impurities. Coal is then transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (14). Emissions from these lifecycle steps were calculated using the EIO-LCA tool developed at Carnegie Mellon University. In order to use this tool, economic values for each step of the lifecycle were necessary. In 1997, the year for which the EIO-LCA tool has data, the price of coal was $18.14/ton (15). Moreover, the cost for rail transport, barge, and truck transport was $11.06/ton, $3.2/ton, and $5.47/ton respectively (14). For a million tons of coal the following emission information was obtained using EIO-LCA.

Table 7: EIO-LCA Emission Data for Coal Lifecycle (16).

Sector	Total GHG Emissions (MT CO_2 Equiv)
Mining	75,000
Rail Transportation	36,000
Water Transportation	3,700
Truck Transportation	5,000

Using a weighted average US coal heat content of 10,266 BTU/lb (17) and the data previously discussed, it was found that the average emission factor for coal mining and transport is 11 lb CO_2/MMBTU.

In 1999, the National Renewable Energy Lab published a report on lifecycle emissions for power generation from coal (18). Upstream coal emissions (including transportation) from underground mines are reported to be 15 lbs CO_2/MMBTU, while upstream coal emissions from surface mines is 9.9 lbs CO_2/MMBTU. As previously mentioned, 67% of coal is currently mines in surface mines, while 33% is mined in underground mines (1). Using this information, the current coal upstream emissions average 12 lbs CO_2/MMBTU, which is very close to the emission factor obtained using EIO-LCA. In the future, the distribution of US mines could change, affecting the average emission factor. For this reason, the range of coal upstream emissions from underground and surface mines described above is used for this paper. Moreover, the average emission factors for coal combustion at utility plants used is 205 lb CO_2/MMBTU (10).

Comparing Natural Gas and Coal Lifecycle Emissions

Emissions factors for the natural gas lifecycle and the coal lifecycle were previously reported in pounds of CO_2 per MMBTU of fuel. Coal and natural gas power plants have

different efficiencies; thus one million BTU of coal does not generate the same amount of electricity as one million BTU of natural gas. For this reason, emission factors must be converted to units of pounds of CO_2 per kWh of electricity generated. This conversion was done using the heat rates of natural gas and coal plants. Figure 6 shows the distribution of these heat rates, and Figure 7 shows the resulting emission factor distribution for coal and natural gas. These distributions were obtained using the cumulative distribution function of EIA electricity generation data for all utility plants in 2003 (7). The minimum value represents the heat rate at which 5% of the electricity generated with the specific fuel is seen. Similarly the mean and maximum values are the heat rates at which 50% and 95% of the electricity has been generated with each fuel. As seen in Figure 6, the average heat rate for natural gas plants is lower than the average heat rate for coal plants, however the upper range of heat rates for natural gas plants surpasses the heat rates for coal plants.

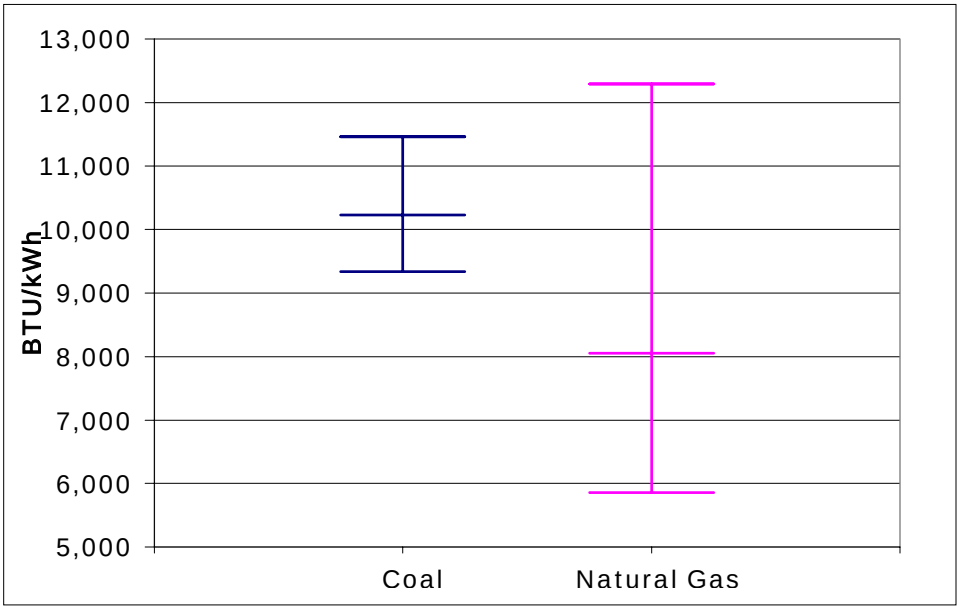

Figure 6: Natural Gas and Coal Plant Heat Rates (7).

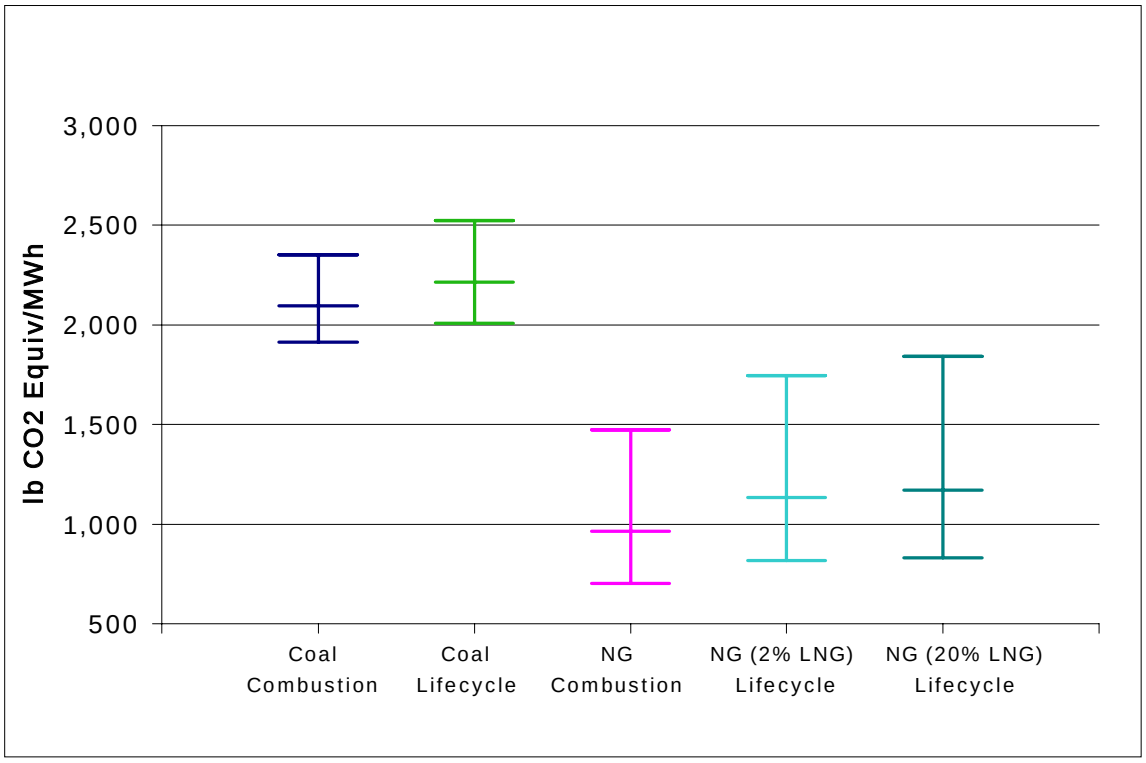

Figure 7: Emission Factors for Coal and Natural Gas Lifecycles.

Note that the average emission factor for coal combustion is higher than the emission factor for natural gas combustion. This does not change too much when the whole lifecycle is considered. More important seems to be the effect that including upstream emissions have in the range of emission factors for natural gas. While the average emission factor for the total coal lifecycle only increases by 5% compared to combustion emissions, the average emission factor for a natural gas mix with 20% LNG is 21% higher than the combustion emissions. Moreover, the maximum emission factor of the natural gas lifecycle gets closer to the minimum coal lifecycle emission factor. These results imply that if emissions at the combustion stage of the lifecycle could be controlled, natural gas would not be a much better alternative to coal in terms of greenhouse gas emissions.

New Generation Capacity

According to the DOE, by 2025 43 GW of inefficient gas and oil fired facilities will be retired, while 281 GW of new capacity will be installed (3). IGGC and NGCC power plants will probably be installed. These plants are generally more efficient than current technologies (average HHV Efficiencies are 37.5% and 50.2% respectively) (19) and thus have lower carbon emissions at the combustion stage. In addition, carbon capture and sequestration (CCS) can be performed more easily with these newer technologies. CCS is a process by which carbon emissions at the power plant are separated from other combustion products, captured and injected into underground geologic formations such as saline formations and depleted oil/gas fields. Experts believe that 90% CCS will be

technologically and economically feasible in the future. Having CCS at IGCC and NGCC plants decreases the efficiency of the plants to average HHV efficiencies of 32.4% and 42.8% respectively (19) but overall lifecycle emissions would be greatly reduced and would be essentially the same for coal and natural gas (with 20% LNG). However, the major contributor for coal emissions would be at the combustion stage, while for natural gas the majority of the emissions would come from upstream processes. Figure 8, shows total emissions with CCS for IGCC and NGCC plants using average upstream emission factors of 11.6 lbs CO_2 Equiv/MMBTU and 25.6 lbs CO_2 Equiv/MMBTU for coal and natural gas respectively

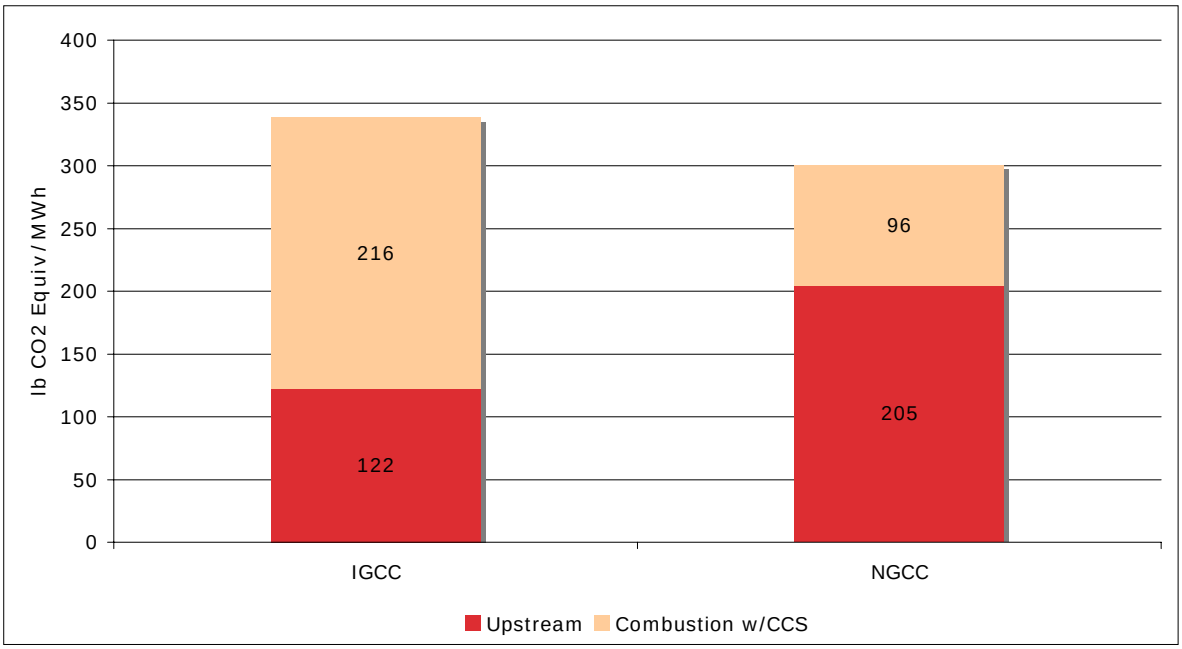

Figure 8: Lifecycle Emission Factors for IGCC and NGCC plants w/ CCS.

Discussion

It has been shown that there is high uncertainty about overall lifecycle carbon emissions for coal and LNG. In the future, as newer generation technologies and CCS are installed, overall emissions from electricity generated with coal and electricity generated with natural gas could be surprisingly similar. There is push right now from power generator to increase import of LNG. They seem to hope that the price of natural gas will decrease with these imports and they will be able to recover the investment they made in natural gas plants that are currently producing under capacity. These investments should be considered sunk costs and it is important to revaluate whether investing billions of dollars in LNG infrastructure will lead us into an energy path that cannot be easily changed as it will be harder to consider these investments as sunk costs once the expected environmental benefits are not achieved.

The analysis presented here only includes carbon emission, and no consideration was given to issues like energy security. Increasingly, LNG will come from areas of the world that are politically unstable. Policymakers should evaluate this increased dependence on foreign fuel before making decisions about future energy investments. In addition, the analysis presented only considers the use of natural gas for electricity generation. Natural gas is an indispensable fuel for many sectors of the US economy. As demand for natural gas from the electric utilities increases, these other sectors will probably be affected by higher natural gas prices. It is important to analyze whether these other sectors constitute a better use for natural gas than electricity generation, which has alternative fuels at its disposal.

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INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990 – 2009

APRIL 15, 2011

U.S. Environmental Protection Agency
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All data tables of this document are available for the full time series 1990 through 2009, inclusive, at the internet site mentioned above.

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For more information regarding climate change and greenhouse gas emissions, see the EPA web site at <http://www.epa.gov/climatechange>.

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Within the EPA, other Offices also contributed data, analysis, and technical review for this report. The Office of Transportation and Air Quality and the Office of Air Quality Planning and Standards provided analysis and review for several of the source categories addressed in this report. The Office of Solid Waste and the Office of Research and Development also contributed analysis and research.

The Energy Information Administration and the Department of Energy contributed invaluable data and analysis on numerous energy-related topics. The U.S. Forest Service prepared the forest carbon inventory, and the Department of Agriculture's Agricultural Research Service and the Natural Resource Ecology Laboratory at Colorado State University contributed leading research on nitrous oxide and carbon fluxes from soils.

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Preface

The United States Environmental Protection Agency (EPA) prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks to comply with existing commitments under the United Nations Framework Convention on Climate Change (UNFCCC). Under decision 3/CP.5 of the UNFCCC Conference of the Parties, national inventories for UNFCCC Annex I parties should be provided to the UNFCCC Secretariat each year by April 15.

In an effort to engage the public and researchers across the country, the EPA has instituted an annual public review and comment process for this document. The availability of the draft document is announced via Federal Register Notice and is posted on the EPA web site. Copies are also mailed upon request. The public comment period is generally limited to 30 days; however, comments received after the closure of the public comment period are accepted and considered for the next edition of this annual report.

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Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic[1] sources and sinks of greenhouse gases is essential for addressing climate change. This inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change.

In 1992, the United States signed and ratified the UNFCCC. As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[2]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[3] The United States views this report as an opportunity to fulfill these commitments.

This chapter summarizes the latest information on U.S. anthropogenic greenhouse gas emission trends from 1990 through 2009. To ensure that the U.S. emissions inventory is comparable to those of other UNFCCC Parties, the estimates presented here were calculated using methodologies consistent with those recommended in the Revised 1996 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), and the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003). Additionally, the U.S. emission inventory has continued to incorporate new methodologies and data from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The structure of this report is consistent with the UNFCCC guidelines for inventory reporting.[4] For most source categories, the IPCC methodologies were expanded, resulting in a more comprehensive and detailed estimate of emissions.

[BEGIN BOX]

Box ES-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[5] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[6] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports

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[1] The term "anthropogenic", in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[2] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>.

[3] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

[4] See < http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

[5] See < http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[6] See < http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>.

are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

[END BOX]

Background Information

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in their national greenhouse gas emission inventories.[7] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas emission inventories.

There are also several gases that do not have a direct global warming effect but indirectly affect terrestrial and/or solar radiation absorption by influencing the formation or destruction of greenhouse gases, including tropospheric and stratospheric ozone. These gases include carbon monoxide (CO), oxides of nitrogen (NO_x), and non-CH_4 volatile organic compounds (NMVOCs). Aerosols, which are extremely small particles or liquid droplets, such as those produced by sulfur dioxide (SO_2) or elemental carbon emissions, can also affect the absorptive characteristics of the atmosphere.

Although the direct greenhouse gases CO_2, CH_4, and N_2O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2005, concentrations of these greenhouse gases have increased globally by 36, 148, and 18 percent, respectively (IPCC 2007).

Beginning in the 1950s, the use of CFCs and other stratospheric ozone depleting substances (ODS) increased by nearly 10 percent per year until the mid-1980s, when international concern about ozone depletion led to the entry into force of the Montreal Protocol. Since then, the production of ODS is being phased out. In recent years, use of ODS substitutes such as HFCs and PFCs has grown as they begin to be phased in as replacements for CFCs and HCFCs. Accordingly, atmospheric concentrations of these substitutes have been growing (IPCC 2007).

Global Warming Potentials

Gases in the atmosphere can contribute to the greenhouse effect both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the earth (e.g., affect cloud formation or albedo).[8] The IPCC developed the Global Warming Potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas.

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[7] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in the annexes of the Inventory report for informational purposes.

[8] Albedo is a measure of the Earth's reflectivity, and is defined as the fraction of the total solar radiation incident on a body that is reflected by it.

The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO_2, and therefore GWP-weighted emissions are measured in teragrams (or million metric tons) of CO_2 equivalent (Tg CO_2 Eq.).[9,10] All gases in this Executive Summary are presented in units of Tg CO_2 Eq.

The UNFCCC reporting guidelines for national inventories were updated in 2006,[11] but continue to require the use of GWPs from the IPCC Second Assessment Report (SAR) (IPCC 1996). This requirement ensures that current estimates of aggregate greenhouse gas emissions for 1990 to 2009 are consistent with estimates developed prior to the publication of the IPCC Third Assessment Report (TAR) (IPCC 2001) and the IPCC Fourth Assessment Report (AR4) (IPCC 2007). Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. All estimates are provided throughout the report in both CO_2 equivalents and unweighted units. A comparison of emission values using the SAR GWPs versus the TAR and AR4 GWPs can be found in Chapter 1 and, in more detail, in Annex 6.1 of this report. The GWP values used in this report are listed below in Table ES-1.

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report

Gas	GWP
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

Source: IPCC (1996)

* The CH_4 GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Global warming potentials are not provided for CO, NO_x, NMVOCs, SO_2, and aerosols because there is no agreed-upon method to estimate the contribution of gases that are short-lived in the atmosphere, spatially variable, or have only indirect effects on radiative forcing (IPCC 1996).

Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2009, total U.S. greenhouse gas emissions were 6,633.2 Tg or million metric tons CO_2 Eq. While total U.S. emissions have increased by 7.3 percent from 1990 to 2009, emissions decreased from 2008 to 2009 by 6.1 percent (427.9 Tg CO_2 Eq.). This decrease was primarily due to (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; and (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly. Since 1990, U.S. emissions have increased at an average annual rate of 0.4 percent.

[9] Carbon comprises 12/44^{ths} of carbon dioxide by weight.

[10] One teragram is equal to 10^{12} grams or one million metric tons.

[11] See <http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

Figure ES-1 through Figure ES-3 illustrate the overall trends in total U.S. emissions by gas, annual changes, and absolute change since 1990. Table ES-2 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2009.

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg CO_2 Eq. or million metric tons CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**5,099.7**	**5,975.0**	**6,113.8**	**6,021.1**	**6,120.0**	**5,921.4**	**5,505.2**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Cropland Remaining Cropland	7.1	7.5	7.9	7.9	8.2	8.7	7.8
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Wetlands Remaining Wetlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
Land Use, Land-Use	*(861.5)*	*(576.6)*	*(1,056.5)*	*(1,064.3)*	*(1,060.9)*	*(1,040.5)*	*(1,015.1)*

Change, and Forestry (Sink)[a]							
Biomass - Wood[b]	*215.2*	*218.1*	*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
International Bunker Fuels[c]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
Biomass - Ethanol[b]	*4.2*	*9.4*	*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**674.9**	**659.9**	**631.4**	**672.1**	**664.6**	**676.7**	**686.3**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Forest Land Remaining Forest Land	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**315.2**	**341.0**	**322.9**	**326.4**	**325.1**	**310.8**	**295.6**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Forest Land Remaining Forest Land	2.7	12.1	8.4	18.0	16.7	10.1	6.7
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Settlements Remaining Settlements	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
HFCs	**36.9**	**103.2**	**120.2**	**123.5**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[d]	0.3	74.3	104.2	109.4	112.3	115.5	120.0

HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Parentheses indicate negative values or sequestration. The net CO_2 flux total includes both emissions and sequestration, and constitutes a net sink in the United States. Sinks are only included in net emissions total.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2009. The primary greenhouse gas emitted by human activities in the United States was CO_2, representing approximately 83.0 percent of total greenhouse gas emissions. The largest source of CO_2, and of overall greenhouse gas emissions, was fossil fuel combustion. CH_4 emissions, which have increased by 1.7 percent since 1990, resulted primarily from natural gas systems, enteric fermentation associated with domestic livestock, and decomposition of wastes in landfills. Agricultural soil management and mobile source fuel combustion were the major sources of N_2O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate HFC emissions. PFC emissions resulted as a by-product of primary aluminum production and from semiconductor manufacturing, while electrical transmission and distribution systems accounted for most SF_6 emissions.

Figure ES-4: 2009 Greenhouse Gas Emissions by Gas (percents based on Tg CO_2 Eq.)

Overall, from 1990 to 2009, total emissions of CO_2 and CH_4 increased by 405.5 Tg CO_2 Eq. (8.0 percent) and 11.4 Tg CO_2 Eq. (1.7 percent), respectively. Conversely, N_2O emissions decreased by 19.6 Tg CO_2 Eq. (6.2 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 54.1 Tg CO_2 Eq. (58.8 percent). From 1990 to 2009, HFCs increased by 88.8 Tg CO_2 Eq. (240.41 percent), PFCs decreased by 15.1 Tg CO_2 Eq. (73.0 percent), and SF_6 decreased by 19.5 Tg CO_2 Eq. (56.8 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon sequestration in forests, trees in urban areas, agricultural soils, and landfilled yard trimmings and food scraps, which, in aggregate, offset 15.3 percent of total emissions in 2009. The following sections describe each gas' contribution to total U.S. greenhouse gas emissions in more detail.

Carbon Dioxide Emissions

The global carbon cycle is made up of large carbon flows and reservoirs. Billions of tons of carbon in the form of CO_2 are absorbed by oceans and living biomass (i.e., sinks) and are emitted to the atmosphere annually through natural processes (i.e., sources). When in equilibrium, carbon fluxes among these various reservoirs are roughly

balanced. Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO_2 have risen about 36 percent (IPCC 2007), principally due to the combustion of fossil fuels. Within the United States, fossil fuel combustion accounted for 94.6 percent of CO_2 emissions in 2009. Globally, approximately 30,313 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[12] Changes in land use and forestry practices can also emit CO_2 (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO_2 (e.g., through net additions to forest biomass). In addition to fossil-fuel combustion, several other sources emit significant quantities of CO_2. These sources include, but are not limited to non-energy use of fuels, iron and steel production and cement production (Figure ES-5).

Figure ES-5: 2009 Sources of CO_2 Emissions

As the largest source of U.S. greenhouse gas emissions, CO_2 from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2009. Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 0.4 percent from 1990 to 2009. The fundamental factors influencing this trend include (1) a generally growing domestic economy over the last 20 years, and (2) overall growth in emissions from electricity generation and transportation activities. Between 1990 and 2009, CO_2 emissions from fossil fuel combustion increased from 4,738.4 Tg CO_2 Eq. to 5,209.0 Tg CO_2 Eq.—a 9.9 percent total increase over the twenty-year period. From 2008 to 2009, these emissions decreased by 356.9 Tg CO_2 Eq. (6.4 percent), the largest decrease in any year over the twenty-year period.

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. In the short term, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants. In the long term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Figure ES-6: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure ES-7: 2009 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

The five major fuel consuming sectors contributing to CO_2 emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. CO_2 emissions are produced by the electricity generation sector as they consume fossil fuel to provide electricity to one of the other four sectors, or "end-use" sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector on the basis of each sector's share of aggregate electricity consumption. This method of distributing emissions assumes that each end-use sector consumes electricity that is generated from the national average mix of fuels according to their carbon intensity. Emissions from electricity generation are also addressed separately after the end-use sectors have been discussed.

[12] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010a).

Note that emissions from U.S. territories are calculated separately due to a lack of specific consumption data for the individual end-use sectors.

Figure ES-6, Figure ES-7, and Table ES-3 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table ES-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (Tg or million metric tons CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Electricity	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Industrial	**1,533.2**	**1,640.8**	**1,560.0**	**1,560.2**	**1,572.0**	**1,517.7**	**1,333.7**
Combustion	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Electricity	686.7	789.8	737.0	712.0	730.0	714.8	603.3
Residential	**931.4**	**1,133.1**	**1,214.7**	**1,152.4**	**1,198.5**	**1,182.2**	**1,123.8**
Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Electricity	593.0	762.4	856.7	830.8	856.1	834.0	784.6
Commercial	**757.0**	**972.1**	**1,027.2**	**1,007.6**	**1,041.1**	**1,031.6**	**985.7**
Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0
Electricity	538.0	741.3	803.7	799.0	821.7	807.4	761.7
U.S. Territories[a]	**27.9**	**35.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**
Electricity Generation	**1,820.8**	**2,296.9**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

[a] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report.

Transportation End-Use Sector. Transportation activities (excluding international bunker fuels) accounted for 33 percent of CO_2 emissions from fossil fuel combustion in 2009.[13] Virtually all of the energy consumed in this end-use sector came from petroleum products. Nearly 65 percent of the emissions resulted from gasoline consumption for personal vehicle use. The remaining emissions came from other transportation activities, including the combustion of diesel fuel in heavy-duty vehicles and jet fuel in aircraft. From 1990 to 2009, transportation emissions rose by 16 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

Industrial End-Use Sector. Industrial CO_2 emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 26 percent of CO_2 from fossil fuel combustion in 2009. Approximately 55 percent of these emissions resulted from direct fossil fuel combustion to produce steam and/or heat for industrial processes. The remaining emissions resulted from consuming electricity for motors, electric furnaces, ovens, lighting, and other applications. In contrast to the other end-use sectors, emissions from industry have steadily declined since 1990. This decline is due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements.

Residential and Commercial End-Use Sectors. The residential and commercial end-use sectors accounted for 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion in 2009. Both sectors relied heavily on electricity for meeting energy demands, with 70 and 77 percent, respectively, of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were due to the consumption of natural gas and petroleum for heating and cooking. Emissions from these end-use sectors have increased 25 percent since 1990, due to increasing electricity consumption for lighting, heating, air

[13] If emissions from international bunker fuels are included, the transportation end-use sector accounted for 35 percent of U.S. emissions from fossil fuel combustion in 2009.

conditioning, and operating appliances.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 36 percent of U.S. energy from fossil fuels and emitted 41 percent of the CO_2 from fossil fuel combustion in 2009. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated with low CO_2 emitting energy technologies, particularly non-fossil options such as nuclear, hydroelectric, or geothermal energy. However, electricity generators rely on coal for over half of their total energy requirements and accounted for 95 percent of all coal consumed for energy in the United States in 2009. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions.

Other significant CO_2 trends included the following:

- CO_2 emissions from non-energy use of fossil fuels have increased 4.7 Tg CO_2 Eq. (4.0 percent) from 1990 through 2009. Emissions from non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq. in 2009, which constituted 2.2 percent of total national CO_2 emissions, approximately the same proportion as in 1990.
- CO_2 emissions from iron and steel production and metallurgical coke production decreased by 24.1 Tg CO_2 Eq. (36.6 percent) from 2008 to 2009, continuing a trend of decreasing emissions from 1990 through 2009 of 57.9 percent (57.7 Tg CO_2 Eq.). This decline is due to the restructuring of the industry, technological improvements, and increased scrap utilization.
- In 2009, CO_2 emissions from cement production decreased by 11.5 Tg CO_2 Eq. (28.4 percent) from 2008. After decreasing in 1991 by two percent from 1990 levels, cement production emissions grew every year through 2006; emissions decreased in the last three years. Overall, from 1990 to 2009, emissions from cement production decreased by 12.8 percent, a decrease of 4.3 Tg CO_2 Eq.
- Net CO_2 uptake from Land Use, Land-Use Change, and Forestry increased by 153.5 Tg CO_2 Eq. (17.8 percent) from 1990 through 2009. This increase was primarily due to an increase in the rate of net carbon accumulation in forest carbon stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Methane Emissions

Methane (CH_4) is more than 20 times as effective as CO_2 at trapping heat in the atmosphere (IPCC 1996). Over the last two hundred and fifty years, the concentration of CH_4 in the atmosphere increased by 148 percent (IPCC 2007). Anthropogenic sources of CH_4 include natural gas and petroleum systems, , agricultural activities, landfills, coal mining, wastewater treatment, stationary and mobile combustion, and certain industrial processes (see Figure ES-8).

Figure ES-8: 2009 Sources of CH_4 Emissions

Some significant trends in U.S. emissions of CH_4 include the following:

- In 2009, CH_4 emissions from coal mining were 71.0 Tg CO_2 Eq., a 3.9 Tg CO_2 Eq. (5.8 percent) increase over 2008 emission levels. The overall decline of 13.0 Tg CO_2 Eq. (15.5 percent) from 1990 results from the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- Natural gas systems were the largest anthropogenic source category of CH_4 emissions in the United States in 2009 with 221.2 Tg CO_2 Eq. of CH_4 emitted into the atmosphere. Those emissions have increased by 31.4 Tg CO_2 Eq. (16.6 percent) since 1990. Methane emissions from this source increased 4 percent from 2008 to 2009 due to an increase in production and production wells.
- Enteric Fermentation is the second largest anthropogenic source of CH_4 emissions in the United States. In 2009, enteric fermentation CH_4 emissions were 139.8 Tg CO_2 Eq. (20 percent of total CH_4 emissions), which represents an increase of 7.7 Tg CO_2 Eq. (5.8 percent) since 1990.

- Methane emissions from manure management increased by 55.9 percent since 1990, from 31.7 Tg CO_2 Eq. in 1990 to 49.5 Tg CO_2 Eq. in 2009. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions. The increase in liquid systems is the combined result of a shift to larger facilities, and to facilities in the West and Southwest, all of which tend to use liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site.
- Landfills are the third largest anthropogenic source of CH_4 emissions in the United States, accounting for 17 percent of total CH_4 emissions (117.5 Tg CO_2 Eq.) in 2009. From 1990 to 2009, CH_4 emissions from landfills decreased by 29.9 Tg CO_2 Eq. (20 percent), with small increases occurring in some interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas collected and combusted,[14] which has more than offset the additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

Nitrous Oxide Emissions

N_2O is produced by biological processes that occur in soil and water and by a variety of anthropogenic activities in the agricultural, energy-related, industrial, and waste management fields. While total N_2O emissions are much lower than CO_2 emissions, N_2O is approximately 300 times more powerful than CO_2 at trapping heat in the atmosphere (IPCC 1996). Since 1750, the global atmospheric concentration of N_2O has risen by approximately 18 percent (IPCC 2007). The main anthropogenic activities producing N_2O in the United States are agricultural soil management, fuel combustion in motor vehicles, manure management, nitric acid production and stationary fuel combustion, (see Figure ES-9).

Figure ES-9: 2009 Sources of N_2O Emissions

Some significant trends in U.S. emissions of N_2O include the following:

- In 2009, N_2O emissions from mobile combustion were 23.9 Tg CO_2 Eq. (approximately 8.1 percent of U.S. N_2O emissions). From 1990 to 2009, N_2O emissions from mobile combustion decreased by 45.6 percent. However, from 1990 to 1998 emissions increased by 25.6 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to an overall decline in N_2O from this source.
- N_2O emissions from adipic acid production were 1.9 Tg CO_2 Eq. in 2009, and have decreased significantly since 1996 from the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 87.7 percent since 1990, and emissions from adipic acid production have remained consistently lower than pre-1996 levels since 1998.
- Agricultural soils accounted for approximately 69.2 percent of N_2O emissions in the United States in 2009. Estimated emissions from this source in 2009 were 204.6 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3.4 percent higher in 2009 than in 1990.

HFC, PFC, and SF_6 Emissions

HFCs and PFCs are families of synthetic chemicals that are used as alternatives to ODS, which are being phased out under the Montreal Protocol and Clean Air Act Amendments of 1990. HFCs and PFCs do not deplete the stratospheric ozone layer, and are therefore acceptable alternatives under the Montreal Protocol.

These compounds, however, along with SF_6, are potent greenhouse gases. In addition to having high global warming potentials, SF_6 and PFCs have extremely long atmospheric lifetimes, resulting in their essentially irreversible accumulation in the atmosphere once emitted. Sulfur hexafluoride is the most potent greenhouse gas the

[14] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

IPCC has evaluated (IPCC 1996).

Other emissive sources of these gases include electrical transmission and distribution systems, HCFC-22 production, semiconductor manufacturing, aluminum production, and magnesium production and processing (see Figure ES-10).

Figure ES-10: 2009 Sources of HFCs, PFCs, and SF_6 Emissions

Some significant trends in U.S. HFC, PFC, and SF_6 emissions include the following:

- Emissions resulting from the substitution of ODS (e.g., CFCs) have been consistently increasing, from small amounts in 1990 to 120.0 Tg CO_2 Eq. in 2009. Emissions from ODS substitutes are both the largest and the fastest growing source of HFC, PFC, and SF_6 emissions. These emissions have been increasing as phase-outs required under the Montreal Protocol come into effect, especially after 1994, when full market penetration was made for the first generation of new technologies featuring ODS substitutes.
- HFC emissions from the production of HCFC-22 decreased by 85.2 percent (31.0 Tg CO_2 Eq.) from 1990 through 2009, due to a steady decline in the emission rate of HFC-23 (i.e., the amount of HFC-23 emitted per kilogram of HCFC-22 manufactured) and the use of thermal oxidation at some plants to reduce HFC-23 emissions.
- SF_6 emissions from electric power transmission and distribution systems decreased by 54.8 percent (15.6 Tg CO_2 Eq.) from 1990 to 2009, primarily because of higher purchase prices for SF_6 and efforts by industry to reduce emissions.
- PFC emissions from aluminum production decreased by 91.5 percent (17.0 Tg CO_2 Eq.) from 1990 to 2009, due to both industry emission reduction efforts and lower domestic aluminum production.

Overview of Sector Emissions and Trends

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2003 UNFCCC Guidelines on Reporting and Review (UNFCCC 2003), Figure ES-11 and Table ES-4 aggregate emissions and sinks by these chapters. Emissions of all gases can be summed from each source category from IPCC guidance. Over the twenty-year period of 1990 to 2009, total emissions in the Energy and Agriculture sectors grew by 463.3 Tg CO_2 Eq. (9 percent), and 35.7 Tg CO_2 Eq. (9 percent), respectively. Emissions decreased in the Industrial Processes, Waste, and Solvent and Other Product Use sectors by 32.9 Tg CO_2 Eq. (10 percent), 24.7 Tg CO_2 Eq. (14 percent) and less than 0.1 Tg CO_2 Eq. (0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry sector (magnitude of emissions plus CO_2 flux from all LULUCF source categories) increased by 143.5 Tg CO_2 Eq. (17 percent).

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg or million metric tons CO_2 Eq.)

Chapter/IPCC Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Energy	5,287.8	6,168.0	6,282.8	6,210.2	6,290.7	6,116.6	5,751.1
Industrial Processes	315.8	348.8	334.1	339.4	350.9	331.7	282.9
Solvent and Other Product Use	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Agriculture	383.6	410.6	418.8	418.8	425.8	426.3	419.3
Land Use, Land-Use Change, and Forestry (Emissions)	15.0	36.3	28.6	49.8	47.5	33.2	25.0
Waste	175.2	143.9	144.9	144.4	144.1	149.0	150.5
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net CO_2 Flux from Land Use, Land-	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

Use Change, and Forestry (Sinks)*							
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

* The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total.
Note: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Energy

The Energy chapter contains emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions. Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2009. In 2009, approximately 83 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 17 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure ES-12). Energy-related activities are also responsible for CH_4 and N_2O emissions (49 percent and 13 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 87 percent of total U.S. greenhouse gas emissions in 2009.

Figure ES-12: 2009 U.S. Energy Consumption by Energy Source

Industrial Processes

The Industrial Processes chapter contains by-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production. Additionally, emissions from industrial processes release HFCs, PFCs, and SF_6. Overall, emission sources in the Industrial Process chapter account for 4 percent of U.S. greenhouse gas emissions in 2009.

Solvent and Other Product Use

The Solvent and Other Product Use chapter contains greenhouse gas emissions that are produced as a by-product of various solvent and other product uses. In the United States, emissions from N_2O from product uses, the only source of greenhouse gas emissions from this sector, accounted for about 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a carbon equivalent basis in 2009.

Agriculture

The Agricultural chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO_2 fluxes, which are addressed in the Land Use, Land-Use Change, and Forestry Chapter). Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented 20 percent and 7 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2009. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions in 2009, accounting for 69 percent. In 2009, emission sources accounted for in the Agricultural chapters were responsible for 6.3 percent of total U.S. greenhouse gas emissions.

Land Use, Land-Use Change, and Forestry

The Land Use, Land-Use Change, and Forestry chapter contains emissions of CH_4 and N_2O, and emissions and removals of CO_2 from forest management, other land-use activities, and land-use change. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps resulted in a net uptake (sequestration) of C in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 85 percent of total 2009 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2009. The net forest sequestration is a result of net forest growth and increasing forest area, as well as a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth in these areas. In agricultural soils, mineral and organic soils sequester approximately 5.5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to permanent pastures and hay production, a reduction in summer fallow areas in semi-arid areas, an increase in the adoption of conservation tillage practices, and an increase in the amounts of organic fertilizers (i.e., manure and sewage sludge) applied to agriculture lands. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO_2 Eq. (Table ES-5). This represents an offset of 18 percent of total U.S. CO_2 emissions, or 15 percent of total greenhouse gas emissions in 2009. Between 1990 and 2009, total land use, land-use change, and forestry net C flux resulted in a 17.8 percent increase in CO_2 sequestration, primarily due to an increase in the rate of net C accumulation in forest C stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual C accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of annual C accumulation increased in urban trees.

Table ES-5: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Sink Category	1990	2000	2005	2006	2007	2008	2009
Forest Land Remaining Forest Land[1]	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements[2]	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table ES-6. The application of crushed limestone and dolomite to managed land (i.e., liming of agricultural soils) and urea fertilization resulted in CO_2 emissions of 7.8 Tg CO_2 Eq. in 2009, an increase of 11 percent relative to 1990. The application of synthetic fertilizers to forest and settlement soils in 2009 resulted in direct N_2O emissions of 1.9 Tg CO_2 Eq. Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils increased by 55 percent since 1990. Forest fires resulted in CH_4 emissions of 7.8 Tg CO_2 Eq., and in N_2O emissions of 6.4 Tg CO_2 Eq. in 2009. CO_2 and N_2O emissions from peatlands totaled 1.1 Tg CO_2 Eq. and less than 0.01 Tg CO_2 Eq. in 2009, respectively.

Table ES-6: Emissions from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Source Category	1990	2000	2005	2006	2007	2008	2009
CO_2	**8.1**	**8.8**	**8.9**	**8.8**	**9.2**	**9.6**	**8.9**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Cropland Remaining Cropland: Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6

Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH_4	**3.2**	**14.3**	**9.8**	**21.6**	**20.0**	**11.9**	**7.8**
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N_2O	**3.7**	**13.2**	**9.8**	**19.5**	**18.3**	**11.6**	**8.3**
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**15.0**	**36.3**	**28.6**	**49.8**	**47.5**	**33.2**	**25.0**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Waste

The Waste chapter contains emissions from waste management activities (except incineration of waste, which is addressed in the Energy chapter). Landfills were the largest source of anthropogenic greenhouse gas emissions in the Waste chapter, accounting for just over 78 percent of this chapter's emissions, and 17 percent of total U.S. CH_4 emissions.[15] Additionally, wastewater treatment accounts for 20 percent of Waste emissions, 4 percent of U.S. CH_4 emissions, and 2 percent of U.S. N_2O emissions. Emissions of CH_4 and N_2O from composting are also accounted for in this chapter; generating emissions of 1.7 Tg CO_2 Eq. and 1.8 Tg CO_2 Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 2.3 percent of total U.S. greenhouse gas emissions in 2009.

Other Information

Emissions by Economic Sector

Throughout the Inventory of U.S. Greenhouse Gas Emissions and Sinks report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes; Solvent Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following economic sectors: Residential, Commercial, Industry, Transportation, Electricity Generation, Agriculture, and U.S. Territories.

Table ES-7 summarizes emissions from each of these sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2009.

Figure ES-13: Emissions Allocated to Economic Sectors

Table ES-7: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg or million metric tons CO_2 Eq.)

Implied Sectors	1990	2000	2005	2006	2007	2008	2009
Electric Power Industry	1,868.9	2,337.6	2,444.6	2,388.2	2,454.0	2,400.7	2,193.0
Transportation	1,545.2	1,932.3	2,017.4	1,994.4	2,003.8	1,890.7	1,812.4
Industry	1,564.4	1,544.0	1,441.9	1,497.3	1,483.0	1,446.9	1,322.7
Agriculture	429.0	485.1	493.2	516.7	520.7	503.9	490.0
Commercial	395.5	381.4	387.2	375.2	389.6	403.5	409.5
Residential	345.1	386.2	371.0	335.8	358.9	367.1	360.1
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5

[15] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land-Use, Land-Use Change, and Forestry chapter of the Inventory report.

Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Land Use, Land-Use Change, and Forestry (Sinks)	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

Note: Totals may not sum due to independent rounding. Emissions include CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.
See Table 2-12 for more detailed data.

Using this categorization, emissions from electricity generation accounted for the largest portion (33 percent) of U.S. greenhouse gas emissions in 2009. Transportation activities, in aggregate, accounted for the second largest portion (27 percent), while emissions from industry accounted for the third largest portion (20 percent) of U.S. greenhouse gas emissions in 2009. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and energy efficiency improvements. The remaining 20 percent of U.S. greenhouse gas emissions were contributed by, in order of importance, the agriculture, commercial, and residential sectors, plus emissions from U.S. territories. Activities related to agriculture accounted for 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation. The commercial sector accounted for 6 percent of emissions while the residential sector accounted for 5 percent of emissions and U.S. territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO_2 emissions from fossil fuel combustion.

CO_2 was also emitted and sequestered by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Electricity is ultimately consumed in the economic sectors described above. Table ES-8 presents greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). To distribute electricity emissions among end-use sectors, emissions from the source categories assigned to electricity generation were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity.[16] These source categories include CO_2 from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO_2 and N_2O from incineration of waste, CH_4 and N_2O from stationary sources, and SF_6 from electrical transmission and distribution systems.

When emissions from electricity are distributed among these sectors, Industrial activities account for the largest share of U.S. greenhouse gas emissions (29 percent) in 2009. Transportation is the second largest contributor to total U.S. emissions (28 percent). The commercial and residential sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2009. Emissions from these sectors increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption (e.g., lighting, appliances, etc.). In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels. Figure ES-14 shows the trend in these emissions by sector from 1990 to 2009.

Table ES-8: U.S Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed (Tg or million metric tons CO_2 Eq.)

Implied Sectors	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Industry	2,238.3	2,314.4	2,162.5	2,194.6	2,192.9	2,146.5	1,910.9
Transportation	1,548.3	1,935.8	2,022.2	1,999.0	2,008.9	1,895.5	1,816.9
Commercial	947.7	1,135.8	1,205.1	1,188.5	1,225.3	1,224.5	1,184.9
Residential	953.8	1,162.2	1,242.9	1,181.5	1,229.6	1,215.1	1,158.9
Agriculture	460.0	518.4	522.7	544.1	553.2	531.1	516.0
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Land Use, Land-Use Change,	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

[16] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

and Forestry (Sinks)							
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

See Table 2-14 for more detailed data.

Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

[BEGIN BOX]

Box ES-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and nonutilities combined—was the largest source of U.S. greenhouse gas emissions in 2009; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-9 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.4 percent since 1990. This rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Figure ES-15).

Table ES-9: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**	**Growth Rate[a]**
GDP[b]	100	140	157	162	165	165	160	2.5%
Electricity Consumption[c]	100	127	134	135	138	138	132	1.5%
Fossil Fuel Consumption[c]	100	117	119	117	119	116	108	0.5%
Energy Consumption[c]	100	116	118	118	120	118	112	0.6%
Population[d]	100	113	118	120	121	122	123	1.1%
Greenhouse Gas Emissions[e]	100	115	117	116	117	114	107	0.4%

[a] Average annual growth rate
[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)
[c] Energy content-weighted values (EIA 2010b)
[d] U.S. Census Bureau (2010)
[e] GWP-weighted values

Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product
Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

Indirect Greenhouse Gases (CO, NO_x, NMVOCs, and SO_2)

The reporting requirements of the UNFCCC[17] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2010, EPA 2009),[18] which are regulated under the Clean Air Act. Table ES- 10 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table ES- 10: Emissions of NO_x, CO, NMVOCs, and SO_2 (Gg)

Gas/Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	**21,707**	**19,116**	**15,900**	**15,039**	**14,380**	**13,547**	**11,468**
Mobile Fossil Fuel Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Fossil Fuel Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Industrial Processes	591	626	569	553	537	520	568
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
Agricultural Burning	8	8	6	7	8	8	8
Solvent Use	1	3	3	4	4	4	3
Waste	0	2	2	2	2	2	2
CO	**130,038**	**92,243**	**70,809**	**67,238**	**63,625**	**60,039**	**51,452**
Mobile Fossil Fuel Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Fossil Fuel Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543
Industrial Processes	4,125	2,216	1,555	1,597	1,640	1,682	1,549
Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Agricultural Burning	268	259	184	233	237	270	247
Oil and Gas Activities	302	146	318	319	320	322	345
Waste	1	8	7	7	7	7	7
Solvent Use	5	45	2	2	2	2	2
NMVOCs	**20,930**	**15,227**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**
Mobile Fossil Fuel Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Solvent Use	5,216	4,384	3,851	3,846	3,839	3,834	2,583
Industrial Processes	2,422	1,773	1,997	1,933	1,869	1,804	1,322
Stationary Fossil Fuel Combustion	912	1,077	716	918	1,120	1,321	424
Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
Waste	673	119	114	113	111	109	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**14,830**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**
Stationary Fossil Fuel Combustion	18,407	12,849	11,541	10,612	10,172	8,891	7,167
Industrial Processes	1,307	1,031	831	818	807	795	798
Mobile Fossil Fuel Combustion	793	632	889	750	611	472	455
Oil and Gas Activities	390	287	181	182	184	187	154
Incineration of Waste	38	29	24	24	24	23	24
Waste	0	1	1	1	1	1	1
Solvent Use	0	1	0	0	0	0	0

[17] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

[18] NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2008).

Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.

Key Categories

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) defines a key category as a "[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both."[19] By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends of individual source and sink categories. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses.

Figure ES-16 presents 2009 emission estimates for the key categories as defined by a level analysis (i.e., the contribution of each source or sink category to the total inventory level). The UNFCCC reporting guidelines request that key category analyses be reported at an appropriate level of disaggregation, which may lead to source and sink category names which differ from those used elsewhere in the inventory report. For more information regarding key categories, see section 1.5 and Annex 1.

Figure ES-16: 2009 Key Categories

Quality Assurance and Quality Control (QA/QC)

The United States seeks to continually improve the quality, transparency, and credibility of the Inventory of U.S. Greenhouse Gas Emissions and Sinks. To assist in these efforts, the United States implemented a systematic approach to QA/QC. While QA/QC has always been an integral part of the U.S. national system for inventory development, the procedures followed for the current inventory have been formalized in accordance with the QA/QC plan and the UNFCCC reporting guidelines.

Uncertainty Analysis of Emission Estimates

While the current U.S. emissions inventory provides a solid foundation for the development of a more detailed and comprehensive national inventory, there are uncertainties associated with the emission estimates. Some of the current estimates, such as those for CO_2 emissions from energy-related activities and cement processing, are considered to have low uncertainties. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty associated with the estimates presented. Acquiring a better understanding of the uncertainty associated with inventory estimates is an important step in helping to prioritize future work and improve the overall quality of the Inventory. Recognizing the benefit of conducting an uncertainty analysis, the UNFCCC reporting guidelines follow the recommendations of the IPCC Good Practice Guidance (IPCC 2000) and require that countries provide single estimates of uncertainty for source and sink categories.

Currently, a qualitative discussion of uncertainty is presented for all source and sink categories. Within the discussion of each emission source, specific factors affecting the uncertainty surrounding the estimates are discussed. Most sources also contain a quantitative uncertainty assessment, in accordance with UNFCCC reporting guidelines.

[19] See Chapter 7 "Methodological Choice and Recalculation" in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

[BEGIN BOX]

Box ES-3: Recalculations of Inventory Estimates

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, "Both methodological changes and refinements over time are an essential part of improving inventory quality. It is good practice to change or refine methods" when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors." In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data.

In each Inventory report, the results of all methodology changes and historical data updates are presented in the "Recalculations and Improvements" chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. In general, when methodological changes have been implemented, the entire time series (in the case of the most recent inventory report, 1990 through 2009) has been recalculated to reflect the change, per the 2006 IPCC Guidelines (IPCC 2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies. References for the data are provided for additional information.

[END BOX]

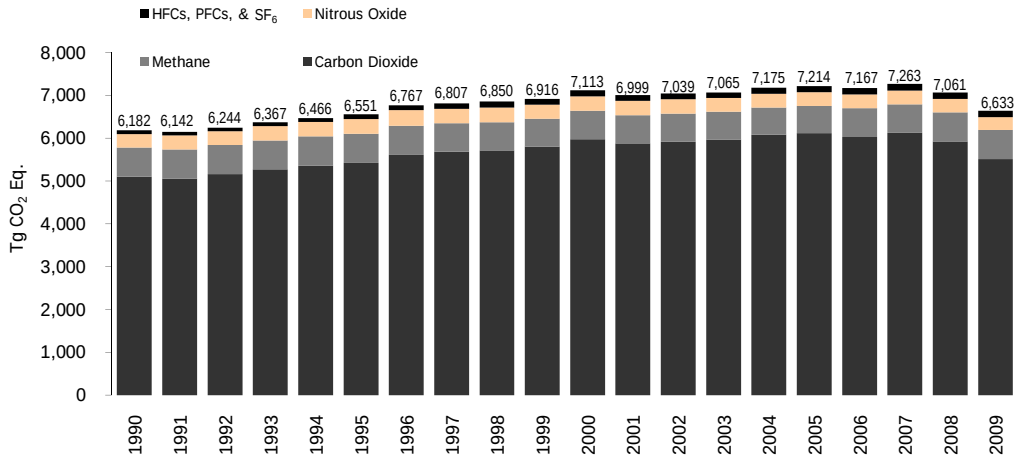


Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

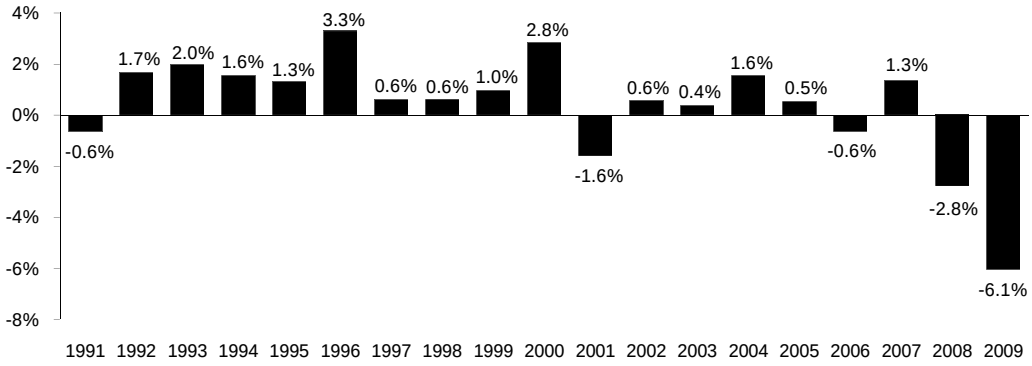


Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

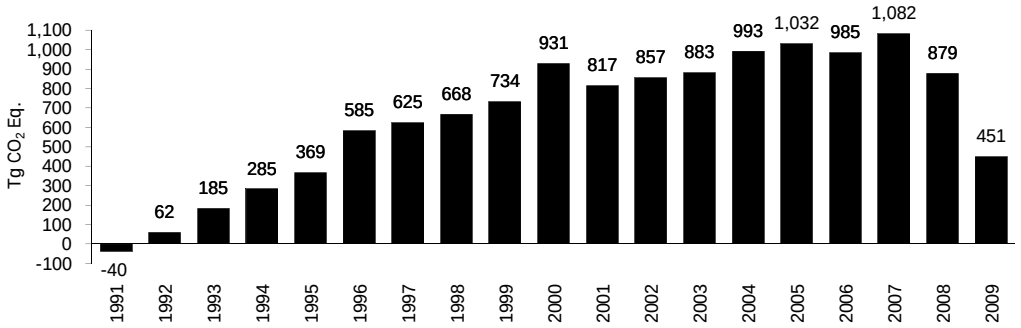


Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

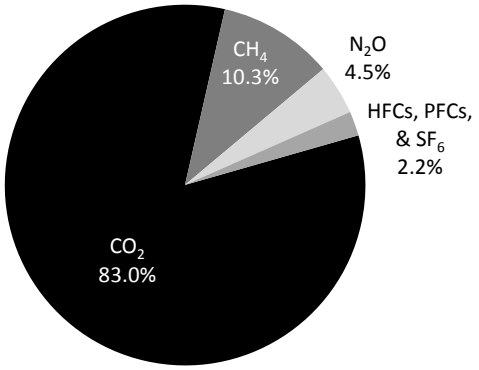


Figure ES-4: 2009 Greenhouse Gas Emissions by Gas (percents based on Tg CO_2 Eq.)

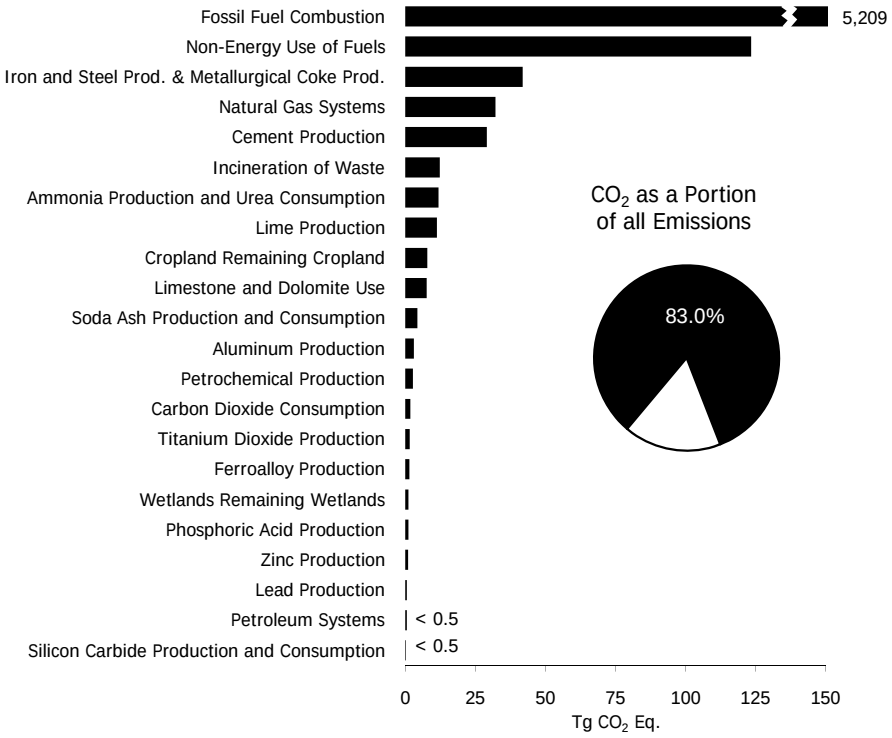


Figure ES-5: 2009 Sources of CO_2 Emissions

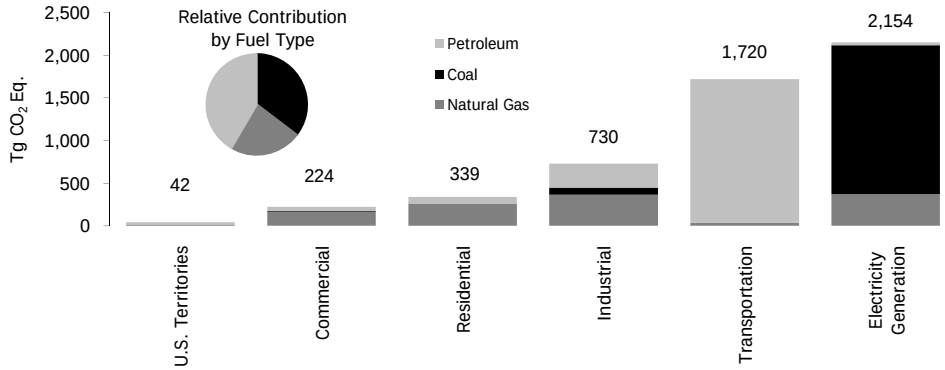


Figure ES-6: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

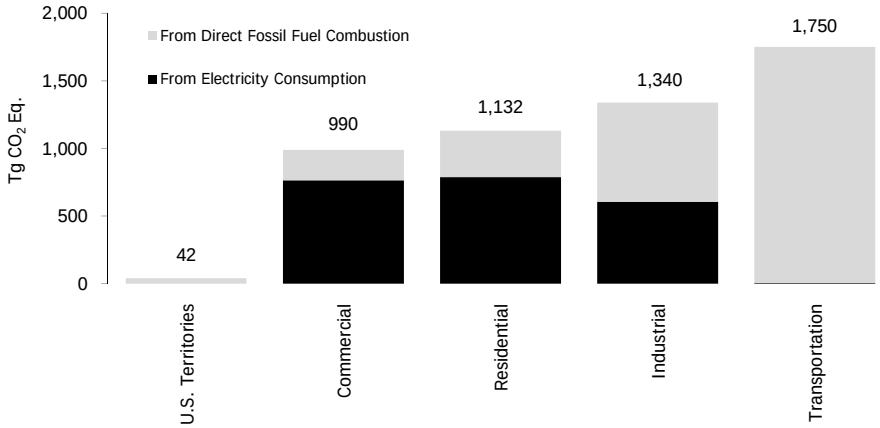


Figure ES-7: 2009 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

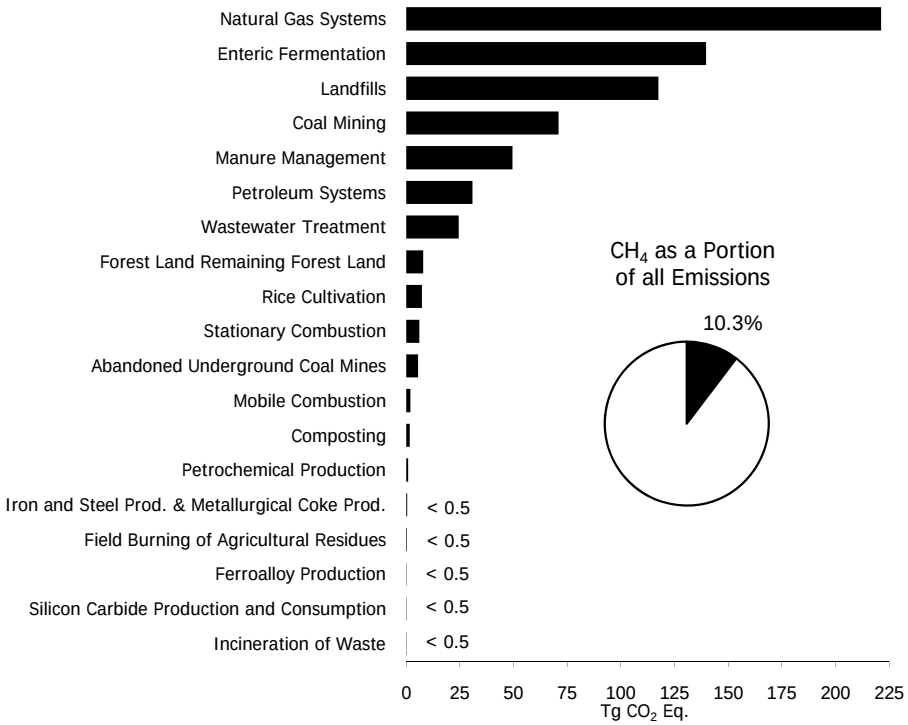


Figure ES-8: 2009 Sources of CH_4 Emissions

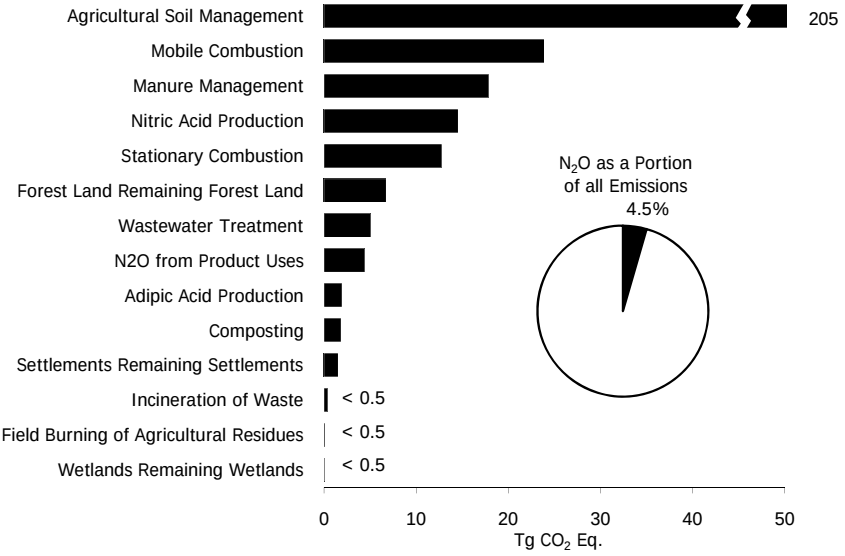


Figure ES-9: 2009 Sources of N_2O Emissions

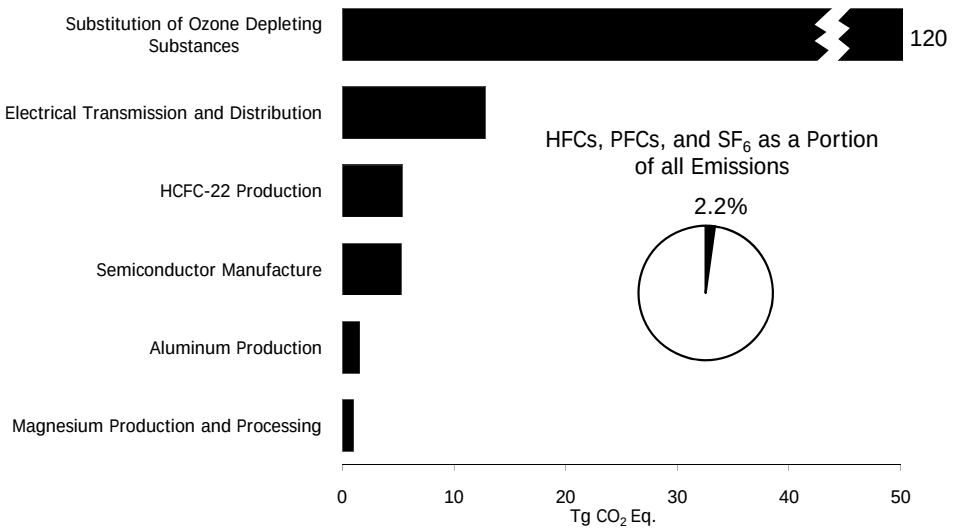
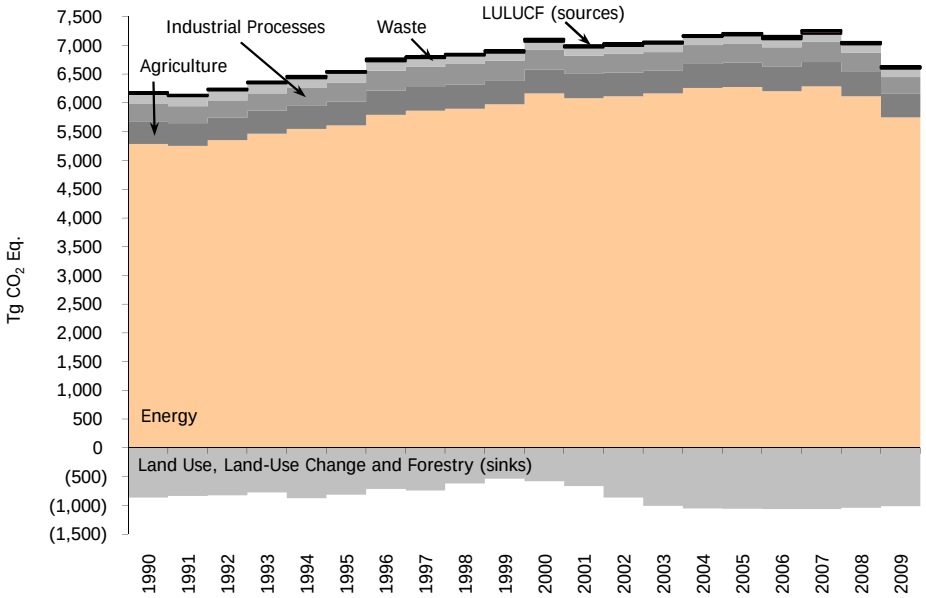


Figure ES-10: 2009 Sources of HFCs, PFCs, and SF_6 Emissions



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sectors

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

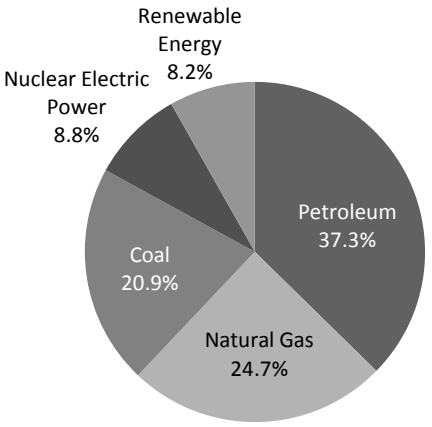


Figure ES-12: 2009 U.S. Energy Consumption by Energy Source

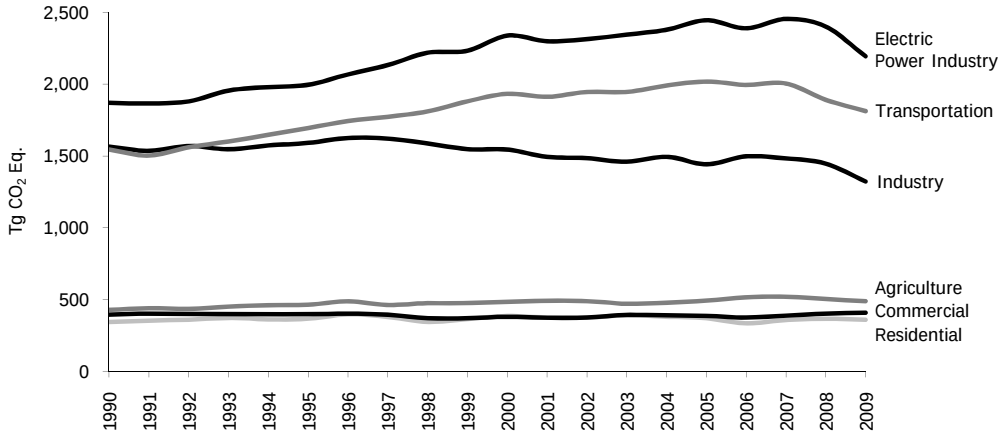


Figure ES-13: Emissions Allocated to Economic Sectors
Note: Does not include U.S. Territories.

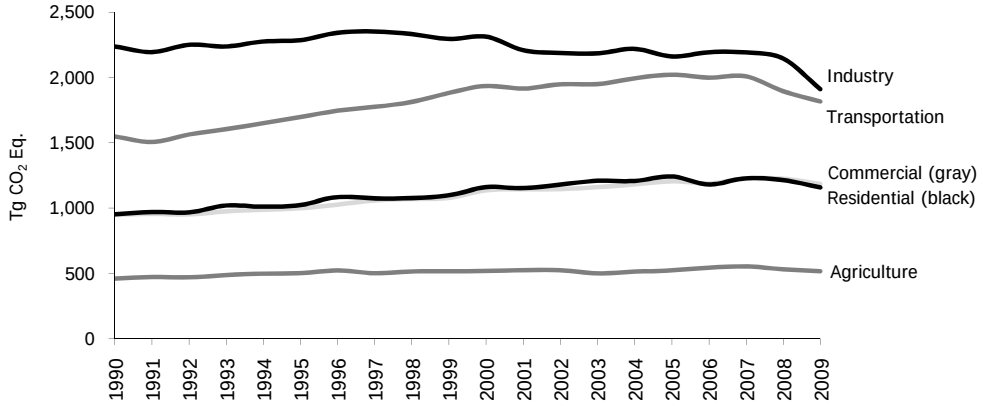


Figure ES-14: Emissions with Electricity Distributed to Economic Sectors
Note: Does not include U.S. Territories.

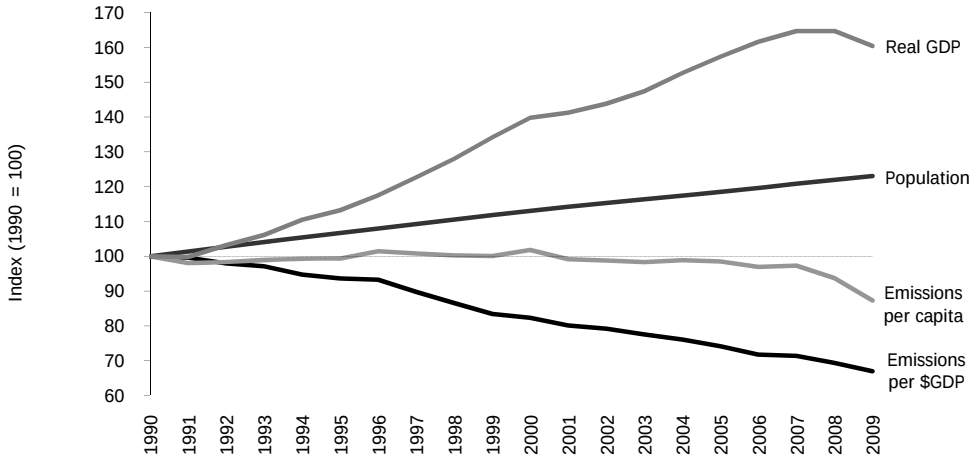


Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

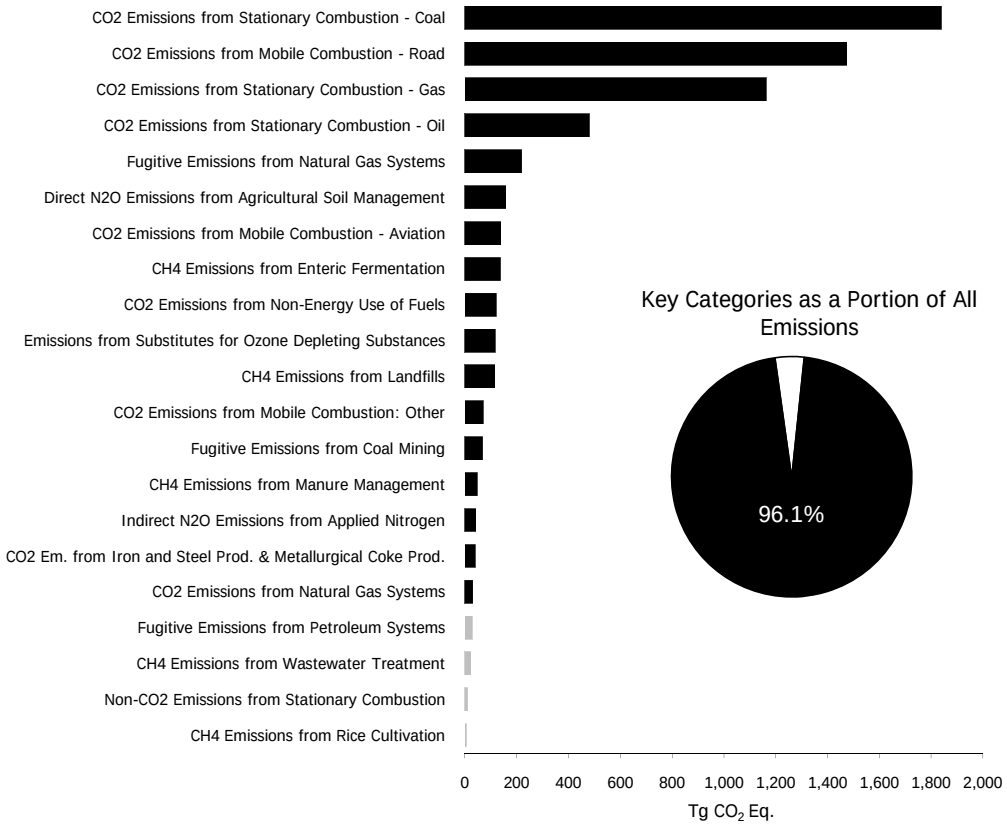


Figure ES-16: 2009 Key Categories

Notes: For a complete discussion of the key category analysis, see Annex 1.
Black bars indicate a Tier 1 level assessment key category.
Gray bars indicate a Tier 2 level assessment key category.

1. Introduction

This report presents estimates by the United States government of U.S. anthropogenic greenhouse gas emissions and sinks for the years 1990 through 2009. A summary of these estimates is provided in Table 2.1 and Table 2.2 by gas and source category in the Trends in Greenhouse Gas Emissions chapter. The emission estimates in these tables are presented on both a full molecular mass basis and on a Global Warming Potential (GWP) weighted basis in order to show the relative contribution of each gas to global average radiative forcing.[20] This report also discusses the methods and data used to calculate these emission estimates.

In 1992, the United States signed and ratified the United Nations Framework Convention on Climate Change (UNFCCC). As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[21,22]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[23] The United States views this report as an opportunity to fulfill these commitments under the UNFCCC.

In 1988, preceding the creation of the UNFCCC, the World Meteorological Organization (WMO) and the United Nations Environment Programme (UNEP) jointly established the Intergovernmental Panel on Climate Change (IPCC). The role of the IPCC is to assess on a comprehensive, objective, open and transparent basis the scientific, technical and socio-economic information relevant to understanding the scientific basis of risk of human-induced climate change, its potential impacts and options for adaptation and mitigation (IPCC 2003). Under Working Group 1 of the IPCC, nearly 140 scientists and national experts from more than thirty countries collaborated in the creation of the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997) to ensure that the emission inventories submitted to the UNFCCC are consistent and comparable between nations. The IPCC accepted the Revised 1996 IPCC Guidelines at its Twelfth Session (Mexico City, September 11-13, 1996). This report presents information in accordance with these guidelines. In addition, this Inventory is in accordance with the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories and the Good Practice Guidance for Land Use, Land-Use Change, and Forestry, which further expanded upon the methodologies in the Revised 1996 IPCC Guidelines. The IPCC has also accepted the 2006 Guidelines for National Greenhouse Gas Inventories (IPCC 2006) at its Twenty-Fifth Session (Mauritius, April 2006). The 2006 IPCC Guidelines build on the previous bodies of work and includes new sources and gases "…as well as updates to the previously published methods whenever scientific and technical knowledge have improved since the previous guidelines were issued." Many of the methodological improvements presented in the 2006 Guidelines have been adopted in this Inventory.

Overall, this inventory of anthropogenic greenhouse gas emissions provides a common and consistent mechanism through which Parties to the UNFCCC can estimate emissions and compare the relative contribution of individual sources, gases, and nations to climate change. The inventory provides a national estimate of sources and sinks for the United States, including all states and U.S. territories[24] . The structure of this report is consistent with the current

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[20] See the section below entitled *Global Warming Potentials* for an explanation of GWP values.

[21] The term "anthropogenic", in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[22] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>. (UNEP/WMO 2000)

[23] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

[24] U.S. Territories include American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands.

UNFCCC Guidelines on Annual Inventories (UNFCCC 2006).

[BEGIN BOX]

Box 1-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC).[25] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[26] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

[END BOX]

1.1. Background Information

Science

For over the past 200 years, the burning of fossil fuels such as coal and oil, deforestation, and other sources have caused the concentrations of heat-trapping "greenhouse gases" to increase significantly in our atmosphere. These gases absorb some of the energy being radiated from the surface of the earth and trap it in the atmosphere, essentially acting like a blanket that makes the earth's surface warmer than it would be otherwise.

Greenhouse gases are necessary to life as we know it, because without them the planet's surface would be about 60 ºF cooler than present. But, as the concentrations of these gases continue to increase in the atmosphere, the Earth's temperature is climbing above past levels. According to NOAA and NASA data, the Earth's average surface temperature has increased by about 1.2 to 1.4 ºF since 1900. The ten warmest years on record (since 1850) have all occurred in the past 13 years (EPA 2009). Most of the warming in recent decades is very likely the result of human activities. Other aspects of the climate are also changing such as rainfall patterns, snow and ice cover, and sea level.

If greenhouse gases continue to increase, climate models predict that the average temperature at the Earth's surface could increase from 2.0 to 11.5 ºF above 1990 levels by the end of this century (IPCC 2007). Scientists are certain that human activities are changing the composition of the atmosphere, and that increasing the concentration of greenhouse gases will change the planet's climate. But they are not sure by how much it will change, at what rate it will change, or what the exact effects will be.[27]

Greenhouse Gases

Although the Earth’s atmosphere consists mainly of oxygen and nitrogen, neither plays a significant role in enhancing the greenhouse effect because both are essentially transparent to terrestrial radiation. The greenhouse effect is primarily a function of the concentration of water vapor, carbon dioxide (CO_2), and other trace gases in the

[25] See <http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[26] See <http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>

[27] For more information see <http://www.epa.gov/climatechange/science>

atmosphere that absorb the terrestrial radiation leaving the surface of the Earth (IPCC 2001). Changes in the atmospheric concentrations of these greenhouse gases can alter the balance of energy transfers between the atmosphere, space, land, and the oceans.[28] A gauge of these changes is called radiative forcing, which is a measure of the influence a factor has in altering the balance of incoming and outgoing energy in the Earth-atmosphere system (IPCC 2001). Holding everything else constant, increases in greenhouse gas concentrations in the atmosphere will produce positive radiative forcing (i.e., a net increase in the absorption of energy by the Earth).

> *Climate change can be driven by changes in the atmospheric concentrations of a number of radiatively active gases and aerosols. We have clear evidence that human activities have affected concentrations, distributions and life cycles of these gases (IPCC 1996).*

Naturally occurring greenhouse gases include water vapor, CO_2, methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in national greenhouse gas inventories.[29] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas inventories.

There are also several gases that, although they do not have a commonly agreed upon direct radiative forcing effect, do influence the global radiation budget. These tropospheric gases include carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and tropospheric (ground level) ozone O_3. Tropospheric ozone is formed by two precursor pollutants, volatile organic compounds (VOCs) and nitrogen oxides (NO_x) in the presence of ultraviolet light (sunlight). Aerosols are extremely small particles or liquid droplets that are often composed of sulfur compounds, carbonaceous combustion products, crustal materials and other human induced pollutants. They can affect the absorptive characteristics of the atmosphere. Comparatively, however, the level of scientific understanding of aerosols is still very low (IPCC 2001).

CO_2, CH_4, and N_2O are continuously emitted to and removed from the atmosphere by natural processes on Earth. Anthropogenic activities, however, can cause additional quantities of these and other greenhouse gases to be emitted or sequestered, thereby changing their global average atmospheric concentrations. Natural activities such as respiration by plants or animals and seasonal cycles of plant growth and decay are examples of processes that only cycle carbon or nitrogen between the atmosphere and organic biomass. Such processes, except when directly or indirectly perturbed out of equilibrium by anthropogenic activities, generally do not alter average atmospheric greenhouse gas concentrations over decadal timeframes. Climatic changes resulting from anthropogenic activities, however, could have positive or negative feedback effects on these natural systems. Atmospheric concentrations of these gases, along with their rates of growth and atmospheric lifetimes, are presented in Table 1-1.

Table 1-1: Global Atmospheric Concentration, Rate of Concentration Change, and Atmospheric Lifetime (years) of Selected Greenhouse Gases

Atmospheric Variable	**CO_2**	**CH_4**	**N_2O**	**SF_6**	**CF_4**
Pre-industrial atmospheric concentration	278 ppm	0.715 ppm	0.270 ppm	0 ppt	40 ppt
Atmospheric concentration	385 ppm	1.741-1.865 ppm[a]	0.321-0.322 ppm[a]	5.6 ppt	74 ppt
Rate of concentration change	1.4 ppm/yr	0.005 ppm/yr[b]	0.26%/yr	Linear[c]	Linear[c]
Atmospheric lifetime (years)	50-200[d]	12[e]	114[e]	3,200	>50,000

Source: Pre-industrial atmospheric concentrations and rate of concentration changes for all gases are from IPCC (2007). The current atmospheric concentration for CO_2 is from NOAA/ESRL (2009).

[28] For more on the science of climate change, see NRC (2001).

[29] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in this document for informational purposes.

[a] The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2006 through September 2007 (CDIAC 2009).
[b] The growth rate for atmospheric CH_4 has been decreasing from 1.4 ppb/yr in 1984 to less than 0 ppb/yr in 2001, 2004, and 2005.
[c] IPCC (2007) identifies the rate of concentration change for SF_6 and CF_4 as linear.
[d] No single lifetime can be defined for CO_2 because of the different rates of uptake by different removal processes.
[e] This lifetime has been defined as an "adjustment time" that takes into account the indirect effect of the gas on its own residence time.

A brief description of each greenhouse gas, its sources, and its role in the atmosphere is given below. The following section then explains the concept of GWPs, which are assigned to individual gases as a measure of their relative average global radiative forcing effect.

Water Vapor (H_2O). Overall, the most abundant and dominant greenhouse gas in the atmosphere is water vapor. Water vapor is neither long-lived nor well mixed in the atmosphere, varying spatially from 0 to 2 percent (IPCC 1996). In addition, atmospheric water can exist in several physical states including gaseous, liquid, and solid. Human activities are not believed to affect directly the average global concentration of water vapor, but, the radiative forcing produced by the increased concentrations of other greenhouse gases may indirectly affect the hydrologic cycle. While a warmer atmosphere has an increased water holding capacity, increased concentrations of water vapor affects the formation of clouds, which can both absorb and reflect solar and terrestrial radiation. Aircraft contrails, which consist of water vapor and other aircraft emittants, are similar to clouds in their radiative forcing effects (IPCC 1999).

Carbon Dioxide. In nature, carbon is cycled between various atmospheric, oceanic, land biotic, marine biotic, and mineral reservoirs. The largest fluxes occur between the atmosphere and terrestrial biota, and between the atmosphere and surface water of the oceans. In the atmosphere, carbon predominantly exists in its oxidized form as CO_2. Atmospheric CO_2 is part of this global carbon cycle, and therefore its fate is a complex function of geochemical and biological processes. CO_2 concentrations in the atmosphere increased from approximately 280 parts per million by volume (ppmv) in pre-industrial times to 385 ppmv in 2008, a 37.5 percent increase (IPCC 2007 and NOAA/ESRL 2009) .[30,31] The IPCC definitively states that "the present atmospheric CO_2 increase is caused by anthropogenic emissions of CO_2" (IPCC 2001). The predominant source of anthropogenic CO_2 emissions is the combustion of fossil fuels. Forest clearing, other biomass burning, and some non-energy production processes (e.g., cement production) also emit notable quantities of CO_2. In it's fourth assessment, the IPCC stated "most of the observed increase in global average temperatures since the mid-20th century is very likely due to the observed increased in anthropogenic greenhouse gas concentrations," of which CO_2 is the most important (IPCC 2007)

Methane. CH_4 is primarily produced through anaerobic decomposition of organic matter in biological systems. Agricultural processes such as wetland rice cultivation, enteric fermentation in animals, and the decomposition of animal wastes emit CH_4, as does the decomposition of municipal solid wastes. CH_4 is also emitted during the production and distribution of natural gas and petroleum, and is released as a by-product of coal mining and incomplete fossil fuel combustion. Atmospheric concentrations of CH_4 have increased by about 143 percent since 1750, from a pre-industrial value of about 722 ppb to 1,741-1,865 ppb in 2007[32], although the rate of increase has been declining. The IPCC has estimated that slightly more than half of the current CH_4 flux to the atmosphere is anthropogenic, from human activities such as agriculture, fossil fuel use, and waste disposal (IPCC 2007).

CH_4 is removed from the atmosphere through a reaction with the hydroxyl radical (OH) and is ultimately converted to CO_2. Minor removal processes also include reaction with chlorine in the marine boundary layer, a soil sink, and stratospheric reactions. Increasing emissions of CH_4 reduce the concentration of OH, a feedback that may increase the atmospheric lifetime of CH_4 (IPCC 2001).

Nitrous Oxide. Anthropogenic sources of N_2O emissions include agricultural soils, especially production of

[30] The pre-industrial period is considered as the time preceding the year 1750 (IPCC 2001).

[31] Carbon dioxide concentrations during the last 1,000 years of the pre-industrial period (i.e., 750-1750), a time of relative climate stability, fluctuated by about ±10 ppmv around 280 ppmv (IPCC 2001).

[32] The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2006 through September 2007 (CDIAC 2009)

nitrogen-fixing crops and forages, the use of synthetic and manure fertilizers, and manure deposition by livestock; fossil fuel combustion, especially from mobile combustion; adipic (nylon) and nitric acid production; wastewater treatment and waste incineration; and biomass burning. The atmospheric concentration of N_2O has increased by 18 percent since 1750, from a pre-industrial value of about 270 ppb to 321-322 ppb in 2007[33], a concentration that has not been exceeded during the last thousand years. N_2O is primarily removed from the atmosphere by the photolytic action of sunlight in the stratosphere (IPCC 2007).

Ozone. Ozone is present in both the upper stratosphere,[34] where it shields the Earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere,[35] where it is the main component of anthropogenic photochemical "smog." During the last two decades, emissions of anthropogenic chlorine and bromine-containing halocarbons, such as CFCs, have depleted stratospheric ozone concentrations. This loss of ozone in the stratosphere has resulted in negative radiative forcing, representing an indirect effect of anthropogenic emissions of chlorine and bromine compounds (IPCC 1996). The depletion of stratospheric ozone and its radiative forcing was expected to reach a maximum in about 2000 before starting to recover. As of IPCC's fourth assessment,"whether or not recently observed changes in ozone trends are already indicative of recovery of the global ozone layer is not yet clear." (IPCC 2007)

The past increase in tropospheric ozone, which is also a greenhouse gas, is estimated to provide the third largest increase in direct radiative forcing since the pre-industrial era, behind CO_2 and CH_4. Tropospheric ozone is produced from complex chemical reactions of volatile organic compounds mixing with NO_x in the presence of sunlight. The tropospheric concentrations of ozone and these other pollutants are short-lived and, therefore, spatially variable. (IPCC 2001)

Halocarbons, Perfluorocarbons, and Sulfur Hexafluoride. Halocarbons are, for the most part, man-made chemicals that have both direct and indirect radiative forcing effects. Halocarbons that contain chlorine (CFCs, HCFCs, methyl chloroform, and carbon tetrachloride) and bromine (halons, methyl bromide, and hydrobromofluorocarbons [HFCs]) result in stratospheric ozone depletion and are therefore controlled under the Montreal Protocol on Substances that Deplete the Ozone Layer. Although CFCs and HCFCs include potent global warming gases, their net radiative forcing effect on the atmosphere is reduced because they cause stratospheric ozone depletion, which itself is an important greenhouse gas in addition to shielding the Earth from harmful levels of ultraviolet radiation. Under the Montreal Protocol, the United States phased out the production and importation of halons by 1994 and of CFCs by 1996. Under the Copenhagen Amendments to the Protocol, a cap was placed on the production and importation of HCFCs by non-Article 5[36] countries beginning in 1996, and then followed by a complete phase-out by the year 2030. While ozone depleting gases covered under the Montreal Protocol and its Amendments are not covered by the UNFCCC; they are reported in this inventory under Annex 6.2 of this report for informational purposes.

HFCs, PFCs, and SF_6 are not ozone depleting substances, and therefore are not covered under the Montreal Protocol. They are, however, powerful greenhouse gases. HFCs are primarily used as replacements for ozone depleting substances but also emitted as a by-product of the HCFC-22 manufacturing process. Currently, they have a small aggregate radiative forcing impact, but it is anticipated that their contribution to overall radiative forcing will increase (IPCC 2001). PFCs and SF_6 are predominantly emitted from various industrial processes including aluminum smelting, semiconductor manufacturing, electric power transmission and distribution, and magnesium

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[33] The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2006 through September 2007 (CDIAC 2009).

[34] The stratosphere is the layer from the troposphere up to roughly 50 kilometers. In the lower regions the temperature is nearly constant but in the upper layer the temperature increases rapidly because of sunlight absorption by the ozone layer. The ozone-layer is the part of the stratosphere from 19 kilometers up to 48 kilometers where the concentration of ozone reaches up to 10 parts per million.

[35] The troposphere is the layer from the ground up to 11 kilometers near the poles and up to 16 kilometers in equatorial regions (i.e., the lowest layer of the atmosphere where people live). It contains roughly 80 percent of the mass of all gases in the atmosphere and is the site for most weather processes, including most of the water vapor and clouds.

[36] Article 5 of the Montreal Protocol covers several groups of countries, especially developing countries, with low consumption rates of ozone depleting substances. Developing countries with per capita consumption of less than 0.3 kg of certain ozone depleting substances (weighted by their ozone depleting potential) receive financial assistance and a grace period of ten additional years in the phase-out of ozone depleting substances.

casting. Currently, the radiative forcing impact of PFCs and SF_6 is also small, but they have a significant growth rate, extremely long atmospheric lifetimes, and are strong absorbers of infrared radiation, and therefore have the potential to influence climate far into the future (IPCC 2001).

Carbon Monoxide. Carbon monoxide has an indirect radiative forcing effect by elevating concentrations of CH_4 and tropospheric ozone through chemical reactions with other atmospheric constituents (e.g., the hydroxyl radical, OH) that would otherwise assist in destroying CH_4 and tropospheric ozone. Carbon monoxide is created when carbon-containing fuels are burned incompletely. Through natural processes in the atmosphere, it is eventually oxidized to CO_2. Carbon monoxide concentrations are both short-lived in the atmosphere and spatially variable.

Nitrogen Oxides. The primary climate change effects of nitrogen oxides (i.e., NO and NO_2) are indirect and result from their role in promoting the formation of ozone in the troposphere and, to a lesser degree, lower stratosphere, where it has positive radiative forcing effects.[37] Additionally, NO_x emissions from aircraft are also likely to decrease CH_4 concentrations, thus having a negative radiative forcing effect (IPCC 1999). Nitrogen oxides are created from lightning, soil microbial activity, biomass burning (both natural and anthropogenic fires) fuel combustion, and, in the stratosphere, from the photo-degradation of N_2O. Concentrations of NO_x are both relatively short-lived in the atmosphere and spatially variable.

Nonmethane Volatile Organic Compounds (NMVOCs). Non-CH_4 volatile organic compounds include substances such as propane, butane, and ethane. These compounds participate, along with NO_x, in the formation of tropospheric ozone and other photochemical oxidants. NMVOCs are emitted primarily from transportation and industrial processes, as well as biomass burning and non-industrial consumption of organic solvents. Concentrations of NMVOCs tend to be both short-lived in the atmosphere and spatially variable.

Aerosols. Aerosols are extremely small particles or liquid droplets found in the atmosphere. They can be produced by natural events such as dust storms and volcanic activity, or by anthropogenic processes such as fuel combustion and biomass burning. Aerosols affect radiative forcing differently than greenhouse gases, and their radiative effects occur through direct and indirect mechanisms: directly by scattering and absorbing solar radiation; and indirectly by increasing droplet counts that modify the formation, precipitation efficiency, and radiative properties of clouds. Aerosols are removed from the atmosphere relatively rapidly by precipitation. Because aerosols generally have short atmospheric lifetimes, and have concentrations and compositions that vary regionally, spatially, and temporally, their contributions to radiative forcing are difficult to quantify (IPCC 2001).

The indirect radiative forcing from aerosols is typically divided into two effects. The first effect involves decreased droplet size and increased droplet concentration resulting from an increase in airborne aerosols. The second effect involves an increase in the water content and lifetime of clouds due to the effect of reduced droplet size on precipitation efficiency (IPCC 2001). Recent research has placed a greater focus on the second indirect radiative forcing effect of aerosols.

Various categories of aerosols exist, including naturally produced aerosols such as soil dust, sea salt, biogenic aerosols, sulfates, and volcanic aerosols, and anthropogenically manufactured aerosols such as industrial dust and carbonaceous[38] aerosols (e.g., black carbon, organic carbon) from transportation, coal combustion, cement manufacturing, waste incineration, and biomass burning.

The net effect of aerosols on radiative forcing is believed to be negative (i.e., net cooling effect on the climate), although because they remain in the atmosphere for only days to weeks, their concentrations respond rapidly to changes in emissions.[39] Locally, the negative radiative forcing effects of aerosols can offset the positive forcing of greenhouse gases (IPCC 1996). "However, the aerosol effects do not cancel the global-scale effects of the much longer-lived greenhouse gases, and significant climate changes can still result" (IPCC 1996).

The IPCC's Third Assessment Report notes that "the indirect radiative effect of aerosols is now understood to also

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[37] NO_x emissions injected higher in the stratosphere, primarily from fuel combustion emissions from high altitude supersonic aircraft, can lead to stratospheric ozone depletion.

[38] Carbonaceous aerosols are aerosols that are comprised mainly of organic substances and forms of black carbon (or soot) (IPCC 2001).

[39] Volcanic activity can inject significant quantities of aerosol producing sulfur dioxide and other sulfur compounds into the stratosphere, which can result in a longer negative forcing effect (i.e., a few years) (IPCC 1996).

encompass effects on ice and mixed-phase clouds, but the magnitude of any such indirect effect is not known, although it is likely to be positive" (IPCC 2001). Additionally, current research suggests that another constituent of aerosols, black carbon, has a positive radiative forcing, and that its presence "in the atmosphere above highly reflective surfaces such as snow and ice, or clouds, may cause a significant positive radiative forcing (IPCC 2007). The primary anthropogenic emission sources of black carbon include diesel exhaust and open biomass burning.

Global Warming Potentials

A global warming potential is a quantified measure of the globally averaged relative radiative forcing impacts of a particular greenhouse gas (see Table 1-2). It is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations involving the original gas produce a gas or gases that are greenhouse gases, or when a gas influences other radiatively important processes such as the atmospheric lifetimes of other gases. The reference gas used is CO_2, and therefore GWP weighted emissions are measured in teragrams of CO_2 equivalent (Tg CO_2 Eq.)[40] The relationship between gigagrams (Gg) of a gas and Tg CO_2 Eq. can be expressed as follows:

$$\text{Tg CO}_2\ \text{Eq} = (\text{Gg of gas}) \times (\text{GWP}) \times \left(\frac{\text{Tg}}{1{,}000\ \text{Gg}} \right)$$

where,

Tg CO_2 Eq. = Teragrams of CO_2 Equivalents

Gg = Gigagrams (equivalent to a thousand metric tons)

GWP = Global Warming Potential

Tg = Teragrams

GWP values allow for a comparison of the impacts of emissions and reductions of different gases. According to the IPCC, GWPs typically have an uncertainty of ±35 percent. 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.

> *Greenhouse gas emissions and removals should be presented on a gas-by-gas basis in units of mass... In addition, consistent with decision 2/CP.3, Parties should report aggregate emissions and removals of greenhouse gases, expressed in CO_2 equivalent terms at summary inventory level, using GWP values provided by the IPCC in its Second Assessment Report... based on the effects of greenhouse gases over a 100-year time horizon.*[41]

Greenhouse gases with relatively long atmospheric lifetimes (e.g., CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) tend to be evenly distributed throughout the atmosphere, and consequently global average concentrations can be determined. The short-lived gases such as water vapor, carbon monoxide, tropospheric ozone, ozone precursors (e.g., NO_x, and NMVOCs), and tropospheric aerosols (e.g., SO_2 products and carbonaceous particles), however, vary regionally, and consequently it is difficult to quantify their global radiative forcing impacts. No GWP values are attributed to these gases that are short-lived and spatially inhomogeneous in the atmosphere.

Table 1-2: Global Warming Potentials and Atmospheric Lifetimes (Years) Used in this Report

Gas	Atmospheric Lifetime	GWP[a]
CO_2	50-200	1

[40] Carbon comprises $12/44^{ths}$ of carbon dioxide by weight.

[41] Framework Convention on Climate Change; <http://unfccc.int/resource/docs/cop8/08.pdf>; 1 November 2002; Report of the Conference of the Parties at its eighth session; held at New Delhi from 23 October to 1 November 2002; Addendum; Part One: Action taken by the Conference of the Parties at its eighth session; Decision -/CP.8; Communications from Parties included in Annex I to the Convention: Guidelines for the Preparation of National Communications by Parties Included in Annex I to the Convention, Part 1: UNFCCC reporting guidelines on annual inventories; p. 7. (UNFCCC 2003)

CH4[b]	12±3	21
N_2O	120	310
HFC-23	264	11,700
HFC-32	5.6	650
HFC-125	32.6	2,800
HFC-134a	14.6	1,300
HFC-143a	48.3	3,800
HFC-152a	1.5	140
HFC-227ea	36.5	2,900
HFC-236fa	209	6,300
HFC-4310mee	17.1	1,300
CF_4	50,000	6,500
C_2F_6	10,000	9,200
C_4F_{10}	2,600	7,000
C_6F_{14}	3,200	7,400
SF_6	3,200	23,900

Source: (IPCC 1996)
[a] 100-year time horizon
[b] The GWP of CH_4 includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

[BEGIN BOX]

Box 1-2: The IPCC Fourth Assessment Report and Global Warming Potentials

In 2007, the IPCC published its Fourth Assessment Report (AR4), which provided an updated and more comprehensive scientific assessment of climate change. Within this report, the GWPs of several gases were revised relative to the SAR and the IPCC's Third Assessment Report (TAR) (IPCC 2001). Thus the GWPs used in this report have been updated twice by the IPCC; although the SAR GWPs are used throughout this report, it is interesting to review the changes to the GWPs and the impact such improved understanding has on the total GWP-weighted emissions of the United States. Since the SAR and TAR, the IPCC has applied an improved calculation of CO_2 radiative forcing and an improved CO_2 response function. The GWPs are drawn from IPCC/TEAP (2005) and the TAR, with updates for those cases where new laboratory or radiative transfer results have been published. Additionally, the atmospheric lifetimes of some gases have been recalculated. In addition, the values for radiative forcing and lifetimes have been recalculated for a variety of halocarbons, which were not presented in the SAR. Table 1-3 presents the new GWPs, relative to those presented in the SAR.

Table 1-3: Comparison of 100-Year GWPs

Gas	**SAR**	**TAR**	**AR4**	**Change from SAR**	
				TAR	**AR4**
CO_2	1	1	1	NC	0
CH_4*	21	23	25	2	4
N_2O	310	296	298	(14)	(12)
HFC-23	11,700	12,000	14,800	300	3,100
HFC-32	650	550	675	(100)	25
HFC-125	2,800	3,400	3,500	600	700
HFC-134a	1,300	1,300	1,430	NC	130
HFC-143a	3,800	4,300	4,470	500	670
HFC-152a	140	120	124	(20)	(16)
HFC-227ea	2,900	3,500	3,220	600	320
HFC-236fa	6,300	9,400	9,810	3,100	3,510
HFC-4310mee	1,300	1,500	1,640	200	340
CF_4	6,500	5,700	7,390	(800)	890
C_2F_6	9,200	11,900	12,200	2,700	3,000

C_4F_10	7,000	8,600	8,860	1,600	1,860
C6F14	7,400	9,000	9,300	1,600	1,900
SF_6	23,900	22,200	22,800	(1,700)	(1,100)

Source: (IPCC 2007, IPCC 2001)
NC (No Change)
Note: Parentheses indicate negative values.
* The GWP of CH_4 includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

To comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. The UNFCCC reporting guidelines for national inventories[42] were updated in 2002 but continue to require the use of GWPs from the SAR so that current estimates of aggregate greenhouse gas emissions for 1990 through 2009 are consistent and comparable with estimates developed prior to the publication of the TAR and AR4. For informational purposes, emission estimates that use the updated GWPs are presented in detail in Annex 6.1 of this report. All estimates provided throughout this report are also presented in unweighted units.

[END BOX]

1.2. Institutional Arrangements

The U.S. Environmental Protection Agency (EPA), in cooperation with other U.S. government agencies, prepares the Inventory of U.S. Greenhouse Gas Emissions and Sinks. A wide range of agencies and individuals are involved in supplying data to, reviewing, or preparing portions of the U.S. Inventory—including federal and state government authorities, research and academic institutions, industry associations, and private consultants.

Within EPA, the Office of Atmospheric Programs (OAP) is the lead office responsible for the emission calculations provided in the Inventory, as well as the completion of the National Inventory Report and the Common Reporting Format tables. The Office of Transportation and Air Quality (OTAQ) is also involved in calculating emissions for the Inventory. While the U.S. Department of State officially submits the annual Inventory to the UNFCCC, EPA's OAP serves as the focal point for technical questions and comments on the U.S. Inventory. The staff of OAP and OTAQ coordinates the annual methodological choice, activity data collection, and emission calculations at the individual source category level. Within OAP, an inventory coordinator compiles the entire Inventory into the proper reporting format for submission to the UNFCCC, and is responsible for the collection and consistency of cross-cutting issues in the Inventory.

Several other government agencies contribute to the collection and analysis of the underlying activity data used in the Inventory calculations. Formal relationships exist between EPA and other U.S. agencies that provide official data for use in the Inventory. The U.S. Department of Energy's Energy Information Administration provides national fuel consumption data and the U.S. Department of Defense provides military fuel consumption and bunker fuels. Informal relationships also exist with other U.S. agencies to provide activity data for use in EPA's emission calculations. These include: the U.S. Department of Agriculture, the U.S. Geological Survey, the Federal Highway Administration, the Department of Transportation, the Bureau of Transportation Statistics, the Department of Commerce, the National Agricultural Statistics Service, and the Federal Aviation Administration. Academic and research centers also provide activity data and calculations to EPA, as well as individual companies participating in voluntary outreach efforts with EPA. Finally, the U.S. Department of State officially submits the Inventory to the UNFCCC each April.

1.3. Inventory Process

EPA has a decentralized approach to preparing the annual U.S. Inventory, which consists of a National Inventory Report (NIR) and Common Reporting Format (CRF) tables. The Inventory coordinator at EPA is responsible for

[42] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

compiling all emission estimates, and ensuring consistency and quality throughout the NIR and CRF tables. Emission calculations for individual sources are the responsibility of individual source leads, who are most familiar with each source category and the unique characteristics of its emissions profile. The individual source leads determine the most appropriate methodology and collect the best activity data to use in the emission calculations, based upon their expertise in the source category, as well as coordinating with researchers and contractors familiar with the sources. A multi-stage process for collecting information from the individual source leads and producing the Inventory is undertaken annually to compile all information and data.

Methodology Development, Data Collection, and Emissions and Sink Estimation

Source leads at EPA collect input data and, as necessary, evaluate or develop the estimation methodology for the individual source categories. For most source categories, the methodology for the previous year is applied to the new "current" year of the Inventory, and inventory analysts collect any new data or update data that have changed from the previous year. If estimates for a new source category are being developed for the first time, or if the methodology is changing for an existing source category (e.g., the United States is implementing a higher Tiered approach for that source category), then the source category lead will develop a new methodology, gather the most appropriate activity data and emission factors (or in some cases direct emission measurements) for the entire time series, and conduct a special source-specific peer review process involving relevant experts from industry, government, and universities.

Once the methodology is in place and the data are collected, the individual source leads calculate emissions and sink estimates. The source leads then update or create the relevant text and accompanying annexes for the Inventory. Source leads are also responsible for completing the relevant sectoral background tables of the Common Reporting Format, conducting quality assurance and quality control (QA/QC) checks, and uncertainty analyses.

Summary Spreadsheet Compilation and Data Storage

The inventory coordinator at EPA collects the source categories' descriptive text and Annexes, and also aggregates the emission estimates into a summary spreadsheet that links the individual source category spreadsheets together. This summary sheet contains all of the essential data in one central location, in formats commonly used in the Inventory document. In addition to the data from each source category, national trend and related data are also gathered in the summary sheet for use in the Executive Summary, Introduction, and Recent Trends sections of the Inventory report. Electronic copies of each year's summary spreadsheet, which contains all the emission and sink estimates for the United States, are kept on a central server at EPA under the jurisdiction of the Inventory coordinator.

National Inventory Report Preparation

The NIR is compiled from the sections developed by each individual source lead. In addition, the inventory coordinator prepares a brief overview of each chapter that summarizes the emissions from all sources discussed in the chapters. The inventory coordinator then carries out a key category analysis for the Inventory, consistent with the IPCC Good Practice Guidance, IPCC Good Practice Guidance for Land Use, Land Use Change and Forestry, and in accordance with the reporting requirements of the UNFCCC. Also at this time, the Introduction, Executive Summary, and Recent Trends sections are drafted, to reflect the trends for the most recent year of the current Inventory. The analysis of trends necessitates gathering supplemental data, including weather and temperature conditions, economic activity and gross domestic product, population, atmospheric conditions, and the annual consumption of electricity, energy, and fossil fuels. Changes in these data are used to explain the trends observed in greenhouse gas emissions in the United States. Furthermore, specific factors that affect individual sectors are researched and discussed. Many of the factors that affect emissions are included in the Inventory document as separate analyses or side discussions in boxes within the text. Text boxes are also created to examine the data aggregated in different ways than in the remainder of the document, such as a focus on transportation activities or emissions from electricity generation. The document is prepared to match the specification of the UNFCCC reporting guidelines for National Inventory Reports.

Common Reporting Format Table Compilation

The CRF tables are compiled from individual tables completed by each individual source lead, which contain source

emissions and activity data. The inventory coordinator integrates the source data into the UNFCCC's "CRF Reporter" for the United States, assuring consistency across all sectoral tables. The summary reports for emissions, methods, and emission factors used, the overview tables for completeness and quality of estimates, the recalculation tables, the notation key completion tables, and the emission trends tables are then completed by the inventory coordinator. Internal automated quality checks on the CRF Reporter, as well as reviews by the source leads, are completed for the entire time series of CRF tables before submission.

QA/QC and Uncertainty

QA/QC and uncertainty analyses are supervised by the QA/QC and Uncertainty coordinators, who have general oversight over the implementation of the QA/QC plan and the overall uncertainty analysis for the Inventory (see sections on QA/QC and Uncertainty, below). These coordinators work closely with the source leads to ensure that a consistent QA/QC plan and uncertainty analysis is implemented across all inventory sources. The inventory QA/QC plan, detailed in a following section, is consistent with the quality assurance procedures outlined by EPA and IPCC.

Expert and Public Review Periods

During the Expert Review period, a first draft of the document is sent to a select list of technical experts outside of EPA. The purpose of the Expert Review is to encourage feedback on the methodological and data sources used in the current Inventory, especially for sources which have experienced any changes since the previous Inventory.

Once comments are received and addressed, a second draft of the document is released for public review by publishing a notice in the U.S. Federal Register and posting the document on the EPA Web site. The Public Review period allows for a 30 day comment period and is open to the entire U.S. public.

Final Submittal to UNFCCC and Document Printing

After the final revisions to incorporate any comments from the Expert Review and Public Review periods, EPA prepares the final National Inventory Report and the accompanying Common Reporting Format Reporter database. The U.S. Department of State sends the official submission of the U.S. Inventory to the UNFCCC. The document is then formatted for printing, posted online, printed by the U.S. Government Printing Office, and made available for the public.

1.4. Methodology and Data Sources

Emissions of greenhouse gases from various source and sink categories have been estimated using methodologies that are consistent with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997). In addition, the United States references the additional guidance provided in the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003), and the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). To the extent possible, the present report relies on published activity and emission factor data. Depending on the emission source category, activity data can include fuel consumption or deliveries, vehicle-miles traveled, raw material processed, etc. Emission factors are factors that relate quantities of emissions to an activity.

The IPCC methodologies provided in the Revised 1996 IPCC Guidelines represent baseline methodologies for a variety of source categories, and many of these methodologies continue to be improved and refined as new research and data become available. This report uses the IPCC methodologies when applicable, and supplements them with other available methodologies and data where possible. Choices made regarding the methodologies and data sources used are provided in conjunction with the discussion of each source category in the main body of the report. Complete documentation is provided in the annexes on the detailed methodologies and data sources utilized in the calculation of each source category.

[BEGIN BOX]

Box 1-3: IPCC Reference Approach

The UNFCCC reporting guidelines require countries to complete a "top-down" reference approach for estimating CO_2 emissions from fossil fuel combustion in addition to their "bottom-up" sectoral methodology. This estimation method uses alternative methodologies and different data sources than those contained in that section of the Energy chapter. The reference approach estimates fossil fuel consumption by adjusting national aggregate fuel production data for imports, exports, and stock changes rather than relying on end-user consumption surveys (see Annex 4 of this report). The reference approach assumes that once carbon-based fuels are brought into a national economy, they are either saved in some way (e.g., stored in products, kept in fuel stocks, or left unoxidized in ash) or combusted, and therefore the carbon in them is oxidized and released into the atmosphere. Accounting for actual consumption of fuels at the sectoral or sub-national level is not required.

[END BOX]

1.5. Key Categories

The IPCC's Good Practice Guidance (IPCC 2000) defines a key category as a "[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both."[43] By definition, key categories include those sources that have the greatest contribution to the absolute level of national emissions. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends and uncertainties of individual source and sink categories. This analysis culls out source and sink categories that diverge from the overall trend in national emissions. Finally, a qualitative evaluation of key categories is performed to capture any categories that were not identified in any of the quantitative analyses.

A Tier 1 approach, as defined in the IPCC's Good Practice Guidance (IPCC 2000), was implemented to identify the key categories for the United States. This analysis was performed twice; one analysis included sources and sinks from the Land Use, Land-Use Change, and Forestry (LULUCF) sector, the other analysis did not include the LULUCF categories. Following the Tier 1 approach, a Tier 2 approach, as defined in the IPCC's Good Practice Guidance (IPCC 2000), was then implemented to identify any additional key categories not already identified in the Tier 1 assessment. This analysis, which includes each source categories' uncertainty assessments (or proxies) in its calculations, was also performed twice to include or exclude LULUCF categories.

In addition to conducting Tier 1 and 2 level and trend assessments, a qualitative assessment of the source categories, as described in the IPCC's Good Practice Guidance (IPCC 2000), was conducted to capture any key categories that were not identified by either quantitative method. One additional key category, international bunker fuels, was identified using this qualitative assessment. International bunker fuels are fuels consumed for aviation or marine international transport activities, and emissions from these fuels are reported separately from totals in accordance with IPCC guidelines. If these emissions were included in the totals, bunker fuels would qualify as a key category according to the Tier 1 approach. The amount of uncertainty associated with estimation of emissions from international bunker fuels also supports the qualification of this source category as key, because it would qualify bunker fuels as a key category according to the Tier 2 approach. Table 1-4 presents the key categories for the United States (including and excluding LULUCF categories) using emissions and uncertainty data in this report, and ranked according to their sector and global warming potential-weighted emissions in 2009. The table also indicates the criteria used in identifying these categories (i.e., level, trend, Tier 1, Tier 2, and/or qualitative assessments). Annex 1 of this report provides additional information regarding the key categories in the United States and the methodologies used to identify them.

[43] See Chapter 7 "Methodological Choice and Recalculation" in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

Table 1-4: Key Categories for the United States (1990-2009)

IPCC Source Categories	Gas	Tier 1				Tier 2				Qual[a]	2009 Emissions (Tg CO_2 Eq.)
		Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF	Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF		
Energy											
CO_2 Emissions from Stationary Combustion - Coal	CO_2	•		•	•	•		•	•		1,841.0
CO_2 Emissions from Mobile Combustion: Road	CO_2	•	•	•	•	•	•	•	•		1,475.6
CO_2 Emissions from Stationary Combustion - Gas	CO_2	•	•	•	•	•	•	•	•		1,164.6
CO_2 Emissions from Stationary Combustion - Oil	CO_2	•	•	•	•	•	•	•	•		483.3
CO_2 Emissions from Mobile Combustion: Aviation	CO_2	•	•	•	•	•	•	•	•		140.7
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	•		•	•	•		•			123.4
CO_2 Emissions from Mobile Combustion: Other	CO_2	•	•	•	•						73.5
CO_2 Emissions from Natural Gas Systems	CO_2	•	•	•	•	•	•	•	•		32.2
CO_2 Emissions from Mobile Combustion: Marine	CO_2	•	•	•	•						30.0
Fugitive Emissions from Natural Gas Systems	CH_4	•	•	•	•	•	•	•	•		221.2
Fugitive Emissions from Coal Mining	CH_4	•	•	•	•	•	•	•	•		71.0
Fugitive Emissions from Petroleum Systems	CH_4	•	•	•	•	•	•	•	•		30.9
Non-CO_2 Emissions from Stationary Combustion	CH_4						•		•		6.2
N_2O Emissions from Mobile Combustion: Road	N_2O	•	•	•	•		•		•		20.3
Non-CO_2 Emissions from Stationary Combustion	N_2O					•		•			12.8
International Bunker Fuels[b]	Several									•	124.4
Industrial Processes											
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	•	•	•	•	•	•	•	•		41.9
CO_2 Emissions from Cement Production	CO_2		•	•	•						29.0
CO_2 Emissions from Ammonia Production and Urea Consumption	CO_2		•		•						11.8
CO_2 Emissions from Aluminum Production	CO_2										3.0
N_2O Emissions from Nitric Acid Production	N_2O				•		•				14.6
N_2O Emissions from Adipic Acid Production	N_2O		•		•		•		•		1.9
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	•	•	•	•		•	•	•		120.0
SF_6 Emissions from Electrical Transmission and Distribution	HiGWP		•		•		•		•		12.8
HFC-23 Emissions from HCFC-22 Production	HiGWP	•	•	•	•		•		•		5.4

IPCC Source Categories	Gas	Tier 1				Tier 2				Qual[a]	2009 Emissions (Tg CO_2 Eq.)
		Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF	Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF		
PFC Emissions from Aluminum Production	HiGWP		•		•		•				1.6
SF_6 Emissions from Magnesium Production and Processing	HiGWP		•		•						1.1
Agriculture											
CH_4 Emissions from Enteric Fermentation	CH_4	•		•		•		•			139.8
CH_4 Emissions from Manure Management	CH_4	•	•	•	•		•		•		49.5
CH_4 Emissions from Rice Cultivation	CH_4					•		•			7.3
Direct N_2O Emissions from Agricultural Soil Management	N_2O	•	•	•	•	•	•	•	•		160.2
Indirect N_2O Emissions from Applied Nitrogen	N_2O	•		•		•	•	•	•		44.4
Waste											
CH_4 Emissions from Landfills	CH_4	•	•	•	•	•	•	•	•		117.5
CH_4 Emissions from Wastewater Treatment	CH_4					•		•			24.5
Land Use, Land Use Change, and Forestry											
CO_2 Emissions from Changes in Forest Carbon Stocks	CO_2			•	•			•	•		(863.1)
CO_2 Emissions from Urban Trees	CO_2			•	•			•	•		(95.9)
CO_2 Emissions from Cropland Remaining Cropland	CO_2				•			•	•		(17.4)
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2				•			•	•		(12.6)
CO_2 Emissions from Grassland Remaining Grassland	CO_2			•	•			•	•		(8.3)
CH_4 Emissions from Forest Fires	CH_4							•	•		7.8
N_2O Emissions from Forest Fires	N_2O								•		6.4
Subtotal Without LULUCF											**6,512.7**
Total Emissions Without LULUCF											**6,608.2**
Percent of Total Without LULUCF											**99%**
Subtotal With LULUCF											**5,529.5**
Total Emissions With LULUCF											**5,618.2**
Percent of Total With LULUCF											**98%**

[a]Qualitative criteria.
[b]Emissions from this source not included in totals.
Note: Parentheses indicate negative values (or sequestration).

1.6. Quality Assurance and Quality Control (QA/QC)

As part of efforts to achieve its stated goals for inventory quality, transparency, and credibility, the United States has developed a quality assurance and quality control plan designed to check, document and improve the quality of its

inventory over time. QA/QC activities on the Inventory are undertaken within the framework of the U.S. QA/QC plan, Quality Assurance/Quality Control and Uncertainty Management Plan for the U.S. Greenhouse Gas Inventory: Procedures Manual for QA/QC and Uncertainty Analysis.

Key attributes of the QA/QC plan are summarized in Figure 1-1. These attributes include:

- specific detailed procedures and forms that serve to standardize the process of documenting and archiving information, as well as to guide the implementation of QA/QC and the analysis of the uncertainty of the inventory estimates;
- expert review as well as QC—for both the inventory estimates and the Inventory (which is the primary vehicle for disseminating the results of the inventory development process). In addition, the plan provides for public review of the Inventory;
- both Tier 1 (general) and Tier 2 (source-specific) quality controls and checks, as recommended by IPCC Good Practice Guidance;
- consideration of secondary data quality and source-specific quality checks (Tier 2 QC) in parallel and coordination with the uncertainty assessment; the development of protocols and templates provides for more structured communication and integration with the suppliers of secondary information;
- record-keeping provisions to track which procedures have been followed, and the results of the QA/QC and uncertainty analysis, and contains feedback mechanisms for corrective action based on the results of the investigations, thereby providing for continual data quality improvement and guided research efforts;
- implementation of QA/QC procedures throughout the whole inventory development process—from initial data collection, through preparation of the emission estimates, to publication of the Inventory;
- a schedule for multi-year implementation; and
- promotion of coordination and interaction within the EPA, across Federal agencies and departments, state government programs, and research institutions and consulting firms involved in supplying data or preparing estimates for the inventory. The QA/QC plan itself is intended to be revised and reflect new information that becomes available as the program develops, methods are improved, or additional supporting documents become necessary.

In addition, based on the national QA/QC plan for the Inventory, source-specific QA/QC plans have been developed for a number of sources. These plans follow the procedures outlined in the national QA/QC plan, tailoring the procedures to the specific text and spreadsheets of the individual sources. For each greenhouse gas emissions source or sink included in this Inventory, a minimum of a Tier 1 QA/QC analysis has been undertaken. Where QA/QC activities for a particular source go beyond the minimum Tier 1 level, further explanation is provided within the respective source category text.

The quality control activities described in the U.S. QA/QC plan occur throughout the inventory process; QA/QC is not separate from, but is an integral part of, preparing the inventory. Quality control—in the form of both good practices (such as documentation procedures) and checks on whether good practices and procedures are being followed—is applied at every stage of inventory development and document preparation. In addition, quality assurance occurs at two stages—an expert review and a public review. While both phases can significantly contribute to inventory quality, the public review phase is also essential for promoting the openness of the inventory development process and the transparency of the inventory data and methods.

The QA/QC plan guides the process of ensuring inventory quality by describing data and methodology checks, developing processes governing peer review and public comments, and developing guidance on conducting an analysis of the uncertainty surrounding the emission estimates. The QA/QC procedures also include feedback loops and provide for corrective actions that are designed to improve the inventory estimates over time.

Figure 1-1: U.S. QA/QC Plan Summary

1.7. Uncertainty Analysis of Emission Estimates

Uncertainty estimates are an essential element of a complete and transparent emissions inventory. Uncertainty information is not intended to dispute the validity of the inventory estimates, but to help prioritize efforts to improve the accuracy of future inventories and guide future decisions on methodological choice. While the U.S. Inventory calculates its emission estimates with the highest possible accuracy, uncertainties are associated to a varying degree with the development of emission estimates for any inventory. Some of the current estimates, such as those for CO_2 emissions from energy-related activities, are considered to have minimal uncertainty associated with them. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty surrounding the estimates presented. Despite these uncertainties, the UNFCCC reporting guidelines follow the recommendation in the 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997) and require that countries provide single point estimates for each gas and emission or removal source category. Within the discussion of each emission source, specific factors affecting the uncertainty associated with the estimates are discussed.

Additional research in the following areas could help reduce uncertainty in the U.S. Inventory:

- *Incorporating excluded emission sources.* Quantitative estimates for some of the sources and sinks of greenhouse gas emissions are not available at this time. In particular, emissions from some land-use activities and industrial processes are not included in the inventory either because data are incomplete or because methodologies do not exist for estimating emissions from these source categories. See Annex 5 of this report for a discussion of the sources of greenhouse gas emissions and sinks excluded from this report.
- *Improving the accuracy of emission factors.* Further research is needed in some cases to improve the accuracy of emission factors used to calculate emissions from a variety of sources. For example, the accuracy of current emission factors applied to CH_4 and N_2O emissions from stationary and mobile combustion is highly uncertain.
- *Collecting detailed activity data*. Although methodologies exist for estimating emissions for some sources, problems arise in obtaining activity data at a level of detail in which aggregate emission factors can be applied. For example, the ability to estimate emissions of SF_6 from electrical transmission and distribution is limited due to a lack of activity data regarding national SF_6 consumption or average equipment leak rates.

The overall uncertainty estimate for the U.S. greenhouse gas emissions inventory was developed using the IPCC Tier 2 uncertainty estimation methodology. Estimates of quantitative uncertainty for the overall greenhouse gas emissions inventory are shown below, in Table 1-5.

The IPCC provides good practice guidance on two approaches—Tier 1 and Tier 2—to estimating uncertainty for individual source categories. Tier 2 uncertainty analysis, employing the Monte Carlo Stochastic Simulation technique, was applied wherever data and resources permitted; further explanation is provided within the respective source category text and in Annex 7. Consistent with the IPCC Good Practice Guidance (IPCC 2000), over a multi-year timeframe, the United States expects to continue to improve the uncertainty estimates presented in this report.

Table 1-5. Estimated Overall Inventory Quantitative Uncertainty (Tg CO_2 Eq. and Percent)

Gas	2009 Emission Estimate[a] (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[b] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[b] (%)		Mean[c] (Tg CO_2 Eq.)	Standard Deviation[c] (Tg CO_2 Eq.)
		Lower Bound[d]	Upper Bound[d]	Lower Bound	Upper Bound		
CO_2	5,504.8	5,436.6	5,813.8	-1%	6%	5,622.5	97.5
CH_4[e]	686.3	623.9	805.4	-9%	17%	702.8	45.3
N_2O[e]	295.6	261.7	425.3	-11%	44%	334.2	42.1
PFC, HFC & SF_6[e]	143.3	134.5	153.4	-6%	7%	143.7	4.8
Total	**6,630.0**	**6,584.2**	**7,033.6**	**-1%**	**6%**	**6,803.2**	**115.0**
Net Emissions (Sources and Sinks)	**5,614.9**	**5,512.3**	**6,055.1**	**-2%**	**8%**	**5,785.4**	**139.1**

Notes:

[a] Emission estimates reported in this table correspond to emissions from only those source categories for which quantitative uncertainty was performed this year. Thus the totals reported in this table exclude approximately 3.1 Tg CO_2 Eq. of emissions for

which quantitative uncertainty was not assessed. Hence, these emission estimates do not match the final total U.S. greenhouse gas emission estimates presented in this Inventory.
[b] The lower and upper bounds for emission estimates correspond to a 95 percent confidence interval, with the lower bound corresponding to 2.5th percentile and the upper bound corresponding to 97.5th percentile.
[c] Mean value indicates the arithmetic average of the simulated emission estimates; standard deviation indicates the extent of deviation of the simulated values from the mean.
[d] The lower and upper bound emission estimates for the sub-source categories do not sum to total emissions because the low and high estimates for total emissions were calculated separately through simulations.
[e] The overall uncertainty estimates did not take into account the uncertainty in the GWP values for CH_4, N_2O and high GWP gases used in the inventory emission calculations for 2009.

Emissions calculated for the U.S. Inventory reflect current best estimates; in some cases, however, estimates are based on approximate methodologies, assumptions, and incomplete data. As new information becomes available in the future, the United States will continue to improve and revise its emission estimates. See Annex 7 of this report for further details on the U.S. process for estimating uncertainty associated with the emission estimates and for a more detailed discussion of the limitations of the current analysis and plans for improvement. Annex 7 also includes details on the uncertainty analysis performed for selected source categories.

1.8. Completeness

This report, along with its accompanying CRF reporter, serves as a thorough assessment of the anthropogenic sources and sinks of greenhouse gas emissions for the United States for the time series 1990 through 2009. Although this report is intended to be comprehensive, certain sources have been identified yet excluded from the estimates presented for various reasons. Generally speaking, sources not accounted for in this inventory are excluded due to data limitations or a lack of thorough understanding of the emission process. The United States is continually working to improve upon the understanding of such sources and seeking to find the data required to estimate related emissions. As such improvements are implemented, new emission sources are quantified and included in the Inventory. For a complete list of sources not included, see Annex 5 of this report.

1.9. Organization of Report

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2006 UNFCCC Guidelines on Reporting and Review (UNFCCC 2006), this Inventory of U.S. Greenhouse Gas Emissions and Sinks is segregated into six sector-specific chapters, listed below in Table 1-6. In addition, chapters on Trends in Greenhouse Gas Emissions and Other information to be considered as part of the U.S. Inventory submission are included.

Table 1-6: IPCC Sector Descriptions

Chapter/IPCC Sector	Activities Included
Energy	Emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions.
Industrial Processes	By-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion.
Solvent and Other Product Use	Emissions, of primarily NMVOCs, resulting from the use of solvents and N_2O from product uses.
Agriculture	Anthropogenic emissions from agricultural activities except fuel combustion, which is addressed under Energy.
Land Use, Land-Use Change, and Forestry	Emissions and removals of CO_2, CH_4, and N_2O from forest management, other land-use activities, and land-use change.
Waste	Emissions from waste management activities.

Source: (IPCC/UNEP/OECD/IEA 1997)

Within each chapter, emissions are identified by the anthropogenic activity that is the source or sink of the greenhouse gas emissions being estimated (e.g., coal mining). Overall, the following organizational structure is consistently applied throughout this report:

Chapter/IPCC Sector: Overview of emission trends for each IPCC defined sector

Source category: Description of source pathway and emission trends.

Methodology: Description of analytical methods employed to produce emission estimates and identification of data references, primarily for activity data and emission factors.

Uncertainty: A discussion and quantification of the uncertainty in emission estimates and a discussion of time-series consistency.

QA/QC and Verification: A discussion on steps taken to QA/QC and verify the emission estimates, where beyond the overall U.S. QA/QC plan, and any key findings.

Recalculations: A discussion of any data or methodological changes that necessitate a recalculation of previous years' emission estimates, and the impact of the recalculation on the emission estimates, if applicable.

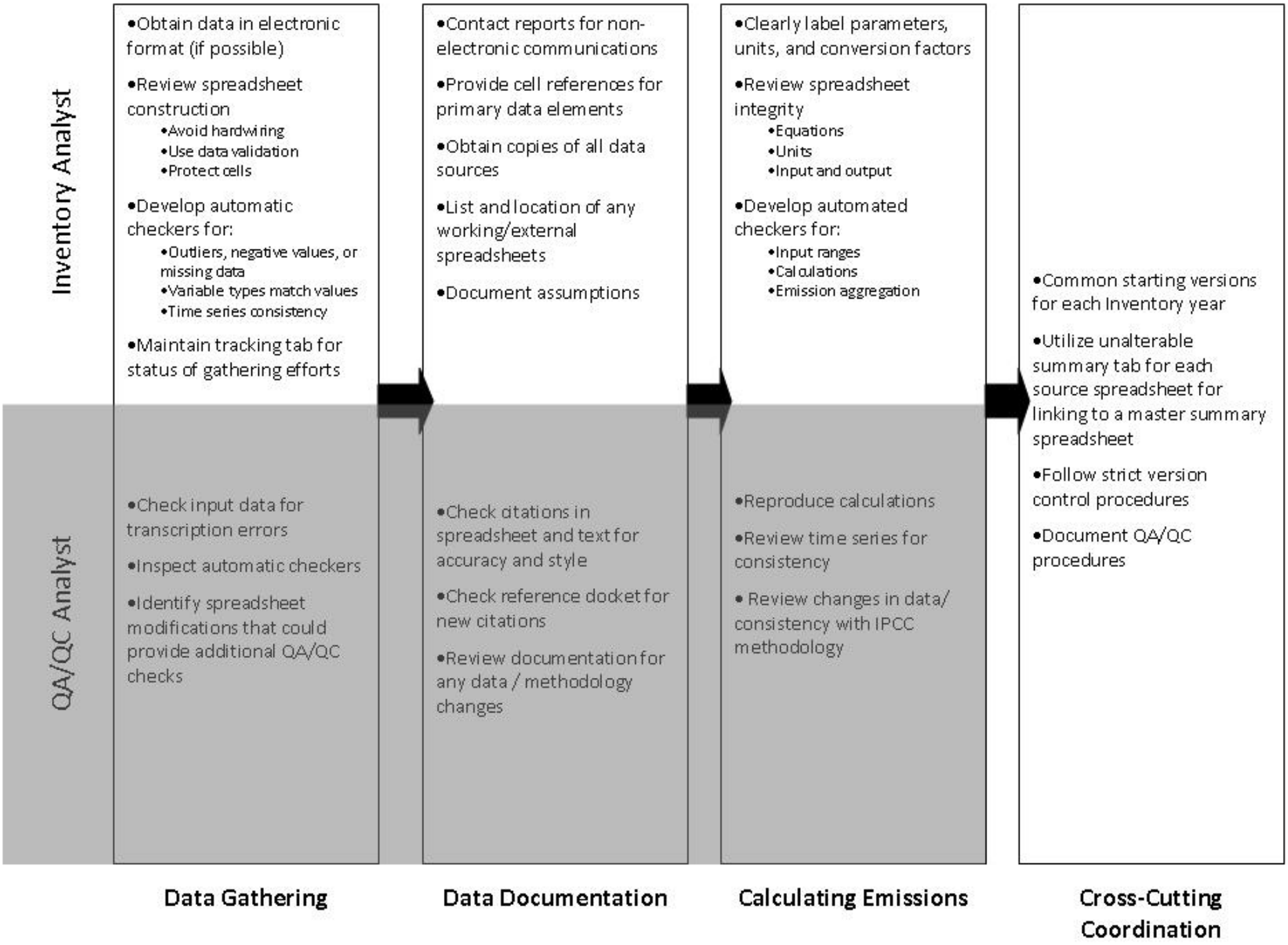
Planned Improvements: A discussion on any source-specific planned improvements, if applicable.

Special attention is given to CO_2 from fossil fuel combustion relative to other sources because of its share of emissions and its dominant influence on emission trends. For example, each energy consuming end-use sector (i.e., residential, commercial, industrial, and transportation), as well as the electricity generation sector, is described individually. Additional information for certain source categories and other topics is also provided in several Annexes listed in Table 1-7.

Table 1-7: List of Annexes

ANNEX 1 Key Category Analysis
ANNEX 2 Methodology and Data for Estimating CO_2 Emissions from Fossil Fuel Combustion
2.1. Methodology for Estimating Emissions of CO_2 from Fossil Fuel Combustion
2.2. Methodology for Estimating the Carbon Content of Fossil Fuels
2.3. Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels
ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories
3.1. Methodology for Estimating Emissions of CH_4, N_2O, and Indirect Greenhouse Gases from Stationary Combustion
3.2. Methodology for Estimating Emissions of CH_4, N_2O, and Indirect Greenhouse Gases from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related Greenhouse Gas Emissions
3.3. Methodology for Estimating CH_4 Emissions from Coal Mining
3.4. Methodology for Estimating CH_4 Emissions from Natural Gas Systems
3.5. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems
3.6. Methodology for Estimating CO_2 and N_2O Emissions from Incineration of Waste
3.7. Methodology for Estimating Emissions from International Bunker Fuels used by the U.S. Military
3.8. Methodology for Estimating HFC and PFC Emissions from Substitution of Ozone Depleting Substances
3.9. Methodology for Estimating CH_4 Emissions from Enteric Fermentation
3.10. Methodology for Estimating CH_4 and N_2O Emissions from Manure Management
3.11. Methodology for Estimating N_2O Emissions from Agricultural Soil Management
3.12. Methodology for Estimating Net Carbon Stock Changes in Forest Lands Remaining Forest Lands
3.13. Methodology for Estimating Net Changes in Carbon Stocks in Mineral and Organic Soils on Croplands and Grasslands
3.14. Methodology for Estimating CH_4 Emissions from Landfills
ANNEX 4 IPCC Reference Approach for Estimating CO_2 Emissions from Fossil Fuel Combustion
ANNEX 5 Assessment of the Sources and Sinks of Greenhouse Gas Emissions Not Included
ANNEX 6 Additional Information
6.1. Global Warming Potential Values
6.2. Ozone Depleting Substance Emissions
6.3. Sulfur Dioxide Emissions
6.4. Complete List of Source Categories
6.5. Constants, Units, and Conversions
6.6. Abbreviations

Figure 1: U.S. QA/QC Plan Summary



2. Trends in Greenhouse Gas Emissions

2.1. Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2009, total U.S. greenhouse gas emissions were 6,633.2 teragrams of carbon dioxide equivalents (Tg CO_2 Eq.); net emissions were 5,618.2 Tg CO_2 Eq. reflecting the influence of sinks (net CO_2 flux from Land Use, Land Use Change, and Forestry).[44] While total U.S. emissions have increased by 7.3 percent from 1990 to 2009, emissions decreased from 2008 to 2009 by 6.1 percent (427.9 Tg CO_2 Eq.). The following factors were primary contributors to this decrease: (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; and (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly.

Figure 2-1: U.S. Greenhouse Gas Emissions by Gas

Figure 2-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

Figure 2-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

As the largest contributor to U.S. greenhouse gas emissions, carbon dioxide (CO_2) from fossil fuel combustion has accounted for approximately 79 percent of global warming potential (GWP) weighted emissions since 1990, from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2009. Emissions from this source category grew by 9.9 percent (470.6 Tg CO_2 Eq.) from 1990 to 2009 and were responsible for most of the increase in national emissions during this period. From 2008 to 2009, these emissions decreased by 6.4 percent (356.9 Tg CO_2 Eq.). Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends.

Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. On an annual basis, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than in a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

In the longer-term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Energy-related CO_2 emissions also depend on the type of fuel or energy consumed and its carbon (C) intensity. Producing a unit of heat or electricity using natural gas instead of coal, for example, can reduce the CO_2 emissions because of the lower C content of natural gas.

A brief discussion of the year to year variability in fuel combustion emissions is provided below, beginning with 2005.

From 2005 to 2006, emissions from fuel combustion decreased for the first time since 2000 to 2001. This decrease occurred across all sectors, with the exception of the industrial sector and the U.S. Territories sector, due to a

[44] Estimates are presented in units of teragrams of carbon dioxide equivalent (Tg CO_2 Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

number of factors. The decrease in emissions from electricity generation is a result of a smaller share of electricity generated by coal and a greater share generated by natural gas. Coal consumption for electricity generation decreased by 1.3 percent while natural gas consumption for electricity generation increased by 6.0 percent in 2006 and nuclear power generation increased by less than 1 percent. The decrease in consumption of transportation fuels is primarily a result of the restraint on fuel consumption caused by rising fuel prices, which directly resulted in a decrease of petroleum consumption within this sector of about 1.1 percent in 2006. The significant decrease in emissions from the residential sector is primarily a result of decreased electricity consumption due to increases in the price of electricity, and warmer winter weather conditions compared to 2005. A moderate increase in industrial sector emissions is the result of growth in industrial output and growth in the U.S. economy. Renewable fuels used to generate electricity increased in 2006, with the greatest growth occurring in generation from wind by 48 percent.

After experiencing a decrease from 2005 to 2006, emissions from fuel combustion grew from 2006 to 2007 at a rate somewhat higher than the average growth rate since 1990. There were a number of factors contributing to this increase. More energy-intensive weather conditions in both the winter and summer resulted in an increase in consumption of heating fuels, as well as an increase in the demand for electricity. This demand for electricity was met with an increase in coal consumption of 1.7 percent, and with an increase in natural gas consumption of 9.9 percent. This increase in fossil fuel consumption, combined with a 14.7 percent decrease in hydropower generation from 2006 to 2007, resulted in an increase in emissions in 2007. The increase in emissions from the residential and commercial sectors is a result of increased electricity consumption due to warmer summer conditions and cooler winter conditions compared to 2006. In addition to these more energy-intensive weather conditions, electricity prices remained relatively stable compared to 2006, and natural gas prices decreased slightly. Emissions from the industrial sector decreased compared to 2006 as a result of a decrease in industrial production and fossil fuels used for electricity generation. Despite an overall decrease in electricity generation from renewable energy in 2007 driven by decreases in hydropower generation, wind and solar generation increased significantly.

Emissions from fossil fuel combustion decreased from 2007 to 2008. Several factors contributed to this decrease in emissions. An increase in energy prices coupled with the economic downturn led to a decrease in energy demand and a resulting decrease in emissions from 2007 to 2008. In 2008, the price of coal, natural gas, and petroleum used to generate electricity, as well as the price of fuels used for transportation, increased significantly. As a result of this price increase, coal, natural gas, and petroleum consumption used for electricity generation decreased by 1.4 percent, 2.5 percent, and 28.8 percent, respectively. The increase in the cost of fuels to generate electricity translated into an increase in the price of electricity, leading to a decrease in electricity consumption across all sectors except the commercial sector. The increase in transportation fuel prices led to a decrease in vehicle miles traveled (VMT) and a 5.5 percent decrease in transportation fossil fuel combustion emissions from 2007 to 2008. Cooler weather conditions in the summer led to a decrease in cooling degree days by 8.7 percent and a decrease in electricity demand compared to 2007, whereas cooler winter conditions led to a 5.6 percent increase in heating degree days compared to 2007 and a resulting increase in demand for heating fuels. The increased emissions from winter heating energy demand was offset by a decrease in emissions from summer cooling related electricity demand. Lastly, renewable energy[45] consumption for electricity generation increased by 9.6 percent from 2007 to 2008, driven by a significant increase in solar and wind energy consumption (of 19.4 percent and 60.2 percent, respectively). This increase in renewable energy generation contributed to a decrease in the carbon intensity of electricity generation.

From 2008 to 2009, CO_2 from fossil fuel combustion emissions experienced a decrease of 6.4 percent, the greatest decrease of any year over the course of the twenty-year period. Various factors contributed to this decrease in emissions. The continued economic downturn resulted in a 2.6 percent decrease in GDP, and a decrease in energy consumption across all sectors. The economic downturn also impacted total industrial production and manufacturing output, which decreased by 9.3 and 10.9 percent, respectively. In 2009, the price of coal used to generate electricity increased, while the price of natural gas used to generate electricity decreased significantly. As a result, natural gas was used for a greater share of electricity generation in 2009 than 2008, and coal was used for a smaller share. The fuel switching from coal to natural gas and additional electricity generation from other energy sources in 2009, which included a 6.8 percent increase in hydropower generation from the previous year, resulted in a decrease in carbon intensity, and in turn, a decrease in emissions from electricity generation. From 2008 to 2009, industrial sector emissions decreased significantly as a result of a decrease in output from energy-intensive industries of 16.6

[45] Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy.

percent in nonmetallic mineral and 31.6 percent in primary metal industries. The residential and commercial sectors only experienced minor decreases in emissions as summer and winter weather conditions were less energy-intensive from 2008 to 2009, and the price of electricity only increased slightly. Heating degree days decreased slightly and cooling degree days decreased by 3.8 percent from 2008 to 2009.

Overall, from 1990 to 2009, total emissions of CO_2 and CH_4 increased by 405.5 Tg CO_2 Eq. (8.0 percent) and 11.4 Tg CO_2 Eq. (1.7 percent), respectively, while N_2O emissions decreased by 19.6 Tg CO_2 Eq. (6.2 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 54.1 Tg CO_2 Eq. (58.8 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of them have extremely high GWPs and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by C sequestration in managed forests, trees in urban areas, agricultural soils, and landfilled yard trimmings. These were estimated to offset 15.3 percent of total emissions in 2009.

Table 2-1 summarizes emissions and sinks from all U.S. anthropogenic sources in weighted units of Tg CO_2 Eq., while unweighted gas emissions and sinks in gigagrams (Gg) are provided in Table 2-2.

Table 2-1: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**5,099.7**	**5,975.0**	**6,113.8**	**6,021.1**	**6,120.0**	**5,921.4**	**5,505.2**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	*1,820.8*	*2,296.9*	*2,402.1*	*2,346.4*	*2,412.8*	*2,360.9*	*2,154.0*
Transportation	*1,485.9*	*1,809.5*	*1,896.6*	*1,878.1*	*1,894.0*	*1,789.9*	*1,719.7*
Industrial	*846.5*	*851.1*	*823.1*	*848.2*	*842.0*	*802.9*	*730.4*
Residential	*338.3*	*370.7*	*357.9*	*321.5*	*342.4*	*348.2*	*339.2*
Commercial	*219.0*	*230.8*	*223.5*	*208.6*	*219.4*	*224.2*	*224.0*
U.S. Territories	*27.9*	*35.9*	*50.0*	*50.3*	*46.1*	*39.8*	*41.7*
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Cropland Remaining Cropland	7.1	7.5	7.9	7.9	8.2	8.7	7.8
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Wetlands Remaining Wetlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(861.5)*	*(576.6)*	*(1,056.5)*	*(1,064.3)*	*(1,060.9)*	*(1,040.5)*	*(1,015.1)*
Biomass—Wood[b]	215.2	218.1	206.9	203.8	203.3	198.4	183.8
International Bunker Fuels[c]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*

Biomass—Ethanol[b]	4.2	9.4	23.0	31.0	38.9	54.8	61.2
CH_4	**674.9**	**659.9**	**631.4**	**672.1**	**664.6**	**676.7**	**686.3**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Forest Land Remaining Forest Land	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Field Burning of Agriculture Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**315.2**	**341.0**	**322.9**	**326.4**	**325.1**	**310.8**	**295.6**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Forest Land Remaining Forest Land	2.7	12.1	8.4	18.0	16.7	10.1	6.7
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Settlements Remaining Settlements	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
HFCs	**36.9**	**103.2**	**120.2**	**123.5**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[d]	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**

Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Parentheses indicate negative values or sequestration.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Table 2-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**5,099,719**	**5,974,991**	**6,113,751**	**6,021,089**	**6,120,009**	**5,921,443**	**5,505,204**
Fossil Fuel Combustion	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
Electricity Generation	*1,820,818*	*2,296,894*	*2,402,142*	*2,346,406*	*2,412,827*	*2,360,919*	*2,154,025*
Transportation	*1,485,937*	*1,809,514*	*1,896,606*	*1,878,125*	*1,893,994*	*1,789,918*	*1,719,685*
Industrial	*846,475*	*851,094*	*823,069*	*848,206*	*842,048*	*802,856*	*730,422*
Residential	*338,347*	*370,666*	*357,903*	*321,513*	*342,397*	*348,221*	*339,203*
Commercial	*218,964*	*230,828*	*223,512*	*208,582*	*219,356*	*224,167*	*223,993*
U.S. Territories	*27,882*	*35,853*	*49,968*	*50,284*	*46,123*	*39,845*	*41,652*
Non-Energy Use of Fuels	118,630	144,933	143,392	145,574	137,233	140,952	123,356
Iron and Steel Production & Metallurgical Coke Production	99,528	85,935	65,925	68,772	71,045	66,015	41,871
Natural Gas Systems	37,574	29,877	29,902	30,755	31,050	32,828	32,171
Cement Production	33,278	40,405	45,197	45,792	44,538	40,531	29,018
Incineration of Waste	7,989	11,112	12,450	12,531	12,700	12,169	12,300
Ammonia Production and Urea Consumption	16,831	16,402	12,849	12,300	14,038	11,949	11,797
Lime Production	11,533	14,088	14,379	15,100	14,595	14,330	11,223
Cropland Remaining Cropland	7,084	7,541	7,854	7,875	8,202	8,654	7,832
Limestone and Dolomite Use	5,127	5,056	6,768	8,035	7,702	6,276	7,649
Soda Ash Production and Consumption	4,141	4,181	4,228	4,162	4,140	4,111	4,265
Aluminum Production	6,831	6,086	4,142	3,801	4,251	4,477	3,009
Petrochemical Production	3,311	4,479	4,181	3,837	3,931	3,449	2,735
Carbon Dioxide Consumption	1,416	1,421	1,321	1,709	1,867	1,780	1,763
Titanium Dioxide Production	1,195	1,752	1,755	1,836	1,930	1,809	1,541
Ferroalloy Production	2,152	1,893	1,392	1,505	1,552	1,599	1,469
Wetlands Remaining Wetlands	1,033	1,227	1,079	879	1,012	992	1,090
Phosphoric Acid Production	1,529	1,382	1,386	1,167	1,166	1,187	1,035
Zinc Production	667	997	1,088	1,088	1,081	1,230	966

Lead Production	516	594	553	560	562	551	525
Petroleum Systems	555	534	490	488	474	453	463
Silicon Carbide Production and Consumption	375	248	219	207	196	175	145
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(861,535)*	*(576,588)*	*(1,056,459)*	*(1,064,330)*	*(1,060,882)*	*(1,040,461)*	*(1,015,074)*
Biomass - Wood[b]	*215,186*	*218,088*	*206,865*	*203,846*	*203,316*	*198,361*	*183,777*
International Bunker Fuels[c]	*111,828*	*98,482*	*109,750*	*128,384*	*127,618*	*133,704*	*123,127*
Biomass - Ethanol[b]	*4,229*	*9,352*	*22,956*	*31,002*	*38,946*	*54,770*	*61,231*
CH_4	**32,136**	**31,423**	**30,069**	**32,004**	**31,647**	**32,225**	**32,680**
Natural Gas Systems	9,038	9,968	9,069	10,364	9,771	10,087	10,535
Enteric Fermentation	6,290	6,502	6,500	6,611	6,715	6,696	6,655
Landfills	7,018	5,317	5,358	5,321	5,299	5,520	5,593
Coal Mining	4,003	2,877	2,710	2,774	2,756	3,196	3,382
Manure Management	1,511	2,019	2,217	2,226	2,416	2,353	2,356
Petroleum Systems	1,685	1,501	1,398	1,398	1,427	1,439	1,473
Wastewater Treatment	1,118	1,199	1,159	1,167	1,163	1,168	1,167
Forest Land Remaining Forest Land	152	682	467	1,027	953	569	372
Rice Cultivation	339	357	326	282	295	343	349
Stationary Combustion	354	315	312	293	308	310	293
Abandoned Underground Coal Mines	288	350	264	261	267	279	262
Mobile Combustion	223	160	119	112	105	97	93
Composting	15	60	75	75	79	80	79
Petrochemical Production	41	59	51	48	48	43	40
Iron and Steel Production & Metallurgical Coke Production	46	44	34	35	33	31	17
Field Burning of Agricultural Residues	13	12	9	11	11	13	12
Ferroalloy Production	1	1	+	+	+	+	+
Silicon Carbide Production and Consumption	1	1	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	*8*	*6*	*7*	*8*	*8*	*8*	*7*
N_2O	**1,017**	**1,100**	**1,042**	**1,053**	**1,049**	**1,002**	**954**
Agricultural Soil Management	638	667	682	674	675	680	660
Mobile Combustion	142	172	119	108	98	84	77
Manure Management	47	55	56	58	58	58	58
Nitric Acid Production	57	63	53	52	62	53	47
Stationary Combustion	41	47	47	47	47	46	41
Forest Land Remaining Forest Land	9	39	27	58	54	33	22
Wastewater Treatment	12	14	15	16	16	16	16
N_2O from Product Uses	14	16	14	14	14	14	14
Adipic Acid Production	51	18	16	14	12	7	6
Composting	1	4	6	6	6	6	6
Settlements Remaining Settlements	3	4	5	5	5	5	5

Incineration of Waste	2	1	1	1	1	1	1
Field Burning of Agricultural Residues	+	+	+	+	+	+	+
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*3*	*3*	*3*	*4*	*4*	*4*	*4*
HFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Substitution of Ozone Depleting Substances[d]	M	M	M	M	M	M	M
HCFC-22 Production	3	2	1	1	1	1	+
Semiconductor Manufacture	+	+	+	+	+	+	+
PFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Semiconductor Manufacture	M	M	M	M	M	M	M
Aluminum Production	M	M	M	M	M	M	M
SF_6	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Electrical Transmission and Distribution	1	1	1	1	1	1	1
Magnesium Production and Processing	+	+	+	+	+	+	+
Semiconductor Manufacture	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg.
M Mixture of multiple gases
[a] The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Parentheses indicate negative values or sequestration.
[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry
[c] Emissions from International Bunker Fuels are not included in totals.
[d] Small amounts of PFC emissions also result from this source.
Note: Totals may not sum due to independent rounding.

Emissions of all gases can be summed from each source category from Intergovernmental Panel on Climate Change (IPCC) guidance. Over the twenty-year period of 1990 to 2009, total emissions in the Energy and Agriculture sectors grew by 463.3 Tg CO_2 Eq. (8.8 percent) and 35.7 Tg CO_2 Eq. (9.3 percent), respectively. Emissions decreased in the Industrial Processes, Waste, and Solvent and Other Product Use sectors by 32.9 Tg CO_2 Eq. (10.4 percent), 24.7 Tg CO_2 Eq. (14.1 percent) and less than 0.1 Tg CO_2 Eq. (less than 0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry sector increased by 153.5 Tg CO_2 Eq. (17.8 percent).

Figure 2-4: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table 2-3: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg CO_2 Eq.)

Chapter/IPCC Sector	1990	2000	2005	2006	2007	2008	2009
Energy	5,287.8	6,168.0	6,282.8	6,210.2	6,290.7	6,116.6	5,751.1
Industrial Processes	315.8	348.8	334.1	339.4	350.9	331.7	282.9
Solvent and Other Product Use	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Agriculture	383.6	410.6	418.8	418.8	425.8	426.3	419.3
Land Use, Land-Use Change, and Forestry (Emissions)	15.0	36.3	28.6	49.8	47.5	33.2	25.0
Waste	175.2	143.9	144.9	144.4	144.1	149.0	150.5

Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Sinks)*	(861.5)	(576.6)	(1056.5)	(1064.3)	(1060.9)	(1040.5)	(1015.1)
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

* The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Please refer to Table 2-9 for a breakout by source.
Note: Totals may not sum due to independent rounding.
Note: Parentheses indicate negative values or sequestration.

Energy

Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2009. In 2009, approximately 83 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 17 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure 2-5 and Figure 2-6). A discussion of specific trends related to CO_2 as well as other greenhouse gas emissions from energy consumption is presented in the Energy chapter. Energy-related activities are also responsible for CH_4 and N_2O emissions (49 percent and 13 percent of total U.S. emissions of each gas, respectively). Table 2-4 presents greenhouse gas emissions from the Energy chapter, by source and gas.

Figure 2-5: 2009 Energy Chapter Greenhouse Gas Sources

Figure 2-6: 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

Table 2-4: Emissions from Energy (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**4,903.2**	**5,781.3**	**5,939.4**	**5,842.5**	**5,938.2**	**5,752.3**	**5,377.3**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Biomass - Wood[a]	*215.2*	*218.1*	*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
International Bunker Fuels[b]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
Biomass - Ethanol[a]	*4.2*	*9.4*	*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**327.4**	**318.6**	**291.3**	**319.2**	**307.3**	**323.6**	**336.8**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Incineration of Waste	+	+	+	+	+	+	+

International Bunker Fuels[b]	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**57.2**	**68.1**	**52.1**	**48.5**	**45.2**	**40.7**	**37.0**
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
International Bunker Fuels[b]	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
Total	**5,287.8**	**6,168.0**	**6,282.8**	**6,210.2**	**6,290.7**	**6,116.6**	**5,751.1**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry

[b] Emissions from International Bunker Fuels are not included in totals.

Note: Totals may not sum due to independent rounding.

Carbon dioxide emissions from fossil fuel combustion are presented in Table 2-5 based on the underlying U.S. energy consumer data collected by EIA. Estimates of CO_2 emissions from fossil fuel combustion are calculated from these EIA "end-use sectors" based on total consumption and appropriate fuel properties (any additional analysis and refinement of the EIA data is further explained in the Energy chapter of this report). EIA's fuel consumption data for the electric power sector comprises electricity-only and combined-heat-and-power (CHP) plants within the NAICS 22 category whose primary business is to sell electricity, or electricity and heat, to the public (nonutility power producers can be included in this sector as long as they meet they electric power sector definition). EIA statistics for the industrial sector include fossil fuel consumption that occurs in the fields of manufacturing, agriculture, mining, and construction. EIA's fuel consumption data for the transportation sector consists of all vehicles whose primary purpose is transporting people and/or goods from one physical location to another. EIA's fuel consumption data for the industrial sector consists of all facilities and equipment used for producing, processing, or assembling goods (EIA includes generators that produce electricity and/or useful thermal output primarily to support on-site industrial activities in this sector). EIA's fuel consumption data for the residential sector consists of living quarters for private households. EIA's fuel consumption data for the commercial sector consists of service-providing facilities and equipment from private and public organizations and businesses (EIA includes generators that produce electricity and/or useful thermal output primarily to support the activities at commercial establishments in this sector). Table 2-5, Figure 2-7, and Figure 2-8 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table 2-5: CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Electricity	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Industrial	**1,533.2**	**1,640.8**	**1,560.0**	**1,560.2**	**1,572.0**	**1,517.7**	**1,333.7**
Combustion	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Electricity	686.7	789.8	737.0	712.0	730.0	714.8	603.3
Residential	**931.4**	**1,133.1**	**1,214.7**	**1,152.4**	**1,198.5**	**1,182.2**	**1,123.8**
Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Electricity	593.0	762.4	856.7	830.8	856.1	834.0	784.6
Commercial	**757.0**	**972.1**	**1,027.2**	**1,007.6**	**1,041.1**	**1,031.6**	**985.7**
Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0
Electricity	538.0	741.3	803.7	799.0	821.7	807.4	761.7
U.S. Territories	**27.9**	**35.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**
Electricity Generation	**1,820.8**	**2,296.9**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

Figure 2-7: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure 2-8: 2009 End-Use Sector Emissions from Fossil Fuel Combustion

The main driver of emissions in the Energy sector is CO_2 from fossil fuel combustion. The transportation end-use sector accounted for 1,724.1 Tg CO_2 Eq. in 2009 or approximately 33 percent of total CO_2 emissions from fossil fuel combustion, the largest share of any end-use sector.[46] The industrial end-use sector accounted for 26 percent of CO_2 emissions from fossil fuel combustion. The residential and commercial end-use sectors accounted for an average 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion. Both end-use sectors were heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances contributing 70 and 77 percent of emissions from the residential and commercial end-use sectors, respectively. Significant trends in emissions from energy source categories over the twenty-year period from 1990 through 2009 included the following:

- Total CO_2 emissions from fossil fuel combustion increased from 4,738.4 Tg CO_2 Eq. to 5,209.0 Tg CO_2 Eq.—a 9.9 percent total increase over the twenty-year period. From 2008 to 2009, these emissions decreased by 356.9 Tg CO_2 Eq. (6.4 percent), the largest decrease of any year over the twenty-year period.
- CO_2 emissions from non-energy use of fossil fuels increased 4.7 Tg CO_2 Eq. (4.0 percent) from 1990 through 2009. Emissions from non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq. in 2009, which constituted 2.2 percent of total national CO_2 emissions.
- CO_2 emissions from incineration of waste (12.3 Tg CO_2 Eq. in 2009) increased by 4.3 Tg CO_2 Eq. (54 percent) from 1990 through 2009, as the volume of plastics and other fossil carbon-containing materials in municipal solid waste grew.
- CH_4 emissions from coal mining were 71.0 Tg CO_2 Eq. in 2009, a decline in emissions of 13.0 Tg CO_2 Eq. (15.5 percent) from 1990. This occurred as a result of the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- CH_4 emissions from natural gas systems were 221.2 Tg CO_2 Eq. in 2009; emissions have increased by 31.4 Tg CO_2 Eq. (16.6 percent) since 1990.
- In 2009, N_2O emissions from mobile combustion were 23.9 Tg CO_2 Eq. (approximately 8.1 percent of U.S. N_2O emissions). From 1990 to 2009, N_2O emissions from mobile combustion decreased by 45.6 percent. However, from 1990 to 1998 emissions increased by 26 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to a steady decline in N_2O from this source.

Industrial Processes

Greenhouse gas emissions are produced as the by-products of many non-energy-related industrial activities. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production (see Figure 2-9). Industrial processes also release HFCs, PFCs and SF_6. In addition to their use as ODS substitutes, HFCs, PFCs, SF_6, and other fluorinated compounds are employed and emitted by a number of other industrial sources in the United States. These industries include aluminum production, HCFC-22 production, semiconductor manufacture, electric power transmission and distribution, and magnesium metal production and processing. Table 2-6 presents greenhouse gas emissions from industrial processes by source category.

[46] Note that electricity generation is the largest emitter of CO_2 when electricity is not distributed among end-use sectors.

Figure 2-9: 2009 Industrial Processes Chapter Greenhouse Gas Sources

Table 2-6: Emissions from Industrial Processes (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**188.4**	**184.9**	**165.4**	**169.9**	**172.6**	**159.5**	**119.0**
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Iron and Steel Production	*97.1*	*83.7*	*63.9*	*66.9*	*69.0*	*63.7*	*40.9*
Metallurgical Coke Production	*2.5*	*2.2*	*2.0*	*1.9*	*2.1*	*2.3*	*1.0*
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Ammonia Production & Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
CH_4	**1.9**	**2.2**	**1.8**	**1.7**	**1.7**	**1.6**	**1.2**
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Iron and Steel Production	*1.0*	*0.9*	*0.7*	*0.7*	*0.7*	*0.6*	*0.4*
Metallurgical Coke Production	+	+	+	+	+	+	+
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
N_2O	**33.5**	**24.9**	**21.5**	**20.5**	**22.9**	**18.5**	**16.5**
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
HFCs	**36.9**	**103.2**	**120.2**	**123.4**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[a]	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	**315.8**	**348.8**	**334.1**	**339.4**	**350.9**	**331.7**	**282.9**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Overall, emissions from industrial processes decreased by 10.4 percent from 1990 to 2009 due to decreases in emissions from several industrial processes, such as iron and steel production and metallurgical coke production, HCFC-22 production, aluminum production, adipic acid production, and electrical transmission and distribution. Significant trends in emissions from industrial processes source categories over the twenty-year period from 1990 through 2009 included the following:

- Combined CO_2 and CH_4 emissions from iron and steel production and metallurgical coke production decreased by 36.6 percent to 42.2 Tg CO_2 Eq. from 2008 to 2009, and have declined overall by 58.2 Tg CO_2 Eq. (58.0 percent) from 1990 through 2009, due to restructuring of the industry, technological improvements, and increased scrap utilization.
- CO_2 emissions from ammonia production and urea consumption (11.8 Tg CO_2 Eq. in 2009) have decreased by 5.0 Tg CO_2 Eq. (29.9 percent) since 1990, due to a decrease in domestic ammonia production. This decrease in ammonia production is primarily attributed to market fluctuations.
- N_2O emissions from adipic acid production were 1.9 Tg CO_2 Eq. in 2009, and have decreased significantly in recent years from the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 87.7 percent since 1990 and by 89.0 percent since a peak in 1995.
- HFC emissions from ODS substitutes have been increasing from small amounts in 1990 to 120.0 Tg CO_2 Eq. in 2009. This increase results from efforts to phase out CFCs and other ODSs in the United States. In the short term, this trend is expected to continue, and will likely accelerate over the next decade as HCFCs—which are interim substitutes in many applications—are phased out under the provisions of the Copenhagen Amendments to the Montreal Protocol.
- PFC emissions from aluminum production decreased by about 91.5 percent (17.0 Tg CO_2 Eq.) from 1990 to 2009, due to both industry emission reduction efforts and lower domestic aluminum production.

Solvent and Other Product Use

Greenhouse gas emissions are produced as a by-product of various solvent and other product uses. In the United States, N_2O Emissions from Product Uses, the only source of greenhouse gas emissions from this sector, accounted for 4.4 Tg CO_2 Eq., or less than 0.1 percent of total U.S. emissions in 2009 (see Table 2-7).

Table 2-7: N_2O Emissions from Solvent and Other Product Use (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
N_2O	**4.4**	**4.9**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Total	**4.4**	**4.9**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**

In 2009, N_2O emissions from product uses constituted 1.5 percent of U.S. N_2O emissions. From 1990 to 2009, emissions from this source category decreased by just under 0.4 percent, though slight increases occurred in intermediate years.

Agriculture

Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues.

In 2009, agricultural activities were responsible for emissions of 419.3 Tg CO_2 Eq., or 6.3 percent of total U.S. greenhouse gas emissions. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented about 20.4 percent and 7.2 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2009. Agricultural soil management activities, such as fertilizer application and other cropping practices, were the largest source of U.S. N_2O emissions in 2009, accounting for 69.2 percent.

Figure 2-10: 2009 Agriculture Chapter Greenhouse Gas Sources

Table 2-8: Emissions from Agriculture (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH_4	**171.2**	**186.7**	**190.1**	**191.7**	**198.2**	**197.5**	**196.8**
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
N_2O	**212.4**	**224.0**	**228.7**	**227.1**	**227.6**	**228.8**	**222.5**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**383.6**	**410.6**	**418.8**	**418.8**	**425.8**	**426.3**	**419.3**

Note: Totals may not sum due to independent rounding.

Some significant trends in U.S. emissions from Agriculture include the following:

- Agricultural soils produced approximately 69 percent of N_2O emissions in the United States in 2009. Estimated emissions from this source in 2009 were 204.6 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3.4 percent higher in 2009 than in 1990. Nitrous oxide emissions from this source have not shown any significant long-term trend, as their estimation is highly sensitive to the amount of N applied to soils, which has not changed significantly over the time-period, and to weather patterns and crop type.
- Enteric fermentation was the largest source of CH_4 emissions in 2009, at 139.8 Tg CO_2 Eq. Generally, emissions decreased from 1996 to 2003, though with a slight increase in 2002. This trend was mainly due to decreasing populations of both beef and dairy cattle and increased digestibility of feed for feedlot cattle. Emissions increased from 2004 through 2007, as both dairy and beef populations increased and the literature for dairy cow diets indicated a trend toward a decrease in feed digestibility for those years. Emissions decreased again in 2008 and 2009 as beef cattle populations decreased again. During the timeframe of this analysis, populations of sheep have decreased 49 percent since 1990 while horse populations have increased over 87 percent, mostly since 1999. Goat and swine populations have increased 25 percent and 23 percent, respectively, during this timeframe.
- Overall, emissions from manure management increased 46 percent between 1990 and 2009. This encompassed an increase of 56 percent for CH_4, from 31.7 Tg CO_2 Eq. in 1990 to 49.5 Tg CO_2 Eq. in 2009; and an increase of 23 percent for N_2O, from 14.5 Tg CO_2 Eq. in 1990 to 17.9 Tg CO_2 Eq. in 2009. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions.

Land Use, Land-Use Change, and Forestry

When humans alter the terrestrial biosphere through land use, changes in land use, and land management practices, they also alter the background carbon fluxes between biomass, soils, and the atmosphere. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps have resulted in an uptake (sequestration) of carbon in the United States, which offset about 15 percent of total U.S. greenhouse gas emissions in 2009. Forests (including vegetation, soils, and harvested wood) accounted for approximately 85 percent of total 2009 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2009. The net forest sequestration is a result of net forest growth, increasing forest area, and a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth and increased urban forest size. In agricultural soils, mineral and organic soils

sequester approximately 5.5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to hay production fields, the limited use of bare-summer fallow areas in semi-arid areas, and an increase in the adoption of conservation tillage practices. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO_2 Eq. (276.8 Tg C) (Table 2-9). This represents an offset of approximately 18 percent of total U.S. CO_2 emissions, or 15 percent of total greenhouse gas emissions in 2009. Between 1990 and 2009, total land use, land-use change, and forestry net C flux resulted in a 17.8 percent increase in CO_2 sequestration.

Table 2-9: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Sink Category	1990	2000	2005	2006	2007	2008	2009
Forest Land Remaining Forest Land	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Land use, land-use change, and forestry source categories also resulted in emissions of CO_2, CH_4, and N_2O that are not included in the net CO_2 flux estimates presented in Table 2-9. The application of crushed limestone and dolomite to managed land (i.e., soil liming) and urea fertilization resulted in CO_2 emissions of 7.8 Tg CO_2 Eq. in 2009, an increase of about 10.6 percent relative to 1990. Lands undergoing peat extraction resulted in CO_2 emissions of 1.1 Tg CO_2 Eq. (1,090 Gg), and N_2O emissions of less than 0.01 Tg CO_2 Eq. N_2O emissions from the application of synthetic fertilizers to forest soils have increased from 0.1 Tg CO_2 Eq. in 1990 to 0.4 Tg CO_2 Eq. in 2009. Settlement soils in 2009 resulted in direct N_2O emissions of 1.5 Tg CO_2 Eq., a 55 percent increase relative to 1990. Emissions from forest fires in 2009 resulted in CH_4 emissions of 7.8 Tg CO_2 Eq., and in N_2O emissions of 6.4 Tg CO_2 Eq. (Table 2-10).

Table 2-10: Emissions from Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Source Category	1990	2000	2005	2006	2007	2008	2009
CO_2	**8.1**	**8.8**	**8.9**	**8.8**	**9.2**	**9.6**	**8.9**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Cropland Remaining Cropland: Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH_4	**3.2**	**14.3**	**9.8**	**21.6**	**20.0**	**11.9**	**7.8**
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N_2O	**3.7**	**13.2**	**9.8**	**19.5**	**18.3**	**11.6**	**8.3**
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**15.0**	**36.3**	**28.6**	**49.8**	**47.5**	**33.2**	**25.0**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Other significant trends from 1990 to 2009 in land use, land-use change, and forestry emissions include:

- Net C sequestration by forest land has increased by almost 27 percent. This is primarily due to increased forest management and the effects of previous reforestation. The increase in intensive forest management resulted in higher growth rates and higher biomass density. The tree planting and conservation efforts of the 1970s and 1980s continue to have a significant impact on sequestration rates. Finally, the forested area in the United States increased over the past 20 years, although only at an average rate of 0.21 percent per year.
- Net sequestration of C by urban trees has increased by 68 percent over the period from 1990 to 2009. This is primarily due to an increase in urbanized land area in the United States.
- Annual C sequestration in landfilled yard trimmings and food scraps has decreased by 48 percent since 1990. This is due in part to a decrease in the amount of yard trimmings and food scraps generated. In addition, the proportion of yard trimmings and food scraps landfilled has decreased, as there has been a significant rise in the number of municipal composting facilities in the United States.

Waste

Waste management and treatment activities are sources of greenhouse gas emissions (see Figure 2-11). In 2009, landfills were the third largest source of anthropogenic CH_4 emissions, accounting for 17 percent of total U.S. CH_4 emissions.[47] Additionally, wastewater treatment accounts for 4 percent of U.S. CH_4 emissions, and 2 percent of N_2O emissions. Emissions of CH_4 and N_2O from composting grew from 1990 to 2009, and resulted in emissions of 3.5 Tg CO_2 Eq. in 2009. A summary of greenhouse gas emissions from the Waste chapter is presented in Table 2-11.

Figure 2-11: 2009 Waste Chapter Greenhouse Gas Sources

Overall, in 2009, waste activities generated emissions of 150.5 Tg CO_2 Eq., or 2.3 percent of total U.S. greenhouse gas emissions.

Table 2-11: Emissions from Waste (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH_4	**171.2**	**138.1**	**138.4**	**137.8**	**137.4**	**142.1**	**143.6**
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
N_2O	**4.0**	**5.9**	**6.5**	**6.6**	**6.7**	**6.8**	**6.9**
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Total	**175.2**	**143.9**	**144.9**	**144.4**	**144.1**	**149.0**	**150.5**

Note: Totals may not sum due to independent rounding.

Some significant trends in U.S. emissions from Waste include the following:

- Combined CO_2 and CH_4 emissions from composting have generally increased since 1990, from 0.7 Tg CO_2 Eq. to 3.5 Tg CO_2 Eq. in 2009, an over four-fold increase over the time series.
- From 1990 to 2009, net CH_4 emissions from landfills decreased by 29.9 Tg CO_2 Eq. (20 percent), with small increases occurring in interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas collected and combusted,[48] which has more than offset the

[47] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land Use, Land-Use Change, and Forestry chapter.

[48] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

- From 1990 to 2009, CH_4 and N_2O emissions from wastewater treatment increased by 1.0 Tg CO_2 Eq. (4.4 percent) and 1.3 Tg CO_2 Eq. (36 percent), respectively.

2.2. Emissions by Economic Sector

Throughout this report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC and detailed above: Energy; Industrial Processes; Solvent and Other Product Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following U.S. economic sectors: residential, commercial, industry, transportation, electricity generation, and agriculture, as well as U.S. territories.

Using this categorization, emissions from electricity generation accounted for the largest portion (33 percent) of U.S. greenhouse gas emissions in 2009. Transportation activities, in aggregate, accounted for the second largest portion (27 percent). Emissions from industry accounted for about 20 percent of U.S. greenhouse gas emissions in 2009. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements. The remaining 20 percent of U.S. greenhouse gas emissions were contributed by the residential, agriculture, and commercial sectors, plus emissions from U.S. territories. The residential sector accounted for 5 percent, and primarily consisted of CO_2 emissions from fossil fuel combustion. Activities related to agriculture accounted for roughly 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation, rather than CO_2 from fossil fuel combustion. The commercial sector accounted for roughly 6 percent of emissions, while U.S. territories accounted for less than 1 percent.

CO_2 was also emitted and sequestered (in the form of C) by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Table 2-12 presents a detailed breakdown of emissions from each of these economic sectors by source category, as they are defined in this report. Figure 2-12 shows the trend in emissions by sector from 1990 to 2009.

Figure 2-12: Emissions Allocated to Economic Sectors

Table 2-12: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg CO_2 Eq. and Percent of Total in 2009)

Sector/Source	1990	2000	2005	2006	2007	2008	2009	Percent[a]
Electric Power Industry	**1,868.9**	**2,337.6**	**2,444.6**	**2,388.2**	**2,454.0**	**2,400.7**	**2,193.0**	**33.1%**
CO_2 from Fossil Fuel Combustion	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0	32.5%
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8	0.2%
Incineration of Waste	8.5	11.5	12.9	12.9	13.1	12.5	12.7	0.2%
Stationary Combustion	8.6	10.6	11.0	10.8	11.0	10.8	9.7	0.1%
Limestone and Dolomite Use	2.6	2.5	3.4	4.0	3.9	3.1	3.8	0.1%
Transportation	**1,545.2**	**1,932.3**	**2,017.4**	**1,994.4**	**2,003.8**	**1,890.7**	**1,812.4**	**27.3%**
CO_2 from Fossil Fuel Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7	25.9%
Substitution of Ozone Depleting Substances	+	55.7	72.9	72.2	68.8	64.9	60.2	0.9%
Mobile Combustion	47.4	55.1	37.7	34.2	30.7	26.4	24.0	0.4%
Non-Energy Use of Fuels	11.8	12.1	10.2	9.9	10.2	9.5	8.5	0.1%
Industry	**1,564.4**	**1,544.0**	**1,441.9**	**1,497.3**	**1,483.0**	**1,446.9**	**1,322.7**	**19.9%**
CO_2 from Fossil Fuel Combustion	815.4	812.3	776.3	799.2	793.6	757.4	683.8	10.3%

Natural Gas Systems	227.4	239.2	220.4	248.4	236.2	244.6	253.4	3.8%
Non-Energy Use of Fuels	101.1	122.8	125.2	126.8	119.8	123.1	111.1	1.7%
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0	1.1%
Iron and Steel Production & Metallurgical Coke Production	100.5	86.9	66.6	69.5	71.7	66.7	42.2	0.6%
Petroleum Systems	35.9	32.0	29.9	29.8	30.4	30.7	31.4	0.5%
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0	0.4%
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6	0.2%
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8	0.2%
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2	0.2%
Substitution of Ozone Depleting Substances	+	3.2	6.4	7.1	7.8	8.5	10.9	0.2%
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5	0.1%
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4	0.1%
Semiconductor Manufacture	2.9	6.2	4.4	4.7	4.8	5.1	5.3	0.1%
Aluminum Production	25.4	14.7	7.1	6.3	8.1	7.2	4.6	0.1%
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4	0.1%
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3	0.1%
Limestone and Dolomite Use	2.6	2.5	3.4	4.0	3.9	3.1	3.8	0.1%
Stationary Combustion	4.7	4.8	4.4	4.6	4.4	4.1	3.6	0.1%
Petrochemical Production	4.2	5.7	5.3	4.8	4.9	4.4	3.6	0.1%
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9	+
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8	+
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5	+
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5	+
Mobile Combustion	0.9	1.1	1.3	1.3	1.3	1.3	1.3	+
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1	+
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0	+
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0	+
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5	+
Silicon Carbide Production and Consumption	0.4	0.3	0.2	0.2	0.2	0.2	0.2	+
Agriculture	**429.0**	**485.1**	**493.2**	**516.7**	**520.7**	**503.9**	**490.0**	**7.4%**
N_2O from Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6	3.1%
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8	2.1%
Manure Management	46.2	59.5	63.8	64.8	68.9	67.3	67.3	1.0%
CO_2 from Fossil Fuel Combustion	31.04	38.79	46.81	49.04	48.44	45.44	46.66	0.7%
CH_4 and N_2O from Forest Fires	5.8	26.0	17.8	39.2	36.4	21.7	14.2	0.2%
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3	0.1%
Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2	0.1%
Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6	0.1%
CO_2 and N_2O from Managed Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1	+
Mobile Combustion	0.3	0.4	0.5	0.5	0.5	0.5	0.5	+
N_2O from Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4	+
Field Burning of Agricultural Residues	0.4	0.4	0.3	0.3	0.3	0.4	0.4	+

Stationary Combustion	+	+	+	+	+	+	+	+
Commercial	**395.5**	**381.4**	**387.2**	**375.2**	**389.6**	**403.5**	**409.5**	**6.2%**
CO_2 from Fossil Fuel Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0	3.4%
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5	1.8%
Substitution of Ozone Depleting Substances	+	5.4	17.6	21.1	24.9	29.1	33.7	0.5%
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5	0.4%
Human Sewage	3.7	4.5	4.8	4.8	4.9	5.0	5.0	0.1%
Composting	0.7	2.6	3.3	3.3	3.5	3.5	3.5	0.1%
Stationary Combustion	1.3	1.3	1.2	1.2	1.2	1.2	1.2	+
Residential	**345.1**	**386.2**	**371.0**	**335.8**	**358.9**	**367.1**	**360.1**	**5.4%**
CO_2 from Fossil Fuel Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2	5.1%
Substitution of Ozone Depleting Substances	0.3	10.1	7.3	8.9	10.7	12.9	15.1	0.2%
Stationary Combustion	5.5	4.3	4.3	3.9	4.2	4.4	4.2	0.1%
Settlement Soil Fertilization	1.0	1.1	1.5	1.5	1.6	1.5	1.5	+
U.S. Territories	**33.7**	**46.0**	**58.2**	**59.3**	**53.5**	**48.4**	**45.5**	**0.7%**
CO_2 from Fossil Fuel Combustion	27.9	35.9	50.0	50.3	46.1	39.8	41.7	0.6%
Non-Energy Use of Fuels	5.7	10.0	8.1	8.8	7.2	8.4	3.7	0.1%
Stationary Combustion	0.1	0.1	0.2	0.2	0.2	0.2	0.2	+
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**	**100.0%**
Sinks	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**	**-15.3%**
CO_2 Flux from Forests[b]	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)	-13.0%
Urban Trees	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)	-1.4%
CO_2 Flux from Agricultural Soil Carbon Stocks	(99.2)	(107.6)	(45.6)	(46.1)	(46.3)	(44.4)	(43.4)	-0.7%
Landfilled Yard Trimmings and Food Scraps	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)	-0.2%
Net Emissions	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**	**84.7%**

Note: Includes all emissions of CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6. Parentheses indicate negative values or sequestration. Totals may not sum due to independent rounding.
ODS (Ozone Depleting Substances)
+ Does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.
[a] Percent of total emissions for year 2009.
[b] Includes the effects of net additions to stocks of carbon stored in harvested wood products.

Emissions with Electricity Distributed to Economic Sectors

It can also be useful to view greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). The generation, transmission, and distribution of electricity, which is the largest economic sector in the United States, accounted for 33 percent of total U.S. greenhouse gas emissions in 2009. Emissions increased by 17 percent since 1990, as electricity demand grew and fossil fuels remained the dominant energy source for generation. Electricity generation-related emissions decreased from 2008 to 2009 by 9 percent, primarily due to decreased CO_2 emissions from fossil fuel combustion. The decrease in electricity-related emissions was due to decreased economic output and the resulting decrease in electricity demand. Electricity-related emissions also declined due to a decrease in the carbon intensity of fuels used to generate electricity. This was caused by fuel switching as the price of coal increased and the price natural gas decreased significantly. The fuel switching from coal to natural gas and additional electricity generation from other energy sources in 2009, which included a 7 percent increase in hydropower generation from the previous year, resulted in a decrease in carbon intensity, and in turn, a decrease in emissions from electricity generation. The electricity generation sector in the United States is composed of traditional electric utilities as well as other entities, such as power marketers and non-utility power producers. The majority of electricity generated by these entities was

through the combustion of coal in boilers to produce high-pressure steam that is passed through a turbine. Table 2-13 provides a detailed summary of emissions from electricity generation-related activities.

Table 2-13: Electricity Generation-Related Greenhouse Gas Emissions (Tg CO_2 Eq.)

Gas/Fuel Type or Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**1,831.4**	**2,310.5**	**2,418.0**	**2,363.0**	**2,429.4**	**2,376.2**	**2,170.1**
CO_2 from Fossil Fuel Combustion	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Coal	*1,547.6*	*1,927.4*	*1,983.8*	*1,953.7*	*1,987.3*	*1,959.4*	*1,747.6*
Natural Gas	*175.3*	*280.8*	*318.8*	*338.0*	*371.3*	*361.9*	*373.1*
Petroleum	*97.5*	*88.4*	*99.2*	*54.4*	*53.9*	*39.2*	*32.9*
Geothermal	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Limestone and Dolomite Use	2.6	2.5	3.4	4.0	3.9	3.1	3.8
CH_4	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Stationary Combustion*	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Incineration of Waste	+	+	+	+	+	+	+
N_2O	**8.5**	**10.4**	**10.7**	**10.5**	**10.6**	**10.4**	**9.4**
Stationary Combustion*	8.1	10.0	10.3	10.1	10.2	10.1	9.0
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
SF_6	**28.4**	**16.0**	**15.1**	**14.1**	**13.2**	**13.3**	**12.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Total	**1,868.9**	**2,337.6**	**2,444.6**	**2,388.2**	**2,454.0**	**2,400.7**	**2,193.0**

Note: Totals may not sum due to independent rounding.

* Includes only stationary combustion emissions related to the generation of electricity.

+ Does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

To distribute electricity emissions among economic end-use sectors, emissions from the source categories assigned to the electricity generation sector were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity (EIA 2010 and Duffield 2006). These three source categories include CO_2 from Fossil Fuel Combustion, CH_4 and N_2O from Stationary Combustion, and SF_6 from Electrical Transmission and Distribution Systems.[49]

When emissions from electricity are distributed among these sectors, industry activities account for the largest share of total U.S. greenhouse gas emissions (28.8 percent), followed closely by emissions from transportation (27.4 percent). Emissions from the residential and commercial sectors also increase substantially when emissions from electricity are included. In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels.

Table 2-14 presents a detailed breakdown of emissions from each of these economic sectors, with emissions from electricity generation distributed to them. Figure 2-13 shows the trend in these emissions by sector from 1990 to 2009.

Figure 2-13: Emissions with Electricity Distributed to Economic Sectors

Table 2-14: U.S Greenhouse Gas Emissions by Economic Sector and Gas with Electricity-Related Emissions Distributed (Tg CO_2 Eq.) and Percent of Total in 2009

Sector/Gas	1990	2000	2005	2006	2007	2008	2009	Percent[a]
Industry	**2,238.3**	**2,314.4**	**2,162.5**	**2,194.6**	**2,192.9**	**2,146.5**	**1,910.9**	**28.8%**
Direct Emissions	***1,564.4***	***1,544.0***	***1,441.9***	***1,497.3***	***1,483.0***	***1,446.9***	***1,322.7***	19.9%

[49] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

CO_2	1,140.5	1,147.9	1,093.8	1,123.1	1,113.7	1,070.1	942.7	14.2%
CH_4	318.8	312.5	285.7	314.1	301.9	318.1	331.2	5.0%
N_2O	41.8	34.0	30.0	29.1	31.4	26.8	24.5	0.4%
HFCs, PFCs, and SF_6	63.3	49.6	32.5	31.0	36.0	31.9	24.2	0.4%
Electricity-Related	***673.9***	***770.4***	***720.5***	***697.3***	***709.9***	***699.7***	***588.3***	8.9%
CO_2	660.3	761.5	712.7	689.9	702.8	692.5	582.2	8.8%
CH_4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	+
N_2O	3.1	3.4	3.2	3.1	3.1	3.0	2.5	+
SF_6	10.2	5.3	4.5	4.1	3.8	3.9	3.4	0.1%
Transportation	**1,548.3**	**1,935.8**	**2,022.2**	**1,999.0**	**2,008.9**	**1,895.5**	**1,816.9**	**27.4%**
Direct Emissions	***1,545.2***	***1,932.3***	***2,017.4***	***1,994.4***	***2,003.8***	***1,890.7***	***1,812.4***	27.3%
CO_2	1,497.8	1,821.6	1,906.8	1,888.0	1,904.2	1,799.4	1,728.2	26.1%
CH_4	4.5	3.1	2.2	2.0	1.9	1.7	1.6	+
N_2O	42.9	51.9	35.5	32.1	28.8	24.6	22.4	0.3%
HFCs[b]	+	55.7	72.9	72.2	68.8	64.9	60.2	0.9%
Electricity-Related	***3.1***	***3.5***	***4.8***	***4.6***	***5.1***	***4.7***	***4.5***	0.1%
CO_2	3.1	3.5	4.8	4.6	5.1	4.7	4.5	0.1%
CH_4	+	+	+	+	+	+	+	+
N_2O	+	+	+	+	+	+	+	+
SF_6	+	+	+	+	+	+	+	+
Commercial	**947.7**	**1,135.8**	**1,205.1**	**1,188.5**	**1,225.3**	**1,224.5**	**1,184.9**	**17.9%**
Direct Emissions	***395.5***	***381.4***	***387.2***	***375.2***	***389.6***	***403.5***	***409.5***	6.2%
CO_2	219.0	230.8	223.5	208.6	219.4	224.2	224.0	3.4%
CH_4	172.1	139.0	139.3	138.7	138.2	143.1	144.5	2.2%
N_2O	4.4	6.2	6.8	6.9	7.1	7.2	7.2	0.1%
HFCs	+	5.4	17.6	21.1	24.9	29.1	33.7	0.5%
Electricity-Related	***552.2***	***754.4***	***817.9***	***813.2***	***835.7***	***821.0***	***775.4***	11.7%
CO_2	541.1	745.7	809.0	804.7	827.4	812.7	767.4	11.6%
CH_4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	+
N_2O	2.5	3.3	3.6	3.6	3.6	3.6	3.3	+
SF_6	8.4	5.2	5.1	4.8	4.5	4.6	4.5	0.1%
Residential	**953.8**	**1,162.2**	**1,242.9**	**1,181.5**	**1,229.6**	**1,215.1**	**1,158.9**	**17.5%**
Direct Emissions	***345.1***	***386.2***	***371.0***	***335.8***	***358.9***	***367.1***	***360.1***	5.4%
CO_2	338.3	370.7	357.9	321.5	342.4	348.2	339.2	5.1%
CH_4	4.4	3.4	3.4	3.1	3.4	3.5	3.4	0.1%
N_2O	2.1	2.1	2.4	2.3	2.4	2.4	2.4	+
HFCs	0.3	10.1	7.3	8.9	10.7	12.9	15.1	0.2%
Electricity-Related	***608.7***	***775.9***	***871.9***	***845.6***	***870.7***	***848.1***	***798.8***	12.0%
CO_2	596.5	767.0	862.4	836.7	862.0	839.4	790.5	11.9%
CH_4	0.2	0.2	0.3	0.3	0.3	0.2	0.2	+
N_2O	2.8	3.4	3.8	3.7	3.8	3.7	3.4	0.1%
SF_6	9.2	5.3	5.4	5.0	4.7	4.7	4.7	0.1%
Agriculture	**460.0**	**518.4**	**522.7**	**544.1**	**553.2**	**531.1**	**516.0**	**7.8%**
Direct Emissions	***429.0***	***485.1***	***493.2***	***516.7***	***520.7***	***503.9***	***490.0***	7.4%
CO_2	39.2	47.6	55.7	57.8	57.7	55.1	55.6	0.8%
CH_4	174.5	201.1	200.1	213.4	218.4	209.6	204.8	3.1%
N_2O	215.3	236.4	237.4	245.4	244.7	239.2	229.7	3.5%
Electricity-Related	***31.0***	***33.3***	***29.4***	***27.4***	***32.5***	***27.2***	***25.9***	0.4%
CO_2	30.4	32.9	29.1	27.1	32.2	26.9	25.7	0.4%
CH_4	+	+	+	+	+	+	+	+
N_2O	0.1	0.1	0.1	0.1	0.1	0.1	0.1	+
SF_6	0.5	0.2	0.2	0.2	0.2	0.2	0.2	+
U.S. Territories	**33.7**	**46.0**	**58.2**	**59.3**	**53.5**	**48.4**	**45.5**	**0.7%**
Total	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**	**100.0%**

Note: Emissions from electricity generation are allocated based on aggregate electricity consumption in each end-use sector. Totals may not sum due to independent rounding.

+ Does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.
[a] Percent of total emissions for year 2009.
[b] Includes primarily HFC-134a.

Industry

The industrial end-use sector includes CO_2 emissions from fossil fuel combustion from all manufacturing facilities, in aggregate. This sector also includes emissions that are produced as a by-product of the non-energy-related industrial process activities. The variety of activities producing these non-energy-related emissions includes methane emissions from petroleum and natural gas systems, fugitive CH_4 emissions from coal mining, by-product CO_2 emissions from cement manufacture, and HFC, PFC, and SF_6 by-product emissions from semiconductor manufacture, to name a few. Since 1990, industrial sector emissions have declined. The decline has occurred both in direct emissions and indirect emissions associated with electricity use. However, the decline in direct emissions has been sharper. In theory, emissions from the industrial end-use sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions. In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive products (e.g., from steel to computer equipment) also have a significant effect on industrial emissions.

Transportation

When electricity-related emissions are distributed to economic end-use sectors, transportation activities accounted for 27 percent of U.S. greenhouse gas emissions in 2009. The largest sources of transportation greenhouse gases in 2009 were passenger cars (35 percent), light duty trucks, which include sport utility vehicles, pickup trucks, and minivans (30 percent), freight trucks (20 percent) and commercial aircraft (6 percent). These figures include direct emissions from fossil fuel combustion, as well as HFC emissions from mobile air conditioners and refrigerated transport allocated to these vehicle types. Table 2-15 provides a detailed summary of greenhouse gas emissions from transportation-related activities with electricity-related emissions included in the totals.

From 1990 to 2009, transportation emissions rose by 17 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

From 2008 to 2009, CO_2 emissions from the transportation end-use sector declined 4 percent. The decrease in emissions can largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. Similarly, increased jet fuel prices were a factor in the 19 percent decrease in commercial aircraft emissions since 2007.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 16 percent from 1990 to 2009. This rise in CO_2 emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 60.2 Tg CO_2 Eq. in 2009, led to an increase in overall emissions from transportation activities of 17 percent.

Although average fuel economy over this period increased slightly due primarily to the retirement of older vehicles, average fuel economy among new vehicles sold annually gradually declined from 1990 to 2004. The decline in new vehicle fuel economy between 1990 and 2004 reflected the increasing market share of light duty trucks, which grew from about one-fifth of new vehicle sales in the 1970s to slightly over half of the market by 2004. Increasing fuel prices have since decreased the momentum of light duty truck sales, and average new vehicle fuel economy has improved since 2005 as the market share of passenger cars increased. VMT growth among all passenger vehicles has also been impacted, remaining stagnant from 2004 to 2007, compared to an average annual growth rate of 2.5 percent over the period 1990 to 2004. The recession supplemented the effect of increasing fuel prices in 2008 and VMT declined by 2.1 percent, the first decrease in annual passenger vehicle VMT since 1990. Overall, VMT grew by 0.2 percent in 2009. Gasoline fuel consumption increased slightly, while consumption of diesel fuel continued to

decrease, due in part to a decrease in commercial activity and freight trucking as a result of the economic recession.

Table 2-15: Transportation-Related Greenhouse Gas Emissions (Tg CO_2 Eq.)

Gas/Vehicle Type	1990	2000	2005	2006	2007	2008	2009
Passenger Cars	**657.4**	**695.3**	**709.5**	**682.9**	**672.0**	**632.5**	**627.4**
CO_2	629.3	644.2	662.3	639.1	632.8	597.9	597.2
CH_4	2.6	1.6	1.1	1.0	0.9	0.8	0.7
N_2O	25.4	25.2	17.8	15.7	13.8	11.7	10.1
HFCs	+	24.3	28.4	27.1	24.6	22.1	19.3
Light-Duty Trucks	**336.6**	**512.1**	**551.3**	**564.0**	**570.3**	**553.8**	**551.0**
CO_2	321.1	467.0	505.9	519.5	528.4	515.1	514.5
CH_4	1.4	1.1	0.7	0.7	0.6	0.6	0.6
N_2O	14.1	22.4	13.7	12.6	11.2	9.5	9.4
HFCs	+	21.7	31.0	31.2	30.1	28.6	26.6
Medium- and Heavy-Duty Trucks	**231.1**	**354.6**	**408.4**	**418.6**	**425.2**	**403.1**	**365.6**
CO_2	230.1	345.8	396.0	406.1	412.5	390.4	353.1
CH_4	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	0.8	1.2	1.1	1.1	1.1	1.0	0.8
HFCs	+	7.4	11.1	11.4	11.5	11.6	11.6
Buses	**8.4**	**11.2**	**12.0**	**12.3**	**12.5**	**12.2**	**11.2**
CO_2	8.4	11.1	11.8	12.0	12.1	11.8	10.8
CH_4	+	+	+	+	+	+	+
N_2O	+	+	+	+	+	+	+
HFCs	+	0.1	0.2	0.3	0.3	0.4	0.4
Motorcycles	**1.8**	**1.9**	**1.7**	**1.9**	**2.1**	**2.2**	**2.2**
CO_2	1.7	1.8	1.6	1.9	2.1	2.1	2.1
CH_4	+	+	+	+	+	+	+
N_2O	+	+	+	+	+	+	+
Commercial Aircraft[a]	**136.8**	**170.9**	**162.8**	**138.5**	**139.5**	**123.4**	**112.5**
CO_2	135.4	169.2	161.2	137.1	138.1	122.2	111.4
CH_4	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	1.3	1.6	1.5	1.3	1.3	1.2	1.1
Other Aircraft[b]	**44.4**	**33.5**	**35.9**	**35.1**	**33.2**	**35.2**	**29.6**
CO_2	43.9	33.1	35.5	34.7	32.8	34.8	29.3
CH_4	0.1	0.1	0.1	0.1	0.1	0.1	+
N_2O	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Ships and Boats[c]	**45.1**	**61.0**	**45.2**	**48.4**	**55.2**	**37.1**	**30.5**
CO_2	44.5	60.0	44.5	47.7	54.4	36.6	30.0
CH_4	+	+	+	+	+	+	+
N_2O	0.6	0.9	0.6	0.7	0.8	0.5	0.4
HFCs	+	0.1	+	+	+	+	+
Rail	**39.0**	**48.1**	**53.0**	**55.1**	**54.3**	**50.6**	**43.3**
CO_2	38.5	45.6	50.3	52.4	51.6	47.9	40.6
CH_4	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	0.3	0.3	0.4	0.4	0.4	0.4	0.3
HFCs	+	2.0	2.2	2.2	2.2	2.3	2.3
Other Emissions from Electricity Generation[d]	0.1	+	0.1	0.1	0.1	0.1	0.1
Pipelines[e]	**36.0**	**35.2**	**32.2**	**32.3**	**34.3**	**35.7**	**35.2**
CO_2	36.0	35.2	32.2	32.3	34.3	35.7	35.2
Lubricants	**11.8**	**12.1**	**10.2**	**9.9**	**10.2**	**9.5**	**8.5**
CO_2	11.8	12.1	10.2	9.9	10.2	9.5	8.5
Total Transportation	**1,548.3**	**1,935.8**	**2,022.2**	**1,999.0**	**2,008.9**	**1,895.4**	**1,816.9**
International Bunker	*113.0*	*99.5*	*110.9*	*129.7*	*129.0*	*135.1*	*124.4*

Fuels[f]			

Note: Totals may not sum due to independent rounding. Passenger cars and light-duty trucks include vehicles typically used for personal travel and less than 8500 lbs; medium- and heavy-duty trucks include vehicles larger than 8500 lbs. HFC emissions primarily reflect HFC-134a.
+ Does not exceed 0.05 Tg CO_2 Eq.
[a] Consists of emissions from jet fuel consumed by domestic operations of commercial aircraft (no bunkers).
[b] Consists of emissions from jet fuel and aviation gasoline consumption by general aviation and military aircraft.
[c] Fluctuations in emission estimates are associated with fluctuations in reported fuel consumption, and may reflect data collection problems.
[d] Other emissions from electricity generation are a result of waste incineration (as the majority of municipal solid waste is combusted in "trash-to-steam" electricity generation plants), electrical transmission and distribution, and a portion of limestone and dolomite use (from pollution control equipment installed in electricity generation plants).
[e] CO_2 estimates reflect natural gas used to power pipelines, but not electricity. While the operation of pipelines produces CH_4 and N_2O, these emissions are not directly attributed to pipelines in the US Inventory.
[f] Emissions from International Bunker Fuels include emissions from both civilian and military activities; these emissions are not included in the transportation totals.

Commercial

The commercial sector is heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Energy-related emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. Landfills and wastewater treatment are included in this sector, with landfill emissions decreasing since 1990 and wastewater treatment emissions increasing slightly.

Residential

The residential sector is heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Emissions from the residential sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. In the long-term, this sector is also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

Agriculture

The agriculture sector includes a variety of processes, including enteric fermentation in domestic livestock, livestock manure management, and agricultural soil management. In 2009, agricultural soil management was the largest source of N_2O emissions, and enteric fermentation was the second largest source of CH_4 emissions in the United States. This sector also includes small amounts of CO_2 emissions from fossil fuel combustion by motorized farm equipment like tractors. The agriculture sector relies less heavily on electricity than the other sectors.

[BEGIN BOX]

Box 2-1: Methodology for Aggregating Emissions by Economic Sector

In presenting the Economic Sectors in the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks, the Inventory expands upon the standard IPCC sectors common for UNFCCC reporting. Discussing greenhouse gas emissions relevant to U.S.-specific sectors improves communication of the report's findings.

In the Electricity Generation economic sector, CO_2 emissions from the combustion of fossil fuels included in the

EIA electric utility fuel consuming sector are apportioned to this economic sector. Stationary combustion emissions of CH_4 and N_2O are also based on the EIA electric utility sector. Additional sources include CO_2, CH_4, and N_2O from waste incineration, as the majority of municipal solid waste is combusted in "trash-to-steam" electricity generation plants. The Electricity Generation economic sector also includes SF_6 from Electrical Transmission and Distribution, and a portion of CO_2 from Limestone and Dolomite Use (from pollution control equipment installed in electricity generation plants).

In the Transportation economic sector, the CO_2 emissions from the combustion of fossil fuels included in the EIA transportation fuel consuming sector are apportioned to this economic sector (additional analyses and refinement of the EIA data is further explained in the Energy chapter of this report). Additional emissions are apportioned from the CH_4 and N_2O from Mobile Combustion, based on the EIA transportation sector. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with emissions from transportation refrigeration/air-conditioning systems to this economic sector. Finally, CO_2 emissions from Non-Energy Uses of Fossil Fuels identified as lubricants for transportation vehicles are included in the Transportation economic sector.

For the Industry economic sector, the CO_2 emissions from the combustion of fossil fuels included in the EIA industrial fuel consuming sector, minus the agricultural use of fuel explained below, are apportioned to this economic sector. Stationary and mobile combustion emissions of CH_4 and N_2O are also based on the EIA industrial sector, minus emissions apportioned to the Agriculture economic sector described below. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with most emissions falling within the Industry economic sector (minus emissions from the other economic sectors). Additionally, all process-related emissions from sources with methods considered within the IPCC Industrial Process guidance have been apportioned to this economic sector. This includes the process-related emissions (i.e., emissions from the actual process to make the material, not from fuels to power the plant) from such activities as Cement Production, Iron and Steel Production and Metallurgical Coke Production, and Ammonia Production. Additionally, fugitive emissions from energy production sources, such as Natural Gas Systems, Coal Mining, and Petroleum Systems are included in the Industry economic sector. A portion of CO_2 from Limestone and Dolomite Use (from pollution control equipment installed in large industrial facilities) are also included in the Industry economic sector. Finally, all remaining CO_2 emissions from Non-Energy Uses of Fossil Fuels are assumed to be industrial in nature (besides the lubricants for transportation vehicles specified above), and are attributed to the Industry economic sector.

As agriculture equipment is included in EIA's industrial fuel consuming sector surveys, additional data is used to extract the fuel used by agricultural equipment, to allow for accurate reporting in the Agriculture economic sector from all sources of emissions, such as motorized farming equipment. Energy consumption estimates are obtained from Department of Agriculture survey data, in combination with separate EIA fuel sales reports. This supplementary data is used to apportion CO_2 emissions from fossil fuel combustion, and CH_4 and N_2O emissions from stationary and mobile combustion (all data is removed from the Industrial economic sector, to avoid double-counting). The other emission sources included in this economic sector are intuitive for the agriculture sectors, such as N_2O emissions from Agricultural Soils, CH_4 from Enteric Fermentation (i.e., exhalation from the digestive tracts of domesticated animals), CH_4 and N_2O from Manure Management, CH_4 from Rice Cultivation, CO_2 emissions from Liming of Agricultural Soils and Urea Application, and CH_4 and N_2O from Forest Fires. N_2O emissions from the Application of Fertilizers to tree plantations (termed "forest land" by the IPCC) are also included in the Agriculture economic sector.

The Residential economic sector includes the CO_2 emissions from the combustion of fossil fuels reported for the EIA residential sector. Stationary combustion emissions of CH_4 and N_2O are also based on the EIA residential fuel consuming sector. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with emissions from residential air-conditioning systems to this economic sector. N_2O emissions from the Application of Fertilizers to developed land (termed "settlements" by the IPCC) are also included in the Residential economic sector.

The Commercial economic sector includes the CO_2 emissions from the combustion of fossil fuels reported in the EIA commercial fuel consuming sector data. Stationary combustion emissions of CH_4 and N_2O are also based on the EIA commercial sector. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with emissions from commercial refrigeration/air-conditioning systems to this economic sector. Public works sources including direct CH_4 from Landfills and CH_4 and N_2O from Wastewater Treatment and

Composting are included in this economic sector.

[END BOX]

[BEGIN BOX]

Box 2-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and non-utilities combined—was the largest source of U.S. greenhouse gas emissions in 2009; (4) emissions per unit of total gross domestic product as a measure of national economic activity; or (5) emissions per capita.

Table 2-16 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.4 percent since 1990. This rate is slightly slower than that for total energy consumption and growth in national population since 1990 and much slower than that for electricity consumption and overall gross domestic product, respectively. Total U.S. greenhouse gas emissions are growing at a rate similar to that of fossil fuel consumption since 1990 (see Table 2-16).

Table 2-16: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	1990	2000	2005	2006	2007	2008	2009	Growth Rate[a]
GDP[b]	100	140	157	162	165	165	160	2.5%
Electricity Consumption[c]	100	127	134	135	138	138	132	1.5%
Fossil Fuel Consumption[c]	100	117	119	117	119	116	108	0.5%
Energy Consumption[c]	100	116	118	118	120	118	112	0.6%
Population[d]	100	113	118	120	121	122	123	1.1%
Greenhouse Gas Emissions[e]	100	115	117	116	117	114	107	0.4%

[a] Average annual growth rate
[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)
[c] Energy-content-weighted values (EIA 2010)
[d] U.S. Census Bureau (2010)
[e] GWP-weighted values

Figure 2-14: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product
Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

2.3. Indirect Greenhouse Gas Emissions (CO, NO_x, NMVOCs, and SO_2)

The reporting requirements of the UNFCCC[50] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of

[50] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases. Carbon monoxide is produced when carbon-containing fuels are combusted incompletely. Nitrogen oxides (i.e., NO and NO_2) are created by lightning, fires, fossil fuel combustion, and in the stratosphere from N_2O. Non-CH_4 volatile organic compounds—which include hundreds of organic compounds that participate in atmospheric chemical reactions (i.e., propane, butane, xylene, toluene, ethane, and many others)—are emitted primarily from transportation, industrial processes, and non-industrial consumption of organic solvents. In the United States, SO_2 is primarily emitted from coal combustion for electric power generation and the metals industry. Sulfur-containing compounds emitted into the atmosphere tend to exert a negative radiative forcing (i.e., cooling) and therefore are discussed separately.

One important indirect climate change effect of NMVOCs and NO_x is their role as precursors for tropospheric ozone formation. They can also alter the atmospheric lifetimes of other greenhouse gases. Another example of indirect greenhouse gas formation into greenhouse gases is CO's interaction with the hydroxyl radical—the major atmospheric sink for CH_4 emissions—to form CO_2. Therefore, increased atmospheric concentrations of CO limit the number of hydroxyl molecules (OH) available to destroy CH_4.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2010, EPA 2009),[51] which are regulated under the Clean Air Act. Table 2-17 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table 2-17: Emissions of NO_x, CO, NMVOCs, and SO_2 (Gg)

Gas/Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	**21,707**	**19,116**	**15,900**	**15,039**	**14,380**	**13,547**	**11,468**
Mobile Fossil Fuel Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Fossil Fuel Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Industrial Processes	591	626	569	553	537	520	568
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
Agricultural Burning	8	8	6	7	8	8	8
Solvent Use	1	3	3	4	4	4	3
Waste	0	2	2	2	2	2	2
CO	**130,038**	**92,243**	**70,809**	**67,238**	**63,625**	**60,039**	**51,452**
Mobile Fossil Fuel Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Fossil Fuel Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543
Industrial Processes	4,125	2,216	1,555	1,597	1,640	1,682	1,549
Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Agricultural Burning	268	259	184	233	237	270	247
Oil and Gas Activities	302	146	318	319	320	322	345
Waste	1	8	7	7	7	7	7
Solvent Use	5	45	2	2	2	2	2
NMVOCs	**20,930**	**15,227**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**
Mobile Fossil Fuel Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Solvent Use	5,216	4,384	3,851	3,846	3,839	3,834	2,583
Industrial Processes	2,422	1,773	1,997	1,933	1,869	1,804	1,322
Stationary Fossil Fuel Combustion	912	1,077	716	918	1,120	1,321	424

[51] NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2009) and EPA (2010).

Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
Waste	673	119	114	113	111	109	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**14,830**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**
Stationary Fossil Fuel Combustion	18,407	12,849	11,541	10,612	10,172	8,891	7,167
Industrial Processes	1,307	1,031	831	818	807	795	798
Mobile Fossil Fuel Combustion	793	632	889	750	611	472	455
Oil and Gas Activities	390	287	181	182	184	187	154
Incineration of Waste	38	29	24	24	24	23	24
Waste	0	1	1	1	1	1	1
Solvent Use	0	1	0	0	0	0	0
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.

[BEGIN BOX]

Box 2-3: Sources and Effects of Sulfur Dioxide

Sulfur dioxide (SO_2) emitted into the atmosphere through natural and anthropogenic processes affects the earth's radiative budget through its photochemical transformation into sulfate aerosols that can (1) scatter radiation from the sun back to space, thereby reducing the radiation reaching the earth's surface; (2) affect cloud formation; and (3) affect atmospheric chemical composition (e.g., by providing surfaces for heterogeneous chemical reactions). The indirect effect of sulfur-derived aerosols on radiative forcing can be considered in two parts. The first indirect effect is the aerosols' tendency to decrease water droplet size and increase water droplet concentration in the atmosphere. The second indirect effect is the tendency of the reduction in cloud droplet size to affect precipitation by increasing cloud lifetime and thickness. Although still highly uncertain, the radiative forcing estimates from both the first and the second indirect effect are believed to be negative, as is the combined radiative forcing of the two (IPCC 2001). However, because SO_2 is short-lived and unevenly distributed in the atmosphere, its radiative forcing impacts are highly uncertain.

Sulfur dioxide is also a major contributor to the formation of regional haze, which can cause significant increases in acute and chronic respiratory diseases. Once SO_2 is emitted, it is chemically transformed in the atmosphere and returns to the earth as the primary source of acid rain. Because of these harmful effects, the United States has regulated SO_2 emissions in the Clean Air Act.

Electricity generation is the largest anthropogenic source of SO_2 emissions in the United States, accounting for 83 percent in 2009. Coal combustion contributes nearly all of those emissions (approximately 92 percent). Sulfur dioxide emissions have decreased in recent years, primarily as a result of electric power generators switching from high-sulfur to low-sulfur coal and installing flue gas desulfurization equipment.

[END BOX]

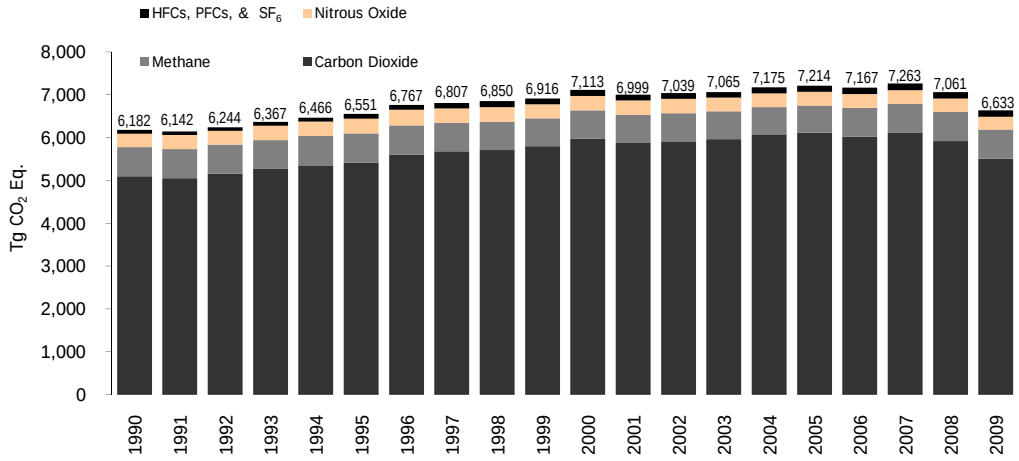


Figure 2-1: U.S. Greenhouse Gas Emissions by Gas

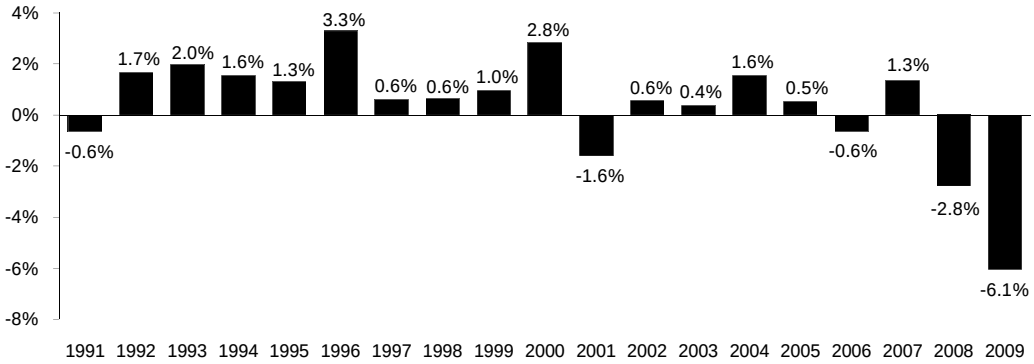


Figure 2-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

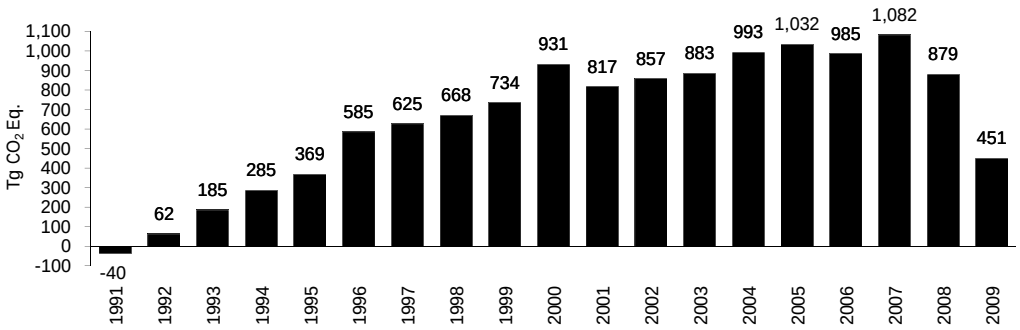
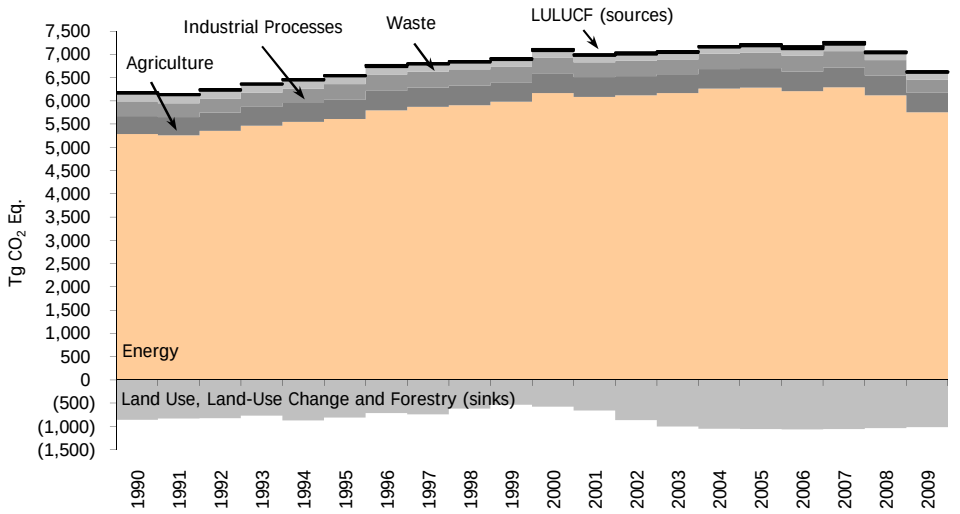


Figure 2-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sector

Figure 2-4: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

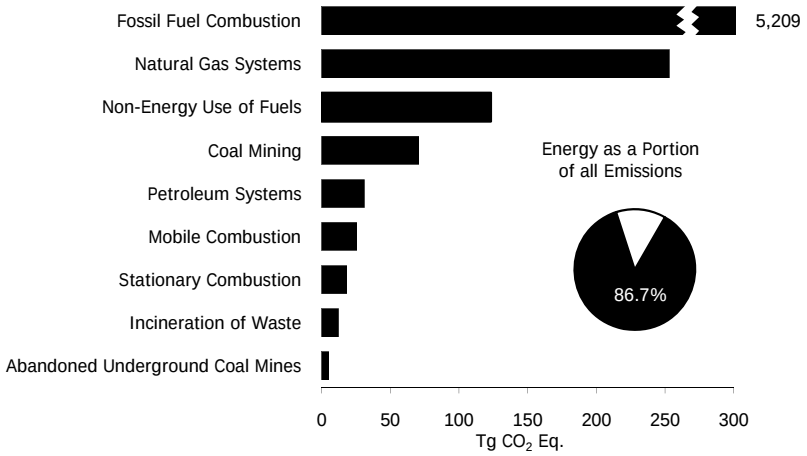


Figure 2-5: 2009 Energy Sector Greenhouse Gas Sources

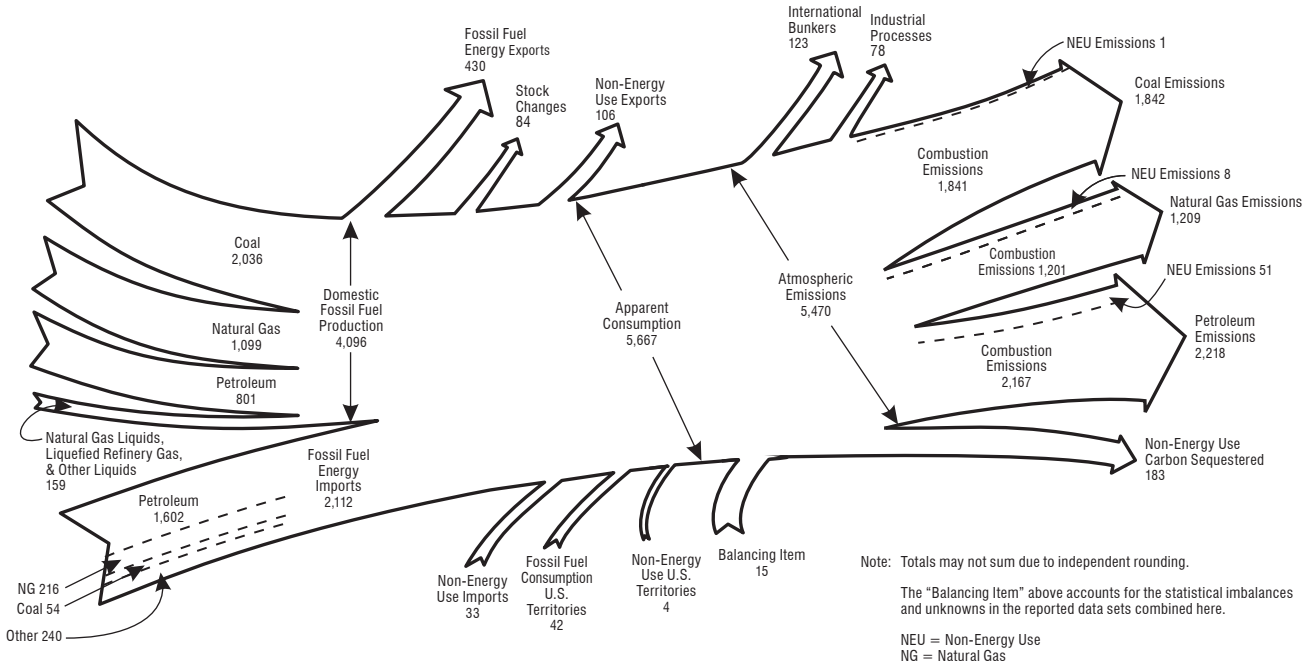


Figure 2-6 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

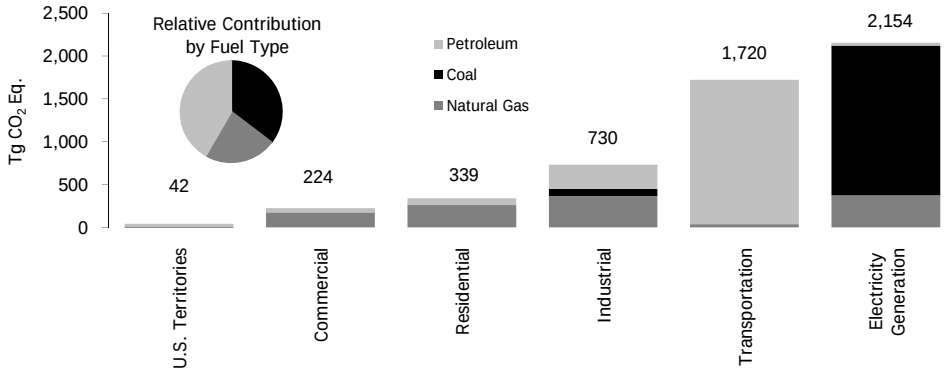


Figure 2-7: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

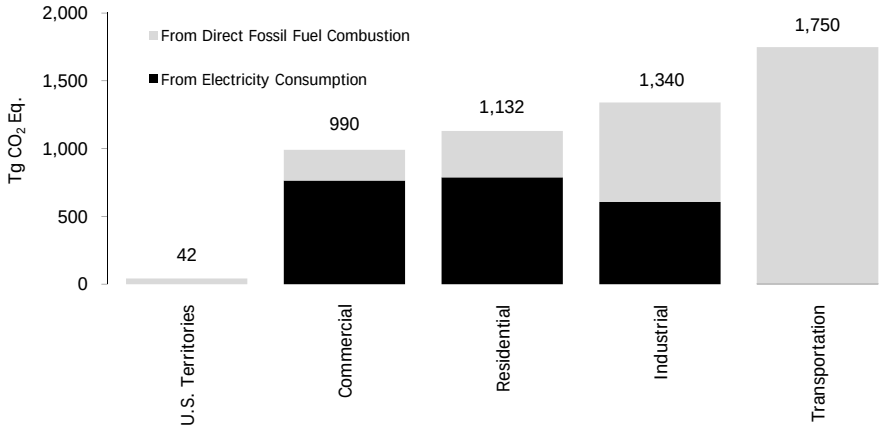


Figure 2-8: 2009 End-Use Sector Emissions from Fossil Fuel Combustion

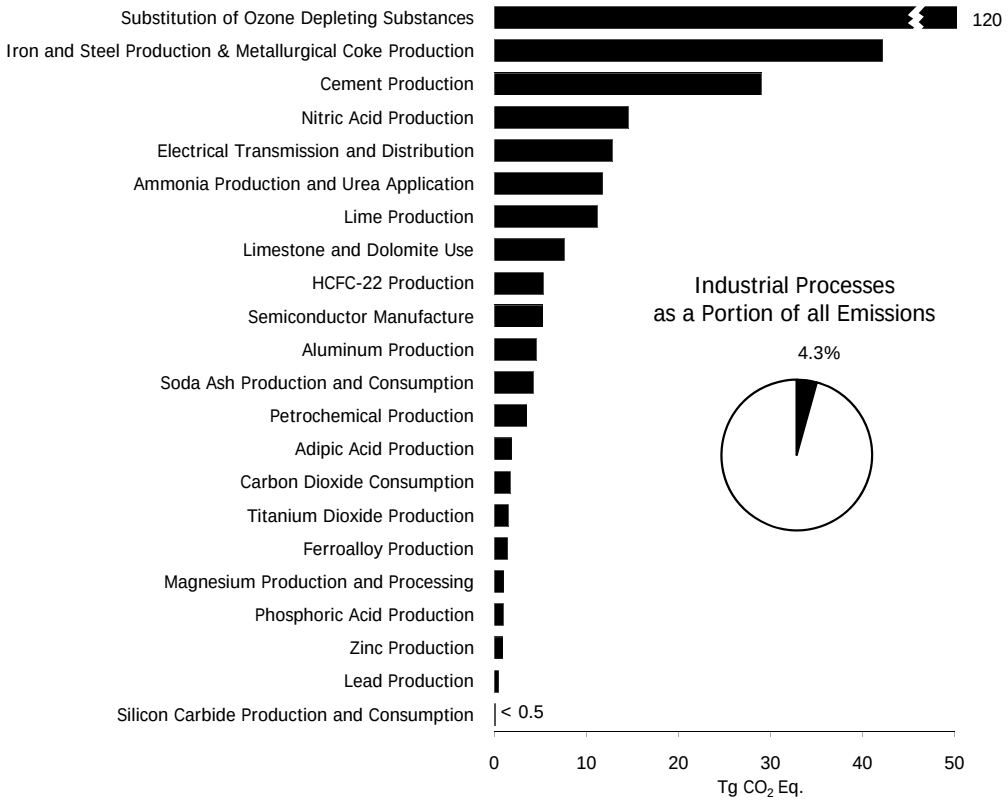


Figure 2-9: 2009 Industrial Processes Chapter Greenhouse Gas Sources

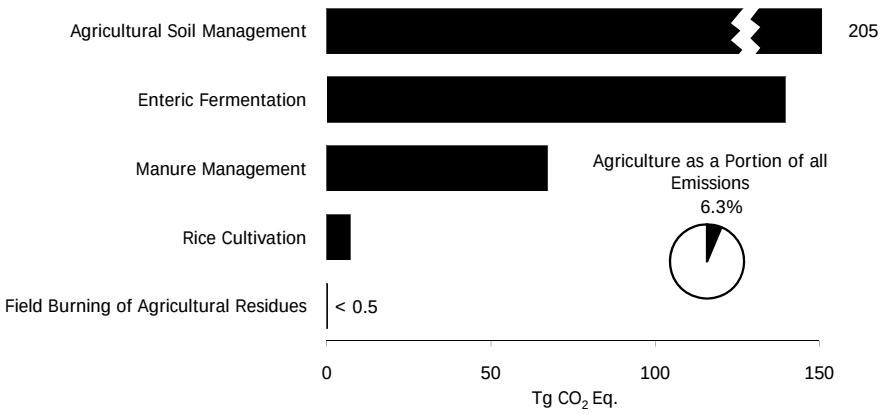


Figure 2-10: 2009 Agriculture Chapter Greenhouse Gas Sources

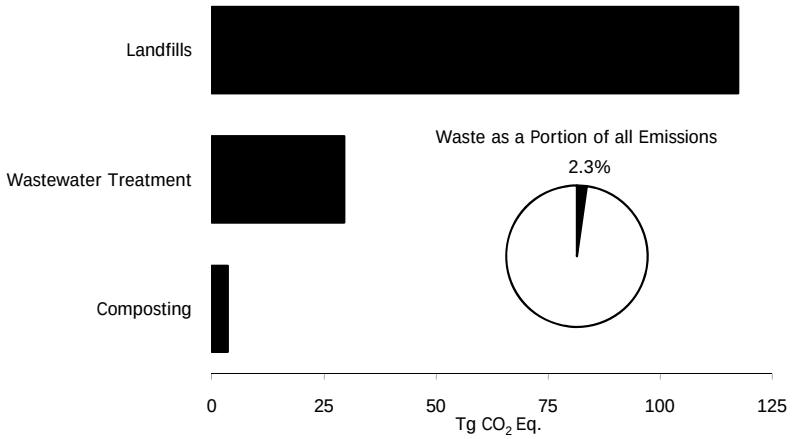


Figure 2-11: 2009 Waste Chapter Greenhouse Gas Sources

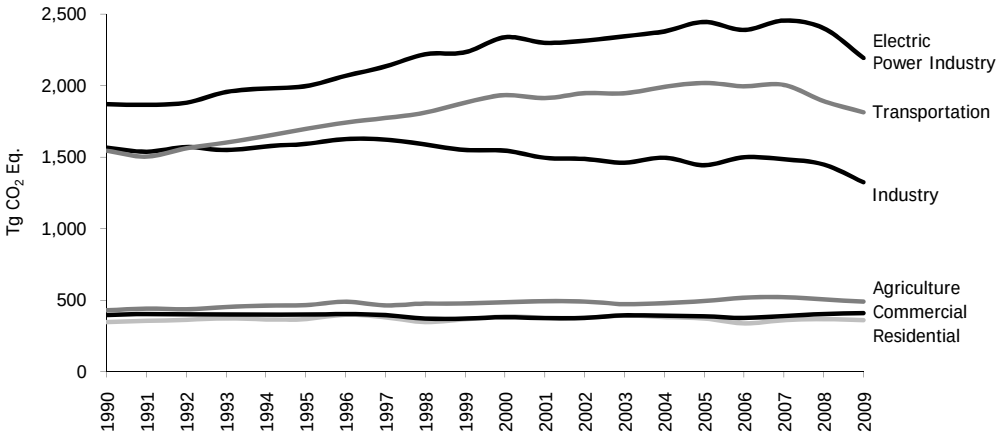


Figure 2-12: Emissions Allocated to Economic Sectors

Note: Does not include U.S. Territories.

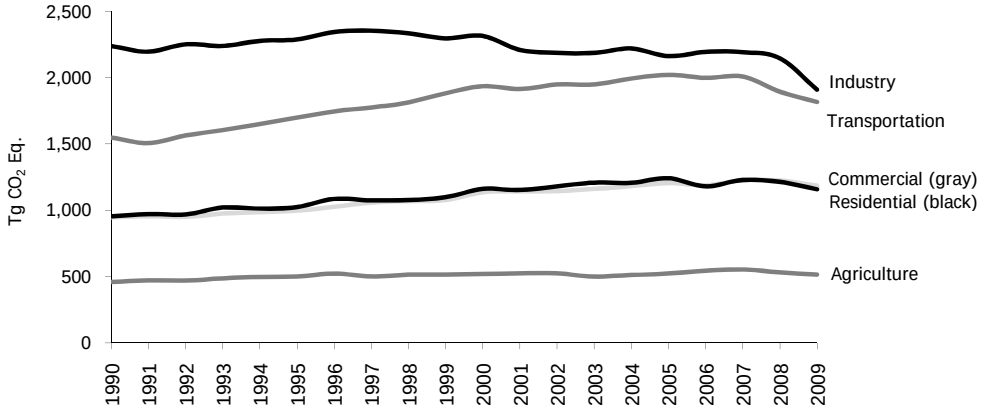


Figure 2-13: Emissions with Electricity Distributed to Economic Sectors

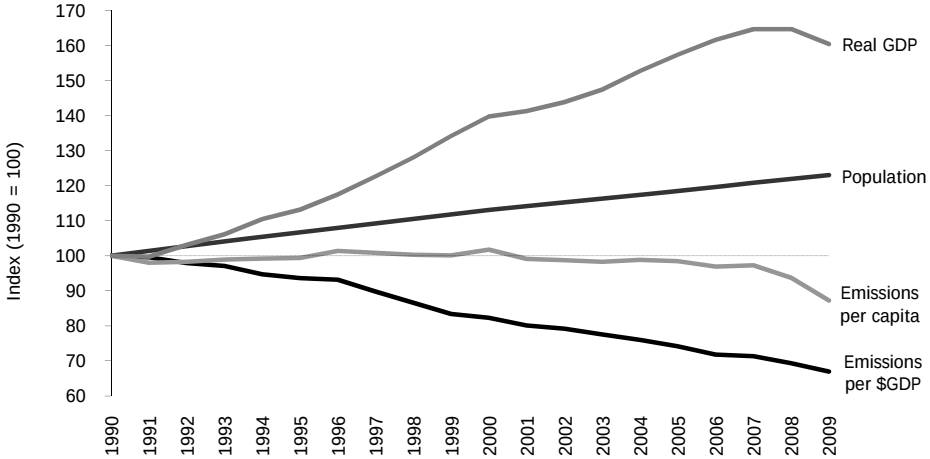


Figure 2-14: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 86.7 percent of total greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis[52] in 2009. This included 98, 49, and 13 percent of the nation's CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 81 percent of national emissions from all sources on a CO_2 equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (5.6 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 3-1). Globally, approximately 30,398 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[53] Due to their relative importance, fossil fuel combustion-related CO_2 emissions are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH_4 and N_2O, and mobile fossil fuel combustion was the second largest source of N_2O emissions in the United States.

Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources

Figure 3-2: 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH_4 from natural gas systems, petroleum systems, and coal mining.

Table 3-1 summarizes emissions from the Energy sector in units of teragrams (or million metric tons) of CO_2 equivalents (Tg CO_2 Eq.), while unweighted gas emissions in gigagrams (Gg) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,751.1 Tg CO_2 Eq. in 2009, an increase of 9 percent since 1990.

Table 3-1: CO_2, CH_4, and N_2O Emissions from Energy (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**4,903.2**	**5,781.3**	**5,939.4**	**5,842.5**	**5,938.2**	**5,752.3**	**5,377.3**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Biomass - Wood[*]	*215.2*	*218.1*	*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
International Bunker Fuels[*]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
Biomass – Ethanol[*]	*4.2*	*9.4*	*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**327.4**	**318.6**	**291.3**	**319.2**	**307.3**	**323.6**	**336.8**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2

[52] Estimates are presented in units of teragrams of carbon dioxide equivalent (Tg CO_2 Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

[53] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010).

Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Incineration of Waste	+	+	+	+	+	+	+
*International Bunker Fuels**	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**57.2**	**68.1**	**52.1**	**48.5**	**45.2**	**40.7**	**37.0**
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
*International Bunker Fuels**	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
Total	**5,287.8**	**6,168.0**	**6,282.8**	**6,210.2**	**6,290.7**	**6,116.6**	**5,751.1**

+ Does not exceed 0.05 Tg CO_2 Eq.

* These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

Table 3-2: CO_2, CH_4, and N_2O Emissions from Energy (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**4,903,171**	**5,781,303**	**5,939,434**	**5,842,464**	**5,938,203**	**5,752,327**	**5,377,271**
Fossil Fuel Combustion	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
Non-Energy Use of Fuels	118,630	144,933	143,392	145,574	137,233	140,952	123,356
Natural Gas Systems	37,574	29,877	29,902	30,755	31,050	32,828	32,171
Incineration of Waste	7,989	11,112	12,450	12,531	12,700	12,169	12,300
Petroleum Systems	555	534	490	488	474	453	463
*Biomass -Wood**	*215,186*	*218,088*	*206,865*	*203,846*	*203,316*	*198,361*	*183,777*
*International Bunker Fuels**	*111,828*	*98,482*	*109,750*	*128,384*	*127,618*	*133,704*	*123,127*
*Biomass - Ethanol**	*4,229*	*9,352*	*22,956*	*31,002*	*38,946*	*54,770*	*61,231*
CH_4	**15,590**	**15,171**	**13,872**	**15,202**	**14,634**	**15,408**	**16,037**
Natural Gas Systems	9,038	9,968	9,069	10,364	9,771	10,087	10,535
Coal Mining	4,003	2,877	2,710	2,774	2,756	3,196	3,382
Petroleum Systems	1,685	1,501	1,398	1,398	1,427	1,439	1,473
Stationary Combustion	354	315	312	293	308	310	293
Abandoned Underground Coal Mines	288	350	264	261	267	279	262
Mobile Combustion	223	160	119	112	105	97	93
Incineration of Waste	+	+	+	+	+	+	+
*International Bunker Fuels**	*8*	*6*	*7*	*8*	*8*	*8*	*7*
N_2O	**185**	**220**	**168**	**156**	**146**	**131**	**120**
Mobile Combustion	142	172	119	108	98	84	77
Stationary Combustion	41	47	47	47	47	46	41
Incineration of Waste	2	1	1	1	1	1	1
*International Bunker Fuels**	*3*	*3*	*3*	*4*	*4*	*4*	*4*

+ Does not exceed 0.05 Tg CO_2 Eq.

* These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

3.1. Fossil Fuel Combustion (IPCC Source Category 1A)

Emissions from the combustion of fossil fuels for energy include the gases CO_2, CH_4, and N_2O. Given that CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO_2 emissions from fossil fuel combustion are discussed at the beginning of this section. Following that is a discussion of emissions of all three gases from fossil fuel combustion presented by sectoral breakdowns. Methodologies for estimating CO_2 from fossil fuel combustion also differ from the estimation of CH_4 and N_2O emissions from stationary combustion and mobile combustion. Thus, three separate descriptions of methodologies, uncertainties, recalculations, and planned improvements are provided at the end of this section. Total CO_2, CH_4, and N_2O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

Table 3-3: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion (Tg CO_2 Eq.)

Gas	1990	2000	2005	2006	2007	2008	2009
CO_2	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
CH_4	12.1	10.0	9.1	8.5	8.7	8.5	8.1
N_2O	56.8	67.7	51.7	48.1	44.9	40.4	36.7
Total	**4,807.3**	**5,627.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

Note: Totals may not sum due to independent rounding.

Table 3-4: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion (Gg)

Gas	1990	2000	2005	2006	2007	2008	2009
CO_2	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
CH_4	577	476	431	405	413	407	386
N_2O	183	219	167	155	145	130	118

Note: Totals may not sum due to independent rounding.

CO_2 from Fossil Fuel Combustion

CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. CO_2 emissions from fossil fuel combustion are presented in Table 3-5. In 2009, CO_2 emissions from fossil fuel combustion decreased by 6.4 percent relative to the previous year. This decrease represents the largest annual decrease in CO_2 emissions from fossil fuel combustion for the twenty-year period.[54] The decrease in CO_2 emissions from fossil fuel combustion was a result of multiple factors including: (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price natural gas decreased significantly; and (3) an increase in non-fossil fuel consumption by approximately 2 percent. In 2009, CO_2 emissions from fossil fuel combustion were 5,209.0 Tg CO_2 Eq., or almost 10 percent above emissions in 1990 (see Table 3-5).[55]

Table 3-5: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq.)

Fuel/Sector	1990	2000	2005	2006	2007	2008	2009
Coal	**1,718.4**	**2,065.5**	**2,112.3**	**2,076.5**	**2,106.0**	**2,072.5**	**1,841.0**
Residential	3.0	1.1	0.8	0.6	0.7	0.7	0.6
Commercial	12.0	8.8	9.3	6.2	6.7	6.5	5.8
Industrial	155.3	127.3	115.3	112.6	107.0	102.6	83.4
Transportation	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,547.6	1,927.4	1,983.8	1,953.7	1,987.3	1,959.4	1,747.6
U.S. Territories	0.6	0.9	3.0	3.4	4.3	3.3	3.5
Natural Gas	**1,000.6**	**1,217.4**	**1,159.0**	**1,141.3**	**1,218.0**	**1,226.0**	**1,200.9**

[54] This decrease also represents the largest absolute and percentage decrease since the beginning of EIA's record of annual energy consumption data, beginning in 1949 (EIA 2010a).

[55] An additional discussion of fossil fuel emission trends is presented in the Trends in U.S. Greenhouse Gas Emissions Chapter.

Residential	238.0	270.7	262.2	237.3	257.0	264.4	257.2
Commercial	142.1	172.5	162.9	153.8	164.0	170.2	167.9
Industrial	409.1	457.2	380.8	377.7	389.0	391.0	365.0
Transportation	36.0	35.6	33.1	33.1	35.3	36.8	36.3
Electricity Generation	175.3	280.8	318.8	338.0	371.3	361.9	373.1
U.S. Territories	NO	0.7	1.3	1.4	1.4	1.6	1.5
Petroleum	**2,019.0**	**2,311.6**	**2,481.5**	**2,434.9**	**2,432.4**	**2,267.1**	**2,166.7**
Residential	97.4	98.8	94.9	83.6	84.6	83.1	81.4
Commercial	64.9	49.6	51.3	48.5	48.7	47.4	50.3
Industrial	282.1	266.6	326.9	357.9	346.0	309.3	282.0
Transportation	1,449.9	1,773.9	1,863.5	1,845.0	1,858.7	1,753.1	1,683.4
Electricity Generation	97.5	88.4	99.2	54.4	53.9	39.2	32.9
U.S. Territories	27.2	34.2	45.7	45.5	40.4	35.0	36.7
Geothermal*	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**

NE (Not estimated)
NO (Not occurring)
* Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

Trends in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally fluctuates in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

Longer-term changes in energy consumption patterns, however, tend to be more a function of aggregate societal trends that affect the scale of consumption (e.g., population, number of cars, size of houses, and number of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs), and social planning and consumer behavior (e.g., walking, bicycling, or telecommuting to work instead of driving).

CO_2 emissions also depend on the source of energy and its carbon (C) intensity. The amount of C in fuels varies significantly by fuel type. For example, coal contains the highest amount of C per unit of useful energy. Petroleum has roughly 75 percent of the C per unit of energy as coal, and natural gas has only about 55 percent.[56] Table 3-6 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in selected sectors.

Table 3-6: Annual Change in CO_2 Emissions and Total 2009 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (Tg CO_2 Eq. and Percent)

Sector	Fuel Type	2005 to 2006		2006 to 2007		2007 to 2008		2008 to 2009		Total 2009
Electricity Generation	Coal	-30.1	-1.5%	33.6	1.7%	-27.9	-1.4%	-211.7	-10.8%	1,747.6
Electricity Generation	Natural Gas	19.2	6.0%	33.3	9.9%	-9.3	-2.5%	11.1	3.1%	373.1
Electricity Generation	Petroleum	-44.8	-45.2%	-0.5	-0.9%	-14.7	-27.2%	-6.3	-16.0%	32.9
Transportation [a]	Petroleum	-18.5	-1.0%	13.7	0.7%	-105.6	-5.7%	-69.7	-4.0%	1,683.4
Residential	Natural Gas	-24.9	-9.5%	19.7	8.3%	7.4	2.9%	-7.3	-2.8%	257.2
Commercial	Natural Gas	-9.1	-5.6%	10.2	6.6%	6.2	3.8%	-2.3	-1.3%	167.9
Industrial	Coal	-2.8	-2.4%	-5.6	-5.0%	-4.4	-4.1%	-19.2	-18.7%	83.4
Industrial	Natural Gas	-3.1	-0.8%	11.3	3.0%	2.0	0.5%	-26.0	-6.6%	365.0
All Sectors [b]	**All Fuels [b]**	**-100.1**	**-1.7%**	**103.6**	**1.8%**	**-190.8**	**-3.3%**	**-356.9**	**-6.4%**	**5,209.0**

[a] Excludes emissions from International Bunker Fuels.
[b] Includes fuels and sectors not shown in table.

[56] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

In the United States, 83 percent of the energy consumed in 2009 was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 3-3 and Figure 3-4). The remaining portion was supplied by nuclear electric power (9 percent) and by a variety of renewable energy sources[57] (8 percent), primarily hydroelectric power and biofuels (EIA 2010). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for an average of 42 percent of total fossil fuel based energy consumption in 2009. Natural gas and coal followed in order of importance, accounting for approximately 32 and 27 percent of total consumption, respectively. Petroleum was consumed primarily in the transportation end-use sector and the vast majority of coal was used in electricity generation. Natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2010).

Figure 3-3: 2009 U.S. Energy Consumption by Energy Source

Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

Figure 3-5: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including CH_4, CO, and NMVOCs.[58] These other C containing non-CO_2 gases are emitted as a by-product of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO_2 in the atmosphere. Therefore, it is assumed that all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

[BEGIN BOX]

Box 3-1: Weather and Non-Fossil Energy Effects on CO_2 from Fossil Fuel Combustion Trends

In 2009, weather conditions remained constant in the winter and slightly cooler in the summer compared to 2008, as heating degree days decreased slightly and cooling degree days decreased by 3.8 percent. Winter conditions were relatively constant in 2009 compared to 2008, and the winter was slightly warmer than normal, with heating degree days in the United States 0.7 percent below normal (see Figure 3-6). Summer conditions were slightly cooler in 2009 compared to 2008, and summer temperatures were slightly cooler than normal, with cooling degree days 1 percent below normal (see Figure 3-7) (EIA 2010).[59]

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2009)

Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2009)

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[57] Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy

[58] See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO_2 gas emissions from fossil fuel combustion.

[59] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F, while cooling degree days are deviations of the mean daily temperature above 65° F. Heating degree days have a considerably greater affect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000. The variation in these normals during this time period was ±10 percent and ±14 percent for heating and cooling degree days, respectively (99 percent confidence interval).

Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors[60]) of existing plants in 2009 remained high at just over 90 percent. Electricity output by hydroelectric power plants increased in 2009 by approximately 6.8 percent. Electricity generated by nuclear plants in 2009 provided nearly 3 times as much of the energy consumed in the United States as hydroelectric plants (EIA 2010). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-8.

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2009)

[END BOX]

Fossil Fuel Combustion Emissions by Sector

In addition to the CO_2 emitted from fossil fuel combustion, CH_4 and N_2O are emitted from stationary and mobile combustion as well. Table 3-7 provides an overview of the CO_2, CH_4, and N_2O emissions from fossil fuel combustion by sector.

Table 3-7: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**1,829.5**	**2,307.5**	**2,413.2**	**2,357.2**	**2,423.8**	**2,371.7**	**2,163.7**
CO_2	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
CH_4	0.6	0.7	0.7	0.7	0.7	0.7	0.7
N_2O	8.1	10.0	10.3	10.1	10.3	10.1	9.0
Transportation	**1,534.6**	**1,866.0**	**1,936.0**	**1,914.1**	**1,926.5**	**1,818.1**	**1,745.5**
CO_2	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
CH_4	4.7	3.4	2.5	2.3	2.2	2.0	2.0
N_2O	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Industrial	**851.2**	**855.9**	**827.5**	**852.8**	**846.5**	**807.0**	**734.1**
CO_2	846.5	851.1	823.1	848.2	842.0	802.9	730.4
CH_4	1.5	1.6	1.4	1.5	1.4	1.3	1.2
N_2O	3.2	3.2	3.0	3.1	3.0	2.8	2.5
Residential	**343.8**	**375.0**	**362.2**	**325.4**	**346.6**	**352.6**	**343.4**
CO_2	338.3	370.7	357.9	321.5	342.4	348.2	339.2
CH_4	4.4	3.4	3.4	3.1	3.4	3.5	3.4
N_2O	1.1	0.9	0.9	0.8	0.9	0.9	0.9
Commercial	**220.2**	**232.1**	**224.8**	**209.7**	**220.6**	**225.4**	**225.2**
CO_2	219.0	230.8	223.5	208.6	219.4	224.2	224.0
CH_4	0.9	0.9	0.9	0.8	0.9	0.9	0.9
N_2O	0.4	0.4	0.4	0.3	0.3	0.3	0.3
U.S. Territories*	**28.0**	**36.0**	**50.2**	**50.5**	**46.3**	**40.0**	**41.8**
Total	**4,807.3**	**5,672.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

Note: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.
* U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O and the

[60]The capacity factor equals generation divided by net summer capacity. Summer capacity is defined as "The maximum output that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30)." Data for both the generation and net summer capacity are from EIA (2010b).

indirect greenhouse gases NO_x, CO, and NMVOCs.[61] CH_4 and N_2O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. N_2O emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. CH_4 emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency.

Mobile combustion produces greenhouse gases other than CO_2, including CH_4, N_2O, and indirect greenhouse gases including NO_x, CO, and NMVOCs. As with stationary combustion, N_2O and NO_x emissions from mobile combustion are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. N_2O from mobile sources, in particular, can be formed by the catalytic processes used to control NO_x, CO, and hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by combustion efficiency and the presence of post-combustion emission controls. CO emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur especially in idle, low speed, and cold start conditions. CH_4 and NMVOC emissions from motor vehicles are a function of the CH_4 content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions (such as catalytic converters).

An alternative method of presenting combustion emissions is to allocate emissions associated with electricity generation to the sectors in which it is used. Four end-use sectors were defined: industrial, transportation, residential, and commercial. In the table below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption, with the exception of CH_4 and N_2O from transportation.[62] Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. This method of distributing emissions assumes that 564 combustion sources focus on the alternative method as presented in Table 3-8.

Table 3-8: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	**1,537.6**	**1,869.5**	**1,940.8**	**1,918.6**	**1,931.5**	**1,822.8**	**1,750.0**
CO_2	1,489.0	1,813.0	1,901.3	1,882.6	1,899.0	1,794.6	1,724.1
CH_4	4.7	3.4	2.5	2.4	2.2	2.0	2.0
N_2O	44.0	53.2	37.0	33.6	30.3	26.2	23.9
Industrial	**1,541.2**	**1,649.3**	**1,567.9**	**1,568.1**	**1,579.7**	**1,525.1**	**1,340.1**
CO_2	1,533.2	1,640.8	1,560.0	1,560.2	1,572.0	1,517.7	1,333.7
CH_4	1.8	1.8	1.7	1.7	1.6	1.6	1.4
N_2O	6.3	6.7	6.2	6.2	6.1	5.8	5.0
Residential	**939.7**	**1,140.9**	**1,222.9**	**1,160.1**	**1,206.7**	**1,190.4**	**1,131.6**
CO_2	931.4	1,133.1	1,214.7	1,152.4	1,198.5	1,182.2	1,123.8
CH_4	4.6	3.6	3.7	3.3	3.6	3.7	3.6
N_2O	3.7	4.2	4.6	4.4	4.5	4.5	4.2
Commercial	**760.8**	**976.8**	**1,032.2**	**1,012.4**	**1,046.0**	**1,036.5**	**990.3**
CO_2	757.0	972.1	1,027.2	1,007.6	1,041.1	1,031.6	985.7
CH_4	1.0	1.1	1.1	1.1	1.1	1.2	1.1
N_2O	2.8	3.6	3.8	3.8	3.8	3.8	3.5
U.S. Territories*	**28.0**	**36.0**	**50.2**	**50.5**	**46.3**	**40.0**	**41.8**
Total	**4,807.3**	**5,672.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

Note: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

* U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

[61] Sulfur dioxide (SO_2) emissions from stationary combustion are addressed in Annex 6.3.

[62] Separate calculations were performed for transportation-related CH_4 and N_2O. The methodology used to calculate these emissions are discussed in the mobile combustion section.

Stationary Combustion

The direct combustion of fuels by stationary sources in the electricity generation, industrial, commercial, and residential sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-9 presents CO_2 emissions from fossil fuel combustion by stationary sources. The CO_2 emitted is closely linked to the type of fuel being combusted in each sector (see Methodology section for CO_2 from fossil fuel combustion). Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O. Table 3-10 and Table 3-11 present CH_4 and N_2O emissions from the combustion of fuels in stationary sources. CH_4 and N_2O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. N_2O emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. CH_4 emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency. Please refer to Table 3-7 for the corresponding presentation of all direct emission sources of fuel combustion.

Table 3-9: CO_2 Emissions from Stationary Fossil Fuel Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**1,820.8**	**2,296.9**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**
Coal	1,547.6	1,927.4	1,983.8	1,953.7	1,987.3	1,959.4	1,747.6
Natural Gas	175.3	280.8	318.8	338.0	371.3	361.9	373.1
Fuel Oil	97.5	88.4	99.2	54.4	53.9	39.2	32.9
Geothermal	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Industrial	**846.5**	**851.1**	**823.1**	**848.2**	**842.0**	**802.9**	**730.4**
Coal	155.3	127.3	115.3	112.6	107.0	102.6	83.4
Natural Gas	409.1	457.2	380.8	377.7	389.0	391.0	365.0
Fuel Oil	282.1	266.6	326.9	357.9	346.0	309.3	282.0
Commercial	**219.0**	**230.8**	**223.5**	**208.6**	**219.4**	**224.2**	**224.0**
Coal	12.0	8.8	9.3	6.2	6.7	6.5	5.8
Natural Gas	142.1	172.5	162.9	153.8	164.0	170.2	167.9
Fuel Oil	64.9	49.6	51.3	48.5	48.7	47.4	50.3
Residential	**338.3**	**370.7**	**357.9**	**321.5**	**342.4**	**348.2**	**339.2**
Coal	3.0	1.1	0.8	0.6	0.7	0.7	0.6
Natural Gas	238.0	270.7	262.2	237.3	257.0	264.4	257.2
Fuel Oil	97.4	98.8	94.9	83.6	84.6	83.1	81.4
U.S. Territories	**27.9**	**35.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Coal	0.6	0.9	3.0	3.4	4.3	3.3	3.5
Natural Gas	NO	0.7	1.3	1.4	1.4	1.6	1.5
Fuel Oil	27.2	34.2	45.7	45.5	40.4	35.0	36.7
Total	**3,252.5**	**3,785.3**	**3,856.6**	**3,775.0**	**3,862.8**	**3,776.0**	**3,489.3**

* U.S. Territories are not apportioned by sector, and emissions are from all fuel combustion sources (stationary and mobile) are presented in this table.

Table 3-10: CH_4 Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Fuel Oil	0.1	0.1	0.1	+	+	+	+
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Industrial	**1.5**	**1.6**	**1.4**	**1.5**	**1.4**	**1.3**	**1.2**
Coal	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Fuel Oil	0.2	0.1	0.2	0.2	0.2	0.2	0.1
Natural Gas	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Wood	0.9	1.0	0.9	0.9	0.8	0.8	0.7
Commercial	**0.9**	**0.9**	**0.9**	**0.8**	**0.9**	**0.9**	**0.9**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.2	0.1	0.1	0.1	0.1
Natural Gas	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Wood	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Residential	**4.4**	**3.4**	**3.4**	**3.1**	**3.4**	**3.5**	**3.4**
Coal	0.2	0.1	0.1	+	+	+	+
Fuel Oil	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.4	0.5	0.5	0.4	0.5	0.5	0.5
Wood	3.5	2.5	2.6	2.3	2.6	2.7	2.6
U.S. Territories	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	+	+	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Total	**7.4**	**6.6**	**6.6**	**6.2**	**6.5**	**6.5**	**6.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-11: N_2O Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**8.1**	**10.0**	**10.3**	**10.1**	**10.2**	**10.1**	**9.0**
Coal	7.6	9.4	9.7	9.5	9.7	9.6	8.5
Fuel Oil	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Wood	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Industrial	**3.2**	**3.2**	**3.0**	**3.1**	**3.0**	**2.8**	**2.5**
Coal	0.8	0.6	0.6	0.6	0.5	0.5	0.4
Fuel Oil	0.5	0.4	0.5	0.6	0.6	0.5	0.4
Natural Gas	0.2	0.3	0.2	0.2	0.2	0.2	0.2
Wood	1.7	1.9	1.7	1.7	1.7	1.6	1.4
Commercial	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	0.1	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	**1.1**	**0.9**	**0.9**	**0.8**	**0.9**	**0.9**	**0.9**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Natural Gas	0.1	0.2	0.1	0.1	0.1	0.1	0.1
Wood	0.7	0.5	0.5	0.5	0.5	0.5	0.5
U.S. Territories	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+

Fuel Oil	0.1		0.1		0.1	0.1	0.1	0.1	0.1
Natural Gas	+		+		+	+	+	+	+
Wood	+		+		+	+	+	+	+
Total	**12.8**		**14.6**		**14.7**	**14.4**	**14.6**	**14.2**	**12.8**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Electricity Generation

The process of generating electricity is the single largest source of CO_2 emissions in the United States, representing 39 percent of total CO_2 emissions from all CO_2 emissions sources across the United States. CH_4 and N_2O accounted for a small portion of emissions from electricity generation, representing less than 0.1 percent and 0.4 percent, respectively.[63] Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 41 percent in 2009. CH_4 and N_2O from electricity generation represented 8 and 25 percent of emissions from CH_4 and N_2O emissions from fossil fuel combustion in 2009, respectively. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-9).

Figure 3-9: Electricity Generation Retail Sales by End-Use Sector

The electric power industry includes all power producers, consisting of both regulated utilities and nonutilities (e.g. independent power producers, qualifying cogenerators, and other small power producers). For the underlying energy data used in this chapter, the Energy Information Administration (EIA) places electric power generation into three functional categories: the electric power sector, the commercial sector, and the industrial sector. The electric power sector consists of electric utilities and independent power producers whose primary business is the production of electricity,[64] while the other sectors consist of those producers that indicate their primary business is something other than the production of electricity.

The industrial, residential, and commercial end-use sectors, as presented in Table 3-8, were reliant on electricity for meeting energy needs. The residential and commercial end-use sectors were especially reliant on electricity consumption for lighting, heating, air conditioning, and operating appliances. Electricity sales to the residential and commercial end-use sectors in 2009 decreased approximately 1.2 percent and 1.0 percent, respectively. The trend in the commercial and residential sectors can largely be attributed to the decreased carbon intensity in the fuels used to generate electricity for these sectors. In addition, electricity consumption in both sectors decreased as a result of the less energy-intensive weather conditions compared to 2008. In 2009, the amount of electricity generated (in kWh) decreased by 4 percent from the previous year. This decline was due to the economic downturn, a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly, and an increase in non-fossil fuel sources used to generate electricity. As a result, CO_2 emissions from the electric power sector decreased by 8.8 percent as the consumption of coal and petroleum for electricity generation decreased by 10.8 percent and 16.6 percent, respectively, in 2009 and the consumption of natural gas for electricity generation, increased by 3.1 percent. The decrease in C intensity of the electricity supply (see Table 3-15) was the result of a decrease in the carbon intensity of fossil fuels consumed to generate electricity and an increase in renewable generation of 5 percent spurred by a 28 percent increase in wind-generated electricity.

[63] Since emissions estimates for U.S. territories cannot be disaggregated by gas in Table 3-7and Table 3-8, the percentages for CH_4 and N_2O exclude U.S. territory estimates.

[64] Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Nonutilities produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to customers).

Industrial Sector

The industrial sector accounted for 14 percent of CO_2 emissions from fossil fuel combustion, 15 percent of CH_4 emissions from fossil fuel combustion, and 7 percent of N_2O emissions from fossil fuel combustion. CO_2, CH_4, and N_2O emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

The industrial sector, per the underlying energy consumption data from EIA, includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy consumption is manufacturing, of which six industries—Petroleum Refineries, Chemicals, Paper, Primary Metals, Food, and Nonmetallic Mineral Products—represent the vast majority of the energy use (EIA 2010 and EIA 2009c).

In theory, emissions from the industrial sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions.[65] In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive products (e.g., from steel to computer equipment) also have a significant effect on industrial emissions.

From 2008 to 2009, total industrial production and manufacturing output decreased by 9.3 and 10.9 percent, respectively (FRB 2010). Over this period, output decreased across all production indices for Food, Petroleum Refineries, Chemicals, Paper, Primary Metals, and Nonmetallic Mineral Products (see Figure 3-10).

Figure 3-10: Industrial Production Indices (Index 2002=100)

Despite the growth in industrial output (41 percent) and the overall U.S. economy (60 percent) from 1990 to 2009, CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 13.7 percent over that time. A number of factors are believed to have caused this disparity between growth in industrial output and decrease in industrial emissions, including: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, and (2) energy-intensive industries such as steel are employing new methods, such as electric arc furnaces, that are less carbon intensive than the older methods. In 2009, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,340.1 Tg CO_2 Eq., or approximately 12.1 percent below 2008 emissions.

Residential and Commercial Sectors

The residential and commercial sectors accounted for 7 and 4 percent of CO_2 emissions from fossil fuel combustion, 42 and 11 percent of CH_4 emissions from fossil fuel combustion, and 2 and 1 percent of N_2O emissions from fossil fuel combustion, respectively. Emissions from these sectors were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both of these end-use sectors. In 2009, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,131.6 Tg CO_2 Eq. and 990.3Tg CO_2 Eq., respectively. Total CO_2, CH_4, and N_2O emissions from the residential and commercial sectors decreased by 4.9 and 4.5 percent from 2008 to 2009, respectively.

Emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. In the long-term, both sectors are also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

Emissions from natural gas consumption represent about 76 and 75 percent of the direct fossil fuel CO_2 emissions from the residential and commercial sectors, respectively. In 2009, natural gas CO_2 emissions from the residential and commercial sectors decreased by 2.8 percent and 1.3 percent, respectively. The decrease in natural gas emissions in both sectors is a result of less energy-intensive weather conditions in the United States compared to

[65] Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

2008.

U.S. Territories

Emissions from U.S. territories are based on the fuel consumption in American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands. As described the Methodology section for CO_2 from fossil fuel combustion, this data is collected separately from the sectoral-level data available for the general calculations. As sectoral information is not available for U.S. Territories, CO_2, CH_4, and N_2O emissions are not presented for U.S. Territories in the tables above, though the emissions will include some transportation and mobile combustion sources.

Transportation Sector

This discussion of transportation emissions follows the alternative method of presenting combustion emissions by allocating emissions associated with electricity generation to the transportation end-use sector, as presented in Table 3-8. For direct emissions from transportation (i.e., not including emissions associated with the sector's electricity consumption), please see Table 3-7.

The transportation end-use sector accounted for 1,745.5 Tg CO_2 Eq. in 2009, which represented 33 percent of CO_2 emissions, 24 percent of CH_4 emissions, and 65 percent of N_2O emissions from fossil fuel combustion, respectively. Fuel purchased in the U.S. for international aircraft and marine travel accounted for an additional 123.1 Tg CO_2 in 2009; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols. Among domestic transportation sources, light duty vehicles (including passenger cars and light-duty trucks) represented 64 percent of CO_2 emissions, medium- and heavy-duty trucks 20 percent, commercial aircraft 6 percent, and other sources 9 percent. Light-duty truck CO_2 emissions increased by 60 percent (193.4 Tg) from 1990 to 2009, representing the largest percentage increase of any transportation mode. General aviation aircraft CO_2 emissions also increased by nearly 60 percent (5.7 Tg) from 1990 to 2009. CO_2 from the domestic operation of commercial aircraft decreased by 18 percent (24.0 Tg) from 1990 to 2009. Across all categories of aviation, CO_2 emissions decreased by 21.6 percent (38.7 Tg) between 1990 and 2009. This includes a 59 percent (20.3 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2. See Table 3-12 for a detailed breakdown of CO_2 emissions by mode and fuel type.

From 1990 to 2009, transportation emissions rose by 17 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

From 2008 to 2009, CO_2 emissions from the transportation end-use sector declined 4 percent. The decrease in emissions can largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. Similarly, increased jet fuel prices were a factor in the 19 percent decrease in commercial aircraft emissions since 2007.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 16 percent from 1990 to 2009. This rise in CO_2 emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 60.2 Tg CO_2 Eq. in 2009, led to an increase in overall emissions from transportation activities of 17 percent.

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 16 percent (235.1 Tg) between 1990 and 2009, an annualized increase of 0.8 percent. The 4 percent decline in emissions between 2008 and 2009 followed the previous year's trend of decreasing emissions. Almost all of the energy consumed by the transportation sector is petroleum-based,

including motor gasoline, diesel fuel, jet fuel, and residual oil.[66] Transportation sources also produce CH_4 and N_2O; these emissions are included in Table 3-13 and Table 3-14 in the "Mobile Combustion" Section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO_2, N_2O, CH_4, and HFCs.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,111.7 Tg in 2009, an increase of 17 percent (161.3 Tg) from 1990. CO_2 emissions from passenger cars and light-duty trucks peaked at 1,184.3 Tg in 2004, and since then have declined about 6 percent. Over the 1990s through early this decade, growth in vehicle travel substantially outweighed improvements in vehicle fuel economy; however, the rate of Vehicle Miles Traveled (VMT) growth slowed considerably starting in 2005 (and declined rapidly in 2008) while average vehicle fuel economy increased. Among new vehicles sold annually, average fuel economy gradually declined from 1990 to 2004 (Figure 3-11), reflecting substantial growth in sales of light-duty trucks—in particular, growth in the market share of sport utility vehicles—relative to passenger cars (Figure 3-12). New vehicle fuel economy improved beginning in 2005, largely due to higher light-duty truck fuel economy standards, which have risen each year since 2005. The overall increase in fuel economy is also due to a slightly lower light-duty truck market share, which peaked in 2004 at 52 percent and declined to 40 percent in 2009.

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2008

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2008

Light-duty truck[67] CO_2 emissions increased by 60 percent (193.4 Tg) from 1990 to 2009, representing the largest percentage increase of any transportation mode. General aviation aircraft CO_2 emissions also increased by nearly 60 percent (5.7 Tg) from 1990 to 2009. CO_2 from the domestic operation of commercial aircraft decreased by 18 percent (24.0 Tg) from 1990 to 2009. Across all categories of aviation[68], CO_2 emissions decreased by 21.6 percent (38.7 Tg) between 1990 and 2009. This includes a 59 percent (20.3 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2.

Table 3-12: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (Tg CO_2 Eq.) [a]

Fuel/Vehicle Type	1990	2000	2005	2006	2007	2008	2009
Gasoline	**983.7**	**1,135.0**	**1,187.8**	**1,178.2**	**1,181.2**	**1,130.3**	**1,125.7**
Passenger Cars	621.4	640.6	658.0	635.0	628.7	594.0	593.3
Light-Duty Trucks	309.1	446.4	478.7	491.5	500.1	486.5	485.9
Medium- and Heavy-Duty Trucks[b]	38.7	36.0	34.9	35.5	36.1	33.7	30.6
Buses	0.3	0.4	0.4	0.4	0.4	0.4	0.3
Motorcycles	1.7	1.8	1.6	1.9	2.1	2.1	2.1
Recreational Boats	12.4	9.8	14.1	14.0	13.9	13.5	13.4
Distillate Fuel Oil (Diesel)	**262.9**	**402.5**	**451.8**	**470.3**	**476.3**	**443.5**	**402.5**
Passenger Cars	7.9	3.7	4.2	4.1	4.1	3.9	3.9
Light-Duty Trucks	11.5	20.1	25.8	26.8	27.3	26.9	26.7
Medium- and Heavy-Duty	190.5	309.6	360.6	370.1	376.1	356.0	321.8

[66] Biofuel estimates are presented for informational purposes only in the Energy chapter, in line with IPCC methodological guidance and UNFCCC reporting obligations. Net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry (see Chapter 7). More information and additional analyses on biofuels are available at EPA's "Renewable Fuels: Regulations & Standards" web page: http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm

[67] Includes "light-duty trucks" fueled by gasoline, diesel and LPG.

[68] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

Trucks[b]							
Buses	8.0	10.2	10.6	10.8	10.8	10.3	9.3
Rail	35.5	42.1	45.6	47.8	46.6	43.2	36.2
Recreational Boats	2.0	2.7	3.1	3.2	3.3	0.9	3.5
Ships and Other Boats	7.5	14.1	8.1	7.5	8.2	2.2	1.2
International Bunker Fuels [c]	*11.7*	*6.3*	*9.4*	*8.8*	*8.2*	*9.0*	*8.3*
Jet Fuel	**176.2**	**199.8**	**194.2**	**169.5**	**168.7**	**155.1**	**138.8**
Commercial Aircraft	135.4	169.2	161.2	137.1	138.1	122.2	111.4
Military Aircraft	34.4	21.1	18.1	16.4	16.1	16.3	14.1
General Aviation Aircraft	6.4	9.5	14.9	16.0	14.5	16.6	13.3
International Bunker Fuels [c]	*46.4*	*58.8*	*56.7*	*74.6*	*73.8*	*75.5*	*69.4*
Aviation Gasoline	**3.1**	**2.5**	**2.4**	**2.3**	**2.2**	**2.0**	**1.8**
General Aviation Aircraft	3.1	2.5	2.4	2.3	2.2	2.0	1.8
Residual Fuel Oil	**22.6**	**33.3**	**19.3**	**23.0**	**29.0**	**19.9**	**12.0**
Ships and Other Boats[d]	22.6	33.3	19.3	23.0	29.0	19.9	12.0
International Bunker Fuels [c]	*53.7*	*33.3*	*43.6*	*45.0*	*45.6*	*49.2*	*45.4*
Natural Gas	**36.0**	**35.6**	**33.1**	**33.1**	**35.3**	**36.8**	**36.3**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.4	0.8	0.8	1.0	1.1	1.1
Pipeline	36.0	35.2	32.2	32.3	34.3	35.7	35.2
LPG	**1.4**	**0.7**	**1.7**	**1.7**	**1.4**	**2.4**	**2.5**
Light-Duty Trucks	0.6	0.5	1.3	1.2	1.0	1.8	1.8
Medium- and Heavy-Duty Trucks[b]	0.8	0.3	0.4	0.5	0.4	0.7	0.7
Buses	+	+	+	+	+	+	+
Electricity	**3.0**	**3.4**	**4.7**	**4.5**	**5.0**	**4.7**	**4.4**
Rail	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Total	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Total (Including Bunkers) [c]	**1,600.8**	**1,911.4**	**2,011.1**	**2,011.0**	**2,026.6**	**1,928.3**	**1,847.2**

[a] This table does not include emissions from non-transportation mobile sources, such as agricultural equipment and construction/mining equipment; it also does not include emissions associated with electricity consumption by pipelines or lubricants used in transportation.
[b] Includes medium- and heavy-duty trucks over 8,500 lbs.
[c] Official estimates exclude emissions from the combustion of both aviation and marine international bunker fuels; however, estimates including international bunker fuel-related emissions are presented for informational purposes.
Note: Totals may not sum due to independent rounding.
Note: See section 3.10 of this chapter, in line with IPCC methodological guidance and UNFCCC reporting obligations, for more information on ethanol.
+ Less than 0.05 Tg CO_2 Eq.
- Unreported or zero

Mobile Fossil Fuel Combustion CH_4 and N_2O Emissions

Mobile combustion includes emissions of CH_4 and N_2O from all transportation sources identified in the U.S. inventory with the exception of pipelines, which are stationary; mobile sources also include non-transportation sources such as construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources (e.g., snowmobiles, lawnmowers, etc.). Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-13 and Table 3-14 provide CH_4 and N_2O emission estimates in Tg CO_2 Eq.[69]

[69] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2009.

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.3 percent) but was the second largest source of U.S. N_2O emissions (9 percent). From 1990 to 2009, mobile source CH_4 emissions declined by 58 percent, to 2.0 Tg CO_2 Eq. (93 Gg), due largely to control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH_4 emissions. Mobile source emissions of N_2O decreased by 46 percent, to 23.9 Tg CO_2 Eq. (77 Gg). Earlier generation control technologies initially resulted in higher N_2O emissions, causing a 26 percent increase in N_2O emissions from mobile sources between 1990 and 1998. Improvements in later-generation emission control technologies have reduced N_2O output, resulting in a 50 percent decrease in mobile source N_2O emissions from 1998 to 2009 (Figure 3-13). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

Figure 3-13: Mobile Source CH_4 and N_2O Emissions

Table 3-13: CH_4 Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2000	2005	2006	2007	2008	2009
Gasoline On-Road	**4.2**	**2.8**	**1.9**	**1.7**	**1.6**	**1.4**	**1.3**
Passenger Cars	2.6	1.6	1.1	1.0	0.9	0.8	0.7
Light-Duty Trucks	1.4	1.1	0.7	0.6	0.6	0.6	0.6
Medium- and Heavy-Duty Trucks and Buses	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	+	+	+	+	+	+	+
Alternative Fuel On-Road	**+**	**+**	**+**	**0.1**	**0.1**	**0.1**	**0.1**
Non-Road	**0.4**	**0.5**	**0.6**	**0.6**	**0.5**	**0.5**	**0.5**
Ships and Boats	+	+	+	+	+	+	+
Rail	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Agricultural Equipment[b]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Construction/Mining Equipment[c]	+	0.1	0.1	0.1	0.1	0.1	0.1
Other[d]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**4.7**	**3.4**	**2.5**	**2.3**	**2.2**	**2.0**	**2.0**

[a] See Annex 3.2 for definitions of on-road vehicle types.
[b] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.
[c] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.
[d] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.
Note: Totals may not sum due to independent rounding.
+ Less than 0.05 Tg CO_2 Eq.

Table 3-14: N_2O Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2000	2005	2006	2007	2008	2009
Gasoline On-Road	**40.1**	**48.4**	**32.1**	**29.0**	**25.5**	**21.8**	**19.9**
Passenger Cars	25.4	25.2	17.7	15.7	13.7	11.7	10.0
Light-Duty Trucks	14.1	22.4	13.6	12.5	11.1	9.5	9.3
Medium- and Heavy-Duty Trucks and Buses	0.6	0.9	0.8	0.7	0.7	0.6	0.5
Motorcycles	+	+	+	+	+	+	+

Diesel On-Road	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Alternative Fuel On-Road	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Non-Road	**3.6**	**4.3**	**4.3**	**4.2**	**4.3**	**3.8**	**3.6**
Ships and Boats	0.6	0.9	0.6	0.7	0.8	0.5	0.4
Rail	0.3	0.3	0.4	0.4	0.4	0.3	0.3
Aircraft	1.7	1.9	1.9	1.6	1.6	1.5	1.3
Agricultural Equipment[b]	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Construction/Mining Equipment[c]	0.3	0.4	0.5	0.5	0.5	0.5	0.5
Other[d]	0.4	0.5	0.6	0.6	0.6	0.6	0.6
Total	**43.9**	**53.2**	**36.9**	**33.6**	**30.3**	**26.1**	**23.9**

[a] See Annex 3.2 for definitions of on-road vehicle types.
[b] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.
[c] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.
[d] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.
Note: Totals may not sum due to independent rounding.
+ Less than 0.05 Tg CO_2 Eq.

CO_2 from Fossil Fuel Combustion

Methodology

The methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates in line with a Tier 2 method in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). A detailed description of the U.S. methodology is presented in Annex 2.1, and is characterized by the following steps:

1. *Determine total fuel consumption by fuel type and sector.* Total fossil fuel consumption for each year is estimated by aggregating consumption data by end-use sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.). Fuel consumption data for the United States were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), primarily from the Monthly Energy Review and published supplemental tables on petroleum product detail (EIA 2011). The EIA does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from Jacobs (2010).[70]

   For consistency of reporting, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA on an annual basis and used in this inventory are predominantly from mid-stream or conversion energy consumers such as refiners and electric power generators. These annual surveys are supplemented with end-use energy consumption surveys, such as the Manufacturing Energy Consumption Survey, that are conducted on a periodic basis (every 4 years). These consumption data sets help inform the annual surveys to arrive at the

[70] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed emissions of 42 Tg CO_2 Eq. in 2009.

national total and sectoral breakdowns for that total. [71]

It is also important to note that U.S. fossil fuel energy statistics are generally presented using gross calorific values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have not been adjusted to correspond to international standards, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).[72]

2. *Subtract uses accounted for in the Industrial Processes chapter.* Portions of the fuel consumption data for seven fuel categories—coking coal, distillate fuel, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil—were reallocated to the industrial processes chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from AISI (2004 through 2010), Coffeyville (2010), U.S. Census Bureau (2010), EIA (2010c), USGS (1991 through 2010), USGS (1994 through 2010), USGS (1995, 1998, 2000 through 2002, 2007, and 2009), USGS (1991 through 2009a), and USGS (1991 through 2009b).[73]

3. *Adjust for conversion of fuels and exports of CO_2.* Fossil fuel consumption estimates are adjusted downward to exclude fuels created from other fossil fuels and exports of CO_2.[74] Synthetic natural gas is created from industrial coal, and is currently included in EIA statistics for both coal and natural gas. Therefore, synthetic natural gas is subtracted from energy consumption statistics.[75] Since October 2000, the Dakota Gasification Plant has been exporting CO_2 to Canada by pipeline. Since this CO_2 is not emitted to the atmosphere in the United States, energy used to produce this CO_2 is subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol were collected from EIA (2011) and data for synthetic natural gas were collected from EIA (2009b), and data for CO_2 exports were collected from the Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), and EIA (2007b).

4. *Adjust Sectoral Allocation of Distillate Fuel Oil and Motor Gasoline.* EPA had conducted a separate bottom-up analysis of transportation fuel consumption based on the Federal Highway Administration's (FHWA) VMT that indicated that the amount of distillate and motor gasoline consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's distillate fuel and motor gasoline consumption was adjusted upward to match the value obtained from the bottom-up analysis based on VMT. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2009 through 2010), Benson (2002 through 2004), DOE (1993 through 2010), EIA (2009a), EIA (1991 through 2010), EPA (2009), and FHWA (1996 through 2010).[76]

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[71] See IPCC Reference Approach for estimating CO_2 emissions from fossil fuel combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

[72] A crude convention to convert between gross and net calorific values is to multiply the heat content of solid and liquid fossil fuels by 0.95 and gaseous fuels by 0.9 to account for the water content of the fuels. Biomass-based fuels in U.S. energy statistics, however, are generally presented using net calorific values.

[73] See sections on Iron and Steel Production and Metallurgical Coke Production, Ammonia Production and Urea Consumption, Petrochemical Production, Titanium Dioxide Production, Ferroalloy Production, Aluminum Production, and Silicon Carbide Production and Consumption in the Industrial Processes chapter.

[74] Energy statistics from EIA(2010c) are already adjusted downward to account for ethanol added to motor gasoline, and biogas in natural gas.

[75] These adjustments are explained in greater detail in Annex 2.1.

[76] FHWA data on vehicle miles traveled from the VM-1 table were not available for 2009 due to a delay caused by changes in data collection procedures. Based on data from FHWA's Traffic Volume Trends Program, the overall increase in VMT between 2008 and 2009 was estimated to be 0.2%. Total VMT was distributed among vehicle classes based on trends in fuel consumption by fuel type between 2008 and 2009, as described below.
Fuel use by vehicle class (also in the VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline was estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel

5. *Adjust for fuels consumed for non-energy uses.* U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. These are fossil fuels that are manufactured into plastics, asphalt, lubricants, or other products. Depending on the end-use, this can result in storage of some or all of the C contained in the fuel for a period of time. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion (since the C in these fuels ends up in products instead of being combusted), these emissions are estimated separately in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption was provided by EIA (2011).

6. *Subtract consumption of international bunker fuels.* According to the UNFCCC reporting guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from international transport activities were calculated separately following the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of C content).[77] The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Energy Support Center (Defense Logistics Agency) of the U.S. Department of Defense (DoD) (DESC 2011) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2006 and 2009); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2010) for 1990 through 2001, 2007 and 2008, and DHS (2008) for 2003 through 2006. Consumption of these fuels was subtracted from the corresponding fuels in the transportation end-use sector. Estimates of international bunker fuel emissions for the United States are discussed in detail later in the International Bunker Fuels section of this chapter.

7. *Determine the total C content of fuels consumed.* Total C was estimated by multiplying the amount of fuel consumed by the amount of C in each fuel. This total C estimate defines the maximum amount of C that could potentially be released to the atmosphere if all of the C in each fuel was converted to CO_2. The C content coefficients used by the United States were obtained from EIA's Emissions of Greenhouse Gases in the United States 2008 (EIA 2009a), and an EPA analysis of C content coefficients used in the mandatory reporting rule (EPA 2010a). A discussion of the methodology used to develop the C content coefficients are presented in Annexes 2.1 and 2.2.

8. *Estimate CO_2 Emissions.* Total CO_2 emissions are the product of the adjusted energy consumption (from the previous methodology steps 1 through 6), the C content of the fuels consumed, and the fraction of C that is oxidized. The fraction oxidized was assumed to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see Annex 2.1).

9. *Allocate transportation emissions by vehicle type.* This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector.

    - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2010); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2010). Fuel use by vehicle class (found in the VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline was estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel were estimated to fall by the same rate that diesel fuel consumption fell overall in 2009.

    - For non-road vehicles, activity data were obtained from AAR (2009 through 2010), APTA (2007 through 2010), BEA (1991 through 2009), Benson (2002 through 2004), DOE (1993 through 2010),

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was estimated to fall by the same rate that diesel fuel consumption fell overall in 2009. VMT was then distributed to vehicle classes based on these fuel consumption estimates, assuming no relative change in MPG between vehicle classes.

[77] See International Bunker Fuels section in this chapter for a more detailed discussion.

DESC (2011), DOC (1991 through 2010), DOT (1991 through 2010), EIA (2009a), EIA (2009d), EIA (2007a), EIA (2002), EIA (1991 through 2011), EPA (2010b), FAA (2008), and Gaffney (2007).

- For jet fuel used by aircraft, CO_2 emissions were calculated directly based on reported consumption of fuel as reported by EIA, and allocated to commercial aircraft using flight-specific fuel consumption data from the Federal Aviation Administration's (FAA) Aviation Environmental Design Tool (AEDT) (FAA 2011). [78] Allocation to domestic general aviation was made using FAA Aerospace Forecast data, and allocation to domestic military uses was made using DoD data (see Annex 3.7).

Heat contents and densities were obtained from EIA (2010) and USAF (1998). [79]

[BEGIN BOX]

Box 3-2: Carbon Intensity of U.S. Energy Consumption

Fossil fuels are the dominant source of energy in the United States, and CO_2 is the dominant greenhouse gas emitted as a product from their combustion. Energy-related CO_2 emissions are impacted by not only lower levels of energy consumption but also by lowering the C intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of C emitted from the combustion of fossil fuels is dependent upon the C content of the fuel and the fraction of that C that is oxidized. Fossil fuels vary in their average C content, ranging from about 53 Tg CO_2 Eq./QBtu for natural gas to upwards of 95 Tg CO_2 Eq./QBtu for coal and petroleum coke.[80] In general, the C content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. The overall C intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 3-15 provides a time series of the C intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For example, the C intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest C intensity, which is related to the large percentage of its energy derived from natural gas for heating. The C intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher C intensities over this period. The C intensity of the transportation sector was closely related to the C content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 Tg CO_2 Eq./EJ), which were the primary sources of energy. Lastly, the electricity generation sector had the highest C intensity due to its heavy reliance on coal for generating electricity.

Table 3-15: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (Tg CO_2 Eq./QBtu)

Sector	1990	2000	2005	2006	2007	2008	2009
Residential [a]	57.4	56.6	56.6	56.5	56.3	56.1	56.0
Commercial [a]	59.2	57.2	57.5	57.2	57.1	56.8	56.9
Industrial [a]	64.3	62.8	64.3	64.5	64.0	63.6	63.2
Transportation [a]	71.1	71.3	71.4	71.6	71.9	71.6	71.5

[78] Data for inventory years 2000 through 2005 were developed using the FAA's System for assessing Aviation's Global Emissions (SAGE) model. That tool has been incorporated into the Aviation Environmental Design Tool (AEDT), which calculates noise in addition to aircraft fuel burn and emissions for all commercial flights globally in a given year. Data for inventory years 2006-2009 were developed using AEDT. The AEDT model dynamically models aircraft performance in space and time to produce fuel burn, emissions and noise. Full flight gate-to-gate analyses are possible for study sizes ranging from a single flight at an airport to scenarios at the regional, national, and global levels. AEDT is currently used by the U.S. government to consider the interdependencies between aircraft-related fuel burn, noise and emissions.

[79] For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO_2) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.7.

[80] One exajoule (EJ) is equal to 10^{18} joules or 0.9478 QBtu.

Electricity Generation [b]	87.3		86.2		85.8	85.4	84.7	84.9	83.7
U.S. Territories [c]	73.0		72.5		73.4	73.5	73.8	73.3	73.1
All Sectors [c]	**73.0**		**73.0**		**73.5**	**73.5**	**73.3**	**73.1**	**72.4**

[a] Does not include electricity or renewable energy consumption.
[b] Does not include electricity produced using nuclear or renewable energy.
[c] Does not include nuclear or renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption.

Over the twenty-year period of 1990 through 2009, however, the C intensity of U.S. energy consumption has been fairly constant, as the proportion of fossil fuels used by the individual sectors has not changed significantly. Per capita energy consumption fluctuated little from 1990 to 2007, but in 2009 was approximately 9 percent below levels in 1990 (see Figure 3-14). Due to a general shift from a manufacturing-based economy to a service-based economy, as well as overall increases in efficiency, energy consumption and energy-related CO_2 emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2010).

Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

C intensity estimates were developed using nuclear and renewable energy data from EIA (2010), EPA (2010a), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

[END BOX]

Uncertainty and Time Series Consistency

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO_2 emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990).

Although statistics of total fossil fuel and other energy consumption are relatively accurate, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) is less certain. For example, for some fuels the sectoral allocations are based on price rates (i.e., tariffs), but a commercial establishment may be able to negotiate an industrial rate or a small industrial establishment may end up paying an industrial rate, leading to a misallocation of emissions. Also, the deregulation of the natural gas industry and the more recent deregulation of the electric power industry have likely led to some minor problems in collecting accurate energy statistics as firms in these industries have undergone significant restructuring.

To calculate the total CO_2 emission estimate from energy-related fossil fuel combustion, the amount of fuel used in these non-energy production processes were subtracted from the total fossil fuel consumption for 2009. The amount of CO_2 emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report. These factors all contribute to the uncertainty in the CO_2 estimates. Detailed discussions on the uncertainties associated with C emitted from Non-Energy Uses of Fossil Fuels can be found within that section of this chapter.

Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided in the International Bunker Fuels section of this chapter). Another source of uncertainty is fuel consumption by U.S. territories. The

United States does not collect energy statistics for its territories at the same level of detail as for the fifty states and the District of Columbia. Therefore, estimating both emissions and bunker fuel consumption by these territories is difficult.

Uncertainties in the emission estimates presented above also result from the data used to allocate CO_2 emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to improve the allocation into detailed transportation end-use sector emissions.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO_2 from fossil fuel combustion was integrated with the relevant variables from the inventory estimation model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 120 input variables were modeled for CO_2 from energy-related Fossil Fuel Combustion (including about 10 for non-energy fuel consumption and about 20 for International Bunker Fuels).

In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input variables and emission factors, based on the SAIC/EIA (2001) report.[81] Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency personnel.[82]

The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties) associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA 2001).[83] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo Sampling.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-16. Fossil fuel combustion CO_2 emissions in 2009 were estimated to be between 5,149.0 and 5,522.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 1 percent below to 6 percent above the 2009 emission estimate of 5,209.0.0 Tg CO_2 Eq.

Table 3-16: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Energy-related Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq. and Percent)

Fuel/Sector	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal [b]	**1,841.0**	**1,779.3**	**2,015.6**	**-3%**	**+9%**
Residential	0.6	0.6	0.7	-6%	+15%
Commercial	5.8	5.5	6.7	-5%	+15%
Industrial	83.4	80.5	97.5	-3%	+17%
Transportation	NE	NE	NE	NA	NA
Electricity Generation	1,747.6	1,680.4	1,915.8	-4%	+10%
U.S. Territories	3.5	3.1	4.2	-12%	+19%

[81] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

[82] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[83] Although, in general, random uncertainties are the main focus of statistical uncertainty analysis, when the uncertainty estimates are elicited from experts, their estimates include both random and systematic uncertainties. Hence, both these types of uncertainties are represented in this uncertainty analysis.

Natural Gas [b]	**1,200.9**	**1,209.4**	**1,276.6**	**+1%**	**+6%**
Residential	257.2	250.0	275.2	-3%	+7%
Commercial	167.9	163.2	179.7	-3%	+7%
Industrial	365.0	374.9	412.7	+3%	+13%
Transportation	36.3	35.2	38.8	-3%	+7%
Electricity Generation	373.1	362.3	392.0	-3%	+5%
U.S. Territories	1.5	1.3	1.7	-12%	+17%
Petroleum [b]	**2,166.7**	**2,067.2**	**2,323.5**	**-5%**	**+7%**
Residential	81.4	76.9	85.7	-6%	+5%
Commercial	50.3	47.9	52.4	-5%	+4%
Industrial	282.0	231.2	330.4	-18%	+17%
Transportation	1,683.4	1,598.6	1,826.8	-5%	+9%
Electric Utilities	32.9	31.5	35.4	-4%	+7%
U.S. Territories	36.7	33.8	40.9	-8%	+11%
Total (excluding Geothermal) [b]	**5,208.6**	**5,148.76**	**5,522.0**	**-1%**	**+6%**
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal) [b,c]	**5,209.0**	**5,149.0**	**5,522.4**	**-1%**	**+6%**

NA (Not Applicable)
NE (Not Estimated)
[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
[b] The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.
[c] Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO_2 emissions from geothermal production.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for CO_2 from fossil fuel combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology used for estimating CO_2 emissions from fossil fuel combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

Recalculations Discussion

The Energy Information Administration (EIA 2011) updated energy consumption statistics across the time series. These revisions primarily impacted the emission estimates for 2007 and 2008. In addition, the coal emissions for U.S. Territories decreased from 2001 to 2008 due to the closure of a coal power plant in the U.S. Virgin Islands. Overall, these changes resulted in an average annual increase of 0.5 Tg CO_2 Eq. (less than 0.1 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2008.

Planned Improvements

To reduce uncertainty of CO_2 from fossil fuel combustion estimates, efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. This improvement is not all-inclusive, and is part of an ongoing analysis and efforts to continually improve the CO_2 from fossil fuel combustion estimates. In addition, further expert elicitation may be conducted to better quantify the total uncertainty associated with emissions from this source.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to

EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

CH_4 and N_2O from Stationary Combustion

Methodology

CH_4 and N_2O emissions from stationary combustion were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type). National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, electricity generation, and U.S. territories. For the CH_4 and N_2O estimates, wood consumption data for the United States was obtained from EIA's Annual Energy Review (EIA 2010). Fuel consumption data for coal, natural gas, and fuel oil for the United States were obtained from EIA's Monthly Energy Review and unpublished supplemental tables on petroleum product detail (EIA 2011). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by Jacobs (2010).[84] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[85] Construction and agricultural fuel use was obtained from EPA (2010a). Estimates for wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc., that are reported as biomass by EIA.

Emission factors for the four end-use sectors were provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). U.S. territories' emission factors were estimated using the U.S. emission factors for the primary sector in which each fuel was combusted.

More detailed information on the methodology for calculating emissions from stationary combustion, including emission factors and activity data, is provided in Annex 3.1.

Uncertainty and Time-Series Consistency

CH_4 emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control).

An uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software.

The uncertainty estimation model for this source category was developed by integrating the CH_4 and N_2O stationary source inventory estimation models with the model for CO_2 from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. About 55 input variables were simulated for the uncertainty analysis of this source category (about 20 from the CO_2 emissions from fossil fuel combustion inventory estimation model and about 35 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N_2O emission factors, based on the SAIC/EIA (2001) report.[86] For these variables, the uncertainty

[84] U.S. territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH_4 and N_2O emissions from combustion by U.S. territories are only included in the stationary combustion totals.

[85] Though emissions from construction and farm use occur due to both stationary and mobile sources, detailed data was not available to determine the magnitude from each. Currently, these emissions are assumed to be predominantly from mobile sources.

[86] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former distribution to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[87] However, the CH_4 emission factors differ from those used by EIA. Since these factors were obtained from IPCC/UNEP/OECD/IEA (1997), uncertainty ranges were assigned based on IPCC default uncertainty estimates (IPCC 2000).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-17. Stationary combustion CH_4 emissions in 2009 (including biomass) were estimated to be between 4.1 and 14.0 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 34 percent below to 127 percent above the 2009 emission estimate of 6.2 Tg CO_2 Eq.[88] Stationary combustion N_2O emissions in 2009 (*including* biomass) were estimated to be between 9.8 and 36.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 23 percent below to 187 percent above the 2009 emissions estimate of 12.8 Tg CO_2 Eq.

Table 3-17: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Energy-Related Stationary Combustion, Including Biomass (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Stationary Combustion	CH_4	6.2	4.1	14.0	-34%	+127%
Stationary Combustion	N_2O	12.8	9.8	36.7	-23%	+187%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

The uncertainties associated with the emission estimates of CH_4 and N_2O are greater than those associated with estimates of CO_2 from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the indirect greenhouse gases, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for stationary combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CH_4, N_2O, and the indirect greenhouse gases from stationary combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated.

Recalculations Discussion

Historical CH_4 and N_2O emissions from stationary sources (excluding CO_2) were revised due to a couple of changes, mainly impacting 2007 and 2008 estimates. Slight changes to emission estimates for sectors are due to revised data from EIA (2010). Wood consumption data in EIA (2011) were revised for the residential, commercial, and industrial sectors for 2007 and 2008 as well as for the electric power sector for 2006 through 2008. The combination of the methodological and historical data changes resulted in an average annual increase of 0.01 Tg CO_2 Eq. (0.2 percent) in CH_4 emissions from stationary combustion and an average annual decrease of 0.08 Tg CO_2 Eq. (0.5 percent) in N_2O emissions from stationary combustion for the period 1990 through 2008.

[87] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[88] The low emission estimates reported in this section have been rounded down to the nearest integer values and the high emission estimates have been rounded up to the nearest integer values.

Planned Improvements

Several items are being evaluated to improve the CH_4 and N_2O emission estimates from stationary combustion and to reduce uncertainty. Efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. Because these data are not broken out by stationary and mobile uses, further research will be aimed at trying to allocate consumption appropriately. In addition, the uncertainty of biomass emissions will be further investigated since it was expected that the exclusion of biomass from the uncertainty estimates would reduce the uncertainty; and in actuality the exclusion of biomass increases the uncertainty. These improvements are not all-inclusive, but are part of an ongoing analysis and efforts to continually improve these stationary estimates.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

CH_4 and N_2O from Mobile Combustion

Methodology

Estimates of CH_4 and N_2O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Activity data included vehicle miles traveled (VMT) for on-road vehicles and fuel consumption for non-road mobile sources. The activity data and emission factors used are described in the subsections that follow. A complete discussion of the methodology used to estimate CH_4 and N_2O emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

On-Road Vehicles

Estimates of CH_4 and N_2O emissions from gasoline and diesel on-road vehicles are based on VMT and emission factors by vehicle type, fuel type, model year, and emission control technology. Emission estimates for alternative fuel vehicles (AFVs)[89] are based on VMT and emission factors by vehicle and fuel type.

Emission factors for gasoline and diesel on-road vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel on-road vehicle emissions factors were developed by ICF (2004). These factors were derived from EPA, California Air Resources Board (CARB) and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of greenhouse gases depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions characteristics of segment 2 were used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts gram per mile emissions of CO_2, CO, HC, NO_x, and PM from vehicles under various conditions, to approximate average driving characteristics.[90]

Emission factors for AFVs were developed by ICF (2006a) after examining Argonne National Laboratory's GREET 1.7–Transportation Fuel Cycle Model (ANL 2006) and Lipman and Delucchi (2002). These sources describe AFV emission factors in terms of ratios to conventional vehicle emission factors. Ratios of AFV to conventional vehicle emissions factors were then applied to estimated Tier 1 emissions factors from light-duty gasoline vehicles to estimate light-duty AFVs. Emissions factors for heavy-duty AFVs were developed in relation to gasoline heavy-duty vehicles. A complete discussion of the data source and methodology used to determine emission factors from

[89] Alternative fuel and advanced technology vehicles are those that can operate using a motor fuel other than gasoline or diesel. This includes electric or other bi-fuel or dual-fuel vehicles that may be partially powered by gasoline or diesel.

[90] Additional information regarding the model can be found online at http://www.epa.gov/OMS/m6.htm.

AFVs is provided in Annex 3.2.

Annual VMT data for 1990 through 2010 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2010).[91] VMT estimates were then allocated from FHWA's vehicle categories to fuel-specific vehicle categories using the calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2010) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2010). VMT for AFVs were taken from Browning (2003). The age distributions of the U.S. vehicle fleet were obtained from EPA (2010a, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2000).

Control technology and standards data for on-road vehicles were obtained from EPA's Office of Transportation and Air Quality (EPA 2007a, 2007b, 2000, 1998, and 1997) and Browning (2005). These technologies and standards are defined in Annex 3.2, and were compiled from EPA (1993, 1994a, 1994b, 1998, 1999a) and IPCC/UNEP/OECD/IEA (1997).

Non-Road Vehicles

To estimate emissions from non-road vehicles, fuel consumption data were employed as a measure of activity, and multiplied by fuel-specific emission factors (in grams of N_2O and CH_4 per kilogram of fuel consumed).[92] Activity data were obtained from AAR (2009 through 2010), APTA (2007 through 2010), APTA (2006), BEA (1991 through 2005), Benson (2002 through 2004), DHS (2008), DOC (1991 through 2008), DOE (1993 through 2010), DESC (2011), DOT (1991 through 2010), EIA (2008a, 2007a, 2007b, 2002), EIA (2007 through 2010), EIA (1991 through 2011), EPA (2009), Esser (2003 through 2004), FAA (2011, 2010, and 2006), Gaffney (2007), and (2006 through 2010). Emission factors for non-road modes were taken from IPCC/UNEP/OECD/IEA (1997) and Browning (2009).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo simulation technique, using @RISK software. The uncertainty analysis was performed on 2009 estimates of CH_4 and N_2O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following four major sets of input variables: (1) vehicle miles traveled (VMT) data, by on-road vehicle and fuel type and (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment type.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched since emissions of these gases from motor vehicles are regulated in the United States, and the uncertainty in these emission estimates is believed to be relatively low. However, a much higher level of uncertainty is associated with CH_4 and N_2O emission factors, because emissions of these gases are not regulated in the United States (and, therefore, there are not adequate emission test data), and because, unlike CO_2 emissions, the emission pathways of CH_4 and N_2O are highly complex.

Mobile combustion CH_4 emissions from all mobile sources in 2009 were estimated to be between 1.8 and 2.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 9 percent below to 15 percent above the corresponding 2009 emission estimate of 2.0 Tg CO_2 Eq. Also at a 95 percent confidence level, mobile combustion N_2O emissions from mobile sources in 2009 were estimated to be between 20.5 and 27.9 Tg CO_2 Eq., indicating a range of 14 percent below to 17 percent above the corresponding 2009 emission estimate of 23.9 Tg CO_2 Eq.

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[91] Fuel use by vehicle class (VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline were estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel were estimated to fall by the same rate that diesel fuel consumption fell overall in 2009. VMT was then distributed to vehicle classes based on these fuel consumption estimates, assuming no relative change in MPG between vehicle classes.

[92] The consumption of international bunker fuels is not included in these activity data, but is estimated separately under the International Bunker Fuels source category.

Table 3-18: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Mobile Sources (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate[a] (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mobile Sources	CH_4	2.0	1.8	2.2	-9%	+15%
Mobile Sources	N_2O	23.9	20.5	27.9	-14%	+17%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

This uncertainty analysis is a continuation of a multi-year process for developing quantitative uncertainty estimates for this source category using the IPCC Tier 2 approach to uncertainty analysis. As a result, as new information becomes available, uncertainty characterization of input variables may be improved and revised. For additional information regarding uncertainty in emission estimates for CH_4 and N_2O please refer to the Uncertainty Annex.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2008. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for mobile combustion was developed and implemented. This plan is based on the IPCC-recommended QA/QC Plan. The specific plan used for mobile combustion was updated prior to collection and analysis of this current year of data. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on the emission factor and activity data sources, as well as the methodology used for estimating emissions. These procedures included a qualitative assessment of the emissions estimates to determine whether they appear consistent with the most recent activity data and emission factors available. A comparison of historical emissions between the current Inventory and the previous Inventory was also conducted to ensure that the changes in estimates were consistent with the changes in activity data and emission factors.

Recalculations Discussion

In order to ensure that these estimates are continuously improved, the calculation methodology is revised annually based on comments from internal and external reviewers. Each year, a number of adjustments are made to the methodologies used in calculating emissions in the current Inventory relative to previous Inventory reports. One of the revisions that were made this year was incorporating motor vehicle age distribution from EPA's MOtor Vehicle Emission Simulator (MOVES) model. MOVES is EPA's tool for estimating emissions from highway vehicles, based on analysis of millions of emission test results and considerable advances in EPA's understanding of vehicle emissions. Population data from the MOVES model was used to estimate the age distribution of motor vehicles in the United States.

Planned Improvements

While the data used for this report represent the most accurate information available, four areas have been identified that could potentially be improved in the short-term given available resources.

1. Develop updated emissions factors for diesel vehicles, motorcycle, and biodiesel vehicles. Previous emission factors were based upon extrapolations from other vehicle classes and new test data from Environment Canada and other sources may allow for better estimation of emission factors for these vehicles.
2. Develop new emission factors for non-road equipment. The current inventory estimates for non-CO_2 emissions from non-road sources are based on emission factors from IPCC guidelines published in 1996. Recent data on non-road sources from Environment Canada and the California Air Resources Board will be investigated in order to assess the feasibility of developing new N_2O and CH_4 emissions factors for non-road equipment.
3. Examine the feasibility of estimating aircraft N_2O and CH_4 emissions by the number of takeoffs and landings, instead of total fuel consumption. Various studies have indicated that aircraft N_2O and CH_4

emissions are more dependent on aircraft takeoffs and landings than on total aircraft fuel consumption; however, aircraft emissions are currently estimated from fuel consumption data. FAA's SAGE and AEDT databases contain detailed data on takeoffs and landings for each calendar year starting in 2000, and could potentially be used to conduct a Tier II analysis of aircraft emissions. This methodology will require a detailed analysis of the number of takeoffs and landings by aircraft type on domestic trips, the development of procedures to develop comparable estimates for years prior to 2000, and the dynamic interaction of ambient air with aircraft exhausts is developed. The feasibility of this approach will be explored.

Develop improved estimates of domestic waterborne fuel consumption. The inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international use from the total sold in the United States. It may be possible to more accurately estimate domestic fuel use and emissions by using detailed data on marine ship activity. The feasibility of using domestic marine activity data to improve the estimates will be investigated. Continue to examine the use of EPA's MOVES model in the development of the inventory estimates, including use for uncertainty analysis. Although the inventory uses some of the underlying data from MOVES, such as vehicle age distributions by model year, MOVES is not used directly in calculating mobile source emissions. As MOVES goes through additional testing and refinement, the use of MOVES will be further explored.

3.2. Carbon Emitted from Non-Energy Uses of Fossil Fuels (IPCC Source Category 1A)

In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses (NEU) in the United States. The fuels used for these purposes are diverse, including natural gas, liquefied petroleum gases (LPG), asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke (manufactured from heavy oil), and coal (metallurgical) coke (manufactured from coking coal). The non-energy applications of these fuels are equally diverse, including feedstocks for the manufacture of plastics, rubber, synthetic fibers and other materials; reducing agents for the production of various metals and inorganic products; and non-energy products such as lubricants, waxes, and asphalt (IPCC 2006).

CO_2 emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 61 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 39 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of the inventory. For example, some of the NEU products release CO_2 at the end of their commercial life when they are combusted after disposal; these emissions are reported separately within the Energy chapter in the Incineration of Waste source category. In addition, there is some overlap between fossil fuels consumed for non-energy uses and the fossil-derived CO_2 emissions accounted for in the Industrial Processes chapter, especially for fuels used as reducing agents. To avoid double-counting, the "raw" non-energy fuel consumption data reported by EIA are modified to account for these overlaps. There are also net exports of petrochemicals that are not completely accounted for in the EIA data, and the inventory calculations make adjustments to address the effect of net exports on the mass of C in non-energy applications.

As shown in Table 3-19, fossil fuel emissions in 2009 from the non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2009, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,451.0 TBtu, an increase of 0.2 percent since 1990 (see Table 3-20). About 49.9 Tg of the C (182.8 Tg CO_2 Eq.) in these fuels was stored, while the remaining 33.6 Tg C (123.4 Tg CO_2 Eq.) was emitted.

Table 3-19: CO_2 Emissions from Non-Energy Use Fossil Fuel Consumption (Tg CO_2 Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
Potential Emissions	310.8	383.6	381.6	381.7	370.1	344.9	306.1
C Stored	192.2	238.6	238.3	236.1	232.8	204.0	182.8
Emissions as a % of Potential	38%	38%	38%	38%	37%	41%	40%
Emissions	**118.6**	**144.9**	**143.4**	**145.6**	**137.2**	**141.0**	**123.4**

Methodology

The first step in estimating C stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The C content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific C content values. Both the non-energy fuel consumption and C content data were supplied by the EIA (2011) (see Annex 2.1). Consumption of natural gas, LPG, pentanes plus, naphthas, other oils, and special naphtha were adjusted to account for net exports of these products that are not reflected in the raw data from EIA. Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-20 and Table 3-21 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes chapter.[93] Consumption values were also adjusted to subtract net exports of intermediary chemicals.

For the remaining non-energy uses, the quantity of C stored was estimated by multiplying the potential emissions by a storage factor.

- For several fuel types—petrochemical feedstocks (including natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors, calculated as the ratio of (a) the C stored by the fuel's non-energy products to (b) the total C content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process and during use. Because losses associated with municipal solid waste management are handled separately in this sector under the Incineration of Waste source category, the storage factors do not account for losses at the disposal end of the life cycle.
- For industrial coking coal and distillate fuel oil, storage factors were taken from IPCC/UNEP/OECD/IEA (1997), which in turn draws from Marland and Rotty (1984).
- For the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), IPCC does not provide guidance on storage factors, and assumptions were made based on the potential fate of C in the respective NEU products.

Table 3-20: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBtu)

Year	1990	2000	2005	2006	2007	2008	2009
Industry	**4,181.1**	**5,214.4**	**5,174.4**	**5,163.2**	**5,060.7**	**4,671.9**	**4,267.7**
Industrial Coking Coal	+	53.0	79.8	62.3	1.7	28.4	6.1
Industrial Other Coal	8.2	12.4	11.9	12.4	12.4	12.4	12.4
Natural Gas to Chemical Plants	277.3	420.3	397.0	407.7	412.5	395.2	366.0
Asphalt & Road Oil	1,170.2	1,275.7	1,323.2	1,261.2	1,197.0	1,012.0	873.1
LPG	1,119.2	1,607.0	1,444.0	1,488.6	1,483.0	1,409.6	1,446.2
Lubricants	186.3	189.9	160.2	156.1	161.2	149.6	134.5
Pentanes Plus	77.5	229.3	146.3	105.5	132.7	114.9	93.4
Naphtha (<401 ° F)	325.9	593.7	679.6	618.1	542.6	467.3	450.7
Other Oil (>401 ° F)	661.4	527.0	514.8	573.4	669.2	599.2	392.5
Still Gas	21.3	12.6	67.7	57.2	44.2	47.3	133.9
Petroleum Coke	54.8	35.3	128.8	172.2	155.9	174.4	133.0
Special Naphtha	100.8	94.4	60.9	68.9	75.5	83.2	44.2
Distillate Fuel Oil	7.0	11.7	16.0	17.5	17.5	17.5	17.5
Waxes	33.3	33.1	31.4	26.1	21.9	19.1	12.2
Miscellaneous Products	137.8	119.2	112.8	136.0	133.5	142.0	151.8
Transportation	**176.0**	**179.4**	**151.3**	**147.4**	**152.2**	**141.3**	**127.1**
Lubricants	176.0	179.4	151.3	147.4	152.2	141.3	127.1
U.S. Territories	**86.7**	**152.2**	**121.9**	**133.4**	**108.4**	**126.7**	**56.3**
Lubricants	0.7	3.1	4.6	6.2	5.9	2.7	1.0

[93] These source categories include Iron and Steel Production, Lead Production, Zinc Production, Ammonia Manufacture, Carbon Black Manufacture (included in Petrochemical Production), Titanium Dioxide Production, Ferroalloy Production, Silicon Carbide Production, and Aluminum Production.

Other Petroleum (Misc. Prod.)	86.0	149.1	117.3	127.2	102.5	124.1	55.2
Total	**4,443.8**	**5,546.0**	**5,447.6**	**5,444.0**	**5,321.3**	**4,940.0**	**4,451.0**

+ Does not exceed 0.05 TBtu

Note: To avoid double-counting, coal coke, petroleum coke, natural gas consumption, and other oils are adjusted for industrial process consumption reported in the Industrial Processes sector. Natural gas, LPG, Pentanes Plus, Naphthas, Special Naphtha, and Other Oils are adjusted to account for exports of chemical intermediates derived from these fuels. For residual oil (not shown in the table), all non-energy use is assumed to be consumed in C black production, which is also reported in the Industrial Processes chapter.

Note: Totals may not sum due to independent rounding.

Table 3-21: 2009 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions

Sector/Fuel Type	Adjusted Non-Energy Use[a] (TBtu)	Carbon Content Coefficient (Tg C/QBtu)	Potential Carbon (Tg C)	Storage Factor	Carbon Stored (Tg C)	Carbon Emissions (Tg C)	Carbon Emissions (Tg CO_2 Eq.)
Industry	**4,267.7**	-	**79.8**	-	**49.5**	**30.3**	**111.1**
Industrial Coking Coal	6.1	31.00	0.2	0.10	0.0	0.2	0.6
Industrial Other Coal	12.4	25.82	0.3	0.58	0.2	0.1	0.5
Natural Gas to Chemical Plants	366.0	14.47	5.3	0.58	3.1	2.2	8.1
Asphalt & Road Oil	873.1	20.55	17.9	1.00	17.9	0.1	0.3
LPG	1,446.2	17.06	24.7	0.58	14.3	10.3	37.9
Lubricants	134.5	20.20	2.7	0.09	0.2	2.5	9.0
Pentanes Plus	93.4	19.10	1.8	0.58	1.0	0.7	2.7
Naphtha (<401° F)	450.7	18.55	8.4	0.58	4.9	3.5	12.9
Other Oil (>401° F)	392.5	20.17	7.9	0.58	4.6	3.3	12.2
Still Gas	133.9	17.51	2.3	0.58	1.4	1.0	3.6
Petroleum Coke	133.0	27.85	3.7	0.30	1.1	2.6	9.5
Special Naphtha	44.2	19.74	0.9	0.58	0.5	0.4	1.3
Distillate Fuel Oil	17.5	20.17	0.4	0.50	0.2	0.2	0.6
Waxes	12.2	19.80	0.2	0.58	0.1	0.1	0.4
Miscellaneous Products	151.8	20.31	3.1	0.00	0.0	3.1	11.3
Transportation	**127.1**	-	**2.6**	-	**0.2**	**2.3**	**8.5**
Lubricants	127.1	20.20	2.6	0.09	0.2	2.3	8.5
U.S. Territories	**56.3**	-	**1.1**	-	**0.1**	**1.0**	**3.7**
Lubricants	1.0	20.20	+	0.09	+	+	0.1
Other Petroleum (Misc. Prod.)	55.2	20.00	1.1	0.10	0.1	1.0	3.6
Total	**4,451.0**	-	**83.5**	-	**49.9**	**33.6**	**123.4**

+ Does not exceed 0.05 Tg

- Not applicable.

[a] To avoid double counting, net exports have been deducted.

Note: Totals may not sum due to independent rounding.

Lastly, emissions were estimated by subtracting the C stored from the potential emissions (see Table 3-19). More detail on the methodology for calculating storage and emissions from each of these sources is provided in Annex 2.3.

Where storage factors were calculated specifically for the United States, data were obtained on (1) products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases including energy recovery, Toxics Release Inventory (TRI) releases, hazardous waste incineration, and volatile organic compound, solvent, and non-combustion CO emissions. Data were taken from a variety of industry sources, government reports, and expert communications. Sources include EPA reports and databases such as compilations of air emission factors (EPA 2001), *National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data* (EPA 2010), *Toxics Release Inventory, 1998* (2000b), *Biennial Reporting System* (EPA 2004, 2007a), and pesticide sales and use estimates

(EPA 1998, 1999, 2002, 2004); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Bureau of the Census (1999, 2004, 2009); Bank of Canada (2009); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (2011); Gosselin, Smith, and Hodge (1984); the Rubber Manufacturers' Association (RMA 2009a,b); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2010); and the American Chemistry Council (ACC 2003-2010). Specific data sources are listed in full detail in Annex 2.3.

Uncertainty and Time-Series Consistency

An uncertainty analysis was conducted to quantify the uncertainty surrounding the estimates of emissions and storage factors from non-energy uses. This analysis, performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide the 95 percent confidence interval, the range of values within which emissions are likely to fall, for this source category.

As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials (natural gas, LPG, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2) asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the "other" category in Table 3-22 and Table 3-23), the storage factors were taken directly from the IPCC *Guidelines for National Greenhouse Gas Inventories*, where available, and otherwise assumptions were made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not available directly from the information sources for all the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-22 (emissions) and Table 3-23 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2009 was estimated to be between 97.6 and 135.3 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 10 percent above the 2009 emission estimate of 123.4 Tg CO_2 Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

Table 3-22: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	79.3	63.4	96.1	-20%	21%
Asphalt	CO_2	0.3	0.1	0.6	-58%	119%
Lubricants	CO_2	17.7	14.6	20.5	-17%	16%
Waxes	CO_2	0.4	0.3	0.7	-29%	74%
Other	CO_2	25.7	10.3	27.0	-60%	5%
Total	**CO_2**	123.4	97.6	135.3	-21%	10%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
NA (Not Applicable)

Table 3-23: Tier 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

Source	Gas	2009 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	58%	56%	60%	-3%	4%
Asphalt	CO_2	99.6%	99.1%	99.8%	-0.5%	0.3%
Lubricants	CO_2	9%	4%	17%	-57%	91%
Waxes	CO_2	58%	49%	71%	-15%	22%
Other	CO_2	17%	16%	66%	-3%	292%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval, as a percentage of the inventory value (also expressed in percent terms).

In Table 3-23, feedstocks and asphalt contribute least to overall storage factor uncertainty on a percentage basis. Although the feedstocks category—the largest use category in terms of total carbon flows—appears to have tight confidence limits, this is to some extent an artifact of the way the uncertainty analysis was structured. As discussed in Annex 2.3, the storage factor for feedstocks is based on an analysis of six fates that result in long-term storage (e.g., plastics production), and eleven that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the total uncertainty around all of these fate processes, the current analysis addresses only the storage fates, and assumes that all C that is not stored is emitted. As the production statistics that drive the storage values are relatively well-characterized, this approach yields a result that is probably biased toward understating uncertainty.

As is the case with the other uncertainty analyses discussed throughout this document, the uncertainty results above address only those factors that can be readily quantified. More details on the uncertainty analysis are provided in Annex 2.3.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for non-energy uses of fossil fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis for non-energy uses involving petrochemical feedstocks and for imports and exports. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology for estimating the fate of C (in terms of storage and emissions) across the various end-uses of fossil C. Emission and storage totals for the different subcategories were compared, and trends across the time series were analyzed to determine whether any corrective actions were needed. Corrective actions were taken to rectify minor errors and to improve the transparency of the calculations, facilitating future QA/QC.

For petrochemical import and export data, special attention was paid to NAICS numbers and titles to verify that none had changed or been removed. Import and export totals were compared for 2009 as well as their trends across the time series.

Recalculations Discussion

In previous Inventories, the storage factor for asphalt was incorrectly assumed to be 100 percent. For the current Inventory, it has been updated to 99.6 percent to reflect some loss of VOCs (see Annex 2.3 for more detailed discussion).

Updates to the EIA Manufacturer's Energy Consumption Survey (MECS) for 2006 were released in the past year. MECS data are only released once every four years and contribute to approximately 28 percent (as a time-weighted average) of the C accounted for in feedstocks. MECS data are used to estimate the amount of C emitted from energy recovery. Updating the energy recovery emission estimates with this new data affected emissions from 2003

through 2009, resulting in annual average increases of 7 percent from 2003 through 2009. In addition, the entire energy recovery time series was recalculated to adjust for energy recovered from combustion of scrap tires. Carbon emissions from scrap tires were inadvertently included in the energy recovery estimates; however, they are already accounted for in the Incineration of Waste category.[94] MECS data were adjusted to remove C from scrap tires used as fuel in cement kilns, lime kilns, and electric arc furnaces. This adjustment resulted in decreases in emissions across the entire time series. Emissions decreased by 0.3, 2.1, 1.3, and 1.5 percent for MECS-reporting years 1991, 1994, 1998, and 2002, respectively. Updating the energy recovery emission estimates with the 2006 MECS data combined with adjusting for combustion of scrap tires increased the 2006 emission estimate by 9.5 percent. Overall, emissions from energy recovery averaged over the entire time series increased by 1.2 percent when compared to last year's inventory estimate because the increase resulting from updating the MECS data more than offsets the decrease from adjusting for scrap tire combustion across the time series.

Planned Improvements

There are several improvements planned for the future:

- Improving the uncertainty analysis. Most of the input parameter distributions are based on professional judgment rather than rigorous statistical characterizations of uncertainty.
- Better characterizing flows of fossil C. Additional fates may be researched, including the fossil C load in organic chemical wastewaters, plasticizers, adhesives, films, paints, and coatings. There is also a need to further clarify the treatment of fuel additives and backflows (especially methyl tert-butyl ether, MTBE).
- Reviewing the trends in fossil fuel consumption for non-energy uses. Annual consumption for several fuel types is highly variable across the time series, including industrial coking coal and other petroleum (miscellaneous products). EPA plans to better understand these trends to identify any mischaracterized or misreported fuel consumption for non-energy uses.
- More accurate accounting of C in petrochemical feedstocks. Since 2001, the C accounted for in the feedstocks C balance outputs (i.e., storage plus emissions) exceeds C inputs. Prior to 2001, the C balance inputs exceed outputs. EPA plans to research this discrepancy by assessing the trends on both sides of the C balance. An initial review of EIA (2011) data indicates that trends in LPG consumption for non-energy uses may largely contribute to this discrepancy.
- More accurate accounting of C in imports and exports. As part of its effort to address the C balance discrepancy, EPA will examine its import/export adjustment methodology to ensure that net exports of intermediaries such as ethylene and propylene are fully accounted for.
- EPA recently researched updating the average carbon content of solvents, since the entire time series depends on one year's worth of solvent composition data. Unfortunately, the data on C emissions from solvents that were readily available do not provide composition data for all categories of solvent emissions and also have conflicting definitions for volatile organic compounds, the source of emissive carbon in solvents. EPA plans to identify additional sources of solvents data in order to update the C content assumptions.

Finally, although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes, default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal and distillate oil), and broad assumptions are being used for miscellaneous products and other petroleum. Over the long term, there are plans to improve these storage factors by conducting analyses of C fate similar to those described in Annex 2.3 or deferring to more updated default storage factors from IPCC where available.

3.3. Incineration of Waste (IPCC Source Category 1A1a)

Incineration is used to manage about 7 to 19 percent of the solid wastes generated in the United States, depending on the source of the estimate and the scope of materials included in the definition of solid waste (EPA 2000, Goldstein

[94] From a regulatory-definition perspective combustion of scrap tires in cement kilns, lime kilns, and electric arc furnaces is not considered "incineration;" however the use of the term "incineration" in this document also applies to the combustion of scrap tires and other materials for energy recovery.

and Matdes 2001, Kaufman et al. 2004, Simmons et al. 2006, van Haaren et al. 2010). In the context of this section, waste includes all municipal solid waste (MSW) as well as tires. In the United States, almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where useful energy is recovered, and thus emissions from waste incineration are accounted for in the Energy chapter. Similarly, tires are combusted for energy recovery in industrial and utility boilers. Incineration of waste results in conversion of the organic inputs to CO_2. According to IPCC guidelines, when the CO_2 emitted is of fossil origin, it is counted as a net anthropogenic emission of CO_2 to the atmosphere. Thus, the emissions from waste incineration are calculated by estimating the quantity of waste combusted and the fraction of the waste that is C derived from fossil sources.

Most of the organic materials in municipal solid wastes are of biogenic origin (e.g., paper, yard trimmings), and have their net C flows accounted for under the Land Use, Land-Use Change, and Forestry chapter. However, some components—plastics, synthetic rubber, synthetic fibers, and carbon black—are of fossil origin. Plastics in the U.S. waste stream are primarily in the form of containers, packaging, and durable goods. Rubber is found in durable goods, such as carpets, and in non-durable goods, such as clothing and footwear. Fibers in municipal solid wastes are predominantly from clothing and home furnishings. As noted above, tires (which contain rubber and carbon black) are also considered a "non-hazardous" waste and are included in the waste incineration estimate, though waste disposal practices for tires differ from municipal solid waste. Estimates on emissions from hazardous waste incineration can be found in Annex 2.3 and are accounted for as part of the carbon mass balance for non-energy uses of fossil fuels.

Approximately 26 million metric tons of MSW was incinerated in the United States in 2009 (EPA 2011). CO_2 emissions from incineration of waste rose 54 percent since 1990, to an estimated 12.3 Tg CO_2 Eq. (12,300 Gg) in 2009, as the volume of tires and other fossil C-containing materials in waste increased (see Table 3-24 and Table 3-25). Waste incineration is also a source of N_2O and CH_4 emissions (De Soete 1993; IPCC 2006). N_2O emissions from the incineration of waste were estimated to be 0.4 Tg CO_2 Eq. (1 Gg N_2O) in 2009, and have not changed significantly since 1990. CH_4 emissions from the incineration of waste were estimated to be less than 0.05 Tg CO_2 Eq. (less than 0.5 Gg CH_4) in 2009, and have not changed significantly since 1990.

Table 3-24: CO_2 and N_2O Emissions from the Incineration of Waste (Tg CO_2 Eq.)

Gas/Waste Product	1990	2000	2005	2006	2007	2008	2009
CO_2	**8.0**	**11.1**	**12.5**	**12.5**	**12.7**	**12.2**	**12.3**
Plastics	5.6	6.1	6.9	6.7	6.7	6.1	6.2
Synthetic Rubber in Tires	0.3	1.5	1.6	1.7	1.8	1.8	1.8
Carbon Black in Tires	0.4	1.8	2.0	2.1	2.3	2.3	2.3
Synthetic Rubber in MSW	0.9	0.7	0.8	0.8	0.8	0.8	0.8
Synthetic Fibers	0.8	1.0	1.2	1.2	1.2	1.2	1.2
N_2O	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
CH_4	+	+	+	+	+	+	+
Total	**8.5**	**11.5**	**12.9**	**12.9**	**13.1**	**12.5**	**12.7**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-25: CO_2 and N_2O Emissions from the Incineration of Waste (Gg)

Gas/Waste Product	1990	2000	2005	2006	2007	2008	2009
CO_2	**7,989**	**11,112**	**12,450**	**12,531**	**12,700**	**12,169**	**12,300**
Plastics	5,588	6,104	6,919	6,722	6,660	6,148	6,233
Synthetic Rubber in Tires	308	1,454	1,599	1,712	1,823	1,823	1,823
Carbon Black in Tires	385	1,818	1,958	2,113	2,268	2,268	2,268
Synthetic Rubber in MSW	872	689	781	775	791	770	782
Synthetic Fibers	838	1,046	1,194	1,208	1,159	1,161	1,195
N_2O	**2**	**1**	**1**	**1**	**1**	**1**	**1**
CH_4	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg.

Methodology

Emissions of CO_2 from the incineration of waste include CO_2 generated by the incineration of plastics, synthetic fibers, and synthetic rubber, as well as the incineration of synthetic rubber and carbon black in tires. These emissions

were estimated by multiplying the amount of each material incinerated by the C content of the material and the fraction oxidized (98 percent). Plastics incinerated in municipal solid wastes were categorized into seven plastic resin types, each material having a discrete C content. Similarly, synthetic rubber is categorized into three product types, and synthetic fibers were categorized into four product types, each having a discrete C content. Scrap tires contain several types of synthetic rubber, as well as carbon black. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of CO_2 were calculated based on the amount of scrap tires used for fuel and the synthetic rubber and carbon black content of tires.

More detail on the methodology for calculating emissions from each of these waste incineration sources is provided in Annex 3.6.

For each of the methods used to calculate CO_2 emissions from the incineration of waste, data on the quantity of product combusted and the C content of the product are needed. For plastics, synthetic rubber, and synthetic fibers, the amount of specific materials discarded as municipal solid waste (i.e., the quantity generated minus the quantity recycled) was taken from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* (EPA 1999 through 2003, 2005 through 2011) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). The proportion of total waste discarded that is incinerated was derived from data in BioCycle's "State of Garbage in America" (van Haaren et al. 2010). The most recent data provides the proportion of waste incinerated for 2008, so the corresponding proportion in 2009 is assumed to be equal to the proportion in 2008. For synthetic rubber and carbon black in scrap tires, information was obtained from U.S. Scrap Tire Markets in the United States, 2007 Edition (RMA 2009a). For 2008 and 2009, synthetic rubber mass in tires is assumed to be equal to that in 2007 due to a lack of more recently available data.

Average C contents for the "Other" plastics category and synthetic rubber in municipal solid wastes were calculated from 1998 and 2002 production statistics: carbon content for 1990 through 1998 is based on the 1998 value; content for 1999 through 2001 is the average of 1998 and 2002 values; and content for 2002 to date is based on the 2002 value. Carbon content for synthetic fibers was calculated from 1999 production statistics. Information about scrap tire composition was taken from the Rubber Manufacturers' Association internet site (RMA 2009b).

The assumption that 98 percent of organic C is oxidized (which applies to all waste incineration categories for CO_2 emissions) was reported in EPA's life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 2006).

Incineration of waste, including MSW, also results in emissions of N_2O and CH_4. These emissions were calculated as a function of the total estimated mass of waste incinerated and an emission factor. As noted above, N_2O and CH_4 emissions are a function of total waste incinerated in each year; for 1990 through 2008, these data were derived from the information published in BioCycle (van Haaren et al. 2010). Data on total waste incinerated was not available for 2009, so this value was assumed to equal the most recent value available (2008). Table 3-26 provides data on municipal solid waste discarded and percentage combusted for the total waste stream. According to Covanta Energy (Bahor 2009) and confirmed by additional research based on ISWA (ERC 2009), all municipal solid waste combustors in the United States are continuously fed stoker units. The emission factors of N_2O and CH_4 emissions per quantity of municipal solid waste combusted are default emission factors for this technology type and were taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

Table 3-26: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted.

Year	Waste Discarded	Waste Incinerated	Incinerated (% of Discards)
1990	235,733,657	30,632,057	13.0
2000	252,328,354	25,974,978	10.3
2005	259,559,787	25,973,520	10.0
2006	267,526,493	25,853,401	9.7
2007	268,279,240	24,788,539	9.2
2008	268,541,088	23,674,017	8.8
2009	268,541,088[a]	23,674,017 [a]	8.8[a]

[a] Assumed equal to 2008 value.
Source: van Haaren et al. (2010).

Uncertainty and Time-Series Consistency

A Tier 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO_2 emissions and N_2O emissions from the incineration of waste (given the very low emissions for CH_4, no uncertainty estimate was derived). IPCC Tier 2 analysis allows the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the Municipal Solid Waste in the United States reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus, uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables.

The uncertainties in the waste incineration emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW incineration rate; fraction oxidized; missing data on waste composition; average C content of waste components; assumptions on the synthetic/biogenic C ratio; and combustion conditions affecting N_2O emissions. The highest levels of uncertainty surround the variables that are based on assumptions (e.g., percent of clothing and footwear composed of synthetic rubber); the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, C content of C black).

The results of the Tier 2 quantitative uncertainty analysis are summarized inTable 3-27. Waste incineration CO_2 emissions in 2009 were estimated to be between 9.8 and 15.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 24 percent above the 2009 emission estimate of 12.3 Tg CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2009 were estimated to be between 0.2 and 1.5 Tg CO_2 Eq. This indicates a range of 51 percent below to 320 percent above the 2009 emission estimate of 0.4 Tg CO_2 Eq.

Table 3-27: Tier 2 Quantitative Uncertainty Estimates for CO_2 and N_2O from the Incineration of Waste (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Incineration of Waste	CO_2	12.3	9.8	15.2	-21%	+24%
Incineration of Waste	N_2O	0.4	0.2	1.5	-51%	+320%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990

through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan was implemented for incineration of waste. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and specifically focused on the emission factor and activity data sources and methodology used for estimating emissions from incineration of waste. Trends across the time series were analyzed to determine whether any corrective actions were needed. Actions were taken to streamline the activity data throughout the calculations on incineration of waste.

Recalculations Discussion

Several changes were made to input variables compared to the previous Inventory, resulting in an overall decrease in the total emissions from the incineration of waste. Formerly, the percentage of overall rubber waste that is synthetic (i.e., fossil-derived rather than biogenic) varied across the product categories, ranging from 25 percent for clothing and footwear to 100 percent synthetic rubber for durable goods and containers and packaging. For the current Inventory, this variable was updated to be 70 percent synthetic rubber for all four waste categories based on an industry average (RMA, 2011). This change resulted in an average 1 percent decrease in CO_2 emissions throughout the time series. In addition, the percentage of waste incinerated was updated for 2008 based on data obtained from The State of Garbage in America report (van Haaren et al., 2010). Because the report is released every other year, the percentage incinerated in 2007 was also updated using linear interpolation from the 2006 and 2008 values. The change in the percentage incinerated, along with the change in the percentage synthetic rubber noted above, decreased the 2007 and 2008 estimates by 4 percent and 7 percent, respectively, relative to the previous report.

Planned Improvements

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

Additional data sources for calculating the N_2O and CH_4 emission factors for U.S. incineration of waste may be investigated.

3.4. Coal Mining (IPCC Source Category 1B1a)

Three types of coal mining related activities release CH_4 to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. Underground coal mines contribute the largest share of CH_4 emissions. In 2009, 135 gassy underground coal mines in the United States employ ventilation systems to ensure that CH_4 levels remain within safe concentrations. These systems can exhaust significant amounts of CH_4 to the atmosphere in low concentrations. Additionally, 23 U.S. coal mines supplement ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of CH_4 before, during, or after mining. In 2009, 14 coal mines collected CH_4 from degasification systems and utilized this gas, thus reducing emissions to the atmosphere. Of these mines, 13 coal mines sold CH_4 to the natural gas pipeline and one coal mine used CH_4 from its degasification system to heat mine ventilation air on site. In addition, one of the coal mines that sold gas to pipelines also used CH_4 to fuel a thermal coal dryer. Surface coal mines also release CH_4 as the overburden is removed and the coal is exposed, but the level of emissions is much lower than from underground mines. Finally, some of the CH_4 retained in the coal after mining is released during processing, storage, and transport of the coal.

Total CH_4 emissions in 2009 were estimated to be 71.0 Tg CO_2 Eq. (3,382 Gg), a decline of 16 percent since 1990 (see Table 3-28 and Table 3-29). Of this amount, underground mines accounted for 71 percent, surface mines accounted for 18 percent, and post-mining emissions accounted for 11 percent. The decline in CH_4 emissions from underground mines from 1996 to 2002 was the result of the reduction of overall coal production, the mining of less gassy coal, and an increase in CH_4 recovered and used. Since that time, underground coal production and the associated methane emissions have remained fairly level, while surface coal production and its associated emissions

have generally increased.

Table 3-28: CH_4 Emissions from Coal Mining (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
UG Mining	62.3	39.4	35.0	35.7	35.7	44.4	50.4
Liberated	67.9	54.4	50.2	54.3	51.0	60.5	67.0
Recovered & Used	(5.6)	(14.9)	(15.1)	(18.7)	(15.3)	(16.1)	(16.5)
Surface Mining	12.0	12.3	13.3	14.0	13.8	14.3	12.9
Post-Mining (UG)	7.7	6.7	6.4	6.3	6.1	6.1	5.6
Post-Mining (Surface)	2.0	2.0	2.2	2.3	2.2	2.3	2.1
Total	**84.1**	**60.4**	**56.9**	**58.2**	**57.9**	**67.1**	**71.0**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Table 3-29: CH_4 Emissions from Coal Mining (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
UG Mining	2,968	1,878	1,668	1,699	1,700	2,113	2,401
Liberated	3,234	2,588	2,389	2,588	2,427	2,881	3,189
Recovered & Used	(265.9)	(710.4)	(720.8)	(889.4)	(727.2)	(768.0)	(787.1)
Surface Mining	573.6	585.7	633.1	668.0	658.9	680.5	614.2
Post-Mining (UG)	368.3	318.1	305.9	298.5	289.6	292.0	266.7
Post-Mining (Surface)	93.2	95.2	102.9	108.5	107.1	110.6	99.8
Total	**4,003**	**2,877**	**2,710**	**2,774**	**2,756**	**3,196**	**3,382**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Methodology

The methodology for estimating CH_4 emissions from coal mining consists of two parts. The first part involves estimating CH_4 emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to determine total emissions. The second step involves estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin-specific emission factors.

Underground mines. Total CH_4 emitted from underground mines was estimated as the sum of CH_4 liberated from ventilation systems and CH_4 liberated by means of degasification systems, minus CH_4 recovered and used. The Mine Safety and Heath Administration (MSHA) samples CH_4 emissions from ventilation systems for all mines with detectable[95] CH_4 concentrations. These mine-by-mine measurements are used to estimate CH_4 emissions from ventilation systems.

Some of the higher-emitting underground mines also use degasification systems (e.g., wells or boreholes) that remove CH_4 before, during, or after mining. This CH_4 can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of CH_4 collected by each of the twenty mines using these systems, depending on available data. For example, some mines report to EPA the amount of CH_4 liberated from their degasification systems. For mines that sell recovered CH_4 to a pipeline, pipeline sales data published by state petroleum and natural gas agencies were used to estimate degasification emissions. For those mines for which no other data are available, default recovery efficiency values were developed, depending on the type of degasification system employed.

Finally, the amount of CH_4 recovered by degasification systems and then used (i.e., not vented) was estimated. In 2009, 13 active coal mines sold recovered CH_4 into the local gas pipeline networks and one coal mine used recovered CH_4 on site for heating. Emissions avoided for these projects were estimated using gas sales data reported by various state agencies. For most mines with recovery systems, companies and state agencies provided individual well production information, which was used to assign gas sales to a particular year. For the few remaining mines, coal mine operators supplied information regarding the number of years in advance of mining that gas recovery

[95] MSHA records coal mine CH_4 readings with concentrations of greater than 50 ppm (parts per million) CH_4. Readings below this threshold are considered non-detectable.

occurs.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining CH_4 emissions were estimated by multiplying basin-specific coal production, obtained from the Energy Information Administration's Annual Coal Report (see Table 3-30) (EIA 2010), by basin-specific emission factors. Surface mining emission factors were developed by assuming that surface mines emit two times as much CH_4 as the average in situ CH_4 content of the coal. Revised data on in situ CH_4 content and emissions factors are taken from EPA (2005), EPA (1996), and AAPG (1984). This calculation accounts for CH_4 released from the strata surrounding the coal seam. For post-mining emissions, the emission factor was assumed to be 32.5 percent of the average in situ CH_4 content of coals mined in the basin.

Table 3-30: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,244	546,808	931,052
2000	338,168	635,581	973,749
2005	334,398	691,448	1,025,846
2006	325,697	728,447	1,054,144
2007	319,139	720,023	1,039,162
2008	323,932	737,832	1,061,764
2009	301,241	671,475	972,716

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Tier 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data, uncertainty is relatively low. A degree of imprecision was introduced because the measurements used were not continuous but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH_4 emissions (Mutmansky and Wang 2000). Estimates of CH_4 recovered by degasification systems are relatively certain because many coal mine operators provided information on individual well gas sales and mined through dates. Many of the recovery estimates use data on wells within 100 feet of a mined area. Uncertainty also exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may vary if the drainage area is found to be larger or smaller than currently estimated.

Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions comprise the majority of total coal mining emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-31. Coal mining CH_4 emissions in 2009 were estimated to be between 62.0 and 82.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 12.7 percent below to 16.1 percent above the 2009 emission estimate of 71.0 Tg CO_2 Eq.

Table 3-31: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Coal Mining (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal Mining	CH_4	71.0	62.0	82.4	-12.7%	+16.1%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

For the current Inventory, there were some changes to pre-2009 emission estimates relative to the previous Inventory. For the current Inventory, the conversion factor for converting short tons to metric tons was updated to 0.90718474 to be consistent with the number of significant digits used in other source categories. In the past, 0.9072 had been used. The factor was updated for all years, thus coal production estimates in Table 3-31 have changed slightly.

Other changes include the recalculation of emissions avoided for two Jim Walter Resources (JWR) mines: Blue Creek #4 Mine and Blue Creek #7 Mine. This resulted in changes to emissions avoided numbers for 2007 and 2008.

In 1998, 2000, 2001, 2002, 2003, and 2004, the emissions avoided for the Blacksville No. 2 mine in West Virginia were assigned to Pennsylvania rather than West Virginia. These emissions avoided were correctly assigned to West Virginia in the current Inventory; however, total emissions were not affected.

The emissions avoided for the Emerald and Cumberland mines were adjusted going back to 2006 based on information provided by the project developer.

3.5. Abandoned Underground Coal Mines (IPCC Source Category 1B1a)

Underground coal mines contribute the largest share of CH_4 emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH_4 after closure. As mines mature and coal seams are mined through, mines are closed and abandoned. Many are sealed and some flood through intrusion of groundwater or surface water into the void. Shafts or portals are generally filled with gravel and capped with a concrete seal, while vent pipes and boreholes are plugged in a manner similar to oil and gas wells. Some abandoned mines are vented to the atmosphere to prevent the buildup of CH_4 that may find its way to surface structures through overburden fractures. As work stops within the mines, the CH_4 liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH_4 at a near-steady rate over an extended period of time, or, if flooded, produce gas for only a few years. The gas can migrate to the surface through the conduits described above, particularly if they have not been sealed adequately. In addition, diffuse emissions can occur when CH_4 migrates to the surface through cracks and fissures in the strata overlying the coal mine. The following factors influence abandoned mine emissions:

- Time since abandonment;
- Gas content and adsorption characteristics of coal;
- CH4 flow capacity of the mine;
- Mine flooding;
- Presence of vent holes; and
- Mine seals.

Gross abandoned mine CH_4 emissions ranged from 6.0 to 9.1 Tg CO_2 Eq. from 1990 through 2009, varying, in general, by less than 1 to approximately 19 percent from year to year. Fluctuations were due mainly to the number of mines closed during a given year as well as the magnitude of the emissions from those mines when active. Gross abandoned mine emissions peaked in 1996 (9.1 Tg CO_2 Eq.) due to the large number of mine closures from 1994 to 1996 (70 gassy mines closed during the three-year period). In spite of this rapid rise, abandoned mine emissions have been generally on the decline since 1996. There were fewer than fifteen gassy mine closures during each of the years from 1998 through 2009, with only ten closures in 2009. By 2009, gross abandoned mine emissions decreased slightly to 8.5 Tg CO_2 Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH_4 recovered and used at 38 mines, resulting in net emissions in 2009 of 5.5 Tg CO_2 Eq.

Table 3-32: CH_4 Emissions from Abandoned Coal Mines (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Abandoned Underground Mines	6.0	8.9	7.0	7.6	8.9	9.0	8.5
Recovered & Used	0.0	1.5	1.5	2.2	3.3	3.2	3.0
Total	**6.0**	**7.4**	**5.5**	**5.5**	**5.6**	**5.9**	**5.5**

Note: Totals may not sum due to independent rounding.

Table 3-33: CH_4 Emissions from Abandoned Coal Mines (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Abandoned Underground Mines	288	422	334	364	425	430	406
Recovered & Used	0	72	70	103	158	150	144
Total	**288**	**350**	**264**	**261**	**267**	**279**	**262**

Note: Totals may not sum due to independent rounding.

Methodology

Estimating CH_4 emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH_4 from the coal to the mine void is primarily dependent on the mine's emissions when active and the extent to which the mine is flooded or sealed. The CH_4 emission rate before abandonment reflects the gas content of the coal, rate of coal mining, and the flow capacity of the mine in much the same way as the initial rate of a water-free conventional gas well reflects the gas content of the producing formation and the flow capacity of the well. A well or a mine which produces gas from a coal seam and the surrounding strata will produce less gas through time as the reservoir of gas is depleted. Depletion of a reservoir will follow a predictable pattern depending on the interplay of a variety of natural physical conditions imposed on the reservoir. The depletion of a reservoir is commonly modeled by mathematical equations and mapped as a type curve. Type curves which are referred to as decline curves have been developed for abandoned coal mines. Existing data on abandoned mine emissions through time, although sparse, appear to fit the hyperbolic type of decline curve used in forecasting production from natural gas wells.

In order to estimate CH_4 emissions over time for a given mine, it is necessary to apply a decline function, initiated upon abandonment, to that mine. In the analysis, mines were grouped by coal basin with the assumption that they will generally have the same initial pressures, permeability and isotherm. As CH_4 leaves the system, the reservoir pressure, Pr, declines as described by the isotherm. The emission rate declines because the mine pressure (Pw) is essentially constant at atmospheric pressure, for a vented mine, and the PI term is essentially constant at the pressures of interest (atmospheric to 30 psia). A rate-time equation can be generated that can be used to predict future emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

$$q = q_i \, (1+bD_it)^{(-1/b)}$$

where,

- q = Gas rate at time t in mmcf/d
- q_i = Initial gas rate at time zero (t_o) in million cubic feet per day mmcfd)
- b = The hyperbolic exponent, dimensionless
- D_i = Initial decline rate, 1/yr
- t = Elapsed time from t_o (years)

This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability and adsorption isotherms (EPA 2003).

The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the rate of emission after mining activities cease, such as sealing and flooding. Based on field measurement data, it was assumed that most U.S. mines prone to flooding will become completely flooded within eight years and therefore no longer have any measurable CH_4 emissions. Based on this assumption, an average decline rate for flooding mines was established by fitting a decline curve to emissions from field measurements. An exponential equation was developed from emissions data measured at eight abandoned mines known to be filling with water located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential equation shown below. There was not enough data to establish basin-specific equations as was done with the vented, non-flooding mines (EPA 2003).

$$q = q_{ie}^{\,(-Dt)}$$

where,

- q = Gas flow rate at time t in mcf/d
- q_i = Initial gas flow rate at time zero (t_o) in mcfd

D = Decline rate, 1/yr
t = Elapsed time from t_o (years)

Seals have an inhibiting effect on the rate of flow of CH_4 into the atmosphere compared to the rate that would be emitted if the mine had an open vent. The total volume emitted will be the same, but will occur over a longer period. The methodology, therefore, treats the emissions prediction from a sealed mine similar to emissions from a vented mine, but uses a lower initial rate depending on the degree of sealing. The computational fluid dynamics simulator was again used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as 100 × (1 − (initial emissions from sealed mine / emission rate at abandonment prior to sealing)). Significant differences are seen between 50 percent, 80 percent and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for emissions from sealed mines (EPA 2003).

For active coal mines, those mines producing over 100 mcfd account for 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that 469 abandoned mines closing after 1972 produced emissions greater than 100 mcfd when active. Further, the status of 273 of the 469 mines (or 58 percent) is known to be either: (1) vented to the atmosphere; (2) sealed to some degree (either earthen or concrete seals); or, (3) flooded (enough to inhibit CH_4 flow to the atmosphere). The remaining 42 percent of the mines were placed in one of the three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2003).

Table 3-34: Number of gassy abandoned mines occurring in U.S. basins grouped by class according to post-abandonment state

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	25	25	48	98	127	224
Illinois	30	3	14	47	25	72
Northern Appl.	42	22	16	80	35	115
Warrior Basin	0	0	16	16	0	16
Western Basins	27	3	2	32	9	41
Total	**124**	**53**	**96**	**273**	**196**	**469**

Inputs to the decline equation require the average emission rate and the date of abandonment. Generally this data is available for mines abandoned after 1972; however, such data are largely unknown for mines closed before 1972. Information that is readily available such as coal production by state and county are helpful, but do not provide enough data to directly employ the methodology used to calculate emissions from mines abandoned after 1971. It is assumed that pre-1972 mines are governed by the same physical, geologic, and hydrologic constraints that apply to post-1972 mines; thus, their emissions may be characterized by the same decline curves.

During the 1970s, 78 percent of CH_4 emissions from coal mining came from seventeen counties in seven states. In addition, mine closure dates were obtained for two states, Colorado and Illinois, for the hundred year period extending from 1900 through 1999. The data were used to establish a frequency of mine closure histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were applied to 145 gassy coal mines estimated to have closed between 1920 and 1971 in the United States, representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal mine CH_4 emission rates during the 1970s (EPA 2003).

Abandoned mines emission estimates are based on all closed mines known to have active mine CH_4 ventilation emission rates greater than 100 mcfd at the time of abandonment. For example, for 1990 the analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to calculate annual emissions for each mine in the database. Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect ventilation emissions only for pre-1990 closures. CH_4 degasification amounts were added to the quantity of CH_4 ventilated for the total CH_4 liberation rate for 21 mines that closed between 1992 and 2009. Since the sample of gassy mines (with active mine emissions greater than 100 mcfd) is assumed to account for 78 percent of the pre-1971 and 98 percent of the post-1971 abandoned mine emissions, the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions.

From 1993 through 2009, emission totals were downwardly adjusted to reflect abandoned mine CH_4 emissions

avoided from those mines. The inventory totals were not adjusted for abandoned mine reductions in 1990 through 1992, because no data was reported for abandoned coal mining CH_4 recovery projects during that time.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted to estimate the uncertainty surrounding the estimates of emissions from abandoned underground coal mines. The uncertainty analysis described below provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

As discussed above, the parameters for which values must be estimated for each mine in order to predict its decline curve are: (1) the coal's adsorption isotherm; (2) CH_4 flow capacity as expressed by permeability; and (3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but values that represent the highest and lowest quartile of the cumulative probability density function of each parameter. Once the low, mid, and high values are selected, they are applied to a probability density function.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-35. Abandoned coal mines CH_4 emissions in 2009 were estimated to be between 4.0 and 7.3 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 27 percent below to 32 percent above the 2009 emission estimate of 5.5 Tg CO_2 Eq. One of the reasons for the relatively narrow range is that mine-specific data is used in the methodology. The largest degree of uncertainty is associated with the unknown status mines (which account for 42 percent of the mines), with a ±57 percent uncertainty.

Table 3-35: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Abandoned Underground Coal Mines (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Underground Coal Mines	CH_4	5.5	4.0	7.3	-27%	+32%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Recalculations Discussion

Changes in pre-2009 emissions avoided relative to the previous Inventory are due to the additions of pre-1972 Grayson Hills Energy and DTE Corinth projects, which were added to the current inventory. There were also two abandoned mines added to the current Inventory, one abandoned in 2007 and one in 2008, which resulted in changes in the liberated emissions relative to the previous report.

3.6. Natural Gas Systems (IPCC Source Category 1B2b)

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted 221.2 Tg CO_2 Eq. (10,535 Gg) of CH_4 in 2009, a 17 percent increase over 1990 emissions (see Table 3-36 and Table 3-37), and 32.2 Tg CO_2 Eq. (32,171 Gg) of non-combustion CO_2 in 2009, a 14 percent decrease over 1990 emissions (see Table 3-38 and Table 3-39). Improvements in management practices and technology, along with the replacement of older equipment, have helped to stabilize emissions. Methane emissions increased since 2008 due to an increase in production and production wells.

CH_4 and non-combustion CO_2 emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas engines and turbine uncombusted exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from

pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Below is a characterization of the four major stages of the natural gas system. Each of the stages is described and the different factors affecting CH_4 and non-combustion CO_2 emissions are discussed.

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Emissions from pneumatic devices, well clean-ups, and gas well completions and re-completions with hydraulic fracturing account for the majority of CH_4 emissions. Flaring emissions account for the majority of the non-combustion CO_2 emissions. Emissions from field production accounted for approximately 59 percent of CH_4 emissions and about 34 percent of non-combustion CO_2 emissions from natural gas systems in 2009.

Processing. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Fugitive CH_4 emissions from compressors, including compressor seals, are the primary emission source from this stage. The majority of non-combustion CO_2 emissions come from acid gas removal units, which are designed to remove CO_2 from natural gas. Processing plants account for about 8 percent of CH_4 emissions and approximately 66 percent of non-combustion CO_2 emissions from natural gas systems.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive CH_4 emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine uncombusted exhaust are also sources of CH_4 emissions from transmission facilities.

Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. CH_4 emissions from the transmission and storage sector account for approximately 20 percent of emissions from natural gas systems, while CO_2 emissions from transmission and storage account for less than 1 percent of the non-combustion CO_2 emissions from natural gas systems.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were over 1,208,000 miles of distribution mains in 2009, an increase from just over 944,000 miles in 1990 (OPS 2010b). Distribution system emissions, which account for approximately 13 percent of CH_4 emissions from natural gas systems and less than 1 percent of non-combustion CO_2 emissions, result mainly from fugitive emissions from gate stations and pipelines. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced emissions from this stage. Distribution system CH_4 emissions in 2009 were 13 percent lower than 1990 levels.

Table 3-36: CH_4 Emissions from Natural Gas Systems (Tg CO_2 Eq.)*

Stage	1990	2000	2005	2006	2007	2008	2009
Field Production	89.2	113.5	105.4	134.0	118.2	122.9	130.3
Processing	18.0	17.7	14.3	14.5	15.1	15.7	17.5
Transmission and Storage	49.2	46.7	41.4	41.0	42.5	43.3	44.4
Distribution	33.4	31.4	29.3	28.3	29.4	29.9	29.0
Total	**189.8**	**209.3**	**190.4**	**217.7**	**205.2**	**211.8**	**221.2**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Table 3-37: CH_4 Emissions from Natural Gas Systems (Gg)*

Stage	1990	2000	2005	2006	2007	2008	2009
Field Production	4,248	5,406	5,021	6,380	5,628	5,854	6,205
Processing	855	841	681	689	717	748	834
Transmission and Storage	2,344	2,224	1,973	1,950	2,025	2,062	2,115

Distribution	1,591	1,497	1,395	1,346	1,402	1,423	1,381
Total	**9,038**	**9,968**	**9,069**	**10,364**	**9,771**	**10,087**	**10,535**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Table 3-38: Non-combustion CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq.)

Stage	1990	2000	2005	2006	2007	2008	2009
Field Production	9.7	6.4	8.0	9.4	9.7	11.3	10.9
Processing	27.8	23.3	21.7	21.2	21.2	21.4	21.2
Transmission and Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Distribution	+	+	+	+	+	+	+
Total	**37.6**	**29.9**	**29.9**	**30.8**	**31.1**	**32.8**	**32.2**

Note: Totals may not sum due to independent rounding.
+ Emissions are less than 0.1 Tg CO_2 Eq.

Table 3-39: Non-combustion CO_2 Emissions from Natural Gas Systems (Gg)

Stage	1990	2000	2005	2006	2007	2008	2009
Field Production	9,704	6,425	8,050	9,438	9,746	11,336	10,877
Processing	27,763	23,343	21,746	21,214	21,199	21,385	21,189
Transmission and Storage	62	64	64	63	64	65	65
Distribution	46	44	41	40	41	42	41
Total	**37,574**	**29,877**	**29,902**	**30,755**	**31,050**	**32,828**	**32,171**

Note: Totals may not sum due to independent rounding.

Methodology

The primary basis for estimates of CH_4 and non-combustion-related CO_2 emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (EPA/GRI 1996). The EPA/GRI study developed over 80 CH_4 emission and activity factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The same activity factors were used to estimate both CH_4 and non-combustion CO_2 emissions. However, the CH_4 emission factors were adjusted for CO_2 content when estimating fugitive and vented non-combustion CO_2 emissions. The EPA/GRI study was based on a combination of process engineering studies and measurements at representative gas facilities. From this analysis, a 1992 emission estimate was developed using the emission and activity factors, except where direct activity data was available (e.g., offshore platform counts, processing plant counts, transmission pipeline miles, and distribution pipelines). For other years, a set of industry activity factor drivers was developed that can be used to update activity factors. These drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations.

Although the inventory primarily uses EPA/GRI emission factors, significant improvements were made to the emissions estimates for three sources this year: gas well cleanups, condensate storage tanks and centrifugal compressors. In addition, data for two sources not included in the EPA/GRI study – gas well completions and gas well workovers (re-completions) with hydraulic fracturing- was added this year. In the case of gas well cleanups, the methodology was revised to use a large sample of well and reservoir characteristics from the HPDI database (HPDI 2009) along with an engineering statics equation (EPA 2006a) to estimate the volume of natural gas necessary to expel a liquid column choking the well production. The same sample E&P Tank sample runs for condensate tank flashing emissions was used; however, the factor was improved by using a large sample distribution of condensate production by gravity from the HPDI database (HPDI 2009) to weigh the sample simulation flashing emissions rather than assuming a uniform distribution of condensate gravities. Additionally, TERC (TERC 2009) data representing two regions was used in the emission factors for those two regions to estimate the effects of separator dump valves malfunctioning and allowing natural gas to vent through the downstream storage tanks. The EPA/GRI emission factor for centrifugal compressors sampled emissions at the seal face of wet seal compressors. A World Gas Conference publication (WGC 2009) on the seal oil degassing vents was used to update this factor and to also account for the emergence of dry seal centrifugal compressors (EPA 2006b), which eliminates seal oil degassing vents and reduces overall emissions. Gas well completions and workovers with hydraulic fracturing were

not common at the time the EPA/GRI survey was conducted. Since then, emissions data has become available through Natural Gas STAR experiences and presentations (EPA 2004, 2007) as these activities became more prevalent. The EPA/GRI study and previous Inventories did, however, include an estimate for well completions without hydraulic fracturing under the source category Completion Flaring. The changes for gas well cleanups, condensate storage tanks, centrifugal compressors, and gas well completions and gas well workovers (re-completions) with hydraulic fracturing are described below in the Recalculations section. See Annex 3.4 for more detailed information on the methodology and data used to calculate CH_4 and non-combustion CO_2 emissions from natural gas systems.

Activity factor data were taken from the following sources: American Gas Association (AGA 1991–1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2010a-d); Monthly Energy Review (EIA 2010f); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2010b,c,e); the Natural Gas STAR Program annual emissions savings (EPA 2010); Oil and Gas Journal (OGJ 1997–2010); Office of Pipeline Safety (OPS 2010a-b); Federal Energy Regulatory Commission (FERC 2010) and other Energy Information Administration publications (EIA 2001, 2004, 2010a,d); World Oil Magazine (2010a-b). Data for estimating emissions from hydrocarbon production tanks were incorporated (EPA 1999). Coalbed CH_4 well activity factors were taken from the Wyoming Oil and Gas Conservation Commission (Wyoming 2009) and the Alabama State Oil and Gas Board (Alabama 2010). Other state well data was taken from: American Association of Petroleum Geologists (AAPG 2004); Brookhaven College (Brookhaven 2004); Kansas Geological Survey (Kansas 2010); Montana Board of Oil and Gas Conservation (Montana 2010); Oklahoma Geological Survey (Oklahoma 2010); Morgan Stanley (Morgan Stanley 2005); Rocky Mountain Production Report (Lippman 2003); New Mexico Oil Conservation Division (New Mexico 2010, 2005); Texas Railroad Commission (Texas 2010a-d); Utah Division of Oil, Gas and Mining (Utah 2010). Emission factors were taken from EPA/GRI (1996). GTI's Unconventional Natural Gas and Gas Composition Databases (GTI 2001) were used to adapt the CH_4 emission factors into non-combustion related CO_2 emission factors and adjust CH_4 emission factors from the EPA/GRI survey. Methane compositions from GTI 2001 are adjusted year to year using gross production by NEMS for oil and gas supply regions from the EIA. Therefore, emission factors may vary from year to year due to slight changes in the methane composition for each NEMS oil and gas supply module region. Additional information about CO_2 content in transmission quality natural gas was obtained via the internet from numerous U.S. transmission companies to help further develop the non-combustion CO_2 emission factors.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted to determine the level of uncertainty surrounding estimates of emissions from natural gas systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), this analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The @RISK model utilizes 1992 (base year) emissions to quantify the uncertainty associated with the emissions estimates using the top twelve emission sources for the year 2009.

The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall for the year 2009. The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-40. Natural gas systems CH_4 emissions in 2009 were estimated to be between 179.1 and 287.6 Tg CO_2 Eq. at a 95 percent confidence level. Natural gas systems non-energy CO_2 emissions in 2009 were estimated to be between 26.1 and 41.9 Tg CO_2 Eq. at 95 percent confidence level.

Table 3-40: Tier 2 Quantitative Uncertainty Estimates for CH_4 and Non-energy CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)[c]	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound[c]	Upper Bound[c]	Lower Bound[c]	Upper Bound[c]

Natural Gas Systems	CH_4	221.2	179.1	287.6	-19%	+30%
Natural Gas Systems[b]	CO_2	32.2	26.1	41.9	-19%	+30%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
[b] An uncertainty analysis for the non-energy CO_2 emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH_4 uncertainty analysis was applied to the point estimate of non-energy CO_2 emissions.
[c] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

A number of potential data sources were investigated to improve selected emission factors in the natural gas industry. First, the HPDI database for well production and well properties was investigated for potential engineering parameters to be used in engineering equations to develop a new emission factor for well cleanups (HPDI 2009). The database was queried to obtain average well depth, shut-in pressure, well counts, and well production from each basin. These parameters were used along with industry experiences to develop an engineering estimate of emissions from each well in each basin of the sample data. The analysis led to a new emission factor for the gas well cleanup source.

Additionally, industry experiences with hydraulic fracturing of tight formations for the completion or workover of natural gas wells were reviewed to account for this source of emissions. Several Partners of the Natural Gas STAR Program have reported recovering substantial volumes of natural gas that would have otherwise been vented following completions or re-completions (workovers) involving hydraulic fracturing. This completion method, which is a large emission source, was not characterized by the base EPA/GRI 1996 study and has not been accounted for in the national Inventory until this year.

A World Gas Conference paper (WGC 2009) gathered 48 sample measurements of centrifugal compressor wet seal oil degassing emissions and published the results. The base year EPA/GRI 1996 study did not measure emissions from the seal oil degassing vent. Instead seal face emissions were quantified and as such this emission source has gone uncharacterized in the national Inventory until this year.

In some production areas the separator liquid level may drop too low such that the produced associated gas blows through the dump valve and vents through the storage tank. These data were included where available for the Inventory. More data will be necessary to potentially separate this source from storage tank flashing emissions and also to represent the true scope of activity across the United States.

A number of other data sources for fugitive emission factors from the processing and transmission and storage segments were reviewed. Several studies have been published since the EPA/GRI 1996 base year study that sample emissions from the same common equipment components. The raw emissions data from these surveys can potentially be combined with the raw data from the base year study to develop stronger emission factors. In addition to common component leaks, several of these studies propose emission factors for pneumatic devices or other sources. These studies require further review and thus the data are not included in the Inventory at this time.

Recalculations Discussion

Methodologies for gas well cleanups and condensate storage tanks were revised for the current Inventory, and new sources of data for centrifugal compressors with wet seals, gas well completions with hydraulic fracturing, and gas well workovers with hydraulic fracturing were used.

The largest increase in emissions relative to the previous Inventory was due to the revised emission factor for gas well cleanups (also referred to in industry as gas well liquids unloading). HPDI well production and well property sample data on well depth, shut-in pressure, and production rates were used in an engineering equation to re-estimate the average unloading emissions by NEMS oil and gas module region for this source (HPDI 2009). This methodological change increased emissions by more than 22 times while decreasing the substantial uncertainty that was associated with the previous emission factor from the EPA/GRI 1996 study. The activity data remained the same as the previous methodology. Emissions from non-Gas STAR Partners were not considered, nor was an independent estimate of the scope of those emissions accounted for. Reductions beyond those reported from Natural

Gas STAR Partners will be considered for inclusion in the next Inventory of sufficient data are available.

The next largest increase in emissions was due to the inclusion of gas well completions and workovers involving hydraulic fracture (i.e. unconventional completions and workovers). The EPA/GRI 1996 study did not account for this emerging technology and the source was previously unaccounted for in the Inventory. The Inventory did account for completion flaring, however, this only includes emissions from completions without hydraulic fracturing (i.e. conventional completions), which the EPA/GRI 1996 study assumes are mostly flared. Unlike completions and workovers without hydraulic fracturing (i.e. conventional workovers), the high pressure venting of gas in order to expel the large volumes of liquid used to fracture the well formation, results in a large emission of natural gas. The Inventory tracks activity data for wells completed with hydraulic fracturing in each region. The gas well completions with hydraulic fracturing was approximated using total number of producing gas wells completed with hydraulic fracturing and the total number of shut-in gas wells completed with hydraulic fracturing from each year. This approximation is made by taking the difference between the number of unconventional wells reported by EIA for the current year and the previous year. Since drilling and hydraulic fracturing in unconventional (e.g. shale, tight, and coal bed methane) formations is a relatively new technology, it is assumed that zero gas wells completed with hydraulic fracturing are shut-in each year. This activity data was used along with a newly developed emission factor to estimate emissions from these sources. It was assumed that approximately 50 percent of emissions from gas well completions and workovers with hydraulic fracturing would be flared due to states such as Wyoming that do not permit the venting of natural gas during well completions.

The same E&P Tank simulation data for hydrocarbon liquids above 45˚API flashing emission in tanks was used as in previous Inventories to estimate emissions from condensate tanks; however, these flashing emissions simulations were coupled with a large sample of condensate production gravities from the HPDI database to improve the factor to account for the average national distribution of condensate gravities. Previously, a simple average of simulation results for each liquid gravity was used. Additionally, the TERC (2009) study provided a small sample of data representing two regions in Texas where separator dump valve malfunctions were detected and measured. This data was applied only to the regions represented by the study to account for this emission source.

Finally, WGC (2009) sample data on centrifugal compressor seal oil degassing vent rates was used to divide the centrifugal compressors source in the processing and transmission and storage segments into two sources—centrifugal compressors equipped with wet seals and centrifugal compressors equipped with dry seals. The seal oil degassing vent (found with compressors using wet seals) was previously unaccounted for in the Inventory. This improved methodology accounted for an increase in emissions from these sources between 50 and 100 percent.

Finally, the previous Inventory activity data are updated with revised values each year. However, the impact of these changes was small compared to the changes described above.

The net effect of these changes was to increase total CH_4 emissions from natural gas systems between 47 and 120 percent each year between 1990 and 2008 relative to the previous report. The natural gas production segment accounted for the largest increases, largely due to the methodological changes to gas well cleanups and the addition of gas well completions and workovers with hydraulic fracturing.

Planned Improvements

Emission reductions reported to Natural Gas STAR are deducted from the total sector emissions each year in the natural gas systems inventory model to estimate emissions. These reported reductions often rely on Inventory emission factors to quantify the extent of reductions. These reductions are also a source of uncertainty that is not currently analyzed in the Inventory. Emissions reductions—in particular from gas well cleanups—may be underestimated, and we intend to investigate whether additional data are available, and if appropriate, revisions to more accurately account for emissions from natural gas systems will be incorporated into future inventories. Additionally, accounting for the uncertainty of these reductions to more accurately provide upper and lower bounds within the 95 percent confidence interval, will be investigated.

Separately, a larger study is currently underway to update selected compressor emission factors used in the national inventory. Most of the activity factors and emission factors in the natural gas inventory are from the EPA/GRI (1996) study. The current measurement-based study to develop updated emission factors for compressors is intended to better reflect current national circumstances. Results from these studies are expected in 2011, and will be incorporated into the Inventory, pending a peer review.

Malfunctioning separator dump valves is not an occurrence isolated to the Texas counties in which the sample data was obtained. New data will be reviewed as it becomes available on this emissions source and emissions will be updated, as appropriate.

Data collected through EPA's Greenhouse Gas Reporting Program (40 CFR Part 98, Mandatory Reporting of Greenhouse Gases; Final Rule, Subpart W) will be reviewed for potential improvements to the natural gas systems emissions estimates. The rule will collect actual activity data using improved quantification methods from those used in several of the studies which form the basis of this Inventory. Data collection for Subpart W began January 1, 2011 with emissions reporting beginning in 2012. These base year 2011 data will be reviewed for inclusion into a future Inventory to improve the accuracy and reduce the uncertainty of the emission estimates.

3.7. Petroleum Systems (IPCC Source Category 1B2a)

CH_4 emissions from petroleum systems are primarily associated with crude oil production, transportation, and refining operations. During each of these activities, CH_4 emissions are released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Fugitive and vented CO_2 emissions from petroleum systems are primarily associated with crude oil production and refining operations but are negligible in transportation operations. Combusted CO_2 emissions from fuels are already accounted for in the Fossil Fuels Combustion source category, and hence have not been taken into account in the Petroleum Systems source category. Total CH_4 and CO_2 emissions from petroleum systems in 2009 were 30.9 Tg CO_2 Eq. (1,473 Gg CH_4) and 0.5 Tg CO_2 (463 Gg), respectively. Since 1990, CH_4 emissions have declined by 13 percent, due to industry efforts to reduce emissions and a decline in domestic oil production (see Table 3-41and Table 3-42). CO_2 emissions have also declined by 17 percent since 1990 due to similar reasons (see Table 3-43 and Table 3-44).

Production Field Operations. Production field operations account for about 98 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for over 90 percent of the emissions from the production sector, unburned CH_4 combustion emissions account for 6.4 percent, fugitive emissions are 3.4 percent, and process upset emissions are slightly under two-tenths of a percent. The most dominant sources of emissions, in order of magnitude, are shallow water offshore oil platforms, natural-gas-powered high bleed pneumatic devices, oil tanks, natural-gas powered low bleed pneumatic devices, gas engines, deep water offshore platforms, and chemical injection pumps. These seven sources alone emit about 94 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and unburned fuel combustion emissions from all equipment housed on oil platforms producing oil and associated gas. Emissions from high and low-bleed pneumatics occur when pressurized gas that is used for control devices is bled to the atmosphere as they cycle open and closed to modulate the system. Emissions from oil tanks occur when the CH_4 entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure. Emissions from gas engines are due to unburned CH_4 that vents with the exhaust. Emissions from chemical injection pumps are due to the 25 percent that use associated gas to drive pneumatic pumps. The remaining six percent of the emissions are distributed among 26 additional activities within the four categories: vented, fugitive, combustion and process upset emissions. For more detailed, source-level data on CH_4 emissions in production field operations, refer to Annex 3.5.

Vented CO_2 associated with natural gas emissions from field operations account for 99 percent of the total CO_2 emissions from this source category, while fugitive and process upsets together account for less than 1 percent of the emissions. The most dominant sources of vented emissions are oil tanks, high bleed pneumatic devices, shallow water offshore oil platforms, low bleed pneumatic devices, and chemical injection pumps. These five sources together account for 98.5 percent of the non-combustion CO_2 emissions from this source category, while the remaining 1.5 percent of the emissions is distributed among 24 additional activities within the three categories: vented, fugitive and process upsets.

Crude Oil Transportation. Crude oil transportation activities account for less than one half of one percent of total CH_4 emissions from the oil industry. Venting from tanks and marine vessel loading operations accounts for 61 percent of CH_4 emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for 19 percent. The remaining 20 percent is distributed among six additional sources within these two categories. Emissions from pump engine drivers and heaters were not estimated due to lack of data.

Crude Oil Refining. Crude oil refining processes and systems account for slightly less than two percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH_4 in all refined products. Within refineries, vented

emissions account for about 86 percent of the emissions, while both fugitive and combustion emissions account for approximately seven percent each. Refinery system blowdowns for maintenance and the process of asphalt blowing—with air, to harden the asphalt—are the primary venting contributors. Most of the fugitive CH_4 emissions from refineries are from leaks in the fuel gas system. Refinery combustion emissions include small amounts of unburned CH_4 in process heater stack emissions and unburned CH_4 in engine exhausts and flares.

Asphalt blowing from crude oil refining accounts for 36 percent of the total non-combustion CO_2 emissions in petroleum systems.

Table 3-41: CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Production Field Operations	**34.7**	**30.8**	**28.7**	**28.7**	**29.3**	**29.6**	**30.3**
Pneumatic device venting	10.3	9.0	8.4	8.3	8.4	8.7	8.8
Tank venting	5.3	4.5	3.9	3.9	4.0	4.0	4.5
Combustion & process upsets	1.9	1.6	1.5	1.5	1.5	1.6	2.0
Misc. venting & fugitives	16.8	15.3	14.5	14.6	15.0	14.8	14.6
Wellhead fugitives	0.6	0.5	0.4	0.4	0.4	0.5	0.5
Crude Oil Transportation	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Refining	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**	**0.5**
Total	**35.4**	**31.5**	**29.4**	**29.4**	**30.0**	**30.2**	**30.9**

Note: Totals may not sum due to independent rounding.

Table 3-42: CH_4 Emissions from Petroleum Systems (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Production Field Operations	**1,653**	**1,468**	**1,366**	**1,365**	**1,396**	**1,409**	**1,444**
Pneumatic device venting	489	428	397	396	398	416	419
Tank venting	250	214	187	188	192	189	212
Combustion & process upsets	88	76	71	71	72	75	94
Misc. venting & fugitives	799	727	691	693	714	707	696
Wellhead fugitives	26	22	19	17	20	23	23
Crude Oil Transportation	**7**	**5**	**5**	**5**	**5**	**5**	**5**
Refining	**25**	**28**	**28**	**28**	**27**	**25**	**24**
Total	**1,685**	**1,501**	**1,398**	**1,398**	**1,427**	**1,439**	**1,473**

Note: Totals may not sum due to independent rounding.

Table 3-43: CO_2 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Production Field Operations	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Pneumatic device venting	+	+	+	+	+	+	+
Tank venting	0.3	0.3	0.2	0.2	0.3	0.2	0.3
Misc. venting & fugitives	+	+	+	+	+	+	+
Wellhead fugitives	+	+	+	+	+	+	+
Crude Refining	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**
Total	**0.6**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-44: CO_2 Emissions from Petroleum Systems (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Production Field Operations	**376**	**323**	**285**	**285**	**292**	**288**	**319**
Pneumatic device venting	27	24	22	22	22	23	23
Tank venting	328	281	246	246	252	247	278
Misc. venting & fugitives	18	17	16	16	16	16	16
Wellhead fugitives	1	1	1	1	1	1	1
Crude Refining	**180**	**211**	**205**	**203**	**182**	**165**	**144**
Total	**555**	**534**	**490**	**488**	**474**	**453**	**463**

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for estimating CH_4 emissions from petroleum systems is a bottom-up approach, based on comprehensive studies of CH_4 emissions from U.S. petroleum systems (EPA 1996, EPA 1999). These studies combined emission estimates from 64 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 33 activities for crude oil production field operations, 11 for crude oil transportation activities, and 20 for refining operations. Annex 3.5 provides greater detail on the emission estimates for these 64 activities. The estimates of CH_4 emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are negligible.

The methodology for estimating CH_4 emissions from the 64 oil industry activities employs emission factors initially developed by EPA (1999). Activity factors for the years 1990 through 2009 were collected from a wide variety of statistical resources. Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by their corresponding activity factor (e.g., equipment count or frequency of activity). EPA (1999) provides emission factors for all activities except those related to offshore oil production and field storage tanks. For offshore oil production, two emission factors were calculated using data collected over a one-year period for all federal offshore platforms (EPA 2005, BOEMRE 2004). One emission factor is for oil platforms in shallow water, and one emission factor is for oil platforms in deep water. Emission factors are held constant for the period 1990 through 2009. The number of platforms in shallow water and the number of platforms in deep water are used as activity factors and are taken from Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) (formerly Minerals Management Service) statistics (BOEMRE 2010a-c). For oil storage tanks, the emissions factor was calculated as the total emissions per barrel of crude charge from E&P Tank data weighted by the distribution of produced crude oil gravities from the HPDI production database (EPA 1999, HPDI 2009).

For some years, complete activity factor data were not available. In such cases, one of three approaches was employed. Where appropriate, the activity factor was calculated from related statistics using ratios developed for EPA (1996). For example, EPA (1996) found that the number of heater treaters (a source of CH_4 emissions) is related to both number of producing wells and annual production. To estimate the activity factor for heater treaters, reported statistics for wells and production were used, along with the ratios developed for EPA (1996). In other cases, the activity factor was held constant from 1990 through 2009 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. The CH_4 and CO_2 sources in the production sector share common activity factors. See Annex 3.5 for additional detail.

Among the more important references used to obtain activity factors are the Energy Information Administration annual and monthly reports (EIA 1990 through 2010, 1995 through 2010, 1995 through 2010a-b), Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA (EPA/GRI 1996a-d), Estimates of Methane Emissions from the U.S. Oil Industry (EPA 1999), consensus of industry peer review panels, BOEMRE reports (BOEMRE 2005, 2010a-c), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), the Oil & Gas Journal (OGJ 2010a,b), the Interstate Oil and Gas Compact Commission (IOGCC 2008), and the United States Army Corps of Engineers (1995-2008).

The methodology for estimating CO_2 emissions from petroleum systems combines vented, fugitive, and process upset emissions sources from 29 activities for crude oil production field operations and one activity from petroleum refining. Emissions are estimated for each activity by multiplying emission factors by their corresponding activity factors. The emission factors for CO_2 are estimated by multiplying the CH_4 emission factors by a conversion factor, which is the ratio of CO_2 content and methane content in produced associated gas. The only exceptions to this methodology are the emission factors for crude oil storage tanks, which are obtained from E&P Tank simulation runs, and the emission factor for asphalt blowing, which was derived using the methodology and sample data from API (2009).

Uncertainty and Time-Series Consistency

This section describes the analysis conducted to quantify uncertainty associated with the estimates of emissions from petroleum systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), the method employed provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the Inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

The detailed, bottom-up Inventory analysis used to evaluate U.S. petroleum systems reduces the uncertainty related to the CH_4 emission estimates in comparison to a top-down approach. However, some uncertainty still remains. Emission factors and activity factors are based on a combination of measurements, equipment design data, engineering calculations and studies, surveys of selected facilities and statistical reporting. Statistical uncertainties arise from natural variation in measurements, equipment types, operational variability and survey and statistical methodologies. Published activity factors are not available every year for all 64 activities analyzed for petroleum systems; therefore, some are estimated. Because of the dominance of the seven major sources, which account for 92 percent of the total methane emissions, the uncertainty surrounding these seven sources has been estimated most rigorously, and serves as the basis for determining the overall uncertainty of petroleum systems emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-45. Petroleum systems CH_4 emissions in 2009 were estimated to be between 23.5 and 76.9 Tg CO_2 Eq., while CO_2 emissions were estimated to be between 0.4 and 1.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 149 percent above the 2009 emission estimates of 30.9 and 0.5 Tg CO_2 Eq. for CH_4 and CO_2, respectively.

Table 3-45: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound[b]	Upper Bound[b]	Lower Bound[b]	Upper Bound[b]
Petroleum Systems	CH_4	30.9	23.5	76.9	-24%	149%
Petroleum Systems	CO_2	0.5	0.4	1.2	-24%	149%

[a] Range of 2009 relative uncertainty predicted by Monte Carlo Simulation, based on 1995 base year activity factors, for a 95 percent confidence interval.
[b] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.
Note: Totals may not sum due to independent rounding

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

As part of QA/QC and verification activities done for the Inventory, potential improvements were identified, which include a new emissions source associated with fixed roof storage tank emissions in the production segment. In some production areas the separator liquid level may drop too low such that the produced associated gas blows through the dump valve and vents through the storage tank. This data was included where available for the Inventory (see Recalculation discussion below). More data will be necessary to potentially add this as a separate source from storage tank flashing emissions and also to represent the true scope of activity across the United States.

Recalculations Discussion

Most revisions for the current Inventory relative to the previous report were due to updating previous years' data with revised data from existing data sources. Well completion venting, well drilling, and offshore platform activity factors were updated from existing data sources from 1990 onward.

Additionally, the emission factor for venting from fixed roof storage tanks in the crude oil production segment was revised. Using the same E&P Tank sample data runs on crude oil gravities ranging up to 45˚API, a new national level flashing emissions factor was developed by using a large sample of production data, sorted by gravity, available from the HPDI database.

A study prepared for the Texas Environmental Research Consortium measured emissions rates from several oil and condensate tanks in Texas (TERC 2009). This data was plotted and compared to the flashing emissions simulated via E&P Tank simulation. EPA observed that additional emissions beyond the flashing were present in approximately 50 percent of the tanks. These emissions may be attributed to separator dump valves malfunctioning or other methods of associated gas entering the tank and venting from the roof. Because the dataset was limited to

represent production from only 14 counties that represent 0.5 percent of U.S. production, the national emission factor was scaled up such that only production from these counties is affected by the occurrence of associated gas venting through the storage tank.

Planned Improvements

As noted above, nearly all emission factors used in the development of the petroleum systems estimates were taken from EPA (1995, 1996, 1999), with the remaining emission factors taken from EPA default values (EPA 2005) and a consensus of industry peer review panels. These emission factors will be reviewed as part of future Inventory work. Results of this review and analysis will be incorporated into future inventories, as appropriate.

Malfunctioning separator dump valves is not an occurrence isolated to the Texas counties in which the sample data was obtained. New data will be reviewed as they become available on this emissions source and emissions updated, as appropriate.

Data collected through EPA's Greenhouse Gas Reporting Program will be reviewed for potential improvements to petroleum systems emissions sources. The rule will collect actual activity data and improved quantification methods from those used in several of the studies which form the basis of this Inventory. This data will be incorporated as appropriate into the current Inventory to improve the accuracy and uncertainty of the emissions estimates. In particular, EPA will investigate whether certain emissions sources currently accounted for in the Energy sector should be separately accounted for in the petroleum systems inventory (e.g., CO_2 process emissions from hydrogen production).

In 2010, all U.S. petroleum refineries were required to collect information on their greenhouse gas emissions. This data will be reported to EPA through its Greenhouse Gas Reporting Program in 2011. Data collected under this program will be evaluated for use in future inventories to improve the calculation of national emissions from petroleum systems.

[BEGIN BOX]

Box 3-3. Carbon Dioxide Transport, Injection, and Geological Storage

Carbon dioxide is produced, captured, transported, and used for Enhanced Oil Recovery (EOR) as well as commercial and non-EOR industrial applications. This CO_2 is produced from both naturally-occurring CO_2 reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the current Inventory, emissions from naturally-produced CO_2 are estimated based on the application.

In the current Inventory report, the CO_2 that is used in non-EOR industrial and commercial applications (e.g., food processing, chemical production) is assumed to be emitted to the atmosphere during its industrial use. These emissions are discussed in the Carbon Dioxide Consumption section. The naturally-occurring CO_2 used in EOR operations is assumed to be fully sequestered. Additionally, all anthropogenic CO_2 emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO_2 is captured or not. These emissions are currently included in the Natural Gas Systems and the Ammonia Production sections of the Inventory report, respectively.

IPCC (IPCC, 2006) included, for the first time, methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO_2. The methodology is based on the principle that the carbon capture and storage system should be handled in a complete and consistent manner across the entire Energy sector. The approach accounts for CO_2 captured at natural and industrial sites as well as emissions from capture, transport, and use. For storage specifically, a Tier 3 methodology is outlined for estimating and reporting emissions based on site-specific evaluations. However, IPCC (IPCC, 2006) notes that if a national regulatory process exists, emissions information available through that process may support development of CO_2 emissions estimates for geologic storage.

Beginning in 2010, facilities that conduct geologic sequestration of CO_2 and all other facilities that inject CO_2 underground will be required to calculate and report greenhouse gas data annually to EPA through its Greenhouse

Gas Reporting Program. The Greenhouse Gas Reporting Rule requires greenhouse gas reporting from facilities that inject CO_2 underground for geologic sequestration, and requires greenhouse gas reporting from all other facilities that inject CO_2 underground for any reason, including enhanced oil and gas recovery. Beginning in 2010, facilities conducting geologic sequestration of CO_2 are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification (MRV) plan, and to report the amount of CO_2 sequestered using a mass balance approach. Data from this program, which will be reported to EPA in early 2012, for the 2011 calendar year, will provide additional facility-specific information about the carbon capture, transport and storage chain, EPA intends to evaluate that information closely and consider opportunities for improving our current inventory estimates.

Preliminary estimates indicate that the amount of CO_2 captured from industrial and natural sites is 47.3 Tg CO_2 (47,340 Gg CO_2) (see Table 3-46 and Table 3-47). Site-specific monitoring and reporting data for CO_2 injection sites (i.e., EOR operations) were not readily available, therefore, these estimates assume all CO_2 is emitted.

Table 3-46: Potential Emissions from CO_2 Capture and Transport (Tg CO_2 Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
Acid Gas Removal Plants	4.8	2.3	5.8	6.2	6.4	6.6	7.0
Naturally Occurring CO_2	20.8	23.2	28.3	30.2	33.1	36.1	39.7
Ammonia Production Plants	+	0.7	0.7	0.7	0.7	0.6	0.6
Pipelines Transporting CO_2	+	+	+	+	+	+	+
Total	**25.6**	**26.1**	**34.7**	**37.1**	**40.1**	**43.3**	**47.3**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note; Totals may not sum due to independent rounding.

Table 3-47: Potential Emissions from CO_2 Capture and Transport (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
Acid Gas Removal Plants	4,832	2,264	5,798	6,224	6,088	6,630	7,035
Naturally Occurring CO_2	20,811	23,208	28,267	30,224	33,086	36,102	39,725
Ammonia Production Plants	+	676	676	676	676	580	580
Pipelines Transporting CO_2	8	8	7	7	7	8	8
Total	**25,643**	**26,149**	**34,742**	**37,124**	**40,141**	**43,311**	**47,340**

+ Does not exceed 0.5 Gg.
Note: Totals do not include emissions from pipelines transporting CO_2
Note; Totals may not sum due to independent rounding.

[END BOX]

3.8. Energy Sources of Indirect Greenhouse Gas Emissions

In addition to the main greenhouse gases addressed above, many energy-related activities generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) from energy-related activities from 1990 to 2009 are reported in Table 3-48.

Table 3-48: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
NO_x	**21,106**	**18,477**	**15,319**	**14,473**	**13,829**	**13,012**	**10,887**
Mobile Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
*International Bunker Fuels**	*2,020*	*1,344*	*1,703*	*1,793*	*1,791*	*1,917*	*1,651*
CO	**125,640**	**89,714**	**69,062**	**65,399**	**61,739**	**58,078**	**49,647**
Mobile Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543

Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Oil and Gas Activities	302	146	318	319	320	322	345
*International Bunker Fuels**	*130*	*128*	*132*	*161*	*160*	*165*	*149*
NMVOCs	**12,620**	**8,952**	**7,798**	**7,702**	**7,604**	**7,507**	**5,333**
Mobile Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Stationary Combustion	912	1,077	716	918	1,120	1,321	424
Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
*International Bunker Fuels**	*61*	*45*	*54*	*59*	*59*	*62*	*57*

* These values are presented for informational purposes only and are not included in totals.
Note: Totals may not sum due to independent rounding.

Methodology

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual categories from various agencies. Depending on the category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and accurate estimates of activity data. A quantitative uncertainty analysis was not performed.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.9. International Bunker Fuels (IPCC Source Category 1: Memo Items)

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UNFCCC, are not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.[96] These decisions are reflected in the IPCC methodological guidance, including the 2006 IPCC Guidelines, in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC 2006).[97]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO_2, CH_4 and N_2O. Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[98] Emissions from ground transport activities—by road vehicles and trains—even when crossing

[96] See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c).

[97] Note that the definition of international bunker fuels used by the UNFCCC differs from that used by the International Civil Aviation Organization.

[98] Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation

international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC Guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC Guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC Guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[99]

Emissions of CO_2 from aircraft are essentially a function of fuel use. CH_4 and N_2O emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). CH_4 is the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N_2O is primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., U.S. Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. CO_2 is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2009 from the combustion of international bunker fuels from both aviation and marine activities were 124.4 Tg CO_2 Eq., or ten percent above emissions in 1990 (see Table 3-49 and Table 3-50). Emissions from international flights and international shipping voyages departing from the United States have increased by 49 percent and decreased by 18 percent, respectively, since 1990. The majority of these emissions were in the form of CO_2; however, small amounts of CH_4 and N_2O were also emitted.

Table 3-49: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (Tg CO_2 Eq.)

Gas/Mode	1990	2000	2005	2006	2007	2008	2009
CO_2	**111.8**	**98.5**	**109.7**	**128.4**	**127.6**	**133.7**	**123.1**
Aviation	46.4	58.8	56.7	74.6	73.8	75.5	69.4
Marine	65.4	39.7	53.0	53.8	53.9	58.2	53.7
CH_4	**0.2**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.1**
Aviation	+	+	+	+	+	+	+
Marine	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**1.1**	**0.9**	**1.0**	**1.2**	**1.2**	**1.2**	**1.1**
Aviation	0.5	0.6	0.6	0.8	0.8	0.8	0.7
Marine	0.5	0.3	0.4	0.4	0.4	0.5	0.4
Total	**113.0**	**99.5**	**110.9**	**129.7**	**129.0**	**135.1**	**124.4**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 3-50: CO_2, CH_4 and N_2O Emissions from International Bunker Fuels (Gg)

Gas/Mode	1990	2000	2005	2006	2007	2008	2009
CO_2	**111,828**	**98,482**	**109,750**	**128,384**	**127,618**	**133,704**	**123,127**
Aviation	46,399	58,785	56,736	74,552	73,762	75,508	69,404
Marine	65,429	39,697	53,014	53,832	53,856	58,196	53,723
CH_4	**8**	**6**	**7**	**8**	**8**	**8**	**7**
Aviation	2	2	2	2	2	2	2

Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

[99] Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

Marine	7	4	5	5	5	6	5
N_2O	**3**	**3**	**3**	**4**	**4**	**4**	**4**
Aviation	2	2	2	2	2	2	2
Marine	2	1	1	1	1	1	1

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Methodology

Emissions of CO_2 were estimated by applying C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO_2 from Fossil Fuel Combustion. C content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil were taken directly from EIA and are presented in Annex 2.1, Annex 2.2, and Annex 3.7 of this Inventory. Density conversions were taken from Chevron (2000), ASTM (1989), and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2010) and USAF (1998), and heat content for jet fuel was taken from EIA (2010). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.7 for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH_4 and N_2O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH_4 and N_2O emissions were obtained from the Revised 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.09 for CH_4 and 0.1 for N_2O For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH_4 and 0.08 for N_2O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Activity data on aircraft fuel consumption for inventory years 2000 through 2005 were developed using the FAA's System for assessing Aviation's Global Emissions (SAGE) model (FAA 2006). That tool has been subsequently replaced by the Aviation Environmental Design Tool (AEDT), which calculates noise in addition to aircraft fuel burn and emissions for flights globally in a given year (FAA 2010). Data for inventory years 2006 through 2009 were developed using AEDT.

International aviation bunker fuel consumption from 1990 to 2009 was calculated by assigning the difference between the sum of domestic activity data (in Tbtu) from SAGE and the AEDT, and the reported EIA transportation jet fuel consumption to the international bunker fuel category for jet fuel from EIA (2010). Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of the percentage of each Service's total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data synthesized from unpublished data by the Defense Energy Support Center, under DoD's Defense Logistics Agency (DESC 2011). Together, the data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 3-51. See Annex 3.7 for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1991 through 2010) for 1990 through 2001, 2007, through 2009, and the Department of Homeland Security's Bunker Report for 2003 through 2006 (DHS 2008). Fuel consumption data for 2002 was interpolated due to inconsistencies in reported fuel consumption data. Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DESC (2011). The total amount of fuel provided to naval vessels was reduced by 13 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in. Table 3-52.

Table 3-51: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**

U.S. and Foreign Carriers	4,934		6,157		5,943	7,809	7,726	7,909	7,270
U.S. Military	862		480		462	400	410	386	368
Total	**5,796**		**6,638**		**6,405**	**8,209**	**8,137**	**8,295**	**7,638**

Note: Totals may not sum due to independent rounding.

Table 3-52: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Residual Fuel Oil	4,781		2,967		3,881	4,004	4,059	4,373	4,040
Distillate Diesel Fuel & Other	617		290		444	446	358	445	426
U.S. Military Naval Fuels	522		329		471	414	444	437	384
Total	**5,920**		**3,586**		**4,796**	**4,864**	**4,861**	**5,254**	**4,850**

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[100] For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. These data may slightly over or under estimate actual total fuel use in aircraft and ships because each Service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty associated with ground fuel estimates for 1997 through 2001. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

There are also uncertainties in fuel end-uses by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-calculate the data set to 1990 using the original set from 1995. The data were adjusted for trends in fuel use based on a closely correlating, but not matching, data set. All assumptions used to develop the estimate were based on process knowledge, Department and military Service data, and expert judgments. The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emission estimates could be reduced through additional data collection.

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the Revised 1996 IPCC Guidelines is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate

[100] See uncertainty discussions under Carbon Dioxide Emissions from Fossil Fuel Combustion.

near-ground level emissions of gases other than CO_2.[101]

There is also concern as to the reliability of the existing DOC (1991 through 2010) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2008. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for international bunker fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CO_2, CH_4, and N_2O from international bunker fuels in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

Recalculations Discussion

Slight changes to emission estimates are due to revisions made to historical activity data for aviation jet fuel consumption using the FAA's AEDT. These historical data changes resulted in changes to the emission estimates for 1990 through 2008 relative to the previous Inventory, which averaged to an annual decrease in emissions from international bunker fuels of 0.13 Tg CO_2 Eq. (0.1 percent) in CO_2 emissions, an annual decrease of less than 0.01 Tg CO_2 Eq. (0.05 percent) in CH_4 emissions, and an annual decrease of less than 0.01 Tg CO_2 Eq. (0.1 percent) in N_2O emissions.

3.10. Wood Biomass and Ethanol Consumption (IPCC Source Category 1A)

The combustion of biomass fuels such as wood, charcoal, and wood waste and biomass-based fuels such as ethanol from corn and woody crops generates CO_2 in addition to CH_4 and N_2O already covered in this chapter. In line with the reporting requirements for inventories submitted under the UNFCCC, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel CO_2 emissions and are not directly included in the energy sector contributions to U.S. totals. In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands. For a more complete description of this methodological approach, see the Land Use, Land-Use Change, and Forestry chapter (Chapter 7), which accounts for the contribution of any resulting CO_2 emissions to U.S. totals within the Land Use, Land-Use Change and Forestry sector's approach.

In 2009, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 183.8 Tg CO_2 Eq. (183,777 Gg) (see Table 3-53 and Table 3-54). As the largest consumer of woody biomass, the industrial sector was responsible for 62 percent of the CO_2 emissions from this source. Emissions from this sector decreased from 2008 to 2009 due to a corresponding decrease in wood consumption. The residential sector was the second largest emitter, constituting 24 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

Table 3-53: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Industrial	135.3	153.6	136.3	138.2	132.6	126.1	114.2
Residential	59.8	43.3	44.3	40.2	44.3	46.4	44.3

[101] U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site, and reported under the Mobile Combustion section. It should be noted that these estimates are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates reported under the Mobile Combustion section overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights, but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. The estimates in Mobile Combustion are also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

Commercial	6.8	7.4	7.2	6.7	7.2	7.5	7.4
Electricity Generation	13.3	13.9	19.1	18.7	19.2	18.3	17.8
Total	**215.2**	**218.1**	**206.9**	**203.8**	**203.3**	**198.4**	**183.8**

Note: Totals may not sum due to independent rounding.

Table 3-54: CO_2 Emissions from Wood Consumption by End-Use Sector (Gg)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Industrial	135,348	153,559	136,269	138,207	132,642	126,145	114,222
Residential	59,808	43,309	44,340	40,215	44,340	46,402	44,340
Commercial	6,779	7,370	7,182	6,675	7,159	7,526	7,406
Electricity Generation	13,252	13,851	19,074	18,748	19,175	18,288	17,809
Total	**215,186**	**218,088**	**206,865**	**203,846**	**203,316**	**198,361**	**183,777**

Note: Totals may not sum due to independent rounding.

Biomass-derived fuel consumption in the United States transportation sector consisted primarily of ethanol use. Ethanol is primarily produced from corn grown in the Midwest, and was used mostly in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles.

In 2009, the United States consumed an estimated 894 trillion Btu of ethanol, and as a result, produced approximately 61.2 Tg CO_2 Eq. (61,231 Gg) (see Table 3-55 and Table 3-56) of CO_2 emissions. Ethanol production and consumption has grown steadily every year since 1990, with the exception of 1996 due to short corn supplies and high prices in that year.

Table 3-55: CO_2 Emissions from Ethanol Consumption (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	4.1	9.2	22.4	30.3	38.1	53.8	60.2
Industrial	0.1	0.1	0.5	0.7	0.7	0.8	0.9
Commercial	+	+	0.1	0.1	0.1	0.1	0.2
Total	**4.2**	**9.4**	**23.0**	**31.0**	**38.9**	**54.8**	**61.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-56: CO_2 Emissions from Ethanol Consumption (Gg)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation[a]	4,139	9,239	22,427	30,255	38,138	53,827	60,176
Industrial	56	87	469	662	674	798	892
Commercial	34	26	60	86	135	146	163
Total	**4,229**	**9,352**	**22,956**	**31,002**	**38,946**	**54,770**	**61,231**

[a] See Annex 3.2, Table A-88 for additional information on transportation consumption of these fuels.

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2010) (see Table 3-57), provided in energy units for the industrial, residential, commercial, and electric generation sectors. One heat content (16.95 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.43 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of woody biomass to obtain CO_2 emission estimates. It was assumed that the woody biomass contains black liquor and other wood wastes, has a moisture content of 12 percent, and is converted into CO_2 with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 Tg C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2010) (see Table 3-58).

Table 3-57: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Industrial	1,442	1,636	1,452	1,472	1,413	1,344	1,217

Residential	580	420	430	390	430	450	430
Commercial	66	71	70	65	69	73	72
Electricity Generation	129	134	185	182	186	177	173
Total	**2,216**	**2,262**	**2,136**	**2,109**	**2,098**	**2,044**	**1,891**

Table 3-58: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	60.5	135.0	327.6	442.0	557.1	786.3	879.0
Industrial	0.8	1.3	6.8	9.7	9.8	11.7	13.0
Commercial	0.5	0.4	0.9	1.3	2.0	2.1	2.4
Total	**61.8**	**136.6**	**335.3**	**452.9**	**568.9**	**800.1**	**894.5**

Uncertainty and Time-Series Consistency

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would decrease emission estimates. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Wood consumption values were revised for 2006 through 2008 based on updated information from EIA's Annual Energy Review (EIA 2010). This adjustment of historical data for wood biomass consumption resulted in an average annual decrease in emissions from wood biomass consumption of 0.8 Tg CO_2 Eq. (0.4 percent) from 1990 through 2008. The C content coefficient for ethanol was also revised to be consistent with the carbon content coefficients used for EPA's Mandatory Greenhouse Gas Reporting Rule. Slight adjustments were made to ethanol consumption based on updated information from EIA (2010), which slightly decreased estimates for ethanol consumed. As a result of these adjustments, average annual emissions from ethanol consumption increased by about 0.3 Tg CO_2 Eq. (1.9 percent) relative to the previous Inventory.

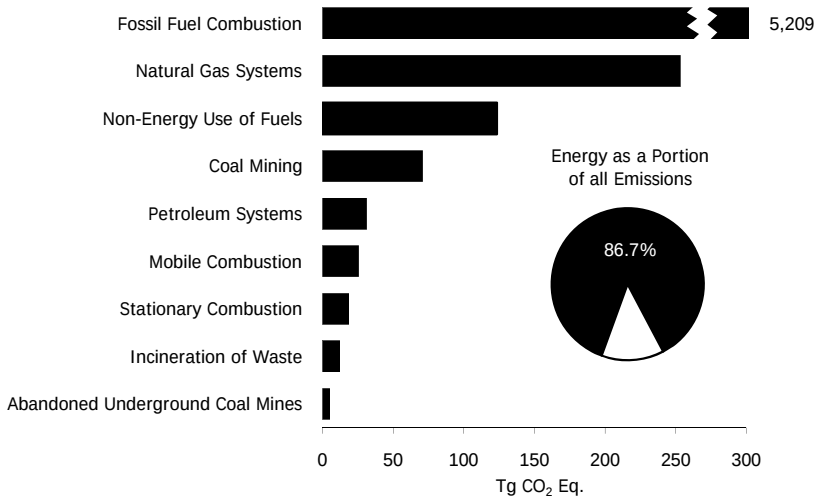

Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources

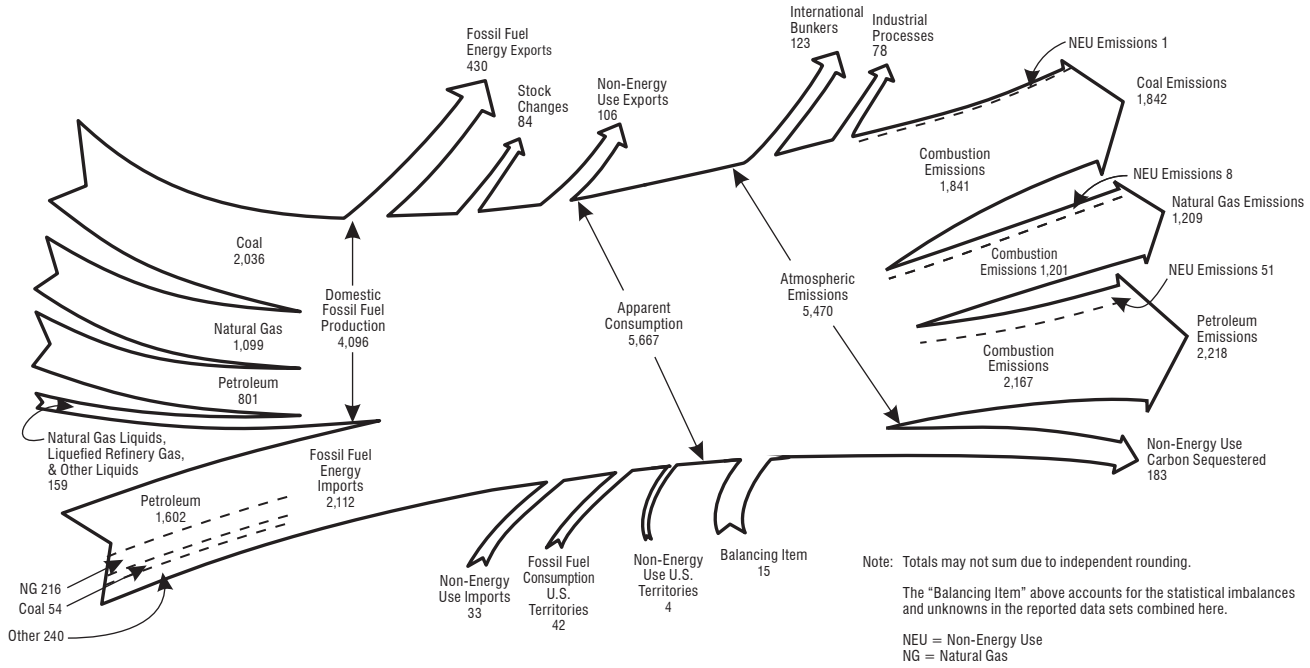

Figure 3-2 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

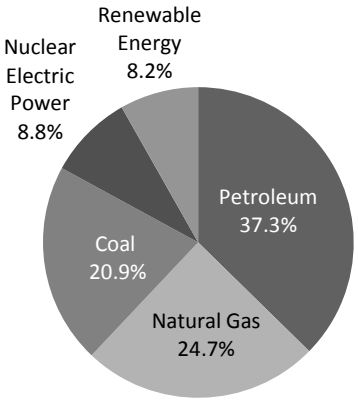

Figure 3-3: 2009 U.S. Energy Consumption by Energy Source

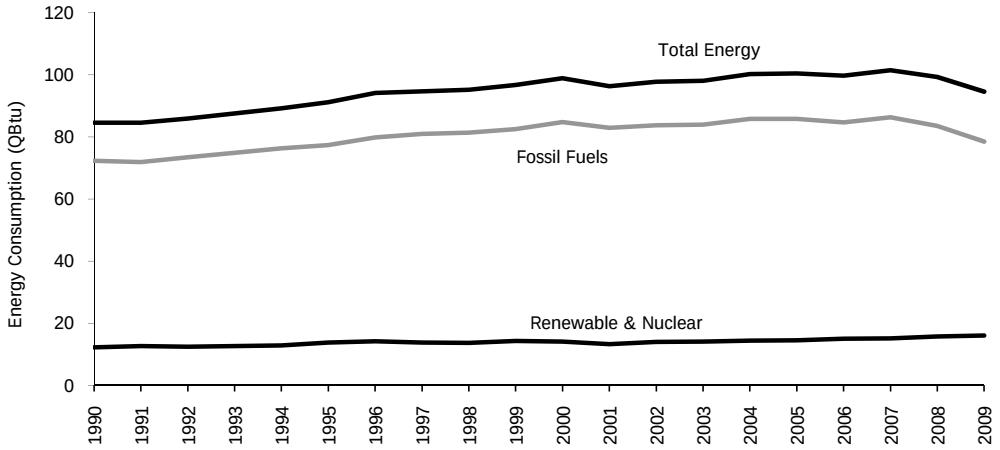

Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

Note: Expressed as gross calorific values.

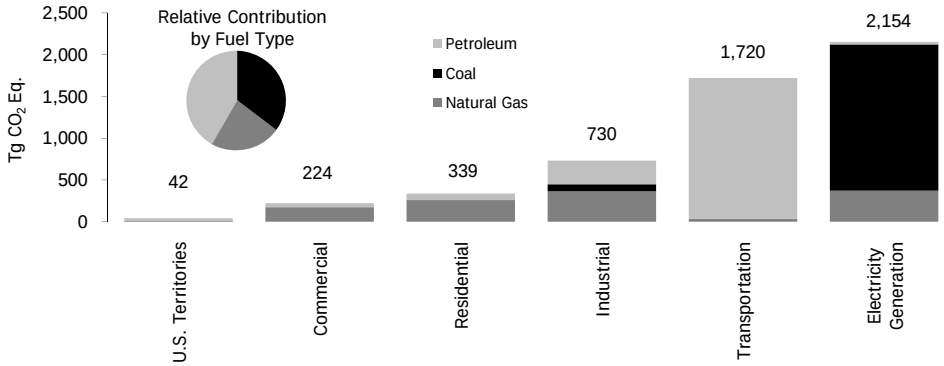

Figure 3-5: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: The electricity generation sector also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

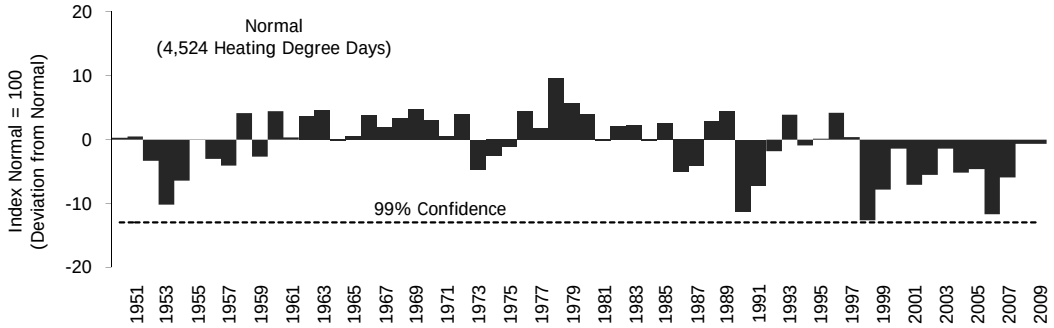

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950-2009)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1971 through 2000.

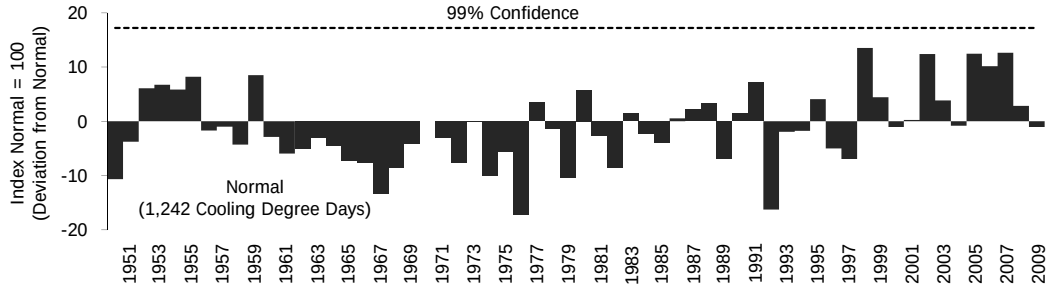

Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950-2009)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1971 through 2000.

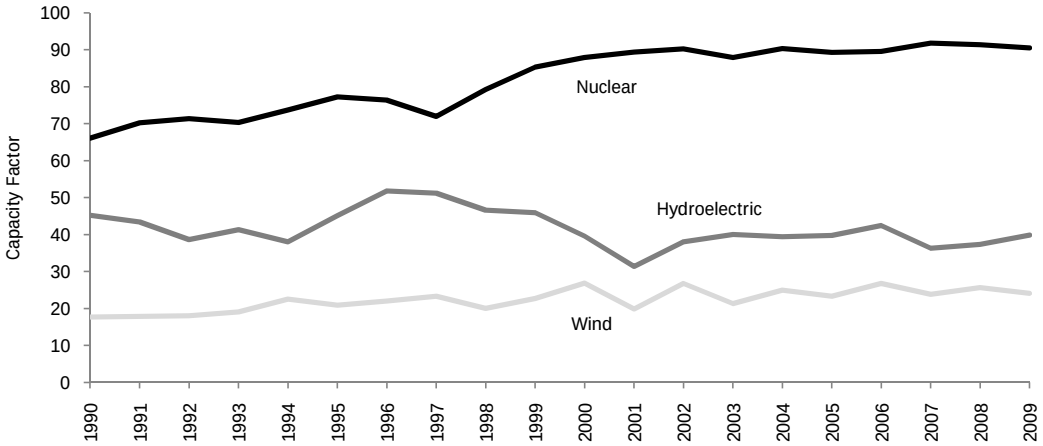

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990-2009)

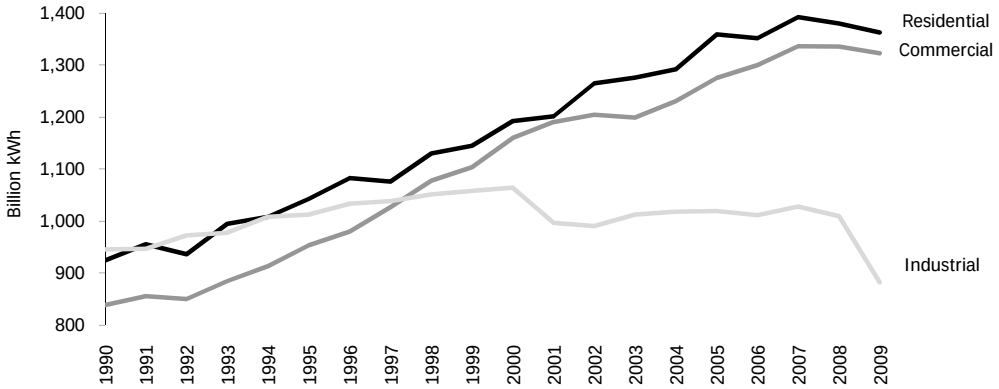

Figure 3-9: Electric Generation Retail Sales by End-Use Sector
Note: The transportation end-use sector consumes minor quanties of electricity.

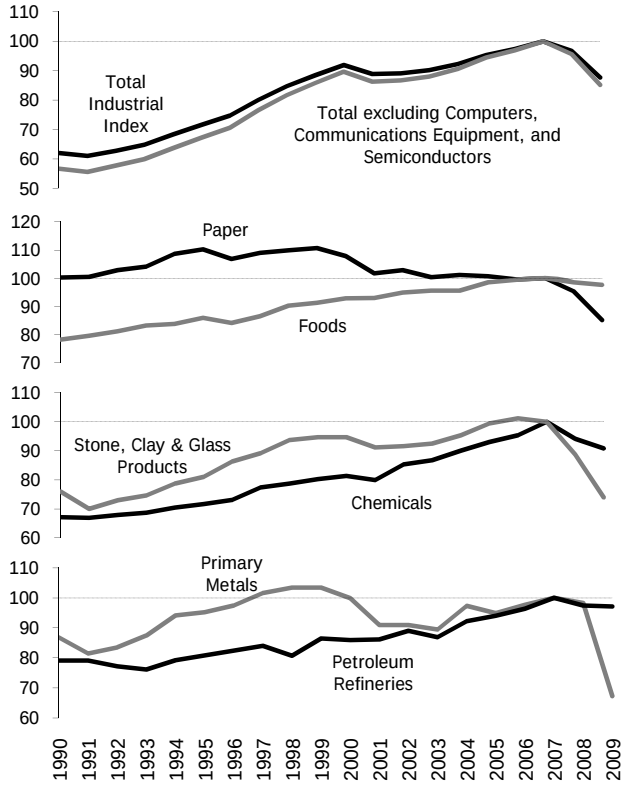

Figure 3-10: Industrial Production Indexes (Index 2007=100)

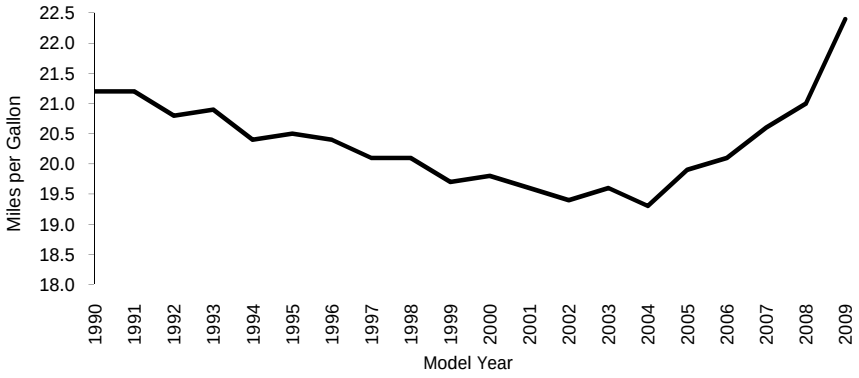

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990-2009

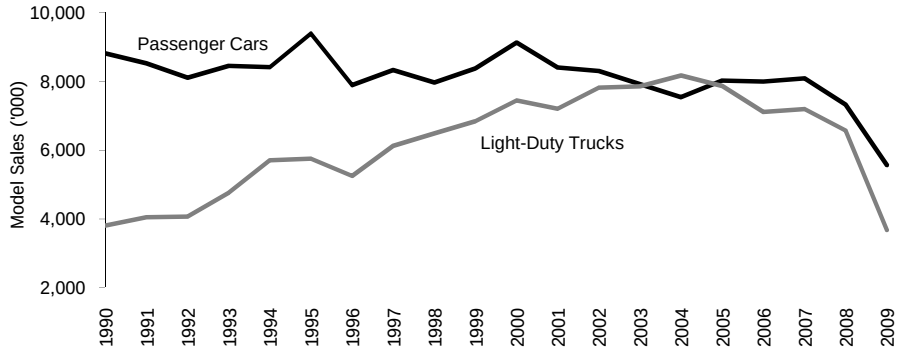

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990-2009

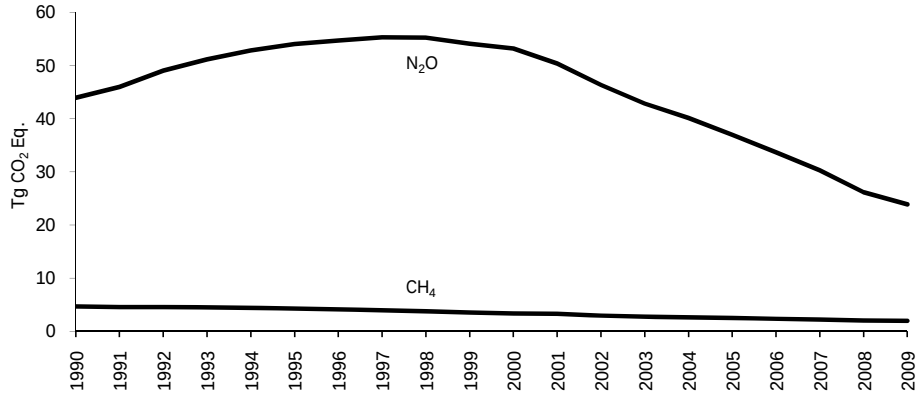

Figure 3-13: Mobile Source CH_4 and N_2O Emissions

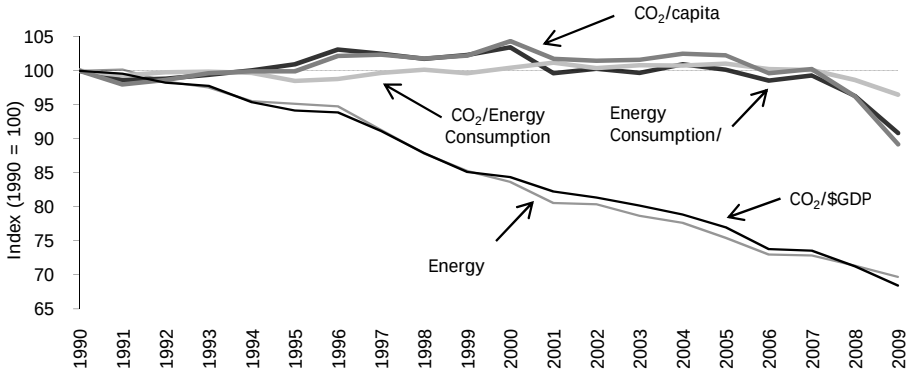

Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

4. Industrial Processes

Greenhouse gas emissions are produced as the by-products of various non-energy-related industrial activities. That is, these emissions are produced from an industrial process itself and are not directly a result of energy consumed during the process. For example, raw materials can be chemically transformed from one state to another. This transformation can result in the release of greenhouse gases such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The processes addressed in this chapter include iron and steel production and metallurgical coke production, cement production, lime production, ammonia production and urea consumption, limestone and dolomite consumption (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and use, aluminum production, titanium dioxide production, CO_2 consumption, ferroalloy production, phosphoric acid production, zinc production, lead production, petrochemical production, silicon carbide production and consumption, nitric acid production, and adipic acid production (see Figure 4-1).

Figure 4-1: 2009 Industrial Processes Chapter Greenhouse Gas Sources

In addition to the three greenhouse gases listed above, there are also industrial sources of man-made fluorinated compounds called hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). The present contribution of these gases to the radiative forcing effect of all anthropogenic greenhouse gases is small; however, because of their extremely long lifetimes, many of them will continue to accumulate in the atmosphere as long as emissions continue. In addition, many of these gases have high global warming potentials; SF_6 is the most potent greenhouse gas the Intergovernmental Panel on Climate Change (IPCC) has evaluated. Usage of HFCs is growing rapidly since they are the primary substitutes for ozone depleting substances (ODSs), which are being phased-out under the Montreal Protocol on Substances that Deplete the Ozone Layer. In addition to their use as ODS substitutes, HFCs, PFCs, and SF_6 are employed and emitted by a number of other industrial sources in the United States. These industries include aluminum production, HCFC-22 production, semiconductor manufacture, electric power transmission and distribution, and magnesium metal production and processing.

In 2009, industrial processes generated emissions of 282.9 teragrams of CO_2 equivalent (Tg CO_2 Eq.), or 4 percent of total U.S. greenhouse gas emissions. CO_2 emissions from all industrial processes were 119.0 Tg CO_2 Eq. (119,010 Gg) in 2009, or 2 percent of total U.S. CO_2 emissions. CH_4 emissions from industrial processes resulted in emissions of approximately 1.2 Tg CO_2 Eq. (58 Gg) in 2009, which was less than 1 percent of U.S. CH_4 emissions. N_2O emissions from adipic acid and nitric acid production were 16.5 Tg CO_2 Eq. (53 Gg) in 2009, or 6 percent of total U.S. N_2O emissions. In 2009 combined emissions of HFCs, PFCs and SF_6 totaled 146.1 Tg CO_2 Eq. Despite the significant increase in HFC emissions associated with increased usage of ODSs, total emissions from industrial processes in 2009 were less than 1990 for the first time since 1994. This decrease is primarily due to significant reductions in emissions from iron and steel production, metallurgical coke production, ammonia production and urea consumption, adipic acid production, HCFC-22 production, aluminum production and cement production.

Table 4-1 summarizes emissions for the Industrial Processes chapter in Tg CO_2 Eq., while unweighted native gas emissions in Gg are provided in Table 4-2. The source descriptions that follow in the chapter are presented in the order as reported to the UNFCCC in the common reporting format tables, corresponding generally to: mineral products, chemical production, metal production, and emissions from the uses of HFCs, PFCs, and SF_6.

Table 4-1: Emissions from Industrial Processes (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**188.4**	**184.9**	**165.4**	**169.9**	**172.6**	**159.5**	**119.0**
Iron and Steel Production an							
Metallurgical Coke							
Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Iron and Steel Productior	*97.1*	*83.7*	*63.9*	*66.9*	*69.0*	*63.7*	*40.9*
Metallurgical Coke							
Production	*2.5*	*2.2*	*2.0*	*1.9*	*2.1*	*2.3*	*1.0*
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Ammonia Production & Urea							
Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8

Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumptio	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Productior	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
CH_4	**1.9**	**2.2**	**1.8**	**1.7**	**1.7**	**1.6**	**1.2**
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production an Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Iron and Steel Productior	*1.0*	*0.9*	*0.7*	*0.7*	*0.7*	*0.6*	*0.4*
Metallurgical Coke Production	+	+	+	+	+	+	+
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
N_2O	**33.5**	**24.9**	**21.5**	**20.5**	**22.9**	**18.5**	**16.5**
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
HFCs	**36.9**	**103.2**	**120.2**	**123.5**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[a]	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacturir HFCs	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.7**	**5.6**
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
Semiconductor Manufacturir PFCs	2.2	4.9	3.2	3.5	3.7	4.0	4.0
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Semiconductor Manufacturir SF_6	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Total	**315.8**	**348.8**	**334.1**	**339.4**	**350.9**	**331.7**	**282.9**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

[a] Small amounts of PFC emissions also result from this source.

Table 4-2: Emissions from Industrial Processes (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**188,431**	**184,919**	**165,384**	**169,870**	**172,592**	**159,470**	**119,010**
Iron and Steel Production and Metallurgical Coke Production	99,528	85,935	65,925	68,772	71,045	66,015	41,871

Iron and Steel Production	*97,058*	*83,740*	*63,882*	*66,852*	*68,991*	*63,682*	*40,914*
Metallurgical Coke Production	*2,470*	*2,195*	*2,043*	*1,919*	*2,054*	*2,334*	*956*
Cement Production	33,278	40,405	45,197	45,792	44,538	40,531	29,018
Ammonia Production & Urea Consumption	16,831	16,402	12,849	12,300	14,038	11,949	11,797
Lime Production	11,533	14,088	14,379	15,100	14,595	14,330	11,223
Limestone and Dolomite Use	5,127	5,056	6,768	8,035	7,702	6,276	7,649
Soda Ash Production and Consumption	4,141	4,181	4,228	4,162	4,140	4,111	4,265
Aluminum Production	6,831	6,086	4,142	3,801	4,251	4,477	3,009
Petrochemical Production	3,311	4,479	4,181	3,837	3,931	3,449	2,735
Carbon Dioxide Consumption	1,416	1,421	1,321	1,709	1,867	1,780	1,763
Titanium Dioxide Production	1,195	1,752	1,755	1,836	1,930	1,809	1,541
Ferroalloy Production	2,152	1,893	1,392	1,505	1,552	1,599	1,469
Phosphoric Acid Production	1,529	1,382	1,386	1,167	1,166	1,187	1,035
Zinc Production	667	997	1,088	1,088	1,081	1,230	966
Lead Production	516	594	553	560	562	551	525
Silicon Carbide Production and Consumption	375	248	219	207	196	175	145
CH_4	**88**	**104**	**86**	**83**	**82**	**75**	**58**
Petrochemical Production	41	59	51	48	48	43	40
Iron and Steel Production and Metallurgical Coke Production	46	44	34	35	33	31	17
Iron and Steel Production	*46*	*44*	*34*	*35*	*33*	*31*	*17*
Metallurgical Coke Production	+	+	+	+	+	+	+
Ferroalloy Production	1	1	+	+	+	+	+
Silicon Carbide Production and Consumption	1	1	+	+	+	+	+
N_2O	**108**	**80**	**69**	**66**	**74**	**60**	**53**
Nitric Acid Production	57	63	53	52	62	53	47
Adipic Acid Production	51	18	16	14	12	7	6
HFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Substitution of Ozone Depleting Substances[a]	M	M	M	M	M	M	M
HCFC-22 Production	3	2	1	1	1	1	+
Semiconductor Manufacturing HFCs	+	+	+	+	+	+	+
PFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Aluminum Production	M	M	M	M	M	M	M
Semiconductor Manufacturing PFCs	M	M	M	M	M	M	M
SF_6	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Electrical Transmission and Distribution	1	1	1	1	1	1	1
Semiconductor	+	+	+	+	+	+	+

Manufacturing SF_6							
Magnesium Production and Processing	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg
M (Mixture of gases)
Note: Totals may not sum due to independent rounding.
[a] Small amounts of PFC emissions also result from this source.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Procedures

Tier 1 quality assurance and quality control procedures have been performed for all industrial process sources. For industrial process sources of CO_2 and CH_4 emissions, a detailed plan was developed and implemented. This plan was based on the overall U.S. strategy, but was tailored to include specific procedures recommended for these sources. Two types of checks were performed using this plan: (1) general, or Tier 1, procedures that focus on annual procedures and checks to be used when gathering, maintaining, handling, documenting, checking, and archiving the data, supporting documents, and files, and (2) source-category specific, or Tier 2, procedures that focus on procedures and checks of the emission factors, activity data, and methodologies used for estimating emissions from the relevant industrial process sources. Examples of these procedures include checks to ensure that activity data and emission estimates are consistent with historical trends; that, where possible, consistent and reputable data sources are used across sources; that interpolation or extrapolation techniques are consistent across sources; and that common datasets and factors are used where applicable.

The general method employed to estimate emissions for industrial processes, as recommended by the IPCC, involves multiplying production data (or activity data) for each process by an emission factor per unit of production. The uncertainty in the emission estimates is therefore generally a function of a combination of the uncertainties surrounding the production and emission factor variables. Uncertainty of activity data and the associated probability density functions for industrial processes CO_2 sources were estimated based on expert assessment of available qualitative and quantitative information. Uncertainty estimates and probability density functions for the emission factors used to calculate emissions from this source were devised based on IPCC recommendations.

Activity data is obtained through a survey of manufacturers conducted by various organizations (specified within each source); the uncertainty of the activity data is a function of the reliability of plant-level production data and is influenced by the completeness of the survey response. The emission factors used were either derived using calculations that assume precise and efficient chemical reactions, or were based upon empirical data in published references. As a result, uncertainties in the emission coefficients can be attributed to, among other things, inefficiencies in the chemical reactions associated with each production process or to the use of empirically-derived emission factors that are biased; therefore, they may not represent U.S. national averages. Additional assumptions are described within each source.

The uncertainty analysis performed to quantify uncertainties associated with the 2009 inventory estimates from industrial processes continues a multi-year process for developing credible quantitative uncertainty estimates for these source categories using the IPCC Tier 2 approach. As the process continues, the type and the characteristics of the actual probability density functions underlying the input variables are identified and better characterized (resulting in development of more reliable inputs for the model, including accurate characterization of correlation between variables), based primarily on expert judgment. Accordingly, the quantitative uncertainty estimates reported in this section should be considered illustrative and as iterations of ongoing efforts to produce accurate uncertainty estimates. The correlation among data used for estimating emissions for different sources can influence the uncertainty analysis of each individual source. While the uncertainty analysis recognizes very significant connections among sources, a more comprehensive approach that accounts for all linkages will be identified as the uncertainty analysis moves forward.

4.1. Cement Production (IPCC Source Category 2A1)

Cement production is an energy- and raw-material-intensive process that results in the generation of CO_2 from both

the energy consumed in making the cement and the chemical process itself.[102] Cement is produced in 36 states and Puerto Rico. CO_2 emitted from the chemical process of cement production is the second largest source of industrial CO_2 emissions in the United States.

During the cement production process, calcium carbonate ($CaCO_3$) is heated in a cement kiln at a temperature of about 1,450°C (2,400°F) to form lime (i.e., calcium oxide or CaO) and CO_2 in a process known as calcination or calcining. A very small amount of carbonates other than $CaCO_3$ and non-carbonates are also present in the raw material; however, for calculation purposes all of the raw material is assumed to be $CaCO_3$. Next, the lime is combined with silica-containing materials to produce clinker (an intermediate product), with the earlier by-product CO_2 being released to the atmosphere. The clinker is then allowed to cool, mixed with a small amount of gypsum and potentially other materials (e.g., slag), and used to make portland cement.[103]

In 2009, U.S. clinker production—including Puerto Rico—totaled 56,116 thousand metric tons (USGS 2011). The resulting CO_2 emissions were estimated to be 29.0 Tg CO_2 Eq. (29,018 Gg) (see Table 4-3).

Table 4-3: CO_2 Emissions from Cement Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	33.3	33,278
2000	40.4	40,405
2005	45.2	45,197
2006	45.8	45,792
2007	44.5	44,538
2008	40.5	40,531
2009	29.0	29,018

Greenhouse gas emissions from cement production grew every year from 1991 through 2006, but have decreased since. Emissions since 1990 have decreased by 13 percent. Emissions decreased significantly between 2008 and 2009, due to the economic recession and associated decrease in demand for construction materials. Cement continues to be a critical component of the construction industry; therefore, the availability of public construction funding, as well as overall economic conditions, have considerable influence on cement production.

Methodology

CO_2 emissions from cement production are created by the chemical reaction of carbon-containing minerals (i.e., calcining limestone) in the cement kiln. While in the kiln, limestone is broken down into CO_2 and lime with the CO_2 released to the atmosphere. The quantity of CO_2 emitted during cement production is directly proportional to the lime content of the clinker. During calcination, each mole of $CaCO_3$ (i.e., limestone) heated in the clinker kiln forms one mole of lime (CaO) and one mole of CO_2:

$$CaCO_3 + \text{heat} \rightarrow CaO + CO_2$$

CO_2 emissions were estimated by applying an emission factor, in tons of CO_2 released per ton of clinker produced, to the total amount of clinker produced. The emission factor used in this analysis is the product of the average lime fraction for clinker of 65 percent and a constant reflecting the mass of CO_2 released per unit of lime (van Oss 2008). This calculation yields an emission factor of 0.51 tons of CO_2 per ton of clinker produced, which was determined as follows:

[102] The CO_2 emissions related to the consumption of energy for cement manufacture are accounted for under CO_2 from Fossil Fuel Combustion in the Energy chapter.

[103] Approximately three percent of total clinker production is used to produce masonry cement, which is produced using plasticizers (e.g., ground limestone, lime) and portland cement (USGS 2011). CO_2 emissions that result from the production of lime used to create masonry cement are included in the Lime Manufacture source category.

$$EF_{\text{Clinker}} = 0.6460 \text{ CaO} \times \left[\frac{44.01 \text{ g/mole CO}_2}{56.08 \text{ g/mole CaO}} \right] = 0.5070 \text{ tons CO}_2\text{/ton clinker}$$

During clinker production, some of the clinker precursor materials remain in the kiln as non-calcinated, partially calcinated, or fully calcinated cement kiln dust (CKD). The emissions attributable to the calcinated portion of the CKD are not accounted for by the clinker emission factor. The IPCC recommends that these additional CKD CO_2 emissions should be estimated as two percent of the CO_2 emissions calculated from clinker production.[104] Total cement production emissions were calculated by adding the emissions from clinker production to the emissions assigned to CKD (IPCC 2006).[105]

The 1990 through 2009 activity data for clinker production (see Table 4-4) were obtained from USGS (US Bureau of Mines 1990 through 1993, USGS 1995 through 2011). The data were compiled by USGS through questionnaires sent to domestic clinker and cement manufacturing plants.

Table 4-4: Clinker Production (Gg)

Year	Clinker
1990	64,355
2000	78,138
2005	87,405
2006	88,555
2007	86,130
2008	78,382
2009	56,116

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates are primarily due to uncertainties in the lime content of clinker and in the percentage of CKD recycled inside the cement kiln. Uncertainty is also associated with the assumption that all calcium-containing raw materials are $CaCO_3$, when a small percentage likely consists of other carbonate and non-carbonate raw materials. The lime content of clinker varies from 60 to 67 percent; 65 percent is used as a representative value (van Oss 2008). CKD loss can range from 1.5 to 8 percent depending upon plant specifications. Additionally, some amount of CO_2 is reabsorbed when the cement is used for construction. As cement reacts with water, alkaline substances such as calcium hydroxide are formed. During this curing process, these compounds may react with CO_2 in the atmosphere to create calcium carbonate. This reaction only occurs in roughly the outer 0.2 inches of surface area. Because the amount of CO_2 reabsorbed is thought to be minimal, it was not estimated.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-5. 2009 CO_2 emissions from cement production were estimated to be between 25.3 and 33.0 Tg CO_2 Eq. at the 95 percent confidence level. This confidence level indicates a range of approximately 13 percent below and 14 percent above the emission estimate of 29.0 Tg CO_2 Eq.

Table 4-5: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Cement Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower	Upper	Lower	Upper

[104] Default IPCC clinker and CKD emission factors were verified through expert consultation with the Portland Cement Association (PCA 2008) and van Oss (2008).

[105] The two percent CO_2 addition associated with CKD is included in the emission estimate for completeness. The cement emission estimate also includes an assumption that all raw material is limestone ($CaCO_3$) when in fact a small percentage is likely composed of non-carbonate materials. Together these assumptions may result in a small emission overestimate (van Oss 2008).

			Bound	Bound	Bound	Bound
Cement Production	CO_2	29.0	25.3	33.0	-13%	+14%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Recalculations Discussion

Activity data for the time series was revised for the current Inventory. Specifically, clinker production data for 1995 through 2008 (excluding 2001) were revised to reflect published USGS data. In a given Inventory year, advance clinker data is typically used. This data is typically finalized several years later by USGS. The published time series was reviewed to ensure time series consistency. Published data generally differed from advance data by approximately 1,000 metric tons, or 1 percent of the total. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the cement source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from cement production. Beginning in 2010, all U.S. cement production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. cement industry, including also improving emission factors for clinker production and CKD.

4.2. Lime Production (IPCC Source Category 2A2)

Lime is an important manufactured product with many industrial, chemical, and environmental applications. Its major uses are in steel making, flue gas desulfurization systems at coal-fired electric power plants, construction, and water purification. For U.S. operations, the term "lime" actually refers to a variety of chemical compounds. These include calcium oxide (CaO), or high-calcium quicklime; calcium hydroxide ($Ca(OH)_2$), or hydrated lime; dolomitic quicklime ([CaO•MgO]); and dolomitic hydrate ([$Ca(OH)_2$•MgO] or [$Ca(OH)_2$•$Mg(OH)_2$]).

Lime production involves three main processes: stone preparation, calcination, and hydration. CO_2 is generated during the calcination stage, when limestone—mostly calcium carbonate ($CaCO_3$)—is roasted at high temperatures in a kiln to produce CaO and CO_2. The CO_2 is given off as a gas and is normally emitted to the atmosphere. Some of the CO_2 generated during the production process, however, is recovered at some facilities for use in sugar refining and precipitated calcium carbonate (PCC) production.[106] In certain additional applications, lime reabsorbs CO_2 during use.

Lime production in the United States—including Puerto Rico—was reported to be 15,781 thousand metric tons in 2009 (USGS 2010). This production resulted in estimated CO_2 emissions of 11.2 Tg CO_2 Eq. (11,223 Gg) (see Table 4-6 and Table 4-7).

Table 4-6: CO_2 Emissions from Lime Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	11.5	11,533
2000	14.1	14,088
2005	14.4	14,379
2006	15.1	15,100
2007	14.6	14,595
2008	14.3	14,330
2009	11.2	11,223

[106] PCC is obtained from the reaction of CO_2 with calcium hydroxide. It is used as a filler and/or coating in the paper, food, and plastic industries.

Table 4-7: Potential, Recovered, and Net CO_2 Emissions from Lime Production (Gg)

Year	Potential	Recovered*	Net Emissions
1990	12,004	471	11,533
2000	14,872	784	14,088
2005	15,131	752	14,379
2006	15,825	725	15,100
2007	15,264	669	14,595
2008	14,977	647	14,330
2009	11,913	690	11,223

* For sugar refining and PCC production.
Note: Totals may not sum due to rounding

Lime production in 2009 decreased by 21 percent compared to 2008, owing mostly to a significant downturn in major markets such as construction and steel. Because of this significant downturn, overall lime production in 2009 was approximately equal to production in 1990. The contemporary lime market is approximately distributed across five end-use categories as follows: environmental uses, 34 percent; metallurgical uses, 31 percent; chemical and industrial uses, 25 percent; construction uses, 9 percent; and refractory dolomite, 1 percent. In the construction sector, lime is used to improve durability in plaster, stucco, and mortars, as well as to stabilize soils. Consumption for metallurgical uses accounted for 57 percent of the overall decrease in lime consumption (USGS 2010).

Methodology

During the calcination stage of lime production, CO_2 is given off as a gas and normally exits the system with the stack gas. To calculate emissions, the amounts of high-calcium and dolomitic lime produced were multiplied by their respective emission factors. The emission factor is the product of a constant reflecting the mass of CO_2 released per unit of lime and the average calcium plus magnesium oxide (CaO + MgO) content for lime (95 percent for both types of lime) (IPCC 2006). The emission factors were calculated as follows:

For high-calcium lime:

$$[(44.01 \text{ g/mole } CO_2) \div (56.08 \text{ g/mole CaO})] \times (0.9500 \text{ CaO/lime}) = 0.7455 \text{ g } CO_2\text{/g lime}$$

For dolomitic lime:

$$[(88.02 \text{ g/mole } CO_2) \div (96.39 \text{ g/mole CaO})] \times (0.9500 \text{ CaO/lime}) = 0.8675 \text{ g } CO_2\text{/g lime}$$

Production was adjusted to remove the mass of chemically combined water found in hydrated lime, determined according to the molecular weight ratios of H_2O to (Ca(OH)2 and [$Ca(OH)_2$•$Mg(OH)_2$]) (IPCC 2000). These factors set the chemically combined water content to 24.3 percent for high-calcium hydrated lime, and 27.2 percent for dolomitic hydrated lime.

Lime emission estimates were multiplied by a factor of 1.02 to account for lime kiln dust (LKD), which is produced as a by-product during the production of lime (IPCC 2006).

Lime emission estimates were further adjusted to account for PCC producers and sugar refineries that recover CO_2 emitted by lime production facilities for use as an input into production or refining processes. For CO_2 recovery by sugar refineries, lime consumption estimates from USGS were multiplied by a CO_2 recovery factor to determine the total amount of CO_2 recovered from lime production facilities. According to industry surveys, sugar refineries use captured CO_2 for 100 percent of their CO_2 input (Lutter 2009). CO_2 recovery by PCC producers was determined by multiplying estimates for the percentage CO_2 of production weight for PCC production at lime plants by a CO_2 recovery factor based on the amount of purchased CO_2 by PCC manufacturers (Prillaman 2008 through 2010). As data were only available starting in 2007, CO_2 recovery for the period 1990 through 2006 was extrapolated by determining a ratio of PCC production at lime facilities to lime consumption for PCC (USGS 1992 through 2008).

Lime production data (high-calcium- and dolomitic-quicklime, high-calcium- and dolomitic-hydrated, and dead-burned dolomite) for 1990 through 2009 (see Table 4-8) were obtained from USGS (1992 through 2010). Natural

hydraulic lime, which is produced from CaO and hydraulic calcium silicates, is not produced in the United States (USGS 2009). Total lime production was adjusted to account for the water content of hydrated lime by converting hydrate to oxide equivalent based on recommendations from the IPCC, and is presented in Table 4-9 (IPCC 2000). The CaO and CaO•MgO contents of lime were obtained from the IPCC (IPCC 2006). Since data for the individual lime types (high calcium and dolomitic) was not provided prior to 1997, total lime production for 1990 through 1996 was calculated according to the three year distribution from 1997 to 1999.

Table 4-8: High-Calcium- and Dolomitic-Quicklime, High-Calcium- and Dolomitic-Hydrated, and Dead-Burned-Dolomite Lime Production (Gg)

Year	High-Calcium Quicklime	Dolomitic Quicklime	High-Calcium Hydrated	Dolomitic Hydrated	Dead-Burned Dolomite
1990	11,166	2,234	1,781	319	342
2000	14,300	3,000	1,550	421	200
2005	14,100	2,990	2,220	474	200
2006	15,000	2,950	2,370	409	200
2007	14,700	2,700	2,240	352	200
2008	14,900	2,310	2,070	358	200
2009	11,800	1,830	1,690	261	200

Table 4-9: Adjusted Lime Production[a] (Gg)

Year	High-Calcium	Dolomitic
1990	12,514	2,809
2000	15,473	3,506
2005	15,781	3,535
2006	16,794	3,448
2007	16,396	3,156
2008	16,467	2,771
2009	13,079	2,220

[a] Minus water content of hydrated lime

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates can be attributed to slight differences in the chemical composition of these products and recovery rates for sugar refineries and PCC manufacturers located at lime plants. Although the methodology accounts for various formulations of lime, it does not account for the trace impurities found in lime, such as iron oxide, alumina, and silica. Due to differences in the limestone used as a raw material, a rigid specification of lime material is impossible. As a result, few plants produce lime with exactly the same properties.

In addition, a portion of the CO_2 emitted during lime production will actually be reabsorbed when the lime is consumed. As noted above, lime has many different chemical, industrial, environmental, and construction applications. In many processes, CO_2 reacts with the lime to create calcium carbonate (e.g., water softening). CO_2 reabsorption rates vary, however, depending on the application. For example, 100 percent of the lime used to produce precipitated calcium carbonate reacts with CO_2; whereas most of the lime used in steel making reacts with impurities such as silica, sulfur, and aluminum compounds. A detailed accounting of lime use in the United States and further research into the associated processes are required to quantify the amount of CO_2 that is reabsorbed.[107]

In some cases, lime is generated from calcium carbonate by-products at pulp mills and water treatment plants.[108]

[107] Representatives of the National Lime Association estimate that CO_2 reabsorption that occurs from the use of lime may offset as much as a quarter of the CO_2 emissions from calcination (Males 2003).

[108] Some carbide producers may also regenerate lime from their calcium hydroxide by-products, which does not result in

The lime generated by these processes is not included in the USGS data for commercial lime consumption. In the pulping industry, mostly using the Kraft (sulfate) pulping process, lime is consumed in order to causticize a process liquor (green liquor) composed of sodium carbonate and sodium sulfide. The green liquor results from the dilution of the smelt created by combustion of the black liquor where biogenic C is present from the wood. Kraft mills recover the calcium carbonate "mud" after the causticizing operation and calcine it back into lime—thereby generating CO_2—for reuse in the pulping process. Although this re-generation of lime could be considered a lime manufacturing process, the CO_2 emitted during this process is mostly biogenic in origin, and therefore is not included in the industrial processes totals (Miner and Upton 2002). In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands (see Chapter 7).

In the case of water treatment plants, lime is used in the softening process. Some large water treatment plants may recover their waste calcium carbonate and calcine it into quicklime for reuse in the softening process. Further research is necessary to determine the degree to which lime recycling is practiced by water treatment plants in the United States.

Uncertainties also remain surrounding recovery rates used for sugar refining and PCC production. The recovery rate for sugar refineries is based on two sugar beet processing and refining facilities located in California that use 100 percent recovered CO_2 from lime plants (Lutter 2010). This analysis assumes that all sugar refineries located on-site at lime plants also use 100 percent recovered CO_2. The recovery rate for PCC producers located on-site at lime plants is based on the 2009 value for PCC manufactured at commercial lime plants, given by the National Lime Association (Prillaman 2010).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-10. Lime CO_2 emissions were estimated to be between 10.4 and 12.3 Tg CO_2 Eq. at the 95 percent confidence level. This confidence level indicates a range of approximately 7 percent below and 10 percent above the emission estimate of 11.2 Tg CO_2 Eq.

Table 4-10: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Lime Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Lime Production	CO_2	11.2	10.4	12.3	-7%	+10%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

No methodological or activity data changes to the time series were made to this source for the current Inventory. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the lime source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from lime production. Beginning in 2010, all U.S. lime production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. lime industry, including improving emission factors for various lime types and LKD.

Future improvements to the lime source category will also involve continued research into CO_2 recovery associated with lime use during sugar refining and precipitate calcium carbonate (PCC) production. Currently, two sugar refining facilities in California have been identified to capture CO_2 produced in lime kilns located on the same site as the sugar refinery (Lutter 2010). Data on CO_2 production by these lime facilities is unavailable. Future work will

emissions of CO_2. In making calcium carbide, quicklime is mixed with coke and heated in electric furnaces. The regeneration of lime in this process is done using a waste calcium hydroxide (hydrated lime) [$CaC_2 + 2H_2O \rightarrow C_2H_2 + Ca(OH)_2$], not calcium carbonate [$CaCO_3$]. Thus, the calcium hydroxide is heated in the kiln to simply expel the water [$Ca(OH)_2 + \text{heat} \rightarrow CaO + H_2O$] and no CO_2 is released.

include research to determine the number of sugar refineries that employ the carbonation technique, the percentage of these that use captured CO_2 from lime production facilities, and the amount of CO_2 recovered per unit of lime production. Future research will also aim to improve estimates of CO_2 recovered as part of the PCC production process using estimates of PCC production and CO_2 inputs rather than lime consumption by PCC facilities.

4.3. Limestone and Dolomite Use (IPCC Source Category 2A3)

Limestone ($CaCO_3$) and dolomite ($CaCO_3MgCO_3$)[109] are basic raw materials used by a wide variety of industries, including construction, agriculture, chemical, metallurgy, glass production, and environmental pollution control. Limestone is widely distributed throughout the world in deposits of varying sizes and degrees of purity. Large deposits of limestone occur in nearly every state in the United States, and significant quantities are extracted for industrial applications. For some of these applications, limestone is heated sufficiently enough to calcine the material and generate CO_2 as a by-product. Examples of such applications include limestone used as a flux or purifier in metallurgical furnaces, as a sorbent in flue gas desulfurization (FGD) systems for utility and industrial plants, or as a raw material in glass manufacturing and magnesium production.

In 2009, approximately 14,928 thousand metric tons of limestone and 3,020 thousand metric tons of dolomite were consumed for these emissive applications. Overall, usage of limestone and dolomite resulted in aggregate CO_2 emissions of 7.6 Tg CO_2 Eq. (7,649 Gg) (see Table 4-11and Table 4-12). Overall, emissions have increased 49 percent from 1990 through 2009.

Table 4-11: CO_2 Emissions from Limestone & Dolomite Use (Tg CO_2 Eq.)

Year	Flux Stone	Glass Making	FGD	Magnesium Production	Other Miscellaneous Uses	Total
1990	2.6	0.2	1.4	0.1	0.8	5.1
2000	2.1	0.4	1.8	0.1	0.7	5.1
2005	2.7	0.4	3.0	0.0	0.7	6.8
2006	4.5	0.7	2.1	0.0	0.7	8.0
2007	2.0	0.3	3.2	0.0	2.2	7.7
2008	1.0	0.4	3.8	0.0	1.1	6.3
2009	1.8	0.1	5.4	0.0	0.4	7.6

Notes: Totals may not sum due to independent rounding. "Other miscellaneous uses" include chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining.

Table 4-12: CO_2 Emissions from Limestone & Dolomite Use (Gg)

Year	Flux Stone	Glass Making	FGD	Magnesium Production	Other Miscellaneous Uses	Total
1990	2,593	217	1,433	64	819	5,127
2000	2,104	371	1,787	73	722	5,056
2005	2,650	425	2,975	0	718	6,768
2006	4,492	747	2,061	0	735	8,035
2007	1,959	333	3,179	0	2,231	7,702
2008	974	387	3,801	0	1,114	6,276
2009	1,785	61	5,406	0	396	7,649

Methodology

CO_2 emissions were calculated by multiplying the quantity of limestone or dolomite consumed by the average C

[109] Limestone and dolomite are collectively referred to as limestone by the industry, and intermediate varieties are seldom distinguished.

content, 12.0 percent for limestone and 13.0 percent for dolomite (based on stoichiometry), and converting this value to CO_2. This methodology was used for flux stone, glass manufacturing, flue gas desulfurization systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining and then converting to CO_2 using a molecular weight ratio. Flux stone used during the production of iron and steel was deducted from the Limestone and Dolomite Use estimate and attributed to the Iron and Steel Production estimate.

Traditionally, the production of magnesium metal was the only other significant use of limestone and dolomite that produced CO_2 emissions. At the start of 2001, there were two magnesium production plants operating in the United States and they used different production methods. One plant produced magnesium metal using a dolomitic process that resulted in the release of CO_2 emissions, while the other plant produced magnesium from magnesium chloride using a CO_2-emissions-free process called electrolytic reduction. However, the plant utilizing the dolomitic process ceased its operations prior to the end of 2001, so beginning in 2002 there were no emissions from this particular sub-use.

Consumption data for 1990 through 2008 of limestone and dolomite used for flux stone, glass manufacturing, flue gas desulfurization systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining (see Table 4-13) were obtained from the USGS *Minerals Yearbook: Crushed Stone Annual Report* (1995 through 2010a) and the U.S. Bureau of Mines (1991 & 1993a). Consumption data for 2009 were obtained from personal communication with the USGS crushed stone commodity specialist (Willett 2010). The production capacity data for 1990 through 2009of dolomitic magnesium metal also came from the USGS (1995 through 2010b) and the U.S. Bureau of Mines (1990 through 1993b). The last plant in the United States that used the dolomitic production process for magnesium metal closed in 2001. The USGS does not mention this process in the *Minerals Yearbook: Magnesium*; therefore, it is assumed that this process continues to be non-existent in the United States (USGS 2010b). During 1990 and 1992, the USGS did not conduct a detailed survey of limestone and dolomite consumption by end-use. Consumption for 1990 was estimated by applying the 1991 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to 1990 total use. Similarly, the 1992 consumption figures were approximated by applying an average of the 1991 and 1993 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to the 1992 total.

Additionally, each year the USGS withholds data on certain limestone and dolomite end-uses due to confidentiality agreements regarding company proprietary data. For the purposes of this analysis, emissive end-uses that contained withheld data were estimated using one of the following techniques: (1) the value for all the withheld data points for limestone or dolomite use was distributed evenly to all withheld end-uses; (2) the average percent of total limestone or dolomite for the withheld end-use in the preceding and succeeding years; or (3) the average fraction of total limestone or dolomite for the end-use over the entire time period.

There is a large quantity of crushed stone reported to the USGS under the category "unspecified uses." A portion of this consumption is believed to be limestone or dolomite used for emissive end uses. The quantity listed for "unspecified uses" was, therefore, allocated to each reported end use according to each end uses fraction of total consumption in that year.[110]

Table 4-13: Limestone and Dolomite Consumption (Thousand Metric Tons)

Activity	1990	2000	2005	2006	2007	2008	2009
Flux Stone	6,737	6,283	7,022	11,030	5,305	3,253	4,623
Limestone	5,804	4,151	3,165	5,208	3,477	1,970	1,631
Dolomite	933	2,132	3,857	5,822	1,827	1,283	2,992
Glass Making	489	843	962	1,693	757	879	139
Limestone	430	843	920	1,629	757	879	139
Dolomite	59	0	43	64	0	0	0
FGD	3,258	4,061	6,761	4,683	7,225	8,639	12,288
Other Miscellaneous Uses	1,835	1,640	1,632	1,671	5,057	2,531	898
Total	**12,319**	**12,826**	**16,377**	**19,078**	**18,344**	**15,302**	**17,948**

Notes: "Other miscellaneous uses" includes chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining. Zero values for limestone and dolomite consumption for glass making result during years when the USGS reports that no limestone or dolomite are consumed for this use.

[110]This approach was recommended by USGS.

Uncertainty and Time Series Consistency

The uncertainty levels presented in this section arise in part due to variations in the chemical composition of limestone. In addition to calcium carbonate, limestone may contain smaller amounts of magnesia, silica, and sulfur, among other minerals. The exact specifications for limestone or dolomite used as flux stone vary with the pyrometallurgical process and the kind of ore processed. Similarly, the quality of the limestone used for glass manufacturing will depend on the type of glass being manufactured.

The estimates below also account for uncertainty associated with activity data. Large fluctuations in reported consumption exist, reflecting year-to-year changes in the number of survey responders. The uncertainty resulting from a shifting survey population is exacerbated by the gaps in the time series of reports. The accuracy of distribution by end use is also uncertain because this value is reported by the manufacturer and not the end user. Additionally, there is significant inherent uncertainty associated with estimating withheld data points for specific end uses of limestone and dolomite. The uncertainty of the estimates for limestone used in glass making is especially high; however, since glass making accounts for a small percent of consumption, its contribution to the overall emissions estimate is low. Lastly, much of the limestone consumed in the United States is reported as "other unspecified uses;" therefore, it is difficult to accurately allocate this unspecified quantity to the correct end-uses.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-14. Limestone and Dolomite Use CO_2 emissions were estimated to be between 6.6 and 9.1 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 13 percent below and 19 percent above the emission estimate of 7.6 Tg CO_2 Eq.

Table 4-14: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Limestone and Dolomite Use (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Limestone and Dolomite Use	CO_2	7.6	6.6	9.1	-13%	+19%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the limestone and dolomite source category involve research into the availability of limestone and dolomite end-use data, including from EPA's new Greenhouse Gas Reporting Program. If sufficient data are available, limestone and dolomite used as process materials in source categories included in future inventories (e.g., glass production, other process use of carbonates) may be removed from this section and will be reported under the appropriate source categories. Additionally, future improvements include revisiting the methodology to distribute withheld data across emissive end-uses for all years to improve consistency of calculations.

4.4. Soda Ash Production and Consumption (IPCC Source Category 2A4)

Soda ash (sodium carbonate, Na_2CO_3) is a white crystalline solid that is readily soluble in water and strongly alkaline. Commercial soda ash is used as a raw material in a variety of industrial processes and in many familiar consumer products such as glass, soap and detergents, paper, textiles, and food. It is used primarily as an alkali, either in glass manufacturing or simply as a material that reacts with and neutralizes acids or acidic substances. Internationally, two types of soda ash are produced, natural and synthetic. The United States produces only natural soda ash and is second only to China in total soda ash production. Trona is the principal ore from which natural soda ash is made.

Only two states produce natural soda ash: Wyoming and California. Of these two states, only net emissions of CO_2

from Wyoming were calculated due to specifics regarding the production processes employed in the state.[111] During the production process used in Wyoming, trona ore is calcined to produce crude soda ash. CO_2 is generated as a by-product of this reaction, and is eventually emitted into the atmosphere. In addition, CO_2 may also be released when soda ash is consumed.

In 2009, CO_2 emissions from the production of soda ash from trona were approximately 1.7 Tg CO_2 Eq. (1,733 Gg). Soda ash consumption in the United States generated 2.5 Tg CO_2 Eq. (2,532 Gg) in 2009. Total emissions from soda ash production and consumption in 2009 were 4.3 Tg CO_2 Eq. (4,265 Gg) (see Table 4-15 and Table 4-16). Emissions have remained relatively constant with some fluctuations since 1990. These fluctuations were strongly related to the behavior of the export market and the U.S. economy. Emissions from the production of soda ash from trona in 2009 are currently proxied to emissions in 2008, due to lack of available data at time of publication. Emissions in 2009 increased by approximately 4 percent from emissions in 2008, and have also increased overall by 3 percent since 1990.

Table 4-15: CO_2 Emissions from Soda Ash Production and Consumption (Tg CO_2 Eq.)

Year	Production	Consumption	Total
1990	1.4	2.7	4.1
2000	1.5	2.7	4.2
2005	1.7	2.6	4.2
2006	1.6	2.5	4.2
2007	1.7	2.5	4.1
2008	1.7	2.4	4.1
2009	1.7	2.5	4.3

Note: Totals may not sum due to independent rounding.

Table 4-16: CO_2 Emissions from Soda Ash Production and Consumption (Gg)

Year	Production	Consumption	Total
1990	1,431	2,710	4,141
2000	1,529	2,652	4,181
2005	1,655	2,573	4,228
2006	1,626	2,536	4,162
2007	1,675	2,465	4,140
2008	1,733	2,378	4,111
2009	1,733	2,532	4,265

Note: Totals may not sum due to independent rounding.

The United States represents about one-fourth of total world soda ash output. Based on final 2007 reported data, the estimated distribution of soda ash by end-use in 2008 was glass making, 49 percent; chemical production, 30 percent; soap and detergent manufacturing, 8 percent; distributors, 5 percent; flue gas desulfurization, 2 percent; water treatment, 2 percent; pulp and paper production, 2 percent; and miscellaneous, 3 percent (USGS 2009). The same distribution by end-use is currently assumed for 2009, due to lack of available data at time of publication.

[111] In California, soda ash is manufactured using sodium carbonate-bearing brines instead of trona ore. To extract the sodium carbonate, the complex brines are first treated with CO_2 in carbonation towers to convert the sodium carbonate into sodium bicarbonate, which then precipitates from the brine solution. The precipitated sodium bicarbonate is then calcined back into sodium carbonate. Although CO_2 is generated as a by-product, the CO_2 is recovered and recycled for use in the carbonation stage and is not emitted. A third state, Colorado, produced soda ash until the plant was idled in 2004. The lone producer of sodium bicarbonate no longer mines trona in the state. For a brief time, $NaHCO_3$ was produced using soda ash feedstocks mined in Wyoming and shipped to Colorado. Because the trona is mined in Wyoming, the production numbers given by the USGS included the feedstocks mined in Wyoming and shipped to Colorado. In this way, the sodium bicarbonate production that took place in Colorado was accounted for in the Wyoming numbers.

Although the United States continues to be a major supplier of world soda ash, China, which surpassed the United States in soda ash production in 2003, is the world's leading producer. While Chinese soda ash production appears to be stabilizing, U.S. competition in Asian markets is expected to continue. Despite this competition, U.S. soda ash production is expected to increase by about 0.5 percent annually (USGS 2008).

Methodology

During the production process, trona ore is calcined in a rotary kiln and chemically transformed into a crude soda ash that requires further processing. CO_2 and water are generated as by-products of the calcination process. CO_2 emissions from the calcination of trona can be estimated based on the following chemical reaction:

$$\underset{\text{[trona]}}{2(Na_3(CO_3)(HCO_3)\cdot 2H_2O)} \rightarrow \underset{\text{[soda ash]}}{3Na_2CO_3} + 5H_2O + CO_2$$

Based on this formula, approximately 10.27 metric tons of trona are required to generate one metric ton of CO_2, or an emission factor of 0.097 metric tons CO_2 per metric ton trona (IPCC 2006). Thus, the 17.8 million metric tons of trona mined in 2008 for soda ash production (USGS 2008) resulted in CO_2 emissions of approximately 1.7 Tg CO_2 Eq. (1,733 Gg). The same production and associated emissions estimates are assumed for 2009 due to lack of available data at time of publication.

Once produced, most soda ash is consumed in glass and chemical production, with minor amounts in soap and detergents, pulp and paper, flue gas desulfurization and water treatment. As soda ash is consumed for these purposes, additional CO_2 is usually emitted. In these applications, it is assumed that one mole of C is released for every mole of soda ash used. Thus, approximately 0.113 metric tons of C (or 0.415 metric tons of CO_2) are released for every metric ton of soda ash consumed.

The activity data for trona production and soda ash consumption (see Table 4-17) were taken from USGS (1994 through 2008). Data for soda ash consumption in 2009 was taken from USGS (2010) *Mineral Commodity Summary: Soda Ash*. Due to lack of 2009 trona production data at time of publication, the 2008 estimate is used as a proxy for 2009. Soda ash production and consumption data were collected by the USGS from voluntary surveys of the U.S. soda ash industry.

Table 4-17: Soda Ash Production and Consumption (Gg)

Year	Production*	Consumption
1990	14,700	6,530
2000	15,700	6,390
2005	17,000	6,200
2006	16,700	6,110
2007	17,200	5,940
2008	17,800	5,730
2009	17,800	6,100

* Soda ash produced from trona ore only.

Uncertainty and Time-Series Consistency

Emission estimates from soda ash production have relatively low associated uncertainty levels in that reliable and accurate data sources are available for the emission factor and activity data. The primary source of uncertainty, however, results from the fact that emissions from soda ash consumption are dependent upon the type of processing employed by each end-use. Specific information characterizing the emissions from each end-use is limited. Therefore, there is uncertainty surrounding the emission factors from the consumption of soda ash.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-18. Soda Ash Production and Consumption CO_2 emissions were estimated to be between 4.0 and 4.6 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below and 7 percent above the emission estimate of 4.3 Tg CO_2 Eq.

Table 4-18: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Soda Ash Production and Consumption (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Soda Ash Production and Consumption	CO_2	4.3	4.0	4.6	-7%	+7%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future inventories are anticipated to estimate emissions from glass production and other use of carbonates. These inventories will extract soda ash consumed for glass production and other use of carbonates from the current soda ash consumption emission estimates and include them under those sources.

In addition, future improvements to the soda ash production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from soda ash production. Beginning in 2010, all U.S. soda ash production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. soda ash production industry, including also improving emission factors associated with trona consumption.

4.5. Ammonia Production (IPCC Source Category 2B1) and Urea Consumption

Emissions of CO_2 occur during the production of synthetic ammonia, primarily through the use of natural gas as a feedstock. The natural gas-based, naphtha-based, and petroleum coke-based processes produce CO_2 and hydrogen (H_2), the latter of which is used in the production of ammonia. One N production plant located in Kansas is producing ammonia from petroleum coke feedstock. In some plants the CO_2 produced is captured and used to produce urea. The brine electrolysis process for production of ammonia does not lead to process-based CO_2 emissions.

There are five principal process steps in synthetic ammonia production from natural gas feedstock. The primary reforming step converts CH_4 to CO_2, carbon monoxide (CO), and H_2 in the presence of a catalyst. Only 30 to 40 percent of the CH_4 feedstock to the primary reformer is converted to CO and CO_2. The secondary reforming step converts the remaining CH_4 feedstock to CO and CO_2. The CO in the process gas from the secondary reforming step (representing approximately 15 percent of the process gas) is converted to CO_2 in the presence of a catalyst, water, and air in the shift conversion step. CO_2 is removed from the process gas by the shift conversion process, and the hydrogen gas is combined with the nitrogen (N_2) gas in the process gas during the ammonia synthesis step to produce ammonia. The CO_2 is included in a waste gas stream with other process impurities and is absorbed by a scrubber solution. In regenerating the scrubber solution, CO_2 is released.

The conversion process for conventional steam reforming of CH_4, including primary and secondary reforming and the shift conversion processes, is approximately as follows:

$$0.88\ CH_4 + 1.26\ Air + 1.24\ H_2O \xrightarrow{\text{(catalyst)}} 0.88\ CO_2 + N_2 + 3\ H_2$$

$$N_2 + 3\ H_2 \rightarrow 2\ NH_3$$

To produce synthetic ammonia from petroleum coke, the petroleum coke is gasified and converted to CO_2 and H_2. These gases are separated, and the H_2 is used as a feedstock to the ammonia production process, where it is reacted with N_2 to form ammonia.

Not all of the CO_2 produced in the production of ammonia is emitted directly to the atmosphere. Both ammonia and CO_2 are used as raw materials in the production of urea [$CO(NH_2)_2$], which is another type of nitrogenous fertilizer that contains C as well as N. The chemical reaction that produces urea is:

$$2\ NH_3 + CO_2 \rightarrow\ \ NH_2COONH_4 \rightarrow CO(NH_2)_2 + H_2O$$

Urea is consumed for a variety of uses, including as a nitrogenous fertilizer, in urea-formaldehyde resins, and as a deicing agent (TIG 2002). The C in the consumed urea is assumed to be released into the environment as CO_2 during use. Therefore, the CO_2 produced by ammonia production that is subsequently used in the production of urea is still emitted during urea consumption. The majority of CO_2 emissions associated with urea consumption are those that result from its use as a fertilizer. These emissions are accounted for in the Cropland Remaining Cropland section of the Land Use, Land-Use Change, and Forestry chapter. CO_2 emissions associated with other uses of urea are accounted for in this chapter. Net emissions of CO_2 from ammonia production in 2009 were 11.8 Tg CO_2 Eq. (11,797 Gg), and are summarized in Table 4-19 and Table 4-20. Emissions of CO_2 from urea consumed for non-fertilizer purposes in 2009 totaled 3.9 Tg CO_2 Eq. (3,942 Gg), and are summarized in Table 4-19 and Table 4-20. The decrease in ammonia production in recent years is due to several factors, including market fluctuations and high natural gas prices. Ammonia production relies on natural gas as both a feedstock and a fuel, and as such, domestic producers are competing with imports from countries with lower gas prices. If natural gas prices remain high, it is likely that domestically produced ammonia will continue to decrease with increasing ammonia imports (EEA 2004).

Table 4-19: CO_2 Emissions from Ammonia Production and Urea Consumption (Tg CO_2 Eq.)

Source	1990	2000	2005	2006	2007	2008	2009
Ammonia Production	13.0	12.2	9.2	8.8	9.1	7.9	7.9
Urea Consumption[a]	3.8	4.2	3.7	3.5	5.0	4.1	3.9
Total	**16.8**	**16.4**	**12.8**	**12.3**	**14.0**	**11.9**	**11.8**

Note: Totals may not sum due to independent rounding.
[a] Urea Consumption is for non-fertilizer purposes only. Urea consumed as a fertilizer is accounted for in the Land Use, Land-Use Change, and Forestry chapter.

Table 4-20: CO_2 Emissions from Ammonia Production and Urea Consumption (Gg)

Source	1990	2000	2005	2006	2007	2008	2009
Ammonia Production	13,047	12,172	9,196	8,781	9,074	7,883	7,855
Urea Consumption[a]	3,784	4,231	3,653	3,519	4,963	4,066	3,942
Total	**16,831**	**16,402**	**12,849**	**12,300**	**14,038**	**11,949**	**11,797**

[a] Urea Consumption is for non-fertilizer purposes only. Urea consumed as a fertilizer is accounted for in the Land Use, Land-Use Change, and Forestry chapter.

Methodology

The calculation methodology for non-combustion CO_2 emissions from production of nitrogenous fertilizers from natural gas feedstock is based on a CO_2 emission factor published by the European Fertilizer Manufacturers Association (EFMA). The selected EFMA factor is based on ammonia production technologies that are similar to those employed in the United States. The CO_2 emission factor (1.2 metric tons CO_2/metric ton NH_3) is applied to the percent of total annual domestic ammonia production from natural gas feedstock. Emissions from fuels consumed for energy purposes during the production of ammonia are accounted for in the Energy chapter. Emissions of CO_2 from ammonia production are then adjusted to account for the use of some of the CO_2 produced from ammonia production as a raw material in the production of urea. For each ton of urea produced, 8.8 of every 12 tons of CO_2 are consumed and 6.8 of every 12 tons of ammonia are consumed (IPCC 2006, EFMA 2000). The CO_2 emissions reported for ammonia production are therefore reduced by a factor of 0.73 multiplied by total annual domestic urea production. Total CO_2 emissions resulting from nitrogenous fertilizer production do not change as a result of this calculation, but some of the CO_2 emissions are attributed to ammonia production and some of the CO_2 emissions are attributed to urea consumption. Those CO_2 emissions that result from the use of urea as a fertilizer are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

The total amount of urea consumed for non-agricultural purposes is estimated by deducting the quantity of urea fertilizer applied to agricultural lands, which is obtained directly from the Land Use, Land-Use Change, and Forestry Chapter and is reported in Table 4-21, from total U.S. production. Total urea production is estimated based on the

amount of urea produced plus the sum of net urea imports and exports. CO_2 emissions associated with urea that is used for non-fertilizer purposes are estimated using a factor of 0.73 tons of CO_2 per ton of urea consumed.

All ammonia production and subsequent urea production are assumed to be from the same process—conventional catalytic reforming of natural gas feedstock, with the exception of ammonia production from petroleum coke feedstock at one plant located in Kansas. The CO_2 emission factor for production of ammonia from petroleum coke is based on plant specific data, wherein all C contained in the petroleum coke feedstock that is not used for urea production is assumed to be emitted to the atmosphere as CO_2 (Bark 2004). Ammonia and urea are assumed to be manufactured in the same manufacturing complex, as both the raw materials needed for urea production are produced by the ammonia production process. The CO_2 emission factor (3.57 metric tons CO_2/metric ton NH_3) is applied to the percent of total annual domestic ammonia production from petroleum coke feedstock.

The emission factor of 1.2 metric ton CO_2/metric ton NH_3 for production of ammonia from natural gas feedstock was taken from the EFMA Best Available Techniques publication, Production of Ammonia (EFMA 1995). The EFMA reported an emission factor range of 1.15 to 1.30 metric ton CO_2/metric ton NH_3, with 1.2 metric ton CO_2/metric ton NH_3 as a typical value. Technologies (e.g., catalytic reforming process) associated with this factor are found to closely resemble those employed in the U.S. for use of natural gas as a feedstock. The EFMA reference also indicates that more than 99 percent of the CH_4 feedstock to the catalytic reforming process is ultimately converted to CO_2. The emission factor of 3.57 metric ton CO_2/metric ton NH_3 for production of ammonia from petroleum coke feedstock was developed from plant-specific ammonia production data and petroleum coke feedstock utilization data for the ammonia plant located in Kansas (Bark 2004). As noted earlier, emissions from fuels consumed for energy purposes during the production of ammonia are accounted for in the Energy chapter. Ammonia production data (see Table 4-21) was obtained from Coffeyville Resources (Coffeyville 2005, 2006, 2007a, 2007b, 2009, 2010) and the Census Bureau of the U.S. Department of Commerce (U.S. Census Bureau 1991 through 1994, 1998 through 2010) as reported in Current Industrial Reports Fertilizer Materials and Related Products annual and quarterly reports. Urea-ammonia nitrate production was obtained from Coffeyville Resources (Coffeyville 2005, 2006, 2007a, 2007b, 2009, 2010). Urea production data for 1990 through 2008 were obtained from the Minerals Yearbook: Nitrogen (USGS 1994 through 2009). Urea production data for 2009 was obtained from the U.S. Bureau of the Census (2010). Import data for urea were obtained from the U.S. Census Bureau Current Industrial Reports Fertilizer Materials and Related Products annual and quarterly reports for 1997 through 2009 (U.S. Census Bureau 1998 through 2010), The Fertilizer Institute (TFI 2002) for 1993 through 1996, and the United States International Trade Commission Interactive Tariff and Trade DataWeb (U.S. ITC 2002) for 1990 through 1992 (see Table 4-21). Urea export data for 1990 through 2009 were taken from U.S. Fertilizer Import/Exports from USDA Economic Research Service Data Sets (U.S. Department of Agriculture 2010).

Table 4-21: Ammonia Production, Urea Production, Urea Net Imports, and Urea Exports (Gg)

Year	Ammonia Production	Urea Production	Urea Applied as Fertilizer	Urea Imports	Urea Exports
1990	15,425	7,450	3,296	1,860	854
2000	14,342	6,910	4,382	3,904	663
2005	10,143	5,270	4,779	5,026	536
2006	9,962	5,410	4,985	5,029	656
2007	10,393	5,590	5,097	6,546	271
2008	9,570	5,240	4,925	5,459	230
2009	9,372	5,084	4,295	5,505	289

Uncertainty and Time-Series Consistency

The uncertainties presented in this section are primarily due to how accurately the emission factor used represents an average across all ammonia plants using natural gas feedstock. Uncertainties are also associated with natural gas feedstock consumption data for the U.S. ammonia industry as a whole, the assumption that all ammonia production and subsequent urea production was from the same process—conventional catalytic reforming of natural gas feedstock, with the exception of one ammonia production plant located in Kansas that is manufacturing ammonia from petroleum coke feedstock. It is also assumed that ammonia and urea are produced at collocated plants from the

same natural gas raw material.

Such recovery may or may not affect the overall estimate of CO_2 emissions depending upon the end use to which the recovered CO_2 is applied. Further research is required to determine whether byproduct CO_2 is being recovered from other ammonia production plants for application to end uses that are not accounted for elsewhere.

Additional uncertainty is associated with the estimate of urea consumed for non-fertilizer purposes. Emissions associated with this consumption are reported in this source category, while those associated with consumption as fertilizer are reported in Cropland Remaining Cropland section of the Land Use, Land-Use Change, and Forestry chapter. The amount of urea used for non-fertilizer purposes is estimated based on estimates of urea production, net urea imports, and the amount of urea used as fertilizer. There is uncertainty associated with the accuracy of these estimates as well as the fact that each estimate is obtained from a different data source.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-22. Ammonia Production and Urea Consumption CO_2 emissions were estimated to be between 10.9 and 12.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below and 8 percent above the emission estimate of 11.8 Tg CO_2 Eq.

Table 4-22: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Ammonia Production and Urea Consumption (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Ammonia Production and Urea Consumption	CO_2	11.8	10.9	12.7	-7%	+8%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

The uncertainty range (-7 percent/+8 percent) has decreased by 7 percent compared to the uncertainty range in the previous Inventory (±11 percent), due to two stoichiometric variables being removed from the uncertainty analysis.

Planned Improvements

Future improvements to the ammonia production and urea consumption category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from ammonia production. Beginning in 2010, all U.S. ammonia production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from U.S. ammonia production. Specifically, the planned improvements include assessing data to update the emission factors to include both fuel and feedstock CO_2 emissions and incorporate CO_2 capture and storage. Methodologies will also be updated if additional ammonia-production plants are found to use hydrocarbons other than natural gas for ammonia production. Additional efforts will be made to find consistent data sources for urea consumption and to report emissions from this consumption appropriately as defined.

4.6. Nitric Acid Production (IPCC Source Category 2B2)

Nitric acid (HNO_3) is an inorganic compound used primarily to make synthetic commercial fertilizers. It is also a major component in the production of adipic acid—a feedstock for nylon—and explosives. Virtually all of the nitric acid produced in the United States is manufactured by the catalytic oxidation of ammonia (EPA 1997). During this reaction, N_2O is formed as a by-product and is released from reactor vents into the atmosphere.

Currently, the nitric acid industry controls for emissions of NO and NO_2 (i.e., NO_x). As such, the industry in the US uses a combination of non-selective catalytic reduction (NSCR) and selective catalytic reduction (SCR) technologies. In the process of destroying NO_x, NSCR systems are also very effective at destroying N_2O. However, NSCR units are generally not preferred in modern plants because of high energy costs and associated high gas temperatures. NSCRs were widely installed in nitric plants built between 1971 and 1977. Approximately 25 percent of nitric acid plants use NSCR and they represent 15.3 percent of estimated national production (EPA 2010a). The remaining 84.7 percent of production occurs using SCR or extended absorption, neither of which is known to reduce N_2O emissions.

N_2O emissions from this source were estimated to be 14.6 Tg CO_2 Eq. (47 Gg) in 2009 (see Table 4-23). Emissions from nitric acid production have decreased by 18 percent since 1990, with the trend in the time series closely tracking the changes in production. Emissions decreased 11.4 percent between 2008 and 2009. Emissions have decreased by 30.8 percent since 1997, the highest year of production in the time series.

Table 4-23: N_2O Emissions from Nitric Acid Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	17.7	57
2000	19.4	63
2005	16.5	53
2006	16.2	52
2007	19.2	62
2008	16.4	53
2009	14.6	47

Methodology

N_2O emissions were calculated by multiplying nitric acid production by the amount of N_2O emitted per unit of nitric acid produced. The emission factor was determined as a weighted average of two known emission factors: 2 kg N_2O/metric ton HNO_3 produced at plants using non-selective catalytic reduction (NSCR) systems and 9 kg N_2O/metric ton HNO_3 produced at plants not equipped with NSCR (IPCC 2006). In the process of destroying NO_x, NSCR systems destroy 80 to 90 percent of the N_2O, which is accounted for in the emission factor of 2 kg N_2O/metric ton HNO_3. Approximately 25 percent of HNO_3 plants in the United States are equipped with NSCR representing 15.3 percent of estimated national production (EPA 2010a). Hence, the emission factor is equal to $(9 \times 0.847) + (2 \times 0.153) = 7.9$ kg N_2O per metric ton HNO_3.

Nitric acid production data for 1990 through 2002 were obtained from the U.S. Census Bureau, Current Industrial Reports (2006). Production data for 2003 were obtained from the U.S. Census Bureau, Current Industrial Reports (2008). Production data for 2004 through 2009 were obtained from the U.S. Census Bureau, Current Industrial Reports (2010) (see Table 4-24).

Table 4-24: Nitric Acid Production (Gg)

Year	Gg
1990	7,195
2000	7,900
2005	6,711
2006	6,572
2007	7,827
2008	6,686
2009	5,924

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2009 N_2O emissions estimate from nitric acid production was calculated using the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) Tier 2 methodology.

Uncertainty associated with the parameters used to estimate N_2O emissions included that of production data, the share of U.S. nitric acid production attributable to each emission abatement technology over the time series, and the emission factors applied to each abatement technology type.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 4-25. N_2O emissions from nitric acid production were estimated to be between 8.8 and 20.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 40 percent below to 42 percent above the 2009 emissions estimate of 14.6 Tg CO_2 Eq.

Table 4-25: Tier 2 Quantitative Uncertainty Estimates for N_2O Emissions from Nitric Acid Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Nitric Acid Production	N_2O	14.6	8.8	20.7	-40%	+42%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the nitric acid production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from nitric acid production. Beginning in 2010, all U.S. nitric acid production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from U.S. nitric acid production. Specifically, the planned improvements include assessing data to update the N_2O emission factors, abatement utilization and destruction factors, and the current share of nitric acid production attributable to various abatement technologies.

Recalculations Discussion

Historical estimates for N_2O emissions from nitric acid production have been revised relative to the previous Inventory based on updated information from EPA (2010) on abatement technologies in use and based on revised production data published by the U.S. Census Bureau (2010). The previous Inventory assumed that approximately 17 percent of facilities accounting for less than 8 percent of national production were equipped with NSCR systems (EPA 2010b). The current Inventory assumes that approximately 25 percent of facilities, accounting for roughly 15 percent of national production, were equipped with NSCR systems (EPA 2010a). This change resulted in a decrease in the weighted average emission factor of 0.6 kg N_2O/metric ton HNO_3 (6.3 percent). Additionally, national nitric acid production values for 1991, 1993-1995, 1997-1999, 2002, and 2008 have been updated relative to the previous Inventory (US Census Bureau 2009, 2010). Revised production in 2008 contributed to an overall decrease in emissions of 2.6 Tg CO_2 Eq. (13.6 percent) in that year; revised production in the other historical years had a negligible impact on emissions. Overall, changes relative to the previous Inventory resulted in an average annual decrease in emissions of 1.3 Tg CO_2 Eq. (6.7 percent) for the period 1990 through 2008.

4.7. Adipic Acid Production (IPCC Source Category 2B3)

Adipic acid production is an anthropogenic source of N_2O emissions. Worldwide, few adipic acid plants exist. The United States and Europe are the major producers. In 2009, the United States had two companies with a total of three adipic acid processes, two of which were operational (CW 2007; Desai 2010; VA DEQ 2009). The United States accounts for the largest share of global adipic acid production capacity (30 percent), followed by the European Union (29 percent) and China (22 percent) (SEI 2010). Adipic acid is a white crystalline solid used in the manufacture of synthetic fibers, plastics, coatings, urethane foams, elastomers, and synthetic lubricants. Commercially, it is the most important of the aliphatic dicarboxylic acids, which are used to manufacture polyesters.

84 percent of all adipic acid produced in the United States is used in the production of nylon 6,6; nine percent is used in the production of polyester polyols; four percent is used in the production of plasticizers; and the remaining four percent is accounted for by other uses, including unsaturated polyester resins and food applications (ICIS 2007). Food grade adipic acid is used to provide some foods with a "tangy" flavor (Thiemens and Trogler 1991).

Adipic acid is produced through a two-stage process during which N_2O is generated in the second stage. The first stage of manufacturing usually involves the oxidation of cyclohexane to form a cyclohexanone/cyclohexanol mixture. The second stage involves oxidizing this mixture with nitric acid to produce adipic acid. N_2O is generated as a by-product of the nitric acid oxidation stage and is emitted in the waste gas stream (Thiemens and Trogler 1991). Process emissions from the production of adipic acid vary with the types of technologies and level of emission controls employed by a facility. In 1990, two of the three major adipic acid-producing plants had N_2O abatement technologies in place and, as of 1998, the three major adipic acid production facilities had control systems in place (Reimer et al. 1999). One small plant, which last operated in April 2006 and represented approximately two percent of production, did not control for N_2O (VA DEQ 2009; ICIS 2007; VA DEQ 2006).

N_2O emissions from adipic acid production were estimated to be 1.9 Tg CO_2 Eq. (6 Gg) in 2009 (see Table 4-26). National adipic acid production has increased by approximately 11 percent over the period of 1990 through 2009, to roughly 820,000 metric tons. Over the same period, emissions have been reduced by 88 percent due to both the widespread installation of pollution control measures in the late 1990s and plant idling in the late 2000s. In April 2006, the smallest of the four facilities ceased production of adipic acid (VA DEQ 2009); furthermore, one of the major adipic acid production facilities was not operational in 2009 (Desai 2010).

Table 4-26: N_2O Emissions from Adipic Acid Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	15.8	51
2000	5.5	18
2005	5.0	16
2006	4.3	14
2007	3.7	12
2008	2.0	7
2009	1.9	6

Methodology

Due to confidential business information, plant names are not provided in this section. The four adipic acid-producing plants will henceforth be referred to as Plants 1 through 4.

For Plants 1 and 2, 1990 to 2009 emission estimates were obtained directly from the plant engineer and account for reductions due to control systems in place at these plants during the time series (Desai 2010). These estimates were based on continuous emissions monitoring equipment installed at the two facilities. In 2009, no Adipic acid production occurred at Plant 1. For Plants 3 and 4, N_2O emissions were calculated by multiplying adipic acid production by an emission factor (i.e., N_2O emitted per unit of adipic acid produced) and adjusting for the percentage of N_2O released as a result of plant-specific emission controls. On the basis of experiments, the overall reaction stoichiometry for N_2O production in the preparation of adipic acid was estimated at approximately 0.3 metric tons of N_2O per metric ton of product (IPCC 2006). Emissions are estimated using the following equation:

$$N_2O \text{ emissions} = (\text{production of adipic acid [metric tons \{MT\} of adipic acid]}) \times (0.3 \text{ MT } N_2O / \text{MT adipic acid}) \times (1 - [N_2O \text{ destruction factor} \times \text{abatement system utility factor}])$$

The "N_2O destruction factor" represents the percentage of N_2O emissions that are destroyed by the installed abatement technology. The "abatement system utility factor" represents the percentage of time that the abatement equipment operates during the annual production period. Overall, in the United States, two of the plants employ catalytic destruction (Plants 1 and 2), one plant employs thermal destruction (Plant 3), and the smallest plant used no N_2O abatement equipment (Plant 4). For Plant 3, which uses thermal destruction and for which no reported plant-specific emissions are available, the N_2O abatement system destruction factor is assumed to be 98.5 percent, and the abatement system utility factor is assumed to be 97 percent (IPCC 2006).

From 1990 to 2003, plant-specific production data were estimated for Plant 3 where direct emission measurements were not available. In order to calculate plant-specific production for this plant, national adipic acid production was allocated to the plant level using the ratio of known plant capacity to total national capacity for all U.S. plants. The estimated plant production for this plant was then used for calculating emissions as described above. For 2004 and 2006, actual plant production data were obtained and used for emission calculations (CW 2007; CW 2005). For 2005, interpolated national production was used for calculating emissions. Updated production data were not available for Plant 3 for 2007 through 2009; therefore, production values for 2007 through 2009 were proxied using 2006 data.

For Plant 4, which last operated in April 2006 (VA DEQ 2009), plant-specific production data were obtained across the time series from 1990 through 2008 (VA DEQ 2010). Since the plant has not operated since 2006, production in 2009 is assumed to be equal to the 2008 estimate, which was zero. The plant-specific production data were then used for calculating emissions as described above.

National adipic acid production data (see Table 4-27) from 1990 through 2009 were obtained from the American Chemistry Council (ACC 2010).

Plant capacities for 1990 through 1994 were obtained from Chemical and Engineering News, "Facts and Figures" and "Production of Top 50 Chemicals" (C&EN 1992 through 1995). Plant capacities for 1995 and 1996 were kept the same as 1994 data. The 1997 plant capacities were taken from Chemical Market Reporter "Chemical Profile: Adipic Acid" (CMR 1998). The 1998 plant capacities for all four plants and 1999 plant capacities for three of the plants were obtained from Chemical Week, Product Focus: Adipic Acid/Adiponitrile (CW 1999). Plant capacities for 2000 for three of the plants were updated using Chemical Market Reporter, "Chemical Profile: Adipic Acid" (CMR 2001). For 2001 through 2005, the plant capacities for three plants were kept the same as the year 2000 capacities. Plant capacity for 1999 to 2005 for the one remaining plant was kept the same as 1998. For 2004 to 2009, although some plant capacity data are available (CW 1999, CMR 2001, ICIS 2007), they are not used to calculate plant-specific production for these years because plant-specific production data for 2004 and 2006 are also available and are used in our calculations instead (CW 2005, CW 2007).

Table 4-27: Adipic Acid Production (Gg)

Year	Gg
1990	735
2000	925
2005	903
2006	964
2007	930
2008	869
2009	819

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2009 N_2O emission estimate from adipic acid production was calculated using the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) Tier 2 methodology. Uncertainty associated with the parameters used to estimate N_2O emissions included that of company specific production data, emission factors for abated and unabated emissions, and company-specific historical emission estimates.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 4-28. N_2O emissions from adipic acid production were estimated to be between 1.2 and 2.8 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 40 percent below to 42 percent above the 2009 emission estimate of 1.9 Tg CO_2 Eq.

Table 4-28: Tier 2 Quantitative Uncertainty Estimates for N_2O Emissions from Adipic Acid Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)	(%)

			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Adipic Acid Production	N_2O	1.9	1.2	2.8	-40%	+42%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations

The current Inventory uses national production data from the ACC (2010) across the full time series. Previous Inventories relied upon a variety of sources and linear interpolation for missing intervening years in the national production time series. This change resulted in an average annual decrease in the national production estimate of approximately 2 percent for the period 1990 through 2008 relative to the previous Inventory. Emissions decreased by less than 0.1 percent over the same time period relative to the previous Inventory.

Planned Improvements

Future improvements to the adipic acid production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from adipic acid production. Beginning in 2010, all U.S. adipic acid production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from U.S. adipic acid production. Specifically, the planned improvements include assessing data to update the N_2O emission factors and update abatement utility and destruction factors based on actual performance of the latest catalytic and thermal abatement equipment at plants with continuous process and emission monitoring equipment.

4.8. Silicon Carbide Production (IPCC Source Category 2B4) and Consumption

CO_2 and CH_4 are emitted from the production[112] of silicon carbide (SiC), a material used as an industrial abrasive. To make SiC, quartz (SiO_2) is reacted with C in the form of petroleum coke. A portion (about 35 percent) of the C contained in the petroleum coke is retained in the SiC. The remaining C is emitted as CO_2, CH_4, or CO.

CO_2 is also emitted from the consumption of SiC for metallurgical and other non-abrasive applications. The USGS reports that a portion (approximately 50 percent) of SiC is used in metallurgical and other non-abrasive applications, primarily in iron and steel production (USGS 2006).

CO_2 from SiC production and consumption in 2009 were 0.1 Tg CO_2 Eq. (145 Gg) (USGS 2009). Approximately 63 percent of these emissions resulted from SiC production while the remainder results from SiC consumption. CH_4 emissions from SiC production in 2009 were 0.01 Tg CO_2 Eq. CH_4 (0.4 Gg) (see Table 4-29 and Table 4-30).

Table 4-29: CO_2 and CH_4 Emissions from Silicon Carbide Production and Consumption (Tg CO_2 Eq.)

Year	1990		2000		2005	2006	2007	2008	2009
CO_2	0.4		0.2		0.2	0.2	0.2	0.2	0.1
CH_4	+		+		+	+	+	+	+
Total	**0.4**		**0.3**		**0.2**	**0.2**	**0.2**	**0.2**	**0.2**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 4-30: CO_2 and CH_4 Emissions from Silicon Carbide Production and Consumption (Gg)

Year	1990		2000		2005	2006	2007	2008	2009

[112] Silicon carbide is produced for both abrasive and metallurgical applications in the United States. Production for metallurgical applications is not available and therefore both CH_4 and CO_2 estimates are based solely upon production estimates of silicon carbide for abrasive applications.

CO_2	375		248		219	207	196	175	145
CH_4	1		1		+	+	+	+	+

+ Does not exceed 0.5 Gg.

Methodology

Emissions of CO_2 and CH_4 from the production of SiC were calculated by multiplying annual SiC production by the emission factors (2.62 metric tons CO_2/metric ton SiC for CO_2 and 11.6 kg CH_4/metric ton SiC for CH_4) provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

Emissions of CO_2 from silicon carbide consumption were calculated by multiplying the annual SiC consumption (production plus net imports) by the percent used in metallurgical and other non-abrasive uses (50 percent) (USGS 2009). The total SiC consumed in metallurgical and other non-abrasive uses was multiplied by the C content of SiC (31.5 percent), which was determined according to the molecular weight ratio of SiC.

Production data for 1990 through 2008 were obtained from the Minerals Yearbook: Manufactured Abrasives (USGS 1991a through 2005a, 2007, and 2009). Production data for 2009 was taken from the Minerals Commodity Summary: Abrasives (Manufactured) (USGS 2010). Silicon carbide consumption by major end use was obtained from the Minerals Yearbook: Silicon (USGS 1991b through 2005b) (see Table 4-31) for years 1990 through 2004 and from the USGS Minerals Commodity Specialist for 2005 and 2006 (Corathers 2006, 2007). Silicon carbide consumption by major end use data for 2009 is proxied using 2008 data due to unavailability of data at time of publication. Net imports for the entire time series were obtained from the U.S. Census Bureau (2005 through 2010).

Table 4-31: Production and Consumption of Silicon Carbide (Metric Tons)

Year	Production	Consumption
1990	105,000	172,465
2000	45,000	225,070
2005	35,000	220,149
2006	35,000	199,937
2007	35,000	179,741
2008	35,000	144,928
2009	35,000	92,280

Uncertainty and Time-Series Consistency

There is uncertainty associated with the emission factors used because they are based on stoichiometry as opposed to monitoring of actual SiC production plants. An alternative would be to calculate emissions based on the quantity of petroleum coke used during the production process rather than on the amount of silicon carbide produced. However, these data were not available. For CH_4, there is also uncertainty associated with the hydrogen-containing volatile compounds in the petroleum coke (IPCC 2006). There is also some uncertainty associated with production, net imports, and consumption data as well as the percent of total consumption that is attributed to metallurgical and other non-abrasive uses.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-32. Silicon carbide production and consumption CO_2 emissions were estimated to be between 9 percent below and 9 percent above the emission estimate of 0.2 Tg CO_2 Eq. at the 95 percent confidence level. Silicon carbide production CH_4 emissions were estimated to be between 9 percent below and 9 percent above the emission estimate of 0.01 Tg CO_2 Eq. at the 95 percent confidence level.

Table 4-32: Tier 2 Quantitative Uncertainty Estimates for CH_4 and CO_2 Emissions from Silicon Carbide Production and Consumption (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Silicon Carbide Production	CO_2	0.2	0.13	0.16	-9%	+9%

and Consumption						
Silicon Carbide Production	CH_4	+	+	+	-9%	+9%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
+ Does not exceed 0.05 Tg CO_2 Eq. or 0.5 Gg.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the silicon carbide production source category include evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from silicon carbide production. Beginning in 2010, all U.S. silicon carbide production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. silicon carbide production industry. In addition, improvements will involve continued research to determine if calcium carbide production and consumption data are available for the United States. If these data are available, calcium carbide emission estimates will be included in this source category. Additionally, as future improvement to the silicon carbide uncertainty analysis, USGS Mineral Commodity Specialists will be contacted to verify the uncertainty range associated with silicon carbide emissive utilization.

4.9. Petrochemical Production (IPCC Source Category 2B5)

The production of some petrochemicals results in the release of small amounts of CH_4 and CO_2 emissions. Petrochemicals are chemicals isolated or derived from petroleum or natural gas. CH_4 emissions are presented here from the production of carbon black, ethylene, ethylene dichloride, and methanol, while CO_2 emissions are presented here for only carbon black production. The CO_2 emissions from petrochemical processes other than carbon black are currently included in the Carbon Stored in Products from Non-Energy Uses of Fossil Fuels Section of the Energy chapter. The CO_2 from carbon black production is included here to allow for the direct reporting of CO_2 emissions from the process and direct accounting of the feedstocks used in the process.

Carbon black is an intense black powder generated by the incomplete combustion of an aromatic petroleum or coal-based feedstock. Most carbon black produced in the United States is added to rubber to impart strength and abrasion resistance, and the tire industry is by far the largest consumer. Ethylene is consumed in the production processes of the plastics industry including polymers such as high, low, and linear low density polyethylene (HDPE, LDPE, LLDPE), polyvinyl chloride (PVC), ethylene dichloride, ethylene oxide, and ethylbenzene. Ethylene dichloride is one of the first manufactured chlorinated hydrocarbons with reported production as early as 1795. In addition to being an important intermediate in the synthesis of chlorinated hydrocarbons, ethylene dichloride is used as an industrial solvent and as a fuel additive. Methanol is an alternative transportation fuel as well as a principle ingredient in windshield wiper fluid, paints, solvents, refrigerants, and disinfectants. In addition, methanol-based acetic acid is used in making PET plastics and polyester fibers.

Emissions of CO_2 and CH_4 from petrochemical production in 2009 were 2.7 Tg CO_2 Eq. (2,735 Gg) and 0.8 Tg CO_2 Eq. (40 Gg), respectively (see Table 4-33 and Table 4-34), totaling 3.6 Tg CO_2 Eq. There has been an overall decrease in CO_2 emissions from carbon black production of 17 percent since 1990. CH_4 emissions from petrochemical production decreased by approximately two percent since 1990.

Table 4-33: CO_2 and CH_4 Emissions from Petrochemical Production (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	3.3	4.5	4.2	3.8	3.9	3.4	2.7
CH_4	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Total	**4.2**	**5.7**	**5.3**	**4.8**	**4.9**	**4.4**	**3.6**

Note: Totals may not sum due to independent rounding.

Table 4-34: CO_2 and CH_4 Emissions from Petrochemical Production (Gg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**

CO_2	3,311	4,479	4,181	3,837	3,931	3,449	2,735
CH_4	41	59	51	48	48	43	40

Methodology

Emissions of CH_4 were calculated by multiplying annual estimates of chemical production by the appropriate emission factor, as follows: 11 kg CH_4/metric ton carbon black, 1 kg CH_4/metric ton ethylene, 0.4 kg CH_4/metric ton ethylene dichloride,[113] and 2 kg CH_4/metric ton methanol. Although the production of other chemicals may also result in CH_4 emissions, insufficient data were available to estimate their emissions.

Emission factors were taken from the Revised 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997). Annual production data (see Table 4-35) were obtained from the American Chemistry Council's Guide to the Business of Chemistry (ACC 2002, 2003, 2005 through 2010) and the International Carbon Black Association (Johnson 2003, 2005 through 2010). Note that 2009 production data for Methanol was not available at time of publication, as such, 2008 methanol production is used as a proxy for 2009.

Table 4-35: Production of Selected Petrochemicals (Thousand Metric Tons)

Chemical	1990	2000	2005	2006	2007	2008	2009
Carbon Black	1,307	1,769	1,651	1,515	1,552	1,362	1,080
Ethylene	16,541	24,970	23,954	25,000	25,392	22,539	22,596
Ethylene Dichloride	6,282	9,866	11,260	9,736	9,566	8,981	8,131
Methanol	3,785	5,221	2,336	1,123	1,068	1,136	1,136

Almost all carbon black in the United States is produced from petroleum-based or coal-based feedstocks using the "furnace black" process (European IPPC Bureau 2004). The furnace black process is a partial combustion process in which a portion of the carbon black feedstock is combusted to provide energy to the process. Carbon black is also produced in the United States by the thermal cracking of acetylene-containing feedstocks ("acetylene black process") and by the thermal cracking of other hydrocarbons ("thermal black process"). One U.S carbon black plant produces carbon black using the thermal black process, and one U.S. carbon black plant produces carbon black using the acetylene black process (The Innovation Group 2004).

The furnace black process produces carbon black from "carbon black feedstock" (also referred to as "carbon black oil"), which is a heavy aromatic oil that may be derived as a byproduct of either the petroleum refining process or the metallurgical (coal) coke production process. For the production of both petroleum-derived and coal-derived carbon black, the "primary feedstock" (i.e., carbon black feedstock) is injected into a furnace that is heated by a "secondary feedstock" (generally natural gas). Both the natural gas secondary feedstock and a portion of the carbon black feedstock are oxidized to provide heat to the production process and pyrolyze the remaining Carbon black feedstock to carbon black. The "tail gas" from the furnace black process contains CO_2, carbon monoxide, sulfur compounds, CH_4, and non-CH_4 volatile organic compounds. A portion of the tail gas is generally burned for energy recovery to heat the downstream carbon black product dryers. The remaining tail gas may also be burned for energy recovery, flared, or vented uncontrolled to the atmosphere.

The calculation of the C lost during the production process is the basis for determining the amount of CO_2 released during the process. The C content of national carbon black production is subtracted from the total amount of C contained in primary and secondary carbon black feedstock to find the amount of C lost during the production process. It is assumed that the C lost in this process is emitted to the atmosphere as either CH_4 or CO_2. The C content of the CH_4 emissions, estimated as described above, is subtracted from the total C lost in the process to calculate the amount of C emitted as CO_2. The total amount of primary and secondary carbon black feedstock consumed in the process (see Table 4-36) is estimated using a primary feedstock consumption factor and a secondary feedstock consumption factor estimated from U.S. Census Bureau (1999, 2004, and 2007) data. The average carbon black feedstock consumption factor for U.S. carbon black production is 1.69 metric tons of carbon black feedstock consumed per metric ton of carbon black produced. The average natural gas consumption factor for

[113] The emission factor obtained from IPCC/UNEP/OECD/IEA (1997), page 2.23 is assumed to have a misprint; the chemical identified should be ethylene dichloride ($C_2H_4Cl_2$) rather than dichloroethylene ($C_2H_2Cl_2$).

U.S. carbon black production is 321 normal cubic meters of natural gas consumed per metric ton of carbon black produced. The amount of C contained in the primary and secondary feedstocks is calculated by applying the respective C contents of the feedstocks to the respective levels of feedstock consumption (EIA 2003, 2004).

Table 4-36: Carbon Black Feedstock (Primary Feedstock) and Natural Gas Feedstock (Secondary Feedstock) Consumption (Thousand Metric Tons)

Activity	1990	2000	2005	2006	2007	2008	2009
Primary Feedstock	2,213	2,993	2,794	2,564	2,627	2,305	1,828
Secondary Feedstock	284	384	359	329	337	296	235

For the purposes of emissions estimation, 100 percent of the primary carbon black feedstock is assumed to be derived from petroleum refining byproducts. Carbon black feedstock derived from metallurgical (coal) coke production (e.g., creosote oil) is also used for carbon black production; however, no data are available concerning the annual consumption of coal-derived carbon black feedstock. Carbon black feedstock derived from petroleum refining byproducts is assumed to be 89 percent elemental C (Srivastava et al. 1999). It is assumed that 100 percent of the tail gas produced from the carbon black production process is combusted and that none of the tail gas is vented to the atmosphere uncontrolled. The furnace black process is assumed to be the only process used for the production of carbon black because of the lack of data concerning the relatively small amount of carbon black produced using the acetylene black and thermal black processes. The carbon black produced from the furnace black process is assumed to be 97 percent elemental C (Othmer et al. 1992).

Uncertainty and Time-Series Consistency

The CH_4 emission factors used for petrochemical production are based on a limited number of studies. Using plant-specific factors instead of average factors could increase the accuracy of the emission estimates; however, such data were not available. There may also be other significant sources of CH_4 arising from petrochemical production activities that have not been included in these estimates.

The results of the quantitative uncertainty analysis for the CO_2 emissions from carbon black production calculation are based on feedstock consumption, import and export data, and carbon black production data. The composition of carbon black feedstock varies depending upon the specific refinery production process, and therefore the assumption that carbon black feedstock is 89 percent C gives rise to uncertainty. Also, no data are available concerning the consumption of coal-derived carbon black feedstock, so CO_2 emissions from the utilization of coal-based feedstock are not included in the emission estimate. In addition, other data sources indicate that the amount of petroleum-based feedstock used in carbon black production may be underreported by the U.S. Census Bureau. Finally, the amount of carbon black produced from the thermal black process and acetylene black process, although estimated to be a small percentage of the total production, is not known. Therefore, there is some uncertainty associated with the assumption that all of the carbon black is produced using the furnace black process.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-37. Petrochemical production CO_2 emissions were estimated to be between 2.0 and 3.6 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 27 percent below to 31 percent above the emission estimate of 2.7 Tg CO_2 Eq. Petrochemical production CH_4 emissions were estimated to be between 0.6 and 1.1 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 26 percent below to 27 percent above the emission estimate of 0.8 Tg CO_2 Eq.

Table 4-37: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petrochemical Production and CO_2 Emissions from Carbon Black Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Petrochemical Production	CO_2	2.7	2.0	3.6	-27%	+31%
Petrochemical Production	CH_4	0.8	0.6	1.1	-26%	+27%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990

through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the petrochemicals source category involve updating the methodology to use CH_4 emission factors for petrochemical production from the IPCC 2006 guidelines rather than the IPCC 1996 guidelines. Further future improvements involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from petrochemical production. Beginning in 2010, all U.S. petrochemical production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. petrochemical production industry, for example using a Tier 2 methodology to calculate emissions from the production of methanol, ethylene, propylene, ethylene dichloride, and ethylene oxide. In addition, the planned improvements include assessing the data EPA obtains to update data sources for acrylonitrile production in the United States.

4.10. Titanium Dioxide Production (IPCC Source Category 2B5)

Titanium dioxide (TiO_2) is a metal oxide manufactured from titanium ore, and is principally used as a pigment. Titanium dioxide is a principal ingredient in white paint, and is also used as a pigment in the manufacture of white paper, foods, and other products. There are two processes for making TiO_2: the chloride process and the sulfate process. The chloride process uses petroleum coke and chlorine as raw materials and emits process-related CO_2. The sulfate process does not use petroleum coke or other forms of C as a raw material and does not emit CO_2.

The chloride process is based on the following chemical reactions:

$$2\ FeTiO_3 + 7\ Cl_2 + 3\ C \rightarrow 2\ TiCl_4 + 2\ FeCl_3 + 3\ CO_2$$

$$2\ TiCl_4 + 2\ O_2 \rightarrow 2\ TiO_2 + 4\ Cl_2$$

The C in the first chemical reaction is provided by petroleum coke, which is oxidized in the presence of the chlorine and $FeTiO_3$ (the Ti-containing ore) to form CO_2. The majority of U.S. TiO_2 was produced in the United States through the chloride process, and a special grade of "calcined" petroleum coke is manufactured specifically for this purpose.

Emissions of CO_2 in 2009 were 1.5 Tg CO_2 Eq. (1,541 Gg), which represents an increase of 29 percent since 1990 (see Table 4-38).

Table 4-38: CO_2 Emissions from Titanium Dioxide (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	1.2	1,195
2000	1.8	1,752
2005	1.8	1,755
2006	1.8	1,836
2007	1.9	1,930
2008	1.8	1,809
2009	1.5	1,541

Methodology

Emissions of CO_2 from TiO_2 production were calculated by multiplying annual TiO_2 production by chloride-process-specific emission factors.

Data were obtained for the total amount of TiO_2 produced each year. For years previous to 2004, it was assumed that TiO_2 was produced using the chloride process and the sulfate process in the same ratio as the ratio of the total U.S. production capacity for each process. As of 2004, the last remaining sulfate-process plant in the United States

had closed; therefore, 100 percent of post-2004 production uses the chloride process (USGS 2005). An emission factor of 0.4 metric tons C/metric ton TiO2 was applied to the estimated chloride-process production. It was assumed that all TiO_2 produced using the chloride process was produced using petroleum coke, although some TiO_2 may have been produced with graphite or other C inputs. The amount of petroleum coke consumed annually in TiO_2 production was calculated based on the assumption that the calcined petroleum coke used in the process is 98.4 percent C and 1.6 percent inert materials (Nelson 1969).

The emission factor for the TiO_2 chloride process was taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). Titanium dioxide production data and the percentage of total TiO_2 production capacity that is chloride process for 1990 through 2008 (see Table 4-39) were obtained through the Minerals Yearbook: Titanium Annual Report (USGS 1991 through 2008). Production data in 2009 was obtained from the Minerals Commodity Summary: Titanium and Titanium Dioxide (USGS 2010). Due to lack of available 2009 capacity data at the time of publication, the 2008 capacity estimate is used as a proxy for 2009. Percentage chloride-process data were not available for 1990 through 1993, and data from the 1994 USGS Minerals Yearbook were used for these years. Because a sulfate-process plant closed in September 2001, the chloride-process percentage for 2001 was estimated based on a discussion with Joseph Gambogi (2002). By 2002, only one sulfate plant remained online in the United States and this plant closed in 2004 (USGS 2005).

Table 4-39: Titanium Dioxide Production (Gg)

Year	Gg
1990	979
2000	1,400
2005	1,310
2006	1,370
2007	1,440
2008	1,350
2009	1,150

Uncertainty and Time-Series Consistency

Although some TiO_2 may be produced using graphite or other C inputs, information and data regarding these practices were not available. Titanium dioxide produced using graphite inputs, for example, may generate differing amounts of CO_2 per unit of TiO_2 produced as compared to that generated through the use of petroleum coke in production. While the most accurate method to estimate emissions would be to base calculations on the amount of reducing agent used in each process rather than on the amount of TiO_2 produced, sufficient data were not available to do so.

Also, annual TiO_2 is not reported by USGS by the type of production process used (chloride or sulfate). Only the percentage of total production capacity by process is reported. The percent of total TiO_2 production capacity that was attributed to the chloride process was multiplied by total TiO_2 production to estimate the amount of TiO_2 produced using the chloride process (since, as of 2004, the last remaining sulfate-process plant in the United States closed). This assumes that the chloride-process plants and sulfate-process plants operate at the same level of utilization. Finally, the emission factor was applied uniformly to all chloride-process production, and no data were available to account for differences in production efficiency among chloride-process plants. In calculating the amount of petroleum coke consumed in chloride-process TiO_2 production, literature data were used for petroleum coke composition. Certain grades of petroleum coke are manufactured specifically for use in the TiO_2 chloride process; however, this composition information was not available.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-40. Titanium dioxide consumption CO_2 emissions were estimated to be between 1.4 and 1.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 13 percent below and 13 percent above the emission estimate of 1.5 Tg CO_2 Eq.

Table 4-40: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Titanium Dioxide Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Titanium Dioxide Production	CO_2	1.5	1.3	1.7	-13%	+13%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the titanium dioxide production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from titanium dioxide production. Beginning in 2010, all U.S. titanium dioxide production facilities using the chloride production process are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. titanium dioxide production industry, including improving the emission factors. In addition, the planned improvements include researching the significance of titanium-slag production in electric furnaces and synthetic-rutile production using the Becher process in the United States. Significant use of these production processes will be included in future estimates.

4.11. Carbon Dioxide Consumption (IPCC Source Category 2B5)

CO_2 is used for a variety of commercial applications, including food processing, chemical production, carbonated beverage production, and refrigeration, and is also used in petroleum production for enhanced oil recovery (EOR). CO_2 used for EOR is injected into the underground reservoirs to increase the reservoir pressure to enable additional petroleum to be produced.

For the most part, CO_2 used in non-EOR applications will eventually be released to the atmosphere, and for the purposes of this analysis CO_2 used in commercial applications other than EOR is assumed to be emitted to the atmosphere. CO_2 used in EOR applications is discussed in the Energy Chapter under "Carbon Capture and Storage, including Enhanced Oil Recovery" and is not discussed in this section.

CO_2 is produced from naturally occurring CO_2 reservoirs, as a by-product from the energy and industrial production processes (e.g., ammonia production, fossil fuel combustion, ethanol production), and as a by-product from the production of crude oil and natural gas, which contain naturally occurring CO_2 as a component. Only CO_2 produced from naturally occurring CO_2 reservoirs and used in industrial applications other than EOR is included in this analysis. Neither by-product CO_2 generated from energy nor industrial production processes nor CO_2 separated from crude oil and natural gas are included in this analysis for a number of reasons. CO_2 captured from biogenic sources (e.g., ethanol production plants) is not included in the inventory. CO_2 captured from crude oil and gas production is used in EOR applications and is therefore reported in the Energy Chapter. Any CO_2 captured from industrial or energy production processes (e.g., ammonia plants, fossil fuel combustion) and used in non-EOR applications is assumed to be emitted to the atmosphere. The CO_2 emissions from such capture and use are

therefore accounted for under Ammonia Production, Fossil Fuel Combustion, or other appropriate source category.[114]

CO_2 is produced as a by-product of crude oil and natural gas production. This CO_2 is separated from the crude oil and natural gas using gas processing equipment, and may be emitted directly to the atmosphere, or captured and reinjected into underground formations, used for EOR, or sold for other commercial uses. A further discussion of CO_2 used in EOR is described in the Energy Chapter under the text box titled "Carbon Dioxide Transport, Injection, and Geological Storage." The only CO_2 consumption that is accounted for in this analysis is CO_2 produced from naturally-occurring CO_2 reservoirs that is used in commercial applications other than EOR.

There are currently two facilities, one in Mississippi and one in New Mexico, producing CO_2 from naturally occurring CO_2 reservoirs for use in both EOR and in other commercial applications (e.g., chemical manufacturing, food production). There are other naturally occurring CO_2 reservoirs, mostly located in the western UnitedStates. Facilities are producing CO_2 from these natural reservoirs, but they are only producing CO_2 for EOR applications, not for other commercial applications (Allis et al. 2000). CO_2 production from these facilities is discussed in the Energy Chapter.

In 2009, the amount of CO_2 produced by the Mississippi and New Mexico facilities for commercial applications and subsequently emitted to the atmosphere was 1.8 Tg CO_2 Eq. (1,763 Gg) (see Table 4-41). This amount represents a decrease of one percent from the previous year and an increase of 24 percent since 1990. This increase was due to an in increase in production at the Mississippi facility, despite the decrease in the percent of the facility's total reported production that was used for commercial applications.

Table 4-41: CO_2 Emissions from CO_2 Consumption (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	1.4	1,416
2000	1.4	1,421
2005	1.3	1,321
2006	1.7	1,709
2007	1.9	1,867
2008	1.8	1,780
2009	1.8	1,763

Methodology

CO_2 emission estimates for 1990 through 2009 were based on production data for the two facilities currently producing CO_2 from naturally-occurring CO_2 reservoirs for use in non-EOR applications. Some of the CO_2 produced by these facilities is used for EOR and some is used in other commercial applications (e.g., chemical manufacturing, food production). It is assumed that 100 percent of the CO_2 production used in commercial applications other than EOR is eventually released into the atmosphere.

CO_2 production data for the Jackson Dome, Mississippi facility and the percentage of total production that was used for EOR and in non-EOR applications were obtained from the Advanced Resources Institute (ARI 2006, 2007) for 1990 to 2000 and from the Annual Reports for Denbury Resources (Denbury Resources 2002 through 2010) for 2001 to 2009 (see Table 4-42). Denbury Resources reported the average CO_2 production in units of MMCF CO_2 per day for 2001 through 2009 and reported the percentage of the total average annual production that was used for EOR. CO_2 production data for the Bravo Dome, New Mexico facility were obtained from the Advanced Resources International, Inc. (ARI 1990 through 2010). The percentage of total production that was used for EOR and in non-EOR applications were obtained from the New Mexico Bureau of Geology and Mineral Resources (Broadhead 2003 and New Mexico Bureau of Geology and Mineral Resources 2006).

Table 4-42: CO_2 Production (Gg CO_2) and the Percent Used for Non-EOR Applications for Jackson Dome and

[114] There are currently four known electric power plants operating in the U.S. that capture CO_2 for use as food-grade CO_2 or other industrial processes; however, insufficient data prevents estimating emissions from these activities as part of Carbon Dioxide Consumption.

Bravo Dome

Year	Jackson Dome CO_2 Production (Gg)	Jackson Dome % Used for Non-EOR	Bravo Dome CO_2 Production (Gg)	Bravo Dome % Used for Non-EOR
1990	1,353	100%	6,301	1%
2000	1,353	100%	6,834	1%
2005	4,678	27%	5,799	1%
2006	6,610	25%	5,613	1%
2007	9,529	19%	5,605	1%
2008	12,312	14%	5,605	1%
2009	13,201	13%	4,639	1%

Uncertainty and Time-Series Consistency

Uncertainty is associated with the number of facilities that are currently producing CO_2 from naturally occurring CO_2 reservoirs for commercial uses other than EOR, and for which the CO_2 emissions are not accounted for elsewhere. Research indicates that there are only two such facilities, which are in New Mexico and Mississippi; however, additional facilities may exist that have not been identified. In addition, it is possible that CO_2 recovery exists in particular production and end-use sectors that are not accounted for elsewhere. Such recovery may or may not affect the overall estimate of CO_2 emissions from that sector depending upon the end use to which the recovered CO_2 is applied. Further research is required to determine whether CO_2 is being recovered from other facilities for application to end uses that are not accounted for elsewhere.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-43. CO_2 consumption CO_2 emissions were estimated to be between 1.3 and 2.3 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 26 percent below to 30 percent above the emission estimate of 1.8 Tg CO_2 Eq.

Table 4-43: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from CO_2 Consumption (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
CO_2 Consumption	CO_2	1.8	1.3	2.3	-26%	+30%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the Carbon Dioxide Consumption source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from carbon dioxide consumption. Beginning in 2010, all U.S. CO_2 producers are required to monitor, calculate and report the quantity of CO_2 supplied to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 on CO_2 supplied from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from consumption of CO_2.

4.12. Phosphoric Acid Production (IPCC Source Category 2B5)

Phosphoric acid (H_3PO_4) is a basic raw material in the production of phosphate-based fertilizers. Phosphate rock is mined in Florida, North Carolina, Idaho, Utah, and other areas of the United States and is used primarily as a raw material for phosphoric acid production. The production of phosphoric acid from phosphate rock produces byproduct gypsum ($CaSO_4$-$2H_2O$), referred to as phosphogypsum.

The composition of natural phosphate rock varies depending upon the location where it is mined. Natural phosphate

rock mined in the United States generally contains inorganic C in the form of calcium carbonate (limestone) and also may contain organic C. The chemical composition of phosphate rock (francolite) mined in Florida is:

$$Ca_{10-x-y}\ Na_x\ Mg_y\ (PO_4)_{6-x}(CO_3)_xF_{2+0.4x}$$

The calcium carbonate component of the phosphate rock is integral to the phosphate rock chemistry. Phosphate rock can also contain organic C that is physically incorporated into the mined rock but is not an integral component of the phosphate rock chemistry. Phosphoric acid production from natural phosphate rock is a source of CO_2 emissions, due to the chemical reaction of the inorganic C (calcium carbonate) component of the phosphate rock.

The phosphoric acid production process involves chemical reaction of the calcium phosphate ($Ca_3(PO_4)_2$) component of the phosphate rock with sulfuric acid (H_2SO_4) and recirculated phosphoric acid (H_3PO_4) (EFMA 2000). The primary chemical reactions for the production of phosphoric acid from phosphate rock are:

$$Ca_3(PO_4)_2 + 4H_3PO_4 \rightarrow 3Ca(H_2PO_4)_2$$

$$3Ca(H_2PO_4)_2 + 3H_2SO_4 + 6H_2O \rightarrow 3CaSO_4 \bullet 6H_2O + 6H_3PO_4$$

The limestone ($CaCO_3$) component of the phosphate rock reacts with the sulfuric acid in the phosphoric acid production process to produce calcium sulfate (phosphogypsum) and CO_2. The chemical reaction for the limestone-sulfuric acid reaction is:

$$CaCO_3 + H_2SO_4 + H_2O \rightarrow CaSO_4 \bullet 2H_2O + CO_2$$

Total marketable phosphate rock production in 2009 was 27.2 million metric tons (USGS 2010). Approximately 87 percent of domestic phosphate rock production was mined in Florida and North Carolina, while approximately 13 percent of production was mined in Idaho and Utah. Total imports of phosphate rock in 2009 were 1.8 million metric tons (USGS 2010). The vast majority, 99 percent, of imported phosphate rock is sourced from Morocco (USGS 2005). Marketable phosphate rock production, including domestic production and imports for consumption, decreased by 13.6 percent between 2008 and 2009. Over the 1990 to 2009 period, production has decreased by 34 percent. Total CO_2 emissions from phosphoric acid production were 1.0 Tg CO_2 Eq. (1,035 Gg) in 2009 (see Table 4-44). According to USGS 2010, the weak market conditions of phosphate rock in the U.S. in 2009 were a result of the global economic crisis that started in late 2008 and carried into 2009.

Table 4-44: CO_2 Emissions from Phosphoric Acid Production (Tg CO_2 Eq. and Gg)

Year	Tg CO2 Eq.	Gg
1990	1.5	1,529
2000	1.4	1,382
2005	1.4	1,386
2006	1.2	1,167
2007	1.2	1,166
2008	1.2	1,187
2009	1.0	1,035

Methodology

CO_2 emissions from production of phosphoric acid from phosphate rock are calculated by multiplying the average amount of calcium carbonate contained in the natural phosphate rock by the amount of phosphate rock that is used annually to produce phosphoric acid, accounting for domestic production and net imports for consumption.

The CO_2 emissions calculation methodology is based on the assumption that all of the inorganic C (calcium carbonate) content of the phosphate rock reacts to CO_2 in the phosphoric acid production process and is emitted with the stack gas. The methodology also assumes that none of the organic C content of the phosphate rock is converted to CO_2 and that all of the organic C content remains in the phosphoric acid product.

From 1993 to 2004, the *USGS Mineral Yearbook: Phosphate Rock* disaggregated phosphate rock mined annually in Florida and North Carolina from phosphate rock mined annually in Idaho and Utah, and reported the annual amounts of phosphate rock exported and imported for consumption (see Table 4-45). For the years 1990, 1991,

1992, 2005, 2006, and 2007 only nationally aggregated mining data was reported by USGS. For these years, the breakdown of phosphate rock mined in Florida and North Carolina, and the amount mined in Idaho and Utah, are approximated using 1993 to 2004 data. Data for domestic production of phosphate rock, exports of phosphate rock (primarily from Florida and North Carolina), and imports of phosphate rock for consumption for 1990 through 2008 were obtained from *USGS Minerals Yearbook: Phosphate Rock* (USGS 1994 through 2010). 2009 data were obtained from *USGS Minerals Commodity Summary: Phosphate Rock* (USGS 2010). From 2004 through 2009, the USGS reported no exports of phosphate rock from U.S. producers (USGS 2005 through 2010).

The carbonate content of phosphate rock varies depending upon where the material is mined. Composition data for domestically mined and imported phosphate rock were provided by the Florida Institute of Phosphate Research (FIPR 2003). Phosphate rock mined in Florida contains approximately 1 percent inorganic C, and phosphate rock imported from Morocco contains approximately 1.46 percent inorganic C. Calcined phosphate rock mined in North Carolina and Idaho contains approximately 0.41 percent and 0.27 percent inorganic C, respectively (see Table 4-46).

Carbonate content data for phosphate rock mined in Florida are used to calculate the CO_2 emissions from consumption of phosphate rock mined in Florida and North Carolina (87 percent of domestic production) and carbonate content data for phosphate rock mined in Morocco are used to calculate CO_2 emissions from consumption of imported phosphate rock. The CO_2 emissions calculation is based on the assumption that all of the domestic production of phosphate rock is used in uncalcined form. As of 2006, the USGS noted that one phosphate rock producer in Idaho produces calcined phosphate rock; however, no production data were available for this single producer (USGS 2006). Carbonate content data for uncalcined phosphate rock mined in Idaho and Utah (13 percent of domestic production) were not available, and carbonate content was therefore estimated from the carbonate content data for calcined phosphate rock mined in Idaho.

Table 4-45: Phosphate Rock Domestic Production, Exports, and Imports (Gg)

Location/Year	1990	2000	2005	2006	2007	2008	2009
U.S. Production[a]	49,800	37,370	36,100	30,100	29,700	30,200	27,200
FL & NC	42,494	31,900	31,227	26,037	25,691	26,123	23,528
ID & UT	7,306	5,470	4,874	4,064	4,010	4,077	3,672
Exports—FL & NC	6,240	299	-	-	-	-	-
Imports—Morocco	451	1,930	2,630	2,420	2,670	2,754	1,800
Total U.S. Consumption	**44,011**	**39,001**	**38,730**	**32,520**	**32,370**	**32,954**	**29,000**

[a] USGS does not disaggregate production data regionally (FL & NC and ID & UT) for 1990, 2005, 2006, and 2007. Data for those years are estimated based on the remaining time series distribution.
- Assumed equal to zero.

Table 4-46: Chemical Composition of Phosphate Rock (percent by weight)

Composition	Central Florida	North Florida	North Carolina (calcined)	Idaho (calcined)	Morocco
Total Carbon (as C)	1.60	1.76	0.76	0.60	1.56
Inorganic Carbon (as C)	1.00	0.93	0.41	0.27	1.46
Organic Carbon (as C)	0.60	0.83	0.35	-	0.10
Inorganic Carbon (as CO_2)	3.67	3.43	1.50	1.00	5.00

Source: FIPR 2003
- Assumed equal to zero.

Uncertainty and Time-Series Consistency

Phosphate rock production data used in the emission calculations were developed by the USGS through monthly and semiannual voluntary surveys of the active phosphate rock mines during 2009. For previous years in the time series, USGS provided the data disaggregated regionally; however, beginning in 2006 only total U.S. phosphate rock production were reported. Regional production for 2008 was estimated based on regional production data from previous years and multiplied by regionally-specific emission factors. There is uncertainty associated with the degree to which the estimated 2008 regional production data represents actual production in those regions. Total U.S. phosphate rock production data are not considered to be a significant source of uncertainty because all the domestic phosphate rock producers report their annual production to the USGS. Data for exports of phosphate rock

used in the emission calculation are reported by phosphate rock producers and are not considered to be a significant source of uncertainty. Data for imports for consumption are based on international trade data collected by the U.S. Census Bureau. These U.S. government economic data are not considered to be a significant source of uncertainty.

An additional source of uncertainty in the calculation of CO_2 emissions from phosphoric acid production is the carbonate composition of phosphate rock; the composition of phosphate rock varies depending upon where the material is mined, and may also vary over time. Another source of uncertainty is the disposition of the organic C content of the phosphate rock. A representative of the FIPR indicated that in the phosphoric acid production process, the organic C content of the mined phosphate rock generally remains in the phosphoric acid product, which is what produces the color of the phosphoric acid product (FIPR 2003a). Organic C is therefore not included in the calculation of CO_2 emissions from phosphoric acid production.

A third source of uncertainty is the assumption that all domestically-produced phosphate rock is used in phosphoric acid production and used without first being calcined. Calcination of the phosphate rock would result in conversion of some of the organic C in the phosphate rock into CO_2. However, according to the USGS, only one producer in Idaho is currently calcining phosphate rock, and no data were available concerning the annual production of this single producer (USGS 2005). For available years, total production of phosphate rock in Utah and Idaho combined amounts to approximately 13 percent of total domestic production on average (USGS 1994 through 2005).

Finally, USGS indicated that approximately 7 percent of domestically-produced phosphate rock is used to manufacture elemental phosphorus and other phosphorus-based chemicals, rather than phosphoric acid (USGS 2006). According to USGS, there is only one domestic producer of elemental phosphorus, in Idaho, and no data were available concerning the annual production of this single producer. Elemental phosphorus is produced by reducing phosphate rock with coal coke, and it is therefore assumed that 100 percent of the carbonate content of the phosphate rock will be converted to CO_2 in the elemental phosphorus production process. The calculation for CO_2 emissions is based on the assumption that phosphate rock consumption, for purposes other than phosphoric acid production, results in CO_2 emissions from 100 percent of the inorganic C content in phosphate rock, but none from the organic C content.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-47. Phosphoric acid production CO_2 emissions were estimated to be between 0.9 and 1.2 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 18 percent below and 19 percent above the emission estimate of 1.0 Tg CO_2 Eq.

Table 4-47: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Phosphoric Acid Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Phosphoric Acid Production	CO_2	1.0	0.9	1.2	-18%	+19%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the phosphoric acid production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from phosphoric acid production. Beginning in 2010, all U.S. phosphoric acid producers are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from facilities based on use of higher tier methods and assess how this data could be used to improve the method for calculating emissions from the U.S. phosphoric acid production industry. Currently, data sources for the carbonate content of the phosphate rock are limited. If additional data sources are found, this information will be incorporated into future estimates. Additionally, as future improvement to the phosphoric acid uncertainty analysis, USGS Mineral Commodity Specialists will be contacted to verify uncertainty ranges associated with phosphate rock

imports and exports.

4.13. Iron and Steel Production (IPCC Source Category 2C1) and Metallurgical Coke Production

The production of iron and steel is an energy-intensive activity that also generates process-related emissions of CO_2 and CH_4. Process emissions occur at each step of steel production from the production of raw materials to the refinement of iron to the making of crude steel. In the United States, steel is produced through both primary and secondary processes. Historically, primary production—using a basic oxygen furnace (BOF) with pig iron as the primary feedstock—has been the dominant method. But secondary production through the use scrap steel and electric arc furnaces (EAFs) has increased significantly in recent years due to the economic advantages of steel recycling, which has been driven by the increased availability of scrap steel. Total production of crude steel in the United States in the time period between 2001 and 2008 ranged from a low of 99,321,000 tons to a high of 109,879,000 tons (2001 and 2004, respectively). But due to the decrease in demand caused by the global economic downturn, crude steel production in the United States decreased to 65,460,000 tons in 2009 (AISI 2010).

Metallurgical coke is an important input in the production of iron and steel. Coke is used to produce iron or pig iron feedstock from raw iron ore. The production of metallurgical coke from coking coal occurs both on-site at "integrated" iron and steel plants and off-site at "merchant" coke plants. Metallurgical coke is produced by heating coking coal in a coke oven in a low-oxygen environment. The process drives off the volatile components of the coking coal and produces coal (metallurgical) coke. Carbon containing byproducts of the metallurgical coke manufacturing process include coke oven gas, coal tar, coke breeze (small-grade coke oven coke with particle size <5mm) and light oil. Coke oven gas is recovered and used for underfiring the coke ovens and within the iron and steel mill. Small amounts of coke oven gas are also sold as synthetic natural gas outside of iron and steel mills (and are accounted for in the Energy chapter). Coal tar is used as a raw material to produce anodes used for primary aluminum production, electric arc furnace (EAF) steel production, and other electrolytic processes, and also is used in the production of other coal tar products. Light oil is sold to petroleum refiners who use the material as an additive for gasoline. The metallurgical coke production process produces CO_2 emissions and fugitive CH_4 emissions.

Iron is produced by first reducing iron oxide (iron ore) with metallurgical coke in a blast furnace. Iron can be introduced into the blast furnace in the form of raw iron ore, taconite pellets (9-16mm iron-containing spheres), briquettes, or sinter. In addition to metallurgical coke and iron, other inputs to the blast furnace include natural gas, fuel oil, and coke oven gas. The carbon in the metallurgical coke used in the blast furnace combines with oxides in the iron ore in a reducing atmosphere to produce blast furnace gas containing carbon monoxide (CO) and CO_2. The CO is then converted and emitted as CO_2 when combusted to either pre-heat the blast air used in the blast furnace or for other purposes at the steel mill. This pig iron or crude iron that is produced from this process contains about 3 to 5 percent carbon by weight. The pig iron production process in a blast furnace produces CO_2 emissions and fugitive CH_4 emissions.

Iron can also be produced through the direct reduction process; wherein, iron ore is reduced to metallic iron in the solid state at process temperatures less than 1000°C. Direct reduced iron production results in process emissions of CO_2 and emissions of CH_4 through the consumption of natural gas used during the reduction process.

Sintering is a thermal process by which fine iron-bearing particles, such as air emission control system dust, are baked, which causes the material to agglomerate into roughly one-inch pellets that are then recharged into the blast furnace for pig iron production. Iron ore particles may also be formed into larger pellets or briquettes by mechanical means, and then agglomerated by heating. The agglomerate is then crushed and screened to produce an iron-bearing feed that is charged into the blast furnace. The sintering process produces CO_2 and fugitive CH_4 emissions through the consumption of carbonaceous inputs (e.g., coke breeze) during the sintering process.

Steel is produced from varying levels of pig iron and scrap steel in specialized BOF and EAF steel-making furnaces. Carbon inputs to BOF steel-making furnaces include pig iron and scrap steel as well as natural gas, fuel oil, and fluxes (e.g., limestone, dolomite). In a BOF, the carbon in iron and scrap steel combines with high-purity oxygen to reduce the carbon content of the metal to the amount desired for the specified grade of steel. EAFs use carbon electrodes, charge carbon and other materials (e.g., natural gas) to aid in melting metal inputs (primarily recycled scrap steel), which are refined and alloyed to produce the desired grade of steel. CO_2 emissions occur in BOFs through the reduction process. In EAFs, CO_2 emissions result primarily from the consumption of carbon electrodes

and also from the consumption of supplemental materials used to augment the melting process.

In addition to the production processes mentioned above, CO_2 is also generated at iron and steel mills through the consumption of process by-products (e.g., blast furnace gas, coke oven gas) used for various purposes including heating, annealing, and electricity generation. Process by-products sold for use as synthetic natural gas are deducted and reported in the Energy chapter (emissions associated with natural gas and fuel oil consumption for these purposes are reported in the Energy chapter).

The majority of CO_2 emissions from the iron and steel production process come from the use of metallurgical coke in the production of pig iron and from the consumption of other process by-products at the iron and steel mill, with lesser amounts emitted from the use of flux and from the removal of carbon from pig iron used to produce steel. Some carbon is also stored in the finished iron and steel products.

According to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006), the production of metallurgical coke from coking coal is considered to be an energy use of fossil fuel and the use of coke in iron and steel production is considered to be an industrial process source. Therefore, the Guidelines suggest that emissions from the production of metallurgical coke should be reported separately in the Energy source, while emissions from coke consumption in iron and steel production should be reported in the industrial process source. However, the approaches and emission estimates for both metallurgical coke production and iron and steel production are both presented here because the activity data used to estimate emissions from metallurgical coke production have significant overlap with activity data used to estimate iron and steel production emissions. Further, some by-products (e.g., coke oven gas) of the metallurgical coke production process are consumed during iron and steel production, and some by-products of the iron and steel production process (e.g., blast furnace gas) are consumed during metallurgical coke production. Emissions associated with the consumption of these by-products are attributed to point of consumption. As an example, CO_2 emissions associated with the combustion of coke oven gas in the blast furnace during pig iron production are attributed to pig iron production. Emissions associated with the use of conventional fuels (e.g., natural gas and fuel oil) for electricity generation, heating and annealing, or other miscellaneous purposes downstream of the iron and steelmaking furnaces are reported in the Energy chapter.

Metallurgical Coke Production

Emissions of CO_2 and CH_4 from metallurgical coke production in 2009 were 1.0 Tg CO_2 Eq. (956 Gg) and less than 0.002 Tg CO_2 Eq. (less than 0.00003 Gg), respectively (see Table 4-48 and Table 4-49), totaling 1.0 Tg CO_2 Eq. Emissions decreased in 2009, and have decreased overall since 1990. In 2009, domestic coke production decreased by 29 percent and has decreased overall since 1990. Coke production in 2009 was 46 percent lower than in 2000 and 60 percent below 1990. Overall, emissions from metallurgical coke production have declined by 61 percent (1.5 Tg CO_2 Eq.) from 1990 to 2009.

Table 4-48: CO_2 and CH_4 Emissions from Metallurgical Coke Production (Tg CO_2 Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
CO_2	2.5	2.2	2.0	1.9	2.1	2.3	1.0
CH_4	+	+	+	+	+	+	+
Total	**2.5**	**2.2**	**2.0**	**1.9**	**2.1**	**2.3**	**1.0**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 4-49: CO_2 and CH_4 Emissions from Metallurgical Coke Production (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
CO_2	2,470	2,195	2,043	1,919	2,054	2,334	956
CH_4	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg

Iron and Steel Production

Emissions of CO_2 and CH_4 from iron and steel production in 2009 were 40.9 Tg CO_2 Eq. (40,914 Gg) and 0.4 Tg CO_2 Eq. (17.4 Gg), respectively (see Table 4-50 through Table 4-53), totaling approximately 41 Tg CO_2 Eq. Emissions decreased in 2009—largely due to decreased steel production associated with the global economic downturn—and have decreased overall since 1990 due to restructuring of the industry, technological improvements, and increased scrap steel utilization. CO_2 emission estimates include emissions from the consumption of

carbonaceous materials in the blast furnace, EAF, and BOF as well as blast furnace gas and coke oven gas consumption for other activities at the steel mill.

In 2009, domestic production of pig iron decreased by 44 percent. Overall, domestic pig iron production has declined since the 1990s. Pig iron production in 2009 was 60 percent lower than in 2000 and 62 percent below 1990. CO_2 emissions from steel production have declined by 15 percent (1.1 Tg CO_2 Eq.) since 1990, while overall CO_2 emissions from iron and steel production have declined by 58 percent (56.1 Tg CO_2 Eq.) from 1990 to 2009.

Table 4-50: CO_2 Emissions from Iron and Steel Production (Tg CO_2 Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
Sinter Production	2.4	2.2	1.7	1.4	1.4	1.3	0.8
Iron Production	47.9	33.8	19.6	23.9	27.3	25.7	15.9
Steel Production	7.5	7.9	8.5	8.9	9.4	7.5	6.4
Other Activities[a]	39.3	39.9	34.2	32.6	31.0	29.1	17.8
Total	**97.1**	**83.7**	**63.9**	**66.9**	**69.0**	**63.7**	**40.9**

Note: Totals may not sum due to independent rounding.
[a] Includes emissions from blast furnace gas and coke oven gas combustion for activities at the steel mill other than consumption in blast furnace, EAFs, or BOFs.

Table 4-51: CO_2 Emissions from Iron and Steel Production (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
Sinter Production	2,448	2,158	1,663	1,418	1,383	1,299	763
Iron Production	47,880	33,818	19,570	23,928	27,262	25,696	15,948
Steel Production	7,475	7,887	8,489	8,924	9,382	7,541	6,389
Other Activities [a]	39,256	39,877	34,160	32,583	30,964	29,146	17,815
Total	**97,058**	**83,740**	**63,882**	**66,852**	**68,991**	**63,682**	**40,914**

Note: Totals may not sum due to independent rounding.
[a] Includes emissions from blast furnace gas and coke oven gas combustion for activities at the steel mill other than consumption in blast furnace, EAFs, or BOFs.

Table 4-52: CH_4 Emissions from Iron and Steel Production (Tg CO_2 Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
Sinter Production	+	+	+	+	+	+	+
Iron Production	0.9	0.9	0.7	0.7	0.7	0.6	0.4
Total	**1.0**	**0.9**	**0.7**	**0.7**	**0.7**	**0.6**	**0.4**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 4-53: CH_4 Emissions from Iron and Steel Production (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
Sinter Production	0.9	0.7	0.6	0.5	0.5	0.4	0.3
Iron Production	44.7	43.1	33.5	34.1	32.7	30.4	17.1
Total	**45.6**	**43.8**	**34.1**	**34.6**	**33.2**	**30.8**	**17.4**

Note: Totals may not sum due to independent rounding.

Methodology

Emission estimates presented in this chapter are based on the methodologies provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006), which call for a mass balance accounting of the carbonaceous inputs and outputs during the iron and steel production process and the metallurgical coke production process.

Metallurgical Coke Production

Coking coal is used to manufacture metallurgical (coal) coke that is used primarily as a reducing agent in the production of iron and steel, but is also used in the production of other metals including lead and zinc (see Lead

Production and Zinc Production in this chapter). Emissions associated with producing metallurgical coke from coking coal are estimated and reported separately from emissions that result from the iron and steel production process. To estimate emission from metallurgical coke production, a Tier 2 method provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) was utilized. The amount of carbon contained in materials produced during the metallurgical coke production process (i.e., coke, coke breeze, coke oven gas, and coal tar) is deducted from the amount of carbon contained in materials consumed during the metallurgical coke production process (i.e., natural gas, blast furnace gas, coking coal). Light oil, which is produced during the metallurgical coke production process, is excluded from the deductions due to data limitations. The amount of carbon contained in these materials is calculated by multiplying the material-specific carbon content by the amount of material consumed or produced (see Table 4-54). The amount of coal tar produced was approximated using a production factor of 0.03 tons of coal tar per ton of coking coal consumed. The amount of coke breeze produced was approximated using a production factor of 0.075 tons of coke breeze per ton of coking coal consumed. Data on the consumption of carbonaceous materials (other than coking coal) as well as coke oven gas production were available for integrated steel mills only (i.e., steel mills with co-located coke plants). Therefore, carbonaceous material (other than coking coal) consumption and coke oven gas production were excluded from emission estimates for merchant coke plants. Carbon contained in coke oven gas used for coke-oven underfiring was not included in the deductions to avoid double-counting.

Table 4-54: Material Carbon Contents for Metallurgical Coke Production

Material	kg C/kg
Coal Tar	0.62
Coke	0.83
Coke Breeze	0.83
Coking Coal	0.73
Material	**kg C/GJ**
Coke Oven Gas	12.1
Blast Furnace Gas	70.8

Source: IPCC 2006, Table 4.3. Coke Oven Gas and Blast Furnace Gas, Table 1.3.

The production processes for metallurgical coke production results in fugitive emissions of CH_4, which are emitted via leaks in the production equipment rather than through the emission stacks or vents of the production plants. The fugitive emissions were calculated by applying Tier 1 emission factors (0.1 g CH_4 per metric ton) taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) for metallurgical coke production.

Data relating to the mass of coking coal consumed at metallurgical coke plants and the mass of metallurgical coke produced at coke plants were taken from the Energy Information Administration (EIA), Quarterly Coal Report October through December (EIA 1998 through 2004) and January through March (EIA 2010a) (see Table 4-55). Data on the volume of natural gas consumption, blast furnace gas consumption, and coke oven gas production for metallurgical coke production at integrated steel mills were obtained from the American Iron and Steel Institute (AISI), *Annual Statistical Report* (AISI 2004 through 20010) and through personal communications with AISI (2008b) (see Table 4-56). The factor for the quantity of coal tar produced per ton of coking coal consumed was provided by AISI (2008b). The factor for the quantity of coke breeze produced per ton of coking coal consumed was obtained through Table 2-1 of the report *Energy and Environmental Profile of the U.S. Iron and Steel Industry* (DOE 2000). Data on natural gas consumption and coke oven gas production at merchant coke plants were not available and were excluded from the emission estimate. Carbon contents for coking coal, metallurgical coke, coal tar, coke oven gas, and blast furnace gas were provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The C content for coke breeze was assumed to equal the C content of coke.

Table 4-55: Production and Consumption Data for the Calculation of CO_2 and CH_4 Emissions from Metallurgical Coke Production (Thousand Metric Tons)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Metallurgical Coke Production							
Coking Coal Consumption at Coke Plants	35,269	26,254	21,259	20,827	20,607	20,022	13,904
Coke Production at Coke Plants	25,054	18,877	15,167	14,882	14,698	14,194	10,109
Coal Breeze Production	2,645	1,969	1,594	1,562	1,546	1,502	1,043
Coal Tar Production	1,058	788	638	625	618	601	417

Table 4-56: Production and Consumption Data for the Calculation of CO_2 Emissions from Metallurgical Coke Production (million ft^3)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Metallurgical Coke Production							
Coke Oven Gas Production[a]	250,767	149,477	114,213	114,386	109,912	103,191	66,155
Natural Gas Consumption	599	180	2,996	3,277	3,309	3,134	2,121
Blast Furnace Gas Consumption	24,602	26,075	4,460	5,505	5,144	4,829	2,435

[a] Includes coke oven gas used for purposes other than coke oven underfiring only.

Iron and Steel Production

Emissions of CO_2 from sinter production and direct reduced iron production were estimated by multiplying total national sinter production and the total national direct reduced iron production by Tier 1 CO_2 emission factors (see Table 4-57). Because estimates of sinter production and direct reduced iron production were not available, production was assumed to equal consumption.

Table 4-57: CO_2 Emission Factors for Sinter Production and Direct Reduced Iron Production

Material Produced	Metric Ton CO_2/Metric Ton
Sinter	0.2
Direct Reduced Iron	0.7

Source: IPCC 2006, Table 4.1.

To estimate emissions from pig iron production in the blast furnace, the amount of C contained in the produced pig iron and blast furnace gas were deducted from the amount of C contained in inputs (i.e., metallurgical coke, sinter, natural ore, pellets, natural gas, fuel oil, coke oven gas, direct coal injection). The C contained in the pig iron, blast furnace gas, and blast furnace inputs was estimated by multiplying the material-specific carbon content by each material type (see Table 4-58). Carbon in blast furnace gas used to pre-heat the blast furnace air is combusted to form CO_2 during this process.

Emissions from steel production in EAFs were estimated by deducting the C contained in the steel produced from the carbon contained in the EAF anode, charge carbon, and scrap steel added to the EAF. Small amounts of C from direct reduced iron, pig iron, and flux additions to the EAFs were also included in the EAF calculation. For BOFs, estimates of C contained in BOF steel were deducted from carbon contained in inputs such as natural gas, coke oven gas, fluxes, and pig iron. In each case, the C was calculated by multiplying material-specific carbon contents by each material type (see Table 4-58). For EAFs, the amount of EAF anode consumed was approximated by multiplying total EAF steel production by the amount of EAF anode consumed per metric ton of steel produced (0.002 metric tons EAF anode per metric ton steel produced (AISI 2008b)). The amount of flux (e.g., limestone and dolomite) used during steel manufacture was deducted from the Limestone and Dolomite Use source category to avoid double-counting.

CO_2 emissions from the consumption of blast furnace gas and coke oven gas for other activities occurring at the steel mill were estimated by multiplying the amount of these materials consumed for these purposes by the material-specific C content (see Table 4-58).

CO_2 emissions associated with the sinter production, direct reduced iron production, pig iron production, steel production, and other steel mill activities were summed to calculate the total CO_2 emissions from iron and steel production (see Table 4-50and Table 4-51).

Table 4-58: Material Carbon Contents for Iron and Steel Production

Material	kg C/kg
Coke	0.83
Direct Reduced Iron	0.02
Dolomite	0.13
EAF Carbon Electrodes	0.82
EAF Charge Carbon	0.83
Limestone	0.12
Pig Iron	0.04

Steel	0.01
Material	**kg C/GJ**
Coke Oven Gas	12.1
Blast Furnace Gas	70.8

Source: IPCC 2006, Table 4.3. Coke Oven Gas and Blast Furnace Gas, Table 1.3.

The production processes for sinter and pig iron result in fugitive emissions of CH_4, which are emitted via leaks in the production equipment rather than through the emission stacks or vents of the production plants. The fugitive emissions were calculated by applying Tier 1 emission factors taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) for sinter production and the 1995 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1995) (see Table 4-59) for pig iron production. The production of direct reduced iron also results in emissions of CH_4 through the consumption of fossil fuels (e.g., natural gas); however, these emissions estimates are excluded due to data limitations.

Table 4-59: CH_4 Emission Factors for Sinter and Pig Iron Production

Material Produced	Factor	Unit
Pig Iron	0.9	g CH_4/kg
Sinter	0.07	kg CH_4/metric ton

Source: Sinter (IPCC 2006, Table 4.2), Pig Iron (IPCC/UNEP/OECD/IEA 1995, Table 2.2)

Sinter consumption and direct reduced iron consumption data were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b) (see Table 4-60). Data on direct reduced iron consumed in EAFs were not available for the years 1990, 1991, 1999, 2006, 2007, 2008, and 2009. EAF direct reduced iron consumption in 1990 and 1991 were assumed to equal consumption in 1992, and consumption in 1999 was assumed to equal the average of 1998 and 2000. EAF consumption in 2006, 2007, 2008, and 2009 were calculated by multiplying the total DRI consumption for all furnaces as provided in the 2009 AISI Annual Statistical Report by the EAF share of total DRI consumption in 2005 (the most recent year that data was available for EAF vs. BOF consumption of DRI). Data on direct reduced iron consumed in BOFs were not available for the years 1990 through 1994, 1999, 2006, 2007, 2008, and 2009. BOF direct reduced iron consumption in 1990 through 1994 was assumed to equal consumption in 1995, and consumption in 1999 was assumed to equal the average of 1998 and 2000. BOF consumption in 2006, 2007, and 2008 were calculated by multiplying the total DRI consumption for all furnaces as provided in the 2009 AISI Annual Statistical Report by the BOF share of total DRI consumption in 2005 (the most recent year that data was available for EAF vs. BOF consumption of DRI). The Tier 1 CO_2 emission factors for sinter production and direct reduced iron production were obtained through the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). Data for pig iron production, coke, natural gas, fuel oil, sinter, and pellets consumed in the blast furnace; pig iron production; and blast furnace gas produced at the iron and steel mill and used in the metallurgical coke ovens and other steel mill activities were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b) (see Table 4-61). Data for EAF steel production, flux, EAF charge carbon, direct reduced iron, pig iron, scrap steel, and natural gas consumption as well as EAF steel production were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2011). The factor for the quantity of EAF anode consumed per ton of EAF steel produced was provided by AISI (AISI 2008b). Data for BOF steel production, flux, direct reduced iron, pig iron, scrap steel, natural gas, natural ore, pellet sinter consumption as well as BOF steel production were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b). Because data on pig iron consumption and scrap steel consumption in BOFs and EAFs were not available for 2006, 2007, and 2009, values for these years were calculated by multiplying the total pig iron and scrap steel consumption for all furnaces as provided in the 2009 AISI Annual Statistical Report by the BOF and EAF shares of total pig iron and scrap consumption in 2005 (the most recent year that data was available for EAF vs. BOF consumption of pig iron and scrap steel). Because pig iron consumption in EAFs was also not available in 2003 and 2004, the average of 2002 and 2005 pig iron consumption data were used. Data on coke oven gas and blast furnace gas consumed at the iron and steel mill other than in the EAF, BOF, or blast furnace were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b). Data on blast furnace gas and coke oven gas sold for use as synthetic natural gas were obtained through EIA's *Natural Gas Annual 2009* (EIA 2010b). C contents for direct reduced iron, EAF carbon electrodes, EAF charge carbon, limestone, dolomite, pig iron, and steel were provided by

the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The C contents for natural gas, fuel oil, and direct injection coal as well as the heat contents for the same fuels were provided by EIA (1992, 2010c). Heat contents for coke oven gas and blast furnace gas were provided in Table 2-2 of the report *Energy and Environmental Profile of the U.S. Iron and Steel Industry* (DOE 2000).

Table 4-60: Production and Consumption Data for the Calculation of CO_2 and CH_4 Emissions from Iron and Steel Production (Thousand Metric Tons)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Sinter Production							
Sinter Production	12,239	10,788	8,315	7,088	6,914	6,497	3,814
Direct Reduced Iron Production							
Direct Reduced Iron Production	936	1,914	1,633	1,497	2,087	1,769	1,243
Pig Iron Production							
Coke Consumption	24,946	19,215	13,832	14,684	15,039	14,251	8,572
Pig Iron Production	49,669	47,888	37,222	37,904	36,337	33,730	19,019
Direct Injection Coal Consumption	1,485	3,012	2,573	2,526	2,734	2,578	1,674
EAF Steel Production							
EAF Anode and Charge Carbon Consumption	67	96	1,127	1,245	1,214	1,109	845
Scrap Steel Consumption	35,743	43,001	37,558	38,033	40,845	40,824	35,472
Flux Consumption	319	654	695	671	567	680	476
EAF Steel Production	33,511	47,860	52,194	56,071	57,004	52,791	36,700
BOF Steel Production							
Pig Iron Consumption	46,564	46,993	32,115	32,638	33,773	29,322	23,134
Scrap Steel Consumption	14,548	14,969	11,612	11,759	12,628	8,029	6,641
Flux Consumption	576	978	582	610	408	431	318
BOF Steel Production	43,973	53,965	42,705	42,119	41,099	39,105	22,659

Table 4-61: Production and Consumption Data for the Calculation of CO_2 Emissions from Iron and Steel Production (million ft^3 unless otherwise specified)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Pig Iron Production							
Natural Gas Consumption	56,273	91,798	59,844	58,344	56,112	53,349	35,933
Fuel Oil Consumption (thousand gallons)	163,397	120,921	16,170	87,702	84,498	55,552	23,179
Coke Oven Gas Consumption	22,033	13,702	16,557	16,649	16,239	15,336	9,951
Blast Furnace Gas Production	1,439,380	1,524,891	1,299,980	1,236,526	1,173,588	1,104,674	672,486
EAF Steel Production							
Natural Gas Consumption	9,604	13,717	14,959	16,070	16,337	15,130	10,518
BOF Steel Production							
Natural Gas Consumption	6,301	6,143	5,026	5,827	11,740	-4,304[a]	-2,670[a]
Coke Oven Gas Consumption	3,851	640	524	559	525	528	373
Other Activities							
Coke Oven Gas Consumption	224,883	135,135	97,132	97,178	93,148	87,327	55,831
Blast Furnace Gas Consumption	1,414,778	1,498,816	1,295,520	1,231,021	1,168,444	1,099,845	670,051

[a] EPA is continuing to work with AISI to investigate why this value is negative.

Uncertainty and Time-Series Consistency

The estimates of CO_2 and CH_4 emissions from metallurgical coke production are based on material production and consumption data and average carbon contents. Uncertainty is associated with the total U.S. coking coal consumption, total U.S. coke production and materials consumed during this process. Data for coking coal consumption and metallurgical coke production are from different data sources (EIA) than data for other carbonaceous materials consumed at coke plants (AISI), which does not include data for merchant coke plants. There is uncertainty associated with the fact that coal tar and coke breeze production were estimated based on coke production because coal tar and coke breeze production data were not available. Since merchant coke plant data is not included in the estimate of other carbonaceous materials consumed at coke plants, the mass balance equation for CO_2 from metallurgical coke production cannot be reasonably completed. Therefore, for the purpose of this analysis, uncertainty parameters are applied to primary data inputs to the calculation (i.e, coking coal consumption and metallurgical coke production) only.

The estimates of CO_2 emissions from iron and steel production are based on material production and consumption data and average C contents. There is uncertainty associated with the assumption that direct reduced iron and sinter consumption are equal to production. There is uncertainty associated with the assumption that all coal used for purposes other than coking coal is for direct injection coal. Some of this coal may be used for electricity generation. There is also uncertainty associated with the C contents for pellets, sinter, and natural ore, which are assumed to equal the C contents of direct reduced iron. For EAF steel production there is uncertainty associated with the amount of EAF anode and charge C consumed due to inconsistent data throughout the time series. Uncertainty is also associated with the use of process gases such as blast furnace gas and coke oven gas. Data are not available to differentiate between the use of these gases for processes at the steel mill versus for energy generation (e.g., electricity and steam generation); therefore, all consumption is attributed to iron and steel production. These data and C contents produce a relatively accurate estimate of CO_2 emissions. However, there are uncertainties associated with each.

For the purposes of the CH_4 calculation from iron and steel production it is assumed that all of the CH_4 escapes as fugitive emissions and that none of the CH_4 is captured in stacks or vents. Additionally, the CO_2 emissions calculation is not corrected by subtracting the C content of the CH_4, which means there may be a slight double counting of C as both CO_2 and CH_4.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-62 for metallurgical coke production and iron and steel production. Total CO_2 emissions from metallurgical coke production and iron and steel production were estimated to be between 35.2 and 48.4 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 16 percent below and 16 percent above the emission estimate of 41.9 Tg CO_2 Eq. Total CH_4 emissions from metallurgical coke production and iron and steel production were estimated to be 0.4 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 21 percent below and 23 percent above the emission estimate of 0.4 Tg CO_2 Eq.

Table 4-62: Tier 2 Quantitative Uncertainty Estimates for CO_2 and CH_4 Emissions from Iron and Steel Production and Metallurgical Coke Production (Tg. CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Metallurgical Coke & Iron and Steel Production	CO_2	41.9	35.2	48.4	-16%	+16%
Metallurgical Coke & Iron and Steel Production	CH_4	0.4	0.3	0.4	-21%	+23%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the Iron and Steel production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from iron and steel production. Beginning in 2010, all U.S. iron and steel producing facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the method for calculating emissions from the U.S. iron and steel industry. Specifically, plans include attributing emissions estimates for the production of metallurgical coke to the Energy chapter as well as identifying the amount of carbonaceous materials, other than coking coal, consumed at merchant coke plants. Additional improvements include identifying the amount of coal used for direct injection and the amount of coke breeze, coal tar, and light oil produced during coke production. Efforts will also be made to identify inputs for preparing Tier 2 estimates for sinter and direct reduced iron production, as well as identifying information to better characterize emissions from the use of process gases and fuels within the Energy and Industrial Processes chapters.

Recalculations Discussion

In the previous Inventory, coal tar production and coke breeze production were incorrectly estimated by multiplying the respective production factors by U.S. coke production at coke plants rather than U.S. coking coal consumption at coke plants (to which the coal tar and coke breeze production factors should be applied). This issue has been corrected and decreased the 1990 through 2008 emissions from metallurgical coke production by an average of 53 percent per year relative to the previous Inventory. The total 1990 through 2008 emissions for metallurgical coke and iron and steel production decreased by an average of 3 percent per year relative to the previous Inventory.

4.14. Ferroalloy Production (IPCC Source Category 2C2)

CO_2 and CH_4 are emitted from the production of several ferroalloys. Ferroalloys are composites of iron and other elements such as silicon, manganese, and chromium. When incorporated in alloy steels, ferroalloys are used to alter the material properties of the steel. Estimates from two types of ferrosilicon (25 to 55 percent and 56 to 95 percent silicon), silicon metal (about 98 percent silicon), and miscellaneous alloys (36 to 65 percent silicon) have been calculated. Emissions from the production of ferrochromium and ferromanganese are not included here because of the small number of manufacturers of these materials in the United States. Subsequently, government information disclosure rules prevent the publication of production data for these production facilities.

Similar to emissions from the production of iron and steel, CO_2 is emitted when metallurgical coke is oxidized during a high-temperature reaction with iron and the selected alloying element. Due to the strong reducing environment, CO is initially produced, and eventually oxidized to CO_2. A representative reaction equation for the production of 50 percent ferrosilicon is given below:

$$Fe_2O_3 + 2SiO_2 + 7C \rightarrow 2FeSi + 7CO$$

While most of the C contained in the process materials is released to the atmosphere as CO_2, a percentage is also released as CH_4 and other volatiles. The amount of CH_4 that is released is dependent on furnace efficiency, operation technique, and control technology.

Emissions of CO_2 from ferroalloy production in 2009 were 1.5 Tg CO_2 Eq. (1,469 Gg) (see Table 4-63 and Table 4-64), which is a 32 percent reduction since 1990. Emissions of CH_4 from ferroalloy production in 2009 were 0.01 Tg CO_2 Eq. (0.406 Gg), which is a 40 percent decrease since 1990.

Table 4-63: CO_2 and CH_4 Emissions from Ferroalloy Production (Tg CO_2 Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
CO_2	2.2	1.9	1.4	1.5	1.6	1.6	1.5
CH_4	+	+	+	+	+	+	+
Total	**2.2**	**1.9**	**1.4**	**1.5**	**1.6**	**1.6**	**1.6**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 4-64: CO_2 and CH_4 Emissions from Ferroalloy Production (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
CO_2	2,152	1,893	1,392	1,505	1,552	1,599	1,469
CH_4	1	1	+	+	+	+	+

Methodology

Emissions of CO_2 and CH_4 from ferroalloy production were calculated by multiplying annual ferroalloy production by material-specific emission factors. Emission factors taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) were applied to ferroalloy production. For ferrosilicon alloys containing 25 to 55 percent silicon and miscellaneous alloys (including primarily magnesium-ferrosilicon, but also including other silicon alloys) containing 32 to 65 percent silicon, an emission factor for 45 percent silicon was applied for CO_2 (2.5 metric tons CO_2/metric ton of alloy produced) and an emission factor for 65 percent silicon was applied for CH_4 (1 kg CH_4/metric ton of alloy produced). Additionally, for ferrosilicon alloys containing 56 to 95 percent silicon, an emission factor for 75 percent silicon ferrosilicon was applied for both CO_2 and CH_4 (4 metric tons CO_2/metric ton alloy produced and 1 kg CH_4/metric ton of alloy produced, respectively). The emission factors for silicon metal equaled 5 metric tons CO_2/metric ton metal produced and 1.2 kg CH_4/metric ton metal produced. It was assumed that 100 percent of the ferroalloy production was produced using petroleum coke using an electric arc furnace process (IPCC 2006), although some ferroalloys may have been produced with coking coal, wood, other biomass, or graphite C inputs. The amount of petroleum coke consumed in ferroalloy production was calculated assuming that the petroleum coke used is 90 percent C and 10 percent inert material.

Ferroalloy production data for 1990 through 2009 (see Table 4-65) were obtained from the USGS through personal communications with the USGS Silicon Commodity Specialist (Corathers 2011) and through the *Minerals Yearbook: Silicon Annual Report* (USGS 1991 through 2010). Because USGS does not provide estimates of silicon metal production for 2006-2009, 2005 production data are used. Until 1999, the USGS reported production of ferrosilicon containing 25 to 55 percent silicon separately from production of miscellaneous alloys containing 32 to 65 percent silicon; beginning in 1999, the USGS reported these as a single category (see Table 4-65). The composition data for petroleum coke was obtained from Onder and Bagdoyan (1993).

Table 4-65: Production of Ferroalloys (Metric Tons)

Year	Ferrosilicon 25%-55%	Ferrosilicon 56%-95%	Silicon Metal	Misc. Alloys 32-65%
1990	321,385	109,566	145,744	72,442
2000	229,000	100,000	184,000	NA
2005	123,000	86,100	148,000	NA
2006	164,000	88,700	148,000	NA
2007	180,000	90,600	148,000	NA
2008	193,000	94,000	148,000	NA
2009	123,932	104,855	148,000	NA

NA (Not Available)

Uncertainty and Time-Series Consistency

Although some ferroalloys may be produced using wood or other biomass as a C source, information and data regarding these practices were not available. Emissions from ferroalloys produced with wood or other biomass would not be counted under this source because wood-based C is of biogenic origin.[115] Even though emissions from ferroalloys produced with coking coal or graphite inputs would be counted in national trends, they may be generated with varying amounts of CO_2 per unit of ferroalloy produced. The most accurate method for these estimates would be to base calculations on the amount of reducing agent used in the process, rather than the amount of ferroalloys produced. These data, however, were not available.

[115] Emissions and sinks of biogenic carbon are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

Emissions of CH_4 from ferroalloy production will vary depending on furnace specifics, such as type, operation technique, and control technology. Higher heating temperatures and techniques such as sprinkle charging will reduce CH_4 emissions; however, specific furnace information was not available or included in the CH_4 emission estimates.

Also, annual ferroalloy production is now reported by the USGS in three broad categories: ferroalloys containing 25 to 55 percent silicon (including miscellaneous alloys), ferroalloys containing 56 to 95 percent silicon, and silicon metal. It was assumed that the IPCC emission factors apply to all of the ferroalloy production processes, including miscellaneous alloys. Finally, production data for silvery pig iron (alloys containing less than 25 percent silicon) are not reported by the USGS to avoid disclosing company proprietary data. Emissions from this production category, therefore, were not estimated.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-66. Ferroalloy production CO_2 emissions were estimated to be between 1.3 and 1.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 13 percent above the emission estimate of 1.5 Tg CO_2 Eq. Ferroalloy production CH_4 emissions were estimated to be between a range of approximately 12 percent below and 12 percent above the emission estimate of 0.01 Tg CO_2 Eq.

Table 4-66: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Ferroalloy Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Ferroalloy Production	CO_2	1.5	1.3	1.7	-12%	+13%
Ferroalloy Production	CH_4	+	+	+	-12%	+12%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
+ Does not exceed 0.05 Tg CO_2 Eq.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the ferroalloy production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from ferroalloy production. Beginning in 2010, all U.S. ferroalloy producing facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. ferroalloy industry, in particular, including emission estimates from production of ferroalloys other than ferrosilicon and silicon metal. If data are available, emissions will be estimated for those ferroalloys. Additionally, research will be conducted to determine whether data are available concerning raw material consumption (e.g., coal coke, limestone and dolomite flux, etc.) for inclusion in ferroalloy production emission estimates.

4.15. Aluminum Production (IPCC Source Category 2C3)

Aluminum is a light-weight, malleable, and corrosion-resistant metal that is used in many manufactured products, including aircraft, automobiles, bicycles, and kitchen utensils. As of last reporting, the United States was the fourth largest producer of primary aluminum, with approximately seven percent of the world total (USGS 2009a). The United States was also a major importer of primary aluminum. The production of primary aluminum—in addition to consuming large quantities of electricity—results in process-related emissions of CO_2 and two perfluorocarbons (PFCs): perfluoromethane (CF_4) and perfluoroethane (C_2F_6).

CO_2 is emitted during the aluminum smelting process when alumina (aluminum oxide, Al_2O_3) is reduced to aluminum using the Hall-Heroult reduction process. The reduction of the alumina occurs through electrolysis in a

molten bath of natural or synthetic cryolite (Na_3AlF_6). The reduction cells contain a carbon lining that serves as the cathode. Carbon is also contained in the anode, which can be a carbon mass of paste, coke briquettes, or prebaked carbon blocks from petroleum coke. During reduction, most of this carbon is oxidized and released to the atmosphere as CO_2.

Process emissions of CO_2 from aluminum production were estimated to be 3.0 Tg CO_2 Eq. (3,009 Gg) in 2009 (see Table 4-67). The carbon anodes consumed during aluminum production consist of petroleum coke and, to a minor extent, coal tar pitch. The petroleum coke portion of the total CO_2 process emissions from aluminum production is considered to be a non-energy use of petroleum coke, and is accounted for here and not under the CO_2 from Fossil Fuel Combustion source category of the Energy sector. Similarly, the coal tar pitch portion of these CO_2 process emissions is accounted for here.

Table 4-67: CO_2 Emissions from Aluminum Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	6.8	6,831
2000	6.1	6,086
2005	4.1	4,142
2006	3.8	3,801
2007	4.3	4,251
2008	4.5	4,477
2009	3.0	3,009

In addition to CO_2 emissions, the aluminum production industry is also a source of PFC emissions. During the smelting process, when the alumina ore content of the electrolytic bath falls below critical levels required for electrolysis, rapid voltage increases occur, which are termed "anode effects." These anode effects cause carbon from the anode and fluorine from the dissociated molten cryolite bath to combine, thereby producing fugitive emissions of CF_4 and C_2F_6. In general, the magnitude of emissions for a given smelter and level of production depends on the frequency and duration of these anode effects. As the frequency and duration of the anode effects increase, emissions increase.

Since 1990, emissions of CF_4 and C_2F_6 have declined by 92 percent and 89 percent, respectively, to 1.3 Tg CO_2 Eq. of CF_4 (0.20 Gg) and 0.30 Tg CO_2 Eq. of C_2F_6 (0.032 Gg) in 2009, as shown in Table 4-68 and Table 4-69. This decline is due both to reductions in domestic aluminum production and to actions taken by aluminum smelting companies to reduce the frequency and duration of anode effects. Since 1990, aluminum production has declined by 57 percent, while the combined CF_4 and C_2F_6 emission rate (per metric ton of aluminum produced) has been reduced by 80 percent.

Table 4-68: PFC Emissions from Aluminum Production (Tg CO_2 Eq.)

Year	CF_4	C_2F_6	Total
1990	15.9	2.7	18.5
2000	7.8	0.8	8.6
2005	2.5	0.4	3.0
2006	2.1	0.4	2.5
2007	3.2	0.6	3.8
2008	2.2	0.5	2.7
2009	1.3	0.3	1.6

Note: Totals may not sum due to independent rounding.

Table 4-69: PFC Emissions from Aluminum Production (Gg)

Year	CF_4	C_2F_6
1990	2.4	0.3
2000	1.2	0.1
2005	0.4	+

2006	0.3	+
2007	0.5	0.1
2008	0.3	0.1
2009	0.2	+

+ Does not exceed 0.05 Gg.

In 2009, U.S. primary aluminum production totaled approximately 1.7 million metric tons, a 35 percent decrease from 2008 production levels (USAA 2010). In 2009, six companies managed production at 13 operational primary aluminum smelters. Four smelters were closed the entire year, and demolition of one smelter that had been idle since 2000 was completed in 2009. Of the operating smelters, three were temporarily idled during some fraction of 2009, and parts of four others were temporarily closed in 2009 (USGS 2010a). During 2009, U.S. primary aluminum production was less for every month when compared to the corresponding month in 2008 (USGS 2009b, USGS 2010b).

For 2010, total production during January through September was approximately 1.28 million metric tons, compared to 1.32 million metric tons for the same period in 2009, only a 3 percent decrease (USGS 2010c). Based on the similarity in production, process CO_2 and PFC emissions are likely to be similar over this period in 2009 given no significant changes in process controls at operational facilities.

Methodology

CO_2 emissions released during aluminum production were estimated by combining individual partner reported data with process-specific emissions modeling. These estimates are based on information gathered by EPA's Voluntary Aluminum Industrial Partnership (VAIP) program.

Most of the CO_2 emissions released during aluminum production occur during the electrolysis reaction of the carbon anode, as described by the following reaction:

$$2Al_2O_3 + 3C \rightarrow 4Al + 3CO_2$$

For prebake smelter technologies, CO_2 is also emitted during the anode baking process. These emissions can account for approximately 10 percent of total process CO_2 emissions from prebake smelters.

Depending on the availability of smelter-specific data, the CO_2 emitted from electrolysis at each smelter was estimated from: (1) the smelter's annual anode consumption, (2) the smelter's annual aluminum production and rate of anode consumption (per ton of aluminum produced) for previous and /or following years, or, (3) the smelter's annual aluminum production and IPCC default CO_2 emission factors. The first approach tracks the consumption and C content of the anode, assuming that all C in the anode is converted to CO_2. Sulfur, ash, and other impurities in the anode are subtracted from the anode consumption to arrive at total C consumption. This approach corresponds to either the IPCC Tier 2 or Tier 3 method, depending on whether smelter-specific data on anode impurities are used. The second approach interpolates smelter-specific anode consumption rates to estimate emissions during years for which anode consumption data are not available. This avoids substantial errors and discontinuities that could be introduced by reverting to Tier 1 methods for those years. The last approach corresponds to the IPCC Tier 1 method (2006) and is used in the absence of present or historic anode consumption data.

The equations used to estimate CO_2 emissions in the Tier 2 and 3 methods vary depending on smelter type (IPCC 2006). For Prebake cells, the process formula accounts for various parameters, including net anode consumption, and the sulfur, ash, and impurity content of the baked anode. For anode baking emissions, the formula accounts for packing coke consumption, the sulfur and ash content of the packing coke, as well as the pitch content and weight of baked anodes produced. For Søderberg cells, the process formula accounts for the weight of paste consumed per metric ton of aluminum produced, and pitch properties, including sulfur, hydrogen, and ash content.

Through the VAIP, anode consumption (and some anode impurity) data have been reported for 1990, 2000, 2003, 2004, 2005, 2006, 2007, 2008, and 2009. Where available, smelter-specific process data reported under the VAIP were used; however, if the data were incomplete or unavailable, information was supplemented using industry average values recommended by IPCC (2006). Smelter-specific CO_2 process data were provided by 18 of the 23 operating smelters in 1990 and 2000, by 14 out of 16 operating smelters in 2003 and 2004, 14 out of 15 operating smelters in 2005, 13 out of 14 operating smelters in 2006, 5 out of 14 operating smelters in, 2007 and 2008, and 3 out of 13 operating smelters in 2009. For years where CO_2 process data were not reported by these companies, estimates were developed through linear interpolation, and/or assuming industry default values.

In the absence of any previous smelter specific process data (i.e., 1 out of 13 smelters in 2009, 1 out of 14 smelters in 2006, 2007, and 2008, 1 out of 15 smelters in 2005, and 5 out of 23 smelters between 1990 and 2003), CO_2 emission estimates were estimated using Tier 1 Søderberg and/or Prebake emission factors (metric ton of CO_2 per metric ton of aluminum produced) from IPCC (2006).

Aluminum production data for 10 out of 13 operating smelters were reported under the VAIP in 2009. Between 1990 and 2008, production data were provided by 21 of the 23 U.S. smelters that operated during at least part of that period. For the non-reporting smelters, production was estimated based on the difference between reporting smelters and national aluminum production levels (USAA 2010), with allocation to specific smelters based on reported production capacities (USGS 2009a).

PFC emissions from aluminum production were estimated using a per-unit production emission factor that is expressed as a function of operating parameters (anode effect frequency and duration), as follows:

$$\text{PFC } (CF_4 \text{ or } C_2F_6) \text{ kg/metric ton Al} = S \times (\text{Anode Effect Minutes/Cell-Day})$$

where,

S = Slope coefficient ((kg PFC/metric ton Al)/(Anode Effect Minutes/Cell-Day))
Anode Effect Minutes/Cell-Day = Anode Effect Frequency/Cell-Day × Anode Effect Duration (minutes)

This approach corresponds to either the Tier 3 or the Tier 2 approach in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006), depending upon whether the slope-coefficient is smelter-specific (Tier 3) or technology-specific (Tier 2). For 1990 through 2009, smelter-specific slope coefficients were available and were used for smelters representing between 30 and 94 percent of U.S. primary aluminum production. The percentage changed from year to year as some smelters closed or changed hands and as the production at remaining smelters fluctuated. For smelters that did not report smelter-specific slope coefficients, IPCC technology-specific slope coefficients were applied (IPCC 2000, 2006). The slope coefficients were combined with smelter-specific anode effect data collected by aluminum companies and reported under the VAIP, to estimate emission factors over time. For 1990 through 2009, smelter-specific anode effect data were available for smelters representing between 80 and 100 percent of U.S. primary aluminum production. Where smelter-specific anode effect data were not available, industry averages were used.

For all smelters, emission factors were multiplied by annual production to estimate annual emissions at the smelter level. For 1990 through 2009, smelter-specific production data were available for smelters representing between 30 and 100 percent of U.S. primary aluminum production. (For the years after 2000, this percentage was near the high end of the range.) Production at non-reporting smelters was estimated by calculating the difference between the production reported under VAIP and the total U.S. production supplied by USGS or USAA and then allocating this difference to non-reporting smelters in proportion to their production capacity. Emissions were then aggregated across smelters to estimate national emissions.

National primary aluminum production data for 2009 were obtained via the United States Aluminum Association (USAA 2010). For 1990 through 2001, and 2006 (see Table 4-70) data were obtained from USGS, Mineral Industry Surveys: Aluminum Annual Report (USGS 1995, 1998, 2000, 2001, 2002, 2007). For 2002 through 2005, and 2007 through 2008 national aluminum production data were obtained from the USAA's Primary Aluminum Statistics (USAA 2004, 2005, 2006, 2008, 2009).

Table 4-70: Production of Primary Aluminum (Gg)

Year	Gg
1990	4,048
2000	3,668
2005	2,478
2006	2,284
2007	2,560
2008	2,659
2009	1,727

Uncertainty and Time Series Consistency

The overall uncertainties associated with the 2009 CO_2, CF_4, and C_2F_6 emission estimates were calculated using Approach 2, as defined by IPCC (2006). For CO_2, uncertainty was assigned to each of the parameters used to estimate CO_2 emissions. Uncertainty surrounding reported production data was assumed to be 1 percent (IPCC 2006). For additional variables, such as net C consumption, and sulfur and ash content in baked anodes, estimates for uncertainties associated with reported and default data were obtained from IPCC (2006). A Monte Carlo analysis was applied to estimate the overall uncertainty of the CO_2 emission estimate for the U.S. aluminum industry as a whole, and the results are provided below.

To estimate the uncertainty associated with emissions of CF_4 and C_2F_6, the uncertainties associated with three variables were estimated for each smelter: (1) the quantity of aluminum produced, (2) the anode effect minutes per cell day (which may be reported directly or calculated as the product of anode effect frequency and anode effect duration), and, (3) the smelter- or technology-specific slope coefficient. A Monte Carlo analysis was then applied to estimate the overall uncertainty of the emission estimate for each smelter and for the U.S. aluminum industry as a whole.

The results of this quantitative uncertainty analysis are summarized in Table 4-71. Aluminum production-related CO_2 emissions were estimated to be between 2.90 and 3.12 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 4 percent below to 4 percent above the emission estimate of 3.01 Tg CO_2 Eq. Also, production-related CF_4 emissions were estimated to be between 1.14 and 1.44 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below to 12 percent above the emission estimate of 1.29 Tg CO_2 Eq. Finally, aluminum production-related C_2F_6 emissions were estimated to be between 0.25 and 0.35 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 17 percent below to 19 percent above the emission estimate of 0.30 Tg CO_2 Eq.

Table 4-71: Tier 2 Quantitative Uncertainty Estimates for CO_2 and PFC Emissions from Aluminum Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to 2009 Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Aluminum Production	CO_2	3.0	2.9	3.1	−4%	+4%
Aluminum Production	CF_4	1.3	1.1	1.4	−12%	+12%
Aluminum Production	C_2F_6	0.3	0.2	0.4	−17%	+19%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

The 2009 emission estimate was developed using either company-wide or site-specific PFC slope coefficients for all but 1 of the 14 operating smelters where default IPCC (2006) slope data was used. In some cases, where smelters are owned by one company, data have been reported on a company-wide basis as totals or weighted averages. Consequently, in the Monte Carlo analysis, uncertainties in anode effect minutes per cell-day, slope coefficients, and aluminum production have been applied to the company as a whole and not to each smelter. This probably overestimates the uncertainty associated with the cumulative emissions from these smelters, because errors that were in fact independent were treated as if they were correlated. It is therefore likely that the uncertainties calculated above for the total U.S. 2009 emission estimates for CF_4 and C_2F_6 are also overestimated.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Beginning in 2010, all primary U.S. aluminum producing facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. primary aluminum production industry.

4.16. Magnesium Production and Processing (IPCC Source Category 2C4)

The magnesium metal production and casting industry uses sulfur hexafluoride (SF_6) as a cover gas to prevent the rapid oxidation of molten magnesium in the presence of air. Sulfur hexafluoride has been used in this application around the world for more than twenty-five years. A dilute gaseous mixture of SF_6 with dry air and/or CO_2 is blown over molten magnesium metal to induce and stabilize the formation of a protective crust. A small portion of the SF_6 reacts with the magnesium to form a thin molecular film of mostly magnesium oxide and magnesium fluoride. The amount of SF_6 reacting in magnesium production and processing is considered to be negligible, and thus all SF_6 used is assumed to be emitted into the atmosphere. Although alternative cover gases, such as AM-cover™ (containing HFC-134a), Novec™ 612 and dilute SO_2 systems can be used, many facilities in the United States are still using traditional SF_6 cover gas systems.

The magnesium industry emitted 1.1 Tg CO_2 Eq. (0.04 Gg) of SF_6 in 2009, representing a decrease of approximately 45 percent from 2008 emissions (See Table 4-72). The decrease can be attributed to die casting facilities in the United States closing or halting production due to reduced demand from the American auto industry and other industrial sectors (USGS 2010a). Production associated with primary and secondary facilities also dropped in 2009. The significant reduction in emissions can also be attributed to industry efforts to switch to cover gas alternatives, such as sulfur dioxide, as part of the EPA's SF_6 Emission Reduction Partnership for the Magnesium Industry.

Table 4-72: SF_6 Emissions from Magnesium Production and Processing (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	5.4	0.2
2000	3.0	0.1
2005	2.9	0.1
2006	2.9	0.1
2007	2.6	0.1
2008	1.9	0.1
2009	1.1	0.04

Methodology

Emission estimates for the magnesium industry incorporate information provided by industry participants in EPA's SF_6 Emission Reduction Partnership for the Magnesium Industry. The Partnership started in 1999 and, currently, participating companies represent 100 percent of U.S. primary and secondary production and 90 percent of the casting sector production (i.e., die, sand, permanent mold, wrought, and anode casting). Absolute emissions for 1999 through 2009 from primary production, secondary production (i.e., recycling), and die casting were generally reported by Partnership participants. Partners reported their SF_6 consumption, which was assumed to be equivalent to emissions. When a partner did not report emissions, they were estimated based on the metal processed and emission rate reported by that partner in previous and (if available) subsequent years. Where data for subsequent years was not available, metal production and emissions rates were extrapolated based on the trend shown by partners reporting in the current and previous years. When it was determined a Partner is no longer in production, their metal production and emissions rates were set to zero if no activity information was available; in one case a partner that closed mid-year was estimated to have produced 50 percent of the metal from the prior year.

Emission factors for 2002 to 2006 for sand casting activities were also acquired through the Partnership. For 2007, 2008 and 2009, the sand casting partner did not report and the reported emission factor from 2005 was utilized as being representative of the industry. The 1999 through 2009 emissions from casting operations (other than die) were estimated by multiplying emission factors (kg SF_6 per metric ton of metal produced or processed) by the amount of metal produced or consumed. The emission factors for casting activities are provided below in Table 4-73. The emission factors for primary production, secondary production and sand casting are withheld to protect company-specific production information. However, the emission factor for primary production has not risen above the average 1995 partner value of 1.1 kg SF_6 per metric ton. The emission factors for the other industry sectors (i.e., permanent mold, wrought, and anode casting) were based on discussions with industry representatives. U.S. magnesium consumption (casting) data from 1990 through 2009 were available from the USGS (USGS 2002, 2003, 2005, 2006, 2007, 2008, 2010).

Table 4-73: SF_6 Emission Factors (kg SF_6 per metric ton of magnesium)

Year	Die Casting	Permanent Mold	Wrought	Anodes
1999	2.14[a]	2	1	1
2000	0.72	2	1	1
2001	0.72	2	1	1
2002	0.71	2	1	1
2003	0.81	2	1	1
2004	0.81	2	1	1
2005	0.79	2	1	1
2006	0.86	2	1	1
2007	0.67	2	1	1
2008	1.15[b]	2	1	1
2009	1.77[b]	2	1	1

[a] This is a weighted average that includes an estimated emission factor of 5.2 kg SF_6 per metric ton of magnesium for die casters that did not participate in the Partnership in 1999. These die casters were assumed to be similar to partners that cast small parts. Due to process requirements, these casters consume larger quantities of SF_6 per metric ton of processed magnesium than casters that process large parts. In later years, die casters participating in the Partnership accounted for all U.S. die casting tracked by USGS.

[b] The emission factor for die casting increased significantly between 2007 and 2008, and again between 2008 and 2009. These increases occurred for two reasons. First, one of the die casters with a significant share of U.S. production that had used SF_6 as a cover gas and that had maintained a relatively low emission rate began using an alternative cover gas in 2008. Since the SF_6 emission factor provided here is based only on die casting operations that use SF_6 as a cover gas, the removal of the low-emitting die caster from the SF_6-using group increased the weighted average emission rate of that group. Second, one SF_6-using die caster experienced a significant leak in its cover gas distribution system in 2009 that resulted in an abnormally high SF_6 emission rate.

To estimate emissions for 1990 through 1998, industry emission factors were multiplied by the corresponding metal production and consumption (casting) statistics from USGS. The primary production emission factors were 1.2 kg per metric ton for 1990 through 1993, and 1.1 kg per metric ton for 1994 through 1997. These factors were based on information provided by U.S. primary producers. For die casting, an emission factor of 4.1 kg per metric ton was used for the period 1990 through 1996. This factor was drawn from an international survey of die casters (Gjestland & Magers 1996). For 1996 through 1998, the emission factors for primary production and die casting were assumed to decline linearly to the level estimated based on partner reports in 1999. This assumption is consistent with the trend in SF_6 sales to the magnesium sector that is reported in the RAND survey of major SF_6 manufacturers, which shows a decline of 70 percent from 1996 to 1999 (RAND 2002). Sand casting emission factors for 2002 through 2009 were provided by the Magnesium Partnership participants, and 1990 through 2001 emission factors for this process were assumed to have been the same as the 2002 emission factor. The emission factor for secondary production from 1990 through 1998 was assumed to be constant at the 1999 average partner value. The emission factors for the other processes (i.e., permanent mold, wrought, and anode casting), about which less is known, were assumed to remain constant at levels defined in Table 4-73.

Uncertainty

To estimate the uncertainty surrounding the estimated 2009 SF_6 emissions from magnesium production and processing, the uncertainties associated with three variables were estimated (1) emissions reported by magnesium producers and processors that participate in the Magnesium Partnership, (2) emissions estimated for magnesium producers and processors that participate in the Partnership but did not report this year, and (3) emissions estimated for magnesium producers and processors that do not participate in the Partnership. An uncertainty of 5 percent was assigned to the data reported by each participant in the Partnership. If partners did not report emissions data during the current reporting year, SF_6 emissions data were estimated using available emission factor and production information reported in prior years; the extrapolation was based on the average trend for partners reporting in the current reporting year and the year prior. The uncertainty associated with the SF_6 usage estimate generated from the extrapolated emission factor and production information was estimated to be 30 percent for each year of extrapolation. The lone sand casting partner did not report in the past two reporting years and its activity and emission factor were held constant at 2005 levels due to a reporting anomaly in 2006 because of malfunctions at the facility. The uncertainty associated with the SF_6 usage for the sand casting partner was 52 percent. For those industry processes that are not represented in Partnership, such as permanent mold and wrought casting, SF_6 emissions were estimated using production and consumption statistics reported by USGS and estimated process-

specific emission factors (see Table 4-73). The uncertainties associated with the emission factors and USGS-reported statistics were assumed to be 75 percent and 25 percent, respectively. Emissions associated with sand casting activities utilized a partner-reported emission factor with an uncertainty of 75 percent. In general, where precise quantitative information was not available on the uncertainty of a parameter, a conservative (upper-bound) value was used.

Additional uncertainties exist in these estimates that are not addressed in this methodology, such as the basic assumption that SF_6 neither reacts nor decomposes during use. The melt surface reactions and high temperatures associated with molten magnesium could potentially cause some gas degradation. Recent measurement studies have identified SF_6 cover gas degradation in die casting applications on the order of 20 percent (Bartos et al. 2007). Sulfur hexafluoride may also be used as a cover gas for the casting of molten aluminum with high magnesium content; however, the extent to which this technique is used in the United States is unknown.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 4-74. SF_6 emissions associated with magnesium production and processing were estimated to be between 1.01 and 1.10 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 6 percent below to 5 percent above the 2008 emission estimate of 1.05 Tg CO_2 Eq.

Table 4-74: Tier 2 Quantitative Uncertainty Estimates for SF_6 Emissions from Magnesium Production and Processing (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Magnesium Production	SF_6	1.05	1.01	1.10	-4%	+4%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Recalculations Discussion

The uncertainty estimates for 2009 are lower relative to the previous inventory uncertainty estimate for 2008 emissions, which is likely due to the fact that emission estimates for 2009 are based more on actual reported data than emission estimates for 2008 were in the 1990-2008 inventory, with two emission sources using projected (highly uncertain) estimates.

Planned Improvements

Cover gas research conducted by the EPA over the last decade has found that SF_6 used for magnesium melt protection can have degradation rates on the order of 20 percent in die casting applications (Bartos et al. 2007). Current emission estimates assume (per the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006)) that all SF_6 utilized is emitted to the atmosphere. Additional research may lead to a revision of IPCC Guidelines to reflect this phenomenon and until such time, developments in this sector will be monitored for possible application to the inventory methodology. Another issue that will be addressed in future inventories is the likely adoption of alternate cover gases by U.S. magnesium producers and processors. These cover gases, which include AM-cover™ (containing HFC-134a) and Novec™ 612, have lower GWPs than SF_6, and tend to quickly degrade during their exposure to the molten metal. Magnesium producers and processors have already begun using these cover gases for 2006 through 2009 in a limited fashion; because the amounts being used by companies on the whole are low enough that they have a minor effect on the overall emissions from the industry, these emissions are only being monitored and recorded at this time.

4.17. Zinc Production (IPCC Source Category 2C5)

Zinc production in the United States consists of both primary and secondary processes. Primary production in the United States is conducted through the electrolytic process while secondary techniques used in the United States include the electrothermic and Waelz kiln processes as well as a range of other metallurgical, hydrometallurgical, and pyrometallurgical processes. Worldwide primary zinc production also employs a pyrometallurgical process using the Imperial Smelting Furnace process; however, this process is not used in the United States (Sjardin 2003). Of the primary and secondary processes used in the United States, only the electrothermic and Waelz kiln secondary

processes result in non-energy CO_2 emissions (Viklund-White 2000).

During the electrothermic zinc production process, roasted zinc concentrate and secondary zinc products enter a sinter feed where they are burned to remove impurities before entering an electric retort furnace. Metallurgical coke added to the electric retort furnace reduces the zinc oxides and produces vaporized zinc, which is then captured in a vacuum condenser. This reduction process produces non-energy CO_2 emissions (Sjardin 2003).

In the Waelz kiln process, EAF dust, which is captured during the recycling of galvanized steel, enters a kiln along with a reducing agent—often metallurgical coke. When kiln temperatures reach approximately 1100–1200°C, zinc fumes are produced, which are combusted with air entering the kiln. This combustion forms zinc oxide, which is collected in a baghouse or electrostatic precipitator, and is then leached to remove chloride and fluoride. Through this process, approximately 0.33 metric ton of zinc is produced for every metric ton of EAF dust treated (Viklund-White 2000).

In 2009, U.S. primary and secondary zinc production was estimated to total 286,000 metric tons (USGS 2010). Since reported activity data for 2009 were not available for all necessary inputs in time for this publication, production values in 2009 were assumed to equal 2008 values in some cases. The resulting emissions of CO_2 from zinc production in 2009 were estimated to be 0.97 Tg CO_2 Eq. (966 Gg) (see Table 4-75). All 2009 CO_2 emissions resulted from secondary zinc production.

Table 4-75: CO_2 Emissions from Zinc Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	0.7	667
2000	1.0	997
2005	1.1	1088
2006	1.1	1088
2007	1.1	1081
2008	1.2	1230
2009	1.0	966

Emissions from zinc production in the U.S. have increased overall due to a gradual shift from non-emissive primary production to emissive secondary production. In 2009, emissions were estimated to be 45 percent higher than they were in 1990.

Methodology

Non-energy CO_2 emissions from zinc production result from the electrothermic and Waelz kiln secondary production processes, which both use metallurgical coke or other C-based materials as reductants. Sjardin (2003) provides an emission factor of 0.43 metric tons CO_2/metric ton zinc produced for emissive zinc production processes; however, this emission factor is based on the Imperial Smelting Furnace production process. Because the Imperial Smelting Furnace production process is not used in the United States, emission factors specific to electrothermic and Waelz kiln processes were needed. Due to the limited amount of information available for these electrothermic processes, only Waelz kiln process-specific emission factors were developed. These emission factors were applied to both the Waelz kiln and electrothermic secondary zinc production processes.

A Waelz kiln emission factor based on the amount of zinc produced was developed based on the amount of metallurgical coke consumed for non-energy purposes per ton of zinc produced, 1.19 metric tons coke/metric ton zinc produced (Viklund-White 2000), and the following equation:

$$EF_{\text{Waelz Kiln}} = \frac{1.19\ metric\ tons\ coke}{metric\ tons\ zinc} \times \frac{0.85\ metric\ tons\ C}{metric\ tons\ coke} \times \frac{3.67\ metric\ tons\ CO_2}{metric\ tons\ C} = \frac{3.70\ metric\ tons\ CO_2}{metric\ tons\ zinc}$$

In addition, a Waelz kiln emission factor based on the amount of EAF dust consumed was developed based on the amount of metallurgical coke consumed per ton of EAF dust consumed, 0.4 metric tons coke/metric ton EAF dust

consumed (Viklund-White 2000), and the following equation:[116]

$$EF_{\text{EAF Dust}} = \frac{0.4\ metric\ tons\ coke}{metric\ tons\ EAF\ dust} \times \frac{0.85\ metric\ tons\ C}{metric\ tons\ coke} \times \frac{3.67\ metric\ tons\ CO_2}{metric\ tons\ C} = \frac{1.24\ metric\ tons\ CO_2}{metric\ tons\ EAF\ Dust}$$

The only companies in the United States that use emissive technology to produce secondary zinc products are Horsehead Corp and Steel Dust Recycling. For Horsehead Corp, EAF dust is recycled in Waelz kilns at their Beaumont, TX; Calumet, IL; Palmerton, PA; and Rockwood, TN facilities (and soon to be performed at their new South Carolina facility). These Waelz kiln facilities produce intermediate zinc products (crude zinc oxide or calcine), most of which is transported to their Monaca, PA facility where the products are smelted into refined zinc using electrothermic technology. Some of Horsehead's intermediate zinc products that are not smelted at Monaca are instead exported to other countries around the world (Horsehead Corp 2010). Steel Dust Recycling recycles EAF dust into intermediate zinc products using Waelz kilns, and then sells the intermediate products to companies who smelt it into refined products.

The total amount of EAF dust consumed by Horsehead Corp at their Waelz kilns was available from Horsehead financial reports for years 2006 through 2009 (Horsehead 2010). Consumption levels for 1990 through 2005 were extrapolated using the percentage change in annual refined zinc production at secondary smelters in the United States as provided by USGS Minerals Yearbook: Zinc (USGS 1994 through 2010). The EAF dust consumption values for each year were then multiplied by the 1.24 metric tons CO_2/metric ton EAF dust consumed emission factor to develop CO_2 emission estimates for Horsehead's Waelz kiln facilities.

The amount of EAF dust consumed by the Steel Dust Recycling facility for 2008 and 2009 (the only two years it has been in operation) was not publically available. Therefore, these consumption values were estimated by calculating the 2008 and 2009 capacity utilization of Horsehead's Waelz kilns and multiplying this utilization ratio by the capacity of Steel Dust Recycling's facility, which were available from the company (Steel Dust Recycling LLC 2010). The 1.24 metric tons CO_2/metric ton EAF dust consumed emission factor was then applied to Steel Dust Recycling's estimated EAF dust consumption to develop CO_2 emission estimates for its Waelz kiln facility.

Refined zinc production levels for Horsehead's Monaca, PA facility (utilizing electrothermic technology) were available from the company for years 2005 through 2009 (Horsehead Corp 2010, Horsehead Corp 2008). Production levels for 1990 through 2004 were extrapolated using the percentage changes in annual refined zinc production at secondary smelters in the United States as provided by USGS Minerals Yearbook: Zinc (USGS 1994 through 2010). The 3.70 metric tons CO_2/metric ton zinc emission factor was then applied to the Monaca facility's production levels to estimate CO_2 emissions for the facility. The Waelz kiln production emission factor was applied in this case rather than the EAF dust consumption emission factor since Horsehead's Monaca facility did not consume EAF dust.

Table 4-76: Zinc Production (Metric Tons)

Year	Primary	Secondary
1990	262,704	95,708
2000	227,800	143,000
2005	191,120	156,000
2006	113,000	156,000
2007	121,000	157,000
2008	125,000	161,000
2009	125,000	161,000

[116] For Waelz kiln based secondary zinc production, IPCC recommends the use of emission factors based on EAF dust consumption rather than the amount of zinc produced since the amount of reduction materials used is more directly dependent on the amount of EAF dust consumed (IPCC 2006).

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates are two-fold, relating to activity data and emission factors used.

First, there is uncertainty associated with the amount of EAF dust consumed in the United States to produce secondary zinc using emission-intensive Waelz kilns. The estimate for the total amount of EAF dust consumed in Waelz kilns is based on (1) an EAF dust consumption value reported annually by Horsehead Corporation as part of its financial reporting to the Securities and Exchange Commission (SEC), and (2) an estimate of the amount of EAF dust consumed at a Waelz kiln facility operated in Alabama by Steel Dust Recycling LLC. Since actual EAF dust consumption information is not available for the Steel Dust Recycling LLC facility, the amount is estimated by multiplying the EAF dust recycling capacity of the facility (available from the company's Web site) by the capacity utilization factor for Horsehead Corporation (which is available from Horsehead's financial reports). Therefore, there is uncertainty associated with the assumption that the capacity utilization of Steel Dust Recycling LLC's Waelz kiln facility is equal to the capacity utilization of Horsehead's Waelz kiln facility. Second, there are uncertainties associated with the emission factors used to estimate CO_2 emissions from secondary zinc production processes. The Waelz kiln emission factors are based on materials balances for metallurgical coke and EAF dust consumed as provided by Viklund-White (2000). Therefore, the accuracy of these emission factors depend upon the accuracy of these materials balances. Data limitations prevented the development of emission factors for the electrothermic process. Therefore, emission factors for the Waelz kiln process were applied to both electrothermic and Waelz kiln production processes. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-77. Zinc production CO_2 emissions were estimated to be between 0.8 and 1.1 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 17 percent below and 18 percent above the emission estimate of 1.0 Tg CO_2 Eq.

Table 4-77: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Zinc Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Zinc Production	CO_2	1.0	0.8	1.1	-17%	+18%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the zinc production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from zinc production. Beginning in 2010, all U.S. zinc producing facilities (both primary and secondary) that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. zinc production industry.

Recalculations Discussion

The methodology for estimating CO_2 emissions from zinc production was revised for the current Inventory based on the availability of new data regarding secondary zinc production in the United States. The previous Inventory methodology assumed that two facilities had produced zinc in the United States using emissive processes since 1990: Horsehead Corporation's Monaca, PA facility (electrothermic) and Horsehead Corporation's Palmerton, PA facility (Waelz kiln). The 3.70 metric tons CO_2/metric ton zinc emission factor was applied to the estimated refined zinc production at the Monaca, PA electrothermic facility, and the 1.24 metric tons CO_2/metric ton EAF dust consumed emission factor was applied to the estimated EAF dust consumption at the Palmerton, PA Waelz kiln facility. The annual zinc production (for the Monaca facility) and EAF dust consumption (for the Palmerton

facility) were estimated using historic values that were published in articles for select years (extrapolation techniques were used for years in which published data was not available). The Monaca, PA facility was assumed to have closed in 2003 and not operated since.

New data for the industry showed that there were emissive zinc-producing facilities not being captured by the previous Inventory methodology. The facilities that were not captured included three Horsehead Corp Waelz kiln facilities in Beaumont, TX; Calumet, IL; and Rockwood, TN as well as a Waelz kiln facility commissioned in 2008 in Millport, AL by Steel Dust Recycling LLC. Also, research showed that the Monaca, PA facility only closed temporarily in 2003 and has been operating every year since (the Monaca, PA facility produces refined zinc from intermediary zinc products produced at Horsehead's other facilities). The updated methodology utilizes EAF dust consumption values and secondary zinc production values released annually by the main secondary zinc producer in the United States (Horsehead Corp.), and also includes the previously overlooked secondary zinc producing facilities in the emission estimates.

As a result of the revised methodology, historical emission estimates decreased by an average of 11 percent between 1990 and 2002, while emission estimates increased by an average of 140 percent between 2003 and 2009. The significant changes in emission estimates for years 2005 through 2008 were largely driven by Horsehead Corp's Monaca, PA facility being captured in the emission calculations for these years.

4.18. Lead Production (IPCC Source Category 2C5)

Lead production in the United States consists of both primary and secondary processes—both of which emit CO_2 (Sjardin 2003). Primary lead production, in the form of direct smelting, occurs at a just a single plant in Missouri. Secondary production largely involves the recycling of lead acid batteries at approximately 21 separate smelters in the United States. Fifteen of those secondary smelters have annual capacities of 15,000 tons or more and were collectively responsible for 99 percent of secondary lead production in 2009 (USGS 2010). Secondary lead production has increased in the United States over the past decade while primary lead production has decreased. In 2009, secondary lead production accounted for approximately 92 percent of total lead production (USGS 2011).

Primary production of lead through the direct smelting of lead concentrate produces CO_2 emissions as the lead concentrates are reduced in a furnace using metallurgical coke (Sjardin 2003). U.S. primary lead production decreased by 24 percent from 2008 to 2009, and has decreased by 75 percent since 1990 (USGS 2011, USGS 1995).

Similar to primary lead production, CO_2 emissions from secondary production result when a reducing agent, usually metallurgical coke, is added to the smelter to aid in the reduction process. CO_2 emissions from secondary production also occur through the treatment of secondary raw materials (Sjardin 2003). U.S. secondary lead production decreased from 2008 to 2009 by 3 percent, and has increased by 20 percent since 1990 (USGS 2011, USGS 1995).

At last reporting, the United States was the third largest mine producer of lead in the world, behind China and Australia, accounting for 11 percent of world production in 2009 (USGS 2011). In 2009, U.S. primary and secondary lead production totaled 1,213,000 metric tons (USGS 2011). The resulting emissions of CO_2 from 2009 production were estimated to be 0.5 Tg CO_2 Eq. (525 Gg) (see Table 4-78). The majority of 2009 lead production is from secondary processes, which accounted for 95 percent of total 2009 CO_2 emissions.

Table 4-78: CO_2 Emissions from Lead Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	0.5	516
2000	0.6	594
2005	0.6	553
2006	0.6	560
2007	0.6	562
2008	0.6	551
2009	0.5	525

After a gradual decrease in total emissions from 1990 to 1995, total emissions have gradually increased since 1995

and emissions in 2009 were two percent greater than in 1990. Although primary production has decreased significantly (75 percent since 1990), secondary production has increased by about 20 percent over the same time period. Since secondary production is more emissions-intensive, the increase in secondary production since 1990 has resulted in a net increase in emissions despite the sharp decrease in primary production (USGS 2011, USGS 1994).

Methodology

Non-energy CO_2 emissions from lead production result from primary and secondary production processes that use metallurgical coke or other C-based materials as reductants. For primary lead production using direct smelting, Sjardin (2003) and the IPCC (2006) provide an emission factor of 0.25 metric tons CO_2/metric ton lead. For secondary lead production, Sjardin (2003) and IPCC (2006) provide an emission factor of 0.25 metric tons CO_2/metric ton lead for direct smelting as well as an emission factor of 0.2 metric tons CO_2/metric ton lead produced for the treatment of secondary raw materials (i.e., pretreatment of lead acid batteries). The direct smelting factor (0.25) and the sum of the direct smelting and pretreatment emission factors (0.45) are multiplied by total U.S. primary and secondary lead production, respectively, to estimate CO_2 emissions.

The 1990 through 2009 activity data for primary and secondary lead production (see Table 4-79) were obtained through the USGS Mineral Yearbook: Lead (USGS 1994 through 2011).

Table 4-79: Lead Production (Metric Tons)

Year	Primary	Secondary
1990	404,000	922,000
2000	341,000	1,130,000
2005	143,000	1,150,000
2006	153,000	1,160,000
2007	123,000	1,180,000
2008	135,000	1,150,000
2009	103,000	1,110,000

Uncertainty and Time-Series Consistency

Uncertainty associated with lead production relates to the emission factors and activity data used. The direct smelting emission factor used in primary production is taken from Sjardin (2003) who averages the values provided by three other studies (Dutrizac et al. 2000, Morris et al. 1983, Ullman 1997). For secondary production, Sjardin (2003) adds a CO_2 emission factor associated with battery treatment. The applicability of these emission factors to plants in the United States is uncertain. There is also a smaller level of uncertainty associated with the accuracy of primary and secondary production data provided by the USGS.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-80. Lead production CO_2 emissions were estimated to be between 0.5 and 0.6 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 14 percent below and 15 percent above the emission estimate of 0.5 Tg CO_2 Eq.

Table 4-80: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Lead Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Lead Production	CO_2	0.5	0.5	0.6	-14%	+15%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the lead production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emission calculations from lead production. Beginning in 2010, all U.S. lead producing facilities (primary and secondary) that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the Program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. lead production industry.

Recalculations Discussion

In previous Inventory reports, CO_2 emissions from secondary lead production were estimated by multiplying secondary lead production values from USGS by an emission factor of 0.2 metric tons CO_2/metric ton lead produced. This emission factor is provided by Sjardin (2003) and IPCC (2006) for the treatment of secondary raw materials (i.e., pretreatment of lead acid batteries). Due to a misinterpretation of language in Sjardin (2003) and IPCC (2006), this was the only emission factor applied to secondary lead production even though an emission factor of 0.25 metric tons CO_2/metric ton lead for direct smelting should have been applied as well. This issue has been corrected for the current Inventory, and increased 1990 through 2008 emissions from lead production by an average of 95 percent per year relative to the previous Inventory.

4.19. HCFC-22 Production (IPCC Source Category 2E1)

Trifluoromethane (HFC-23 or CHF_3) is generated as a by-product during the manufacture of chlorodifluoromethane (HCFC-22), which is primarily employed in refrigeration and air conditioning systems and as a chemical feedstock for manufacturing synthetic polymers. Between 1990 and 2000, U.S. production of HCFC-22 increased significantly as HCFC-22 replaced chlorofluorocarbons (CFCs) in many applications. Between 2000 and 2007, U.S. production fluctuated but generally remained above 1990 levels. In 2008 and 2009, U.S. production declined markedly. Because HCFC-22 depletes stratospheric ozone, its production for non-feedstock uses is scheduled to be phased out by 2020 under the U.S. Clean Air Act.[117] Feedstock production, however, is permitted to continue indefinitely.

HCFC-22 is produced by the reaction of chloroform ($CHCl_3$) and hydrogen fluoride (HF) in the presence of a catalyst, $SbCl_5$. The reaction of the catalyst and HF produces $SbCl_xF_y$, (where $x + y = 5$), which reacts with chlorinated hydrocarbons to replace chlorine atoms with fluorine. The HF and chloroform are introduced by submerged piping into a continuous-flow reactor that contains the catalyst in a hydrocarbon mixture of chloroform and partially fluorinated intermediates. The vapors leaving the reactor contain HCFC-21 ($CHCl_2F$), HCFC-22 ($CHClF_2$), HFC-23 (CHF_3), HCl, chloroform, and HF. The under-fluorinated intermediates (HCFC-21) and chloroform are then condensed and returned to the reactor, along with residual catalyst, to undergo further fluorination. The final vapors leaving the condenser are primarily HCFC-22, HFC-23, HCl and residual HF. The HCl is recovered as a useful byproduct, and the HF is removed. Once separated from HCFC-22, the HFC-23 may be released to the atmosphere, recaptured for use in a limited number of applications, or destroyed.

Emissions of HFC-23 in 2009 were estimated to be 5.4 Tg CO_2 Eq. (0.5 Gg) (Table 4-81). This quantity represents a 60 percent decrease from 2008 emissions and a 85 percent decline from 1990 emissions. The decrease from 2008 emissions was caused by a 27 percent decrease in HCFC-22 production and a 46 percent decrease in the HFC-23 emission rate. The decline from 1990 emissions is due to a 34 percent decrease in HCFC-22 production and a 78 percent decrease in the HFC-23 emission rate since 1990. The decrease in the emission rate is primarily attributable to five factors: (a) five plants that did not capture and destroy the HFC-23 generated have ceased production of HCFC-22 since 1990, (b) one plant that captures and destroys the HFC-23 generated began to produce HCFC-22, (c) one plant implemented and documented a process change that reduced the amount of HFC-23 generated, and (d) the same plant began recovering HFC-23, primarily for destruction and secondarily for sale, and (e) another plant began destroying HFC-23. All three HCFC-22 production plants operating in the United States in 2009 used thermal oxidation to significantly lower their HFC-23 emissions.

[117] As construed, interpreted, and applied in the terms and conditions of the *Montreal Protocol on Substances that Deplete the Ozone Layer*. [42 U.S.C. §7671m(b), CAA §614]

Table 4-81: HFC-23 Emissions from HCFC-22 Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	36.4	3
2000	28.6	2
2005	15.8	1
2006	13.8	1
2007	17.0	1
2008	13.6	1
2009	5.4	0.46

Methodology

To estimate HFC-23 emissions for five of the eight HCFC-22 plants that have operated in the United States since 1990, methods comparable to the Tier 3 methods in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) were used. For the other three plants, the last of which closed in 1993, methods comparable to the Tier 1 method in the 2006 IPCC Guidelines were used. Emissions from these three plants have been calculated using the recommended emission factor for unoptimized plants operating before 1995 (0.04 kg HCFC-23/kg HCFC-22 produced).

The five plants that have operated since 1994 measured concentrations of HFC-23 to estimate their emissions of HFC-23. Plants using thermal oxidation to abate their HFC-23 emissions monitor the performance of their oxidizers to verify that the HFC-23 is almost completely destroyed. Plants that release (or historically have released) some of their byproduct HFC-23 periodically measure HFC-23 concentrations in the output stream using gas chromatography. This information is combined with information on quantities of products (e.g., HCFC-22) to estimate HFC-23 emissions.

In most years, including 2010, an industry association aggregates and reports to EPA country-level estimates of HCFC-22 production and HFC-23 emissions (ARAP 1997, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010). However, in 1997 and 2008, EPA (through a contractor) performed comprehensive reviews of plant-level estimates of HFC-23 emissions and HCFC-22 production (RTI 1997; RTI 2008). These reviews enabled EPA to review, update, and where necessary, correct U.S. totals, and also to perform plant-level uncertainty analyses (Monte-Carlo simulations) for 1990, 1995, 2000, 2005, and 2006. Estimates of annual U.S. HCFC-22 production are presented in Table 4-82.

Table 4-82: HCFC-22 Production (Gg)

Year	Gg
1990	139
2000	186
2005	156
2006	154
2007	162
2008	126
2009	91

Uncertainty and Time Series Consistency

The uncertainty analysis presented in this section was based on a plant-level Monte Carlo simulation for 2006. The Monte Carlo analysis used estimates of the uncertainties in the individual variables in each plant's estimating procedure. This analysis was based on the generation of 10,000 random samples of model inputs from the probability density functions for each input. A normal probability density function was assumed for all measurements and biases except the equipment leak estimates for one plant; a log-normal probability density function was used for this plant's equipment leak estimates. The simulation for 2006 yielded a 95-percent

confidence interval for U.S. emissions of 6.8 percent below to 9.6 percent above the reported total.

Because plant-level emissions data for 2009 were not available, the relative errors yielded by the Monte Carlo simulation for 2006 were applied to the U.S. emission estimate for 2009. The resulting estimates of absolute uncertainty are likely to be accurate because (1) the methods used by the three plants to estimate their emissions are not believed to have changed significantly since 2006, and (2) although the distribution of emissions among the plants may have changed between 2008 and 2009 (because both HCFC-22 production and the HFC-23 emission rate declined significantly), the two plants that contribute significantly to emissions were estimated to have similar relative uncertainties in their 2006 (as well as 2005) emission estimates. Thus, changes in the relative contributions of these two plants to total emissions are not likely to have a large impact on the uncertainty of the national emission estimate.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-83. HFC-23 emissions from HCFC-22 production were estimated to be between 5.0 and 5.9 Tg CO_2 Eq. at the 95percent confidence level. This indicates a range of approximately 7 percent below and 10 percent above the emission estimate of 5.4 Tg CO_2 Eq.

Table 4-83: Quantitative Uncertainty Estimates for HFC-23 Emissions from HCFC-22 Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
HCFC-22 Production	HFC-23	5.4	5.0	5.9	-7%	+10%

[a] Range of emissions reflects a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Beginning in 2010, all U.S. HCFC-22 production facilities are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Data collected under this program will be used in future inventories to improve the calculation of national emissions from HCFC-22 production

4.20. Substitution of Ozone Depleting Substances (IPCC Source Category 2F)

Hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) are used as alternatives to several classes of ozone-depleting substances (ODSs) that are being phased out under the terms of the Montreal Protocol and the Clean Air Act Amendments of 1990.[118] Ozone depleting substances—chlorofluorocarbons (CFCs), halons, carbon tetrachloride, methyl chloroform, and hydrochlorofluorocarbons (HCFCs)—are used in a variety of industrial applications including refrigeration and air conditioning equipment, solvent cleaning, foam production, sterilization, fire extinguishing, and aerosols. Although HFCs and PFCs are not harmful to the stratospheric ozone layer, they are potent greenhouse gases. Emission estimates for HFCs and PFCs used as substitutes for ODSs are provided in Table 4-84 and Table 4-85.

Table 4-84: Emissions of HFCs and PFCs from ODS Substitutes (Tg CO_2 Eq.)

Gas	1990	2000	2005	2006	2007	2008	2009
HFC-23	+	+	+	+	+	+	+
HFC-32	+	+	0.3	0.6	1.0	1.3	1.7
HFC-125	+	5.2	10.1	12.5	15.1	18.2	21.6
HFC-134a	+	60.4	75.1	75.0	72.3	69.3	66.7
HFC-143a	+	4.1	12.2	14.4	16.7	19.2	22.0
HFC-236fa	+	0.5	0.8	0.8	0.9	0.9	0.9

[118] [42 U.S.C § 7671, CAA § 601]

CF_4	+		+		+	+	+	+	+
Others*	0.3		4.0		5.6	6.0	6.3	6.7	7.0
Total	**0.3**		**74.3**		**104.2**	**109.4**	**112.3**	**115.5**	**120.0**

+ Does not exceed 0.05 Tg CO_2 Eq.

* Others include HFC-152a, HFC-227ea, HFC-245fa, HFC-4310mee, C_4F_{10}, and PFC/PFPEs, the latter being a proxy for a diverse collection of PFCs and perfluoropolyethers (PFPEs) employed for solvent applications. For estimating purposes, the GWP value used for PFC/PFPEs was based upon C_6F_{14}.

Note: Totals may not sum due to independent rounding.

Table 4-85: Emissions of HFCs and PFCs from ODS Substitution (Mg)

Gas	1990		2000		2005	2006	2007	2008	2009
HFC-23	+		1		1	1	1	2	2
HFC-32	+		26		505	971	1,465	1,977	2,540
HFC-125	+		1,855		3,619	4,453	5,393	6,486	7,730
HFC-134a	+		46,465		57,777	57,728	55,603	53,294	51,281
HFC-143a	+		1,089		3,200	3,782	4,402	5,044	5,798
HFC-236fa	+		85		125	131	136	141	144
CF_4	+		1		2	2	2	2	2
Others*	M		M		M	M	M	M	M

M (Mixture of Gases)

+ Does not exceed 0.5 Mg

* Others include HFC-152a, HFC-227ea, HFC-245fa, HFC-4310mee, C_4F_{10}, and PFC/PFPEs, the latter being a proxy for a diverse collection of PFCs and perfluoropolyethers (PFPEs) employed for solvent applications.

In 1990 and 1991, the only significant emissions of HFCs and PFCs as substitutes to ODSs were relatively small amounts of HFC-152a—used as an aerosol propellant and also a component of the refrigerant blend R-500 used in chillers—and HFC-134a in refrigeration end-uses. Beginning in 1992, HFC-134a was used in growing amounts as a refrigerant in motor vehicle air-conditioners and in refrigerant blends such as R-404A.[119] In 1993, the use of HFCs in foam production began, and in 1994 these compounds also found applications as solvents. In 1995, ODS substitutes for halons entered widespread use in the United States as halon production was phased-out.

The use and subsequent emissions of HFCs and PFCs as ODS substitutes has been increasing from small amounts in 1990 to 120.0 Tg CO_2 Eq. in 2009. This increase was in large part the result of efforts to phase out CFCs and other ODSs in the United States. In the short term, this trend is expected to continue, and will likely accelerate over the next decade as HCFCs, which are interim substitutes in many applications, are themselves phased-out under the provisions of the Copenhagen Amendments to the Montreal Protocol. Improvements in the technologies associated with the use of these gases and the introduction of alternative gases and technologies, however, may help to offset this anticipated increase in emissions.

Table 4-86 presents emissions of HFCs and PFCs as ODS substitutes by end-use sector for 1990 through 2009. The end-use sectors that contributed the most toward emissions of HFCs and PFCs as ODS substitutes in 2009 include refrigeration and air-conditioning (104.9 Tg CO_2 Eq., or approximately 87 percent), aerosols (9.1 Tg CO_2 Eq., or approximately 8 percent), and foams (3.9 Tg CO_2 Eq., or approximately 3 percent). Within the refrigeration and air-conditioning end-use sector, motor vehicle air-conditioning was the highest emitting end-use (45.9 Tg CO_2 Eq.), followed by refrigerated retail food and transport. Each of the end-use sectors is described in more detail below.

Table 4-86: Emissions of HFCs and PFCs from ODS Substitutes (Tg CO_2 Eq.) by Sector

Gas	1990		2000		2005	2006	2007	2008	2009
Refrigeration/Air Conditioning	+		61.6		93.1	97.6	99.8	102.3	104.9
Aerosols	0.3		10.1		7.3	7.7	8.2	8.6	9.1
Foams	+		0.3		1.9	2.1	2.3	2.5	3.9
Solvents	+		2.1		1.3	1.3	1.3	1.3	1.3
Fire Protection	+		0.2		0.5	0.6	0.7	0.7	0.8
Total	**0.3**		**74.3**		**104.2**	**109.4**	**112.3**	**115.5**	**120.0**

[119] R-404A contains HFC-125, HFC-143a, and HFC-134a.

Refrigeration/Air Conditioning

The refrigeration and air-conditioning sector includes a wide variety of equipment types that have historically used CFCs or HCFCs. End-uses within this sector include motor vehicle air-conditioning, retail food refrigeration, refrigerated transport (e.g., ship holds, truck trailers, railway freight cars), household refrigeration, residential and small commercial air-conditioning/and heat pumps, chillers (large comfort cooling), cold storage facilities, and industrial process refrigeration (e.g., systems used in food processing, chemical, petrochemical, pharmaceutical, oil and gas, and metallurgical industries). As the ODS phaseout is taking effect, most equipment is being or will eventually be retrofitted or replaced to use HFC-based substitutes. Common HFCs in use today in refrigeration/air-conditioning equipment are HFC-134a, R-410A[120], R-404A, and R-507A[121]. These HFCs are emitted to the atmosphere during equipment manufacture and operation (as a result of component failure, leaks, and purges), as well as at servicing and disposal events.

Aerosols

Aerosol propellants are used in metered dose inhalers (MDIs) and a variety of personal care products and technical/specialty products (e.g., duster sprays and safety horns). Many pharmaceutical companies that produce MDIs—a type of inhaled therapy used to treat asthma and chronic obstructive pulmonary disease—have committed to replace the use of CFCs with HFC-propellant alternatives. The earliest ozone-friendly MDIs were produced with HFC-134a, but the industry has started to use HFC-227ea as well. Conversely, since the use of CFC propellants was banned in 1978, most consumer aerosol products have not transitioned to HFCs, but to "not-in-kind" technologies, such as solid roll-on deodorants and finger-pump sprays. The transition away from ODS in specialty aerosol products has also led to the introduction of non-fluorocarbon alternatives (e.g., hydrocarbon propellants) in certain applications, in addition to HFC-134a or HFC-152a. These propellants are released into the atmosphere as the aerosol products are used.

Foams

CFCs and HCFCs have traditionally been used as foam blowing agents to produce polyurethane (PU), polystyrene, polyolefin, and phenolic foams, which are used in a wide variety of products and applications. Since the Montreal Protocol, flexible PU foams as well as other types of foam, such as polystyrene sheet, polyolefin, and phenolic foam, have transitioned almost completely away from fluorocompounds, into alternatives such as CO_2, methylene chloride, and hydrocarbons. The majority of rigid PU foams have transitioned to HFCs—primarily HFC-134a and HFC-245fa. Today, these HFCs are used to produce polyurethane appliance, PU commercial refrigeration, PU spray, and PU panel foams—used in refrigerators, vending machines, roofing, wall insulation, garage doors, and cold storage applications. In addition, HFC-152a is used to produce polystyrene sheet/board foam, which is used in food packaging and building insulation. Emissions of blowing agents occur when the foam is manufactured as well as during the foam lifetime and at foam disposal, depending on the particular foam type.

Solvents

CFCs, methyl chloroform (1,1,1-trichloroethane or TCA), and to a lesser extent carbon tetrachloride (CCl_4) were historically used as solvents in a wide range of cleaning applications, including precision, electronics, and metal cleaning. Since their phaseout, metal cleaning end-use applications have primarily transitioned to non-fluorocarbon solvents and not-in-kind processes. The precision and electronics cleaning end-uses have transitioned in part to high-GWP gases, due to their high reliability, excellent compatibility, good stability, low toxicity, and selective solvency. These applications rely on HFC-4310mee, HFC-365mfc, HFC-245fa, and to a lesser extent, PFCs. Electronics cleaning involves removing flux residue that remains after a soldering operation for printed circuit boards and other contamination-sensitive electronics applications. Precision cleaning may apply to either electronic components or to metal surfaces, and is characterized by products, such as disk drives, gyroscopes, and optical components, that require a high level of cleanliness and generally have complex shapes, small clearances, and other cleaning

[120] R-410A contains HFC-32 and HFC-125.

[121] R-507A, also called R-507, contains HFC-125 and HFC-143a.

challenges. The use of solvents yields fugitive emissions of these HFCs and PFCs.

Fire Protection

Fire protection applications include portable fire extinguishers ("streaming" applications) that originally used halon 1211, and total flooding applications that originally used halon 1301, as well as some halon 2402. Since the production and sale of halons were banned in the United States in 1994, the halon replacement agent of choice in the streaming sector has been dry chemical, although HFC-236ea is also used to a limited extent. In the total flooding sector, HFC-227ea has emerged as the primary replacement for halon 1301 in applications that require clean agents. Other HFCs, such as HFC-23, HFC-236fa, and HFC-125, are used in smaller amounts. The majority of HFC-227ea in total flooding systems is used to protect essential electronics, as well as in civil aviation, military mobile weapons systems, oil/gas/other process industries, and merchant shipping. As fire protection equipment is tested or deployed, emissions of these HFCs occur.

Methodology

A detailed Vintaging Model of ODS-containing equipment and products was used to estimate the actual—versus potential—emissions of various ODS substitutes, including HFCs and PFCs. The name of the model refers to the fact that it tracks the use and emissions of various compounds for the annual "vintages" of new equipment that enter service in each end-use. The Vintaging Model predicts ODS and ODS substitute use in the United States based on modeled estimates of the quantity of equipment or products sold each year containing these chemicals and the amount of the chemical required to manufacture and/or maintain equipment and products over time. Emissions for each end-use were estimated by applying annual leak rates and release profiles, which account for the lag in emissions from equipment as they leak over time. By aggregating the data for nearly 60 different end-uses, the model produces estimates of annual use and emissions of each compound. Further information on the Vintaging Model is contained in Annex 3.8.

Uncertainty

Given that emissions of ODS substitutes occur from thousands of different kinds of equipment and from millions of point and mobile sources throughout the United States, emission estimates must be made using analytical tools such as the Vintaging Model or the methods outlined in IPCC (2006). Though the model is more comprehensive than the IPCC default methodology, significant uncertainties still exist with regard to the levels of equipment sales, equipment characteristics, and end-use emissions profiles that were used to estimate annual emissions for the various compounds.

The Vintaging Model estimates emissions from nearly 60 end-uses. The uncertainty analysis, however, quantifies the level of uncertainty associated with the aggregate emissions resulting from the top 21 end-uses, comprising over 95 percent of the total emissions, and 5 other end-uses. These 26 end-uses comprise 97 percent of the total emissions. In an effort to improve the uncertainty analysis, additional end-uses are added annually, with the intention that over time uncertainty for all emissions from the Vintaging Model will be fully characterized. Any end-uses included in previous years' uncertainty analysis were included in the current uncertainty analysis, whether or not those end-uses were included in the top 95 percent of emissions from ODS Substitutes.

In order to calculate uncertainty, functional forms were developed to simplify some of the complex "vintaging" aspects of some end-use sectors, especially with respect to refrigeration and air-conditioning, and to a lesser degree, fire extinguishing. These sectors calculate emissions based on the entire lifetime of equipment, not just equipment put into commission in the current year, thereby necessitating simplifying equations. The functional forms used variables that included growth rates, emission factors, transition from ODSs, change in charge size as a result of the transition, disposal quantities, disposal emission rates, and either stock for the current year or original ODS consumption. Uncertainty was estimated around each variable within the functional forms based on expert judgment, and a Monte Carlo analysis was performed. The most significant sources of uncertainty for this source category include the emission factors for retail food equipment and refrigerated transport, as well as the percent of non-MDI aerosol propellant that is HFC-152a.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-87. Substitution of ozone depleting substances HFC and PFC emissions were estimated to be between 111.8 and 129.3 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below to 8 percent above the emission

estimate of 120.0 Tg CO_2 Eq.

Table 4-87: Tier 2 Quantitative Uncertainty Estimates for HFC and PFC Emissions from ODS Substitutes (Tg CO_2 Eq. and Percent)

Source	Gases	2009 Emission Estimate (Tg CO_2 Eq.)[a]	Uncertainty Range Relative to Emission Estimate[b] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Substitution of Ozone Depleting Substances	HFCs and PFCs	117.1	109.0	126.5	-7%	+8%

[a] 2009 emission estimates and the uncertainty range presented in this table correspond to selected end-uses within the aerosols, foams, solvents, fire extinguishing agents, and refrigerants sectors, but not for other remaining categories. Therefore, because the uncertainty associated with emissions from "other" ODS substitutes was not estimated, they were excluded in the estimates reported in this table.
[b] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Recalculations Discussion

An extensive review of the MDI aerosol, unitary air-conditioning, and domestic refrigerator foams markets resulted in revisions to the Vintaging Model since the previous Inventory. For MDI aerosols, the charge size for both the CFC and HFC propellants was revised. Based on research on substitutes and growth in the market, the percent of the CFC market that transitions to HFCs over the time series and the overall size of the MDI market decreased. For unitary air-conditioning, a review of air conditioner sales data reduced the quantity of air-conditioning equipment introduced into the market for 1990 through1993 and 2008, while increasing the quantity of equipment sold into the market for 1994 through 2009. A review of the domestic refrigerator foams market increased the quantity of blowing agent consumed in the foam and decreased the quantity of blowing agent emitted during the foam manufacturing process. Overall, these changes to the Vintaging Model increased greenhouse gas emissions on average by 0.5 percent across the time series.

4.21. Semiconductor Manufacture (IPCC Source Category 2F6)

The semiconductor industry uses multiple long-lived fluorinated gases in plasma etching and plasma enhanced chemical vapor deposition (PECVD) processes to produce semiconductor products. The gases most commonly employed are trifluoromethane (HFC-23 or CHF_3), perfluoromethane (CF_4), perfluoroethane (C_2F_6), nitrogen trifluoride (NF_3), and sulfur hexafluoride (SF_6), although other compounds such as perfluoropropane (C_3F_8) and perfluorocyclobutane (c-C_4F_8) are also used. The exact combination of compounds is specific to the process employed.

A single 300 mm silicon wafer that yields between 400 to 500 semiconductor products (devices or chips) may require as many as 100 distinct fluorinated-gas-using process steps, principally to deposit and pattern dielectric films. Plasma etching (or patterning) of dielectric films, such as silicon dioxide and silicon nitride, is performed to provide pathways for conducting material to connect individual circuit components in each device. The patterning process uses plasma-generated fluorine atoms, which chemically react with exposed dielectric film to selectively remove the desired portions of the film. The material removed as well as undissociated fluorinated gases flow into waste streams and, unless emission abatement systems are employed, into the atmosphere. PECVD chambers, used for depositing dielectric films, are cleaned periodically using fluorinated and other gases. During the cleaning cycle the gas is converted to fluorine atoms in plasma, which etches away residual material from chamber walls, electrodes, and chamber hardware. Undissociated fluorinated gases and other products pass from the chamber to waste streams and, unless abatement systems are employed, into the atmosphere. In addition to emissions of unreacted gases, some fluorinated compounds can also be transformed in the plasma processes into different fluorinated compounds which are then exhausted, unless abated, into the atmosphere. For example, when C_2F_6 is used in cleaning or etching, CF_4 is generated and emitted as a process by-product. Besides dielectric film etching and PECVD chamber cleaning, much smaller quantities of fluorinated gases are used to etch polysilicon films and

refractory metal films like tungsten.

For 2009, total weighted emissions of all fluorinated greenhouse gases by the U.S. semiconductor industry were estimated to be 5.3 Tg CO_2 Eq. Combined emissions of all fluorinated greenhouse gases are presented in Table 4-88 and Table 4-89 below for years 1990, 2000 and the period 2005 to 2009. The rapid growth of this industry and the increasing complexity (growing number of layers)[122] of semiconductor products led to an increase in emissions of 148 percent between 1990 and 1999, when emissions peaked at 7.2 Tg CO_2 Eq. The emissions growth rate began to slow after 1998, and emissions declined by 26 percent between 1999 and 2009. Together, industrial growth and adoption of emissions reduction technologies, including but not limited to abatement technologies, resulted in a net increase in emissions of 83 percent between 1990 and 2009.

Table 4-88: PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture (Tg CO_2 Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
CF_4	0.7	1.8	1.1	1.2	1.3	1.4	1.5
C_2F_6	1.5	3.0	2.0	2.2	2.3	2.4	2.5
C_3F_8	0.0	0.1	0.0	0.0	0.0	0.1	0.0
C_4F_8	0.0	0.0	0.1	0.1	0.1	0.1	0.0
HFC-23	0.2	0.3	0.2	0.3	0.3	0.3	0.3
SF_6	0.5	1.1	1.0	1.0	0.8	0.9	1.0
NF_3*	0.0	0.2	0.4	0.7	0.5	0.6	0.5
Total	**2.9**	**6.2**	**4.4**	**4.7**	**4.8**	**5.1**	**5.3**

Note: Totals may not sum due to independent rounding.
* NF_3 emissions are presented for informational purposes, using the AR4 GWP of 17,200, and are not included in totals.

Table 4-89: PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture (Mg)

Year	1990	2000	2005	2006	2007	2008	2009
CF_4	115	281	168	181	198	216	227
C_2F_6	160	321	216	240	249	261	271
C_3F_8	0	18	5	5	6	13	5
C_4F_8	0	0	13	13	7	7	4
HFC-23	15	23	18	22	23	25	28
SF_6	22	45	40	40	34	36	40
NF_3	3	11	26	40	30	33	30

Methodology

Emissions are based on Partner reported emissions data received through the EPA's PFC Reduction/Climate Partnership and the EPA's PFC Emissions Vintage Model (PEVM), a model which estimates industry emissions in the absence of emission control strategies (Burton and Beizaie 2001).[123] The availability and applicability of Partner data differs across the 1990 through 2009 time series. Consequently, emissions from semiconductor manufacturing were estimated using four distinct methods, one each for the periods 1990 through 1994, 1995 through 1999, 2000 through 2006, and 2007 through 2009.

1990 through 1994

From 1990 through 1994, Partnership data was unavailable and emissions were modeled using the PEVM (Burton

[122] Complexity is a term denoting the circuit required to connect the active circuit elements (transistors) on a chip. Increasing miniaturization, for the same chip size, leads to increasing transistor density, which, in turn, requires more complex interconnections between those transistors. This increasing complexity is manifested by increasing the levels (i.e., layers) of wiring, with each wiring layer requiring fluorinated gas usage for its manufacture.

[123] A Partner refers to a participant in the U.S. EPA PFC Reduction/Climate Partnership for the Semiconductor Industry. Through a Memorandum of Understanding (MoU) with the EPA, Partners voluntarily report their PFC emissions to the EPA by way of a third party, which aggregates the emissions.

and Beizaie 2001).[124] 1990 to 1994 emissions are assumed to be uncontrolled, since reduction strategies such as chemical substitution and abatement were yet to be developed.

PEVM is based on the recognition that PFC emissions from semiconductor manufacturing vary with: (1) the number of layers that comprise different kinds of semiconductor devices, including both silicon wafer and metal interconnect layers, and (2) silicon consumption (i.e., the area of semiconductors produced) for each kind of device. The product of these two quantities, Total Manufactured Layer Area (TMLA), constitutes the activity data for semiconductor manufacturing. PEVM also incorporates an emission factor that expresses emissions per unit of layer-area. Emissions are estimated by multiplying TMLA by this emission factor.

PEVM incorporates information on the two attributes of semiconductor devices that affect the number of layers: (1) linewidth technology (the smallest manufactured feature size), [125] and (2) product type (discrete, memory or logic).[126] For each linewidth technology, a weighted average number of layers is estimated using VLSI product-specific worldwide silicon demand data in conjunction with complexity factors (i.e., the number of layers per Integrated Circuit (IC)) specific to product type (Burton and Beizaie 2001, ITRS 2007). PEVM derives historical consumption of silicon (i.e., square inches) by linewidth technology from published data on annual wafer starts and average wafer size (VLSI Research, Inc. 2010).

The emission factor in PEVM is the average of four historical emission factors, each derived by dividing the total annual emissions reported by the Partners for each of the four years between 1996 and 1999 by the total TMLA estimated for the Partners in each of those years. Over this period, the emission factors varied relatively little (i.e., the relative standard deviation for the average was 5 percent). Since Partners are believed not to have applied significant emission reduction measures before 2000, the resulting average emission factor reflects uncontrolled emissions. The emission factor is used to estimate world uncontrolled emissions using publicly available data on world silicon consumption.

1995 through 1999

For 1995 through 1999, total U.S. emissions were extrapolated from the total annual emissions reported by the Partners (1995 through 1999). Partner-reported emissions are considered more representative (e.g., in terms of capacity utilization in a given year) than PEVM estimated emissions, and are used to generate total U.S. emissions when applicable. The emissions reported by the Partners were divided by the ratio of the total capacity of the plants operated by the Partners and the total capacity of all of the semiconductor plants in the United States; this ratio represents the share of capacity attributable to the Partnership. This method assumes that Partners and non-Partners have identical capacity utilizations and distributions of manufacturing technologies. Plant capacity data is contained in the World Fab Forecast (WFF) database and its predecessors, which is updated quarterly (Semiconductor Equipment and Materials Industry 2010).

2000 through 2006

The emission estimate for the years 2000 through 2006—the period during which Partners began the consequential application of PFC-reduction measures—was estimated using a combination of Partner reported emissions and PEVM modeled emissions. The emissions reported by Partners for each year were accepted as the quantity emitted from the share of the industry represented by those Partners. Remaining emissions, those from non-Partners, were

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[124] Various versions of the PEVM exist to reflect changing industrial practices. From 1990 to 1994 emissions estimates are from PEVM v1.0, completed in September 1998. The emission factor used to estimate 1990 to 1994 emissions is an average of the 1995 and 1996 emissions factors, which were derived from Partner reported data for those years.

[125] By decreasing features of Integrated Circuit components, more components can be manufactured per device, which increases its functionality. However, as those individual components shrink it requires more layers to interconnect them to achieve the functionality. For example, a microprocessor manufactured with the smallest feature sizes (65 nm) might contain as many as 1 billion transistors and require as many as 11 layers of component interconnects to achieve functionality while a device manufactured with 130 nm feature size might contain a few hundred million transistors and require 8 layers of component interconnects (ITRS 2007).

[126] Memory devices manufactured with the same feature sizes as microprocessors (a logic device) require approximately one-half the number of interconnect layers, whereas discrete devices require only a silicon base layer and no interconnect layers (ITRS 2007). Since discrete devices did not start using PFCs appreciably until 2004, they are only accounted for in the PEVM emissions estimates from 2004 onwards.

estimated using PEVM and the method described above. This is because non-Partners are assumed not to have implemented any PFC-reduction measures, and PEVM models emissions without such measures. The portion of the U.S. total attributed to non-Partners is obtained by multiplying PEVM's total U.S. emissions figure by the non-Partner share of U. S. total silicon capacity for each year as described above.[127,128] Annual updates to PEVM reflect published figures for actual silicon consumption from VLSI Research, Inc., revisions and additions to the world population of semiconductor manufacturing plants, and changes in IC fabrication practices within the semiconductor industry (see ITRS 2007 and Semiconductor Equipment and Materials Industry 2010).[129,130,131]

2007 through 2009

For the years 2007 through 2009, emissions were also estimated using a combination of Partner reported emissions and PEVM modeled emissions; however, two improvements were made to the estimation method employed for the previous years in the time series. First, the 2007 through 2009 emission estimates account for the fact that Partners and non-Partners employ different distributions of manufacturing technologies, with the Partners using manufacturing technologies with greater transistor densities and therefore greater numbers of layers.[132] Second, the scope of the 2007 through 2009 estimates is expanded relative to the estimates for the years 2000 through 2006 to include emissions from Research and Development (R&D) fabs. This was feasible through the use of more detailed data published in the World Fab Forecast. PEVM databases are updated annually as described above. The published world average capacity utilization for 2007 and 2008 was used for production fabs while in 2008 for R&D fabs a 20 percent figure was assumed (SIA 2009).

In addition, publicly available actual utilization data was used to account for differences in fab utilization for manufacturers of discrete and IC products for the emissions in 2009 for non-partners. PEVM estimates were adjusted using technology weighted capacity shares that reflect relative influence of different utilization.

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[127] This approach assumes that the distribution of linewidth technologies is the same between Partners and non-Partners. As discussed in the description of the method used to estimate 2007 emissions, this is not always the case.

[128] Generally 5 percent or less of the fields needed to estimate TMLA shares are missing values in the World Fab Watch databases. In the 2007 World Fab Watch database used to generate the 2006 non-Partner TMLA capacity share, these missing values were replaced with the corresponding mean TMLA across fabs manufacturing similar classes of products. However, the impact of replacing missing values on the non-Partner TMLA capacity share was inconsequential.

[129] Special attention was given to the manufacturing capacity of plants that use wafers with 300 mm diameters because the actual capacity of these plants is ramped up to design capacity, typically over a 2–3 year period. To prevent overstating estimates of partner-capacity shares from plants using 300 mm wafers, *design* capacities contained in WFW were replaced with estimates of *actual installed* capacities for 2004 published by Citigroup Smith Barney (2005). Without this correction, the partner share of capacity would be overstated, by approximately 5 percent. For perspective, approximately 95 percent of all new capacity additions in 2004 used 300 mm wafers, and by year-end those plants, on average, could operate at approximately 70 percent of the design capacity. For 2005, actual installed capacities were estimated using an entry in the World Fab Watch database (April 2006 Edition) called "wafers/month, 8-inch equivalent," which denoted the actual installed capacity instead of the fully-ramped capacity. For 2006, actual installed capacities of new fabs were estimated using an average monthly ramp rate of 1100 wafer starts per month (wspm) derived from various sources such as semiconductor fabtech, industry analysts, and articles in the trade press. The monthly ramp rate was applied from the first-quarter of silicon volume (FQSV) to determine the average design capacity over the 2006 period.

[130] In 2006, the industry trend in co-ownership of manufacturing facilities continued. Several manufacturers, who are Partners, now operate fabs with other manufacturers, who in some cases are also Partners and in other cases are not Partners. Special attention was given to this occurrence when estimating the Partner and non-Partner shares of U.S. manufacturing capacity.

[131] Two versions of PEVM are used to model non-Partner emissions during this period. For the years 2000 to 2003 PEVM v3.2.0506.0507 was used to estimate non-Partner emissions. During this time, discrete devices did not use PFCs during manufacturing and therefore only memory and logic devices were modeled in the PEVM v3.2.0506.0507. From 2004 onwards, discrete device fabrication started to use PFCs, hence PEVM v4.0.0701.0701, the first version of PEVM to account for PFC emissions from discrete devices, was used to estimate non-Partner emissions for this time period.

[132] EPA considered applying this change to years before 2007, but found that it would be difficult due to the large amount of data (i.e., technology-specific global and non-Partner TMLA) that would have to be examined and manipulated for each year. This effort did not appear to be justified given the relatively small impact of the improvement on the total estimate for 2007 and the fact that the impact of the improvement would likely be lower for earlier years because the estimated share of emissions accounted for by non-Partners is growing as Partners continue to implement emission-reduction efforts.

Gas-Specific Emissions

Two different approaches were also used to estimate the distribution of emissions of specific fluorinated gases. Before 1999, when there was no consequential adoption of fluorinated-gas-reducing measures, a fixed distribution of fluorinated-gas use was assumed to apply to the entire U.S. industry. This distribution was based upon the average fluorinated-gas purchases made by semiconductor manufacturers during this period and the application of IPCC default emission factors for each gas (Burton and Beizaie 2001). For the 2000 through 2009 period, the 1990 through 1999 distribution was assumed to apply to the non-Partners. Partners, however, began reporting gas-specific emissions during this period. Thus, gas-specific emissions for 2000 through 2009 were estimated by adding the emissions reported by the Partners to those estimated for the non-Partners.

Data Sources

Partners estimate their emissions using a range of methods. For 2009, it is assumed that most Partners used a method at least as accurate as the IPCC's Tier 2a Methodology, recommended in the 2006 IPCC Guidelines for National Greenhouse Inventories (IPCC 2006). Data used to develop emission estimates are attributed in part to estimates provided by the members of the Partnership, and in part from data obtained from PEVM estimates. Estimates of operating plant capacities and characteristics for Partners and non-Partners were derived from the Semiconductor Equipment and Materials Industry (SEMI) World Fab Forecast (formerly World Fab Watch) database (1996 through 2009) (e.g., Semiconductor Materials and Equipment Industry, 2010). Actual world capacity utilizations for 2009 were obtained from Semiconductor International Capacity Statistics (SICAS) (SIA, 2009). Estimates of silicon consumed by linewidth from 1990 through 2009 were derived from information from VLSI Research, Inc. (2010), and the number of layers per linewidth was obtained from International Technology Roadmap for Semiconductors: 2006 Update (Burton and Beizaie 2001, ITRS 2007, ITRS 2008).

Uncertainty and Time Series Consistency

A quantitative uncertainty analysis of this source category was performed using the IPCC-recommended Tier 2 uncertainty estimation methodology, the Monte Carlo Stochastic Simulation technique. The equation used to estimate uncertainty is:

$$\text{U.S. emissions} = \sum\text{Partnership gas-specific submittals} + [(\text{non-Partner share of World TMLA}) \times (\text{PEVM Emission Factor} \times \text{World TMLA})]$$

The Monte Carlo analysis results presented below relied on estimates of uncertainty attributed to the four quantities on the right side of the equation. Estimates of uncertainty for the four quantities were in turn developed using the estimated uncertainties associated with the individual inputs to each quantity, error propagation analysis, Monte Carlo simulation, and expert judgment. The relative uncertainty associated with World TMLA estimate in 2009 is about ±10 percent, based on the uncertainty estimate obtained from discussions with VLSI, Inc. For the share of World layer-weighted silicon capacity accounted for by non-Partners, a relative uncertainty of ±8 percent was estimated based on a separate Monte Carlo simulation to account for the random occurrence of missing data in the World Fab Watch database. For the aggregate PFC emissions data supplied to the partnership, a relative uncertainty of ±50 percent was estimated for each gas-specific PFC emissions value reported by an individual Partner, and error propagation techniques were used to estimate uncertainty for total Partnership gas-specific submittals.[133] A relative uncertainty of approximately ±10 percent was estimated for the PEVM emission factor, based on the standard deviation of the 1996 to 1999 emission factors.[134] All estimates of uncertainties are given at 95-percent confidence intervals.

In developing estimates of uncertainty, consideration was also given to the nature and magnitude of the potential bias that World activity data (i.e., World TMLA) might have in its estimates of the number of layers associated with devices manufactured at each technology node. The result of a brief analysis indicated that U.S. TMLA overstates the average number of layers across all product categories and all manufacturing technologies for 2004 by 0.12 layers or 2.9 percent. The same upward bias is assumed for World TMLA, and is represented in the uncertainty analysis by deducting the absolute bias value from the World activity estimate when it is incorporated into the

[133] Error propagation resulted in Partnership gas-specific uncertainties ranging from 17 to 27 percent.

[134] The average of 1996 to 1999 emission factor is used to derive the PEVM emission factor.

Monte Carlo analysis.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-90. The emissions estimate for total U.S. PFC emissions from semiconductor manufacturing were estimated to be between 4.8 and 5.9 Tg CO_2 Eq. at a 95 percent confidence level. This range represents 10 percent below to 11 percent above the 2009 emission estimate of 5.3 Tg CO_2 Eq. This range and the associated percentages apply to the estimate of total emissions rather than those of individual gases. Uncertainties associated with individual gases will be somewhat higher than the aggregate, but were not explicitly modeled.

Table 4-90: Tier 2 Quantitative Uncertainty Estimates for HFC, PFC, and SF_6 Emissions from Semiconductor Manufacture (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate[a] (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[b] (Tg CO_2 Eq.)		(%)	
			Lower Bound[c]	Upper Bound[c]	Lower Bound	Upper Bound
Semiconductor Manufacture	HFC, PFC, and SF_6	5.3	4.8	5.9	−10%	+11%

[a] Because the uncertainty analysis covered all emissions (including NF_3), the emission estimate presented here does not match that shown in Table 4-88.
[b] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
[c] Absolute lower and upper bounds were calculated using the corresponding lower and upper bounds in percentages.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

With the exception of possible future updates to emission factors, the method to estimate non-Partner related emissions (i.e., PEVM) is not expected to change. Future improvements to the national emission estimates will primarily be associated with determining the portion of national emissions to attribute to Partner report totals (about 80 percent in recent years) and improvements in estimates of non-Partner totals. As the nature of the Partner reports change through time and industry-wide reduction efforts increase, consideration will be given to what emission reduction efforts—if any—are likely to be occurring at non-Partner facilities. Currently, none are assumed to occur.

Another point of consideration for future national emissions estimates is the inclusion of PFC emissions from heat transfer fluid (HTF) loss to the atmosphere and the production of photovoltaic cells (PVs). Heat transfer fluids, of which some are liquid perfluorinated compounds, are used during testing of semiconductor devices and, increasingly, are used to manage heat during the manufacture of semiconductor devices. Evaporation of these fluids is a source of emissions (EPA 2006). PFCs are also used during manufacture of PV cells that use silicon technology, specifically, crystalline, polycrystalline, and amorphous silicon technologies. PV manufacture is growing in the United States, and therefore may be expected to constitute a growing share of U.S. PFC emissions from the electronics sector.

4.22. Electrical Transmission and Distribution (IPCC Source Category 2F7)

The largest use of SF_6, both in the United States and internationally, is as an electrical insulator and interrupter in equipment that transmits and distributes electricity (RAND 2004). The gas has been employed by the electric power industry in the United States since the 1950s because of its dielectric strength and arc-quenching characteristics. It is used in gas-insulated substations, circuit breakers, and other switchgear. Sulfur hexafluoride has replaced flammable insulating oils in many applications and allows for more compact substations in dense urban areas.

Fugitive emissions of SF_6 can escape from gas-insulated substations and switchgear through seals, especially from older equipment. The gas can also be released during equipment manufacturing, installation, servicing, and disposal. Emissions of SF_6 from equipment manufacturing and from electrical transmission and distribution systems were estimated to be 12.8 Tg CO_2 Eq. (0.5 Gg) in 2009. This quantity represents a 55 percent decrease from the estimate for 1990 (see Table 4-91 and Table 4-92). This decrease is believed to have two causes: a sharp increase in the price of SF_6 during the 1990s and a growing awareness of the environmental impact of SF_6 emissions through

programs such as EPA's SF_6 Emission Reduction Partnership for Electric Power Systems.

Table 4-91: SF_6 Emissions from Electric Power Systems and Electrical Equipment Manufacturers (Tg CO_2 Eq.)

Year	Electric Power Systems	Electrical Equipment Manufacturers	Total
1990	28.1	0.3	28.4
2000	15.4	0.7	16.0
2005	14.1	1.1	15.1
2006	13.1	1.0	14.1
2007	12.4	0.8	13.2
2008	12.1	1.3	13.3
2009	12.1	0.7	12.8

Note: Totals may not sum due to independent rounding.

Table 4-92: SF_6 Emissions from Electric Power Systems and Electrical Equipment Manufacturers (Gg)

Year	Emissions
1990	1.2
2000	0.7
2005	0.6
2006	0.6
2007	0.6
2008	0.6
2009	0.5

Methodology

The estimates of emissions from Electric Transmission and Distribution are comprised of emissions from electric power systems and emissions from the manufacture of electrical equipment. The methodologies for estimating both sets of emissions are described below.

1999 through 2009 Emissions from Electric Power Systems

Emissions from electric power systems from 1999 to 2009 were estimated based on: (1) reporting from utilities participating in EPA's SF_6 Emission Reduction Partnership for Electric Power Systems (Partners), which began in 1999; and, (2) the relationship between emissions and utilities' transmission miles as reported in the 2001, 2004, 2007, and 2010 Utility Data Institute (UDI) Directories of Electric Power Producers and Distributors (UDI 2001, 2004, 2007, 2010). (Transmission miles are defined as the miles of lines carrying voltages above 34.5 kV.) Over the period from 1999 to 2009, Partner utilities, which for inventory purposes are defined as utilities that either currently are or previously have been part of the Partnership, represented between 42 percent and 47 percent of total U.S. transmission miles. For each year, the emissions reported by or estimated for Partner utilities were added to the emissions estimated for utilities that have never participated in the Partnership (i.e., non-Partners).[135]

Partner utilities estimated their emissions using a Tier 3 utility-level mass balance approach (IPCC 2006). If a Partner utility did not provide data for a particular year, emissions were interpolated between years for which data were available or extrapolated based on Partner-specific transmission mile growth rates. In 2009, non-reporting Partners accounted for approximately 8 percent of the total emissions attributed to Partner utilities.

Emissions from non-Partners in every year since 1999 were estimated using the results of a regression analysis that showed that the emissions from reporting utilities were most strongly correlated with their transmission miles. The results of this analysis are not surprising given that, in the United States, SF_6 is contained primarily in transmission

[135] Partners in EPA's SF_6 Emission Reduction Partnership reduced their emissions by approximately 61% from 1999 to 2008.

equipment rated above 34.5 kV. The equations were developed based on the 1999 SF_6 emissions reported by a subset of 42 Partner utilities (representing approximately 23 percent of U.S. transmission miles) and 2000 transmission mileage data obtained from the 2001 UDI Directory of Electric Power Producers and Distributors (UDI 2001). Two equations were developed, one for small and one for large utilities (i.e., with fewer or more than 10,000 transmission miles, respectively). The distinction between utility sizes was made because the regression analysis showed that the relationship between emissions and transmission miles differed for small and large transmission networks. The same equations were used to estimate non-Partner emissions in 1999 and every year thereafter because non-Partners were assumed not to have implemented any changes that would have resulted in reduced emissions since 1999.

The regression equations are:

Non-Partner small utilities (fewer than 10,000 transmission miles, in kilograms):

$$\text{Emissions (kg)} = 1.001 \times \text{Transmission Miles}$$

Non-Partner large utilities (more than 10,000 transmission miles, in kilograms):

$$\text{Emissions (kg)} = 0.58 \times \text{Transmission Miles}$$

Data on transmission miles for each non-Partner utility for the years 2000, 2003, 2006, and 2009 were obtained from the 2001, 2004, 2007, and 2010 UDI Directories of Electric Power Producers and Distributors, respectively (UDI 2001, 2004, 2007, 2010). The U.S. transmission system grew by over 25,000 miles between 2000 and 2003 and by over 52,000 miles between 2003 and 2006. These periodic increases are assumed to have occurred gradually. Therefore, transmission mileage was assumed to increase at an annual rate of 1.3 percent between 2000 and 2003 and 2.6 percent between 2003 and 2006. This growth rate slowed to 0.2% from 2006 to 2009 as transmission miles increased by just 4,400 miles (approximately).

As a final step, total electric power system emissions were determined for each year by summing the Partner reported and estimated emissions (reported data was available through the EPA's SF_6 Emission Reduction Partnership for Electric Power Systems) and the non-Partner emissions (determined using the 1999 regression equations).

1990 through 1998 Emissions from Electric Power Systems

Because most participating utilities reported emissions only for 1999 through 2009, modeling was used to estimate SF_6 emissions from electric power systems for the years 1990 through 1998. To perform this modeling, U.S. emissions were assumed to follow the same trajectory as global emissions from this source during the 1990 to 1999 period. To estimate global emissions, the RAND survey of global SF_6 sales were used, together with the following equation for estimating emissions, which is derived from the mass-balance equation for chemical emissions (Volume 3, Equation 7.3) in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). [136] (Although equation 7.3 of the IPCC Guidelines appears in the discussion of substitutes for ozone-depleting substances, it is applicable to emissions from any long-lived pressurized equipment that is periodically serviced during its lifetime.)

$$\text{Emissions (kilograms } SF_6) = SF_6 \text{ purchased to refill existing equipment (kilograms)} + \text{nameplate capacity of retiring equipment (kilograms)} \text{ [137]}$$

Note that the above equation holds whether the gas from retiring equipment is released or recaptured; if the gas is recaptured, it is used to refill existing equipment, thereby lowering the amount of SF_6 purchased by utilities for this purpose.

Gas purchases by utilities and equipment manufacturers from 1961 through 2003 are available from the RAND (2004) survey. To estimate the quantity of SF_6 released or recovered from retiring equipment, the nameplate capacity of retiring equipment in a given year was assumed to equal 81.2 percent of the amount of gas purchased by

[136] Ideally, sales to utilities in the U.S. between 1990 and 1999 would be used as a model. However, this information was not available. There were only two U.S. manufacturers of SF_6 during this time period, so it would not have been possible to conceal sensitive sales information by aggregation.

[137] Nameplate capacity is defined as the amount of SF_6 within fully charged electrical equipment.

electrical equipment manufacturers 40 years previous (e.g., in 2000, the nameplate capacity of retiring equipment was assumed to equal 81.2 percent of the gas purchased in 1960). The remaining 18.8 percent was assumed to have been emitted at the time of manufacture. The 18.8 percent emission factor is an average of IPCC default SF_6 emission rates for Europe and Japan for 1995 (IPCC 2006). The 40-year lifetime for electrical equipment is also based on IPCC (2006). The results of the two components of the above equation were then summed to yield estimates of global SF_6 emissions from 1990 through 1999.

U.S. emissions between 1990 and 1999 are assumed to follow the same trajectory as global emissions during this period. To estimate U.S. emissions, global emissions for each year from 1990 through 1998 were divided by the estimated global emissions from 1999. The result was a time series of factors that express each year's global emissions as a multiple of 1999 global emissions. Historical U.S. emissions were estimated by multiplying the factor for each respective year by the estimated U.S. emissions of SF_6 from electric power systems in 1999 (estimated to be 15.0 Tg CO_2 Eq.).

Two factors may affect the relationship between the RAND sales trends and actual global emission trends. One is utilities' inventories of SF_6 in storage containers. When SF_6 prices rise, utilities are likely to deplete internal inventories before purchasing new SF_6 at the higher price, in which case SF_6 sales will fall more quickly than emissions. On the other hand, when SF_6 prices fall, utilities are likely to purchase more SF_6 to rebuild inventories, in which case sales will rise more quickly than emissions. This effect was accounted for by applying 3-year smoothing to utility SF_6 sales data. The other factor that may affect the relationship between the RAND sales trends and actual global emissions is the level of imports from and exports to Russia and China. SF_6 production in these countries is not included in the RAND survey and is not accounted for in any another manner by RAND. However, atmospheric studies confirm that the downward trend in estimated global emissions between 1995 and 1998 was real (see the Uncertainty discussion below).

1990 through 2009 Emissions from Manufacture of Electrical Equipment

The 1990 to 2009 emission estimates for original equipment manufacturers (OEMs) were derived by assuming that manufacturing emissions equal 10 percent of the quantity of SF_6 provided with new equipment. The quantity of SF_6 provided with new equipment was estimated based on statistics compiled by the National Electrical Manufacturers Association (NEMA). These statistics were provided for 1990 to 2000; the quantities of SF_6 provided with new equipment for 2001 to 2009 were estimated using Partner reported data and the total industry SF_6 nameplate capacity estimate (137.4 Tg CO_2 Eq. in 2009). Specifically, the ratio of new nameplate capacity to total nameplate capacity of a subset of Partners for which new nameplate capacity data was available from 1999 to 2009 was calculated. This ratio was then multiplied by the total industry nameplate capacity estimate to derive the amount of SF_6 provided with new equipment for the entire industry. The 10 percent emission rate is the average of the "ideal" and "realistic" manufacturing emission rates (4 percent and 17 percent, respectively) identified in a paper prepared under the auspices of the International Council on Large Electric Systems (CIGRE) in February 2002 (O'Connell et al. 2002).

Uncertainty

To estimate the uncertainty associated with emissions of SF_6 from Electric Transmission and Distribution, uncertainties associated with three quantities were estimated: (1) emissions from Partners, (2) emissions from non-Partners, and (3) emissions from manufacturers of electrical equipment. A Monte Carlo analysis was then applied to estimate the overall uncertainty of the emissions estimate.

Total emissions from the SF_6 Emission Reduction Partnership include emissions from both reporting and non-reporting Partners. For reporting Partners, individual Partner-reported SF_6 data was assumed to have an uncertainty of 10 percent. Based on a Monte Carlo analysis, the cumulative uncertainty of all Partner reported data was estimated to be 5.3 percent. The uncertainty associated with extrapolated or interpolated emissions from non-reporting Partners was assumed to be 20 percent.

There are two sources of uncertainty associated with the regression equations used to estimate emissions in 2009 from non-Partners: (1) uncertainty in the coefficients (as defined by the regression standard error estimate), and (2) the uncertainty in total transmission miles for non-Partners. In addition, there is uncertainty associated with the assumption that the emission factor used for non-Partner utilities (which accounted for approximately 57 percent of U.S. transmission miles in 2009) will remain at levels defined by Partners who reported in 1999. However, the last

source of uncertainty was not modeled.

Uncertainties were also estimated regarding (1) the quantity of SF_6 supplied with equipment by equipment manufacturers, which is projected from Partner provided nameplate capacity data and industry SF_6 nameplate capacity estimates, and (2) the manufacturers' SF_6 emissions rate.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-93. Electrical Transmission and Distribution SF_6 emissions were estimated to be between 10.2 and 15.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 21 percent below and 22 percent above the emission estimate of 12.8 Tg CO_2 Eq.

Table 4-93: Tier 2 Quantitative Uncertainty Estimates for SF_6 Emissions from Electrical Transmission and Distribution (Tg CO_2 Eq. and percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to 2009 Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Electrical Transmission and Distribution	SF_6	12.8	10.2	15.7	-21%	+22%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

In addition to the uncertainty quantified above, there is uncertainty associated with using global SF_6 sales data to estimate U.S. emission trends from 1990 through 1999. However, the trend in global emissions implied by sales of SF_6 appears to reflect the trend in global emissions implied by changing SF_6 concentrations in the atmosphere. That is, emissions based on global sales declined by 29 percent between 1995 and 1998, and emissions based on atmospheric measurements declined by 27 percent over the same period.

Several pieces of evidence indicate that U.S. SF_6 emissions were reduced as global emissions were reduced. First, the decreases in sales and emissions coincided with a sharp increase in the price of SF_6 that occurred in the mid-1990s and that affected the United States as well as the rest of the world. A representative from DILO, a major manufacturer of SF_6 recycling equipment, stated that most U.S. utilities began recycling rather than venting SF_6 within two years of the price rise. Finally, the emissions reported by the one U.S. utility that reported 1990 through 1999 emissions to EPA showed a downward trend beginning in the mid-1990s.

Recalculations Discussion

SF_6 emission estimates for the period 1990 through 2008 were updated based on (1) new data from EPA's SF_6 Emission Reduction Partnership; (2) revisions to interpolated and extrapolated non-reported Partner data; and (3) a correction made to 2004 transmission mile data for a large Partnership utility that had been interpreted incorrectly from the UDI database in previous years. Updating the 2004 transmission mile data for the Partner changed the annual transmission mile growth rates used to extrapolate total U.S. transmission mile values for years in which a UDI database was not purchased (including 1999). This recalculation impacted emission estimates in two ways. First, the regression coefficients used to estimate emissions for non-Partners are based on 1999 transmission miles and emissions for Partners that reported emissions in 1999, so the change in 1999 transmission miles affected the regression coefficients. The result was that the regression coefficient for utilities with fewer than 10,000 transmission miles increased from 0.89 to 1.001 kg of emissions per transmission mile, while the regression coefficient for utilities with more than 10,000 transmission miles increased very slightly from 0.577 to 0.578 kg of emissions per transmission mile. The second impact of the updated annual transmission mile growth rates was that the total non-Partner transmission miles that the regression coefficients are applied to were also affected. Based on the revisions listed above, SF_6 emissions from electric transmission and distribution increased between 4 to 9 percent for each year from 1990 through 2008.

In addition, the method for estimating potential emissions from the sector was updated for the 1990-2009 Inventory. In previous years, potential emissions were assumed to equal total industry SF_6 purchases, which were developed from two components: (1) purchases by Partner utilities from bulk gas distributors, and (2) purchases by electrical equipment manufacturers from bulk gas distributors. This previous method led to concerns of double-counting since Partners sometimes were recording all SF_6 received in cylinders from any source (including equipment

manufacturers) as gas received from bulk distributors. Therefore, SF_6 that was purchased by a utility from an equipment manufacturer was sometimes counted as a purchase by both the equipment manufacturer and the utility. The new method still assumes that potential emissions are equal to industry purchases, but estimates total purchases for the industry by adding the total amount of gas purchased by all U.S. utilities from any source (bulk distributor or equipment manufacturer) to estimated emissions from equipment manufacturers. It is assumed that all SF_6 purchased by equipment manufacturers is either emitted or sent to utilities.

4.23. Industrial Sources of Indirect Greenhouse Gases

In addition to the main greenhouse gases addressed above, many industrial processes generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) from non-energy industrial processes from 1990 to 2009 are reported in Table 4-94.

Table 4-94: NO_x, CO, and NMVOC Emissions from Industrial Processes (Gg)

Gas/Source	1990	1995	2000	2005	2006	2007	2008	2009
NO_x	**591**	**607**	**626**	**569**	**553**	**537**	**520**	**568**
Other Industrial Processes	343	362	435	437	418	398	379	436
Chemical & Allied Product Manufacturing	152	143	95	55	57	59	61	55
Metals Processing	88	89	81	60	61	62	62	60
Storage and Transport	3	5	14	15	15	16	16	15
Miscellaneous*	5	8	2	2	2	2	2	2
CO	**4,125**	**3,959**	**2,216**	**1,555**	**1,597**	**1,640**	**1,682**	**1,549**
Metals Processing	2,395	2,159	1,175	752	788	824	859	752
Other Industrial Processes	487	566	537	484	474	464	454	484
Chemical & Allied Product Manufacturing	1,073	1,110	327	189	206	223	240	187
Storage and Transport	69	23	153	97	100	103	104	97
Miscellaneous*	101	102	23	32	30	27	25	29
NMVOCs	**2,422**	**2,642**	**1,773**	**1,997**	**1,933**	**1,869**	**1,804**	**1,322**
Storage and Transport	1,352	1,499	1,067	1,308	1,266	1,224	1,182	662
Other Industrial Processes	364	408	412	415	398	383	367	395
Chemical & Allied Product Manufacturing	575	599	230	213	211	210	207	206
Metals Processing	111	113	61	44	44	43	42	44
Miscellaneous*	20	23	3	17	14	10	7	15

* Miscellaneous includes the following categories: catastrophic/accidental release, other combustion, health services, cooling towers, and fugitive dust. It does not include agricultural fires or slash/prescribed burning, which are accounted for under the Field Burning of Agricultural Residues source.
Note: Totals may not sum due to independent rounding.

Methodology

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual categories from various agencies. Depending on the category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and accurate estimates of activity data. A quantitative uncertainty analysis was not performed.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2008. Details on the emission trends through time are described in more detail in the Methodology section, above.

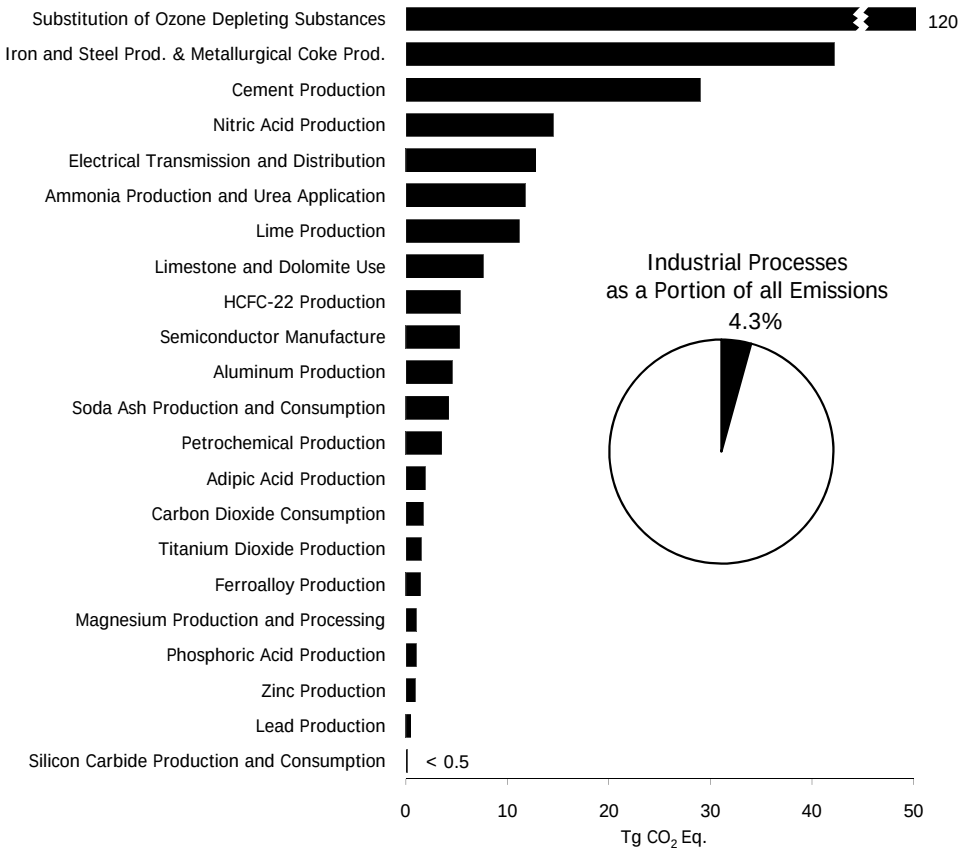


Figure 4-1: 2009 Industrial Processes Chapter Greenhouse Gas Sources

5. Solvent and Other Product Use

Greenhouse gas emissions are produced as a by-product of various solvent and other product uses. In the United States, emissions from Nitrous Oxide (N_2O) Product Uses, the only source of greenhouse gas emissions from this sector, accounted for less than 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a CO_2 equivalent basis in 2009 (see Table 5-1). Indirect greenhouse gas emissions also result from solvent and other product use, and are presented in Table 5-5 in gigagrams (Gg).

Table 5-1: N_2O Emissions from Solvent and Other Product Use (Tg CO_2 Eq. and Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
N_2O from Product Uses							
Tg CO_2 Eq.	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Gg	14	16	14	14	14	14	14

5.1. Nitrous Oxide from Product Uses (IPCC Source Category 3D)

N_2O is a clear, colorless, oxidizing liquefied gas, with a slightly sweet odor. Two companies operate a total of five N_2O production facilities in the United States (Airgas 2007; FTC 2001). N_2O is primarily used in carrier gases with oxygen to administer more potent inhalation anesthetics for general anesthesia, and as an anesthetic in various dental and veterinary applications. As such, it is used to treat short-term pain, for sedation in minor elective surgeries, and as an induction anesthetic. The second main use of N_2O is as a propellant in pressure and aerosol products, the largest application being pressure-packaged whipped cream. Small quantities of N_2O also are used in the following applications:

- Oxidizing agent and etchant used in semiconductor manufacturing;
- Oxidizing agent used, with acetylene, in atomic absorption spectrometry;
- Production of sodium azide, which is used to inflate airbags;
- Fuel oxidant in auto racing; and
- Oxidizing agent in blowtorches used by jewelers and others (Heydorn 1997).

Production of N_2O in 2009 was approximately 15 Gg (Table 5-2).

Table 5-2: N_2O Production (Gg)

Year	Gg
1990	16
2000	17
2005	15
2006	15
2007	15
2008	15
2009	15

N_2O emissions were 4.4 Tg CO_2 Eq. (14 Gg) in 2009 (Table 5-3). Production of N_2O stabilized during the 1990s because medical markets had found other substitutes for anesthetics, and more medical procedures were being performed on an outpatient basis using local anesthetics that do not require N_2O. The use of N_2O as a propellant for whipped cream has also stabilized due to the increased popularity of cream products packaged in reusable plastic tubs (Heydorn 1997).

Table 5-3: N_2O Emissions from N_2O Product Usage (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	4.4	14

2000	4.9	16
2005	4.4	14
2006	4.4	14
2007	4.4	14
2008	4.4	14
2009	4.4	14

Methodology

Emissions from N_2O product usage were calculated by first multiplying the total amount of N_2O produced in the United States by the share of the total quantity of N_2O attributed to each end use. This value was then multiplied by the associated emission rate for each end use. After the emissions were calculated for each end use, they were added together to obtain a total estimate of N_2O product usage emissions. Emissions were determined using the following equation:

$$N_2O \text{ Product Usage Emissions} = \sum i \text{ [Total U.S. Production of } N_2O\text{]} \times \text{[Share of Total Quantity of } N_2O \text{ Usage by Sector i]} \times \text{[Emissions Rate for Sector i]}$$

where,

i = Sector.

The share of total quantity of N_2O usage by end use represents the share of national N_2O produced that is used by the specific subcategory (i.e., anesthesia, food processing, etc.). In 2009, the medical/dental industry used an estimated 89.5 percent of total N_2O produced, followed by food processing propellants at 6.5 percent. All other categories combined used the remainder of the N_2O produced. This subcategory breakdown has changed only slightly over the past decade. For instance, the small share of N_2O usage in the production of sodium azide has declined significantly during the 1990s. Due to the lack of information on the specific time period of the phase-out in this market subcategory, most of the N_2O usage for sodium azide production is assumed to have ceased after 1996, with the majority of its small share of the market assigned to the larger medical/dental consumption subcategory (Heydorn 1997). The N_2O was allocated across the following categories: medical applications, food processing propellant, and sodium azide production (pre-1996). A usage emissions rate was then applied for each sector to estimate the amount of N_2O emitted.

Only the medical/dental and food propellant subcategories were estimated to release emissions into the atmosphere, and therefore these subcategories were the only usage subcategories with emission rates. For the medical/dental subcategory, due to the poor solubility of N_2O in blood and other tissues, none of the N_2O is assumed to be metabolized during anesthesia and quickly leaves the body in exhaled breath. Therefore, an emission factor of 100 percent was used for this subcategory (IPCC 2006). For N_2O used as a propellant in pressurized and aerosol food products, none of the N_2O is reacted during the process and all of the N_2O is emitted to the atmosphere, resulting in an emission factor of 100 percent for this subcategory (IPCC 2006). For the remaining subcategories, all of the N_2O is consumed/reacted during the process, and therefore the emission rate was considered to be zero percent (Tupman 2002).

The 1990 through 1992 N_2O production data were obtained from SRI Consulting's Nitrous Oxide, North America report (Heydorn 1997). N_2O production data for 1993 through 1995 were not available. Production data for 1996 was specified as a range in two data sources (Heydorn 1997, Tupman 2002). In particular, for 1996, Heydorn (1997) estimates N_2O production to range between 13.6 and 18.1 thousand metric tons. Tupman (2003) provided a narrower range (15.9 to 18.1 thousand metric tons) for 1996 that falls within the production bounds described by Heydorn (1997). Tupman (2003) data are considered more industry-specific and current. Therefore, the midpoint of the narrower production range was used to estimate N_2O emissions for years 1993 through 2001 (Tupman 2003). The 2002 and 2003 N_2O production data were obtained from the Compressed Gas Association Nitrous Oxide Fact Sheet and Nitrous Oxide Abuse Hotline (CGA 2002, 2003). These data were also provided as a range. For example, in 2003, CGA (2003) estimates N_2O production to range between 13.6 and 15.9 thousand metric tons. Due to unavailable data, production estimates for years 2004 through 2009 were held at the 2003 value.

The 1996 share of the total quantity of N_2O used by each subcategory was obtained from SRI Consulting's Nitrous

Oxide, North America report (Heydorn 1997). The 1990 through 1995 share of total quantity of N_2O used by each subcategory was kept the same as the 1996 number provided by SRI Consulting. The 1997 through 2001share of total quantity of N_2O usage by sector was obtained from communication with a N_2O industry expert (Tupman 2002). The 2002 and 2003 share of total quantity of N_2O usage by sector was obtained from CGA (2002, 2003). Due to unavailable data, the share of total quantity of N_2O usage data for years 2004 through 2009 was assumed to equal the 2003 value. The emissions rate for the food processing propellant industry was obtained from SRI Consulting's Nitrous Oxide, North America report (Heydorn 1997), and confirmed by a N_2O industry expert (Tupman 2002). The emissions rate for all other subcategories was obtained from communication with a N_2O industry expert (Tupman 2002). The emissions rate for the medical/dental subcategory was obtained from the 2006 IPCC Guidelines.

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2009 N_2O emission estimate from N_2O product usage was calculated using the IPCC Guidelines for National Greenhouse Gas Inventories (2006) Tier 2 methodology. Uncertainty associated with the parameters used to estimate N_2O emissions include production data, total market share of each end use, and the emission factors applied to each end use, respectively.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 5-4. N_2O emissions from N_2O product usage were estimated to be between 4.1 and 4.7 Tg CO_2 Eq. at the 95 percent confidence level (or in 19 out of 20 Monte Carlo Stochastic Simulations). This indicates a range of approximately 8 percent below to 8 percent above the 2009 emissions estimate of 4.4 Tg CO_2 Eq.

Table 5-4: Tier 2 Quantitative Uncertainty Estimates for N_2O Emissions from N_2O Product Usage (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
N_2O Product Usage	N_2O	4.4	4.1	4.7	-8%	+8%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Note that this uncertainty range (±8 percent) has increased by 12 percent compared to the uncertainty range in last year's Inventory (±2 percent), due to a correction to the uncertainty input parameters. Furthermore, methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time-series are described in more detail in the Methodology section, above.

Planned Improvements

Planned improvements include a continued evaluation of alternative production statistics for cross verification, a reassessment of N_2O product use subcategories to accurately represent trends, investigation of production and use cycles, and the potential need to incorporate a time lag between production and ultimate product use and resulting release of N_2O. Additionally, planned improvements include considering imports and exports of N_2O for product uses.

5.2. Indirect Greenhouse Gas Emissions from Solvent Use

The use of solvents and other chemical products can result in emissions of various ozone precursors (i.e., indirect greenhouse gases).[138] Non-CH_4 volatile organic compounds (NMVOCs), commonly referred to as "hydrocarbons," are the primary gases emitted from most processes employing organic or petroleum based solvents. As some of industrial applications also employ thermal incineration as a control technology, combustion by-products, such as carbon monoxide (CO) and nitrogen oxides (NO_x), are also reported with this source category. In the United States,

[138] Solvent usage in the United States also results in the emission of small amounts of hydrofluorocarbons (HFCs) and hydrofluoroethers (HFEs), which are included under Substitution of Ozone Depleting Substances in the Industrial Processes chapter.

emissions from solvents are primarily the result of solvent evaporation, whereby the lighter hydrocarbon molecules in the solvents escape into the atmosphere. The evaporation process varies depending on different solvent uses and solvent types. The major categories of solvent uses include: degreasing, graphic arts, surface coating, other industrial uses of solvents (i.e., electronics, etc.), dry cleaning, and non-industrial uses (i.e., uses of paint thinner, etc.).

Total emissions of NO_x, NMVOCs, and CO from 1990 to 2009 are reported in Table 5-5.

Table 5-5: Emissions of NO_x, CO, and NMVOC from Solvent Use (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	**1**	**3**	**3**	**4**	**4**	**4**	**3**
Surface Coating	1	3	3	4	4	4	3
Graphic Arts	+	+	+	+	+	+	+
Degreasing	+	+	+	+	+	+	+
Dry Cleaning	+	+	+	+	+	+	+
Other Industrial Processes[a]	+	+	+	+	+	+	+
Non-Industrial Processes[b]	+	+	+	+	+	+	+
Other	NA	+	+	+	+	+	+
CO	**5**	**45**	**2**	**2**	**2**	**2**	**2**
Surface Coating	+	45	2	2	2	2	2
Other Industrial Processes[a]	4	+	+	+	+	+	+
Dry Cleaning	+	+	+	+	+	+	+
Degreasing	+	+	+	+	+	+	+
Graphic Arts	+	+	+	+	+	+	+
Non-Industrial Processes[b]	+	+	+	+	+	+	+
Other	NA	+	+	+	+	+	+
NMVOCs	**5,216**	**4,384**	**3,851**	**3,846**	**3,839**	**3,834**	**2,583**
Surface Coating	2,289	1,766	1,578	1,575	1,573	1,571	1,058
Non-Industrial Processes[b]	1,724	1,676	1,446	1,444	1,441	1,439	970
Degreasing	675	316	280	280	280	279	188
Dry Cleaning	195	265	230	230	229	229	154
Graphic Arts	249	222	194	193	193	193	130
Other Industrial Processes[a]	85	98	88	88	87	87	59
Other	+	40	36	36	36	36	24

[a] Includes rubber and plastics manufacturing, and other miscellaneous applications.
[b] Includes cutback asphalt, pesticide application adhesives, consumer solvents, and other miscellaneous applications.
Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.5 Gg.

Methodology

Emissions were calculated by aggregating solvent use data based on information relating to solvent uses from different applications such as degreasing, graphic arts, etc. Emission factors for each consumption category were then applied to the data to estimate emissions. For example, emissions from surface coatings were mostly due to solvent evaporation as the coatings solidify. By applying the appropriate solvent-specific emission factors to the amount of solvents used for surface coatings, an estimate of emissions was obtained. Emissions of CO and NO_x result primarily from thermal and catalytic incineration of solvent-laden gas streams from painting booths, printing operations, and oven exhaust.

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of solvent purchased) as an indicator of emissions. National activity data were collected for individual applications from various agencies.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's Compilation of Air Pollutant Emission Factors,

AP-42 (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and the reliability of correlations between activity data and actual emissions.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

6. Agriculture

Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes. This chapter provides an assessment of non-carbon-dioxide emissions from the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues (see Figure 6-1). Carbon dioxide (CO_2) emissions and removals from agriculture-related land-use activities, such as liming of agricultural soils and conversion of grassland to cultivated land, are presented in the Land Use, Land-Use Change, and Forestry chapter. Carbon dioxide emissions from on-farm energy use are accounted for in the Energy chapter.

Figure 6-1: 2009 Agriculture Chapter Greenhouse Gas Emission Sources

In 2009, the Agriculture sector was responsible for emissions of 419.3 teragrams of CO_2 equivalents (Tg CO_2 Eq.), or 6.3 percent of total U.S. greenhouse gas emissions. Methane (CH_4) and nitrous oxide (N_2O) were the primary greenhouse gases emitted by agricultural activities. Methane emissions from enteric fermentation and manure management represent about 20 percent and 7 percent of total CH_4 emissions from anthropogenic activities, respectively. Of all domestic animal types, beef and dairy cattle were by far the largest emitters of CH_4. Rice cultivation and field burning of agricultural residues were minor sources of CH_4. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions, accounting for 69 percent. Manure management and field burning of agricultural residues were also small sources of N_2O emissions.

Table 6-1 and Table 6-2 present emission estimates for the Agriculture sector. Between 1990 and 2009, CH_4 emissions from agricultural activities increased by 14.9 percent, while N_2O emissions fluctuated from year to year, but overall increased by 4.8 percent.

Table 6-1: Emissions from Agriculture (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH_4	**171.2**	**186.7**	**190.1**	**191.7**	**198.2**	**197.5**	**196.8**
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
N_2O	**212.4**	**224.0**	**228.7**	**227.1**	**227.6**	**228.8**	**222.5**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**383.6**	**410.6**	**418.8**	**418.8**	**425.8**	**426.3**	**419.3**

Note: Totals may not sum due to independent rounding.

Table 6-2: Emissions from Agriculture (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH_4	**8,153**	**8,890**	**9,052**	**9,129**	**9,437**	**9,405**	**9,372**
Enteric Fermentation	6,290	6,502	6,500	6,611	6,715	6,696	6,655
Manure Management	1,511	2,019	2,217	2,226	2,416	2,353	2,356
Rice Cultivation	339	357	326	282	295	343	349
Field Burning of Agricultural Residues	13	12	9	11	11	13	12
N_2O	**685**	**722**	**738**	**732**	**734**	**738**	**718**
Agricultural Soil Management	638	667	682	674	675	680	660

Manure Management	47	55	56	58	58	58	58
Field Burning of Agricultural Residues	+	+	+	+	+	+	+

+ Less than 0.5 Gg.
Note: Totals may not sum due to independent rounding.

6.1. Enteric Fermentation (IPCC Source Category 4A)

Methane is produced as part of normal digestive processes in animals. During digestion, microbes resident in an animal's digestive system ferment food consumed by the animal. This microbial fermentation process, referred to as enteric fermentation, produces CH_4 as a byproduct, which can be exhaled or eructated by the animal. The amount of CH_4 produced and emitted by an individual animal depends primarily upon the animal's digestive system, and the amount and type of feed it consumes.

Ruminant animals (e.g., cattle, buffalo, sheep, goats, and camels) are the major emitters of CH_4 because of their unique digestive system. Ruminants possess a rumen, or large "fore-stomach," in which microbial fermentation breaks down the feed they consume into products that can be absorbed and metabolized. The microbial fermentation that occurs in the rumen enables them to digest coarse plant material that non-ruminant animals cannot. Ruminant animals, consequently, have the highest CH_4 emissions among all animal types.

Non-ruminant animals (e.g., swine, horses, and mules) also produce CH_4 emissions through enteric fermentation, although this microbial fermentation occurs in the large intestine. These non-ruminants emit significantly less CH_4 on a per-animal basis than ruminants because the capacity of the large intestine to produce CH_4 is lower.

In addition to the type of digestive system, an animal's feed quality and feed intake also affect CH_4 emissions. In general, lower feed quality and/or higher feed intake leads to higher CH_4 emissions. Feed intake is positively correlated to animal size, growth rate, and production (e.g., milk production, wool growth, pregnancy, or work). Therefore, feed intake varies among animal types as well as among different management practices for individual animal types (e.g., animals in feedlots or grazing on pasture).

Methane emission estimates from enteric fermentation are provided in Table 6-3 and Table 6-4. Total livestock CH_4 emissions in 2009 were 139.8 Tg CO_2 Eq. (6,655 Gg). Beef cattle remain the largest contributor of CH_4 emissions from enteric fermentation, accounting for 71 percent in 2009. Emissions from dairy cattle in 2009 accounted for 24 percent, and the remaining emissions were from horses, sheep, swine, and goats.

From 1990 to 2009, emissions from enteric fermentation have increased by 5.8 percent. Generally, emissions decreased from 1996 to 2003, though with a slight increase in 2002. This trend was mainly due to decreasing populations of both beef and dairy cattle and increased digestibility of feed for feedlot cattle. Emissions increased from 2004 through 2007, as both dairy and beef populations have undergone increases and the literature for dairy cow diets indicated a trend toward a decrease in feed digestibility for those years. Emissions decreased again in 2008 and 2009 as beef cattle populations again decreased. During the timeframe of this analysis, populations of sheep have decreased 49 percent while horse populations have increased over 87 percent, mostly since 1999. Goat and swine populations have increased 25 percent and 23 percent, respectively, during this timeframe.

Table 6-3: CH_4 Emissions from Enteric Fermentation (Tg CO_2 Eq.)

Livestock Type	1990	2000	2005	2006	2007	2008	2009
Beef Cattle	94.5	100.6	99.3	100.9	101.6	100.7	99.6
Dairy Cattle	31.8	30.7	30.4	31.1	32.4	32.9	33.2
Horses	1.9	2.0	3.5	3.6	3.6	3.6	3.6
Sheep	1.9	1.2	1.0	1.0	1.0	1.0	1.0
Swine	1.7	1.9	1.9	1.9	2.1	2.1	2.1
Goats	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**132.1**	**136.5**	**136.5**	**138.8**	**141.0**	**140.6**	**139.8**

Note: Totals may not sum due to independent rounding.

Table 6-4: CH_4 Emissions from Enteric Fermentation (Gg)

Livestock Type	1990	2000	2005	2006	2007	2008	2009
Beef Cattle	4,502	4,790	4,731	4,803	4,837	4,796	4,742
Dairy Cattle	1,513	1,460	1,449	1,479	1,544	1,564	1,581

Horses	91	94	166	171	171	171	171
Sheep	91	56	49	50	49	48	46
Swine	81	88	92	93	98	101	99
Goats	13	12	14	15	16	16	16
Total	**6,290**	**6,502**	**6,500**	**6,611**	**6,715**	**6,696**	**6,655**

Note: Totals may not sum due to independent rounding.

Methodology

Livestock emission estimate methodologies fall into two categories: cattle and other domesticated animals. Cattle, due to their large population, large size, and particular digestive characteristics, account for the majority of CH_4 emissions from livestock in the United States. A more detailed methodology (i.e., IPCC Tier 2) was therefore applied to estimate emissions for all cattle except for bulls. Emission estimates for other domesticated animals (horses, sheep, swine, goats, and bulls) were handled using a less detailed approach (i.e., IPCC Tier 1).

While the large diversity of animal management practices cannot be precisely characterized and evaluated, significant scientific literature exists that provides the necessary data to estimate cattle emissions using the IPCC Tier 2 approach. The Cattle Enteric Fermentation Model (CEFM), developed by EPA and used to estimate cattle CH_4 emissions from enteric fermentation, incorporates this information and other analyses of livestock population, feeding practices, and production characteristics.

National cattle population statistics were disaggregated into the following cattle sub-populations:

- Dairy Cattle
    - Calves
    - Heifer Replacements
    - Cows
- Beef Cattle
    - Calves
    - Heifer Replacements
    - Heifer and Steer Stockers
    - Animals in Feedlots (Heifers and Steers)
    - Cows
    - Bulls

Calf birth rates, end-of-year population statistics, detailed feedlot placement information, and slaughter weight data were used to create a transition matrix that models cohorts of individual animal types and their specific emission profiles. The key variables tracked for each of the cattle population categories are described in Annex 3.9. These variables include performance factors such as pregnancy and lactation as well as average weights and weight gain. Annual cattle population data were obtained from the U.S. Department of Agriculture's (USDA) National Agricultural Statistics Service (NASS) QuickStats database (USDA 2010).

Diet characteristics were estimated by region for U.S. dairy, beef, and feedlot cattle. These estimates were used to calculate Digestible Energy (DE) values (expressed as the percent of gross energy intake digested by the animal) and CH_4 conversion rates (Y_m) (expressed as the fraction of gross energy converted to CH_4) for each population category. The IPCC recommends Y_m values of 3.0±1.0 percent for feedlot cattle and 6.5±1.0 percent for other well-fed cattle consuming temperate-climate feed types (IPCC 2006). Given the availability of detailed diet information for different regions and animal types in the United States, DE and Y_m values unique to the United States were developed, rather than using the recommended IPCC values. The diet characterizations and estimation of DE and Y_m values were based on information from state agricultural extension specialists, a review of published forage quality studies and scientific literature, expert opinion, and modeling of animal physiology. The diet characteristics for dairy cattle were based on Donovan (1999) and an extensive review of nearly 20 years of literature. Dairy replacement heifer diet assumptions were based on the observed relationship in the literature between dairy cow and

dairy heifer diet characteristics. The diet assumptions for beef cattle were derived from NRC (2000). For feedlot animals, the DE and Y_m values used for 1990 were recommended by Johnson (1999). Values for DE and Y_m for 1991 through 1999 were linearly extrapolated based on the 1990 and 2000 data. DE and Y_m values for 2000 onwards were based on survey data in Galyean and Gleghorn (2001) and Vasconcelos and Galyean (2007). For grazing beef cattle, DE values were based on diet information in NRC (2000) and Y_m values were based on Johnson (2002). Weight and weight gains for cattle were estimated from Holstein Association USA (2010), Enns (2008), Lippke et al. (2000), Pinchack et al., (2004), Platter et al. (2003), Skogerboe et al. (2000), and expert opinion. See Annex 3.9 for more details on the method used to characterize cattle diets and weights in the United States.

To estimate CH_4 emissions from all cattle types except bulls and calves younger than 7 months,[139] the population was divided into state, age, sub-type (i.e., dairy cows and replacements, beef cows and replacements, heifer and steer stockers, and heifers and steers in feedlots), and production (i.e., pregnant, lactating) groupings to more fully capture differences in CH_4 emissions from these animal types. The transition matrix was used to simulate the age and weight structure of each sub-type on a monthly basis, to more accurately reflect the fluctuations that occur throughout the year. Cattle diet characteristics were then used in conjunction with Tier 2 equations from IPCC (2006) to produce CH_4 emission factors for the following cattle types: dairy cows, beef cows, dairy replacements, beef replacements, steer stockers, heifer stockers, steer feedlot animals, and heifer feedlot animals. To estimate emissions from cattle, population data from the transition matrix were multiplied by the calculated emission factor for each cattle type. More details are provided in Annex 3.9.

Emission estimates for other animal types were based on average emission factors representative of entire populations of each animal type. Methane emissions from these animals accounted for a minor portion of total CH_4 emissions from livestock in the United States from 1990 through 2009. Also, the variability in emission factors for each of these other animal types (e.g., variability by age, production system, and feeding practice within each animal type) is less than that for cattle. Annual livestock population data for these other livestock types, except horses and goats, as well as feedlot placement information, were obtained for all years from USDA NASS (USDA 2010). Horse population data were obtained from the Food and Agriculture Organization of the United Nations (FAO) FAOSTAT database (FAO 2010), because USDA does not estimate U.S. horse populations annually. Goat population data were obtained for 1992, 1997, 2002, and 2007 (USDA 2010); these data were interpolated and extrapolated to derive estimates for the other years. Methane emissions from sheep, goats, swine, and horses were estimated by using emission factors utilized in Crutzen et al. (1986, cited in IPCC 2006). These emission factors are representative of typical animal sizes, feed intakes, and feed characteristics in developed countries. The methodology is the same as that recommended by IPCC (2006).

See Annex 3.9 for more detailed information on the methodology and data used to calculate CH_4 emissions from enteric fermentation.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis for this source category was performed through the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique as described in ICF (2003). These uncertainty estimates were developed for the 1990 through 2001 Inventory report. No significant changes occurred in the method of data collection, data estimation methodology, or other factors that influence the uncertainty ranges around the 2009 activity data and emission factor input variables used in the current submission. Consequently, these uncertainty estimates were directly applied to the 2009 emission estimates.

A total of 185 primary input variables (177 for cattle and 8 for non-cattle) were identified as key input variables for the uncertainty analysis. A normal distribution was assumed for almost all activity- and emission factor-related input variables. Triangular distributions were assigned to three input variables (specifically, cow-birth ratios for the three most recent years included in the 2001 model run) to capture the fact that these variables cannot be negative. For some key input variables, the uncertainty ranges around their estimates (used for inventory estimation) were collected from published documents and other public sources; others were based on expert opinion and best estimates. In addition, both endogenous and exogenous correlations between selected primary input variables were

[139] Emissions from bulls are estimated using a Tier 1 approach because it is assumed there is minimal variation in population and diets. Because calves younger than 7 months consume mainly milk and the IPCC recommends the use of methane conversion factor of zero for all juveniles consuming only milk, this results in no methane emissions from this subcategory of cattle.

modeled. The exogenous correlation coefficients between the probability distributions of selected activity-related variables were developed through expert judgment.

The uncertainty ranges associated with the activity data-related input variables were plus or minus 10 percent or lower. However, for many emission factor-related input variables, the lower- and/or the upper-bound uncertainty estimates were over 20 percent. The results of the quantitative uncertainty analysis are summarized in Table 6-5. Enteric fermentation CH_4 emissions in 2009 were estimated to be between 124.4 and 165.0 Tg CO_2 Eq. at a 95 percent confidence level, which indicates a range of 11 percent below to 18 percent above the 2009 emission estimate of 139.8 Tg CO_2 Eq. Among the individual cattle sub-source categories, beef cattle account for the largest amount of CH_4 emissions as well as the largest degree of uncertainty in the inventory emission estimates. Among non-cattle, horses account for the largest degree of uncertainty in the inventory emission estimates because there is a higher degree of uncertainty among the FAO population estimates used for horses than for the USDA population estimates used for swine, goats, and sheep.

Table 6-5: Quantitative Uncertainty Estimates for CH_4 Emissions from Enteric Fermentation (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a, b]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Enteric Fermentation	CH_4	139.8	124.4	165.0	-11%	+18%

[a] Range of emissions estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
[b] Note that the relative uncertainty range was estimated with respect to the 2001 emission estimates submitted in 2003 and applied to the 2009 estimates.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section.

QA/QC and Verification

In order to ensure the quality of the emission estimates from enteric fermentation, the IPCC Tier 1 and Tier 2 Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. QA/QC plan. Tier 2 QA procedures included independent peer review of emission estimates. Because there were no major modifications to the CEFM for 2009, QA/QC emphasis for the current Inventory was placed on cleaning up documentation and references within the model, and review of external data sources. For example, during the course of the QA/QC activities for this source category, it was noted that the U.S. total for 2009 Cattle On Feed data provided via USDA's Quickstats database did not match the total calculated from summing all individual states. The appropriate party was contacted at USDA, and it was determined that data for New Mexico and North Carolina were included individually, as well as within the "Other States" aggregate number, so they were being double counted in the U.S. total. This issue was quickly resolved.

In addition, over the past few years, particular importance has been placed on harmonizing the data exchange between the enteric fermentation and manure management source categories. The current inventory submission now utilizes the transition matrix from the CEFM for estimating cattle populations and weights for both source categories, and the CEFM is used to output volatile solids and nitrogen (N) excretion estimates using the diet assumptions in the model in conjunction with the energy balance equations from the IPCC (2006). This approach should complete the resolution of the discrepancies noted in previous reviews of these sectors, and facilitate the QA/QC process for both of these source categories.

Recalculations Discussion

There were several modifications to the estimates relative to the previous Inventory that had an effect on emission estimates, including the following:

- The average weight assumed for mature dairy cows has changed from the 1,550 pounds used in previous inventories to 1,500 pounds (Johnson 2010; Holstein Association 2010).
- The USDA published revised estimates in several categories that affected historical emissions estimated for

cattle and swine for 2008. Calves, beef replacements, and feedlot cattle all saw slight modifications to their 2008 populations, while swine population categories were modified so that the categories "<60 pounds" and "60-119 pounds" were replaced with "<50 pounds" and "50-119" pounds. Additionally, 2008 lactation estimates for Arkansas, Connecticut, Indiana, Nebraska, New Jersey, Oklahoma, South Carolina, and Vermont were updated by USDA.

- For the 1990 through 2009 inventory, goat population data were taken from the 2007 *Census of Agriculture*. For 2007 population values, the Census's 2007 "Total Goat" population for each state was used. Using the 2002 and 2007 data points, the population for the intervening years was interpolated, and the population for 2008 and 2009 were set equal to the population for 2007. The updated Census data resulted in a change in population values from 2003 through 2008 as populations for these years were previously set equal to the 2002 population.

As a result of these changes, dairy cattle emissions decreased an average of 11.5 Gg (0.8 percent) per year and beef cattle emissions decreased an average of 0.13 Gg (less than 0.01 percent) per year over the entire time series relative to the previous Inventory. Historical emission estimates for 2008 increased by 1.3 percent for goats as a result of the USDA population revisions described above.

Planned Improvements

Continued research and regular updates are necessary to maintain a current model of cattle diet characterization, feedlot placement data, rates of weight gain and calving, among other data inputs. Ongoing revisions could include some of the following options:

- Reviewing and updating the diet assumptions for foraging beef cattle;
- Estimating bull emissions using the IPCC Tier 2 approach;
- Updating input variables that are from older data sources, such as beef births by month and beef cow lactation rates;
- The possible breakout of other animal types (i.e., sheep, swine, goats, horses) from national estimates to state-level estimates; and
- Including bison in the estimates for other domesticated animals.

In addition, recent changes that have been implemented to the CEFM warrant an assessment of the current uncertainty analysis; therefore, a revision of the quantitative uncertainty surrounding emission estimates from this source category will be initiated.

6.2. Manure Management (IPCC Source Category 4B)

The management of livestock manure can produce anthropogenic CH_4 and N_2O emissions. Methane is produced by the anaerobic decomposition of manure. Direct N_2O emissions are produced as part of the N cycle through the nitrification and denitrification of the organic N in livestock dung and urine.[140] Indirect N_2O emissions are produced as result of the volatilization of N as NH_3 and NO_x and runoff and leaching of N during treatment, storage and transportation.

When livestock or poultry manure are stored or treated in systems that promote anaerobic conditions (e.g., as a liquid/slurry in lagoons, ponds, tanks, or pits), the decomposition of materials in the manure tends to produce CH_4. When manure is handled as a solid (e.g., in stacks or drylots) or deposited on pasture, range, or paddock lands, it tends to decompose aerobically and produce little or no CH_4. Ambient temperature, moisture, and manure storage or residency time affect the amount of CH_4 produced because they influence the growth of the bacteria responsible for CH_4 formation. For non-liquid-based manure systems, moist conditions (which are a function of rainfall and

[140] Direct and indirect N_2O emissions from dung and urine spread onto fields either directly as daily spread or after it is removed from manure management systems (e.g., lagoon, pit, etc.) and from livestock dung and urine deposited on pasture, range, or paddock lands are accounted for and discussed in the Agricultural Soil Management source category within the Agriculture sector.

humidity) can promote CH_4 production. Manure composition, which varies by animal diet, growth rate, and type, including the animal's digestive system, also affects the amount of CH_4 produced. In general, the greater the energy content of the feed, the greater the potential for CH_4 emissions. However, some higher-energy feeds also are more digestible than lower quality forages, which can result in less overall waste excreted from the animal.

The production of direct N_2O emissions from livestock manure depends on the composition of the manure and urine, the type of bacteria involved in the process, and the amount of oxygen and liquid in the manure system. For direct N_2O emissions to occur, the manure must first be handled aerobically where ammonia (NH_3) or organic N is converted to nitrates and nitrites (nitrification), and then handled anaerobically where the nitrates and nitrites are reduced to dinitrogen gas (N_2), with intermediate production of N_2O and nitric oxide (NO) (denitrification) (Groffman et al. 2000). These emissions are most likely to occur in dry manure handling systems that have aerobic conditions, but that also contain pockets of anaerobic conditions due to saturation. A very small portion of the total N excreted is expected to convert to N_2O in the waste management system (WMS). Indirect N_2O emissions are produced when nitrogen is lost from the system through volatilization (as NH_3 or NO_x) or through runoff and leaching. The vast majority of volatilization losses from these operations are NH_3. Although there are also some small losses of NO_x, there are no quantified estimates available for use, so losses due to volatilization are only based on NH_3 loss factors. Runoff losses would be expected from operations that house animals or store manure in a manner that is exposed to weather. Runoff losses are also specific to the type of animal housed on the operation due to differences in manure characteristics. Little information is known about leaching from manure management systems as most research focuses on leaching from land application systems. Since leaching losses are expected to be minimal, leaching losses are coupled with runoff losses and the runoff/leaching estimate does not include any leaching losses.

Estimates of CH_4 emissions in 2009 were 49.5 Tg CO_2 Eq. (2,356 Gg), 56 percent higher than in 1990. Emissions increased on average by 0.9 Tg CO_2 Eq. (2.5 percent) annually over this period. The majority of this increase was from swine and dairy cow manure, where emissions increased 45 and 95 percent, respectively. Although the majority of manure in the United States is handled as a solid, producing little CH_4, the general trend in manure management, particularly for dairy and swine (which are both shifting towards larger facilities), is one of increasing use of liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site. Although national dairy animal populations have been generally decreasing, some states have seen increases in their dairy populations as the industry becomes more concentrated in certain areas of the country. These areas of concentration, such as California, New Mexico, and Idaho, tend to utilize more liquid-based systems to manage (flush or scrape) and store manure. Thus the shift toward larger facilities is translated into an increasing use of liquid manure management systems, which have higher potential CH_4 emissions than dry systems. This shift was accounted for by incorporating state and WMS-specific CH_4 conversion factor (MCF) values in combination with the 1992, 1997, and 2002 farm-size distribution data reported in the *Census of Agriculture* (USDA 2009a). Methane emissions from sheep have decreased significantly since 1990 (a 54 percent decrease from 1990 to 2009); however, this is mainly due to population changes. Overall, sheep contribute less than one percent of CH_4 emissions from animal manure management. From 2008 to 2009, there was a less than 1 percent increase in total CH_4 emissions, due to minor shifts in the animal populations and the resultant effects on manure management system allocations.

In 2009, total N_2O emissions were estimated to be 17.9 Tg CO_2 Eq. (58 Gg); in 1990, emissions were 14.5 Tg CO_2 Eq. (47 Gg). These values include both direct and indirect N_2O emissions from manure management. Nitrous oxide emissions have remained fairly steady since 1990. Small changes in N_2O emissions from individual animal groups exhibit the same trends as the animal group populations, with the overall net effect that N_2O emissions showed a 23 percent increase from 1990 to 2009 and a less than 1 percent decrease from 2008 through 2009.

Table 6-6 and Table 6-7 provide estimates of CH_4 and N_2O emissions from manure management by animal category.

Table 6-6: CH_4 and N_2O Emissions from Manure Management (Tg CO_2 Eq.)

Gas/Animal Type	1990	2000	2005	2006	2007	2008	2009
CH_4[a]	**31.7**	**42.4**	**46.6**	**46.7**	**50.7**	**49.4**	**49.5**
Dairy Cattle	12.6	18.9	21.4	21.7	24.2	24.1	24.5
Beef Cattle	2.7	2.8	2.8	2.9	2.9	2.8	2.7
Swine	13.1	17.5	19.0	18.7	20.3	19.3	19.0
Sheep	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Goats	+	+	+	+	+	+	+
Poultry	2.8	2.7	2.7	2.7	2.8	2.7	2.7
Horses	0.5	0.4	0.6	0.6	0.6	0.5	0.5
N_2O[b]	**14.5**	**17.1**	**17.3**	**18.0**	**18.1**	**17.9**	**17.9**
Dairy Cattle	5.3	5.6	5.6	5.8	5.8	5.7	5.8
Beef Cattle	6.1	7.8	7.5	8.0	7.9	7.8	7.8
Swine	1.2	1.6	1.8	1.8	1.9	2.0	2.0
Sheep	0.1	0.3	0.4	0.4	0.4	0.4	0.3
Goats	+	+	+	+	+	+	+
Poultry	1.5	1.6	1.7	1.7	1.7	1.7	1.6
Horses	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Total	**46.2**	**59.5**	**63.8**	**64.8**	**68.9**	**67.3**	**67.3**

+ Less than 0.05 Tg CO_2 Eq.
[a]Accounts for CH_4 reductions due to capture and destruction of CH_4 at facilities using anaerobic digesters.
[b]Includes both direct and indirect N_2O emissions.
Note: Totals may not sum due to independent rounding.

Table 6-7: CH_4 and N_2O Emissions from Manure Management (Gg)

Gas/Animal Type	1990	2000	2005	2006	2007	2008	2009
CH_4[a]	**1,511**	**2,019**	**2,217**	**2,226**	**2,416**	**2,353**	**2,356**
Dairy Cattle	599	900	1,018	1,034	1,151	1,147	1,168
Beef Cattle	128	133	132	139	136	131	130
Swine	624	834	905	889	965	918	903
Sheep	7	4	3	3	3	3	3
Goats	1	1	1	1	1	1	1
Poultry	131	127	129	131	134	129	127
Horses	22	20	28	28	27	24	24
N_2O[b]	**47**	**55**	**56**	**58**	**58**	**58**	**58**
Dairy Cattle	17	18	18	19	19	18	19
Beef Cattle	20	25	24	26	26	25	25
Swine	4	5	6	6	6	6	6
Sheep	+	1	1	1	1	1	1
Goats	+	+	+	+	+	+	+
Poultry	5	5	5	5	5	5	5
Horses	1	1	1	1	1	1	1

+ Less than 0.5 Gg.
[a]Accounts for CH_4 reductions due to capture and destruction of CH_4 at facilities using anaerobic digesters.
[b]Includes both direct and indirect N_2O emissions.
Note: Totals may not sum due to independent rounding.

Methodology

The methodologies presented in IPCC (2006) form the basis of the CH_4 and N_2O emission estimates for each animal type. This section presents a summary of the methodologies used to estimate CH_4 and N_2O emissions from manure management for this Inventory. See Annex 3.10 for more detailed information on the methodology and data used to calculate CH_4 and N_2O emissions from manure management.

Methane Calculation Methods

The following inputs were used in the calculation of CH_4 emissions:

- Animal population data (by animal type and state);
- Typical animal mass (TAM) data (by animal type);
- Portion of manure managed in each waste management system (WMS), by state and animal type;
- Volatile solids (VS) production rate (by animal type and state or United States);
- Methane producing potential (B_o) of the volatile solids (by animal type); and

- Methane conversion factors (MCF), the extent to which the CH_4 producing potential is realized for each type of WMS (by state and manure management system, including the impacts of any biogas collection efforts).

Methane emissions were estimated by first determining activity data, including animal population, TAM, WMS usage, and waste characteristics. The activity data sources are described below:

- Annual animal population data for 1990 through 2009 for all livestock types, except horses and goats were obtained from USDA NASS. For cattle, the USDA populations were utilized in conjunction with birth rates, detailed feedlot placement information, and slaughter weight data to create the transition matrix in the CEFM that models cohorts of individual animal types and their specific emission profiles. The key variables tracked for each of the cattle population categories are described in Section 6.1 and in more detail in Annex 3.9. Horse population data were obtained from the FAOSTAT database (FAO 2010). Goat population data for 1992, 1997, 2002, and 2007 were obtained from the *Census of Agriculture* (USDA 2009a).
- The TAM is an annual average weight which was obtained for animal types other than cattle from information in USDA's *Agricultural Waste Management Field Handbook* (USDA 1996a), the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1999) and others (EPA 1992, Safley 2000, ERG 2010a). For a description of the TAM used for cattle, please see section 6.1, Enteric Fermentation.
- WMS usage was estimated for swine and dairy cattle for different farm size categories using data from USDA (USDA 1996b, 1998b, 2000a) and EPA (ERG 2000a, EPA 2002a, 2002b). For beef cattle and poultry, manure management system usage data were not tied to farm size but were based on other data sources (ERG 2000a, USDA 2000b, UEP 1999). For other animal types, manure management system usage was based on previous estimates (EPA 1992).
- VS production rates for all cattle except for bulls and calves were calculated by head for each state and animal type in the CEFM. VS production rates by animal mass for all other animals were determined using data from USDA's *Agricultural Waste Management Field Handbook* (USDA 1996a, 2008) and data from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998).
- The maximum CH_4 producing capacity of the VS (B_o) was determined for each animal type based on literature values (Morris 1976, Bryant et al, 1976, Hashimoto 1981, Hashimoto 1984, EPA 1992, Hill 1982, and Hill 1984).
- MCFs for dry systems were set equal to default IPCC factors based on state climate for each year (IPCC 2006). MCFs for liquid/slurry, anaerobic lagoon, and deep pit systems were calculated based on the forecast performance of biological systems relative to temperature changes as predicted in the van't Hoff-Arrhenius equation which is consistent with IPCC (2006) Tier 2 methodology.
- Anaerobic digestion system data were obtained from the EPA AgSTAR Program, including information presented in the *AgSTAR Digest* (EPA 2000, 2003, 2006). Anearobic digester emissions were calculated based on estimated methane production and collection and destruction efficiency assumptions (ERG 2008).

To estimate CH_4 emissions for cattle, the estimated amount of VS (kg per animal-year) managed in each WMS for each animal type, state, and year were taken from the CEFM. For animals other than cattle, the annual amount of VS (kg per year) from manure excreted in each WMS was calculated for each animal type, state, and year. This calculation multiplied the animal population (head) by the VS excretion rate (kg VS per 1,000 kg animal mass per day), the TAM (kg animal mass per head) divided by 1,000, the WMS distribution (percent), and the number of days per year (365.25).

The estimated amount of VS managed in each WMS was used to estimate the CH_4 emissions (kg CH_4 per year) from each WMS. The amount of VS (kg per year) were multiplied by the maximum CH_4 producing capacity of the VS (B_o) (m^3 CH_4 per kg VS), the MCF for that WMS (percent), and the density of CH_4 (kg CH_4 per m^3 CH_4). The CH_4 emissions for each WMS, state, and animal type were summed to determine the total U.S. CH_4 emissions.

Nitrous Oxide Calculation Methods

The following inputs were used in the calculation of direct and indirect N_2O emissions:

- Animal population data (by animal type and state);

- TAM data (by animal type);
- Portion of manure managed in each WMS (by state and animal type);
- Total Kjeldahl N excretion rate (Nex);
- Direct N_2O emission factor (EF_{WMS});
- Indirect N_2O emission factor for volitalization ($EF_{volitalization}$);
- Indirect N_2O emission factor for runoff and leaching ($EF_{runoff/leach}$);
- Fraction of nitrogen loss from volitalization of NH_3 and NO_x ($Frac_{gas}$); and
- Fraction of nitrogen loss from runoff and leaching ($Frac_{runoff/leach}$).

N_2O emissions were estimated by first determining activity data, including animal population, TAM, WMS usage, and waste characteristics. The activity data sources (except for population, TAM, and WMS, which were described above) are described below:

- Nex rates for all cattle except for bulls and calves were calculated by head for each state and animal type in the CEFM. Nex rates by animal mass for all other animals were determined using data from USDA's *Agricultural Waste Management Field Handbook* (USDA 1996a, 2008) and data from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998).
- All N_2O emission factors (direct and indirect) were taken from IPCC (2006).
- Country-specific estimates for the fraction of N loss from volatilization ($Frac_{gas}$) and runoff and leaching ($Frac_{runoff/leach}$) were developed. $Frac_{gas}$ values were based on WMS-specific volatilization values as estimated from EPA's *National Emission Inventory - Ammonia Emissions from Animal Agriculture Operations* (EPA 2005). $Frac_{runoff/leaching}$ values were based on regional cattle runoff data from EPA's Office of Water (EPA 2002b; see Annex 3.1).

To estimate N_2O emissions for cattle, the estimated amount of N excreted (kg per animal-year) managed in each WMS for each animal type, state, and year were taken from the CEFM. For animals other than cattle, the amount of N excreted (kg per year) in manure in each WMS for each animal type, state, and year was calculated. The population (head) for each state and animal was multiplied by TAM (kg animal mass per head) divided by 1,000, the nitrogen excretion rate (Nex, in kg N per 1000 kg animal mass per day), WMS distribution (percent), and the number of days per year.

Direct N_2O emissions were calculated by multiplying the amount of N excreted (kg per year) in each WMS by the N_2O direct emission factor for that WMS (EF_{WMS}, in kg N_2O-N per kg N) and the conversion factor of N_2O-N to N_2O. These emissions were summed over state, animal, and WMS to determine the total direct N_2O emissions (kg of N_2O per year).

Next, indirect N_2O emissions from volatilization (kg N_2O per year) were calculated by multiplying the amount of N excreted (kg per year) in each WMS by the fraction of N lost through volatilization ($Frac_{tas}$) divided by 100, and the emission factor for volatilization ($EF_{volatilization}$, in kg N_2O per kg N), and the conversion factor of N_2O-N to N_2O. Indirect N_2O emissions from runoff and leaching (kg N_2O per year) were then calculated by multiplying the amount of N excreted (kg per year) in each WMS by the fraction of N lost through runoff and leaching ($Frac_{runoff/leach}$) divided by 100, and the emission factor for runoff and leaching ($EF_{runoff/leach}$, in kg N_2O per kg N), and the conversion factor of N_2O-N to N_2O. The indirect N_2O emissions from volatilization and runoff and leaching were summed to determine the total indirect N_2O emissions.

The direct and indirect N_2O emissions were summed to determine total N_2O emissions (kg N_2O per year).

Uncertainty and Time-Series Consistency

An analysis (ERG 2003) was conducted for the manure management emission estimates presented in the 1990 through 2001 Inventory report to determine the uncertainty associated with estimating CH_4 and N_2O emissions from livestock manure management. The quantitative uncertainty analysis for this source category was performed in 2002 through the IPCC-recommended Tier 2 uncertainty estimation methodology, the Monte Carlo Stochastic Simulation technique. The uncertainty analysis was developed based on the methods used to estimate CH_4 and N_2O emissions from manure management systems. A normal probability distribution was assumed for each source data category. The series of equations used were condensed into a single equation for each animal type and state. The equations for each animal group contained four to five variables around which the uncertainty analysis was

performed for each state. These uncertainty estimates were directly applied to the 2009 emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 6-8. Manure management CH_4 emissions in 2009 were estimated to be between 40.6 and 59.4 Tg CO_2 Eq. at a 95 percent confidence level, which indicates a range of 18 percent below to 20 percent above the actual 2009 emission estimate of 49.5 Tg CO_2 Eq. At the 95 percent confidence level, N_2O emissions were estimated to be between 15.0 and 22.1 Tg CO_2 Eq. (or approximately 16 percent below and 24 percent above the actual 2009 emission estimate of 17.9 Tg CO_2 Eq.).

Table 6-8: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O (Direct and Indirect) Emissions from Manure Management (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Manure Management	CH_4	49.5	40.6	59.4	-18%	+20%
Manure Management	N_2O	17.9	15.0	22.1	-16%	+24%

[a]Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Tier 2 activities focused on comparing estimates for the previous and current inventories for N_2O emissions from managed systems and CH_4 emissions from livestock manure. All errors identified were corrected. Order of magnitude checks were also conducted, and corrections made where needed. Manure N data were checked by comparing state-level data with bottom up estimates derived at the county level and summed to the state level. Similarly, a comparison was made by animal and WMS type for the full time series, between national level estimates for nitrogen excreted and the sum of county estimates for the full time series.

Recalculations Discussion

The CEFM produces VS and Nex data for cattle that are used in the manure management inventory. As a result, all changes to the CEFM described in Section 6.1 Enteric Fermentation contributed to changes in the VS and Nex data utilized for calculating CH_4 and N_2O emissions from manure management. In addition, to standardize the estimates of TAM between the CEFM and the manure management source category, the total VS and Nex estimates in units of kg per head per year from the CEFM were used in the manure management calculations in the current Inventory. With these changes, CH_4 and N_2O emission estimates from manure management systems are higher than reported in the previous Inventory for both beef and dairy cattle. Methane emissions from beef and dairy cattle were higher by 7 and 24 percent, respectively, while N_2O emissions were higher by 1 and 5 percent for beef and dairy cattle, respectively, averaged over the 1990 to 2008 time series.

In addition to changes in cattle Nex and VS data, the VS and Nex for other animal types were updated using data from USDA's updated *Agricultural Waste Management Field Handbook* (USDA 2008). Data from both the previous *Handbook* and the updated the *Handbook* were used to create a time series of VS and Nex data across all inventory years for all animals (ERG 2010b). The VS and Nex updates for all animals contributed to an average emission increase of 9.5 percent for CH_4 and 2.7 percent for N_2O across the time series.

For the current Inventory, USDA population data were used that included updated market swine categories. USDA changed the "market swine under 60 lbs." category to "market swine under 50 lbs." for years 2008 and 2009. In addition, USDA changed the "market swine from 60-119 lbs." to "market swine from 50-119 lbs." for the same years. This update resulted in a change in TAM estimates for those two swine categories which contributed to an overall decrease in CH_4 emissions from swine of 1.6 percent and an overall increase in N_2O emissions from swine of 20.9 percent in 2008.

The goat population was updated to reflect the USDA 2007 Census of Agriculture. This change resulted in an increase in both $CH_4$and N_2O emissions for goats from the years 2003 through 2008 by 13 percent and 16 percent on average, respectively.

Planned Improvements

A recent journal article (Lory et al., 2010) criticized the IPCC and EPA methodology used to estimate greenhouse gas emissions from manure management. After review of the methodologies, EPA does not feel that any changes to the IPCC inventory methodologies are required as a result of this article; for more specific information, please see EPA's detailed response to the article (Bartram et al., 2010). EPA will continue to investigate any new or additional data sources identified that contain updated information that can be used to improve the inventory emission estimates. Also, EPA will continue to seek empirical data to compare inventory estimates to specific systems, in order to improve the methodology used to estimate greenhouse gas emissions from manure management.

USDA's 2007 *Census of Agriculture* data are finalized and available. These data will be incorporated into the county-level population estimates used for the Agricultural Soils source category and the estimates of MCF and utilize it to update the WMS distributions for swine and dairy animals.

Due to time constraints, the temperature data used to estimate MCFs were not updated for the current Inventory. Updated temperature data will be obtained and applied for subsequent Inventory reports.

The uncertainty analysis will be updated in the future to more accurately assess uncertainty of emission calculations. This update is necessary due to the extensive changes in emission calculation methodology that was made in the 1990 through 2006 Inventory, including estimation of emissions at the WMS level and the use of new calculations and variables for indirect N_2O emissions.

6.3. Rice Cultivation (IPCC Source Category 4C)

Most of the world's rice, and all rice in the United States, is grown on flooded fields. When fields are flooded, aerobic decomposition of organic material gradually depletes most of the oxygen present in the soil, causing anaerobic soil conditions. Once the environment becomes anaerobic, CH_4 is produced through anaerobic decomposition of soil organic matter by methanogenic bacteria. As much as 60 to 90 percent of the CH_4 produced is oxidized by aerobic methanotrophic bacteria in the soil (some oxygen remains at the interfaces of soil and water, and soil and root system) (Holzapfel-Pschorn et al. 1985, Sass et al. 1990). Some of the CH_4 is also leached away as dissolved CH_4 in floodwater that percolates from the field. The remaining un-oxidized CH_4 is transported from the submerged soil to the atmosphere primarily by diffusive transport through the rice plants. Minor amounts of CH_4 also escape from the soil via diffusion and bubbling through floodwaters.

The water management system under which rice is grown is one of the most important factors affecting CH_4 emissions. Upland rice fields are not flooded, and therefore are not believed to produce CH_4. In deepwater rice fields (i.e., fields with flooding depths greater than one meter), the lower stems and roots of the rice plants are dead, so the primary CH_4 transport pathway to the atmosphere is blocked. The quantities of CH_4 released from deepwater fields, therefore, are believed to be significantly less than the quantities released from areas with shallower flooding depths. Some flooded fields are drained periodically during the growing season, either intentionally or accidentally. If water is drained and soils are allowed to dry sufficiently, CH_4 emissions decrease or stop entirely. This is due to soil aeration, which not only causes existing soil CH_4 to oxidize but also inhibits further CH_4 production in soils. All rice in the United States is grown under continuously flooded conditions; none is grown under deepwater conditions. Mid-season drainage does not occur except by accident (e.g., due to levee breach).

Other factors that influence CH_4 emissions from flooded rice fields include fertilization practices (especially the use of organic fertilizers), soil temperature, soil type, rice variety, and cultivation practices (e.g., tillage, seeding, and weeding practices). The factors that determine the amount of organic material available to decompose (i.e., organic fertilizer use, soil type, rice variety,[141] and cultivation practices) are the most important variables influencing the amount of CH_4 emitted over the growing season; the total amount of CH_4 released depends primarily on the amount of organic substrate available. Soil temperature is known to be an important factor regulating the activity of methanogenic bacteria, and therefore the rate of CH_4 production. However, although temperature controls the amount of time it takes to convert a given amount of organic material to CH_4, that time is short relative to a growing season, so the dependence of total emissions over an entire growing season on soil temperature is weak. The application of synthetic fertilizers has also been found to influence CH_4 emissions; in particular, both nitrate and

[141] The roots of rice plants shed organic material, which is referred to as "root exudate." The amount of root exudate produced by a rice plant over a growing season varies among rice varieties.

sulfate fertilizers (e.g., ammonium nitrate and ammonium sulfate) appear to inhibit CH_4 formation.

Rice is cultivated in eight states: Arkansas, California, Florida, Louisiana, Mississippi, Missouri, Oklahoma, and Texas.[142] Soil types, rice varieties, and cultivation practices for rice vary from state to state, and even from farm to farm. However, most rice farmers apply organic fertilizers in the form of residue from the previous rice crop, which is left standing, disked, or rolled into the fields. Most farmers also apply synthetic fertilizer to their fields, usually urea. Nitrate and sulfate fertilizers are not commonly used in rice cultivation in the United States. In addition, the climatic conditions of southwest Louisiana, Texas, and Florida often allow for a second, or ratoon, rice crop. Ratoon crops are much less common or non-existent in Arkansas, California, Mississippi, Missouri, Oklahoma, and northern areas of Louisiana. Methane emissions from ratoon crops have been found to be considerably higher than those from the primary crop. This second rice crop is produced from regrowth of the stubble after the first crop has been harvested. Because the first crop's stubble is left behind in ratooned fields, and there is no time delay between cropping seasons (which would allow the stubble to decay aerobically), the amount of organic material that is available for anaerobic decomposition is considerably higher than with the first (i.e., primary) crop.

Rice cultivation is a small source of CH_4 in the United States (Table 6-9 and Table 6-10). In 2009, CH_4 emissions from rice cultivation were 7.3 Tg CO_2 Eq. (349 Gg). Annual emissions fluctuated unevenly between the years 1990 and 2009, ranging from an annual decrease of 14 percent to an annual increase of 17 percent. There was an overall decrease of 17 percent between 1990 and 2006, due to an overall decrease in primary crop area.[143] However, emission levels increased again by 24 percent between 2006 and 2009 due to a slight increase in rice crop area in all states. The factors that affect the rice acreage in any year vary from state to state, although the price of rice relative to competing crops is the primary controlling variable in most states.

Table 6-9: CH_4 Emissions from Rice Cultivation (Tg CO_2 Eq.)

State	1990	2000	2005	2006	2007	2008	2009
Primary	**5.1**	**5.5**	**6.0**	**5.1**	**4.9**	**5.3**	**5.6**
Arkansas	2.1	2.5	2.9	2.5	2.4	2.5	2.6
California	0.7	1.0	0.9	0.9	1.0	0.9	1.0
Florida	+	+	+	+	+	+	+
Louisiana	1.0	0.9	0.9	0.6	0.7	0.8	0.8
Mississippi	0.4	0.4	0.5	0.3	0.3	0.4	0.4
Missouri	0.1	0.3	0.4	0.4	0.3	0.4	0.4
Oklahoma	+	+	+	+	0.0	0.0	0.0
Texas	0.6	0.4	0.4	0.3	0.3	0.3	0.3
Ratoon	**2.1**	**2.0**	**0.8**	**0.9**	**1.3**	**1.9**	**1.8**
Arkansas	+	+	+	+	+	+	+
Florida	+	0.1	+	+	+	+	+
Louisiana	1.1	1.3	0.5	0.5	0.9	1.2	1.1
Texas	0.9	0.7	0.4	0.4	0.3	0.6	0.7
Total	**7.1**	**7.5**	**6.8**	**5.9**	**6.2**	**7.2**	**7.3**

+ Less than 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 6-10: CH_4 Emissions from Rice Cultivation (Gg)

State	1990	2000	2005	2006	2007	2008	2009
Primary	**241**	**260**	**287**	**241**	**235**	**254**	**265**
Arkansas	102	120	139	119	113	119	125
California	34	47	45	44	45	44	47
Florida	1	2	1	1	1	1	1
Louisiana	46	41	45	29	32	39	39

[142] A very small amount of rice is grown on about 20 acres in South Carolina; however, this amount was determined to be too insignificant to warrant inclusion in national emission estimates.
[143] The 14 percent decrease occurred between 2005 and 2006; the 17 percent increase happened between 1993 and 1994.

Mississippi	21	19	22	16	16	19	21
Missouri	7	14	18	18	15	17	17
Oklahoma	+	+	+	+	0	+	+
Texas	30	18	17	13	12	15	14
Ratoon	**98**	**97**	**39**	**41**	**60**	**89**	**84**
Arkansas	+	+	1	+	+	+	+
Florida	2	2	+	1	1	1	2
Louisiana	52	61	22	22	42	59	51
Texas	45	34	17	18	16	29	31
Total	**339**	**357**	**326**	**282**	**295**	**343**	**349**

+ Less than 0.5 Gg

Note: Totals may not sum due to independent rounding.

Methodology

IPCC (2006) recommends using harvested rice areas, area-based daily emission factors (i.e., amount of CH_4 emitted per day per unit harvested area), and length of growing season to estimate annual CH_4 emissions from rice cultivation. This Inventory uses the recommended methodology and employs Tier 2 U.S.-specific emission factors derived from rice field measurements. State-specific and daily emission factors were not available, however, so average U.S. seasonal emission factors were used. Seasonal emissions have been found to be much higher for ratooned crops than for primary crops, so emissions from ratooned and primary areas are estimated separately using emission factors that are representative of the particular growing season. This approach is consistent with IPCC (2006).

The harvested rice areas for the primary and ratoon crops in each state are presented in Table 6-11, and the area of ratoon crop area as a percent of primary crop area is shown in Table 6-12. Primary crop areas for 1990 through 2009 for all states except Florida and Oklahoma were taken from U.S. Department of Agriculture's Field Crops Final Estimates 1987–1992 (USDA 1994), Field Crops Final Estimates 1992–1997 (USDA 1998), Field Crops Final Estimates 1997–2002 (USDA 2003), and Crop Production Summary (USDA 2005 through 2010). Source data for non-USDA sources of primary and ratoon harvest areas are shown in Table 6-13. California, Mississippi, Missouri, and Oklahoma have not ratooned rice over the period 1990 through 2009 (Guethle 1999 through 2010; Lee 2003 through 2007; Mutters 2002 through 2005; Street 1999 through 2003; Walker 2005, 2007 through 2008; Buehring 2009 through 2010).

Table 6-11: Rice Areas Harvested (Hectares)

State/Crop	1990	2000	2005	2006	2007	2008	2009
Arkansas							
Primary	485,633	570,619	661,675	566,572	536,220	564,549	594,901
Ratoon[a]	-	-	662	6	5	6	6
California	159,854	221,773	212,869	211,655	215,702	209,227	225,010
Florida							
Primary	4,978	7,801	4,565	4,575	6,242	5,463	5,664
Ratoon	2,489	3,193	0	1,295	1,873	1,639	2,266
Louisiana							
Primary	220,558	194,253	212,465	139,620	152,975	187,778	187,778
Ratoon	66,168	77,701	27,620	27,924	53,541	75,111	65,722
Mississippi	101,174	88,223	106,435	76,487	76,487	92,675	98,341
Missouri	32,376	68,393	86,605	86,605	72,036	80,534	80,939
Oklahoma	617	283	271	17	0	77	0
Texas							
Primary	142,857	86,605	81,344	60,704	58,681	69,607	68,798
Ratoon	57,143	43,302	21,963	23,675	21,125	36,892	39,903
Total Primary	***1,148,047***	***1,237,951***	***1,366,228***	***1,146,235***	***1,118,343***	***1,209,911***	***1,261,431***

Total Ratoon	***125,799***	***124,197***	***50,245***	***52,899***	***76,544***	***113,648***	***107,897***
Total	**1,273,847**	**1,362,148**	**1,416,473**	**1,199,135**	**1,194,887**	**1,323,559**	**1,369,328**

[a] Arkansas ratooning occurred only in 1998, 1999, and 2005 through 2009.
Note: Totals may not sum due to independent rounding.

Table 6-12: Ratooned Area as Percent of Primary Growth Area

State	1990	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Arkansas	0%		+	+	0%					0.1%	+	+	+	+
Florida	50%			65%	41%	60%	54%	100%	77%	0%	28%	30%	30%	40%
Louisiana	30%				40%	30%	15%	35%	30%	13%	20%	35%	40%	35%
Texas	40%				50%	40%	37%	38%	35%	27%	39%	36%	53%	58%

+ Indicates ratooning rate less than 0.1 percent.

Table 6-13: Non-USDA Data Sources for Rice Harvest Information

State/Crop	1990	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Arkansas											
Ratoon	Wilson (2002 – 2007, 2009 – 2010)										
Florida											
Primary	Scheuneman (1999 – 2001)		Deren (2002)	Kirstein (2003, 2006)			Gonzales (2006 – 2010)				
Ratoon	Scheuneman (1999)		Deren (2002)	Kirstein (2003-2004)		Cantens (2005)	Gonzales (2006 – 2010)				
Louisiana											
Ratoon	Bollich (2000)	Linscombe (1999, 2001 – 2010)									
Oklahoma											
Primary	Lee (2003-2007)								Anderson (2008 – 2010)		
Texas											
Ratoon	Klosterboer (1999 – 2003)				Stansel (2004 – 2005)		Texas Ag Experiment Station (2006 – 2010)				

To determine what CH_4 emission factors should be used for the primary and ratoon crops, CH_4 flux information from rice field measurements in the United States was collected. Experiments that involved atypical or nonrepresentative management practices (e.g., the application of nitrate or sulfate fertilizers, or other substances believed to suppress CH_4 formation), as well as experiments in which measurements were not made over an entire flooding season or floodwaters were drained mid-season, were excluded from the analysis. The remaining experimental results[144] were then sorted by season (i.e., primary and ratoon) and type of fertilizer amendment (i.e., no fertilizer added, organic fertilizer added, and synthetic and organic fertilizer added). The experimental results from primary crops with added synthetic and organic fertilizer (Bossio et al. 1999; Cicerone et al. 1992; Sass et al. 1991a, 1991b) were averaged to derive an emission factor for the primary crop, and the experimental results from ratoon crops with added synthetic fertilizer (Lindau and Bollich 1993, Lindau et al. 1995) were averaged to derive an emission factor for the ratoon crop. The resultant emission factor for the primary crop is 210 kg CH_4/hectare-season, and the resultant emission factor for the ratoon crop is 780 kg CH_4/hectare-season.

Uncertainty and Time-Series Consistency

The largest uncertainty in the calculation of CH_4 emissions from rice cultivation is associated with the emission factors. Seasonal emissions, derived from field measurements in the United States, vary by more than one order of

[144] In some of these remaining experiments, measurements from individual plots were excluded from the analysis because of the aforementioned reasons. In addition, one measurement from the ratooned fields (i.e., the flux of 1,490 kg CH_4/hectare-season in Lindau and Bollich 1993) was excluded, because this emission rate is unusually high compared to other flux measurements in the United States, as well as IPCC (2006) default emission factors.

magnitude. This inherent variability is due to differences in cultivation practices, particularly fertilizer type, amount, and mode of application; differences in cultivar type; and differences in soil and climatic conditions. A portion of this variability is accounted for by separating primary from ratooned areas. However, even within a cropping season or a given management regime, measured emissions may vary significantly. Of the experiments used to derive the emission factors applied here, primary emissions ranged from 22 to 479 kg CH_4/hectare-season and ratoon emissions ranged from 481 to 1,490 kg CH_4/hectare-season. The uncertainty distributions around the primary and ratoon emission factors were derived using the distributions of the relevant primary or ratoon emission factors available in the literature and described above. Variability about the rice emission factor means was not normally distributed for either primary or ratooned crops, but rather skewed, with a tail trailing to the right of the mean. A lognormal statistical distribution was, therefore, applied in the Tier 2 Monte Carlo analysis.

Other sources of uncertainty include the primary rice-cropped area for each state, percent of rice-cropped area that is ratooned, and the extent to which flooding outside of the normal rice season is practiced. Expert judgment was used to estimate the uncertainty associated with primary rice-cropped area for each state at 1 to 5 percent, and a normal distribution was assumed. Uncertainties were applied to ratooned area by state, based on the level of reporting performed by the state. No uncertainties were calculated for the practice of flooding outside of the normal rice season because CH_4 flux measurements have not been undertaken over a sufficient geographic range or under a broad enough range of representative conditions to account for this source in the emission estimates or its associated uncertainty.

To quantify the uncertainties for emissions from rice cultivation, a Monte Carlo (Tier 2) uncertainty analysis was performed using the information provided above. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 6-14. Rice cultivation CH_4 emissions in 2009 were estimated to be between 2.5 and 18.0 Tg CO_2 Eq. at a 95 percent confidence level, which indicates a range of 65 percent below to 146 percent above the actual 2009 emission estimate of 7.3 Tg CO_2 Eq.

Table 6-14: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Rice Cultivation (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Rice Cultivation	CH_4	7.3	2.5	18.0	-65%	+146%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for rice cultivation was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on comparing trends across years, states, and cropping seasons to attempt to identify any outliers or inconsistencies. No problems were found.

Planned Improvements

A possible future improvement is to create region-specific emission factors for rice cultivation. The current methodology uses a nationwide average emission factor, derived from several studies done in a number of states. The prospective improvement would take the same studies and average them by region, presumably resulting in more spatially specific emission factors.

6.4. Agricultural Soil Management (IPCC Source Category 4D)

Nitrous oxide is produced naturally in soils through the microbial processes of nitrification and denitrification.[145] A number of agricultural activities increase mineral N availability in soils, thereby increasing the amount available for nitrification and denitrification, and ultimately the amount of N_2O emitted. These activities increase soil mineral N either directly or indirectly (see Figure 6-2). Direct increases occur through a variety of management practices that add or lead to greater release of mineral N to the soil, including fertilization; application of managed livestock manure and other organic materials such as sewage sludge; deposition of manure on soils by domesticated animals in pastures, rangelands, and paddocks (PRP) (i.e., by grazing animals and other animals whose manure is not managed); production of N-fixing crops and forages; retention of crop residues; and drainage and cultivation of organic cropland soils (i.e., soils with a high organic matter content, otherwise known as histosols).[146] Other agricultural soil management activities, including irrigation, drainage, tillage practices, and fallowing of land, can influence N mineralization in soils and thereby affect direct emissions. Mineral N is also made available in soils through decomposition of soil organic matter and plant litter, as well as asymbiotic fixation of N from the atmosphere,[147] and these processes are influenced by agricultural management through impacts on moisture and temperature regimes in soils. These additional sources of mineral N are included at the recommendation of IPCC (2006) for complete accounting of management impacts on greenhouse gas emissions, as discussed in the Methodology section. Indirect emissions of N_2O occur through two pathways: (1) volatilization and subsequent atmospheric deposition of applied/mineralized N,[148] and (2) surface runoff and leaching of applied/mineralized N into groundwater and surface water. Direct emissions from agricultural lands (i.e., cropland and grassland) are included in this section, while direct emissions from forest lands and settlements are presented in the Land Use, Land-Use Change, and Forestry chapter. However, indirect N_2O emissions from all land-uses (cropland, grassland, forest lands, and settlements) are reported in this section.

Figure 6-2: Sources and Pathways of N that Result in N_2O Emissions from Agricultural Soil Management

Agricultural soils produce the majority of N_2O emissions in the United States. Estimated emissions from this source in 2009 were 204.6 Tg CO_2 Eq. (660 Gg N_2O) (see Table 6-15 and Table 6-16). Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3 percent higher in 2009 than in 1990. Year-to-year fluctuations are largely a reflection of annual variation in weather patterns, synthetic fertilizer use, and crop production. On average, cropland accounted for approximately 70 percent of total direct emissions, while grassland accounted for approximately 30 percent. These percentages are about the same for indirect emissions since forest lands and settlements account for such a small percentage of total indirect emissions. Estimated direct and indirect N_2O emissions by sub-source category are shown in Table 6-17 and Table 6-18.

Table 6-15: N_2O Emissions from Agricultural Soils (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Direct	**153.8**	**162.6**	**167.5**	**163.7**	**165.1**	**166.6**	**160.2**
Cropland	102.9	115.6	118.1	115.6	117.8	117.9	112.0
Grassland	50.9	47.1	49.4	48.1	47.3	48.7	48.2
Indirect (All Land-Use Types)	**44.0**	**44.1**	**43.9**	**45.2**	**44.3**	**44.1**	**44.4**

[145] Nitrification and denitrification are driven by the activity of microorganisms in soils. Nitrification is the aerobic microbial oxidation of ammonium (NH_4^+) to nitrate (NO_3^-), and denitrification is the anaerobic microbial reduction of nitrate to N_2. Nitrous oxide is a gaseous intermediate product in the reaction sequence of denitrification, which leaks from microbial cells into the soil and then into the atmosphere. Nitrous oxide is also produced during nitrification, although by a less well-understood mechanism (Nevison 2000).

[146] Drainage and cultivation of organic soils in former wetlands enhances mineralization of N-rich organic matter, thereby increasing N_2O emissions from these soils.

[147] Asymbiotic N fixation is the fixation of atmospheric N_2 by bacteria living in soils that do not have a direct relationship with plants.

[148] These processes entail volatilization of applied or mineralized N as NH_3 and NO_x, transformation of these gases within the atmosphere (or upon deposition), and deposition of the N primarily in the form of particulate NH_4^+, nitric acid (HNO_3), and NO_x.

Cropland	37.5	37.7	36.8	38.6	37.6	37.5	37.5
Grassland	6.1	5.8	6.3	5.9	5.9	5.9	6.2
Forest Land	+	0.1	0.1	0.1	0.1	0.1	0.1
Settlements	0.3	0.4	0.6	0.6	0.6	0.6	0.6
Total	**197.8**	**206.8**	**211.3**	**208.9**	**209.4**	**210.7**	**204.6**

+ Less than 0.05 Tg CO_2 Eq.

Table 6-16: N_2O Emissions from Agricultural Soils (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Direct	**496**	**525**	**540**	**528**	**533**	**538**	**517**
Cropland	332	373	381	373	380	380	361
Grassland	164	152	159	155	152	157	155
Indirect (All Land-Use Types)	**142**	**142**	**142**	**146**	**143**	**142**	**143**
Cropland	121	122	119	125	121	121	121
Grassland	20	19	20	19	19	19	20
Forest Land	0	+	+	+	+	+	+
Settlements	1	1	2	2	2	2	2
Total	**638**	**667**	**682**	**674**	**675**	**680**	**660**

+ Less than 0.5 Gg N_2O

Table 6-17: Direct N_2O Emissions from Agricultural Soils by Land Use Type and N Input Type (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Cropland	**102.9**	**115.6**	**118.1**	**115.6**	**117.8**	**117.9**	**112.0**
Mineral Soils	100.1	112.7	115.2	112.7	114.9	115.0	109.1
Mineralization and Asymbiotic Fixation	*44.6*	*50.6*	*50.5*	*49.7*	*50.9*	*50.9*	*47.1*
Synthetic Fertilizer	*32.3*	*36.0*	*38.6*	*36.7*	*37.4*	*37.3*	*36.9*
Residue N[a]	*12.4*	*14.3*	*13.7*	*13.8*	*13.9*	*14.3*	*13.1*
Organic Amendments[b]	*10.8*	*11.8*	*12.3*	*12.5*	*12.8*	*12.5*	*12.1*
Organic Soils	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Grassland	**50.9**	**47.1**	**49.4**	**48.1**	**47.3**	**48.7**	**48.2**
Residue N[c]	15.6	13.8	14.6	14.2	13.9	14.4	14.1
PRP Manure	8.1	7.9	8.2	8.1	8.0	8.2	7.9
Synthetic Fertilizer	3.9	3.9	4.1	4.0	3.9	4.0	3.9
Managed Manure[d]	1.5	1.6	1.6	1.6	1.6	1.6	1.6
Sewage Sludge	0.3	0.4	0.5	0.5	0.5	0.5	0.5
Mineralization and Asymbiotic Fixation	21.5	19.5	20.4	19.7	19.3	20.0	20.1
Total	**153.8**	**162.6**	**167.5**	**163.7**	**165.1**	**166.6**	**160.2**

[a] Cropland residue N inputs include N in unharvested legumes as well as crop residue N.
[b] Organic amendment inputs include managed manure amendments, daily spread manure amendments, and commercial organic fertilizers (i.e., dried blood, dried manure, tankage, compost, and other).
[c] Grassland residue N inputs include N in ungrazed legumes as well as ungrazed grass residue N
[d] Accounts for managed manure and daily spread manure amendments that are applied to grassland soils.

Table 6-18: Indirect N_2O Emissions from all Land-Use Types (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Cropland	**37.5**	**37.7**	**36.8**	**38.6**	**37.6**	**37.5**	**37.5**
Volatilization & Atm. Deposition	11.6	12.7	13.1	14.2	12.8	12.9	13.4
Surface Leaching & Run-Off	25.8	25.0	23.7	24.4	24.9	24.5	24.1
Grassland	**6.1**	**5.8**	**6.3**	**5.9**	**5.9**	**5.9**	**6.2**
Volatilization & Atm. Deposition	5.1	4.7	4.8	4.8	4.7	4.7	4.7

Surface Leaching & Run-Off	1.0	1.2	1.5	1.1	1.2	1.2	1.5
Forest Land	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Volatilization & Atm. Deposition	+	+	+	+	+	+	+
Surface Leaching & Run-Off	+	0.1	0.1	0.1	0.1	0.1	0.1
Settlements	**0.3**	**0.4**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**
Volatilization & Atm. Deposition	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Surface Leaching & Run-Off	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Total	**44.0**	**44.1**	**43.9**	**45.2**	**44.3**	**44.1**	**44.4**

+ Less than 0.05 Tg CO_2 Eq.

Figure 6-3 through Figure 6-6 show regional patterns in direct N_2O emissions, and also show N losses from volatilization, leaching, and runoff that lead to indirect N_2O emissions. Average annual emissions and N losses are shown for croplands that produce major crops and from grasslands in each state. Direct N_2O emissions from croplands tend to be high in the Corn Belt (Illinois, Iowa, Indiana, Ohio, southern Minnesota, southern Wisconsin, and eastern Nebraska), where a large portion of the land is used for growing highly fertilized corn and N-fixing soybean crops. Direct emissions are also high in Missouri, Kansas, and Texas, primarily from irrigated cropping in western Texas, dryland wheat in Kansas, and hay cropping in eastern Texas and Missouri. Direct emissions are low in many parts of the eastern United States because a small portion of land is cultivated, and also low in many western states where rainfall and access to irrigation water are limited.

Direct emissions (Tg CO_2 Eq./state/year) from grasslands are highest in the central and western United States (Figure 6-4) where a high proportion of the land is used for cattle grazing. Some areas in the Great Lake states, the Northeast, and Southeast have moderate to low emissions even though emissions from these areas tend to be high on a per unit area basis, because the total amount of grassland is much lower than in the central and western United States.

Indirect emissions from croplands and grasslands (Figure 6-5 and Figure 6-6) show patterns similar to direct emissions, because the factors that control direct emissions (N inputs, weather, soil type) also influence indirect emissions. However, there are some exceptions, because the processes that contribute to indirect emissions (NO_3^- leaching, N volatilization) do not respond in exactly the same manner as the processes that control direct emissions (nitrification and denitrification). For example, coarser-textured soils facilitate relatively high indirect emissions in Florida grasslands due to high rates of N volatilization and NO_3^- leaching, even though they have only moderate rates of direct N_2O emissions.

Figure 6-3: Major Crops, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO_2 Eq./year)
[Figure will be provided in public review]

Figure 6-4: Grasslands, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO_2 Eq./year)
[Figure will be provided in public review]

Figure 6-5: Major Crops, Average Annual N Losses Leading to Indirect N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Gg N/year)
[Figure will be provided in public review]

Figure 6-6: Grasslands, Average Annual N Losses Leading to Indirect N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Gg N/year)
[Figure will be provided in public review]

Methodology

The *2006 IPCC Guidelines* (IPCC 2006) divide the Agricultural Soil Management source category into four components: (1) direct emissions due to N additions to cropland and grassland mineral soils, including synthetic

fertilizers, sewage sludge applications, crop residues, organic amendments, and biological N fixation associated with planting of legumes on cropland and grassland soils; (2) direct emissions from drainage and cultivation of organic cropland soils; (3) direct emissions from soils due to the deposition of manure by livestock on PRP grasslands; and (4) indirect emissions from soils and water due to N additions and manure deposition to soils that lead to volatilization, leaching, or runoff of N and subsequent conversion to N_2O.

The United States has adopted recommendations from IPCC (2006) on methods for agricultural soil management. These recommendations include (1) estimating the contribution of N from crop residues to indirect soil N_2O emissions; (2) adopting a revised emission factor for direct N_2O emissions to the extent that Tier 1 methods are used in the Inventory (described later in this section); (3) removing double counting of emissions from N-fixing crops associated with the biological N fixation and crop residue N input categories; (4) using revised crop residue statistics to compute N inputs to soils based on harvest yield data to the extent that Tier 1 methods are used in the Inventory; (5) accounting for indirect as well as direct emissions from N made available via mineralization of soil organic matter and litter, in addition to asymbiotic fixation[149] (i.e., computing total emissions from managed land); and (6) reporting all emissions from managed lands, largely because management affects all processes leading to soil N_2O emissions. One recommendation from IPCC (2006) that has not been adopted is the accounting of emissions from pasture renewal, which involves occasional plowing to improve forage production. This practice is not common in the United States, and is not estimated.

The methodology used to estimate emissions from agricultural soil management in the United States is based on a combination of IPCC Tier 1 and 3 approaches. A Tier 3, process-based model (DAYCENT) was used to estimate direct emissions from major crops on mineral (i.e., non-organic) soils; as well as most of the direct emissions from grasslands. The Tier 3 approach has been specifically designed and tested to estimate N_2O emissions in the United States, accounting for more of the environmental and management influences on soil N_2O emissions than the IPCC Tier 1 method (see Box 6-1 for further elaboration). The Tier 1 IPCC (2006) methodology was used to estimate (1) direct emissions from non-major crops on mineral soils (e.g., barley, oats, vegetables, and other crops); (2) the portion of the grassland direct emissions that were not estimated with the Tier 3 DAYCENT model (i.e., federal grasslands); and (3) direct emissions from drainage and cultivation of organic cropland soils. Indirect emissions were also estimated with a combination of DAYCENT and the IPCC Tier 1 method.

In past Inventories, attempts were made to subtract "background" emissions that would presumably occur if the lands were not managed. However, this approach is likely to be inaccurate for estimating the anthropogenic influence on soil N_2O emissions. Moreover, if background emissions could be measured or modeled based on processes unaffected by anthropogenic activity, they would be a very small portion of the total emissions, due to the high inputs of N to agricultural soils from fertilization and legume cropping. Given the recommendation from IPCC (2006) and the influence of management on all processes leading to N_2O emissions from soils in agricultural systems, the decision was made to report total emissions from managed lands for this source category. Annex 3.11 provides more detailed information on the methodologies and data used to calculate N_2O emissions from each component.

[BEGIN BOX]

Box 6-1. Tier 1 vs. Tier 3 Approach for Estimating N_2O Emissions

The IPCC (2006) Tier 1 approach is based on multiplying activity data on different N inputs (e.g., synthetic fertilizer, manure, N fixation, etc.) by the appropriate default IPCC emission factors to estimate N_2O emissions on an input-by-input basis. The Tier 1 approach requires a minimal amount of activity data, readily available in most countries (e.g., total N applied to crops); calculations are simple; and the methodology is highly transparent. In contrast, the Tier 3 approach developed for this Inventory employs a process-based model (i.e., DAYCENT) that represents the interaction of N inputs and the environmental conditions at specific locations. Consequently, the Tier

[149] N inputs from asymbiotic N fixation are not directly addressed in *2006 IPCC Guidelines*, but are a component of the total emissions from managed lands and are included in the Tier 3 approach developed for this source.

3 approach is likely to produce more accurate estimates; it accounts more comprehensively for land-use and management impacts and their interaction with environmental factors (i.e., weather patterns and soil characteristics), which will enhance or dampen anthropogenic influences. However, the Tier 3 approach requires more detailed activity data (e.g., crop-specific N amendment rates), additional data inputs (e.g., daily weather, soil types, etc.), and considerable computational resources and programming expertise. The Tier 3 methodology is less transparent, and thus it is critical to evaluate the output of Tier 3 methods against measured data in order to demonstrate the adequacy of the method for estimating emissions (IPCC 2006). Another important difference between the Tier 1 and Tier 3 approaches relates to assumptions regarding N cycling. Tier 1 assumes that N added to a system is subject to N_2O emissions only during that year and cannot be stored in soils and contribute to N_2O emissions in subsequent years. This is a simplifying assumption that is likely to create bias in estimated N_2O emissions for a specific year. In contrast, the process-based model used in the Tier 3 approach includes such legacy effects when N added to soils is re-mineralized from soil organic matter and emitted as N_2O during subsequent years.

[END BOX]

Direct N_2O Emissions from Cropland Soils

Major Crop Types on Mineral Cropland Soils

The DAYCENT ecosystem model (Del Grosso et al. 2001, Parton et al. 1998) was used to estimate direct N_2O emissions from mineral cropland soils that are managed for production of major crops—specifically corn, soybeans, wheat, alfalfa hay, other hay, sorghum, and cotton—representing approximately 90 percent of total croplands in the United States. For these croplands, DAYCENT was used to simulate crop growth, soil organic matter decomposition, greenhouse gas fluxes, and key biogeochemical processes affecting N_2O emissions, and the simulations were driven by model input data generated from daily weather records (Thornton et al. 1997, 2000; Thornton and Running 1999), land management surveys (see citations below), and soil physical properties determined from national soil surveys (Soil Survey Staff 2005). Note that the influence of land-use change on soil N_2O emissions was not addressed in this analysis, but is a planned improvement.

DAYCENT simulations were conducted for each major crop at the county scale in the United States. Simulating N_2O emissions at the county scale was facilitated by soil and weather data that were available for every county with more than 100 acres of agricultural land, and by land management data (e.g., timing of planting, harvesting, and intensity of cultivation) that were available at the agricultural-region level as defined by the Agricultural Sector Model (McCarl et al. 1993). ASM has 63 agricultural regions in the contiguous United States. Most regions correspond to one state, except for those states with greater heterogeneity in agricultural practices; in such cases, more than one region is assigned to a state. While cropping systems were simulated for each county, the results best represent emissions at regional (i.e., state) and national levels due to the regional scale of management data, which include model parameters that determined the influence of management activities on soil N_2O emissions (e.g., when crops were planted/harvested).

Nitrous oxide emissions from managed agricultural lands are the result of interactions among anthropogenic activities (e.g., N fertilization, manure application, tillage) and other driving variables, such as weather and soil characteristics. These factors influence key processes associated with N dynamics in the soil profile, including immobilization of N by soil microbial organisms, decomposition of organic matter, plant uptake, leaching, runoff, and volatilization, as well as the processes leading to N_2O production (nitrification and denitrification). It is not possible to partition N_2O emissions into each anthropogenic activity directly from model outputs due to the complexity of the interactions (e.g., N_2O emissions from synthetic fertilizer applications cannot be distinguished from those resulting from manure applications). To approximate emissions by activity, the amount of mineral N added to the soil for each of these sources was determined and then divided by the total amount of mineral N that was made available in the soil according to the DAYCENT model. The percentages were then multiplied by the total of direct N_2O emissions in order to approximate the portion attributed to key practices. This approach is only an approximation because it assumes that all N made available in soil has an equal probability of being released as N_2O, regardless of its source, which is unlikely to be the case (Delgado et al., 2009). However, this approach allows for further disaggregation of emissions by source of N, which is valuable for reporting purposes and is analogous to the reporting associated with the IPCC (2006) Tier 1 method, in that it associates portions of the total soil N_2O

emissions with individual sources of N.

DAYCENT was used to estimate direct N_2O emissions due to mineral N available from: (1) the application of synthetic fertilizers; (2) the application of livestock manure; (3) the retention of crop residues (i.e., leaving residues in the field after harvest instead of burning or collecting residues); and (4) mineralization of soil organic matter and litter, in addition to asymbiotic fixation. Note that commercial organic fertilizers are addressed with the Tier 1 method because county-level application data would be needed to simulate applications in DAYCENT, and currently data are only available at the national scale. The third and fourth sources are generated internally by the DAYCENT model. For the first two practices, annual changes in soil mineral N due to anthropogenic activity were obtained or derived from the following sources:

- Crop-specific N-fertilization rates: Data sources for fertilization rates include Alexander and Smith (1990), Anonymous (1924), Battaglin and Goolsby (1994), Engle and Makela (1947), ERS (1994, 2003), Fraps and Asbury (1931), Ibach and Adams (1967), Ibach et al. (1964), NFA (1946), NRIAI (2003), Ross and Mehring (1938), Skinner (1931), Smalley et al. (1939), Taylor (1994), and USDA (1966, 1957, 1954, 1946). Information on fertilizer use and rates by crop type for different regions of the United States were obtained primarily from the USDA *Economic Research Service Cropping Practices Survey* (ERS 1997) with additional data from other sources, including the National Agricultural Statistics Service (NASS 1992, 1999, 2004).

- Managed manure production and application to croplands and grasslands: Manure N amendments and daily spread manure N amendments applied to croplands and grasslands (not including PRP manure) were determined using USDA Manure N Management Databases for 1997 (Kellogg et al. 2000; Edmonds et al. 2003). Amendment data for 1997 were scaled to estimate values for other years based on the availability of managed manure N for application to soils in 1997 relative to other years. The amount of available N from managed manure for each livestock type was calculated as described in the Manure Management section (Section 6.2) and Annex 3.10.

- Retention of crop residue, N mineralization from soil organic matter, and asymbiotic N fixation from the atmosphere: The IPCC approach considers crop residue N and N mineralized from soil organic matter as activity data. However, they are not treated as activity data in DAYCENT simulations because residue production, N fixation, mineralization of N from soil organic matter, and asymbiotic fixation are internally generated by the model as part of the simulation. In other words, DAYCENT accounts for the influence of N fixation, mineralization of N from soil organic matter, and retention of crop residue on N_2O emissions, but these are not model inputs. The DAYCENT simulations also accounted for the approximately 3 percent of grain crop residues that were assumed to be burned based on state inventory data (ILENR 1993, Oregon Department of Energy 1995, Noller 1996, Wisconsin Department of Natural Resources 1993, and Cibrowski 1996), and therefore did not contribute to soil N_2O emissions.

- Historical and modern crop rotation and management information (e.g., timing and type of cultivation, timing of planting/harvest, etc.): These activity data were derived from Hurd (1930, 1929), Latta (1938), Iowa State College Staff Members (1946), Bogue (1963), Hurt (1994), USDA (2000a) as extracted by Eve (2001) and revised by Ogle (2002), CTIC (1998), Piper et al. (1924), Hardies and Hume (1927), Holmes (1902, 1929), Spillman (1902, 1905, 1907, 1908), Chilcott (1910), Smith (1911), Kezer (ca. 1917), Hargreaves (1993), ERS (2002), Warren (1911), Langston et al. (1922), Russell et al. (1922), Elliott and Tapp (1928), Elliott (1933), Ellsworth (1929), Garey (1929), Hodges et al. (1930), Bonnen and Elliott (1931), Brenner et al. (2002, 2001), and Smith et al. (2002).

DAYCENT simulations produced per-area estimates of N_2O emissions (g N_2O-N/m^2) for major crops in each county, which were multiplied by the cropland areas in each county to obtain county-scale emission estimates. Cropland area data were from NASS (USDA 2010a, 2010b). The emission estimates by reported crop areas in the county were scaled to the regions (and states for mapping purposes when there was more than one region in a state), and the national estimate was calculated by summing results across all regions. DAYCENT is sensitive to interannual variability in weather patterns and other controlling variables, so emissions associated with individual activities vary through time even if the management practices remain the same (e.g., if N fertilization remains the same for two years). In contrast, Tier 1 methods do not capture this variability and rather have a linear, monotonic response that depends solely on management practices. DAYCENT's ability to capture these interactions between management and environmental conditions produces more accurate estimates of N_2O emissions than the Tier 1 method.

Non-Major Crop Types on Mineral Cropland Soils

The IPCC (2006) Tier 1 methodology was used to estimate direct N_2O emissions for mineral cropland soils that are managed for production of non-major crop types, including barley, oats, tobacco, sugarcane, sugar beets, sunflowers, millet, rice, peanuts, and other crops that were not included in the DAYCENT simulations. Estimates of direct N_2O emissions from N applications to non-major crop types were based on mineral soil N that was made available from the following practices: (1) the application of synthetic commercial fertilizers; (2) application of managed manure and non-manure commercial organic fertilizers;[150] and (3) the retention of above- and below-ground crop residues in agricultural fields (i.e., crop biomass that is not harvested). Non-manure organic amendments were not included in the DAYCENT simulations because county-level data were not available. Consequently, non-manure organic amendments, as well as additional manure that was not added to major crops in the DAYCENT simulations, were included in the Tier 1 analysis. The influence of land-use change on soil N_2O emissions from non-major crops has not been addressed in this analysis, but is a planned improvement. The following sources were used to derive activity data:

- A process-of-elimination approach was used to estimate synthetic N fertilizer additions for non-major crops, because little information exists on their fertilizer application rates. The total amount of fertilizer used on farms has been estimated by the USGS from sales records (Ruddy et al. 2006), and these data were aggregated to obtain state-level N additions to farms. After subtracting the portion of fertilizer applied to major crops and grasslands (see sections on Major Crops and Grasslands for information on data sources), the remainder of the total fertilizer used on farms was assumed to be applied to non-major crops.
- A process-of-elimination approach was used to estimate manure N additions for non-major crops, because little information exists on application rates for these crops. The amount of manure N applied to major crops and grasslands was subtracted from total manure N available for land application (see sections on Major Crops and Grasslands for information on data sources), and this difference was assumed to be applied to non-major crops.
- Non-manure, non-sewage-sludge commercial organic fertilizer additions were based on organic fertilizer consumption statistics, which were converted to units of N using average organic fertilizer N content (TVA 1991 through 1994; AAPFCO 1995 through 2010). Manure and sewage sludge components were subtracted from total commercial organic fertilizers to avoid double counting.
- Crop residue N was derived by combining amounts of above- and below-ground biomass, which were determined based on crop production yield statistics (USDA 1994, 1998, 2003, 2005, 2006, 2008, 2009, 2010a), dry matter fractions (IPCC 2006), linear equations to estimate above-ground biomass given dry matter crop yields from harvest (IPCC 2006), ratios of below-to-above-ground biomass (IPCC 2006), and N contents of the residues (IPCC 2006). Approximately 3 percent of the crop residues were burned and therefore did not contribute to soil N_2O emissions, based on state inventory data (ILENR 1993, Oregon Department of Energy 1995, Noller 1996, Wisconsin Department of Natural Resources 1993, and Cibrowski 1996).

The total increase in soil mineral N from applied fertilizers and crop residues was multiplied by the IPCC (2006) default emission factor to derive an estimate of direct N_2O emissions from non-major crop types.

Drainage and Cultivation of Organic Cropland Soils

The IPCC (2006) Tier 1 methods were used to estimate direct N_2O emissions due to drainage and cultivation of organic soils at a state scale. State-scale estimates of the total area of drained and cultivated organic soils were obtained from the *National Resources Inventory* (NRI) (USDA 2000a, as extracted by Eve 2001 and amended by Ogle 2002). Temperature data from Daly et al. (1994, 1998) were used to subdivide areas into temperate and sub-tropical climates using the climate classification from IPCC (2006). Data were available for 1982, 1992 and 1997. To estimate annual emissions, the total temperate area was multiplied by the IPCC default emission factor for temperate regions, and the total sub-tropical area was multiplied by the average of the IPCC default emission factors for temperate and tropical regions (IPCC 2006).

[150] Commercial organic fertilizers include dried blood, tankage, compost, and other; dried manure and sewage sludge that are used as commercial fertilizer have been excluded to avoid double counting. The dried manure N is counted with the non-commercial manure applications, and sewage sludge is assumed to be applied only to grasslands.

Direct N_2O Emissions from Grassland Soils

As with N_2O from croplands, the Tier 3 process-based DAYCENT model and Tier 1 method described in IPCC (2006) were combined to estimate emissions from grasslands. Grasslands include pastures and rangelands used for grass forage production, where the primary use is livestock grazing. Rangelands are typically extensive areas of native grasslands that are not intensively managed, while pastures are often seeded grasslands, possibly following tree removal, which may or may not be improved with practices such as irrigation and interseeding legumes.

DAYCENT was used to simulate county-scale N_2O emissions from non-federal grasslands resulting from manure deposited by livestock directly onto pastures and rangelands (i.e., PRP manure), N fixation from legume seeding, managed manure amendments (i.e., manure other than PRP manure), and synthetic fertilizer application. Other N inputs were simulated within the DAYCENT framework, including N input from mineralization due to decomposition of soil organic matter and N inputs from senesced grass litter, as well as asymbiotic fixation of N from the atmosphere. The simulations used the same weather, soil, and synthetic N fertilizer data as discussed under the section for Major Crop Types on Mineral Cropland Soils. Managed manure N amendments to grasslands were estimated from Edmonds et al. (2003) and adjusted for annual variation using data on the availability of managed manure N for application to soils, according to methods described in the Manure Management section (Section 6.2) and Annex 3.10. Biological N fixation is simulated within DAYCENT and therefore was not an input to the model.

Manure N deposition from grazing animals (i.e., PRP manure) is another key input of N to grasslands. The amounts of PRP manure N applied on non-federal and federal grasslands in each county were based on the proportion of non-federal to federal grassland area (See below for more information on area data). The amount of PRP manure applied on non-federal grasslands was an input to the DAYCENT model (see Annex 3.10), and included approximately 91 percent of total PRP manure. The remainder of the PRP manure N excretions in each county was assumed to be excreted on federal grasslands (i.e., DAYCENT simulations were only conducted for non-federal grasslands), and the N_2O emissions were estimated using the IPCC (2006) Tier 1 method with IPCC default emission factors. Sewage sludge was assumed to be applied on grasslands because of the heavy metal content and other pollutants in human waste that limit its use as an amendment to croplands. Sewage sludge application was estimated from data compiled by EPA (1993, 1999, 2003), McFarland (2001), and NEBRA (2007). Sewage sludge data on soil amendments to agricultural lands were only available at the national scale, and it was not possible to associate application with specific soil conditions and weather at the county scale. Therefore, DAYCENT could not be used to simulate the influence of sewage sludge amendments on N_2O emissions from grassland soils, and consequently, emissions from sewage sludge were estimated using the IPCC (2006) Tier 1 method.

Grassland area data were consistent with the Land Representation reported in Section 7.1. Data were obtained from the U.S. Department of Agriculture *National Resources Inventory* (USDA 2000a, Nusser and Goebel 1997, http://www.ncgc.nrcs.usda.gov/products/nri/index.htm) and the U.S. Geological Survey (USGS) National Land Cover Dataset (NLCD, Vogelman et al. 2001, http://www.mrlc.gov), which were reconciled with the Forest Inventory and Analysis Data (http://fia.fs.us/tools-data/data). The area data for pastures and rangeland were aggregated to the county level to estimate non-federal and federal grassland areas.

DAYCENT simulations produced per-area estimates of N_2O emissions (g N_2O-N/m^2) for pasture and rangelands, which were multiplied by the non-federal grassland areas in each county. The county-scale N_2O emission estimates for non-federal grasslands were scaled to the 63 agricultural regions (and to the state level for mapping purposes if there was more than one region in a state), and the national estimate was calculated by summing results across all regions. Tier 1 estimates of N_2O emissions for the PRP manure N deposited on federal grasslands and applied sewage sludge N were produced by multiplying the N input by the appropriate emission factor. Tier 1 estimates for emissions from manure N were calculated at the state level and aggregated to the entire country but emission from sewage sludge N were calculated exclusively at the national scale.

Total Direct N_2O Emissions from Cropland and Grassland Soils

Annual direct emissions from major and non-major crops on mineral cropland soils, from drainage and cultivation of organic cropland soils, and from grassland soils were summed to obtain the total direct N_2O emissions from agricultural soil management (see Table 6-15 and Table 6-16).

Indirect N_2O Emissions from Managed Soils of all Land-Use Types

This section describes the methods used for estimating indirect soil N_2O emissions from all land-use types (i.e.,

croplands, grasslands, forest lands, and settlements). Indirect N_2O emissions occur when mineral N made available through anthropogenic activity is transported from the soil either in gaseous or aqueous forms and later converted into N_2O. There are two pathways leading to indirect emissions. The first pathway results from volatilization of N as NO_x and NH_3 following application of synthetic fertilizer, organic amendments (e.g., manure, sewage sludge), and deposition of PRP manure. N made available from mineralization of soil organic matter and asymbiotic fixation also contributes to volatilized N emissions. Volatilized N can be returned to soils through atmospheric deposition, and a portion of the deposited N is emitted to the atmosphere as N_2O. The second pathway occurs via leaching and runoff of soil N (primarily in the form of NO_3^-) that was made available through anthropogenic activity on managed lands, mineralization of soil organic matter, and asymbiotic fixation. The NO_3^- is subject to denitrification in water bodies, which leads to N_2O emissions. Regardless of the eventual location of the indirect N_2O emissions, the emissions are assigned to the original source of the N for reporting purposes, which here includes croplands, grasslands, forest lands, and settlements.

Indirect N_2O Emissions from Atmospheric Deposition of Volatilized N from Managed Soils

As in the direct emissions calculation, the Tier 3 DAYCENT model and IPCC (2006) Tier 1 methods were combined to estimate the amount of N that was volatilized and eventually emitted as N_2O. DAYCENT was used to estimate N volatilization for land areas whose direct emissions were simulated with DAYCENT (i.e., major croplands and most grasslands). The N inputs included are the same as described for direct N_2O emissions in the sections on major crops and grasslands. Nitrogen volatilization for all other areas was estimated using the Tier 1 method and default IPCC fractions for N subject to volatilization (i.e., N inputs on non-major croplands, PRP manure N excretion on federal grasslands, sewage sludge application on grasslands). The Tier 1 method and default fractions were also used to estimate N subject to volatilization from N inputs on settlements and forest lands (see the Land Use, Land-Use Change, and Forestry chapter). For the volatilization data generated from both the DAYCENT and Tier 1 approaches, the IPCC (2006) default emission factor was used to estimate indirect N_2O emissions occurring due to re-deposition of the volatilized N (Table 6-18).

Indirect N_2O Emissions from Leaching/Runoff

As with the calculations of indirect emissions from volatilized N, the Tier 3 DAYCENT model and IPCC (2006) Tier 1 method were combined to estimate the amount of N that was subject to leaching and surface runoff into water bodies, and eventually emitted as N_2O. DAYCENT was used to simulate the amount of N transported from lands used to produce major crops and most grasslands. N transport from all other areas was estimated using the Tier 1 method and the IPCC (2006) default factor for the proportion of N subject to leaching and runoff. This N transport estimate includes N applications on croplands that produce non-major crops, sewage sludge amendments on grasslands, PRP manure N excreted on federal grasslands, and N inputs on settlements and forest lands. For both the DAYCENT and IPCC (2006) Tier 1 methods, nitrate leaching was assumed to be an insignificant source of indirect N_2O in cropland and grassland systems in arid regions as discussed in IPCC (2006). In the United States, the threshold for significant nitrate leaching is based on the potential evapotranspiration (PET) and rainfall amount, similar to IPCC (2006), and is assumed to be negligible in regions where the amount of precipitation plus irrigation does not exceed 80 percent of PET. For leaching and runoff data estimated by the DAYCENT and Tier 1 approaches, the IPCC (2006) default emission factor was used to estimate indirect N_2O emissions that occur in groundwater and waterways (Table 6-18).

Uncertainty and Time-Series Consistency

Uncertainty was estimated for each of the following five components of N_2O emissions from agricultural soil management: (1) direct emissions calculated by DAYCENT; (2) the components of indirect emissions (N volatilized and leached or runoff) calculated by DAYCENT; (3) direct emissions calculated with the IPCC (2006) Tier 1 method; (4) the components of indirect emissions (N volatilized and leached or runoff) calculated with the IPCC (2006) Tier 1 method; and (5) indirect emissions calculated with the IPCC (2006) Tier 1 method. Uncertainty in direct emissions, which account for the majority of N_2O emissions from agricultural management, as well as the components of indirect emissions calculated by DAYCENT were estimated with a Monte Carlo Analysis, addressing uncertainties in model inputs and structure (i.e., algorithms and parameterization) (Del Grosso et al., 2010). Uncertainties in direct emissions calculated with the IPCC (2006) Tier 1 method, the proportion of volatilization and leaching or runoff estimated with the IPCC (2006) Tier 1 method, and indirect N_2O emissions were estimated with a simple error propagation approach (IPCC 2006). Additional details on the uncertainty

methods are provided in Annex 3.11.

Uncertainties from the Tier 1 and Tier 3 (i.e., DAYCENT) estimates were combined using simple error propagation (IPCC 2006), and the results are summarized in Table 6-19. Agricultural direct soil N_2O emissions in 2009 were estimated to be between 118.3 and 250.6 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 26 percent below and 56 percent above the 2009 emission estimate of 160.2 Tg CO_2 Eq. The indirect soil N_2O emissions in 2009 were estimated to range from 22.4 to 111.6 Tg CO_2 Eq. at a 95 percent confidence level, indicating an uncertainty of 50 percent below and 151 percent above the 2009 emission estimate of 44.4 Tg CO_2 Eq.

Table 6-19: Quantitative Uncertainty Estimates of N_2O Emissions from Agricultural Soil Management in 2009 (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Direct Soil N_2O Emissions	N_2O	160.2	118.3	250.6	-26%	+56%
Indirect Soil N_2O Emissions	N_2O	44.4	22.4	111.6	-50%	+151%

Note: Due to lack of data, uncertainties in areas for major crops, managed manure N production, PRP manure N production, other organic fertilizer amendments, indirect losses of N in the DAYCENT simulations, and sewage sludge amendments to soils are currently treated as certain; these sources of uncertainty will be included in future Inventories.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

For quality control, DAYCENT results for N_2O emissions and NO_3^- leaching were compared with field data representing various cropland and grassland systems, soil types, and climate patterns (Del Grosso et al. 2005, Del Grosso et al. 2008), and further evaluated by comparing to emission estimates produced using the IPCC (2006) Tier 1 method for the same sites. Nitrous oxide measurement data were available for 11 sites in the United States and one in Canada, representing 30 different combinations of fertilizer treatments and cultivation practices. DAYCENT estimates of N_2O emissions were closer to measured values at all sites compared to the IPCC Tier 1 estimate, except for Colorado dryland cropping (Figure 6-7). In general, IPCC Tier 1 methodology tends to over-estimate emissions when observed values are low and under-estimate emissions when observed values are high, while DAYCENT estimates are less biased. This is not surprising because DAYCENT accounts for site-level factors (weather, soil type) that influence N_2O emissions. Nitrate leaching data were available for three sites in the United States representing nine different combinations of fertilizer amendments. Linear regressions of simulated vs. observed emission and leaching data yielded correlation coefficients of 0.89 and 0.94 for annual N_2O emissions and NO_3^- leaching, respectively. This comparison demonstrates that DAYCENT provides relatively high predictive capability for N_2O emissions and NO_3^- leaching, and is an improvement over the IPCC Tier 1 method (see additional information in Annex 3.11).

Figure 6-7: Comparison of Measured Emissions at Field Sites and Modeled Emissions Using the DAYCENT Simulation Model

Spreadsheets containing input data and probability distribution functions required for DAYCENT simulations of major croplands and grasslands and unit conversion factors were checked, as were the program scripts that were used to run the Monte Carlo uncertainty analysis. Several errors were identified following re-organization of the calculation spreadsheets, and corrective actions have been taken. In particular, some of the links between spreadsheets were missing or needed to be modified. Spreadsheets containing input data, emission factors, and calculations required for the Tier 1 approach were checked and no errors were found.

Recalculations Discussion

Two major revisions were made in the Agricultural Soil Management section for the current Inventory.

First, the methodology used to estimate grassland areas was updated and revised to be consistent with the Land Representation used in the Land Use, Land Use Change and Forestry sector (see Section 7.1). This led to an overall decrease in grassland area, and lower emissions than reported in the prior Inventory. Second, the methodology used to calculate livestock manure N was changed such that total manure N added to soils increased by approximately 11 percent (see Section 6.2 for details).

The recalculations had opposite impacts on the emissions, with less grassland area tending to decrease emissions and higher manure N inputs tending to increase emissions. In some years emissions were higher overall, but on average, these changes led to a lower amount of N_2O emissions from agricultural soil management by about 1.5 percent over the time series relative to the previous Inventory.

Planned Improvements

A key improvement is underway for Agricultural Soil Management to incorporate more land-use survey data from the NRI (USDA 2000a) into the DAYCENT simulation analysis, beyond the area estimates for rangeland and pasture that are currently used to estimate emissions from grasslands. NRI has a record of land-use activities since 1979 for all U.S. agricultural land, which is estimated at about 386 Mha. NASS is used as the basis for land-use records in the current Inventory, and there are three major disadvantages to this dataset. First, most crops are grown in rotation with other crops (e.g., corn-soybean), but NASS data provide no information regarding rotation histories. In contrast, NRI is designed to track rotation histories, which is important because emissions from any particular year can be influenced by the crop that was grown the previous year. Second, NASS does not conduct a complete survey of cropland area each year, leading to gaps in the land base. NRI provides a complete history of cropland areas for four out of every five years from 1979 to 1997, and then every year after 1998. Third, the current inventory based on NASS does not quantify the influence of land-use change on emissions, which can be addressed using the NRI survey records. NRI also provides additional information on pasture land management that can be incorporated into the analysis (particularly the use of irrigation). Using NRI data will also make the Agricultural Soil Management methods more consistent with the methods used to estimate C stock changes for agricultural soils. The structure of model input files that contain land management data are currently being extensively revised to facilitate use of the annualized NRI data. This improvement is planned for completion by the next Inventory.

Another improvement is to reconcile the amount of crop residues burned with the Field Burning of Agricultural Residues source category (Section 6.5). This year the methodology for Field Burning of Agricultural Residues was significantly updated, but the changes were implemented too late for the new estimates of crop residues burned to be incorporated into the DAYCENT runs for the Agricultural Soil Management source. Next year the estimates will be reconciled; meanwhile the estimates presented in this section use the previous year's methodology for determining crop residues burned.

Other planned improvements are minor but will lead to more accurate estimates, including updating DAYMET weather data for more recent years following the release of new data, and using a rice-crop-specific emission factor for N amendments to rice areas.

6.5. Field Burning of Agricultural Residues (IPCC Source Category 4F)

Farming activities produce large quantities of agricultural crop residues, and farmers use or dispose of these residues in a variety of ways. For example, agricultural residues can be left on or plowed into the field; composted and then applied to soils; landfilled; or burned in the field. Alternatively, they can be collected and used as fuel, animal bedding material, supplemental animal feed, or construction material. Field burning of crop residues is not considered a net source of CO_2, because the C released to the atmosphere as CO_2 during burning is assumed to be reabsorbed during the next growing season. Crop residue burning is, however, a net source of CH_4, N_2O, CO, and NO_x, which are released during combustion.

Field burning is not a common method of agricultural residue disposal in the United States. The primary crop types whose residues are typically burned in the United States are corn, cotton, lentils, rice, soybeans, sugarcane, and wheat (McCarty 2009). In 2009, CH_4 and N_2O emissions from field burning were 0.2 Tg CO_2 Eq. (12 Gg) and 0.1 Tg. CO_2 Eq. (0.3 Gg), respectively. Annual emissions from this source over the period 1990 to 2009 have remained

relatively constant, averaging approximately 0.2 Tg CO_2 Eq. (1 Gg) of CH_4 and 0.1 Tg CO_2 Eq. (0.3 Gg) of N_2O (see Table 6-20 and Table 6-21).

Table 6-20: CH_4 and N_2O Emissions from Field Burning of Agricultural Residues (Tg CO_2 Eq.)

Gas/Crop Type	1990	2000	2005	2006	2007	2008	2009
CH_4	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.3**	**0.2**
Corn	+	+	+	+	+	+	+
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	+	+	+	+	0.1	+	+
Soybeans	+	+	+	+	+	+	+
Sugarcane	0.1	0.1	+	0.1	+	+	+
Wheat	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Corn	+	+	+	+	+	+	+
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	+	+	+	+	+	+	+
Soybeans	+	+	+	+	+	+	+
Sugarcane	+	+	+	+	+	+	+
Wheat	+	+	+	+	+	+	+
Total	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.4**	**0.4**

+ Less than 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 6-21: CH_4, N_2O, CO, and NO_x Emissions from Field Burning of Agricultural Residues (Gg)

Gas/Crop Type	1990	2000	2005	2006	2007	2008	2009
CH_4	**13**	**12**	**9**	**11**	**11**	**13**	**12**
Corn	1	1	1	2	1	1	2
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	2	2	2	2	3	2	2
Soybeans	1	1	1	1	1	1	1
Sugarcane	3	2	1	3	1	2	2
Wheat	6	6	4	4	5	6	5
N_2O	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Corn	+	+	+	+	+	+	+
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	+	+	+	+	+	+	+
Soybeans	+	+	+	+	+	+	+
Sugarcane	+	+	+	+	+	+	+
Wheat	+	+	+	+	+	+	+
CO	**268**	**259**	**184**	**233**	**237**	**270**	**247**
NO_x	**8**	**8**	**6**	**7**	**8**	**8**	**8**

+ Less than 0.5 Gg
Note: Totals may not sum due to independent rounding.

Methodology

The Tier 2 methodology used for estimating greenhouse gas emissions from field burning of agricultural residues in the United States is consistent with IPCC (2006) (for more details, see Box 6-2). In order to estimate the amounts of C and N released during burning, the following equation was used:

C or N released = Σ over all crop types and states (Area Burned ÷ Crop Area Harvested × Crop Production ×

Residue/Crop Ratio × Dry Matter Fraction × Burning Efficiency × Combustion Efficiency × Fraction of C or N)

where,

Area Burned	=	Total area of crop burned, by state
Crop Area Harvested	=	Total area of crop harvested, by state
Crop Production	=	Annual production of crop in Gg, by state
Residue/Crop Ratio	=	Amount of residue produced per unit of crop production, by state
Dry Matter Fraction	=	Amount of dry matter per unit of biomass for a crop
Fraction of C or N	=	Amount of C or N per unit of dry matter for a crop
Burning Efficiency	=	The proportion of prefire fuel biomass consumed[151]
Combustion Efficiency	=	The proportion of C or N released with respect to the total amount of C or N available in the burned material, respectively[151]

Crop production and area harvested were available by state and year from USDA (2010) for all crops (except rice in Florida and Oklahoma, as detailed below). The amount C or N released was used in the following equation to determine the CH_4, CO, N_2O and NO_x emissions from the field burning of agricultural residues:

CH_4 and CO, or N_2O and NO_x Emissions from Field Burning of Agricultural Residues = (C or N Released) × (Emissions Ratio for C or N) × (Conversion Factor)

where,

Emissions Ratio	= g CH_4-C or CO-C/g C released, or g N_2O-N or NO_x-N/g N released
Conversion Factor	= conversion, by molecular weight ratio, of CH_4-C to C (16/12), or CO-C to C (28/12), or N_2O-N to N (44/28), or NO_x-N to N (30/14)

[BEGIN BOX]

Box 6-2: Comparison of Tier 2 U.S. Inventory Approach and IPCC (2006) Default Approach

This Inventory calculates emissions from Burning of Agricultural Residues using a Tier 2 methodology that is based on IPCC/UNEP/OECD/IEA (1997) and incorporates crop- and country-specific emission factors and variables. The equation used in this Inventory varies slightly in form from the one presented in the IPCC (2006) guidelines, but both equations rely on the same underlying variables. The IPCC (2006) equation was developed to be broadly applicable to all types of biomass burning, and, thus, is not specific to agricultural residues. IPCC (2006) default factors are provided only for four crops (wheat, corn, rice, and sugarcane), while this Inventory analyzes emissions from seven crops. A comparison of the methods and factors used in (1) the current Inventory and (2) the default IPCC (2006) approach was undertaken to determine the magnitude of the difference in overall estimates resulting from the two approaches. The IPCC (2006) approach was not used because crop-specific emission factors for N_2O were not available for all crops. In order to maintain consistency of methodology, the IPCC/UNEP/OECD/IEA (1997) approach presented in the Methodology section was used.

The IPCC (2006) default approach resulted in 12 percent higher emissions of CH_4 and 25 percent higher emissions of N_2O than the current estimates in this Inventory. It is reasonable to maintain the current methodology, since the IPCC (2006) defaults are only available for four crops and are worldwide average estimates, while current inventory estimates are based on U.S.-specific, crop-specific, published data.

[END BOX]

[151] In IPCC/UNEP/OECD/IEA (1997), the equation for C or N released contains the variable 'fraction oxidized in burning.' This variable is equivalent to (burning efficiency × combustion efficiency).

Crop production data for all crops except rice in Florida and Oklahoma were taken from USDA's QuickStats service (USDA 2010). Rice production and area data for Florida and Oklahoma, which are not collected by USDA, were estimated separately. Average primary and ratoon crop yields for Florida (Schueneman and Deren 2002) were applied to Florida acreages (Schueneman 1999, 2001; Deren 2002; Kirstein 2003, 2004; Cantens 2004, 2005; Gonzalez 2007 through 2010), and crop yields for Arkansas (USDA 2010) were applied to Oklahoma acreages[152] (Lee 2003 through 2006; Anderson 2008 through 2010). The production data for the crop types whose residues are burned are presented in Table 6-22. Crop weight by bushel was obtained from Murphy (1993).

The fraction of crop area burned was calculated using data on area burned by crop type and state[153] from McCarty (2010) for corn, cotton, lentils, rice, soybeans, sugarcane, and wheat.[154] McCarty (2010) used remote sensing data from Moderate Resolution Imaging Spectroradiometer (MODIS) to estimate area burned by crop. For the inventory analysis, the state-level area burned data were divided by state-level crop area harvested data to estimate the percent of crop area burned by crop and by state. The average fraction of area burned by crop across all states is shown in Table 6-23. All crop area harvested data were from USDA (2010), except for rice acreage in Florida and Oklahoma, which is not measured by USDA (Schueneman 1999, 2001; Deren 2002; Kirstein 2003, 2004; Cantens 2004, 2005; Gonzalez 2007 through 2010; Lee 2003 through 2006; Anderson 2008 through 2010). Data on crop area burned were only available from McCarty (2010) for the years 2003 through 2007. For other years in the time series, the percent area burned was assumed to be equal to the average percent area burned from the 5 years for which data were available. This average was taken at the crop and state level. Table 6-23 shows these percent area estimates aggregated for the United States as a whole, at the crop level.

All residue/crop product mass ratios except sugarcane and cotton were obtained from Strehler and Stützle (1987). The datum for sugarcane is from Kinoshita (1988) and that of cotton from Huang et al. (2007). The residue/crop ratio for lentils was assumed to be equal to the average of the values for peas and beans. Residue dry matter fractions for all crops except soybeans, lentils, and cotton were obtained from Turn et al. (1997). Soybean and lentil dry matter fractions were obtained from Strehler and Stützle (1987); the value for lentil residue was assumed to equal the value for bean straw. The cotton dry matter fraction was taken from Huang et al. (2007). The residue C contents and N contents for all crops except soybeans and cotton are from Turn et al. (1997). The residue C content for soybeans is the IPCC default (IPCC/UNEP/OECD/IEA 1997). The N content of soybeans is from Barnard and Kristoferson (1985). The C and N contents of lentils were assumed to equal those of soybeans. The C and N contents of cotton are from Lachnicht et al. (2004). These data are listed in Table 6-24. The burning efficiency was assumed to be 93 percent, and the combustion efficiency was assumed to be 88 percent, for all crop types, except sugarcane (EPA 1994). For sugarcane, the burning efficiency was assumed to be 81 percent (Kinoshita 1988) and the combustion efficiency was assumed to be 68 percent (Turn et al. 1997). Emission ratios and conversion factors for all gases (see Table 6-25) were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Table 6-22: Agricultural Crop Production (Gg of Product)

Crop	1990	2000	2005	2006	2007	2008	2009
Corn[a]	201,534	251,854	282,263	267,503	331,177	307,142	333,011
Cotton	3,376	3,742	5,201	4,700	4,182	2,790	2,654
Lentils	40	137	238	147	166	109	266
Rice	7,114	8,705	10,132	8,843	9,033	9,272	9,972
Soybeans	52,416	75,055	83,507	87,001	72,859	80,749	91,417
Sugarcane	25,525	32,763	24,137	26,820	27,188	25,041	27,608
Wheat	74,292	60,641	57,243	49,217	55,821	68,016	60,366

[a] Corn for grain (i.e., excludes corn for silage).

[152] Rice production yield data are not available for Oklahoma, so the Arkansas values are used as a proxy.

[153] Alaska and Hawaii were excluded.

[154] McCarty (2009) also examined emissions from burning of Kentucky bluegrass and a general "other crops/fallow" category, but USDA crop area and production data were insufficient to estimate emissions from these crops using the methodology employed in the Inventory. McCarty (2009) estimates that approximately 18 percent of crop residue emissions result from burning of the Kentucky bluegrass and "other" categories.

Table 6-23: U.S. Average Percent Crop Area Burned by Crop (Percent)

State	1990	2000	2005	2006	2007	2008	2009
Corn	+	+	+	+	+	+	+
Cotton	1	1	1	1	1	2	1
Lentils	3	2	+	2	1	1	1
Rice	10	10	6	8	12	9	9
Soybeans	+	+	+	+	+	+	+
Sugarcane	59	40	26	56	26	39	37
Wheat	3	3	2	3	3	3	3

+ Less than 0.5 percent

Table 6-24: Key Assumptions for Estimating Emissions from Field Burning of Agricultural Residues

Crop	Residue/Crop Ratio	Dry Matter Fraction	C Fraction	N Fraction	Burning Efficiency (Fraction)	Combustion Efficiency (Fraction)
Corn	1.0	0.91	0.448	0.006	0.93	0.88
Cotton	1.6	0.90	0.445	0.012	0.93	0.88
Lentils	2.0	0.85	0.450	0.023	0.93	0.88
Rice	1.4	0.91	0.381	0.007	0.93	0.88
Soybeans	2.1	0.87	0.450	0.023	0.93	0.88
Sugarcane	0.2	0.62	0.424	0.004	0.81	0.68
Wheat	1.3	0.93	0.443	0.006	0.93	0.88

Table 6-25: Greenhouse Gas Emission Ratios and Conversion Factors

Gas	Emission Ratio	Conversion Factor
CH_4:C	0.005[a]	16/12
CO:C	0.060[a]	28/12
N_2O:N	0.007[b]	44/28
NO_x:N	0.121[b]	30/14

[a] Mass of C compound released (units of C) relative to mass of total C released from burning (units of C).
[b] Mass of N compound released (units of N) relative to mass of total N released from burning (units of N).

Uncertainty and Time-Series Consistency

Due to data and time limitations, uncertainty resulting from the fact that emissions from burning of Kentucky bluegrass and "other" residues are not included in the emissions estimates was not incorporated into the uncertainty analysis. The results of the Tier 2 Monte Carlo uncertainty analysis are summarized in Table 6-26. Methane emissions from field burning of agricultural residues in 2009 were estimated to be between 0.15 and 0.35 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 40 percent below and 42 percent above the 2009 emission estimate of 0.25 Tg CO_2 Eq. Also at the 95 percent confidence level, N_2O emissions were estimated to be between 0.07 and 0.14 Tg CO_2 Eq. (or approximately 30 percent below and 31 percent above the 2009 emission estimate of 0.10 Tg CO_2 Eq.).

Table 6-26: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Field Burning of Agricultural Residues (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Field Burning of Agricultural Residues	CH_4	0.25	0.15	0.35	-40%	+42%
Field Burning of Agricultural Residues	N_2O	0.10	0.07	0.14	-30%	+31%

[a]Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990

through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for field burning of agricultural residues was implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on comparing trends across years, states, and crops to attempt to identify any outliers or inconsistencies. For some crops and years in Florida and Oklahoma, the total area burned as measured by McCarty (2010) was greater than the area estimated for that crop, year, and state by USDA (2010), leading to a percent area burned estimate of greater than 100 percent. In such cases, it was assumed that the percent crop area burned for that state was 100 percent.

Recalculations Discussion

The methodology over the entire time series was revised relative to the previous Inventory to incorporate state- and crop-level data on area burned from McCarty (2010). (1) Cotton and lentils were added as crops; peanuts and barley were removed, because McCarty (2009) indicated that their residues are not burned in significant quantities in the United States; (2) fraction of residue burned was calculated at the state and crop level based on McCarty (2010) and USDA (2010) data, rather than a blanket application of 3 percent burned for all crops except rice and sugarcane, as was used in the previous Inventory; (3) since data from McCarty (2010) were only available for 5 years, the percent area burned for those 5 years was averaged by crop and state and used as an estimate for the remaining years in the time series. Because the percent area burned was lower than previously assumed for almost all crops, these recalculations have resulted in an average decrease in CH_4 emissions of 71 percent and an average decrease in N_2O emissions of 79 percent across the time series, relative to the previous Inventory.

Planned Improvements

Further investigation will be made into inconsistent data from Florida and Oklahoma as mentioned in the QA/QC and verification section, and attempts will be made to revise or further justify the assumption of 100 percent of area burned for those crops and years where the estimated percent area burned exceeded 100 percent. The availability of useable area harvested and other data for bluegrass and the “other crops” category in McCarty (2010) will also be investigated, in order to try to incorporate these emissions into the Inventory.

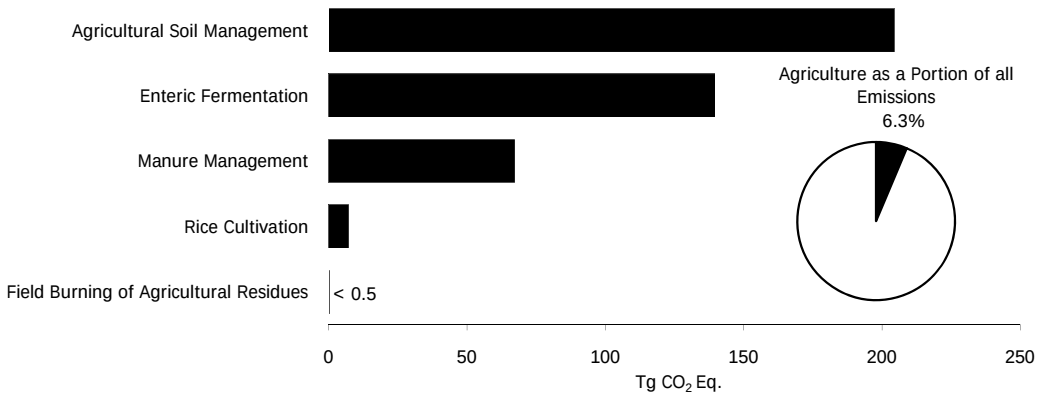
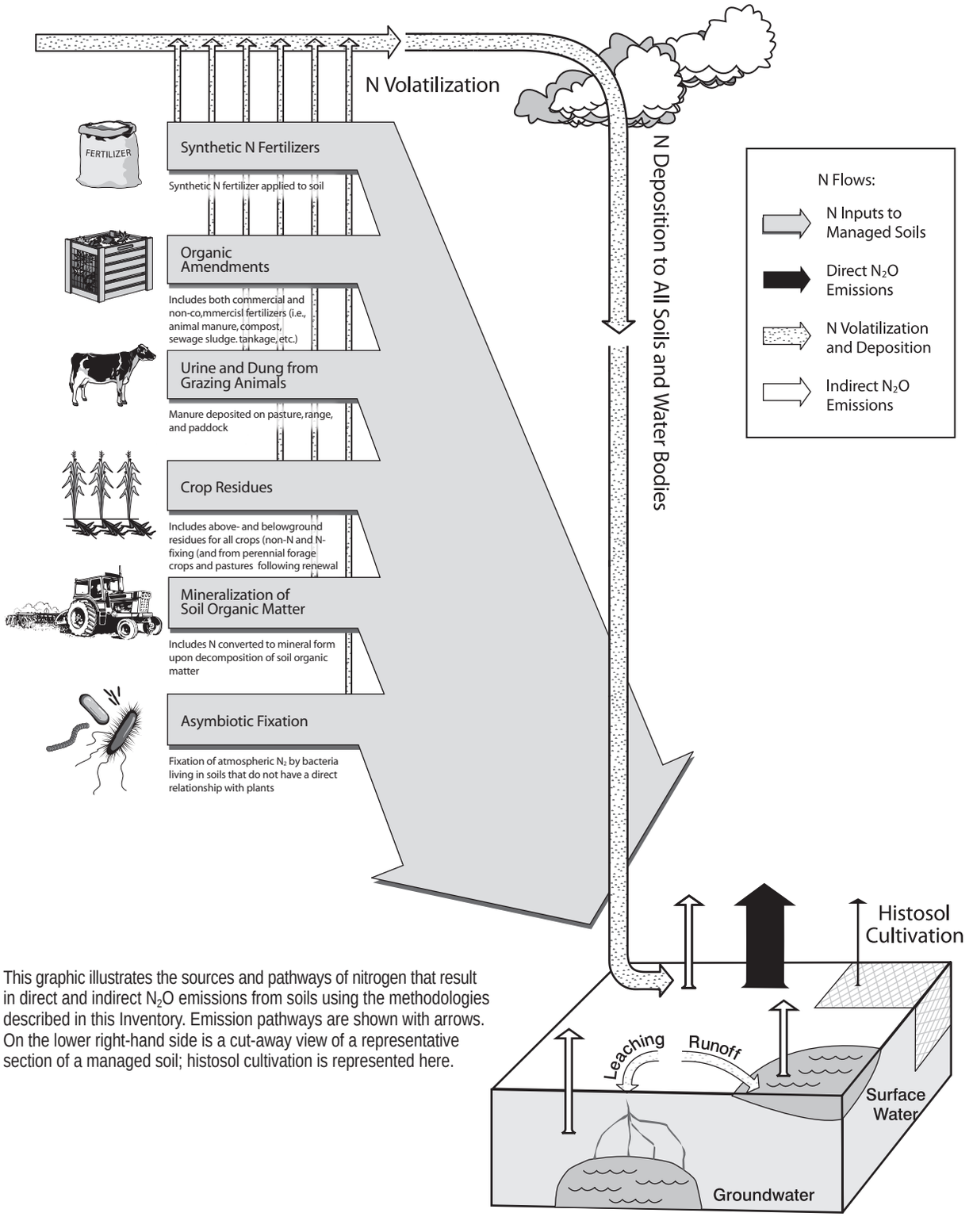


Figure 6-1: 2009 Agriculture Chapter Greenhouse Gas Sources

Figure 6-2

Sources and Pathways of N that Result in N_2O Emissions from Agricultural Soil Management



This graphic illustrates the sources and pathways of nitrogen that result in direct and indirect N_2O emissions from soils using the methodologies described in this Inventory. Emission pathways are shown with arrows. On the lower right-hand side is a cut-away view of a representative section of a managed soil; histosol cultivation is represented here.

Figure 6-3

Major Crops, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO_2 Eq/year)

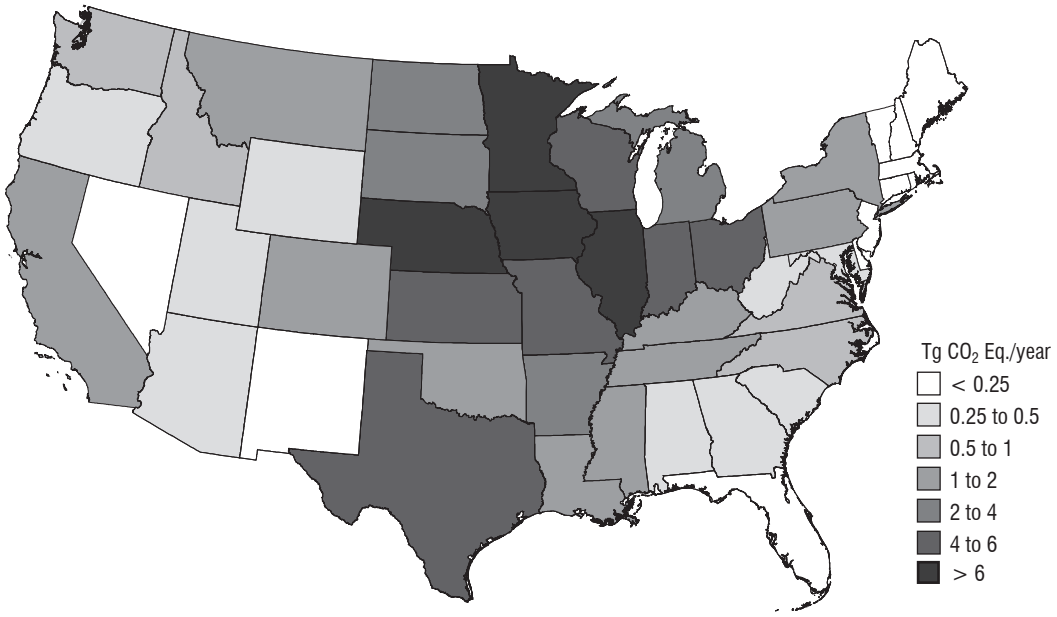


Figure 6-4

Grasslands, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO_2 Eq./year)

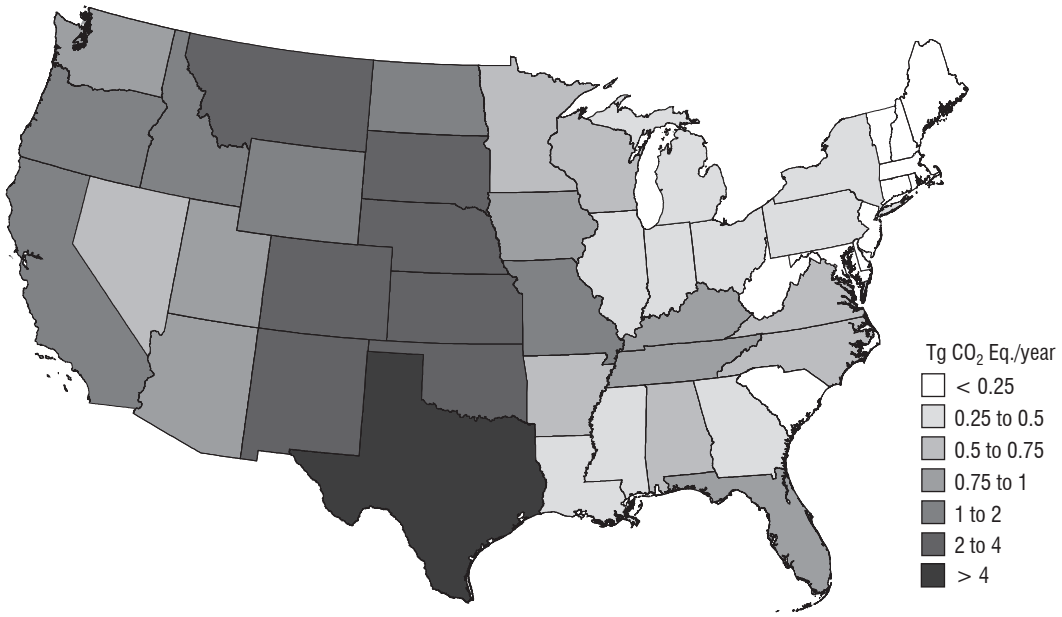


Figure 6-5

Major Crops, Average Annual N Losses Leading to Indirect N_2O Emissions Using the DAYCENT Model, 1990–2009 (Gg N/year)

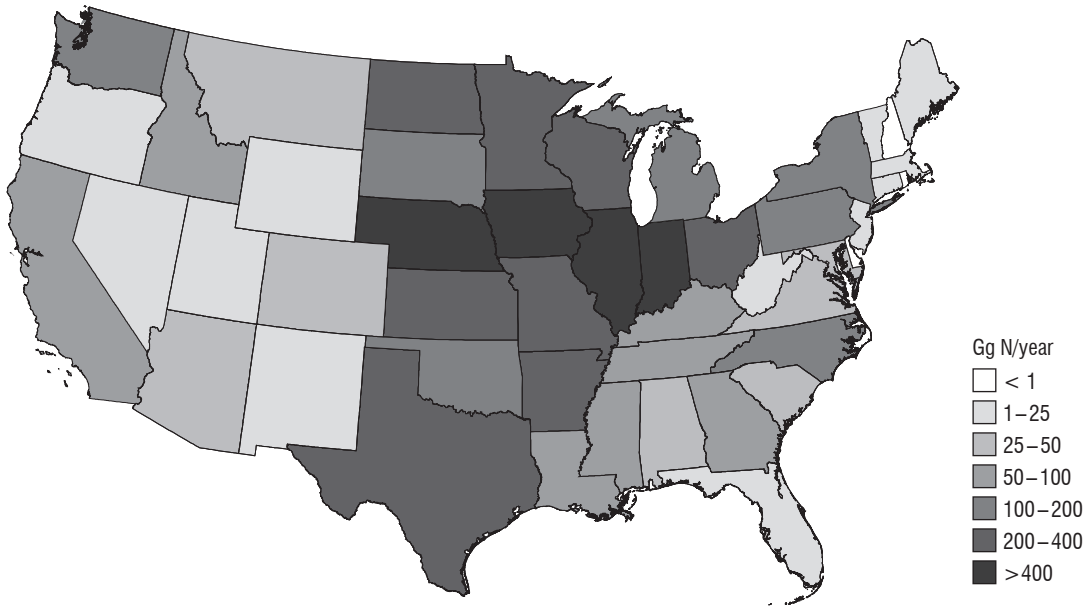


Figure 6-6

Grasslands, Average Annual N Losses Leading to Indirect N_2O Emissions Using the DAYCENT Model, 1990–2009 (Gg N/year)

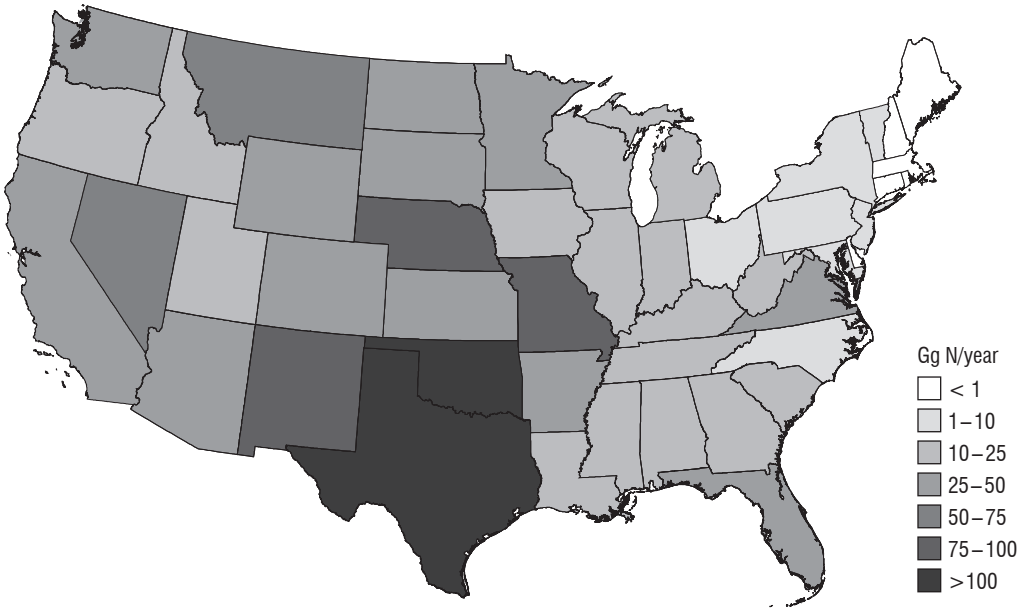
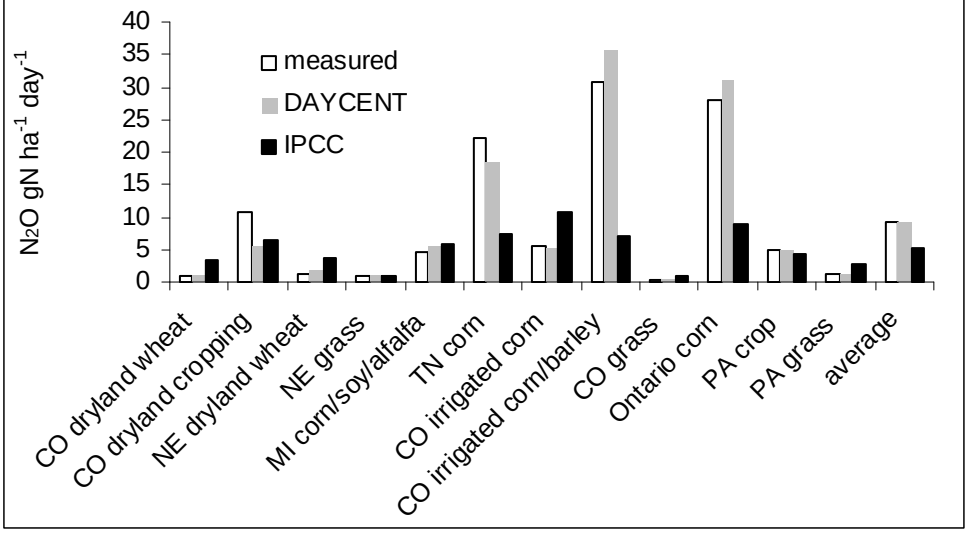


Figure 6-7

Comparison of Measured Emissions at Field Sites with Modeled Emissions Using the DAYCENT Simulation Model



7. Land Use, Land-Use Change, and Forestry

This chapter provides an assessment of the net greenhouse gas flux[155] resulting from the uses and changes in land types and forests in the United States. The Intergovernmental Panel on Climate Change *2006 Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) recommends reporting fluxes according to changes within and conversions between certain land-use types termed forest land, cropland, grassland, and settlements (as well as wetlands). The greenhouse gas flux from *Forest Land Remaining Forest Land* is reported using estimates of changes in forest carbon (C) stocks, non-carbon dioxide (CO_2) emissions from forest fires, and the application of synthetic fertilizers to forest soils. The greenhouse gas flux reported in this chapter from agricultural lands (i.e., cropland and grassland) includes changes in organic C stocks in mineral and organic soils due to land use and management, and emissions of CO_2 due to the application of crushed limestone and dolomite to managed land (i.e., soil liming) and urea fertilization. Fluxes are reported for four agricultural land use/land-use change categories: *Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland,* and *Land Converted to Grassland.* Fluxes resulting from *Settlements Remaining Settlements* include those from urban trees and soil fertilization. Landfilled yard trimmings and food scraps are accounted for separately under *Other*.

The estimates in this chapter, with the exception of CO_2 fluxes from wood products and urban trees, and CO_2 emissions from liming and urea fertilization, are based on activity data collected at multiple-year intervals, which are in the form of forest, land-use, and municipal solid waste surveys. CO_2 fluxes from forest C stocks (except the wood product components) and from agricultural soils (except the liming component) are calculated on an average annual basis from data collected in intervals ranging from 1 to 10 years. The resulting annual averages are applied to years between surveys. Calculations of non-CO_2 emissions from forest fires are based on forest CO_2 flux data. For the landfilled yard trimmings and food scraps source, periodic solid waste survey data were interpolated so that annual storage estimates could be derived. This flux has been applied to the entire time series, and periodic U.S. census data on changes in urban area have been used to develop annual estimates of CO_2 flux.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO_2 Eq. (276.8 Tg C) (Table 7-1 and Table 7-2). This represents an offset of approximately 15.3 percent of total U.S. CO_2 emissions. Total land use, land-use change, and forestry net C sequestration[156] increased by approximately 17.8 percent between 1990 and 2009. This increase was primarily due to an increase in the rate of net C accumulation in forest C stocks. Net C accumulation in *Forest Land Remaining Forest Land, Land Converted to Grassland,* and *Settlements Remaining Settlements* increased, while net C accumulation in *Cropland Remaining Cropland, Grassland Remaining Grassland,* and landfilled yard trimmings and food scraps slowed over this period. Emissions from *Land Converted to Cropland* increased between 1990 and 2009.

Table 7-1: Net CO_2 Flux from Carbon Stock Changes in Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Sink Category	1990	2000	2005	2006	2007	2008	2009
Forest Land Remaining Forest Land[1]	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements[2]	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

[155] The term "flux" is used here to encompass both emissions of greenhouse gases to the atmosphere, and removal of C from the atmosphere. Removal of C from the atmosphere is also referred to as "carbon sequestration."

[156] Carbon sequestration estimates are net figures. The C stock in a given pool fluctuates due to both gains and losses. When losses exceed gains, the C stock decreases, and the pool acts as a source. When gains exceed losses, the C stock increases, and the pool acts as a sink. This is also referred to as net C sequestration.

[1] Estimates include C stock changes on both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land.*
[2] Estimates include C stock changes on both *Settlements Remaining Settlements* and *Land Converted to Settlements.*

Table 7-2: Net CO_2 Flux from Carbon Stock Changes in Land Use, Land-Use Change, and Forestry (Tg C)

Sink Category	1990	2000	2005	2006	2007	2008	2009
Forest Land Remaining Forest Land[1]	(185.7)	(103.2)	(248.6)	(250.2)	(248.7)	(243.0)	(235.4)
Cropland Remaining Cropland	(8.0)	(8.2)	(5.0)	(5.2)	(5.4)	(4.9)	(4.7)
Land Converted to Cropland	0.6	0.6	1.6	1.6	1.6	1.6	1.6
Grassland Remaining Grassland	(14.2)	(14.3)	(2.4)	(2.4)	(2.3)	(2.3)	(2.3)
Land Converted to Grassland	(5.4)	(7.4)	(6.7)	(6.6)	(6.5)	(6.5)	(6.4)
Settlements Remaining Settlements[2]	(15.6)	(21.1)	(23.9)	(24.5)	(25.1)	(25.6)	(26.2)
Other (Landfilled Yard Trimmings and Food Scraps)	(6.6)	(3.6)	(3.1)	(3.0)	(3.0)	(3.1)	(3.4)
Total	**(235.0)**	**(157.3)**	**(288.1)**	**(290.3)**	**(289.3)**	**(283.8)**	**(276.8)**

Note: 1 Tg C = 1 teragram C = 1 million metric tons C. Parentheses indicate net sequestration. Totals may not sum due to independent rounding.
[1] Estimates include C stock changes on both *Forest Land Remaining Forest Land and Land Converted to Forest Land*.
[2] Estimates include C stock changes on both *Settlements Remaining Settlements* and *Land Converted to Settlements.*

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table 7-3 and Table 7-4. Liming of agricultural soils and urea fertilization in 2009 resulted in CO_2 emissions of 4.2 Tg CO_2 Eq. (4,221 Gg) and 3.6 Tg CO_2 Eq. (3,612 Gg), respectively. Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO_2 emissions of 1.1 Tg CO_2 Eq. (1,090 Gg), and nitrous oxide (N_2O) emissions of less than 0.05 Tg CO_2 Eq. The application of synthetic fertilizers to forest soils in 2009 resulted in direct N_2O emissions of 0.4 Tg CO_2 Eq. (1 Gg). Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils in 2009 accounted for 1.5 Tg CO_2 Eq. (5 Gg) in 2009. This represents an increase of 55 percent since 1990. Forest fires in 2009 resulted in methane (CH_4) emissions of 7.8 Tg CO_2 Eq. (372 Gg), and in N_2O emissions of 6.4 Tg CO_2 Eq. (21 Gg).

Table 7-3: Emissions from Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Source Category	1990	2000	2005	2006	2007	2008	2009
CO_2	**8.1**	**8.8**	**8.9**	**8.8**	**9.2**	**9.6**	**8.9**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH_4	**3.2**	**14.3**	**9.8**	**21.6**	**20.0**	**11.9**	**7.8**
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N_2O	**3.7**	**13.2**	**9.8**	**19.5**	**18.3**	**11.6**	**8.3**
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils[1]	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils[2]	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**15.0**	**36.3**	**28.6**	**49.8**	**47.5**	**33.2**	**25.0**

+ Less than 0.05 Tg CO_2 Eq.
Note: These estimates include direct emissions only. Indirect N_2O emissions are reported in the Agriculture chapter. Totals may

not sum due to independent rounding.
[1] Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land*, and *Land Converted to Forest Land*, but not from land-use conversion.
[2] Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements*, and *Land Converted to Settlements*, but not from land-use conversion.

Table 7-4: Emissions from Land Use, Land-Use Change, and Forestry (Gg)

Source Category	1990	2000	2005	2006	2007	2008	2009
CO_2	**8,117**	**8,768**	**8,933**	**8,754**	**9,214**	**9,646**	**8,922**
Cropland Remaining Cropland:							
Liming of Agricultural Soils	4,667	4,328	4,349	4,220	4,464	5,042	4,221
Urea Fertilization	2,417	3,214	3,504	3,656	3,738	3,612	3,612
Wetlands Remaining Wetlands:							
Peatlands Remaining Peatlands	1,033	1,227	1,079	879	1,012	992	1,090
CH_4	**152**	**682**	**467**	**1,027**	**953**	**569**	**372**
Forest Land Remaining Forest Land: Forest Fires	152	682	467	1,027	953	569	372
N_2O	**12**	**43**	**32**	**63**	**59**	**37**	**27**
Forest Land Remaining Forest Land: Forest Fires	8	38	26	57	53	31	21
Forest Land Remaining Forest Land: Forest Soils[1]	+	1	1	1	1	1	1
Settlements Remaining Settlements: Settlement Soils[2]	3	4	5	5	5	5	5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+

+ Less than 0.5 Gg
Note: These estimates include direct emissions only. Indirect N_2O emissions are reported in the Agriculture chapter. Totals may not sum due to independent rounding.
[1] Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land*, and *Land Converted to Forest Land*, but not from land-use conversion.
[2] Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements*, and *Land Converted to Settlements*, but not from land-use conversion.

[BEGIN BOX]

Box 7-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC).[157] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[158] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

[END BOX]

[157] See http://www.ipcc-nggip.iges.or.jp/public/index.html.

[158] See http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php.

7.1. Representation of the U.S. Land Base

A national land-use categorization system that is consistent and complete both temporally and spatially is needed in order to assess land use and land-use change status and the associated greenhouse gas fluxes over the inventory time series. This system should be consistent with IPCC (2006), such that all countries reporting on national greenhouse gas fluxes to the UNFCCC should (1) describe the methods and definitions used to determine areas of managed and unmanaged lands in the country, (2) describe and apply a consistent set of definitions for land-use categories over the entire national land base and time series associated with the greenhouse gas inventory, such that increases in the land areas within particular land-use categories are balanced by decreases in the land areas of other categories, and (3) account for greenhouse gas fluxes on all managed lands. The implementation of such a system helps to ensure that estimates of greenhouse gas fluxes are as accurate as possible. This section of the Inventory has been developed in order to comply with this guidance.

Multiple databases are used to track land management in the United States, which are also used as the basis to classify U.S. land area into the six IPCC land-use categories (i.e., *Forest Land Remaining Forest Land*, *Cropland Remaining Cropland*, *Grassland Remaining Grassland*, *Wetlands Remaining Wetlands*, *Settlements Remaining Settlements* and *Other Land Remaining Other Land*) and thirty land-use change categories (e.g., *Cropland Converted to Forest Land*, *Grassland Converted to Forest Land*, *Wetlands Converted to Forest Land*, *Settlements Converted to Forest Land*, *Other Land Converted to Forest Lands*)[159] (IPCC 2006). The primary databases are the U.S. Department of Agriculture (USDA) National Resources Inventory (NRI)[160] and the USDA Forest Service (USFS) Forest Inventory and Analysis (FIA)[161] Database. The U.S. Geological Survey (USGS) National Land Cover Dataset (NLCD)[162] is also used to identify land uses in regions that were not included in the NRI or FIA. The total land area included in the U.S. Inventory is 786 million hectares, and this entire land base is considered managed.[163] In 2009, the United States had a total of 274 million hectares of Forest Land (a 4 percent increase since 1990), 163 million hectares of Cropland (down 4.4 percent since 1990), 258 million hectares of Grassland (down 4.2 percent since 1990), 26 million hectares of Wetlands (down 4.9 percent since 1990), 49 million hectares of Settlements (up 24.5 percent since 1990), and 14 million hectares of Other Land. It is important to note that the land base formally classified for the Inventory (see Table 7-5) is considered managed. Alaska is not formally included in the current land representation, but there is a planned improvement underway to include this portion of the United States in future inventories. In addition, wetlands are not differentiated between managed and unmanaged, although some wetlands would be unmanaged according to the U.S. definition (see definition later in this section). Future improvements will include a differentiation between managed and unmanaged wetlands. In addition, carbon stock changes are not currently estimated for the entire land base, which leads to discrepancies between the area data presented here and in the subsequent sections of the NIR. Planned improvements are underway or in development phases to conduct an inventory of carbon stock changes on all managed land (e.g., federal grasslands).

Dominant land uses vary by region, largely due to climate patterns, soil types, geology, proximity to coastal regions, and historical settlement patterns, although all land-uses occur within each of the fifty states (Figure 7-1). Forest Land tends to be more common in the eastern states, mountainous regions of the western United States, and Alaska. Cropland is concentrated in the mid-continent region of the United States, and Grassland is more common in the western United States. Wetlands are fairly ubiquitous throughout the United States, though they are more common in the upper Midwest and eastern portions of the country. Settlements are more concentrated along the coastal margins and in the eastern states.

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[159] Land-use category definitions are provided in the Methodology section.

[160] NRI data is available at <http://www.ncgc.nrcs.usda.gov/products/nri/index.html>.

[161] FIA data is available at <http://fia.fs.fed .us/tools-data/data/>.

[162] NLCD data is available at <http://www.mrlc.gov/>.

[163] The current land representation does not include areas from Alaska or U.S. territories, but there are planned improvements to include these regions in future reports.

Table 7-5: Size of Land Use and Land-Use Change Categories on Managed Land Area by Land Use and Land Use Change Categories (thousands of hectares)

Land Use & Land-Use Change Categories[a]	1990	2000	2005	2006	2007	2008	2009
Total Forest Land	**263,878**	**268,790**	**271,322**	**272,107**	**272,891**	**273,677**	**274,462**
FF	257,180	253,080	255,444	256,181	256,917	257,655	258,392
CF	1,266	2,793	2,976	2,983	2,991	2,998	3,006
GF	4,879	11,347	11,122	11,157	11,193	11,229	11,264
WF	63	201	205	205	206	207	207
SF	101	268	303	304	305	306	307
OF	389	1,102	1,273	1,276	1,279	1,282	1,285
Total Cropland	**170,632**	**164,401**	**163,192**	**163,178**	**163,164**	**163,151**	**163,137**
CC	155,433	144,004	145,531	145,518	145,506	145,493	145,481
FC	1,105	1,101	805	804	803	802	802
GC	13,298	17,834	15,513	15,513	15,513	15,512	15,512
WC	163	264	234	234	234	234	234
SC	470	886	825	825	825	825	825
OC	162	311	283	283	283	283	283
Total Grassland	**269,643**	**263,092**	**260,565**	**260,012**	**259,458**	**258,904**	**258,350**
GG	260,064	245,460	243,839	243,395	242,951	242,506	242,061
FG	1,463	3,048	2,787	2,773	2,759	2,745	2,730
CG	7,502	13,303	12,632	12,541	12,451	12,360	12,270
WG	230	373	339	338	338	337	336
SG	129	255	255	253	252	250	249
OG	255	653	714	712	709	706	704
Total Wetlands	**27,788**	**27,560**	**27,173**	**26,983**	**26,793**	**26,603**	**26,412**
WW	27,179	26,155	25,701	25,519	25,338	25,157	24,976
FW	138	378	401	398	395	393	390
CW	134	348	351	348	344	341	338
GW	286	633	675	672	670	668	665
SW	<1	3	3	3	3	3	3
OW	51	43	43	42	42	42	42
Total Settlements	**39,518**	**47,558**	**49,247**	**49,238**	**49,229**	**49,220**	**49,212**
SS	34,742	34,055	34,975	34,966	34,958	34,949	34,941
FS	1,842	5,480	5,872	5,872	5,872	5,871	5,871
CS	1,373	3,599	3,673	3,672	3,672	3,672	3,672
GS	1,498	4,183	4,479	4,479	4,479	4,479	4,479
WS	3	29	32	32	32	32	32
OS	60	212	217	217	217	217	217
Total Other Land	**14,385**	**14,443**	**14,346**	**14,327**	**14,309**	**14,290**	**14,272**
OO	13,397	12,286	12,104	12,087	12,069	12,051	12,033
FO	193	506	559	559	559	559	559
CO	279	440	499	499	499	499	499
GO	458	1,085	1,058	1,057	1,057	1,056	1,056
WO	55	115	114	114	114	114	113
SO	3	11	12	12	12	12	12
Grand Total	**785,845**	**785,845**	**785,845**	**785,845**	**785,845**	**785,845**	**785,845**

[a]The abbreviations are "F" for Forest Land, "C" for Cropland, "G" for Grassland, "W" for Wetlands, "S" for Settlements, and "O" for Other Lands. Lands remaining in the same land use category are identified with the land use abbreviation given twice (e.g., "FF" is Forest Land Remaining Forest Land), and land use change categories are identified with the previous land use abbreviation followed by the new land use abbreviation (e.g., "CF" is Cropland Converted to Forest Land).

Notes: All land areas reported in this table are considered managed. A planned improvement is underway to deal with an exception for wetlands which includes both managed and unmanaged lands based on the definitions for the current U.S. Land Representation Assessment. In addition, U.S. Territories have not been classified into land uses and are not included in the U.S. Land Representation Assessment. See Planned Improvements for discussion on plans to include Alaska and territories in future Inventories.

Figure 7-1. Percent of Total Land Area in the General Land-Use Categories for 2009

Methodology

IPCC Approaches for Representing Land Areas

IPCC (2006) describes three approaches for representing land areas. Approach 1 provides data on the total area for each individual land-use category, but does not provide detailed information on changes of area between categories and is not spatially explicit other than at the national or regional level. With Approach 1, total net conversions between categories can be detected, but not the individual changes between the land-use categories that led to those net changes. Approach 2 introduces tracking of individual land-use changes between the categories (e.g., Forest Land to Cropland, Cropland to Forest Land, Grassland to Cropland, etc.), using surveys or other forms of data that do not provide location data on specific parcels of land. Approach 3 extends Approach 2 by providing location data on specific parcels of land, such as maps, along with the land-use history. The three approaches are not presented as hierarchical tiers and are not mutually exclusive.

According to IPCC (2006), the approach or mix of approaches selected by an inventory agency should reflect calculation needs and national circumstances. For this analysis, the NRI, FIA, and the NLCD have been combined to provide a complete representation of land use for managed lands. These data sources are described in more detail later in this section. All of these datasets have a spatially-explicit time series of land-use data, and therefore Approach 3 is used to provide a full representation of land use in the U.S. Inventory. Lands are treated as remaining in the same category (e.g., *Cropland Remaining Cropland*) if a land-use change has not occurred in the last 20 years. Otherwise, the land is classified in a land-use-change category based on the current use and most recent use before conversion to the current use (e.g., *Cropland Converted to Forest Land*).

Definitions of Land Use in the United States

Managed and Unmanaged Land

The U.S. definitions of managed and unmanaged lands are similar to the basic IPCC (2006) definition of managed land, but with some additional elaboration to reflect national circumstances. Based on the following definitions, most lands in the United States are classified as managed:

- *Managed Land*: Land is considered managed if direct human intervention has influenced its condition. Direct intervention includes altering or maintaining the condition of the land to produce commercial or non-commercial products or services; to serve as transportation corridors or locations for buildings, landfills, or other developed areas for commercial or non-commercial purposes; to extract resources or facilitate acquisition of resources; or to provide social functions for personal, community or societal objectives. Managed land also includes legal protection of lands (e.g., wilderness, preserves, parks, etc.) for conservation purposes (i.e., meets societal objectives).[164]
- *Unmanaged Land*: All other land is considered unmanaged. Unmanaged land is largely comprised of areas inaccessible to human intervention due to the remoteness of the locations, or lands with essentially no development interest or protection due to limited personal, commercial or social value. Though these lands may be influenced indirectly by human actions such as atmospheric deposition of chemical species

[164] Wetlands are an exception to this general definition, because these lands, as specified by IPCC (2006), are only considered managed if they are created through human activity, such as dam construction, or the water level is artificially altered by human activity. Distinguishing between managed and unmanaged wetlands is difficult, however, due to limited data availability. Wetlands are not characterized by use within the NRI. Therefore, unless wetlands are managed for cropland or grassland, it is not possible to know if they are artificially created or if the water table is managed based on the use of NRI data. See the Planned Improvements section of the Inventory for work being done to refine the Wetland area estimates.

produced in industry, they are not influenced by a direct human intervention.[165]

Land-Use Categories

As with the definition of managed lands, IPCC (2006) provides general non-prescriptive definitions for the six main land-use categories: Forest Land, Cropland, Grassland, Wetlands, Settlements and Other Land. In order to reflect U.S. circumstances, country-specific definitions have been developed, based predominantly on criteria used in the land-use surveys for the United States. Specifically, the definition of Forest Land is based on the FIA definition of forest,[166] while definitions of Cropland, Grassland, and Settlements are based on the NRI.[167] The definitions for Other Land and Wetlands are based on the IPCC (2006) definitions for these categories.

- *Forest Land*: A land-use category that includes areas at least 36.6 m wide and 0.4 ha in size with at least 10 percent cover (or equivalent stocking) by live trees of any size, including land that formerly had such tree cover and that will be naturally or artificially regenerated. Forest land includes transition zones, such as areas between forest and non-forest lands that have at least 10 percent cover (or equivalent stocking) with live trees and forest areas adjacent to urban and built-up lands. Roadside, streamside, and shelterbelt strips of trees must have a crown width of at least 36.6 m and continuous length of at least 110.6 m to qualify as forest land. Unimproved roads and trails, streams, and clearings in forest areas are classified as forest if they are less than 36.6 m wide or 0.4 ha in size, otherwise they are excluded from Forest Land and classified as Settlements. Tree-covered areas in agricultural production settings, such as fruit orchards, or tree-covered areas in urban settings, such as city parks, are not considered forest land (Smith et al. 2009). NOTE: This definition applies to all U.S. lands and territories. However, at this time, data availability is limited for remote or inaccessible areas such as interior Alaska

- *Cropland*: A land-use category that includes areas used for the production of adapted crops for harvest; this category includes both cultivated and non-cultivated lands.[168] Cultivated crops include row crops or close-grown crops and also hay or pasture in rotation with cultivated crops. Non-cultivated cropland includes continuous hay, perennial crops (e.g., orchards) and horticultural cropland. Cropland also includes land with alley cropping and windbreaks,[169] as well as lands in temporary fallow or enrolled in conservation reserve programs (i.e., set-asides[170]). Roads through Cropland, including interstate highways, state highways, other paved roads, gravel roads, dirt roads, and railroads are excluded from Cropland area estimates and are, instead, classified as Settlements.

- *Grassland*: A land-use category on which the plant cover is composed principally of grasses, grass-like plants, forbs, or shrubs suitable for grazing and browsing, and includes both pastures and native rangelands.[171] This includes areas where practices such as clearing, burning, chaining, and/or chemicals are applied to maintain the grass vegetation. Savannas, some wetlands and deserts, in addition to tundra are considered Grassland.[172] Woody plant communities of low forbs and shrubs, such as mesquite, chaparral, mountain shrub, and pinyon-juniper, are also classified as Grassland if they do not meet the criteria for Forest Land. Grassland includes land managed with agroforestry practices such as silvipasture and windbreaks, assuming the stand or woodlot does not meet the criteria for Forest Land. Roads through

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[165] There will be some areas that qualify as Forest Land or Grassland according to the land use criteria, but are classified as unmanaged land due to the remoteness of their location.

[166] See <http://socrates.lv-hrc.nevada.edu/fia/ab/issues/pending/glossary/Glossary_5_30_06.pdf>.

[167] See <http://www.nrcs.usda.gov/technical/land/nri01/glossary.html>.

[168] A minor portion of Cropland occurs on federal lands, and is not currently included in the C stock change inventory. A planned improvement is underway to include these areas in future C inventories.

[169] Currently, there is no data source to account for biomass C stock change associated with woody plant growth and losses in alley cropping systems and windbreaks in cropping systems, although these areas are included in the cropland land base.

[170] A set-aside is cropland that has been taken out of active cropping and converted to some type of vegetative cover, including, for example, native grasses or trees.

[171] Grasslands on federal lands are included in the managed land base, but C stock changes are not estimated on these lands. Federal grassland areas have been assumed to have negligible changes in C due to limited land use and management change, but planned improvements are underway to further investigate this issue and include these areas in future C inventories.

[172] IPCC (2006) guidelines do not include provisions to separate desert and tundra as land categories.

Grassland, including interstate highways, state highways, other paved roads, gravel roads, dirt roads, and railroads are excluded from Grassland area estimates and are, instead, classified as Settlements.

- *Wetlands*: A land-use category that includes land covered or saturated by water for all or part of the year. Managed Wetlands are those where the water level is artificially changed, or were created by human activity. Certain areas that fall under the managed Wetlands definition are covered in other areas of the IPCC guidance and/or the inventory, including Cropland (e.g., rice cultivation), Grassland, and Forest Land (including drained or undrained forested wetlands).
- *Settlements*: A land-use category representing developed areas consisting of units of 0.25 acres (0.1 ha) or more that includes residential, industrial, commercial, and institutional land; construction sites; public administrative sites; railroad yards; cemeteries; airports; golf courses; sanitary landfills; sewage treatment plants; water control structures and spillways; parks within urban and built-up areas; and highways, railroads, and other transportation facilities. Also included are tracts of less than 10 acres (4.05 ha) that may meet the definitions for Forest Land, Cropland, Grassland, or Other Land but are completely surrounded by urban or built-up land, and so are included in the settlement category. Rural transportation corridors located within other land uses (e.g., Forest Land, Cropland) are also included in Settlements.
- *Other Land*: A land-use category that includes bare soil, rock, ice, non-settlement transportation corridors, and all land areas that do not fall into any of the other five land-use categories. It allows the total of identified land areas to match the managed national area.

Land-Use Data Sources: Description and Application to U.S. Land Area Classification

U.S. Land-Use Data Sources

The three main data sources for land area and use data in the United States are the NRI, FIA, and the NLCD. For the Inventory, the NRI is the official source of data on all land uses on non-federal lands (except forest land), and is also used as the resource to determine the total land base for the conterminous United States and Hawaii. The NRI is conducted by the USDA Natural Resources Conservation Service and is designed to assess soil, water, and related environmental resources on non-federal lands. The NRI has a stratified multi-stage sampling design, where primary sample units are stratified on the basis of county and township boundaries defined by the U.S. Public Land Survey (Nusser and Goebel 1997). Within a primary sample unit (typically a 160-acre [64.75 ha] square quarter-section), three sample points are selected according to a restricted randomization procedure. Each point in the survey is assigned an area weight (expansion factor) based on other known areas and land-use information (Nusser and Goebel 1997). The NRI survey utilizes data derived from remote sensing imagery and site visits in order to provide detailed information on land use and management, particularly for croplands and grasslands, and is used as the basis to account for C stock changes in agricultural lands (except federal Grasslands). The NRI survey was conducted every 5 years between 1982 and 1997, but shifted to annualized data collection in 1998. This Inventory incorporates data through 2003 from the NRI.

The FIA program, conducted by the USFS, is the official source of data on Forest Land area and management data for the Inventory. FIA engages in a hierarchical system of sampling, with sampling categorized as Phases 1 through 3, in which sample points for phases are subsets of the previous phase. Phase 1 refers to collection of remotely-sensed data (either aerial photographs or satellite imagery) primarily to classify land into forest or non-forest and to identify landscape patterns like fragmentation and urbanization. Phase 2 is the collection of field data on a network of ground plots that enable classification and summarization of area, tree, and other attributes associated with forest land uses. Phase 3 plots are a subset of Phase 2 plots where data on indicators of forest health are measured. Data from all three phases are also used to estimate C stock changes for forest land. Historically, FIA inventory surveys had been conducted periodically, with all plots in a state being measured at a frequency of every 5 to 14 years. A new national plot design and annual sampling design was introduced by FIA about ten years ago. Most states, though, have only recently been brought into this system. Annualized sampling means that a portion of plots throughout each state is sampled each year, with the goal of measuring all plots once every 5 years. See Annex 3.12 to see the specific survey data available by state. The most recent year of available data varies state by state (2002 through 2009).

Though NRI provides land-area data for both federal and non-federal lands, it only includes land-use data on non-federal lands, and FIA only records data for forest land.[173] Consequently, major gaps exist when the datasets are combined, such as federal grassland operated by the Bureau of Land Management (BLM), USDA, and National Park Service, as well as most of Alaska.[174] The NLCD is used as a supplementary database to account for land use on federal lands that are not included in the NRI and FIA databases. The NLCD land-cover classification scheme, available for 1992 and 2001, has been applied over the conterminous United States (Homer et al. 2007). The 2001 product also provides land use data that has been used for Hawaii federal lands. For this analysis, the NLCD Retrofit Land Cover Change Product was used in order to represent both land use and land-use change for federal lands in the conterminous U.S. (Homer et al. 2007). It is based primarily on Landsat Thematic Mapper imagery. The NLCD contains 21 categories of land-cover information, which have been aggregated into the IPCC land-use categories, and the data are available at a spatial resolution of 30 meters. The federal land portion of the NLCD was extracted from the dataset using the federal land area boundary map from the National Atlas (2005). This map represents federal land boundaries in 2005, so as part of the analysis, the federal land area was adjusted annually based on the NRI federal land area estimates (i.e., land is periodically transferred between federal and non-federal ownership). Consequently, the portion of the land base categorized with NLCD data varied from year to year, corresponding to an increase or decrease in the federal land base. The NLCD is strictly a source of land-cover information, however, and does not provide the necessary site conditions, crop types, and management information from which to estimate C stock changes on those lands.

Another step in the analysis is to address gaps as well as overlaps in the representation of the U.S. land base between the Agricultural Carbon Stock Inventory (*Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland*) and Forest Land Carbon Stock Inventory (*Forest Land Remaining Forest Land* and *Land Converted to Forest Land*), which are based on the NRI and FIA databases, respectively. NRI and FIA have different criteria for classifying forest land and sampling designs, leading to discrepancies in the resulting estimates of Forest Land area on non-federal land. Similarly, there are discrepancies between the NLCD and FIA data for defining and classifying Forest Land on federal lands. Moreover, dependence exists between the Forest Land area and the amount of land designated as other land uses in both the NRI and the NLCD, such as the amount of Grassland, Cropland, and Wetlands, relative to the Forest Land area. This results in inconsistencies among the three databases for estimated Forest Land area, as well as for the area estimates for other land-use categories. FIA is the main database for forest statistics, and consequently, the NRI and NLCD were adjusted to achieve consistency with FIA estimates of Forest Land. The adjustments were made at a state-scale, and it was assumed that the majority of the discrepancy in forest area was associated with an under- or over-prediction of Grassland and Wetland area in the NRI and NLCD due to differences in Forest Land definitions. Specifically, the Forest Land area for a given state according to the NRI and NLCD was adjusted to match the FIA estimates of Forest Land for non-federal and federal land, respectively. In a second step, corresponding increases or decreases were made in the area estimates of Grassland and Wetland from the NRI and NLCD, in order to balance the change in forest area, and therefore not change the overall amount of managed land within an individual state. The adjustments were based on the proportion of land within each of these land-use categories at the state-level. (i.e., a higher proportion of Grassland led to a larger adjustment in Grassland area).

As part of Quality Assurance /Quality Control (QA/QC), the land base derived from the NRI, FIA and NLCD was compared to the Topologically Integrated Geographic Encoding and Referencing (TIGER) survey (U.S. Census Bureau 2010). The U.S. Census Bureau gathers data on the U.S. population and economy, and has a database of land areas for the country. The land area estimates from the U.S. Census Bureau differ from those provided by the land-use surveys used in the Inventory because of discrepancies in the reporting approach for the census and the methods used in the NRI, FIA, and NLCD. The area estimates of land-use categories, based on NRI, FIA, and NLCD, are derived from remote sensing data instead of the land survey approach used by the U.S. Census Survey. More importantly, the U.S. Census Survey does not provide a time series of land-use change data or land management information, which is critical for conducting emission inventories and is provided from the NRI and FIA surveys. Consequently, the U.S. Census Survey was not adopted as the official land area estimate for the Inventory. Rather, the NRI data were adopted because this database provides full coverage of land area and land use

[173] FIA does collect some data on non-forest land use, but these are held in regional databases versus the national database. The status of these data is being investigated.

[174] The survey programs also do not include U.S. Territories with the exception of non-federal lands in Puerto Rico, which are included in the NRI survey. Furthermore, NLCD does not include coverage for U.S. Territories.

for the conterminous United States and Hawaii. Regardless, the total difference between the U.S. Census Survey and the data sources used in the Inventory is about 25 million hectares for the total land base of about 786 million hectares currently included in the Inventory, or a 3.1 percent difference. Much of this difference is associated with open waters in coastal regions and the Great Lakes. NRI does not include as much of the area of open waters in these regions as the U.S. Census Survey.

Approach for Combining Data Sources

The managed land base in the United States has been classified into the six IPCC land-use categories using definitions[175] developed to meet national circumstances, while adhering to IPCC (2006). In practice, the land was initially classified into a variety of land-use categories using the NRI, FIA and NLCD, and then aggregated into the thirty-six broad land use and land-use-change categories identified in IPCC (2006). Details on the approach used to combine data sources for each land use are described below as are the gaps that will be reconciled as part of ongoing planned improvements:

- *Forest Land*: Both non-federal and federal forest lands in both the continental United States and coastal Alaska are covered by FIA. FIA is used as the basis for both Forest Land area data as well as to estimate C stocks and fluxes on Forest Land. Interior Alaska is not currently surveyed by FIA, but NLCD has a new product for Alaska that will be incorporated into the assessment as a planned improvement for future reports. Forest Lands in U.S. territories are currently excluded from the analysis, but FIA surveys are currently being conducted on U.S. territories and will become available in the future. NRI is being used in the current report to provide Forest Land areas on non-federal lands in Hawaii. Currently, federal forest land in Hawaii is evaluated with the 2001 NLCD, but FIA data will be collected in Hawaii in the future.

- *Cropland*: Cropland is classified using the NRI, which covers all non-federal lands within 49 states (excluding Alaska), including state and local government-owned land as well as tribal lands. NRI is used as the basis for both Cropland area data as well as to estimate C stocks and fluxes on Cropland. Croplands in U.S. territories are excluded from both NRI data collection and the NLCD. NLCD has a new product for Alaska that will be incorporated into the assessment as a planned improvement for future reports.

- *Grassland*: Grassland on non-federal lands is classified using the NRI within 49 states (excluding Alaska), including state and local government-owned land as well as tribal lands. NRI is used as the basis for both Grassland area data as well as to estimate C stocks and fluxes on Grassland. U.S. territories are excluded from both NRI data collection and the current release of the NLCD product. Grassland on federal Bureau of Land Management lands, Department of Defense lands, National Parks and within USFS lands are covered by the NLCD. In addition, federal and non-federal grasslands in Alaska are currently excluded from the analysis, but NLCD has a new product for Alaska that will be incorporated into the assessment for future reports.

- *Wetlands*: NRI captures wetlands on non-federal lands within 49 states (excluding Alaska), while federal wetlands are covered by the NLCD. Alaska and U.S. territories are excluded. This currently includes both managed and unmanaged wetlands as no database has yet been applied to make this distinction. See Planned Improvements for details.

- *Settlements*: The NRI captures non-federal settlement area in 49 states (excluding Alaska). If areas of Forest Land or Grassland under 10 acres (4.05 ha) are contained within settlements or urban areas, they are classified as Settlements (urban) in the NRI database. If these parcels exceed the 10 acre (4.05 ha) threshold and are Grassland, they will be classified as such by NRI. Regardless of size, a forested area is classified as non-forest by FIA if it is located within an urban area. Settlements on federal lands are covered by NLCD. Settlements in U.S. territories are currently excluded from NRI and NLCD. NLCD has a new product for Alaska that will be incorporated into the assessment as a planned improvement for future reports.

- *Other Land*: Any land not falling into the other five land categories and, therefore, categorized as Other Land is classified using the NRI for non-federal areas in the 49 states (excluding Alaska) and NLCD for the federal lands. Other land in U.S. territories is excluded from the NLCD. NLCD has a new product for

[175] Definitions are provided in the previous section.

Alaska that will be incorporated into the assessment as a planned improvement for future reports.

Some lands can be classified into one or more categories due to multiple uses that meet the criteria of more than one definition. However, a ranking has been developed for assignment priority in these cases. The ranking process is initiated by distinguishing between managed and unmanaged lands. The managed lands are then assigned, from highest to lowest priority, in the following manner:

Settlements > Cropland > Forest Land > Grassland > Wetlands > Other Land

Settlements are given the highest assignment priority because they are extremely heterogeneous with a mosaic of patches that include buildings, infrastructure and travel corridors, but also open grass areas, forest patches, riparian areas, and gardens. The latter examples could be classified as Grassland, Forest Land, Wetlands, and Cropland, respectively, but when located in close proximity to settlement areas they tend to be managed in a unique manner compared to non-settlement areas. Consequently, these areas are assigned to the Settlements land-use category. Cropland is given the second assignment priority, because cropping practices tend to dominate management activities on areas used to produce food, forage or fiber. The consequence of this ranking is that crops in rotation with grass will be classified as Cropland, and land with woody plant cover that is used to produce crops (e.g., orchards) is classified as Cropland, even though these areas may meet the definitions of Grassland or Forest Land, respectively. Similarly, Wetlands are considered Croplands if they are used for crop production, such as rice or cranberries. Forest Land occurs next in the priority assignment because traditional forestry practices tend to be the focus of the management activity in areas with woody plant cover that are not croplands (e.g., orchards) or settlements (e.g., housing subdivisions with significant tree cover). Grassland occurs next in the ranking, while Wetlands and Other Land complete the list.

The assignment priority does not reflect the level of importance for reporting greenhouse gas emissions and removals on managed land, but is intended to classify all areas into a single land use. Currently, the IPCC does not make provisions in the guidelines for assigning land to multiple uses. For example, a Wetland is classified as Forest Land if the area has sufficient tree cover to meet the stocking and stand size requirements. Similarly, Wetlands are classified as Cropland if they are used for crop production, such as rice or cranberries. In either case, emissions from Wetlands are included in the Inventory if human interventions are influencing emissions from Wetlands, in accordance with the guidance provided in IPCC (2006).

Recalculations Discussion

No major revisions were made to the time series for the current Inventory. However, new data were incorporated from FIA on forestland areas, which was used to make minor adjustments to the time series. FIA conducts a survey of plots annually so that each plot is visited every 5 years (Note: some states have not initiated the annual sampling regime, as discussed previously). Consequently, the time series is updated each year as new data are collected over the 5 year cycles.

Planned Improvements

Area data by land-use category are not estimated for major portions of Alaska or any of the U.S. territories. A key planned improvement is to incorporate land-use data from these areas into the Inventory. For Alaska, a new NLCD 2001 data product will be used to cover those land areas presently omitted. Fortunately, most of the managed land in the United States is included in the current land-use statistics, but a complete accounting is a key goal for the near future. Data sources will also be evaluated for representing land use on federal and non-federal lands in U.S. territories.

Additional work will be conducted to reconcile differences in Forest Land estimates between the NRI and FIA, evaluating the assumption that the majority of discrepancies in Forest Land areas are associated with an over- or under-estimation of Grassland and Wetland area. In some regions of the United States, a discrepancy in Forest Land areas between NRI and FIA may be associated with an over- or under-prediction of other land uses, and an analysis is planned to develop region-specific adjustments.

There are also other databases that may need to be reconciled with the NRI and NLCD datasets, particularly for Settlements and Wetlands. Urban area estimates, used to produce C stock and flux estimates from urban trees, are currently based on population data (1990 and 2000 U.S. Census data). Using the population statistics, “urban clusters” are defined as areas with more than 500 people per square mile. The USFS is currently moving ahead with

an urban forest inventory program so that urban forest area estimates will be consistent with FIA forest area estimates outside of urban areas, which would be expected to reduce omissions and overlap of forest area estimates along urban boundary areas.

7.2. Forest Land Remaining Forest Land

Changes in Forest Carbon Stocks (IPCC Source Category 5A1)

For estimating C stocks or stock change (flux), C in forest ecosystems can be divided into the following five storage pools (IPCC 2003):

- Aboveground biomass, which includes all living biomass above the soil including stem, stump, branches, bark, seeds, and foliage. This category includes live understory.
- Belowground biomass, which includes all living biomass of coarse living roots greater than 2 mm diameter.
- Dead wood, which includes all non-living woody biomass either standing, lying on the ground (but not including litter), or in the soil.
- Litter, which includes the litter, fumic, and humic layers, and all non-living biomass with a diameter less than 7.5 cm at transect intersection, lying on the ground.
- Soil organic C (SOC), including all organic material in soil to a depth of 1 meter but excluding the coarse roots of the aboveground pools.

In addition, there are two harvested wood pools necessary for estimating C flux:

- Harvested wood products (HWP) in use.
- HWP in solid waste disposal sites (SWDS).

C is continuously cycled among these storage pools and between forest ecosystems and the atmosphere as a result of biological processes in forests (e.g., photosynthesis, respiration, growth, mortality, decomposition, and disturbances such as fires or pest outbreaks) and anthropogenic activities (e.g., harvesting, thinning, clearing, and replanting). As trees photosynthesize and grow, C is removed from the atmosphere and stored in living tree biomass. As trees die and otherwise deposit litter and debris on the forest floor, C is released to the atmosphere or transferred to the soil by organisms that facilitate decomposition.

The net change in forest C is not equivalent to the net flux between forests and the atmosphere because timber harvests do not cause an immediate flux of C of all vegetation C to the atmosphere. Instead, harvesting transfers a portion of the C stored in wood to a "product pool." Once in a product pool, the C is emitted over time as CO_2 when the wood product combusts or decays. The rate of emission varies considerably among different product pools. For example, if timber is harvested to produce energy, combustion releases C immediately. Conversely, if timber is harvested and used as lumber in a house, it may be many decades or even centuries before the lumber decays and C is released to the atmosphere. If wood products are disposed of in SWDS, the C contained in the wood may be released many years or decades later, or may be stored almost permanently in the SWDS.

This section quantifies the net changes in C stocks in the five forest C pools and two harvested wood pools. The net change in stocks for each pool is estimated, and then the changes in stocks are summed over all pools to estimate total net flux. The focus on C implies that all C-based greenhouse gases are included, and the focus on stock change suggests that specific ecosystem fluxes do not need to be separately itemized in this report. Disturbances from forest fires and pest outbreaks are implicitly included in the net changes. For instance, an inventory conducted after fire counts only the trees that are left. The change between inventories thus accounts for the C changes due to fires; however, it may not be possible to attribute the changes to the disturbance specifically. The IPCC (2003) recommends reporting C stocks according to several land-use types and conversions, specifically *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*. Currently, consistent datasets are just becoming available for the conterminous United States to allow forest land conversions and forest land remaining forest land to be identified, and research is ongoing to properly use that information based on research results. Thus, net changes in all forest-related land, including non-forest land converted to forest and forests converted to non-forest, are reported here.

Forest C storage pools, and the flows between them via emissions, sequestration, and transfers, are shown in Figure 7-2. In the figure, boxes represent forest C storage pools and arrows represent flows between storage pools or between storage pools and the atmosphere. Note that the boxes are not identical to the storage pools identified in this chapter. The storage pools identified in this chapter have been refined in this graphic to better illustrate the processes that result in transfers of C from one pool to another, and emissions to as well as uptake from the atmosphere.

Figure 7-2: Forest Sector Carbon Pools and Flows

Approximately 33 percent (304 million hectares) of the U.S. land area is forested (Smith et al. 2009). The current forest carbon inventory includes 271 million hectares in the conterminous 48 states (USDA Forest Service 2010a, 2010b) that are considered managed and are included in this inventory. An additional 6.1 million hectares of southeast and south central Alaskan forest are inventoried and are included here. Three notable differences exist in forest land defined in Smith et al. (2009) and the forest land included in this report, which is based on USDA Forest Service (2010b). Survey data are not yet available from Hawaii and a large portion of interior Alaska, but estimates of these areas are included in Smith et al. (2009). Alternately, survey data for west Texas has only recently become available, and these forests contribute to overall carbon stock reported below. While Hawaii and U.S. territories have relatively small areas of forest land and will thus probably not influence the overall C budget substantially, these regions will be added to the C budget as sufficient data become available. Agroforestry systems are also not currently accounted for in the inventory, since they are not explicitly inventoried by either the Forest Inventory and Analysis (FIA) program of the U.S. Department of Agriculture (USDA) Forest Service or the National Resources Inventory (NRI) of the USDA Natural Resources Conservation Service (Perry et al. 2005).

Sixty-eight percent of U.S. forests (208 million hectares) are classified as timberland, meaning they meet minimum levels of productivity. Nine percent of Alaska forests overall and 81 percent of forests in the conterminous United States are classified as timberlands. Of the remaining nontimberland forests, 30 million hectares are reserved forest lands (withdrawn by law from management for production of wood products) and 66 million hectares are lower productivity forest lands (Smith et al. 2009). Historically, the timberlands in the conterminous 48 states have been more frequently or intensively surveyed than other forest lands.

Forest land area declined by approximately 10 million hectares over the period from the early 1960s to the late 1980s. Since then, forest area has increased by about 12 million hectares. Current trends in forest area represent average annual change of less than 0.2 percent. Given the low rate of change in U.S. forest land area, the major influences on the current net C flux from forest land are management activities and the ongoing impacts of previous land-use changes. These activities affect the net flux of C by altering the amount of C stored in forest ecosystems. For example, intensified management of forests that leads to an increased rate of growth increases the eventual biomass density of the forest, thereby increasing the uptake of C.[176] Though harvesting forests removes much of the aboveground C, on average the volume of annual net growth nationwide is about 72 percent higher than the volume of annual removals on timberlands (Smith et al. 2009). The reversion of cropland to forest land increases C storage in biomass, forest floor, and soils. The net effects of forest management and the effects of land-use change involving forest land are captured in the estimates of C stocks and fluxes presented in this chapter.

In the United States, improved forest management practices, the regeneration of previously cleared forest areas, and timber harvesting and use have resulted in net uptake (i.e., net sequestration) of C each year from 1990 through 2009. The rate of forest clearing begun in the 17th century following European settlement had slowed by the late 19th century. Through the later part of the 20th century many areas of previously forested land in the United States were allowed to revert to forests or were actively reforested. The impacts of these land-use changes still influence C fluxes from these forest lands. More recently, the 1970s and 1980s saw a resurgence of federally-sponsored forest management programs (e.g., the Forestry Incentive Program) and soil conservation programs (e.g., the Conservation Reserve Program), which have focused on tree planting, improving timber management activities, combating soil erosion, and converting marginal cropland to forests. In addition to forest regeneration and management, forest

[176] The term "biomass density" refers to the mass of live vegetation per unit area. It is usually measured on a dry-weight basis. Dry biomass is 50 percent C by weight.

harvests have also affected net C fluxes. Because most of the timber harvested from U.S. forests is used in wood products, and many discarded wood products are disposed of in SWDS rather than by incineration, significant quantities of C in harvested wood are transferred to long-term storage pools rather than being released rapidly to the atmosphere (Skog and Nicholson 1998, Skog 2008). The size of these long-term C storage pools has increased during the last century.

Changes in C stocks in U.S. forests and harvested wood were estimated to account for net sequestration of 863 Tg CO_2 Eq. (235 Tg C) in 2009 (Table 7-6, Table 7-7, and Table 7-8). In addition to the net accumulation of C in harvested wood pools, sequestration is a reflection of net forest growth and increasing forest area over this period. Overall, average C in forest ecosystem biomass (aboveground and belowground) increased from 67 to 73 Mg C/ha between 1990 and 2010 (see Annex 3-12 for average C densities by specific regions and forest types). Continuous, regular annual surveys are not available over the period for each state; therefore, estimates for non-survey years were derived by interpolation between known data points. Survey years vary from state to state, and national estimates are a composite of individual state surveys. Therefore, changes in sequestration over the interval 1990 to 2009 are the result of the sequences of new inventories for each state. C in forest ecosystem biomass had the greatest effect on total change through increases in C density and total forest land. Management practices that increase C stocks on forest land, as well as afforestation and reforestation efforts, influence the trends of increased C densities in forests and increased forest land in the United States.

The decline in net additions to HWP carbon stocks continued though 2009 from the recent high point in 2006. This is due to sharp declines in U.S. production of solidwood and paper products in 2009 primarily due to the decline in housing construction. The low level of gross additions to solidwood and paper products in use in 2009 was exceeded by discards from uses. The result is a net reduction in the amount of HWP carbon that is held in products in use during 2009. For 2009, additions to landfills still exceeded emissions from landfills and the net additions to landfills have remained relatively stable. Overall, there were net carbon additions to HWP in use and in landfills combined in 2009.

Table 7-6: Net Annual Changes in C Stocks (Tg CO_2/yr) in Forest and Harvested Wood Pools

Carbon Pool	1990	2000	2005	2006	2007	2008	2009
Forest	**(549.3)**	**(265.4)**	**(806.1)**	**(808.9)**	**(808.9)**	**(808.9)**	**(808.9)**
Aboveground Biomass	(360.0)	(287.0)	(447.9)	(447.9)	(447.9)	(447.9)	(447.9)
Belowground Biomass	(70.9)	(57.5)	(88.4)	(88.4)	(88.4)	(88.4)	(88.4)
Dead Wood	(31.6)	(12.9)	(30.8)	(33.5)	(33.5)	(33.5)	(33.5)
Litter	(32.2)	27.5	(41.9)	(41.9)	(41.9)	(41.9)	(41.9)
Soil Organic Carbon	(54.7)	64.6	(197.2)	(197.2)	(197.2)	(197.2)	(197.2)
Harvested Wood	**(131.8)**	**(112.9)**	**(105.4)**	**(108.6)**	**(103.0)**	**(82.1)**	**(54.3)**
Products in Use	(64.8)	(47.0)	(45.4)	(45.1)	(39.1)	(19.1)	6.8
SWDS	(67.0)	(65.9)	(59.9)	(63.4)	(63.8)	(63.0)	(61.1)
Total Net Flux	**(681.1)**	**(378.3)**	**(911.5)**	**(917.5)**	**(911.9)**	**(891.0)**	**(863.1)**

Note: Forest C stocks do not include forest stocks in U.S. territories, Hawaii, a portion of managed forests in Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere). Total net flux is an estimate of the actual net flux between the total forest C pool and the atmosphere. Forest area estimates are based on interpolation and extrapolation of inventory data as described in the text and in Annex 3.12. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding.

Table 7-7: Net Annual Changes in C Stocks (Tg C/yr) in Forest and Harvested Wood Pools

Carbon Pool	1990	2000	2005	2006	2007	2008	2009
Forest	**(149.8)**	**(72.4)**	**(219.9)**	**(220.6)**	**(220.6)**	**(220.6)**	**(220.6)**
Aboveground Biomass	(98.2)	(78.3)	(122.1)	(122.1)	(122.1)	(122.1)	(122.1)
Belowground Biomass	(19.3)	(15.7)	(24.1)	(24.1)	(24.1)	(24.1)	(24.1)
Dead Wood	(8.6)	(3.5)	(8.4)	(9.1)	(9.1)	(9.1)	(9.1)

Litter	(8.8)	7.5	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)
Soil Organic C	(14.9)	17.6	(53.8)	(53.8)	(53.8)	(53.8)	(53.8)
Harvested Wood	**(35.9)**	**(30.8)**	**(28.7)**	**(29.6)**	**(28.1)**	**(22**.4)	**(14.8)**
Products in Use	(17.7)	(12.8)	(12.4)	(12.3)	(10.7)	(5.2)	1.9
SWDS	(18.3)	(18.0)	(16.3)	(17.3)	(17.4)	(17.2)	(16.7)
Total Net Flux	**(185.7)**	**(103.2)**	**(248.6)**	**(250.2)**	**(248.7)**	**(243**.0)	**(235.4)**

Note: Forest C stocks do not include forest stocks in U.S. territories, Hawaii, a portion of managed lands in Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere). Total net flux is an estimate of the actual net flux between the total forest C pool and the atmosphere. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding.

Stock estimates for forest and harvested wood C storage pools are presented in Table 7-8. Together, the aboveground live and forest soil pools account for a large proportion of total forest C stocks. C stocks in all non-soil pools increased over time. Therefore, C sequestration was greater than C emissions from forests, as discussed above. Figure 7-4 shows county-average C densities for live trees on forest land, including both above- and belowground biomass.

Table 7-8: Forest area (1000 ha) and C Stocks (Tg C) in Forest and Harvested Wood Pools

	1990	2000	2005	2006	2007	2008	2009	2010
Forest Area (1000 ha)	**269,137**	**274,183**	**276,769**	**277,561**	**278,354**	**279,147**	**279,939**	**280,732**
Carbon Pools (Tg C)								
Forest	**42,783**	**44,108**	**44,886**	**45,105**	**45,326**	**45,547**	**45,767**	**45,988**
Aboveground Biomass	15,072	16,024	16,536	16,658	16,780	16,902	17,024	17,147
Belowground Biomass	2,995	3,183	3,285	3,309	3,333	3,357	3,381	3,405
Dead Wood	2,960	3,031	3,060	3,068	3,077	3,086	3,096	3,105
Litter	4,791	4,845	4,862	4,873	4,885	4,896	4,908	4,919
Soil Organic C	16,96	17,025	17,143	17,197	17,251	17,304	17,358	17,412
Harvested Wood	**1,859**	**2,187**	**2,325**	**2,354**	**2,383**	**2,412**	**2,434**	**2,449**
Products in Use	1,231	1,382	1,436	1,448	1,460	1,471	1,476	1,474
SWDS	628	805	890	906	923	941	958	974
Total C Stock	**44,643**	**46,296**	**47,211**	**47,459**	**47,710**	**47,958**	**48,201**	**48,437**

Note: Forest area estimates include portions of managed forests in Alaska for which survey data are available. Forest C stocks do not include forest stocks in U.S. territories, Hawaii, a large portion of Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Wood product stocks include exports, even if the logs are processed in other countries, and exclude imports. Forest area estimates are based on interpolation and extrapolation of inventory data as described in Smith et al. (2010) and in Annex 3.12. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding. Inventories are assumed to represent stocks as of January 1 of the inventory year. Flux is the net annual change in stock. Thus, an estimate of flux for 2006 requires estimates of C stocks for 2006 and 2007.

Figure 7-3: Estimates of Net Annual Changes in C Stocks for Major C Pools

Figure 7-4: Average C Density in the Forest Tree Pool in the Conterminous United States, 2009

[BEGIN BOX]

Box 7-2: CO_2 Emissions from Forest Fires

As stated previously, the forest inventory approach implicitly accounts for emissions due to disturbances such as forest fires, because only C remaining in the forest is estimated. Net C stock change is estimated by subtracting consecutive C stock estimates. A disturbance removes C from the forest. The inventory data on which net C stock estimates are based already reflect this C loss. Therefore, estimates of net annual changes in C stocks for U.S. forestland already account for CO_2 emissions from forest fires occurring in the lower 48 states as well as in the proportion of Alaska's managed forest land captured in this inventory. Because it is of interest to quantify the magnitude of CO_2 emissions from fire disturbance, these estimates are being highlighted here, using the full extent of available data. Non-CO_2 greenhouse gas emissions from forest fires are also quantified in a separate section below.

The IPCC (2003) methodology and IPCC (2006) default combustion factor for wildfire were employed to estimate CO_2 emissions from forest fires. CO_2 emissions for wildfires and prescribed fires in the lower 48 states and wildfires in Alaska in 2009 were estimated to be 124.3 Tg CO_2/yr. This amount is masked in the estimate of net annual forest carbon stock change for 2009, however, because this net estimate accounts for the amount sequestered minus any emissions.

Table 7-9: Estimates of CO_2 (Tg/yr) emissions for the lower 48 states and Alaska[1]

Year	CO_2 emitted from Wildfires in Lower 48 States (Tg/yr)	CO_2 emitted from Prescribed Fires in Lower 48 States (Tg/yr)	CO_2 emitted from Wildfires in Alaska (Tg/yr)	Total CO_2 emitted (Tg/yr)
1990	42.1	8.5	+	50.7
2000	225.1	2.1	+	227.3
2005	131.0	24.8	+	155.9
2006	313.6	29.3	+	342.9
2007	284.1	34.0	+	318.1
2008	169.0	20.8	+	189.8
2009	97.1	27.3	+	124.3

+ Does not exceed 0.05 Tg CO_2 Eq.

[1] Note that these emissions have already been accounted for in the estimates of net annual changes in C stocks, which account for the amount sequestered minus any emissions.

[END BOX]

Methodology and Data Sources

The methodology described herein is consistent with IPCC (2003, 2006) and IPCC/UNEP/OECD/IEA (1997). Forest ecosystem C stocks and net annual C stock change are determined according to stock-difference methods, which involve applying C estimation factors to forest inventory data and interpolating between successive inventory-based estimates of C stocks. Harvested wood C estimates are based on factors such as the allocation of wood to various primary and end-use products as well as half-life (the time at which half of amount placed in use will have been discarded from use) and expected disposition (e.g., product pool, SWDS, combustion). An overview of the different methodologies and data sources used to estimate the C in forest ecosystems or harvested wood products is provided here. See Annex 3.12 for details and additional information related to the methods and data.

Forest Ecosystem Carbon from Forest Inventory

Forest ecosystem stock and flux estimates are based on the stock-difference method and calculations for all estimates are in units of C. Separate estimates are made for the five IPCC C storage pools described above. All estimates are based on data collected from the extensive array of permanent forest inventory plots in the United States as well as models employed to fill gaps in field data. Carbon conversion factors are applied at the disaggregated level of each inventory plot and then appropriately expanded to population estimates. A combination

of tiers as outlined by IPCC (2006) is used. The Tier 3 biomass C values are from forest inventory tree-level data. The Tier 2 dead organic and soil C pools are based on empirical or process models from the inventory data. All carbon conversion factors are specific to regions or individual states within the U.S., which are further classified according to characteristic forest types within each region.

The first step in developing forest ecosystem estimates is to identify useful inventory data and resolve any inconsistencies among datasets. Forest inventory data were obtained from the USDA Forest Service FIA program (Frayer and Furnival 1999, USDA Forest Service 2010b). Inventories include data collected on permanent inventory plots on forest lands[177] and are organized as a number of separate datasets, each representing a complete inventory, or survey, of an individual state at a specified time. Some of the more recent annual inventories reported for some states include "moving window" averages, which means that a portion—but not all—of the previous year's inventory is updated each year (USDA Forest Service 2010d). Forest C calculations are organized according to these state surveys, and the frequency of surveys varies by state. All available data sets are identified for each state starting with pre-1990 data, and all unique surveys are identified for stock and change calculations. Since C stock change is based on differences between successive surveys within each state, accurate estimates of net C flux thus depend on consistent representation of forest land between these successive inventories. In order to achieve this consistency from 1990 to the present, states are sometimes subdivided into sub-state areas where the sum of sub-state inventories produces the best whole-state representation of C change as discussed in Smith et al. (2010).

The principal FIA datasets employed are freely available for download at USDA Forest Service (2010b) as the Forest Inventory and Analysis Database (FIADB) Version 4.0. However, to achieve consistent representation (spatial and temporal), two other general sources of past FIA data are included as necessary. First, older FIA plot- and tree-level data—not in the current FIADB format—are used if available. Second, Resources Planning Act Assessment (RPA) databases, which are periodic, plot-level only, summaries of state inventories, are used mostly to provide the data at or before 1990. An additional forest inventory data source is the Integrated Database (IDB), which is a compilation of periodic forest inventory data from the 1990s for California, Oregon, and Washington (Waddell and Hiserote 2005). These data were identified by Heath et al. (submitted) as the most appropriate non-FIADB sources for these states and are included in this inventory. See USDA Forest Service (2010a) for information on current and older data as well as additional FIA Program features. A detailed list of the specific forest inventory data used in this inventory is in Annex 3.12.

Forest C stocks are estimated from inventory data by a collection of conversion factors and models (Birdsey and Heath 1995, Birdsey and Heath 2001, Heath et al. 2003, Smith et al. 2004, Smith et al. 2006), which have been formalized in an FIADB-to-carbon calculator (Smith et al. 2010). The conversion factors and model coefficients are categorized by region and forest type, and forest C stock estimates are calculated from application of these factors at the scale of FIA inventory plots. The results are estimates of C density (Mg C per hectare) for six forest ecosystem pools: live trees, standing dead trees, understory vegetation, down dead wood, forest floor, and soil organic matter. The six carbon pools used in the FIADB-to-carbon calculator are aggregated to the 5 carbon pools defined by IPCC (2006): aboveground biomass, belowground biomass, dead wood, litter, and soil organic matter. All non-soil pools except forest floor are separated into aboveground and belowground components. The live tree and understory C pools are pooled as biomass, and standing dead trees and down dead wood are pooled as dead wood, in accordance with IPCC (2006).

Once plot-level C stocks are calculated as C densities on *Forest Land Remaining Forest Land* for the five IPCC (2006) reporting pools, the stocks are expanded to population estimates according to methods appropriate to the respective inventory data (for example, see Bechtold and Patterson (2005)). These expanded C stock estimates are summed to state or sub-state total C stocks. Annualized estimates of C stocks are developed by using available FIA inventory data and interpolating or extrapolating to assign a C stock to each year in the 1990 through2010 time series. Flux, or net annual stock change, is estimated by calculating the difference between two successive years and applying the appropriate sign convention; net increases in ecosystem C are identified as negative flux. By convention, inventories are assigned to represent stocks as of January 1 of the inventory year; an estimate of flux for 1996 requires estimates of C stocks for 1996 and 1997, for example. Additional discussion of the use of FIA inventory data and the C conversion process is in Annex 3.12.

[177] Forest land in the United States includes land that is at least 10 percent stocked with trees of any size. Timberland is the most productive type of forest land, which is on unreserved land and is producing or capable of producing crops of industrial wood.

Carbon in Biomass

Live tree C pools include aboveground and belowground (coarse root) biomass of live trees with diameter at diameter breast height (d.b.h.) of at least 2.54 cm at 1.37 m above the forest floor. Separate estimates are made for full-tree and aboveground-only biomass in order to estimate the belowground component. If inventory plots include data on individual trees, tree C is based on Jenkins et al. (2003) and is a function of species and diameter. Some inventory data do not provide measurements of individual trees; tree C in these plots is estimated from plot-level volume of merchantable wood, or growing-stock volume, of live trees, which is calculated from updates of Smith et al. (2003). These biomass conversion and expansion factors (BCEFs) are applied to about 3 percent of the inventory records, all of which are pre-1998 data. Some inventory data, particularly some of the older datasets, may not include sufficient information to calculate tree C because of incomplete or missing tree or volume data; C estimates for these plots are based on averages from similar, but more complete, inventory data. This applies to an additional 2 percent of inventory records, which represent older (pre-1998) non-timberlands.

Understory vegetation is a minor component of biomass, which is defined as all biomass of undergrowth plants in a forest, including woody shrubs and trees less than 2.54 cm d.b.h. In the current inventory, it is assumed that 10 percent of total understory C mass is belowground. Estimates of C density are based on information in Birdsey (1996). Understory frequently represents over 1 percent of C in biomass, but its contribution rarely exceeds 2 percent of the total.

Carbon in Dead Organic Matter

Dead organic matter is initially calculated as three separate pools with C stocks modeled from inventory data. Estimates are specific to regions and forest types within each region, and stratification of forest land for dead organic matter calculations is identical to that used for biomass through the state and sub-state use of FIA data as discussed above. The two components of dead wood—standing dead trees and down dead wood—are estimated separately. The standing dead tree C pools include aboveground and belowground (coarse root) mass and include trees of at least 2.54 cm d.b.h. Calculations are BCEF-like factors based on updates of Smith et al. (2003). Down dead wood is defined as pieces of dead wood greater than 7.5 cm diameter, at transect intersection, that are not attached to live or standing dead trees. Down dead wood includes stumps and roots of harvested trees. Ratios of down dead wood to live tree are used to estimate this quantity. Litter C is the pool of organic C (also known as duff, humus, and fine woody debris) above the mineral soil and includes woody fragments with diameters of up to 7.5 cm. Estimates are based on equations of Smith and Heath (2002).

Carbon in Forest Soil

Soil organic C (SOC) includes all organic material in soil to a depth of 1 meter but excludes the coarse roots of the biomass or dead wood pools. Estimates of SOC are based on the national STATSGO spatial database (USDA 1991), which includes region and soil type information. SOC determination is based on the general approach described by Amichev and Galbraith (2004). Links to FIA inventory data were developed with the assistance of the USDA Forest Service FIA Geospatial Service Center by overlaying FIA forest inventory plots on the soil C map. This method produced mean SOC densities stratified by region and forest type group. It did not provide separate estimates for mineral or organic soils but instead weighted their contribution to the overall average based on the relative amount of each within forest land. Thus, forest SOC is a function of species and location, and net change also depends on these two factors as total forest area changes. In this respect, SOC provides a country-specific reference stock for 1990-present, but it does not reflect effects of past land use.

Harvested Wood Carbon

Estimates of the HWP contribution to forest C sinks and emissions (hereafter called “HWP Contribution”) are based on methods described in Skog (2008) using the WOODCARB II model. These methods are based on IPCC (2006) guidance for estimating HWP C. IPCC (2006) provides methods that allow Parties to report HWP Contribution using one of several different accounting approaches: production, stock change and atmospheric flow, as well as a default method that assumes there is no change in HWP C stocks (see Annex 3.12 for more details about each approach). The United States uses the production accounting approach to report HWP Contribution. Under the production approach, C in exported wood is estimated as if it remains in the United States, and C in imported wood is not included in inventory estimates. Though reported U.S. HWP estimates are based on the production approach, estimates resulting from use of the two alternative approaches, the stock change and atmospheric flow approaches,

are also presented for comparison (see Annex 3.12). Annual estimates of change are calculated by tracking the additions to and removals from the pool of products held in end uses (i.e., products in use such as housing or publications) and the pool of products held in solid waste disposal sites (SWDS).

Solidwood products added to pools include lumber and panels. End-use categories for solidwood include single and multifamily housing, alteration and repair of housing, and other end-uses. There is one product category and one end-use category for paper. Additions to and removals from pools are tracked beginning in 1900, with the exception that additions of softwood lumber to housing begins in 1800. Solidwood and paper product production and trade data are from USDA Forest Service and other sources (Hair and Ulrich 1963; Hair 1958; USDC Bureau of Census; 1976; Ulrich, 1985, 1989; Steer 1948; AF&PA 2006a 2006b; Howard 2003, 2007). Estimates for disposal of products reflect the change over time in the fraction of products discarded to SWDS (as opposed to burning or recycling) and the fraction of SWDS that are in sanitary landfills versus dumps.

There are five annual HWP variables that are used in varying combinations to estimate HWP Contribution using any one of the three main approaches listed above. These are:

(1A) annual change of C in wood and paper products in use in the United States,

(1B) annual change of C in wood and paper products in SWDS in the United States,

(2A) annual change of C in wood and paper products in use in the United States and other countries where the wood came from trees harvested in the United States,

(2B) annual change of C in wood and paper products in SWDS in the United States and other countries where the wood came from trees harvested in the United States,

(3) C in imports of wood, pulp, and paper to the United States,

(4) C in exports of wood, pulp and paper from the United States, and

(5) C in annual harvest of wood from forests in the United States.

The sum of variables 2A and 2B yields the estimate for HWP Contribution under the production accounting approach. A key assumption for estimating these variables is that products exported from the United States and held in pools in other countries have the same half lives for products in use, the same percentage of discarded products going to SWDS, and the same decay rates in SWDS as they would in the United States.

Uncertainty and Time Series Consistency

A quantitative uncertainty analysis placed bounds on current flux for forest ecosystems as well as C in harvested wood products through Monte Carlo simulation of the Methods described above and probabilistic sampling of C conversion factors and inventory data. See Annex 3.12 for additional information. The 2009 flux estimate for forest C stocks is estimated to be between -1,014 and -714 Tg CO_2 Eq. at a 95 percent confidence level. This includes a range of -662 to -959 Tg CO_2 Eq. in forest ecosystems and -69 to -41 Tg CO_2 Eq. for HWP.

Table 7-10: Tier 2 Quantitative Uncertainty Estimates for Net CO_2 Flux from Forest Land Remaining Forest Land: Changes in Forest C Stocks (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Flux Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Flux Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Forest Ecosystem	CO_2	(808.9)	(959.4)	(661.7)	-19%	-18%
Harvested Wood Products	CO_2	(54.3)	(68.6)	(41.0)	-27%	-24%
Total Forest	**CO_2**	**(863.1)**	**(1,014.4)**	**(713.9)**	**-18%**	**-17%**

Note: Parentheses indicate negative values or net sequestration.
[a]Range of flux estimates predicted by Monte Carlo stochastic simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section,

above.

QA/QC and Verification

As discussed above, the FIA program has conducted consistent forest surveys based on extensive statistically-based sampling of most of the forest land in the conterminous United States, dating back to 1952. The main purpose of the FIA program has been to estimate areas, volume of growing stock, and timber products output and utilization factors. The FIA program includes numerous quality assurance and quality control (QA/QC) procedures, including calibration among field crews, duplicate surveys of some plots, and systematic checking of recorded data. Because of the statistically-based sampling, the large number of survey plots, and the quality of the data, the survey databases developed by the FIA program form a strong foundation for C stock estimates. Field sampling protocols, summary data, and detailed inventory databases are archived and are publicly available on the Internet (USDA Forest Service 2010d).

Many key calculations for estimating current forest C stocks based on FIA data were developed to fill data gaps in assessing forest carbon and have been in use for many years to produce national assessments of forest C stocks and stock changes (see additional discussion and citations in the Methodology section above and in Annex 3.12). General quality control procedures were used in performing calculations to estimate C stocks based on survey data. For example, the derived C datasets, which include inventory variables such as areas and volumes, were compared to standard inventory summaries such as the forest resource statistics of Smith et al. (2009) or selected population estimates generated from FIADB 4.0, which are available at an FIA internet site (USDA Forest Service 2009b). Agreement between the C datasets and the original inventories is important to verify accuracy of the data used. Finally, C stock estimates were compared with previous inventory report estimates to ensure that any differences could be explained by either new data or revised calculation methods (see the "Recalculations" discussion, below).

Estimates of the HWP variables and the HWP contribution under the production accounting approach use data from U.S. Census and USDA Forest Service surveys of production and trade. Factors to convert wood and paper to units C are based on estimates by industry and Forest Service published sources. The WOODCARB II model uses estimation methods suggested by IPCC (2006). Estimates of annual C change in solidwood and paper products in use were calibrated to meet two independent criteria. The first criterion is that the WOODCARB II model estimate of C in houses standing in 2001 needs to match an independent estimate of C in housing based on U.S. Census and USDA Forest Service survey data. Meeting the first criterion resulted in an estimated half life of about 80 years for single family housing built in the 1920s, which is confirmed by other U.S. Census data on housing. The second criterion is that the WOODCARB II model estimate of wood and paper being discarded to SWDS needs to match EPA estimates of discards each year over the period 1990 to 2000 (EPA 2006). These criteria help reduce uncertainty in estimates of annual change in C in products in use in the United States and, to a lesser degree, reduce uncertainty in estimates of annual change in C in products made from wood harvested in the United States. In addition, WOODCARB II landfill decay rates have been validated by ensuring that estimates of CH_4 emissions from landfills based on EPA (2006) data are reasonable in comparison with CH_4 estimates based on WOODCARB II landfill decay rates.

Recalculations Discussion

The basic models used to estimate forest ecosystem and HWP C stocks and change are unchanged from the previous Inventory (Smith et al. 2010, Skog 2008). Many of the state-level estimates for 1990 through the present are relatively similar to the values previously reported (EPA 2010). Recent forest inventory additions to the FIADB include newer annual inventory data for most states including Oklahoma, which had the effect of increasing overall net sequestration estimated for the interval from 2000 through 2008. An additional change to the FIADB was the addition of some older periodic inventories for some southern states; these were incorporated into the calculations but did not appreciably affect national trends. The addition of the IDB forest inventories for a part of the series for California, Oregon, and Washington did affect recalculations for those states and the United States as a whole; it tended to decrease net sequestration throughout the 1990 to 2008 interval. However, the decreased sequestration associated with the use of the IDB was offset by the increased sequestration associated with newer annual inventory data for the post-2000 interval.

Planned Improvements

The ongoing annual surveys by the FIA Program will improve precision of forest C estimates as new state surveys

become available (USDA Forest Service 2010b), particularly in western states. The annual surveys will eventually include all states. To date, three states are not yet reporting any data from the annualized sampling design of FIA: Hawaii, New Mexico and Wyoming. Estimates for these states are currently based on older, periodic data. Hawaii and U.S. territories will also be included when appropriate forest C data are available. In addition, the more intensive sampling of down dead wood, litter, and soil organic C on some of the permanent FIA plots continues and will substantially improve resolution of C pools at the plot level for all U.S. forest land as this information becomes available (Woodall et al. in press). Improved resolution, incorporating more of Alaska's forests, and using annualized sampling data as it becomes available for those states currently not reporting are planned for future reporting.

As more information becomes available about historical land use, the ongoing effects of changes in land use and forest management will be better accounted for in estimates of soil C (Birdsey and Lewis 2003, Woodbury et al. 2006, Woodbury et al. 2007). Currently, soil C estimates are based on the assumption that soil C density depends only on broad forest type group, not on land-use history, but long-term residual effects on soil and forest floor C stocks are likely after land-use change. Estimates of such effects depend on identifying past land use changes associated with forest lands.

Similarly, agroforestry practices, such as windbreaks or riparian forest buffers along waterways, are not currently accounted for in the inventory. In order to properly account for the C stocks and fluxes associated with agroforestry, research will be needed that provides the basis and tools for including these plantings in a nation-wide inventory, as well as the means for entity-level reporting.

Non-CO_2 Emissions from Forest Fires

Emissions of non-CO_2 gases from forest fires were estimated using the default IPCC (2003) methodology incorporating default IPCC (2006) emissions factors and combustion factor for wildfires. Emissions from this source in 2009 were estimated to be 7.8 Tg CO_2 Eq**.** of CH_4 and 6.4 Tg CO_2 Eq. of N_2O, as shown in Table 7-11 and Table 7-12. The estimates of non-CO_2 emissions from forest fires account for wildfires in the lower 48 states and Alaska as well as prescribed fires in the lower 48 states.

Table 7-11: Estimated Non-CO_2 Emissions from Forest Fires (Tg CO_2 Eq.) for U.S. Forests[1]

Gas	1990	2000	2005	2006	2007	2008	2009
CH_4	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N_2O	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Total	**5.8**	**26.0**	**17.8**	**39.2**	**36.3**	**21.7**	**14.2**

[1] Calculated based on C emission estimates in *Changes in Forest Carbon Stocks* and default factors in IPCC (2003, 2006).

Table 7-12: Estimated Non-CO_2 Emissions from Forest Fires (Gg Gas) for U.S. Forests[1]

Gas	1990	2000	2005	2006	2007	2008	2009
CH_4	152	682	467	1,027	953	569	372
N_2O	8	38	26	57	53	31	21

[1] Calculated based on C emission estimates *in Changes in Forest Carbon Stocks* and default factors in IPCC (2003, 2006).

Methodology

The IPCC (2003) Tier 2 default methodology was used to calculate non-CO_2 emissions from forest fires. However, more up-to-date default emission factors from IPCC (2006) were converted into gas-specific emission ratios and incorporated into the methodology**.** Estimates of CH_4 and N_2O emissions were calculated by multiplying the total estimated CO_2 emitted from forest burned by the gas-specific emissions ratios. CO_2 emissions were estimated by multiplying total C emitted (Table 7-13) by the C to CO_2 conversion factor of 44/12 and by 92.8 percent, which is the estimated proportion of C emitted as CO_2 (Smith 2008a). The equations used were:

$$CH_4 \text{ Emissions} = (\text{C released}) \times 92.8\% \times (44/12) \times (CH_4 \text{ to } CO_2 \text{ emission ratio})$$

$$N_2O \text{ Emissions} = (\text{C released}) \times 92.8\% \times (44/12) \times (N_2O \text{ to } CO_2 \text{ emission ratio})$$

Estimates for C emitted from forest fires are the same estimates used to generate estimates of CO_2 presented earlier in Box 7-1. Estimates for C emitted include emissions from wildfires in both Alaska and the lower 48 states as well

as emissions from prescribed fires in the lower 48 states only (based on expert judgment that prescribed fires only occur in the lower 48 states) (Smith 2008a). The IPCC (2006) default combustion factor of 0.45 for "all 'other' temperate forests" was applied in estimating C emitted from both wildfires and prescribed fires. See the explanation in Annex 3.12 for more details on the methodology used to estimate C emitted from forest fires.

Table 7-13: Estimated Carbon Released from Forest Fires for U.S. Forests

Year	C Emitted (Tg/yr)
1990	14.9
2000	66.8
2005	45.8
2006	100.8
2007	93.5
2008	55.8
2009	36.5

Uncertainty and Time-Series Consistency

Non-CO_2 gases emitted from forest fires depend on several variables, including: forest area for Alaska and the lower 48 states; average C densities for wildfires in Alaska, wildfires in the lower 48 states, and prescribed fires in the lower 48 states; emission ratios; and combustion factor values (proportion of biomass consumed by fire). To quantify the uncertainties for emissions from forest fires, a Monte Carlo (Tier 2) uncertainty analysis was performed using information about the uncertainty surrounding each of these variables. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-14.

Table 7-14: Tier 2 Quantitative Uncertainty Estimates of Non-CO_2 Emissions from Forest Fires in Forest Land Remaining Forest Land (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Non-CO_2 Emissions from Forest Fires	CH_4	7.8	2.2	19.2	-72%	+145%
Non-CO_2 Emissions from Forest Fires	N_2O	6.4	1.8	15.7	-72%	+145%

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Source-specific quality control measures for forest fires included checking input data, documentation, and calculations to ensure data were properly handled through the inventory process. Errors that were found during this process were corrected as necessary.

Recalculations Discussion

This is the second year in which non-CO_2 emissions were calculated using the 2006 IPCC default emission factors for CH_4 and N_2O instead of the 2003 IPCC default emission factors. These default emission factors were converted to CH_4 to CO_2 and N_2O to CO_2 emission ratios and then multiplied by CO_2 emissions to estimate CH_4 and N_2O emissions. The previous 2003 IPCC methodology provides emission ratios that are multiplied by total carbon emitted.

Planned Improvements

The default combustion factor of 0.45 from IPCC (2006) was applied in estimating C emitted from both wildfires and prescribed fires. Additional research into the availability of a combustion factor specific to prescribed fires is

being conducted.

Direct N_2O Fluxes from Forest Soils (IPCC Source Category 5A1)

Of the synthetic N fertilizers applied to soils in the United States, no more than one percent is applied to forest soils. Application rates are similar to those occurring on cropped soils, but in any given year, only a small proportion of total forested land receives N fertilizer. This is because forests are typically fertilized only twice during their approximately 40-year growth cycle (once at planting and once approximately 20 years later). Thus, while the rate of N fertilizer application for the area of forests that receives N fertilizer in any given year is relatively high, the average annual application is quite low as inferred by dividing all forest land that may undergo N fertilization at some point during its growing cycle by the amount of N fertilizer added to these forests in a given year. Direct N_2O emissions from forest soils in 2009 were 0.4 Tg CO_2 Eq. (1 Gg). Emissions have increased by 455 percent from 1990 to 2009 as a result of an increase in the area of N fertilized pine plantations in the southeastern United States and Douglas-fir timberland in western Washington and Oregon. Total forest soil N_2O emissions are summarized in Table 7-15.

Table 7-15: Direct N_2O Fluxes from Soils in *Forest Land Remaining Forest Land* (Tg CO_2 Eq. and Gg N_2O)

Year	Tg CO_2 Eq.	Gg
1990	0.1	0.2
2000	0.4	1.3
2005	0.4	1.2
2006	0.4	1.2
2007	0.4	1.2
2008	0.4	1.2
2009	0.4	1.2

Note: These estimates include direct N_2O emissions from N fertilizer additions only. Indirect N_2O emissions from fertilizer additions are reported in the Agriculture chapter. These estimates include emissions from both *Forest Land Remaining Forest Land* and from *Land Converted to Forest Land.*

Methodology

The IPCC Tier 1 approach was used to estimate N_2O from soils within *Forest Land Remaining Forest Land*. According to U.S. Forest Service statistics for 1996 (USDA Forest Service 2001), approximately 75 percent of trees planted were for timber, and about 60 percent of national total harvested forest area is in the southeastern United States. Although southeastern pine plantations represent the majority of fertilized forests in the United States, this Inventory also accounted for N fertilizer application to commercial Douglas-fir stands in western Oregon and Washington. For the Southeast, estimates of direct N_2O emissions from fertilizer applications to forests were based on the area of pine plantations receiving fertilizer in the southeastern United States and estimated application rates (Albaugh et al. 2007). Not accounting for fertilizer applied to non-pine plantations is justified because fertilization is routine for pine forests but rare for hardwoods (Binkley et al. 1995). For each year, the area of pine receiving N fertilizer was multiplied by the weighted average of the reported range of N fertilization rates (121 lbs. N per acre). Area data for pine plantations receiving fertilizer in the Southeast were not available for 2005, 2006, 2007 and 2008, so data from 2004 were used for these years. For commercial forests in Oregon and Washington, only fertilizer applied to Douglas-fir was accounted for, because the vast majority (~95 percent) of the total fertilizer applied to forests in this region is applied to Douglas-fir (Briggs 2007). Estimates of total Douglas-fir area and the portion of fertilized area were multiplied to obtain annual area estimates of fertilized Douglas-fir stands. The annual area estimates were multiplied by the typical rate used in this region (200 lbs. N per acre) to estimate total N applied (Briggs 2007), and the total N applied to forests was multiplied by the IPCC (2006) default emission factor of 1 percent to estimate direct N_2O emissions. The volatilization and leaching/runoff N fractions for forest land, calculated according to the IPCC default factors of 10 percent and 30 percent, respectively, were included with the indirect emissions in the Agricultural Soil Management source category (consistent with reporting guidance that all indirect emissions are included in the Agricultural Soil Management source category).

Uncertainty and Time-Series Consistency

The amount of N_2O emitted from forests depends not only on N inputs and fertilized area, but also on a large number of variables, including organic C availability, oxygen gas partial pressure, soil moisture content, pH, temperature, and tree planting/harvesting cycles. The effect of the combined interaction of these variables on N_2O flux is complex and highly uncertain. IPCC (2006) does not incorporate any of these variables into the default methodology, except variation in estimated fertilizer application rates and estimated areas of forested land receiving N fertilizer. All forest soils are treated equivalently under this methodology. Furthermore, only synthetic N fertilizers are captured, so applications of organic N fertilizers are not estimated. However, the total quantity of organic N inputs to soils is included in the Agricultural Soil Management and *Settlements Remaining Settlements* sections.

Uncertainties exist in the fertilization rates, annual area of forest lands receiving fertilizer, and the emission factors. Fertilization rates were assigned a default level[178] of uncertainty at ±50 percent, and area receiving fertilizer was assigned a ±20 percent according to expert knowledge (Binkley 2004). IPCC (2006) provided estimates for the uncertainty associated with direct N_2O emission factor for synthetic N fertilizer application to soils. Quantitative uncertainty of this source category was estimated through the IPCC-recommended Tier 2 uncertainty estimation methodology. The uncertainty ranges around the 2005 activity data and emission factor input variables were directly applied to the 2009 emissions estimates. The results of the quantitative uncertainty analysis are summarized in Table 7-16. N_2O fluxes from soils were estimated to be between 0.1 and 1.1 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 59 percent below and 211 percent above the 2009 emission estimate of 0.4 Tg CO_2 Eq.

Table 7-16: Quantitative Uncertainty Estimates of N_2O Fluxes from Soils in *Forest Land Remaining Forest Land* (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Forest Land Remaining Forest Land:						
N_2O Fluxes from Soils	N_2O	0.4	0.1	1.1	-59%	+211%

Note: This estimate includes direct N_2O emissions from N fertilizer additions to both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.

Planned Improvements

State-level area data will be acquired for southeastern pine plantations and northwestern Douglas-fir forests receiving fertilizer to estimate soil N_2O emission by state and provide information about regional variation in emission patterns.

7.3. Land Converted to Forest Land (IPCC Source Category 5A2)

Land-use change is constantly occurring, and areas under a number of differing land-use types are converted to forest each year, just as forest land is converted to other uses. However, the magnitude of these changes is not currently known. Given the paucity of available land-use information relevant to this particular IPCC source category, it is not possible to separate CO_2 or N_2O fluxes on *Land Converted to Forest Land* from fluxes on *Forest Land Remaining Forest Land* at this time.

7.4. Cropland Remaining Cropland (IPCC Source Category 5B1)

Mineral and Organic Soil Carbon Stock Changes

Soils contain both organic and inorganic forms of C, but soil organic C (SOC) stocks are the main source and sink for atmospheric CO_2 in most soils. Changes in inorganic C stocks are typically minor. In addition, soil organic C is

[178] Uncertainty is unknown for the fertilization rates so a conservative value of ±50% was used in the analysis.

the dominant organic C pool in cropland ecosystems, because biomass and dead organic matter have considerably less C and those pools are relatively ephemeral. IPCC (2006) recommends reporting changes in soil organic C stocks due to agricultural land-use and management activities on mineral and organic soils.[179]

Typical well-drained mineral soils contain from 1 to 6 percent organic C by weight, although mineral soils that are saturated with water for substantial periods during the year may contain significantly more C (NRCS 1999). Conversion of mineral soils from their native state to agricultural uses can cause as much as half of the SOC to be decomposed and the C lost to the atmosphere. The rate and ultimate magnitude of C loss will depend on pre-conversion conditions, conversion method and subsequent management practices, climate, and soil type. In the tropics, 40 to 60 percent of the C loss generally occurs within the first 10 years following conversion; C stocks continue to decline in subsequent decades but at a much slower rate. In temperate regions, C loss can continue for several decades, reducing stocks by 20 to 40 percent of native C levels. Eventually, the soil can reach a new equilibrium that reflects a balance between C inputs (e.g., decayed plant matter, roots, and organic amendments such as manure and crop residues) and C loss through microbial decomposition of organic matter. However, land use, management, and other conditions may change before the new equilibrium is reached. The quantity and quality of organic matter inputs and their rate of decomposition are determined by the combined interaction of climate, soil properties, and land use. Land use and agricultural practices such as clearing, drainage, tillage, planting, grazing, crop residue management, fertilization, and flooding can modify both organic matter inputs and decomposition, and thereby result in a net flux of C to or from the pool of soil C.

Organic soils, also referred to as histosols, include all soils with more than 12 to 20 percent organic C by weight, depending on clay content (NRCS 1999, Brady and Weil 1999). The organic layer of these soils can be very deep (i.e., several meters), forming under inundated conditions in which minimal decomposition of plant residue occurs. When organic soils are prepared for crop production, they are drained and tilled, leading to aeration of the soil, which accelerates the rate of decomposition and CO_2 emissions. Because of the depth and richness of the organic layers, C loss from drained organic soils can continue over long periods of time. The rate of CO_2 emissions varies depending on climate and composition (i.e., decomposability) of the organic matter. Also, the use of organic soils for annual crop production leads to higher C loss rates than drainage of organic soils in grassland or forests, due to deeper drainage and more intensive management practices in cropland (Armentano and Verhoeven 1990, as cited in IPCC/UNEP/OECD/IEA 1997). Carbon losses are estimated from drained organic soils under both grassland and cropland management in this Inventory.

Cropland Remaining Cropland includes all cropland in an inventory year that had been cropland for the last 20 years[180] according to the USDA NRI land-use survey (USDA-NRCS 2000). The Inventory includes all privately-owned croplands in the conterminous United States and Hawaii, but there is a minor amount of cropland on federal lands that is not currently included in the estimation of C stock changes, leading to a discrepancy between the total amount of managed area in *Cropland Remaining Cropland* (see Section 7.1) and the cropland area included in the Inventory. It is important to note that plans are being made to include federal croplands in future C inventories.

The area of *Cropland Remaining Cropland* changes through time as land is converted to or from cropland management. CO_2 emissions and removals[181] due to changes in mineral soil C stocks are estimated using a Tier 3 approach for the majority of annual crops. A Tier 2 IPCC method is used for the remaining crops (vegetables, tobacco, perennial/horticultural crops, and rice) not included in the Tier 3 method. In addition, a Tier 2 method is used for very gravelly, cobbly, or shaley soils (i.e., classified as soils that have greater than 35 percent of soil volume comprised of gravel, cobbles, or shale) and for additional changes in mineral soil C stocks that were not addressed with the Tier 3 approach (i.e., change in C stocks after 2003 due to Conservation Reserve Program enrollment). Emissions from organic soils are estimated using a Tier 2 IPCC method.

Of the two sub-source categories, land-use and land management of mineral soils was the most important component of total net C stock change between 1990 and 2009 (see Table 7-17 and Table 7-18). In 2009, mineral soils were estimated to remove 45.1 Tg CO_2 Eq. (12.3 Tg C). This rate of C storage in mineral soils represented about a 20 percent decrease in the rate since the initial reporting year of 1990. Emissions from organic soils were

[179] CO_2 emissions associated with liming are also estimated but are included in a separate section of the report.

[180] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

[181] Note that removals occur through crop and forage uptake of CO_2 into biomass C that is later incorporated into soil pools.

27.7 Tg CO_2 Eq. (7.5 Tg C) in 2009. In total, U.S. agricultural soils in *Cropland Remaining Cropland* removed approximately 17.4 Tg CO_2 Eq. (4.7 Tg C) in 2009.

Table 7-17: Net CO_2 Flux from Soil C Stock Changes in *Cropland Remaining Cropland* (Tg CO_2 Eq.)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(56.8)	(57.9)	(45.9)	(46.8)	(47.3)	(45.7)	(45.1)
Organic Soils	27.4	27.7	27.7	27.7	27.7	27.7	27.7
Total Net Flux	**(29.4)**	**(30.2)**	**(18.3)**	**(19.1)**	**(19.7)**	**(18.1)**	**(17.4)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

Table 7-18: Net CO_2 Flux from Soil C Stock Changes in *Cropland Remaining Cropland* (Tg C)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(15.5)	(15.8)	(12.5)	(12.8)	(12.9)	(12.5)	(12.3)
Organic Soils	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Total Net Flux	**(8.0)**	**(8.2)**	**(5.0)**	**(5.2)**	**(5.4)**	**(4.9)**	**(4.7)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

The net reduction in soil C accumulation over the time series (39 percent from 1990 to 2009) was largely due to the declining influence of annual cropland enrolled in the Conservation Reserve Program, which began in the late 1980s. However, there were still positive increases in C stocks from land enrolled in the reserve program, as well as intensification of crop production by limiting the use of bare-summer fallow in semi-arid regions, increased hay production, and adoption of conservation tillage (i.e., reduced- and no-till practices).

The spatial variability in annual CO_2 flux associated with C stock changes in mineral and organic soils is displayed in Figure 7-5 and Figure 7-6. The highest rates of net C accumulation in mineral soils occurred in the Midwest, which is the area with the largest amounts of cropland managed with conservation tillage. Rates were also high in the Great Plains due to enrollment in the Conservation Reserve Program. Emission rates from drained organic soils were highest along the southeastern coastal region, in the northeast central United States surrounding the Great Lakes, and along the central and northern portions of the West Coast.

Figure 7-5: Total Net Annual CO_2 Flux for Mineral Soils under Agricultural Management within States, 2009, *Cropland Remaining Cropland*

Figure 7-6: Total Net Annual CO_2 Flux for Organic Soils under Agricultural Management within States, 2009, *Cropland Remaining Cropland*

Methodology

The following section includes a description of the methodology used to estimate changes in soil C stocks due to: (1) agricultural land-use and management activities on mineral soils; and (2) agricultural land-use and management activities on organic soils for *Cropland Remaining Cropland.*

Soil C stock changes were estimated for *Cropland Remaining Cropland* (as well as agricultural land falling into the IPCC categories *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland*) according to land-use histories recorded in the USDA National Resources Inventory (NRI) survey (USDA-NRCS 2000). The NRI is a statistically-based sample of all non-federal land, and includes approximately 260,000 points in agricultural land for the conterminous United States and Hawaii.[182] Each point is associated with an "expansion factor" that allows scaling of C stock changes from NRI points to the entire country (i.e., each expansion factor represents the amount of area with the same land-use/management history as the sample point). Land-use and some

[182] NRI points were classified as agricultural if under grassland or cropland management between 1990 and 2003.

management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. For cropland, data were collected for 4 out of 5 years in the cycle (i.e., 1979-1982, 1984-1987, 1989-1992, and 1994-1997). However, the NRI program began collecting annual data in 1998, and data are currently available through 2003. NRI points were classified as *Cropland Remaining Cropland* in a given year between 1990 and 2009 if the land use had been cropland for 20 years.[183] Cropland includes all land used to produce food and fiber, or forage that is harvested and used as feed (e.g., hay and silage).

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach was applied to estimate C stock changes for mineral soils used to produce a majority of annual crops in the United States (Ogle et al. 2010). The remaining crops on mineral soils were estimated using an IPCC Tier 2 method (Ogle et al. 2003), including vegetables, tobacco, perennial/horticultural crops, rice, and crops rotated with these crops. The Tier 2 method was also used for very gravelly, cobbly, or shaley soils (greater than 35 percent by volume). Mineral SOC stocks were estimated using a Tier 2 method for these areas because the Century model, which is used for the Tier 3 method, has not been fully tested to address its adequacy for estimating C stock changes associated with certain crops and rotations, as well as cobbly, gravelly, or shaley soils. An additional stock change calculation was made for mineral soils using Tier 2 emission factors, accounting for enrollment patterns in the Conservation Reserve Program after 2003, which was not addressed by the Tier 3 methods.

Further elaboration on the methodology and data used to estimate stock changes from mineral soils are described below and in Annex 3.13.

Tier 3 Approach

Mineral SOC stocks and stock changes were estimated using the Century biogeochemical model (Parton et al. 1987, 1988, 1994; Metherell et al. 1993), which simulates the dynamics of C and other elements in cropland, grassland, forest, and savanna ecosystems. It uses monthly weather data as an input, along with information about soil physical properties. Input data on land use and management are specified at monthly resolution and include land-use type, crop/forage type, and management activities (e.g., planting, harvesting, fertilization, manure amendments, tillage, irrigation, residue removal, grazing, and fire). The model computes net primary productivity and C additions to soil, soil temperature, and water dynamics, in addition to turnover, stabilization, and mineralization of soil organic matter C and nutrient (N, K, S) elements. This method is more accurate than the Tier 1 and 2 approaches provided by the IPCC, because the simulation model treats changes as continuous over time rather than the simplified discrete changes represented in the default method (see Box 7-3 for additional information). National estimates were obtained by simulating historical land-use and management patterns as recorded in the USDA National Resources Inventory (NRI) survey.

[BEGIN BOX]

Box 7-3: Tier 3 Approach for Soil C Stocks Compared to Tier 1 or 2 Approaches

A Tier 3 model-based approach is used to inventory soil C stock changes on the majority of agricultural land with mineral soils. This approach entails several fundamental differences compared to the IPCC Tier 1 or 2 methods, which are based on a classification of land areas into a number of discrete classes based on a highly aggregated classification of climate, soil, and management (i.e., only six climate regions, seven soil types and eleven management systems occur in U.S. agricultural land under the IPCC classification). Input variables to the Tier 3 model, including climate, soils, and management activities (e.g., fertilization, crop species, tillage, etc.), are represented in considerably more detail both temporally and spatially, and exhibit multi-dimensional interactions through the more complex model structure compared with the IPCC Tier 1 or 2 approach. The spatial resolution of

[183] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began. Therefore, the classification prior to 2002 was based on less than 20 years of recorded land-use history for the time series.

the analysis is also finer in the Tier 3 method compared to the lower tier methods as implemented in the United States for previous Inventories (e.g., 3,037 counties versus 181 Major Land Resource Areas (MLRAs), respectively).

In the Century model, soil C dynamics (and CO_2 emissions and uptake) are treated as continuous variables, which change on a monthly time step. Carbon emissions and removals are an outcome of plant production and decomposition processes, which are simulated in the model structure. Thus, changes in soil C stocks are influenced by not only changes in land use and management but also inter-annual climate variability and secondary feedbacks between management activities, climate, and soils as they affect primary production and decomposition. This latter characteristic constitutes one of the greatest differences between the methods, and forms the basis for a more complete accounting of soil C stock changes in the Tier 3 approach compared with Tier 2 methodology.

Because the Tier 3 model simulates a continuous time period rather than the equilibrium step change used in the IPCC methodology (Tier 1 and 2), the Tier 3 model addresses the delayed response of soils to management and land-use changes. Delayed responses can occur due to variable weather patterns and other environmental constraints that interact with land use and management and affect the time frame over which stock changes occur. Moreover, the Tier 3 method also accounts for the overall effect of increasing yields and, hence, C input to soils that have taken place across management systems and crop types within the United States. Productivity has increased by 1 to 2 percent annually over the past 4 to 5 decades for most major crops in the United States (Reilly and Fuglie 1998), which is believed to have led to increases in cropland soil C stocks (e.g., Allmaras et al. 2000). This is a major difference from the IPCC-based Tier 1 and 2 approaches, in which trends in soil C stocks only capture discrete changes in management and/or land use, rather than a longer term trend such as gradual increases in crop productivity.

[END BOX]

Additional sources of activity data were used to supplement the land-use information from NRI. The Conservation Technology Information Center (CTIC 1998) provided annual data on tillage activity at the county level since 1989, with adjustments for long-term adoption of no-till agriculture (Towery 2001). Information on fertilizer use and rates by crop type for different regions of the United States were obtained primarily from the USDA Economic Research Service Cropping Practices Survey (ERS 1997) with additional data from other sources, including the National Agricultural Statistics Service (NASS 1992, 1999, 2004). Frequency and rates of manure application to cropland during 1997 were estimated from data compiled by the USDA Natural Resources Conservation Service (Edmonds et al. 2003), and then adjusted using county-level estimates of manure available for application in other years. Specifically, county-scale ratios of manure available for application to soils in other years relative to 1997 were used to adjust the area amended with manure (see Annex 3.13 for further details). Greater availability of managed manure N relative to 1997 was, thus, assumed to increase the area amended with manure, while reduced availability of manure N relative to 1997 was assumed to reduce the amended area. The amount of manure produced by each livestock type was calculated for managed and unmanaged waste management systems based on methods described in the Manure Management section (Section 6.2) and annex (Annex 3.10).

Manure amendments were an input to the Century Model based on manure N available for application from all managed or unmanaged systems except Pasture/Range/Paddock.[184] Data on the county-level N available for application were estimated for managed systems based on the total amount of N excreted in manure minus N losses during storage and transport, and including the addition of N from bedding materials. Nitrogen losses include direct nitrous oxide emissions, volatilization of ammonia and NO_x, runoff and leaching, and poultry manure used as a feed supplement. More information on these losses is available in the description of the Manure Management source category. For unmanaged systems, it is assumed that no N losses or additions occur prior to the application of manure to the soil.

Monthly weather data were used as an input in the model simulations, based on an aggregation of gridded weather data to the county scale from the Parameter-elevation Regressions on Independent Slopes Model (PRISM) database

[184] Pasture/Range/Paddock manure additions to soils are addressed in the *Grassland Remaining Grassland* and *Land Converted to Grassland* categories.

(Daly et al. 1994). Soil attributes, which were obtained from an NRI database, were assigned based on field visits and soil series descriptions. Each NRI point was run 100 times as part of the uncertainty assessment, yielding a total of over 18 million simulation runs for the analysis. Carbon stock estimates from Century were adjusted using a structural uncertainty estimator accounting for uncertainty in model algorithms and parameter values (Ogle et al. 2007, 2010). C stocks and 95 percent confidence intervals were estimated for each year between 1990 and 2003, but C stock changes from 2004 to 2009 were assumed to be similar to 2003 because no additional activity data are currently available from the NRI for the latter years.

Tier 2 Approach

In the IPCC Tier 2 method, data on climate, soil types, land-use, and land management activity were used to classify land area to apply appropriate stock change factors. MLRAs formed the base spatial unit for mapping climate regions in the United States; each MLRA represents a geographic unit with relatively similar soils, climate, water resources, and land uses (NRCS 1981). MLRAs were classified into climate regions according to the IPCC categories using the PRISM climate database of Daly et al. (1994).

Reference C stocks were estimated using the National Soil Survey Characterization Database (NRCS 1997) with cultivated cropland as the reference condition, rather than native vegetation as used in IPCC (2003, 2006). Changing the reference condition was necessary because soil measurements under agricultural management are much more common and easily identified in the National Soil Survey Characterization Database (NRCS 1997) than those that are not considered cultivated cropland.

U.S.-specific stock change factors were derived from published literature to determine the impact of management practices on SOC storage, including changes in tillage, cropping rotations and intensification, and land-use change between cultivated and uncultivated conditions (Ogle et al. 2003, Ogle et al. 2006). U.S. factors associated with organic matter amendments were not estimated because there were an insufficient number of studies to analyze those impacts. Instead, factors from IPCC (2003) were used to estimate the effect of those activities. Euliss and Gleason (2002) provided the data for computing the change in SOC storage resulting from restoration of wetland enrolled in the Conservation Reserve Program.

Activity data were primarily based on the historical land-use/management patterns recorded in the NRI. Each NRI point was classified by land use, soil type, climate region (using PRISM data, Daly et al. 1994) and management condition. Classification of cropland area by tillage practice was based on data from the Conservation Tillage Information Center (CTIC 1998, Towery 2001) as described above. Activity data on wetland restoration of Conservation Reserve Program land were obtained from Euliss and Gleason (2002). Manure N amendments over the inventory time period were based on application rates and areas amended with manure N from Edmonds et al. (2003), in addition to the managed manure production data discussed in the previous methodology subsection on the Tier 3 analysis for mineral soils.

Combining information from these data sources, SOC stocks for mineral soils were estimated 50,000 times for 1982, 1992, and 1997, using a Monte Carlo simulation approach and the probability distribution functions for U.S.-specific stock change factors, reference C stocks, and land-use activity data (Ogle et al. 2002, Ogle et al. 2003). The annual C flux for 1990 through 1992 was determined by calculating the average annual change in stocks between 1982 and 1992; annual C flux for 1993 through 2009 was determined by calculating the average annual change in stocks between 1992 and 1997.

Additional Mineral C Stock Change

Annual C flux estimates for mineral soils between 1990 and 2009 were adjusted to account for additional C stock changes associated with gains or losses in soil C after 2003 due to changes in Conservation Reserve Program enrollment. The change in enrollment acreage relative to 2003 was based on data from USDA-FSA (2009) for 2004 through 2009, and the differences in mineral soil areas were multiplied by 0.5 metric tons C per hectare per year to estimate the net effect on soil C stocks. The stock change rate is based on estimations using the IPCC method (see Annex 3.13 for further discussion).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Cropland Remaining Cropland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), with U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC

rates. The final estimates included a measure of uncertainty as determined from the Monte Carlo simulation with 50,000 iterations. Emissions were based on the 1992 and 1997 *Cropland Remaining Cropland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty associated with the *Cropland Remaining Cropland* land-use category was addressed for changes in agricultural soil C stocks (including both mineral and organic soils). Uncertainty estimates are presented in Table 7-19 for mineral soil C stocks and organic soil C stocks disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006). The combined uncertainty was calculated by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. More details on how the individual uncertainties were developed are in Annex 3.13. The combined uncertainty for soil C stocks in *Cropland Remaining Cropland* ranged from 172 percent below to 167 percent above the 2009 stock change estimate of -17.4 Tg CO_2 Eq.

Table 7-19: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Cropland Remaining Cropland* (Tg CO_2 Eq. and Percent)

Source	2009 Flux Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)		Uncertainty Range Relative to Flux Estimate (%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mineral Soil C Stocks: Cropland Remaining Cropland, Tier 3 Inventory Methodology	(42.3)	(69.6)	(15.1)	-64%	+64%
Mineral Soil C Stocks: Cropland Remaining Cropland, Tier 2 Inventory Methodology	(3.0)	(6.9)	0.8	-127%	+128%
Mineral Soil C Stocks: Cropland Remaining Cropland (Change in CRP enrollment relative to 2003)	(0.3)	(0.1)	(0.4)	-50%	+50%
Organic Soil C Stocks: Cropland Remaining Cropland, Tier 2 Inventory Methodology	27.7	15.8	36.9	-43%	+33%
Combined Uncertainty for Flux associated with Agricultural Soil Carbon Stock Change in Cropland Remaining Cropland	**(17.4)**	**(47.3)**	**11.6**	**-172%**	**+167%**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

Quality control measures included checking input data, model scripts, and results to ensure data were properly handled throughout the inventory process. As discussed in the uncertainty section, results were compared to field measurements, and a statistical relationship was developed to assess uncertainties in the model's predictive capability. The comparisons included over 40 long-term experiments, representing about 800 combinations of management treatments across all of the sites (Ogle et al. 2007). Inventory reporting forms and text were reviewed and revised as needed to correct transcription errors.

Planned Improvements

The first improvement is to update the Tier 2 inventory analysis with the latest annual National Resources Inventory (NRI) data. While the land base for the Tier 3 approach uses the latest available data from the NRI, the Tier 2 portion of the Inventory has not updated and is based on the Revised 1997 NRI data product (USDA-NRCS 2000).

This improvement will extend the time series of the land use data from 1997 through 2003 for the Tier 2 portion of the Inventory.

The second improvement is to incorporate remote sensing in the analysis for estimation of crop and forage production, and conduct the Tier 3 assessment of soil C stock changes and soil nitrous oxide emissions in a single analysis. Specifically, the Enhanced Vegetation Index (EVI) product that is derived from MODIS satellite imagery is being used to refine the production estimation for the Tier 3 assessment framework based on the DAYCENT simulation model. EVI reflects changes in plant "greenness" over the growing season and can be used to compute production based on the light use efficiency of the crop or forage (Potter et al. 1993). In the current framework, production is simulated based on the weather data, soil characteristics, and the genetic potential of the crop. While this method produces reasonable results, remote sensing can be used to refine the productivity estimates and reduce biases in crop production and subsequent C input to soil systems. It is anticipated that precision in the Tier 3 assessment framework will be increased by 25 percent or more with the new method. In addition, DAYCENT is currently used for estimating soil nitrous oxide emissions in the Inventory, and can also be used to estimate soil organic C stock changes using the same algorithms in the CENTURY model. Simulating both soil C stock changes and nitrous oxide emissions in a single analysis will ensure consistency in the treatment of these sources, which are coupled through the N and C cycles in agricultural systems.

CO_2 Emissions from Agricultural Liming

IPCC (2006) recommends reporting CO_2 emissions from lime additions (in the form of crushed limestone ($CaCO_3$) and dolomite ($CaMg(CO_3)_2$) to agricultural soils. Limestone and dolomite are added by land managers to ameliorate acidification. When these compounds come in contact with acid soils, they degrade, thereby generating CO_2. The rate and ultimate magnitude of degradation of applied limestone and dolomite depends on the soil conditions, climate regime, and the type of mineral applied. Emissions from liming have fluctuated over the past nineteen years, ranging from 3.8 Tg CO_2 Eq. to 5.0 Tg CO_2 Eq. In 2009, liming of agricultural soils in the United States resulted in emissions of 4.2 Tg CO_2 Eq. (1.2 Tg C), representing about a 10 percent decrease in emissions since 1990 (see Table 7-20 and Table 7-21). The trend is driven entirely by the amount of lime and dolomite estimated to have been applied to soils over the time period.

Table 7-20: Emissions from Liming of Agricultural Soils (Tg CO_2 Eq.)

Source	1990		2000		2005	2006	2007	2008	2009
Liming of Soils[1]	4.7		4.3		4.3	4.2	4.5	5.0	4.2

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.
[1] Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland,* and *Settlements Remaining Settlements*.

Table 7-21: Emissions from Liming of Agricultural Soils (Tg C)

Source	1990		2000		2005	2006	2007	2008	2009
Liming of Soils[1]	1.3		1.2		1.2	1.2	1.2	1.4	1.2

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.
[1] Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland,* and *Settlements Remaining Settlements*.

Methodology

CO_2 emissions from degradation of limestone and dolomite applied to agricultural soils were estimated using a Tier 2 methodology consistent with IPCC (2006). The annual amounts of limestone and dolomite applied (see Table 7-22) were multiplied by CO_2 emission factors from West and McBride (2005). These emission factors (0.059 metric ton C/metric ton limestone, 0.064 metric ton C/metric ton dolomite) are lower than the IPCC default emission factors because they account for the portion of agricultural lime that may leach through the soil and travel by rivers to the ocean (West and McBride 2005). This analysis of lime dissolution is based on liming occurring in the Mississippi River basin, where the vast majority of all U.S. liming takes place (West 2008). U.S. liming that does not occur in the Mississippi River basin tends to occur under similar soil and rainfall regimes, and, thus, the emission factor is appropriate for use across the United States (West 2008). The annual application rates of limestone and dolomite were derived from estimates and industry statistics provided in the *Minerals Yearbook* and *Mineral Industry Surveys* (Tepordei 1993 through 2006; Willett 2007a, b, 2009 through 2010; USGS 2008 through

2010). To develop these data, the U.S. Geological Survey (USGS; U.S. Bureau of Mines prior to 1997) obtained production and use information by surveying crushed stone manufacturers. Because some manufacturers were reluctant to provide information, the estimates of total crushed limestone and dolomite production and use were divided into three components: (1) production by end-use, as reported by manufacturers (i.e., "specified" production); (2) production reported by manufacturers without end-uses specified (i.e., "unspecified" production); and (3) estimated additional production by manufacturers who did not respond to the survey (i.e., "estimated" production).

The "unspecified" and "estimated" amounts of crushed limestone and dolomite applied to agricultural soils were calculated by multiplying the percentage of total "specified" limestone and dolomite production applied to agricultural soils by the total amounts of "unspecified" and "estimated" limestone and dolomite production. In other words, the proportion of total "unspecified" and "estimated" crushed limestone and dolomite that was applied to agricultural soils (as opposed to other uses of the stone) was assumed to be proportionate to the amount of "specified" crushed limestone and dolomite that was applied to agricultural soils. In addition, data were not available for 1990, 1992, and 2009 on the fractions of total crushed stone production that were limestone and dolomite, and on the fractions of limestone and dolomite production that were applied to soils. To estimate the 1990 and 1992 data, a set of average fractions were calculated using the 1991 and 1993 data. These average fractions were applied to the quantity of "total crushed stone produced or used" reported for 1990 and 1992 in the 1994 *Minerals Yearbook* (Tepordei 1996). To estimate 2009 data, the previous year's fractions were applied to a 2009 estimate of total crushed stone presented in the USGS *Mineral Industry Surveys: Crushed Stone and Sand and Gravel in the First Quarter of 2010* (USGS 2010); thus, the 2009 data in Table 7-20 through Table 7-22 are shaded to indicate that they are based on a combination of data and projections.

The primary source for limestone and dolomite activity data is the *Minerals Yearbook*, published by the Bureau of Mines through 1994 and by the USGS from 1995 to the present. In 1994, the "Crushed Stone" chapter in the *Minerals Yearbook* began rounding (to the nearest thousand metric tons) quantities for total crushed stone produced or used. It then reported revised (rounded) quantities for each of the years from 1990 to 1993. In order to minimize the inconsistencies in the activity data, these revised production numbers have been used in all of the subsequent calculations. Since limestone and dolomite activity data are also available at the state level, the national-level estimates reported here were broken out by state, although state-level estimates are not reported here.

Table 7-22: Applied Minerals (Million Metric Tons)

Mineral	1990		2000		2005	2006	2007	2008	2009
Limestone	19.01		15.86		18.09	16.54	17.46	20.55	17.20
Dolomite	2.36		3.81		1.85	2.73	2.92	2.54	2.13

Note: These numbers represent amounts applied to *Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland*, and *Settlements Remaining Settlements*. Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

Uncertainty and Time-Series Consistency

Uncertainty regarding limestone and dolomite activity data inputs was estimated at ±15 percent and assumed to be uniformly distributed around the inventory estimate (Tepordei 2003b). Analysis of the uncertainty associated with the emission factors included the following: the fraction of agricultural lime dissolved by nitric acid versus the fraction that reacts with carbonic acid, and the portion of bicarbonate that leaches through the soil and is transported to the ocean. Uncertainty regarding the time associated with leaching and transport was not accounted for, but should not change the uncertainty associated with CO_2 emissions (West 2005). The uncertainties associated with the fraction of agricultural lime dissolved by nitric acid and the portion of bicarbonate that leaches through the soil were each modeled as a smoothed triangular distribution between ranges of zero percent to 100 percent. The uncertainty surrounding these two components largely drives the overall uncertainty estimates reported below. More information on the uncertainty estimates for Liming of Agricultural Soils is contained within the Uncertainty Annex.

A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the uncertainty of CO_2 emissions from liming. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-23. CO_2 emissions from Liming of Agricultural Soils in 2008 were estimated to be between 0.1 and 8.4 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of 97 percent below to 99 percent above the 2009 emission estimate of 4.2 Tg CO_2 Eq.

Table 7-23: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Liming of Agricultural Soils (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emissions Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Liming of Agricultural Soils[1]	CO_2	4.2	0.1	8.4	-97%	+99%

[a]Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
[1] Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland,* and *Settlements Remaining Settlements*.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. The QA/QC analysis did not reveal any inaccuracies or incorrect input values.

Recalculations Discussion

Several adjustments were made in the current Inventory to improve the results. The quantity of applied minerals reported in the previous Inventory for 2007 has been revised; the updated activity data for 2007 are approximately 1,480 thousand metric tons greater than the data used for the previous Inventory, consequently, the reported emissions resulting from liming in 2007 increased by about 8.4 percent. In the previous Inventory, to estimate 2008 data, the previous year's fractions were applied to a 2008 estimate of total crushed stone presented in the USGS *Mineral Industry Surveys: Crushed Stone and Sand and Gravel in the First Quarter of 2009* (USGS 2009). Since publication of the previous Inventory, the *Minerals Yearbook* has published actual quantities of crushed stone sold or used by producers in the United States in 2008. These values have replaced those used in the previous Inventory to calculate the quantity of minerals applied to soil and the emissions from liming. The updated activity data for 2008 are approximately 5,460 thousand metric tons greater than the data used in the previous Inventory. As a result, the reported emissions from liming in 2008 increased by about 36 percent.

CO_2 Emissions from Urea Fertilization

The use of urea ($CO(NH_2)_2$) as fertilizer leads to emissions of CO_2 that was fixed during the industrial production process. Urea in the presence of water and urease enzymes is converted into ammonium (NH_4^+), hydroxyl ion (OH^-), and bicarbonate (HCO_3^-). The bicarbonate then evolves into CO_2 and water. Emissions from urea fertilization in the United States totaled 3.6 Tg CO_2 Eq. (1.0 Tg C) in 2009 (Table 7-24 and Table 7-25). Emissions from urea fertilization have grown 49 percent between 1990 and 2009, due to an increase in the use of urea as fertilizer.

Table 7-24: CO_2 Emissions from Urea Fertilization in *Cropland Remaining Cropland* (Tg CO_2 Eq.)

Source	1990		2000		2005	2006	2007	2008	2009
Urea Fertilization[1]	2.4		3.2		3.5	3.7	3.7	3.6	3.6

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.
[1] Also includes emissions from urea fertilization on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Forest Land Remaining Forest Land*.

Table 7-25: CO_2 Emissions from Urea Fertilization in *Cropland Remaining Cropland* (Tg C)

Source	1990		2000		2005	2006	2007	2008	2009
Urea Fertilization[1]	0.7		0.9		1.0	1.0	1.0	1.0	1.0

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.
[1] Also includes emissions from urea fertilization on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Forest Land Remaining Forest Land*.

Methodology

Carbon dioxide emissions from the application of urea to agricultural soils were estimated using the IPCC (2006) Tier 1 methodology. The annual amounts of urea fertilizer applied (see Table 7-26) were derived from state-level fertilizer sales data provided in *Commercial Fertilizers* (TVA 1991, 1992, 1993, 1994; AAPFCO 1995 through 2010) and were multiplied by the default IPCC (2006) emission factor of 0.20, which is equal to the C content of urea on an atomic weight basis. Because fertilizer sales data are reported in fertilizer years (July through June), a calculation was performed to convert the data to calendar years (January through December). According to historic monthly fertilizer use data (TVA 1992b), 65 percent of total fertilizer used in any fertilizer year is applied between January and June of that calendar year, and 35 percent of total fertilizer used in any fertilizer year is applied between July and December of the previous calendar year. Fertilizer sales data for the 2009 fertilizer year were not available in time for publication. Accordingly, urea application in the 2009 fertilizer year was assumed to be equal to that of the 2008 fertilizer year. Since 2010 fertilizer year data were not available, July through December 2009 fertilizer consumption was assumed to be equal to July through December 2008 fertilizer consumption; thus, the 2009 data in Table 7-24 through Table 7-26 are shaded to indicate that they are based on a combination of data and projections. State-level estimates of CO_2 emissions from the application of urea to agricultural soils were summed to estimate total emissions for the entire United States.

Table 7-26: Applied Urea (Million Metric Tons)

	1990	2000	2005	2006	2007	2008	2009
Urea Fertilizer[1]	3.30	4.38	4.78	4.98	5.10	4.92	4.92

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.
[1]These numbers represent amounts applied to all agricultural land, including *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Forest Land Remaining Forest Land*.

Uncertainty and Time-Series Consistency

Uncertainty estimates are presented in Table 7-27 for Urea Fertilization. A Tier 2 Monte Carlo analysis was completed. The largest source of uncertainty was the default emission factor, which assumes that 100 percent of the C applied to soils is ultimately emitted into the environment as CO_2. This factor does not incorporate the possibility that some of the C may be retained in the soil. The emission estimate is, thus, likely to be high. In addition, each urea consumption data point has an associated uncertainty. Urea for non-fertilizer use, such as aircraft deicing, may be included in consumption totals; it was determined through personal communication with Fertilizer Regulatory Program Coordinator David L. Terry (2007), however, that this amount is most likely very small. Research into aircraft deicing practices also confirmed that urea is used minimally in the industry; a 1992 survey found a known annual usage of approximately 2,000 tons of urea for deicing; this would constitute 0.06 percent of the 1992 consumption of urea (EPA 2000). Similarly, surveys conducted from 2002 to 2005 indicate that total urea use for deicing at U.S. airports is estimated to be 3,740 MT per year, or less than 0.07 percent of the fertilizer total for 2007 (Itle 2009). Lastly, there is uncertainty surrounding the assumptions behind the calculation that converts fertilizer years to calendar years. CO_2 emissions from urea fertilization of agricultural soils in 2009 were estimated to be between 2.1 and 3.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of 43 percent below to 3 percent above the 2009 emission estimate of 3.6 Tg CO_2 Eq.

Table 7-27: Quantitative Uncertainty Estimates for CO_2 Emissions from Urea Fertilization (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emissions Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emissions Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Urea Fertilization	CO_2	3.6	2.1	3.7	-43%	+3%

[a]Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
Note: These numbers represent amounts applied to all agricultural land, *including Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Forest Land Remaining Forest Land*.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. Inventory reporting forms and text were reviewed. No errors were found.

Recalculations Discussion

July to December 2007 urea application data were updated with assumptions for fertilizer year 2008, and the 2007 emission estimate was revised accordingly. The activity data decreased about 800,000 metric tons for 2007 and this change resulted in an approximately 3 percent decrease in emissions in 2007 relative to the previous Inventory. In the previous Inventory, the application for this period was calculated based on application during July to December 2006. January to June 2008 data were also used to update 2008 emission estimates. The activity data decreased about 270,000 metric tons for 2008, resulting in an approximately 5 percent decrease in emissions in 2008 relative to the previous Inventory.

Planned Improvements

The primary planned improvement is to investigate using a Tier 2 or Tier 3 approach, which would utilize country-specific information to estimate a more precise emission factor.

7.5. Land Converted to Cropland (IPCC Source Category 5B2)

Land Converted to Cropland includes all cropland in an inventory year that had been another land use at any point during the previous 20 years[185] according to the USDA NRI land-use survey (USDA-NRCS 2000). Consequently, lands are retained in this category for 20 years as recommended by the IPCC guidelines (IPCC 2006) unless there is another land-use change. The Inventory includes all privately-owned croplands in the conterminous United States and Hawaii, but there is a minor amount of cropland on federal lands that is not currently included in the estimation of C stock changes, leading to a discrepancy between the total amount of managed area in *Land Converted to Cropland* (see Section 7.1) and the cropland area included in the Inventory. It is important to note that plans are being made to include these areas in future C inventories.

Background on agricultural C stock changes is provided in *Cropland Remaining Cropland* and will only be summarized here for *Land Converted to Cropland*. Soils are the largest pool of C in agricultural land, and also have the greatest potential for storage or release of C, because biomass and dead organic matter C pools are relatively small and ephemeral compared with soils. The IPCC (2006) recommends reporting changes in soil organic C stocks due to: (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.[186]

Land-use and management of mineral soils in *Land Converted to Cropland* generally led to relatively small increases in soil C during the 1990s but the pattern changed to small losses of C through the latter part of the time series (Table 7-28 and Table 7-29). The total rate of change in soil C stocks was 5.9 Tg CO_2 Eq. (1.6 Tg C) in 2009. Mineral soils were estimated to lose 3.3 Tg CO_2 Eq. (0.9 Tg C) in 2009, while drainage and cultivation of organic soils led to annual losses of 2.6 Tg CO_2 Eq. (0.7 Tg C) in 2009.

Table 7-28: Net CO_2 Flux from Soil C Stock Changes in Land *Converted to Cropland* (Tg CO_2 Eq.)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(0.3)	(0.3)	3.3	3.3	3.3	3.3	3.3
Organic Soils	2.4	2.6	2.6	2.6	2.6	2.6	2.6
Total Net Flux	**2.2**	**2.4**	**5.9**	**5.9**	**5.9**	**5.9**	**5.9**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

Table 7-29: Net CO_2 Flux from Soil C Stock Changes in *Land Converted to Cropland* (Tg C)

[185] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

[186] CO_2 emissions associated with liming are also estimated but included in a separate section of the report.

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(0.1)	(0.1)	0.9	0.9	0.9	0.9	0.9
Organic Soils	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total Net Flux	**0.6**	**0.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

The spatial variability in annual CO_2 flux associated with C stock changes in mineral and organic soils for *Land Converted to Cropland* is displayed in Figure 7-7 and Figure 7-8. While a large portion of the United States had net losses of soil C for *Land Converted to Cropland*, there were some notable areas with net C accumulation in the Great Plains, Midwest, mid-Atlantic states. These areas were gaining C following conversion, because the land had been brought into hay production, including grass and legume hay, leading to enhanced plant production relative to the previous land use, and thus higher C input to the soil. Emissions from organic soils were largest in California, Florida, and the upper Midwest, which coincided with largest concentrations of cultivated organic soils in the United States.

Figure 7-7: Total Net Annual CO_2 Flux for Mineral Soils under Agricultural Management within States, 2009, *Land Converted to Cropland*

Figure 7-8: Total Net Annual CO_2 Flux for Organic Soils under Agricultural Management within States, 2009, *Land Converted to Cropland*

Methodology

The following section includes a brief description of the methodology used to estimate changes in soil C stocks due to agricultural land-use and management activities on mineral and organic soils for *Land Converted to Cropland*. Further elaboration on the methodologies and data used to estimate stock changes for mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.13.

Soil C stock changes were estimated for *Land Converted to Cropland* according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2000). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. However, the NRI program initiated annual data collection in 1998, and the annual data are currently available through 2003. NRI points were classified as *Land Converted to Cropland* in a given year between 1990 and 2009 if the land use was cropland but had been another use during the previous 20 years. Cropland includes all land used to produce food or fiber, or forage that is harvested and used as feed (e.g., hay and silage).

Mineral Soil Carbon Stock Changes

A Tier 3 model-based approach was applied to estimate C stock changes for soils on *Land Converted to Cropland* used to produce a majority of all crops (Ogle et al. 2010). Soil C stock changes on the remaining soils were estimated with the IPCC Tier 2 method (Ogle et al. 2003), including land used to produce vegetable, tobacco, perennial/horticultural crops, and rice; land on very gravelly, cobbly, or shaley soils (greater than 35 percent by volume); and land converted from forest or federal ownership.[187]

Tier 3 Approach

Mineral SOC stocks and stock changes were estimated using the Century biogeochemical model for the Tier 3

[187] Federal land is not a land use, but rather an ownership designation that is treated as forest or nominal grassland for purposes of these calculations. The specific use for federal lands is not identified in the NRI survey (USDA-NRCS 2000).

methods. National estimates were obtained by using the model to simulate historical land-use change patterns as recorded in the USDA National Resources Inventory (USDA-NRCS 2000). The methods used for *Land Converted to Cropland* are the same as those described in the Tier 3 portion of *Cropland Remaining Cropland* section for mineral soils (see *Cropland Remaining Cropland* Tier 3 methods section and Annex 3.13 for additional information).

Tier 2 Approach

For the mineral soils not included in the Tier 3 analysis, SOC stock changes were estimated using a Tier 2 Approach for *Land Converted to Cropland* as described in the Tier 2 portion of *Cropland Remaining Cropland* section for mineral soils (see *Cropland Remaining Cropland* Tier 2 methods section for additional information).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Land Converted to Cropland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), with U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. The final estimates included a measure of uncertainty as determined from the Monte Carlo simulation with 50,000 iterations. Emissions were based on the 1992 and 1997 *Land Converted to Cropland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty analysis for mineral soil C stock changes using the Tier 3 and Tier 2 approaches were based on the same method described for *Cropland Remaining Cropland*, except that the uncertainty inherent in the structure of the Century model was not addressed. The uncertainty for annual C emission estimates from drained organic soils in *Land Converted to Cropland* was estimated using the Tier 2 approach, as described in the *Cropland Remaining Cropland* section.

Uncertainty estimates are presented in Table 7-30 for each subsource (i.e., mineral soil C stocks and organic soil C stocks) disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in agricultural soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. The combined uncertainty for soil C stocks in *Land Converted to Cropland* was estimated to be 40 percent below and 36 percent above the inventory estimate of 5.9 Tg CO_2 Eq.

Table 7-30: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Land Converted to Cropland* (Tg CO_2 Eq. and Percent)

Source	2009 Flux Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mineral Soil C Stocks: Land Converted to Cropland, Tier 3 Inventory Methodology	(0.8)	(1.5)	(0.1)	-84%	+84%
Mineral Soil C Stocks: Land Converted to Cropland, Tier 2 Inventory Methodology	4.1	2.3	5.8	-44%	+41%
Organic Soil C Stocks: Land Converted to Cropland, Tier 2 Inventory Methodology	2.6	1.2	3.7	-53%	+41%
Combined Uncertainty for Flux associated with Soil Carbon Stock Change in Land Converted to Cropland	**5.9**	**3.5**	**8.1**	**-40%**	**+36%**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section,

above.

QA/QC and Verification

See QA/QC and Verification section under *Cropland Remaining Cropland*.

Planned Improvements

The empirically-based uncertainty estimator described in the *Cropland Remaining Cropland* section for the Tier 3 approach has not been developed to estimate uncertainties related to the structure of the Century model for *Land Converted to Cropland,* but this is a planned improvement. This improvement will produce a more rigorous assessment of uncertainty. See Planned Improvements section under *Cropland Remaining Cropland* for additional planned improvements.

7.6. Grassland Remaining Grassland (IPCC Source Category 5C1)

Grassland Remaining Grassland includes all grassland in an inventory year that had been grassland for the previous 20 years[188] according to the USDA NRI land use survey (USDA-NRCS 2000). The Inventory includes all privately-owned grasslands in the conterminous United States and Hawaii, but does not address changes in C stocks for grasslands on federal lands, leading to a discrepancy between the total amount of managed area in *Grassland Remaining Grassland* (see Section 7.1) and the grassland area included in the Inventory. While federal grasslands probably have minimal changes in land management and C stocks, plans are being made to further evaluate and potentially include these areas in future C inventories.

Background on agricultural C stock changes is provided in the *Cropland Remaining Cropland* section and will only be summarized here for *Grassland Remaining Grassland*. Soils are the largest pool of C in agricultural land, and also have the greatest potential for storage or release of C, because biomass and dead organic matter C pools are relatively small and ephemeral compared to soils. IPCC (2006) recommends reporting changes in soil organic C stocks due to: (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.[189]

Land-use and management of mineral soils in *Grassland Remaining Grassland* increased soil C, while organic soils lost relatively small amounts of C in each year 1990 through 2009. Due to the pattern for mineral soils, the overall trend was a gain in soil C over the time series although the rates varied from year to year, with a net removal of 8.3 Tg CO_2 Eq. (2.3 Tg C) in 2009. There was considerable variation over the time series driven by variability in weather patterns and associated interaction with land management activity. The change rates on per hectare basis were small, however, even in the years with larger total changes in stocks. Overall, flux rates declined by 43.8 Tg CO_2 Eq. (12.0 Tg C) when comparing the net change in soil C from 1990 and 2009.

Table 7-31: Net CO_2 Flux from Soil C Stock Changes in *Grassland Remaining Grassland* (Tg CO_2 Eq.)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(56.0)	(56.3)	(12.6)	(12.4)	(12.3)	(12.2)	(12.0)
Organic Soils	3.9	3.7	3.7	3.7	3.7	3.7	3.7
Total Net Flux	**(52.2)**	**(52.6)**	**(8.9)**	**(8.8)**	**(8.6)**	**(8.5)**	**(8.3)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

Table 7-32: Net CO_2 Flux from Soil C Stock Changes in Grassland Remaining Grassland (Tg C)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(15.3)	(15.3)	(3.4)	(3.4)	(3.4)	(3.3)	(3.3)
Organic Soils	1.1	1.0	1.0	1.0	1.0	1.0	1.0
Total Net Flux	**(14.2)**	**(14.3)**	**(2.4)**	**(2.4)**	**(2.3)**	**(2.3)**	**(2.3)**

[188] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

[189] CO_2 emissions associated with liming are also estimated but included in a separate section of the report.

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

The spatial variability in annual CO_2 flux associated with C stock changes in mineral and organic soils is displayed in Figure 7-9 and Figure 7-10. Grassland gained soil organic C in several regions during 2009, including the Northeast, Midwest, Southwest and far western states; although these were relatively small increases in C on a per-hectare basis. Emission rates from drained organic soils were highest along the southeastern coastal region, in the northeast central United States surrounding the Great Lakes, and along the central and northern portions of the West Coast.

Figure 7-9: Total Net Annual CO_2 Flux for Mineral Soils under Agricultural Management within States, 2009, *Grassland Remaining Grassland*

Figure 7-10: Total Net Annual CO_2 Flux for Organic Soils under Agricultural Management within States, 2009, *Grassland Remaining Grassland*

Methodology

The following section includes a brief description of the methodology used to estimate changes in soil C stocks due to agricultural land-use and management activities on mineral and organic soils for *Grassland Remaining Grassland*. Further elaboration on the methodologies and data used to estimate stock changes from mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.13.

Soil C stock changes were estimated for *Grassland Remaining Grassland* according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2000). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. However, the NRI program initiated annual data collection in 1998, and the annual data are currently available through 2003. NRI points were classified as *Grassland Remaining Grassland* in a given year between 1990 and 2009 if the land use had been grassland for 20 years. Grassland includes pasture and rangeland used for grass forage production, where the primary use is livestock grazing. Rangelands are typically extensive areas of native grassland that are not intensively managed, while pastures are often seeded grassland, possibly following tree removal, that may or may not be improved with practices such as irrigation and interseeding legumes.

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach was applied to estimate C stock changes for most mineral soils in *Grassland Remaining Grassland*. The C stock changes for the remaining soils were estimated with an IPCC Tier 2 method (Ogle et al. 2003), including gravelly, cobbly, or shaley soils (greater than 35 percent by volume) and additional stock changes associated with sewage sludge amendments.

Tier 3 Approach

Mineral soil organic C stocks and stock changes for *Grassland Remaining Grassland* were estimated using the Century biogeochemical model, as described in *Cropland Remaining Cropland*. Historical land-use and management patterns were used in the Century simulations as recorded in the USDA National Resources Inventory (NRI) survey, with supplemental information on fertilizer use and rates from the USDA Economic Research Service Cropping Practices Survey (ERS 1997) and National Agricultural Statistics Service (NASS 1992, 1999, 2004). Frequency and rates of manure application to grassland during 1997 were estimated from data compiled by the USDA Natural Resources Conservation Service (Edmonds, et al. 2003), and then adjusted using county-level estimates of manure available for application in other years. Specifically, county-scale ratios of manure available for application to soils in other years relative to 1997 were used to adjust the area amended with manure (see Annex 3.13 for further details). Greater availability of managed manure N relative to 1997 was, thus, assumed to increase the area amended with manure, while reduced availability of manure N relative to 1997 was assumed to reduce the

amended area.

The amount of manure produced by each livestock type was calculated for managed and unmanaged waste management systems based on methods described in the Manure Management Section (Section 6.2) and Annex (Annex 3.10). In contrast to manure amendments, Pasture/Range/Paddock (PRP) manure N deposition was estimated internally in the Century model, as part of the grassland system simulations (i.e., PRP manure deposition was not an external input into the model). See the Tier 3 methods in *Cropland Remaining Cropland* section for additional discussion on the Tier 3 methodology for mineral soils.

Tier 2 Approach

The Tier 2 approach is based on the same methods described in the Tier 2 portion of *Cropland Remaining Cropland* section for mineral soils (see *Cropland Remaining Cropland* Tier 2 methods section and Annex 3.13 for additional information).

Additional Mineral C Stock Change Calculations

Annual C flux estimates for mineral soils between 1990 and 2009 were adjusted to account for additional C stock changes associated with sewage sludge amendments using a Tier 2 method. Estimates of the amounts of sewage sludge N applied to agricultural land were derived from national data on sewage sludge generation, disposition, and N content. Total sewage sludge generation data for 1988, 1996, and 1998, in dry mass units, were obtained from an EPA report (EPA 1999) and estimates for 2004 were obtained from an independent national biosolids survey (NEBRA 2007). These values were linearly interpolated to estimate values for the intervening years. N application rates from Kellogg et al. (2000) were used to determine the amount of area receiving sludge amendments. Although sewage sludge can be added to land managed for other land uses, it was assumed that agricultural amendments occur in grassland. Cropland is assumed to rarely be amended with sewage sludge due to the high metal content and other pollutants in human waste. The soil C storage rate was estimated at 0.38 metric tons C per hectare per year for sewage sludge amendments to grassland. The stock change rate is based on country-specific factors and the IPCC default method (see Annex 3.13 for further discussion).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Grassland Remaining Grassland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), which utilizes U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. Emissions were based on the 1992 and 1997 *Grassland Remaining Grassland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty estimates are presented in Table 7-33 for each subsource (i.e., mineral soil C stocks and organic soil C stocks) disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in agricultural soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. The combined uncertainty for soil C stocks in *Grassland Remaining Grassland* was estimated to be 32 percent below and 25 percent above the inventory estimate of -8.3 Tg CO_2 Eq.

Table 7-33: Tier 2 Quantitative Uncertainty Estimates for C Stock Changes occurring within *Grassland Remaining Grassland* (Tg CO_2 Eq. and Percent)

Source	2009 Flux Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)		Uncertainty Range Relative to Flux Estimate (%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mineral Soil C Stocks Grassland Remaining Grassland, Tier 3 Methodology	(10.6)	(11.4)	(9.8)	-7%	+7%

Mineral Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology	(0.2)	(0.3)	0.0	-89%	+127%
Mineral Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology (Change in Soil C due to Sewage Sludge Amendments)	(1.2)	(1.9)	(0.6)	-50%	+50%
Organic Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology	3.7	1.2	5.5	-66%	+49%
Combined Uncertainty for Flux Associated with Agricultural Soil Carbon Stock Change in Grassland Remaining Grassland	**(8.3)**	**(11.0)**	**(6.3)**	**-32%**	**+25%**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Uncertainties in Mineral Soil Carbon Stock Changes

The uncertainty analysis for *Grassland Remaining Grassland* using the Tier 3 approach and Tier 2 approach were based on the same method described for *Cropland Remaining Cropland*, except that the uncertainty inherent in the structure of the Century model was not addressed. See the Tier 3 approach for mineral soils under the *Cropland Remaining Cropland* section for additional discussion.

A ±50 percent uncertainty was assumed for additional adjustments to the soil C stocks between 1990 and 2009 to account for additional C stock changes associated with amending grassland soils with sewage sludge.

Uncertainties in Soil Carbon Stock Changes for Organic Soils

Uncertainty in C emissions from organic soils was estimated using country-specific factors and a Monte Carlo analysis. Probability distribution functions for emission factors were derived from a synthesis of 10 studies, and combined with uncertainties in the NRI land use and management data for organic soils in the Monte Carlo analysis. See the Tier 2 section under minerals soils of *Cropland Remaining Cropland* for additional discussion.

QA/QC and Verification

Quality control measures included checking input data, model scripts, and results to ensure data were properly handled through the inventory process. A minor error was found in the post-processing results to compute the final totals, which was corrected. No additional errors were found.

Recalculations Discussion

There were minor changes in the estimated area of grasslands associated with reconciling the forestland areas from the Forest Inventory and Analysis (FIA) survey with the data from the National Resources Inventory (NRI) (see section 7.1 for more information. The revised areas led to small changes in the soil C stock changes for *Grassland Remaining Grassland*.

Planned Improvements

The main planned improvement for the next Inventory is to integrate the assessments of soil C stock changes and soil N_2O emissions into a single analysis. This improvement will ensure that the N and C cycles are treated consistently in the Inventory, which is important because the cycles of these elements are linked through plant and soil processes in agricultural lands. This improvement will include the development of an empirically-based uncertainty analysis, which will provide a more rigorous assessment of uncertainty. See Planned Improvements section under *Cropland Remaining Cropland* for additional planned improvements.

7.7. Land Converted to Grassland (IPCC Source Category 5C2)

Land Converted to Grassland includes all grassland in an inventory year that had been in another land use at any point during the previous 20 years[190] according to the USDA NRI land-use survey (USDA-NRCS 2000). Consequently, lands are retained in this category for 20 years as recommended by IPCC (2006) unless there is another land use change. The Inventory includes all privately-owned grasslands in the conterminous United States and Hawaii, but does not address changes in C stocks for grasslands on federal lands, leading to a discrepancy between the total amount of managed area for *Land Converted to Grassland* (see Section 7.1) and the grassland area included in the Inventory. It is important to note that plans are being made to include these areas in future C inventories.

Background on agricultural C stock changes is provided in *Cropland Remaining Cropland* and will only be summarized here for *Land Converted to Grassland*. Soils are the largest pool of C in agricultural land, and also have the greatest potential for storage or release of C, because biomass and dead organic matter C pools are relatively small and ephemeral compared with soils. IPCC (2006) recommend reporting changes in soil organic C stocks due to: (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.[191]

Land-use and management of mineral soils in *Land Converted to Grassland* led to an increase in soil C stocks from 1990 through 2009, which was largely due to annual cropland conversion to pasture (see Table 7-34 and Table 7-35). For example, the stock change rates were estimated to remove 20.3 Tg CO_2 Eq./yr (5.5 Tg C) and 24.5 Tg CO_2 Eq./yr (6.7 Tg C) from mineral soils in 1990 and 2009, respectively. Drainage of organic soils for grazing management led to losses varying from 0.5 to 0.9 Tg CO_2 Eq./yr (0.1 to 0.2 Tg C).

Table 7-34: Net CO_2 Flux from Soil C Stock Changes for *Land Converted to Grassland* (Tg CO_2 Eq.)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils[a]	(20.3)	(28.1)	(25.3)	(25.1)	(24.9)	(24.7)	(24.5)
Organic Soils	0.5	0.9	0.9	0.9	0.9	0.9	0.9
Total Net Flux	**(19.8)**	**(27.2)**	**(24.4)**	**(24.2)**	**(24.0)**	**(23.8)**	**(23.6)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.
[a] Stock changes due to application of sewage sludge are reported in *Grassland Remaining Grassland*.

Table 7-35: Net CO_2 Flux from Soil C Stock Changes for *Land Converted to Grassland* (Tg C)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils[a]	(5.5)	(7.7)	(6.9)	(6.8)	(6.8)	(6.7)	(6.7)
Organic Soils	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Total Net Flux	**(5.4)**	**(7.4)**	**(6.7)**	**(6.6)**	**(6.5)**	**(6.5)**	**(6.4)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.
[a] Stock changes due to application of sewage sludge in *Land Converted to Grassland* are reported in *Grassland Remaining Grassland*.

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The spatial variability in annual CO_2 flux associated with C stock changes in mineral soils is displayed in Figure 7-11and Figure 7-12. Soil C stock increased in most states for *Land Converted to Grassland*. The largest gains were in the South-Central region, Midwest, and northern Great Plains. The patterns were driven by conversion of annual cropland into continuous pasture. Emissions from organic soils were largest in California, Florida, and the upper Midwest, coinciding with largest concentrations of organic soils in the United States that are used for agricultural production.

Figure 7-11: Total Net Annual CO_2 Flux for Mineral Soils under Agricultural Management within States, 2009,

[190] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.
[191] CO_2 emissions associated with liming are also estimated but included in a separate section of the report.

Figure 7-12: Total Net Annual CO_2 Flux for Organic Soils under Agricultural Management within States, 2009, *Land Converted to Grassland*

Methodology

This section includes a brief description of the methodology used to estimate changes in soil C stocks due to agricultural land-use and management activities on mineral soils for *Land Converted to Grassland*. Biomass C stock changes are not explicitly included in this category but losses of associated with conversion of forest to grassland are included in the *Forest Land Remaining Forest Land* section. Further elaboration on the methodologies and data used to estimate stock changes from mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.13.

Soil C stock changes were estimated for *Land Converted to Grassland* according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2000). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. However, the NRI program initiated annual data collection in 1998, and the annual data are currently available through 2003. NRI points were classified as *Land Converted to Grassland* in a given year between 1990 and 2009 if the land use was grassland, but had been another use in the previous 20 years. Grassland includes pasture and rangeland used for grass forage production, where the primary use is livestock grazing. Rangeland typically includes extensive areas of native grassland that are not intensively managed, while pastures are often seeded grassland, possibly following tree removal, that may or may not be improved with practices such as irrigation and interseeding legumes.

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach was applied to estimate C stock changes for *Land Converted to Grassland* on most mineral soils. C stock changes on the remaining soils were estimated with an IPCC Tier 2 approach (Ogle et al. 2003), including prior cropland used to produce vegetables, tobacco, perennial/horticultural crops, and rice; land areas with very gravelly, cobbly, or shaley soils (greater than 35 percent by volume); and land converted from forest or federal ownership.[192] A Tier 2 approach was also used to estimate additional changes in mineral soil C stocks due to sewage sludge amendments. However, stock changes associated with sewage sludge amendments are reported in the *Grassland Remaining Grassland* section.

Tier 3 Approach

Mineral SOC stocks and stock changes were estimated using the Century biogeochemical model as described for *Grassland Remaining Grassland*. Historical land-use and management patterns were used in the Century simulations as recorded in the NRI survey, with supplemental information on fertilizer use and rates from the USDA Economic Research Service Cropping Practices Survey (ERS 1997) and the National Agricultural Statistics Service (NASS 1992, 1999, 2004) (see *Grassland Remaining Grassland* Tier 3 methods section for additional information).

Tier 2 Approach

The Tier 2 approach used for *Land Converted to Grassland* on mineral soils is the same as described for *Cropland Remaining Cropland* (See *Cropland Remaining Cropland* Tier 2 Approach and Annex 3.13 for additional information).

[192] Federal land is not a land use, but rather an ownership designation that is treated as forest or nominal grassland for purposes of these calculations. The specific use for federal lands is not identified in the NRI survey (USDA-NRCS 2000).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Land Converted to Grassland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), which utilizes U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. Emissions were based on the 1992 and 1997 *Land Converted to Grassland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty analysis for mineral soil C stock changes using the Tier 3 and Tier 2 approaches were based on the same method described in *Cropland Remaining Cropland*, except that the uncertainty inherent in the structure of the Century model was not addressed. The uncertainty or annual C emission estimates from drained organic soils in *Land Converted to Grassland* was estimated using the Tier 2 approach, as described in the *Cropland Remaining Cropland* section.

Uncertainty estimates are presented in Table 7-36 for each subsource (i.e., mineral soil C stocks and organic soil C stocks), disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in agricultural soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006) (i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities). The combined uncertainty for soil C stocks in *Land Converted to Grassland* ranged from 15 percent below to 15 percent above the 2009 estimate of -23.6 Tg CO_2 Eq.

Table 7-36: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Land Converted to Grassland* (Tg CO_2 Eq. and Percent)

Source	2009 Flux Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mineral Soil C Stocks: Land Converted to Grassland, Tier 3 Inventory Methodology	(19.5)	(22.2)	(16.7)	-14%	+14%
Mineral Soil C Stocks: Land Converted to Grassland, Tier 2 Inventory Methodology	(5.0)	(7.0)	(2.8)	-39%	+43%
Organic Soil C Stocks: Land Converted to Grassland, Tier 2 Inventory Methodology	0.9	0.2	1.8	-76%	+104%
Combined Uncertainty for Flux associated with Agricultural Soil Carbon Stocks in Land Converted to Grassland	**(23.6)**	**(27.0)**	**(20.0)**	**-15%**	**+15%**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

See the QA/QC and Verification section under *Grassland Remaining Grassland*.

Recalculations Discussion

There were minor changes in the current Inventory relative to the previous version in the estimated area of grasslands associated with reconciling the forestland areas from the Forest Inventory and Analysis (FIA) survey with the data from the National Resources Inventory (NRI) (see section 7.1 for more information). The revised areas led to small changes in the soil C stock changes for *Land Converted to Grassland*.

Planned Improvements

The main planned improvement for the next Inventory is to integrate the assessments of soil C stock changes and soil nitrous oxide emissions into a single analysis. This improvement will ensure that the nitrogen and carbon cycles are treated consistently in the national inventory, which is important because the cycles of these elements are linked through plant and soil processes in agricultural lands. This improvement will include the development of an empirically-based uncertainty analysis, which will provide a more rigorous assessment of uncertainty. See Planned Improvements section under *Cropland Remaining Cropland* for additional planned improvements.

7.8. Wetlands Remaining Wetlands

Peatlands Remaining Peatlands

Emissions from Managed Peatlands

Managed peatlands are peatlands which have been cleared and drained for the production of peat. The production cycle of a managed peatland has three phases: land conversion in preparation for peat extraction (e.g., draining, and clearing surface biomass), extraction (which results in the emissions reported under *Peatlands Remaining Peatlands*), and abandonment, restoration or conversion of the land to another use.

CO_2 emissions from the removal of biomass and the decay of drained peat constitute the major greenhouse gas flux from managed peatlands. Managed peatlands may also emit CH_4 and N_2O. The natural production of CH_4 is largely reduced but not entirely shut down when peatlands are drained in preparation for peat extraction (Strack et al., 2004 as cited in IPCC 2006); however, CH_4 emissions are assumed to be insignificant under Tier 1 (IPCC, 2006). N_2O emissions from managed peatlands depend on site fertility. In addition, abandoned and restored peatlands continue to release greenhouse gas emissions, and at present no methodology is provided by IPCC (2006) to estimate greenhouse gas emissions or removals from restored peatlands. This inventory estimates both CO_2 and N_2O emissions from *Peatlands Remaining Peatlands* in accordance with Tier 1 IPCC (2006) guidelines.

CO_2 and N_2O Emissions from *Peatlands Remaining Peatlands*

IPCC (2006) recommends reporting CO_2 and N_2O emissions from lands undergoing active peat extraction (i.e., *Peatlands Remaining Peatlands*) as part of the estimate for emissions from managed wetlands. Peatlands occur in wetland areas where plant biomass has sunk to the bottom of water bodies and water-logged areas and exhausted the oxygen supply below the water surface during the course of decay. Due to these anaerobic conditions, much of the plant matter does not decompose but instead forms layers of peat over decades and centuries. In the United States, peat is extracted for horticulture and landscaping growing media, and for a wide variety of industrial, personal care, and other products. It has not been used for fuel in the United States for many decades. Peat is harvested from two types of peat deposits in the United States: sphagnum bogs in northern states and wetlands in states further south. The peat from sphagnum bogs in northern states, which is nutrient poor, is generally corrected for acidity and mixed with fertilizer. Production from more southerly states is relatively coarse (i.e., fibrous) but nutrient rich.

IPCC (2006) recommends considering both on-site and off-site emissions when estimating CO_2 emissions from *Peatlands Remaining Peatlands* using the Tier 1 approach. Current methodologies estimate only on-site N_2O emissions, since off-site N_2O estimates are complicated by the risk of double-counting emissions from nitrogen fertilizers added to horticultural peat. On-site emissions from managed peatlands occur as the land is cleared of vegetation and the underlying peat is exposed to sun and weather. As this occurs, some peat deposit is lost and CO_2 is emitted from the oxidation of the peat. On-site N_2O is emitted during draining depending on site fertility and if the deposit contains significant amounts of organic nitrogen in inactive form. Draining land in preparation for peat extraction allows bacteria to convert the nitrogen into nitrates which leach to the surface where they are reduced to N_2O.

Off-site CO_2 emissions from managed peatlands occur from the horticultural and landscaping use of peat. CO_2 emissions occur as the nutrient-poor (but now fertilizer-enriched) peat is used in bedding plants, other greenhouse and plant nursery production, and by consumers, and as nutrient-rich (but relatively coarse) peat is used directly in landscaping, athletic fields, golf courses, and plant nurseries. Most of the CO_2 emissions from peat occur off-site, as the peat is processed and sold to firms which, in the United States, use it predominately for horticultural purposes. The magnitude of the CO_2 emitted from peat depends on whether the peat has been extracted from nutrient-rich or

nutrient-poor peat deposits.

Total emissions from *Peatlands Remaining Peatlands* were estimated to be 1.095 Tg CO_2 Eq. in 2009 (see Table 7-37) comprising 1.090 Tg CO_2 Eq. (1,090 Gg) of CO_2 and 0.005 Tg CO_2 Eq. (0.016 Gg) of N_2O. Total emissions in 2009 were about 10 percent larger than total emissions in 2008, with the increase due to the higher peat production reported in Alaska in 2009.

Total emissions from *Peatlands Remaining Peatlands* have fluctuated between 0.88 and 1.23 Tg CO_2 Eq. across the time series with a decreasing trend from 1990 until 1994 followed by an increasing trend through 2000. Since 2000, total emissions show a decreasing trend until 2006 followed by an increasing trend in recent years. CO_2 emissions from *Peatlands Remaining Peatlands* have fluctuated between 0.88 and 1.23 Tg CO_2 across the time series and drive the trends in total emissions. N_2O emissions remained close to zero across the time series, with a decreasing trend from 1990 until 1995 followed by an increasing trend through 2000. N_2O emissions decreased between 2000 and 2008, followed by a leveling off in 2009.

Table 7-37: Emissions from *Peatlands Remaining Peatlands* (Tg CO_2 Eq.)

Gas	1990	2000	2005	2006	2007	2008	2009
CO_2	1.0	1.2	1.1	0.9	1.0	1.0	1.1
N_2O	+	+	+	+	+	+	+
Total	**1.0**	**1.2**	**1.1**	**0.9**	**1.0**	**1.0**	**1.1**

+ Less than 0.01 Tg CO_2 Eq.

Note: These numbers are based on U.S. production data in accordance with Tier 1 guidelines, which does not take into account imports, exports and stockpiles (i.e., apparent consumption).

Table 7-38: Emissions from *Peatlands Remaining Peatlands* (Gg)

Gas	1990	2000	2005	2006	2007	2008	2009
CO_2	1,033	1,227	1,079	879	1,012	992	1,090
N_2O	+	+	+	+	+	+	+

+ Less than 0.05 Gg

Note: These numbers are based on U.S. production data in accordance with Tier 1 guidelines, which does not take into account imports, exports and stockpiles (i.e., apparent consumption).

Methodology

Off-Site CO_2 Emissions

CO_2 emissions from domestic peat production were estimated using a Tier 1 methodology consistent with IPCC (2006). Off-site CO_2 emissions from *Peatlands Remaining Peatlands* were calculated by apportioning the annual weight of peat produced in the United States (Table 7-39) into peat extracted from nutrient-rich deposits and peat extracted from nutrient-poor deposits using annual percentage by weight figures. These nutrient-rich and nutrient-poor production values were then multiplied by the appropriate default carbon fraction conversion factor taken from IPCC (2006) in order to obtain off-site emission estimates. For the lower 48 states, both annual percentages of peat type by weight and domestic peat production data were sourced from estimates and industry statistics provided in the *Minerals Yearbook* and *Mineral Commodity Summaries* from the U.S. Geological Survey (USGS 1991–2010). To develop these data, the U.S. Geological Survey (USGS; U.S. Bureau of Mines prior to 1997) obtained production and use information by surveying domestic peat producers. The USGS often receives a response to the survey from most of the smaller peat producers, but fewer of the larger ones. For example, of the four active operations producing 23,000 or more metric tons per year, two did not respond to the survey in 2007. As a result, the USGS estimates production from the non-respondent peat producers based on responses to previous surveys (responses from 2004 and 2005, in the case above) or other sources.

The Alaska estimates rely on reported peat production from Alaska's annual Mineral Industry Reports (Szumigala et al. 2010). Similar to the U.S. Geological Survey, Alaska's Mineral Industry Report methodology solicits voluntary reporting of peat production from producers. However, the report does not estimate production for the non-reporting producers, resulting in larger inter-annual variation in reported peat production from Alaska depending on the number of producers who report in a given year (Szumigala 2011). In addition, in both the lower 48 states and Alaska, large variations in peat production can also result from variations in precipitation and the subsequent

moisture conditions, since unusually wet years can hamper peat production (USGS 2010). The methodology estimates Alaska emissions separately from lower 48 emissions because the state conducts its own mineral survey and reports peat production by volume, rather than by weight (Table 7-40). However, volume production data was used to calculate off-site CO_2 emissions from Alaska applying the same methodology but with volume-specific carbon fraction conversion factors from IPCC (2006).[193]

The *apparent consumption* of peat, which includes production plus imports minus exports plus the decrease in stockpiles, in the United States is over two-and-a-half times the amount of domestic peat production. Therefore, off-site CO_2 emissions from the use of all horticultural peat within the United States are not accounted for using the Tier 1 approach. The United States has increasingly imported peat from Canada for horticultural purposes; from 2005 to 2008, imports of sphagnum moss (nutrient-poor) peat from Canada represented 97 percent of total U.S. peat imports (USGS 2010). Most peat produced in the United States is reed-sedge peat, generally from southern states, which is classified as nutrient rich by IPCC (2006). Higher-tier calculations of CO_2 emissions from apparent consumption would involve consideration of the percentages of peat types stockpiled (nutrient rich versus nutrient poor) as well as the percentages of peat types imported and exported.

Table 7-39: Peat Production of Lower 48 States (in thousands of Metric Tons)

Type of Deposit	1990	2000	2005	2006	2007	2008	2009
Nutrient-Rich	595.1	728.6	657.6	529.0	581.0	559.7	554.2
Nutrient-Poor	55.4	63.4	27.4	22.0	54.0	55.4	54.8
Total Production	**692.0**	**792.0**	**685.0**	**551.0**	**635.0**	**615.0**	**609.0**

Sources: *Minerals Yearbook: Peat* (1990–2008 Reports), *Mineral Commodity Summaries: Peat* (1996–2009 Reports), and Apodaca (2010). United States Geological Survey.

Table 7-40: Peat Production of Alaska (in thousands of Cubic Meters)

	1990	2000	2005	2006	2007	2008	2009
Total Production	**49.7**	**27.2**	**47.8**	**50.8**	**52.3**	**64.1**	**183.9**

Sources: *Alaska's Mineral Industry* (1992–2009) Reports. Division of Geological & Geophysical Surveys, Alaska Department of Natural Resources.

On-site CO_2 Emissions

IPCC (2006) suggests basing the calculation of on-site emissions estimates on the area of peatlands managed for peat extraction differentiated by the nutrient type of the deposit (rich versus poor). Information on the area of land managed for peat extraction is currently not available for the United States, but in accordance with IPCC (2006), an average production rate for the industry was applied to derive an area estimate. In a mature industrialized peat industry, such as exists in the United States and Canada, the vacuum method[194] can extract up to 100 metric ton per hectare per year (Cleary et al. 2005 as cited in IPCC 2006). The area of land managed for peat extraction in the United States was estimated using nutrient-rich and nutrient-poor production data and the assumption that 100 metric tons of peat are extracted from a single hectare in a single year. The annual land area estimates were then multiplied by the appropriate nutrient-rich or nutrient-poor IPCC (2006) default emission factor in order to calculate on-site CO_2 emission estimates. Production data are not available by weight for Alaska. In order to calculate on-site emissions resulting from *Peatlands Remaining Peatlands* in Alaska, the production data by volume were converted to weight using annual average bulk peat density values, and then converted to land area estimates using the same assumption that a single hectare yields 100 metric tons. The IPCC (2006) on-site emissions equation also includes a term which accounts for emissions resulting from the change in carbon stocks that occurs during the clearing of vegetation prior to peat extraction. Area data on land undergoing conversion to peatlands for peat extraction is also unavailable for the United States. However, USGS records show that the number of active operations in the United

[193] Peat produced from Alaska was assumed to be nutrient poor; as is the case in Canada, "where deposits of high-quality [but nutrient poor] sphagnum moss are extensive" (USGS 2008).

[194] The vacuum method is one type of extraction that annually "mills" or breaks up the surface of the peat into particles, which then dry during the summer months. The air-dried peat particles are then collected by vacuum harvesters and transported from the area to stockpiles (IPCC 2006).

States has been declining since 1990; therefore it seems reasonable to assume that no new areas are being cleared of vegetation for managed peat extraction. Other changes in carbon stocks in living biomass on managed peatlands are also assumed to be zero under the Tier 1 methodology (IPCC 2006).

On-site N_2O Emissions

IPCC (2006) suggests basing the calculation of on-site N_2O emissions estimates on the area of nutrient-rich peatlands managed for peat extraction. These area data are not available directly for the United States, but the on-site CO_2 emissions methodology above details the calculation of area data from production data. In order to estimate N_2O emissions, the area of nutrient rich *Peatlands Remaining Peatlands* was multiplied by the appropriate default emission factor taken from IPCC (2006).

Uncertainty

The uncertainty associated with peat production data was estimated to be ± 25 percent (Apodaca 2008) and assumed to be normally distributed. The uncertainty associated with peat production data stems from the fact that the USGS receives data from the smaller peat producers but estimates production from some larger peat distributors. This same uncertainty and distribution was assumed for the peat type production percentages. The uncertainty associated with the Alaskan reported production data was assumed to be the same as the lower 48 states, or ± 25 percent with a normal distribution. It should be noted that the Alaskan Department of Natural Resources estimate that around half of producers do not respond to their survey with peat production data; therefore, the production numbers reported are likely to underestimate Alaska peat production (Szumigala 2008). The uncertainty associated with the average bulk density values was estimated to be ± 25 percent with a normal distribution (Apodaca 2008). IPCC (2006) gives uncertainty values for the emissions factors for the area of peat deposits managed for peat extraction based on the range of underlying data used to determine the emissions factors. The uncertainty associated with the emission factors was assumed to be triangularly distributed. The uncertainty values surrounding the carbon fractions were based on IPCC (2006) and the uncertainty was assumed to be uniformly distributed. Based on these values and distributions, a Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the uncertainty of CO_2 and N_2O emissions from *Peatlands Remaining Peatlands*. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-41. CO_2 emissions from *Peatlands Remaining Peatlands* in 2009 were estimated to be between 0.8 and 1.5 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of 30 percent below to 34 percent above the 2009 emission estimate of 1.1 Tg CO_2 Eq. N_2O emissions from *Peatlands Remaining Peatlands* in 2009 were estimated to be between 0.001 and 0.007 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of 74 percent below to 41 percent above the 2009 emission estimate of 0.005 Tg CO_2 Eq.

Table 7-41: Tier-2 Quantitative Uncertainty Estimates for CO_2 Emissions from *Peatlands Remaining Peatlands*

Source	Gas	2009 Emissions Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emissions Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Peatlands Remaining Peatlands	CO_2	1.1	0.8	1.5	-30%	34%
	N_2O	+	+	+	-74%	41%

+ Does not exceed 0.01 Tg CO_2 Eq. or 0.5 Gg.

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. The QA/QC analysis did not reveal any inaccuracies or incorrect input values.

Recalculations Discussion

The current Inventory represents the third Inventory report in which emissions from *Peatlands Remaining Peatlands* are included . A revised 2008 estimate of peat production by volume for Alaska was reported in 2010 (Szumigala et

al. 2010). Updating the 2008 production data with this revised estimate led to a 5 percent increase over the previous 2008 emission estimate.

Planned Improvements

In order to further improve estimates of CO_2 and N_2O emissions from *Peatlands Remaining Peatlands*, future efforts will consider options for obtaining better data on the quantity of peat harvested per hectare and the total area undergoing peat extraction.

7.9. Settlements Remaining Settlements

Changes in Carbon Stocks in Urban Trees (IPCC Source Category 5E1)

Urban forests constitute a significant portion of the total U.S. tree canopy cover (Dwyer et al. 2000). Urban areas (cities, towns, and villages) are estimated to cover over 4 percent of the United States (Nowak et al. 2005). With an average tree canopy cover of 27 percent, urban areas account for approximately 3 percent of total tree cover in the continental United States (Nowak et al. 2001). Trees in urban areas of the United States were estimated to account for an average annual net sequestration of 76.5 Tg CO_2 Eq. (20.9 Tg C) over the period from 1990 through 2009. Net C flux from urban trees in 2009 was estimated to be -95.9 Tg CO_2 Eq. (-26.2 Tg C). Annual estimates of CO_2 flux (Table 7-42) were developed based on periodic (1990 and 2000) U.S. Census data on urbanized area. This estimated urban area is smaller than the area categorized as *Settlements* in the Representation of the U.S. Land Base developed for this report, by an average of 21 percent over the 1990 through 2009 time series—i.e., the Census urban area is a subset of the *Settlements* area. Census area data are preferentially used to develop C flux estimates for this source category since these data are more applicable for use with the available peer-reviewed data on urban tree canopy cover and urban tree C sequestration. Annual sequestration increased by 68 percent between 1990 and 2009 due to increases in urban land area. Data on C storage and urban tree coverage were collected since the early 1990s and have been applied to the entire time series in this report.

Net C flux from urban trees is proportionately greater on an area basis than that of forests. This trend is primarily the result of different net growth rates in urban areas versus forests—urban trees often grow faster than forest trees because of the relatively open structure of the urban forest (Nowak and Crane 2002). However, areas in each case are accounted for differently. Because urban areas contain less tree coverage than forest areas, the C storage per hectare of land is in fact smaller for urban areas. However, urban tree reporting occurs on a basis of C sequestered per unit area of tree cover, rather than C sequestered per total land area. Areas covered by urban trees, therefore, appear to have a greater C density than do forested areas (Nowak and Crane 2002).

Table 7-42: Net C Flux from Urban Trees (Tg CO_2 Eq. and Tg C)

Year	Tg CO_2 Eq.	Tg C
1990	(57.1)	(15.6)
2000	(77.5)	(21.1)
2005	(87.8)	(23.9)
2006	(89.8)	(24.5)
2007	(91.9)	(25.1)
2008	(93.9)	(25.6)
2009	(95.9)	(26.2)

Note: Parentheses indicate net sequestration.

Methodology

Methods for quantifying urban tree biomass, C sequestration, and C emissions from tree mortality and decomposition were taken directly from Nowak and Crane (2002) and Nowak (1994). In general, the methodology used by Nowak and Crane (2002) to estimate net C sequestration in urban trees followed three steps. First, field data from 14 cities were used to generate allometric estimates of biomass from measured tree dimensions. Second, estimates of tree growth and biomass increment were generated from published literature and adjusted for tree condition and land-use class to generate estimates of gross C sequestration in urban trees. Third, estimates of C emissions due to mortality and decomposition were subtracted from gross C sequestration values to derive estimates

of net C sequestration. Sequestration estimates for these cities, in units of carbon sequestered per unit area of tree cover, were then used to estimate urban forest C sequestration in the U.S. by using urban area estimates from U.S. Census data and urban tree cover estimates from remote sensing data, an approach consistent with Nowak and Crane (2002).

This approach is also consistent with the default IPCC methodology in IPCC (2006), although sufficient data are not yet available to separately determine interannual gains and losses in C stocks in the living biomass of urban trees. Annual changes in net C flux from urban trees are based solely on changes in total urban area in the United States.

In order to generate the allometric relationships between tree dimensions and tree biomass, Nowak and Crane (2002) and Nowak (1994, 2007c, 2009) collected field measurements in a number of U.S. cities between 1989 and 2002. For a sample of trees in each of the cities in Table 7-43, data including tree measurements of stem diameter, tree height, crown height and crown width, and information on location, species, and canopy condition were collected. The data for each tree were converted into C storage by applying allometric equations to estimate aboveground biomass, a root-to-shoot ratio to convert aboveground biomass estimates to whole tree biomass, moisture content, a C content of 50 percent (dry weight basis), and an adjustment factor of 0.8 to account for urban trees having less aboveground biomass for a given stem diameter than predicted by allometric equations based on forest trees (Nowak 1994). C storage estimates for deciduous trees include only carbon stored in wood. These calculations were then used to develop an allometric equation relating tree dimensions to C storage for each species of tree, encompassing a range of diameters.

Tree growth was estimated using annual height growth and diameter growth rates for specific land uses and diameter classes. Growth calculations were adjusted by a factor to account for tree condition (fair to excellent, poor, critical, dying, or dead). For each tree, the difference in C storage estimates between year 1 and year (x + 1) represents the gross amount of C sequestered. These annual gross C sequestration rates for each species (or genus), diameter class, and land-use condition (e.g., parks, transportation, vacant, golf courses) were then scaled up to city estimates using tree population information. The area of assessment for each city was defined by its political boundaries; parks and other forested urban areas were thus included in sequestration estimates (Nowak 2011).

Most of the field data used to develop the methodology of Nowak et al. were analyzed using the U.S. Forest Service's Urban Forest Effects (UFORE) model. UFORE is a computer model that uses standardized field data from random plots in each city and local air pollution and meteorological data to quantify urban forest structure, values of the urban forest, and environmental effects, including total C stored and annual C sequestration. UFORE was used with field data from a stratified random sample of plots in each city to quantify the characteristics of the urban forest. (Nowak et al. 2007a).

Gross C emissions result from tree death and removals. Estimates of gross C emissions from urban trees were derived by applying estimates of annual mortality and condition, and assumptions about whether dead trees were removed from the site to the total C stock estimate for each city. Estimates of annual mortality rates by diameter class and condition class were derived from a study of street-tree mortality (Nowak 1986). Different decomposition rates were applied to dead trees left standing compared with those removed from the site. For removed trees, different rates were applied to the removed/aboveground biomass in contrast to the belowground biomass. The estimated annual gross C emission rates for each species (or genus), diameter class, and condition class were then scaled up to city estimates using tree population information.

The field data for 13 of the 14 cities are described in Nowak and Crane (2002), Nowak et al. (2007a), and references cited therein. Data for the remaining city, Chicago, were taken from unpublished results (Nowak 2009). The allometric equations applied to the field data for each tree were taken from the scientific literature (see Nowak 1994, Nowak et al. 2002), but if no allometric equation could be found for the particular species, the average result for the genus was used. The adjustment (0.8) to account for less live tree biomass in urban trees was based on information in Nowak (1994). A root-to-shoot ratio of 0.26 was taken from Cairns et al. (1997), and species- or genus-specific moisture contents were taken from various literature sources (see Nowak 1994). Tree growth rates were taken from existing literature. Average diameter growth was based on the following sources: estimates for trees in forest stands came from Smith and Shifley (1984); estimates for trees on land uses with a park-like structure came from deVries (1987); and estimates for more open-grown trees came from Nowak (1994). Formulas from Fleming (1988) formed the basis for average height growth calculations. As described above, growth rates were adjusted to account for tree condition. Growth factors for Atlanta, Boston, Freehold, Jersey City, Moorestown, New York, Philadelphia, and Woodbridge were adjusted based on the typical growth conditions of different land-use categories (e.g., forest stands, park-like stands). Growth factors for the more recent studies in Baltimore, Chicago, Minneapolis, San

Francisco, Syracuse, and Washington were adjusted using an updated methodology based on the condition of each individual tree, which is determined using tree competition factors (depending on whether it is open grown or suppressed) (Nowak 2007b). Assumptions for which dead trees would be removed versus left standing were developed specific to each land use and were based on expert judgment of the authors. Decomposition rates were based on literature estimates (Nowak and Crane 2002).

Estimates of gross and net sequestration rates for each of the 14 cities (Table 7-43) were compiled in units of C sequestration per unit area of tree canopy cover. These rates were used in conjunction with estimates of national urban area and urban tree cover data to calculate national annual net C sequestration by urban trees for the United States. This method was described in Nowak and Crane (2002) and has been modified to incorporate U.S. Census data.

Specifically, urban area estimates were based on 1990 and 2000 U.S. Census data. The 1990 U.S. Census defined urban land as "urbanized areas," which included land with a population density greater than 1,000 people per square mile, and adjacent "urban places," which had predefined political boundaries and a population total greater than 2,500. In 2000, the U.S. Census replaced the "urban places" category with a new category of urban land called an "urban cluster," which included areas with more than 500 people per square mile. Urban land area increased by approximately 36 percent from 1990 to 2000; Nowak et al. (2005) estimate that the changes in the definition of urban land are responsible for approximately 20 percent of the total reported increase in urban land area from 1990 to 2000. Under both 1990 and 2000 definitions, the urban category encompasses most cities, towns, and villages (i.e., it includes both urban and suburban areas).

Settlements area, as assessed in the Representation of the U.S. Land Base developed for this report, encompassed all developed parcels greater than 0.1 hectares in size, including rural transportation corridors, and as previously mentioned represent a larger area than the Census-derived urban area estimates. However, the Census-derived urban area estimates were deemed to be more suitable for estimating national urban tree cover given the data available in the peer-reviewed literature. Specifically, tree canopy cover of U.S. urban areas was estimated by Nowak et al. (2001) to be 27 percent, assessed across Census-delineated urbanized areas, urban places, and places containing urbanized area. This canopy cover percentage is multiplied by the urban area estimated for each year to produce an estimate of national urban tree cover area.

Net annual C sequestration estimates were derived for the 14 cities by subtracting the gross annual emission estimates from the gross annual sequestration estimates. The gross and net annual C sequestration values for each city were divided by each city's area of tree cover to determine the average annual sequestration rates per unit of tree area for each city. The median value for gross sequestration per unit area of tree cover (0.29 kg C/m^2-yr) was then multiplied by the estimate of national urban tree cover area to estimate national annual gross sequestration, per the methods of Nowak and Crane (2002). To estimate national annual net sequestration, the estimate of national annual gross sequestration was multiplied by the average of the ratios of net to gross sequestration (0.72) for those cities that had both estimates. The urban tree cover estimates for each of the 14 cities and the United States were obtained from Dwyer et al. (2000), Nowak et al. (2002), Nowak (2007a), and Nowak (2009). The urban area estimates were taken from Nowak et al. (2005).

Table 7-43: C Stocks (Metric Tons C), Annual C Sequestration (Metric Tons C/yr), Tree Cover (Percent), and Annual C Sequestration per Area of Tree Cover (kg C/m^2-yr) for 14 U.S. Cities

City	Carbon Stocks	Gross Annual Sequestration	Net Annual Sequestration	Tree Cover	Gross Annual Sequestration per Area of Tree Cover	Net Annual Sequestration per Area of Tree Cover	Net:Gross Annual Sequestration Ratio
Atlanta, GA	1,219,256	42,093	32,169	36.7%	0.34	0.26	0.76
Baltimore, MD	541,589	14,696	9,261	21.0%	0.35	0.22	0.63
Boston, MA	289,392	9,525	6,966	22.3%	0.30	0.22	0.73
Chicago, IL	649,000	22,800	16,100	17.2%	0.22	0.16	0.71
Freehold, NJ	18,144	494	318	34.4%	0.28	0.18	0.64
Jersey City, NJ	19,051	807	577	11.5%	0.18	0.13	0.71
Minneapolis, MN	226,796	8,074	4,265	26.4%	0.20	0.11	0.53
Moorestown, NJ	106,141	3,411	2,577	28.0%	0.32	0.24	0.76
New York, NY	1,224,699	38,374	20,786	20.9%	0.23	0.12	0.54
Philadelphia, PA	480,808	14,606	10,530	15.7%	0.27	0.20	0.72

San Francisco, CA	175,994	4,627	4,152	11.9%	0.33	0.29	0.90
Syracuse, NY	156,943	4,917	4,270	23.1%	0.33	0.29	0.87
Washington, DC	477,179	14,696	11,661	28.6%	0.32	0.26	0.79
Woodbridge, NJ	145,150	5,044	3,663	29.5%	0.28	0.21	0.73
					Median: 0.29		**Mean:** 0.72

NA = not analyzed.
Sources: Nowak and Crane (2002), Nowak (2007a,c), and Nowak (2009).

Uncertainty and Time-Series Consistency

Uncertainty associated with changes in C stocks in urban trees includes the uncertainty associated with urban area, percent urban tree coverage, and estimates of gross and net C sequestration for each of the 14 U.S. cities. A 10 percent uncertainty was associated with urban area estimates while a 5 percent uncertainty was associated with percent urban tree coverage. Both of these uncertainty estimates were based on expert judgment. Uncertainty associated with estimates of gross and net C sequestration for each of the 14 U.S. cities was based on standard error estimates for each of the city-level sequestration estimates reported by Nowak (2007c) and Nowak (2009). These estimates are based on field data collected in each of the 14 U.S. cities, and uncertainty in these estimates increases as they are scaled up to the national level.

Additional uncertainty is associated with the biomass equations, conversion factors, and decomposition assumptions used to calculate C sequestration and emission estimates (Nowak et al. 2002). These results also exclude changes in soil C stocks, and there may be some overlap between the urban tree C estimates and the forest tree C estimates. Due to data limitations, urban soil flux is not quantified as part of this analysis, while reconciliation of urban tree and forest tree estimates will be addressed through the land-representation effort described in the Planned Improvements section of this chapter.

A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the overall uncertainty of the sequestration estimate. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-44. The net C flux from changes in C stocks in urban trees in 2009 was estimated to be between -116.8 and -77.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 22 percent below and 19 percent above the 2009 flux estimate of -95.9 Tg CO_2 Eq.

Table 7-44: Tier 2 Quantitative Uncertainty Estimates for Net C Flux from Changes in C Stocks in Urban Trees (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Flux Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)		Uncertainty Range Relative to Flux Estimate (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Changes in C Stocks in Urban Trees	CO_2	(95.9)	(116.8)	(77.7)	−22%	+19%

Note: Parentheses indicate negative values or net sequestration.

Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

The net C flux resulting from urban trees was predominately calculated using estimates of gross and net C sequestration estimates for urban trees and urban tree coverage area published in the literature. The validity of these data for their use in this section of the inventory was evaluated through correspondence established with an author of the papers. Through this correspondence, the methods used to collect the urban tree sequestration and area data were further clarified and the use of these data in the inventory was reviewed and validated (Nowak 2002a, 2007b, 2011).

Planned Improvements

A consistent representation of the managed land base in the United States is being developed. A component of this effort, which is discussed at the beginning of the Land Use, Land-Use Change, and Forestry chapter, will involve reconciling the overlap between urban forest and non-urban forest greenhouse gas inventories. It is highly likely

that urban forest inventories are including areas also defined as forest land under the Forest Inventory and Analysis (FIA) program of the USDA Forest Service, resulting in "double-counting" of these land areas in estimates of C stocks and fluxes for the inventory. The Forest Service is currently conducting research that will define urban area boundaries and make it possible to distinguish forest from forested urban areas. Once those data become available, they will be incorporated into estimates of net C flux resulting from urban trees.

Urban forest data for additional cities are expected in the near future, as are updated data for cities currently included in the estimates. The use of these data will further refine the estimated median sequestration value. It may also be possible to report C losses and gains separately in the future. It is currently not possible, since existing studies estimate rather than measure natality or mortality; net sequestration estimates are based on assumptions about whether dead trees are being removed, burned, or chipped. There is an effort underway to assess urban tree loss to mortality and removals, which would allow for direct calculation of C losses and gains from observed rather than estimated natality and mortality of trees.

Data from the 2010 U.S. Census is expected to provide updated U.S. urbanized area, which would allow for refinement of the urban area time series. Revisions to urban area time series will result in revisions to prior years' C flux estimates.

A revised average tree canopy cover percentage for U.S. urban areas is anticipated to become available in the peer-reviewed literature in the near future, which would allow for updated C flux estimates. Furthermore, urban tree cover data specific to each state is also expected in the near future. It may be possible to develop a set of state-specific sequestration rates for more granular and regionally precise C flux estimates by coupling these data with adjusted growth rates for each U.S. state. Future research may also enable more complete coverage of changes in the C stock in urban trees for all *Settlements* land. To provide estimates for all *Settlements*, research would need to establish the extent of overlap between *Settlements* and Census-defined urban areas, and would have to characterize sequestration on non-urban *Settlements* land.

Direct N_2O Fluxes from Settlement Soils (IPCC Source Category 5E1)

Of the synthetic N fertilizers applied to soils in the United States, approximately 2.5 percent are currently applied to lawns, golf courses, and other landscaping occurring within settlement areas. Application rates are lower than those occurring on cropped soils, and, therefore, account for a smaller proportion of total U.S. soil N_2O emissions per unit area. In addition to synthetic N fertilizers, a portion of surface applied sewage sludge is applied to settlement areas. In 2009, N_2O emissions from this source were 1.5 Tg CO_2 Eq. (4.9 Gg). There was an overall increase of 55 percent over the period from 1990 through 2009 due to a general increase in the application of synthetic N fertilizers to an expanding settlement area. Interannual variability in these emissions is directly attributable to interannual variability in total synthetic fertilizer consumption and sewage sludge applications in the United States. Emissions from this source are summarized in Table 7-45.

Table 7-45: Direct N_2O Fluxes from Soils in *Settlements Remaining Settlements* (Tg CO_2 Eq. and Gg N_2O)

Year	Tg CO_2 Eq.	Gg
1990	1.0	3.2
2000	1.1	3.7
2005	1.5	4.7
2006	1.5	4.8
2007	1.6	5.1
2008	1.5	4.9
2009	1.5	4.9

Note: These estimates include direct N_2O emissions from N fertilizer additions only. Indirect N_2O emissions from fertilizer additions are reported in the Agriculture chapter. These estimates include emissions from both *Settlements Remaining Settlements* and from *Land Converted to Settlements.*

Methodology

For soils within *Settlements Remaining Settlements*, the IPCC Tier 1 approach was used to estimate soil N_2O emissions from synthetic N fertilizer and sewage sludge additions. Estimates of direct N_2O emissions from soils in settlements were based on the amount of N in synthetic commercial fertilizers applied to settlement soils, and the

amount of N in sewage sludge applied to non-agricultural land and surface disposal of sewage sludge (see Annex 3.11 for a detailed discussion of the methodology for estimating sewage sludge application).

Nitrogen applications to settlement soils are estimated using data compiled by the USGS (Ruddy et al. 2006). The USGS estimated on-farm and non-farm fertilizer use is based on sales records at the county level from 1982 through 2001 (Ruddy et al. 2006). Non-farm N fertilizer was assumed to be applied to settlements and forest lands; values for 2002 through 2008 were based on 2001 values adjusted for annual total N fertilizer sales in the United States because there is no new activity data on application after 2001. Settlement application was calculated by subtracting forest application from total non-farm fertilizer use. Sewage sludge applications were derived from national data on sewage sludge generation, disposition, and N content (see Annex 3.11 for further detail). The total amount of N resulting from these sources was multiplied by the IPCC default emission factor for applied N (1 percent) to estimate direct N_2O emissions (IPCC 2006). The volatilized and leached/runoff N fractions for settlements, calculated with the IPCC default volatilization factors (10 or 20 percent, respectively, for synthetic or organic N fertilizers) and leaching/runoff factor for wet areas (30 percent), were included with indirect emissions, as reported in the N_2O Emissions from Agricultural Soil Management source category of the Agriculture chapter (consistent with reporting guidance that all indirect emissions are included in the Agricultural Soil Management source category).

Uncertainty and Time-Series Consistency

The amount of N_2O emitted from settlements depends not only on N inputs and fertilized area, but also on a large number of variables, including organic C availability, oxygen gas partial pressure, soil moisture content, pH, temperature, and irrigation/watering practices. The effect of the combined interaction of these variables on N_2O flux is complex and highly uncertain. The IPCC default methodology does not explicitly incorporate any of these variables, except variations in fertilizer N and sewage sludge application rates. All settlement soils are treated equivalently under this methodology.

Uncertainties exist in both the fertilizer N and sewage sludge application rates in addition to the emission factors. Uncertainty in fertilizer N application was assigned a default level[195] of ±50 percent. Uncertainty in the amounts of sewage sludge applied to non-agricultural lands and used in surface disposal was derived from variability in several factors, including: (1) N content of sewage sludge; (2) total sludge applied in 2000; (3) wastewater existing flow in 1996 and 2000; and (4) the sewage sludge disposal practice distributions to non-agricultural land application and surface disposal. Uncertainty in the emission factors was provided by the IPCC (2006).

Quantitative uncertainty of this source category was estimated through the IPCC-recommended Tier 2 uncertainty estimation methodology. The uncertainty ranges around the 2005 activity data and emission factor input variables were directly applied to the 2009 emission estimates. The results of the quantitative uncertainty analysis are summarized in Table 7-46. N_2O emissions from soils in Settlements Remaining Settlements in 2009 were estimated to be between 0.8 and 4.0 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 49 percent below to 163 percent above the 2009 emission estimate of 1.5 Tg CO_2 Eq.

Table 7-46: Quantitative Uncertainty Estimates of N_2O Emissions from Soils in *Settlements Remaining Settlements* (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emissions (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Settlements Remaining Settlements:						
N_2O Fluxes from Soils	N_2O	1.5	0.8	4.0	-49%	163%

Note: This estimate includes direct N_2O emissions from N fertilizer additions to both *Settlements Remaining Settlements* and from *Land Converted to Settlements*.

[195] No uncertainty is provided with the USGS application data (Ruddy et al. 2006) so a conservative ±50% was used in the analysis.

Planned Improvements

A minor improvement is planned to update the uncertainty analysis for direct emissions from settlements to be consistent with the most recent activity data for this source.

7.10. Land Converted to Settlements (Source Category 5E2)

Land-use change is constantly occurring, and land under a number of uses undergoes urbanization in the United States each year. However, data on the amount of land converted to settlements is currently lacking. Given the lack of available information relevant to this particular IPCC source category, it is not possible to separate CO_2 or N_2O fluxes on *Land Converted to Settlements* from fluxes on *Settlements Remaining Settlements* at this time.

7.11. Other (IPCC Source Category 5G)

Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills

In the United States, a significant change in C stocks results from the removal of yard trimmings (i.e., grass clippings, leaves, and branches) and food scraps from settlements to be disposed in landfills. Yard trimmings and food scraps account for a significant portion of the municipal waste stream, and a large fraction of the collected yard trimmings and food scraps are discarded in landfills. C contained in landfilled yard trimmings and food scraps can be stored for very long periods.

Carbon storage estimates are associated with particular land uses. For example, harvested wood products are accounted for under *Forest Land Remaining Forest Land* because these wood products are a component of the forest ecosystem. The wood products serve as reservoirs to which C resulting from photosynthesis in trees is transferred, but the removals in this case occur in the forest. C stock changes in yard trimmings and food scraps are associated with settlements, but removals in this case do not occur within settlements. To address this complexity, yard trimming and food scrap C storage is therefore reported under the "Other" source category.

Both the amount of yard trimmings collected annually and the fraction that is landfilled have declined over the last decade. In 1990, over 53 million metric tons (wet weight) of yard trimmings and food scraps were generated (i.e., put at the curb for collection to be taken to disposal sites or to composting facilities) (EPA 2011; Schneider 2007, 2008). Since then, programs banning or discouraging yard trimmings disposal have led to an increase in backyard composting and the use of mulching mowers, and a consequent 5 percent decrease in the tonnage generated (i.e., collected for composting or disposal). At the same time, an increase in the number of municipal composting facilities has reduced the proportion of collected yard trimmings that are discarded in landfills—from 72 percent in 1990 to 33 percent in 2009. The net effect of the reduction in generation and the increase in composting is a 57 percent decrease in the quantity of yard trimmings disposed in landfills since 1990.

Food scraps generation has grown by 44 percent since 1990, and though the proportion of food scraps discarded in landfills has decreased slightly from 82 percent in 1990 to 80 percent in 2009, the tonnage disposed in landfills has increased considerably (by 40 percent). Overall, the decrease in the yard trimmings landfill disposal rate has more than compensated for the increase in food scrap disposal in landfills, and the net result is a decrease in annual landfill carbon storage from 24.2 Tg CO_2 Eq. in 1990 to 12.6 Tg CO_2 Eq. in 2009 (Table 7-47 and Table 7-48).

Table 7-47: Net Changes in Yard Trimming and Food Scrap Stocks in Landfills (Tg CO_2 Eq.)

Carbon Pool	1990	2000	2005	2006	2007	2008	2009
Yard Trimmings	**(21.0)**	**(8.8)**	**(7.3)**	**(7.5)**	**(7.0)**	**(7.3)**	**(8.5)**
Grass	(1.8)	(0.7)	(0.6)	(0.6)	(0.6)	(0.7)	(0.8)
Leaves	(9.0)	(3.9)	(3.3)	(3.4)	(3.2)	(3.4)	(3.9)
Branches	(10.2)	(4.2)	(3.3)	(3.4)	(3.2)	(3.3)	(3.8)
Food Scraps	**(3.2)**	**(4.4)**	**(4.3)**	**(3.5)**	**(3.9)**	**(3.9)**	**(4.1)**
Total Net Flux	**(24.2)**	**(13.2)**	**(11.5)**	**(11.0)**	**(10.9)**	**(11.2)**	**(12.6)**

Note: Totals may not sum due to independent rounding.

Table 7-48: Net Changes in Yard Trimming and Food Scrap Stocks in Landfills (Tg C)

Carbon Pool	1990	2000	2005	2006	2007	2008	2009
Yard Trimmings	**(5.7)**	**(2.4)**	**(2.0)**	**(2.0)**	**(1.9)**	**(2.0)**	**(2.3)**
Grass	(0.5)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Leaves	(2.5)	(1.1)	(0.9)	(0.9)	(0.9)	(0.9)	(1.1)
Branches	(2.8)	(1.2)	(0.9)	(0.9)	(0.9)	(0.9)	(1.0)
Food Scraps	**(0.9)**	**(1.2)**	**(1.2)**	**(1.0)**	**(1.1)**	**(1.1)**	**(1.1)**
Total Net Flux	**(6.6)**	**(3.6)**	**(3.1)**	**(3.0)**	**(3.0)**	**(3.1)**	**(3.4)**

Note: Totals may not sum due to independent rounding.

Methodology

When wastes of biogenic origin (such as yard trimmings and food scraps) are landfilled and do not completely decompose, the C that remains is effectively removed from the global C cycle. Empirical evidence indicates that yard trimmings and food scraps do not completely decompose in landfills (Barlaz 1998, 2005, 2008; De la Cruz and Barlaz 2010), and thus the stock of carbon in landfills can increase, with the net effect being a net atmospheric removal of carbon. Estimates of net C flux resulting from landfilled yard trimmings and food scraps were developed by estimating the change in landfilled C stocks between inventory years, based on methodologies presented for the Land Use, Land-Use Change, and Forestry sector in IPCC (2003). C stock estimates were calculated by determining the mass of landfilled C resulting from yard trimmings or food scraps discarded in a given year; adding the accumulated landfilled C from previous years; and subtracting the mass of C landfilled in previous years that decomposed.

To determine the total landfilled C stocks for a given year, the following were estimated: (1) the composition of the yard trimmings; (2) the mass of yard trimmings and food scraps discarded in landfills; (3) the C storage factor of the landfilled yard trimmings and food scraps; and (4) the rate of decomposition of the degradable C. The composition of yard trimmings was assumed to be 30 percent grass clippings, 40 percent leaves, and 30 percent branches on a wet weight basis (Oshins and Block 2000). The yard trimmings were subdivided, because each component has its own unique adjusted C storage factor and rate of decomposition. The mass of yard trimmings and food scraps disposed of in landfills was estimated by multiplying the quantity of yard trimmings and food scraps discarded by the proportion of discards managed in landfills. Data on discards (i.e., the amount generated minus the amount diverted to centralized composting facilities) for both yard trimmings and food scraps were taken primarily from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures for 2009* (EPA 2011), which provides data for 1960, 1970, 1980, 1990, 2000, and 2005 through 2009. To provide data for some of the missing years, detailed backup data were obtained from Schneider (2007, 2008). Remaining years in the time series for which data were not provided were estimated using linear interpolation. The EPA (2011) report does not subdivide discards of individual materials into volumes landfilled and combusted, although it provides an estimate of the proportion of overall waste stream discards managed in landfills[196] and combustors with energy recovery (i.e., ranging from 100 percent and 0 percent, respectively, in 1960 to 81 percent and 19 percent in 2000); it is assumed that the proportion of each individual material (food scraps, grass, leaves, branches) that is landfilled is the same as the proportion across the overall waste stream.

The amount of C disposed of in landfills each year, starting in 1960, was estimated by converting the discarded landfilled yard trimmings and food scraps from a wet weight to a dry weight basis, and then multiplying by the initial (i.e., pre-decomposition) C content (as a fraction of dry weight). The dry weight of landfilled material was calculated using dry weight to wet weight ratios (Tchobanoglous et al. 1993, cited by Barlaz 1998) and the initial C contents and the C storage factors were determined by Barlaz (1998, 2005, 2008) (Table 7-49).

The amount of C remaining in the landfill for each subsequent year was tracked based on a simple model of C fate. As demonstrated by Barlaz (1998, 2005, 2008), a portion of the initial C resists decomposition and is essentially persistent in the landfill environment. Barlaz (1998, 2005, 2008) conducted a series of experiments designed to

[196] EPA (2011) reports discards in two categories: "combustion with energy recovery" and "landfill, other disposal," which includes combustion without energy recovery. For years in which there is data from previous EPA reports on combustion without energy recovery, EPA assumes these estimates are still applicable. For 2000 to present, EPA assumes that any combustion of MSW that occurs includes energy recovery, so all discards to "landfill, other disposal" are assumed to go to landfills.

measure biodegradation of yard trimmings, food scraps, and other materials, in conditions designed to promote decomposition (i.e., by providing ample moisture and nutrients). After measuring the initial C content, the materials were placed in sealed containers along with a "seed" containing methanogenic microbes from a landfill. Once decomposition was complete, the yard trimmings and food scraps were re-analyzed for C content; the C remaining in the solid sample can be expressed as a proportion of initial C (shown in the row labeled "CS" in Table 7-49).

The modeling approach applied to simulate U.S. landfill C flows builds on the findings of Barlaz (1998, 2005, 2008). The proportion of C stored is assumed to persist in landfills. The remaining portion is assumed to degrade, resulting in emissions of CH_4 and CO_2 (the CH_4 emissions resulting from decomposition of yard trimmings and food scraps are accounted for in the "Waste" chapter). The degradable portion of the C is assumed to decay according to first-order kinetics.

The first-order decay rates, *k*, for each component were derived from De la Cruz and Barlaz (2010). De la Cruz and Barlaz (2010) calculate first-order decay rates using laboratory data published in Eleazer et al. (1997), and a correction factor, *f*, is found so that the weighted average decay rate for all components is equal to the AP-42 default decay rate (0.04) for mixed MSW for regions that receive more than 25 inches of rain annually. Because AP-42 values were developed using landfill data from approximately 1990, 1990 waste composition for the United States from EPA's *Characterization of Municipal Solid Waste in the United States: 1990 Update* was used to calculate *f*. This correction factor is then multiplied by the Eleazer et al. (1997) decay rates of each waste component to develop field-scale first-order decay rates.

De la Cruz and Barlaz (2010) also use other assumed initial decay rates for mixed MSW in place of the AP-42 default value based on different types of environments in which landfills in the United States are found, including dry conditions (less than 25 inches of rain annually, k=0.02) and bioreactor landfill conditions (moisture is controlled for rapid decomposition, k=0.12). The *Landfills* section of the Inventory (which estimates CH_4 emissions) estimates the overall MSW decay rate by partitioning the U.S. landfill population into three categories, based on annual precipitation ranges of (1) less than 20 inches of rain per year, (2) 20 to 40 inches of rain per year, and (3) greater than 40 inches of rain per year. These correspond to overall MSW decay rates of 0.020, 0.038, and 0.057 yr^{-1}, respectively.

De la Cruz and Barlaz (2010) calculate component-specific decay rates corresponding to the first value (0.020 yr^{-1}), but not for the other two overall MSW decay rates. To maintain consistency between landfill methodologies across the Inventory, the correction factors (*f*) were developed for decay rates of 0.038 and 0.057 yr^{-1} through linear interpolation. A weighted national average component-specific decay rate was calculated by assuming that waste generation is proportional to population (the same assumption used in the landfill methane emission estimate), based on population data from the 2000 U.S. Census. The component-specific decay rates are shown in Table 7-49.

For each of the four materials (grass, leaves, branches, food scraps), the stock of C in landfills for any given year is calculated according to the following formula:

$$LFC_{i,t} = \sum_{n}^{t} W_{i,n} \times (1 - MC_i) \times ICC_i \times \{[CS_i \times ICC_i] + [(1 - (CS_i \times ICC_i)) \times e^{-k(t-n)}]\}$$

where,

t	=	Year for which C stocks are being estimated (year),
i	=	Waste type for which C stocks are being estimated (grass, leaves, branches, food scraps),
$LFC_{i,t}$	=	Stock of C in landfills in year t, for waste i (metric tons),
$W_{i,n}$	=	Mass of waste i disposed in landfills in year n (metric tons, wet weight),
n	=	Year in which the waste was disposed (year, where $1960 < n < t$),
MC_i	=	Moisture content of waste i (percent of water),
CS_i	=	Proportion of initial C that is stored for waste i (percent),
ICC_i	=	Initial C content of waste i (percent),
e	=	Natural logarithm, and
k	=	First-order decay rate for waste i, ($year^{-1}$).

For a given year *t*, the total stock of C in landfills ($TLFC_t$) is the sum of stocks across all four materials (grass, leaves, branches, food scraps). The annual flux of C in landfills (F_t) for year *t* is calculated as the change in stock compared to the preceding year:

$$F_t = TLFC_t - TLFC_{(t-1)}$$

Thus, the C placed in a landfill in year *n* is tracked for each year *t* through the end of the inventory period (2009). For example, disposal of food scraps in 1960 resulted in depositing about 1,135,000 metric tons of C. Of this amount, 16 percent (179,000 metric tons) is persistent; the remaining 84 percent (956,000 metric tons) is degradable. By 1965, more than half of the degradable portion (518,000 metric tons) decomposes, leaving a total of 617,000 metric tons (the persistent portion, plus the remainder of the degradable portion).

Continuing the example, by 2009, the total food scraps C originally disposed in 1960 had declined to 179,000 metric tons (i.e., virtually all degradable C had decomposed). By summing the C remaining from 1960 with the C remaining from food scraps disposed in subsequent years (1961 through 2009), the total landfill C from food scraps in 2009 was 35.9 million metric tons. This value is then added to the C stock from grass, leaves, and branches to calculate the total landfill C stock in 2009, yielding a value of 247.1 million metric tons (as shown in Table 7-50). In exactly the same way total net flux is calculated for forest C and harvested wood products, the total net flux of landfill C for yard trimmings and food scraps for a given year (Table 7-48) is the difference in the landfill C stock for that year and the stock in the preceding year. For example, the net change in 2009 shown in Table 7-48 (3.4 Tg C) is equal to the stock in 2009 (247.1 Tg C) minus the stock in 2008 (243.7 Tg C).

The C stocks calculated through this procedure are shown in Table 7-50.

Table 7-49: Moisture Content (%), C Storage Factor, Proportion of Initial C Sequestered (%), Initial C Content (%), and Decay Rate ($year^{-1}$) for Landfilled Yard Trimmings and Food Scraps in Landfills

	Yard Trimmings			Food Scraps
Variable	**Grass**	**Leaves**	**Branches**	
Moisture Content (% H_2O)	70	30	10	70
CS, proportion of initial C stored (%)	53	85	77	16
Initial C Content (%)	45	46	49	51
Decay Rate ($year^{-1}$)	0.323	0.185	0.016	0.156

Table 7-50: C Stocks in Yard Trimmings and Food Scraps in Landfills (Tg C)

Carbon Pool	1990	2000	2005	2006	2007	2008	2009
Yard Trimmings	**155.8**	**191.9**	**202.9**	**205.0**	**206.9**	**208.9**	**211.2**
Branches	74.6	92.4	97.5	98.5	99.3	100.2	101.3
Leaves	66.7	82.4	87.3	88.3	89.1	90.1	91.1
Grass	14.5	17.2	18.1	18.2	18.4	18.6	18.8
Food Scraps	**21.3**	**27.0**	**31.7**	**32.7**	**33.7**	**34.8**	**35.9**
Total Carbon Stocks	**177.2**	**218.9**	**234.6**	**237.6**	**240.6**	**243.7**	**247.1**

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

The uncertainty analysis for landfilled yard trimmings and food scraps includes an evaluation of the effects of uncertainty for the following data and factors: disposal in landfills per year (tons of C), initial C content, moisture content, decay rate, and proportion of C stored. The C storage landfill estimates are also a function of the composition of the yard trimmings (i.e., the proportions of grass, leaves and branches in the yard trimmings mixture). There are respective uncertainties associated with each of these factors.

A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the overall uncertainty of the sequestration estimate. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-51. Total yard trimmings and food scraps CO_2 flux in 2009 was estimated to be between -21.2 and -6.2 Tg CO_2 Eq. at a 95 percent confidence level (or 19 of 20 Monte Carlo stochastic simulations). This indicates a range of 68 percent below to 51 percent above the 2009 flux estimate of -12.6 Tg CO_2 Eq. More information on the uncertainty estimates for Yard Trimmings and Food Scraps in Landfills is contained within the Uncertainty Annex.

Table 7-51: Tier 2 Quantitative Uncertainty Estimates for CO_2 Flux from Yard Trimmings and Food Scraps in Landfills (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Flux Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Flux Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Flux Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Yard Trimmings and Food Scraps	CO_2	(12.6)	(21.2)	(6.2)	-68%	+51%

[a] Range of flux estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
Note: Parentheses indicate negative values or net C sequestration.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation and did not reveal any systematic inaccuracies or incorrect input values.

Recalculations Discussion

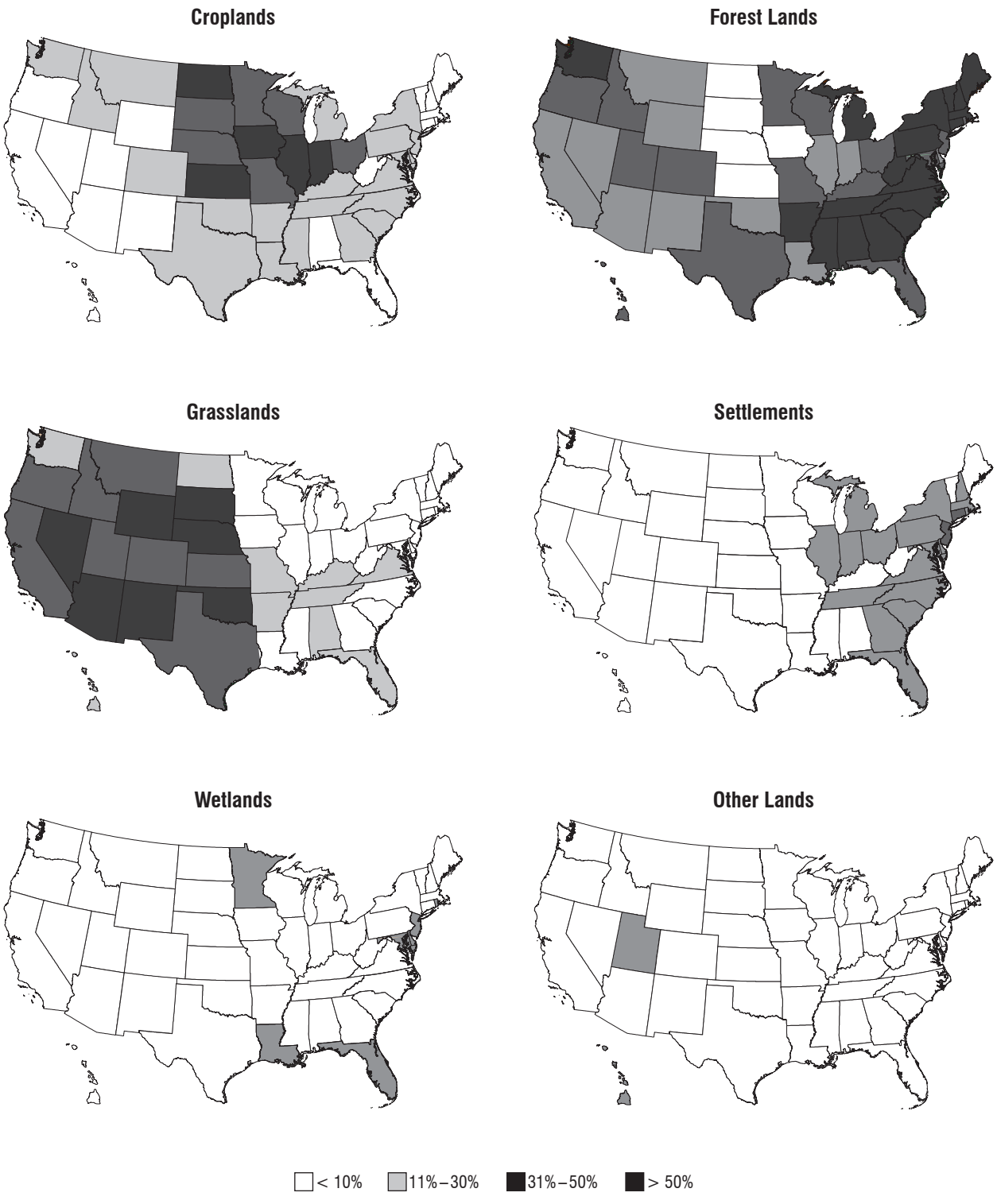
First-order decay rate constants were updated based on De la Cruz and Barlaz (2010), as described in the methodology section. Input data were updated for the years: 1990, 2000, 2005, and 2007 through 2009 based on the updated values reported in *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures for 2009* (EPA 2011). As a result, C storage estimates for those years were revised relative to the previous Inventory. While data inputs for intervening years in the timeseries were not revised, overall C storage in any given year is dependent on the previous year's storage (as shown in the second equation above), and so C storage estimates for those years were also revised. These revisions resulted in an annual average increase in C stored in landfills of 4.2 percent across the timeseries.

Planned Improvements

Future work is planned to evaluate the potential contribution of inorganic C, primarily in the form of carbonates, to landfill sequestration, as well as the consistency between the estimates of C storage described in this chapter and the estimates of landfill CH_4 emissions described in the Waste chapter.

Figure 7-1

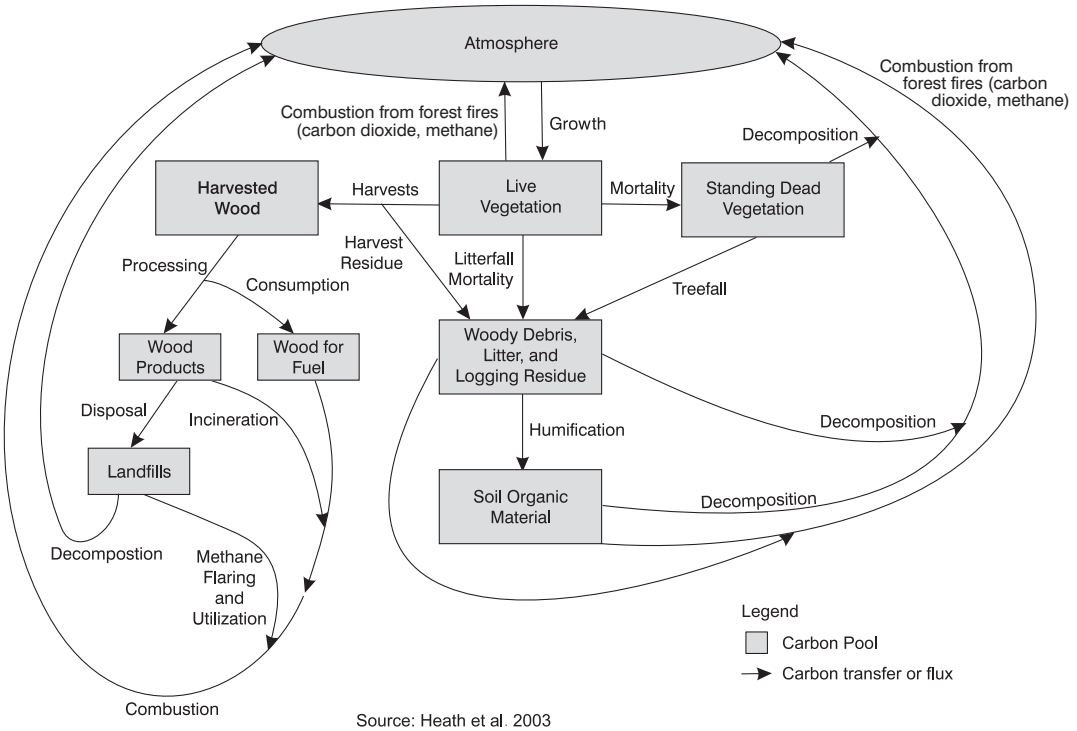
Percent of Total Land Area in the General Land Use Categories for 2009



Note: Land use/land-use change categories were aggregated into the 6 general land-use categories based on the current use in 2009.

Figure 7-2

Forest Sector Carbon Pools and Flows



Source: Heath et al. 2003

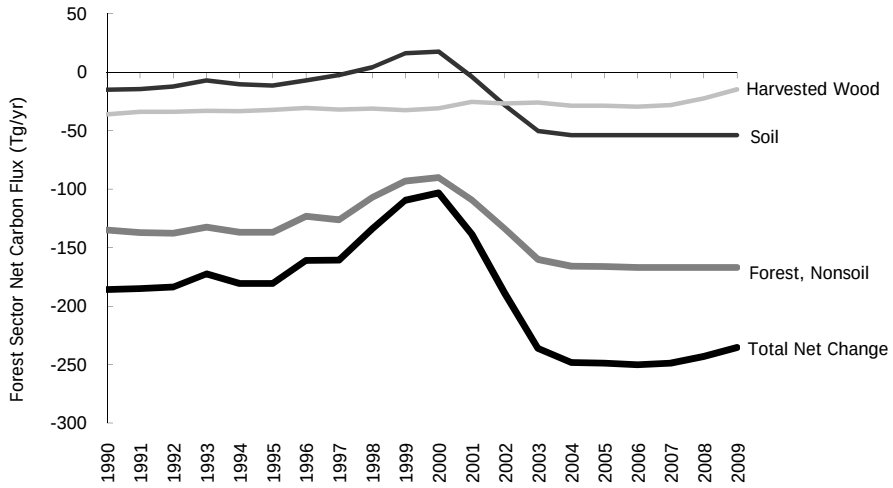


Figure 7-3: Estimates of Net Annual Changes in C Stocks for Major C Pools

Figure 7-4

Average C Density in the Forest Tree Pool in the Conterminous United States, 2009

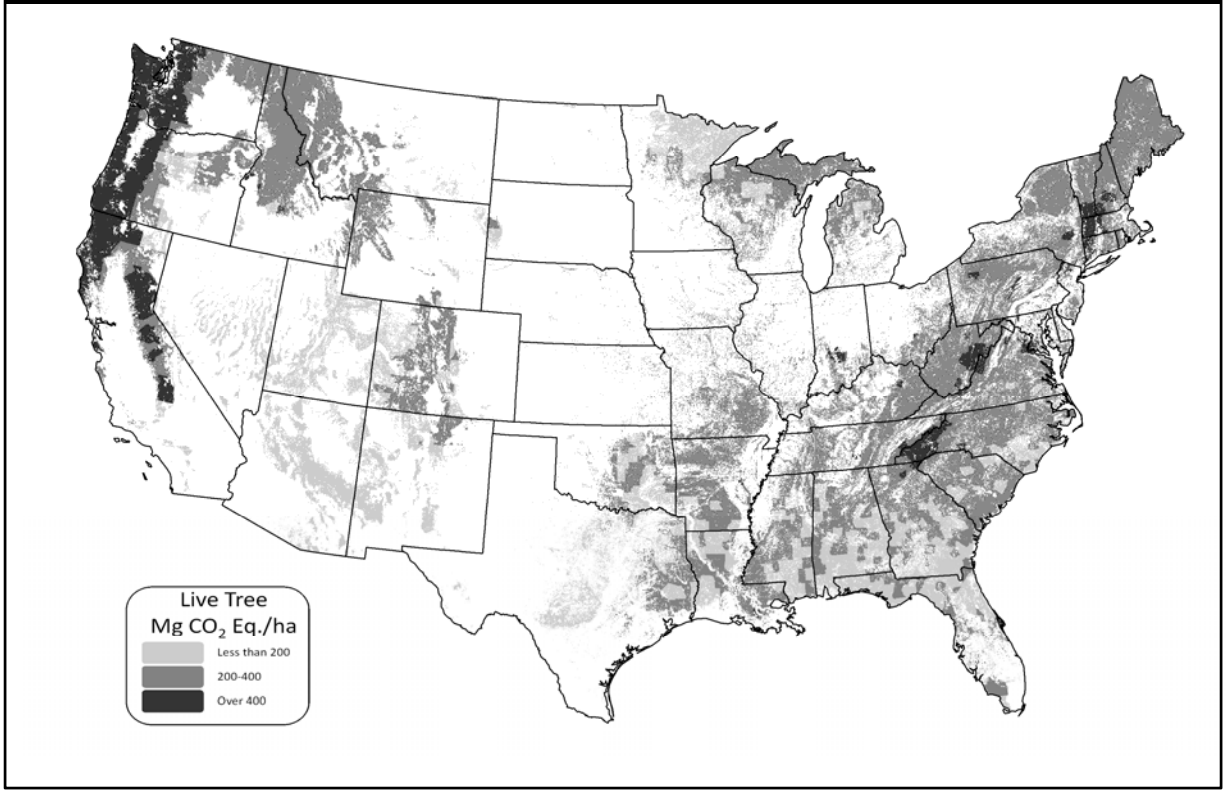
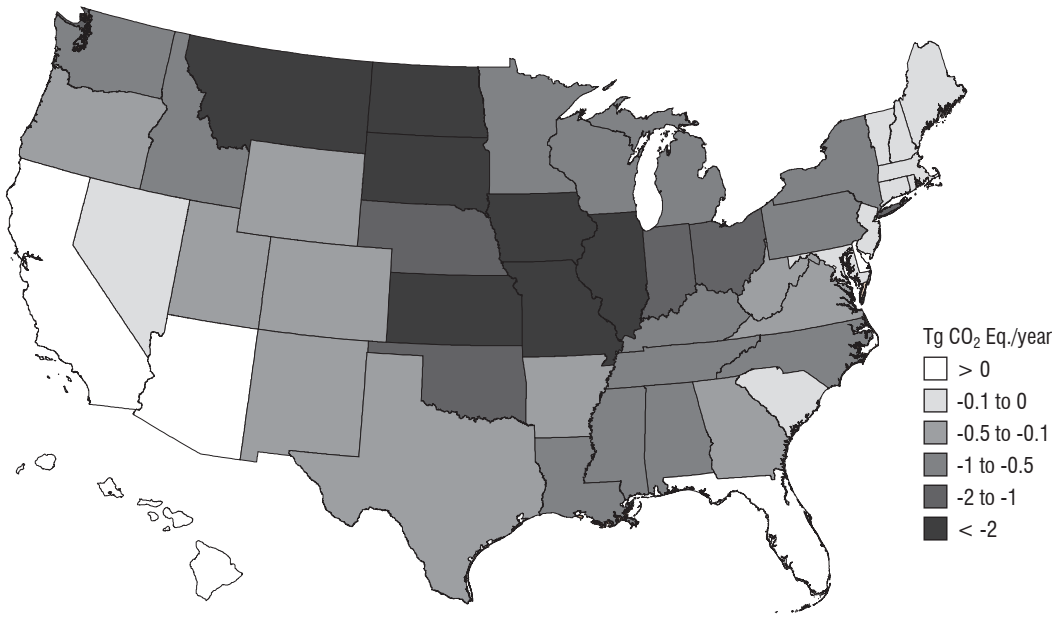


Figure 7-5

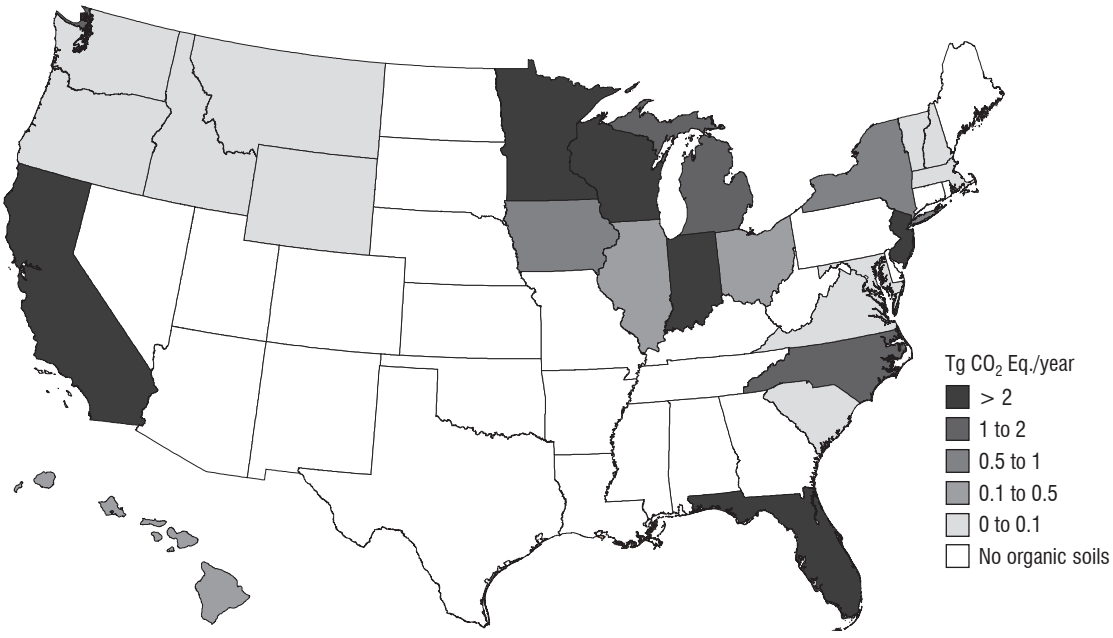
Total Net Annual CO_2 Flux for Mineral Soils Under Agricultural Management within States, 2009, *Cropland Remaining Cropland*



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-6

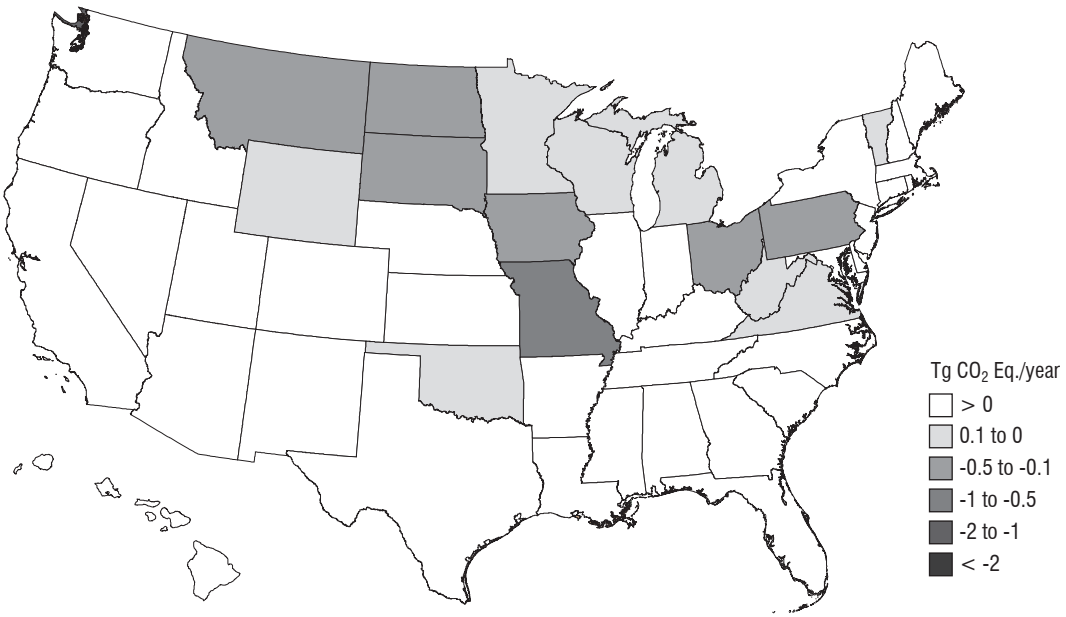
Total Net Annual CO_2 Flux for Organic Soils Under Agricultural Management within States, 2009, *Cropland Remaining Cropland*



Note: Values greater than zero represent emissions.

Figure 7-7

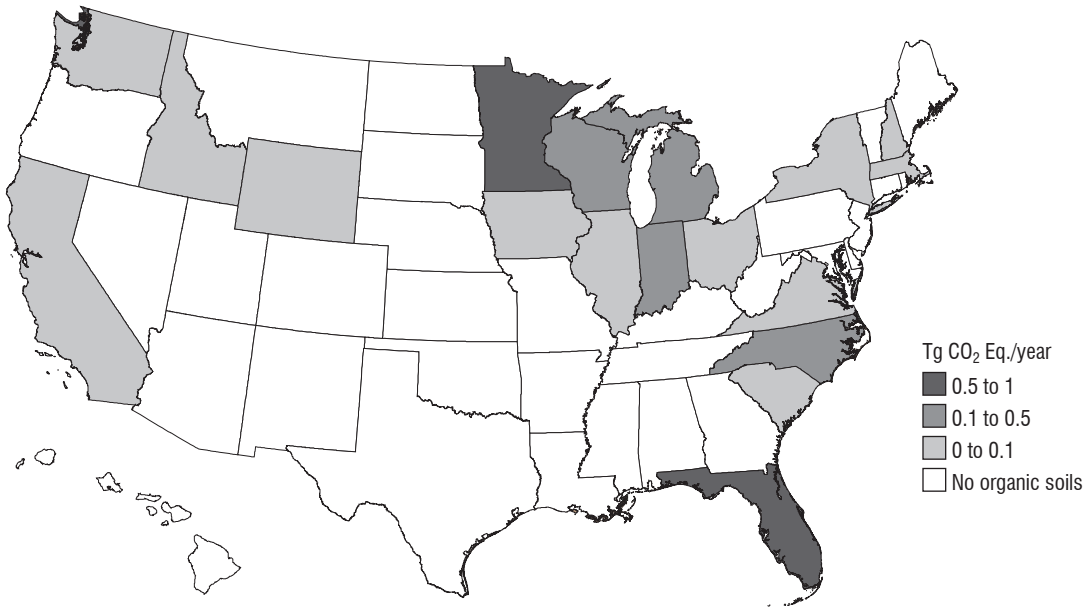
Total Net Annual CO_2 Flux for Mineral Soils Under Agricultural Management within States, 2009, *Land Converted to Cropland*



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-8

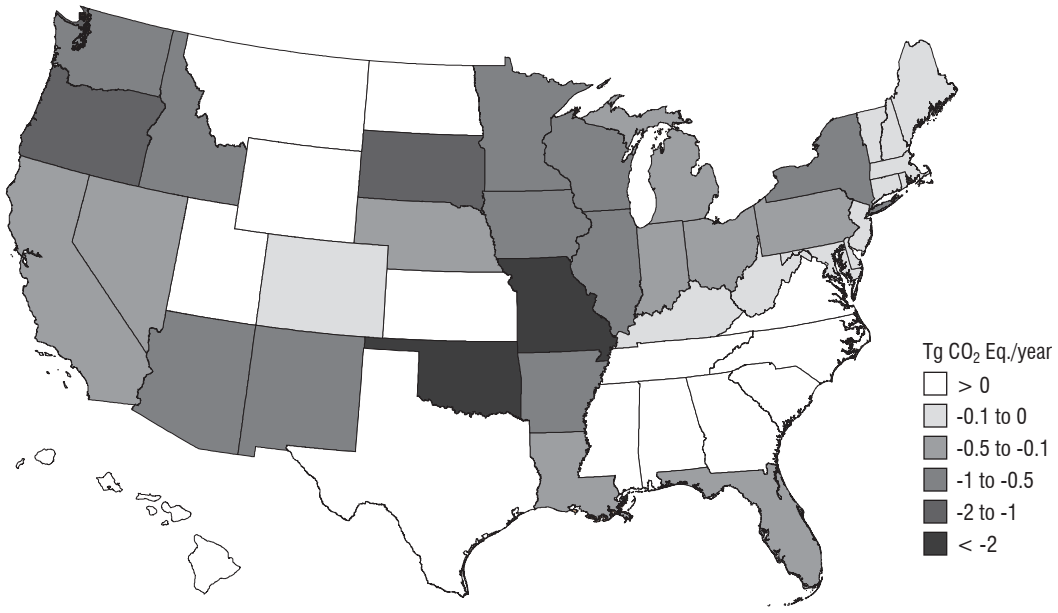
Total Net Annual CO_2 Flux for Organic Soils Under Agricultural Management within States, 2009, *Land Converted to Cropland*



Note: Values greater than zero represent emissions.

Figure 7-9

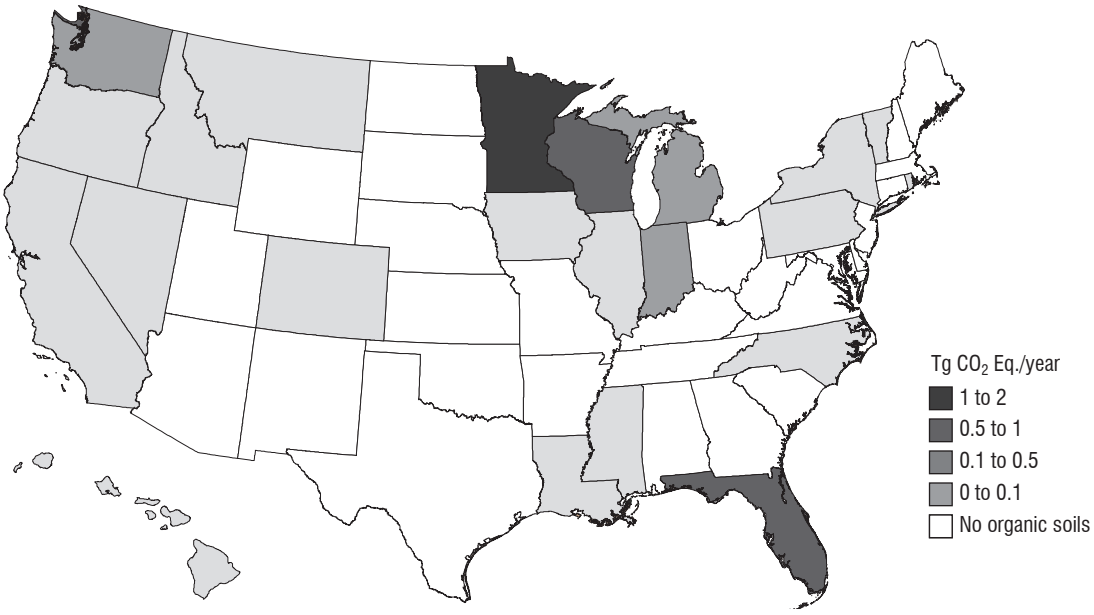
Total Net Annual CO_2 Flux for Mineral Soils Under Agricultural Management within States, 2009, *Grassland Remaining Grassland*



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-10

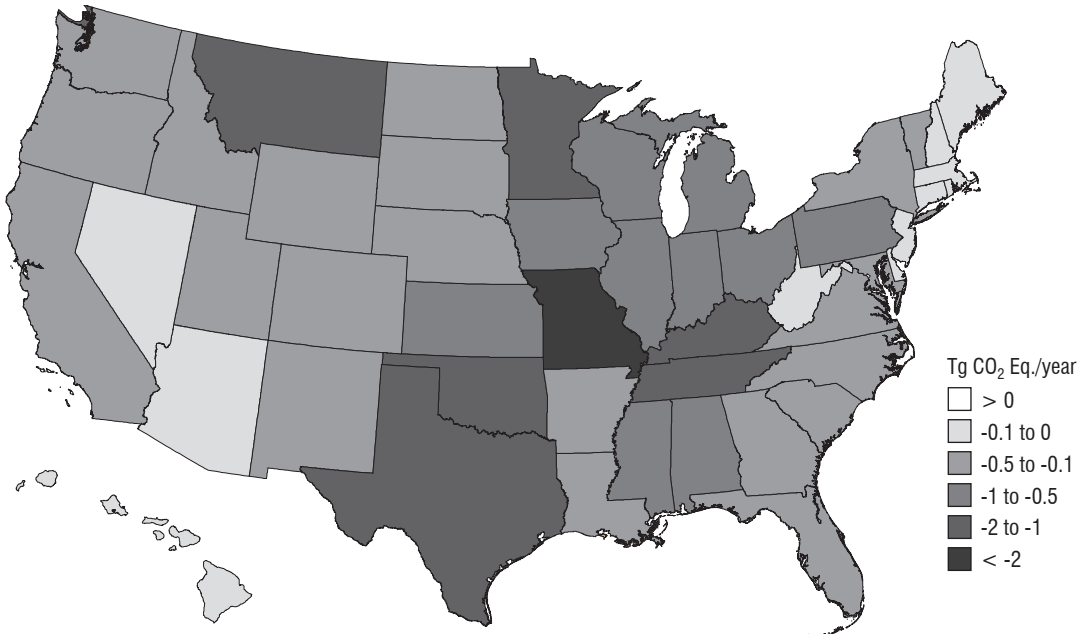
Total Net Annual CO_2 Flux for Organic Soils Under Agricultural Management within States, 2009, *Grassland Remaining Grassland*



Note: Values greater than zero represent emissions.

Figure 7-11

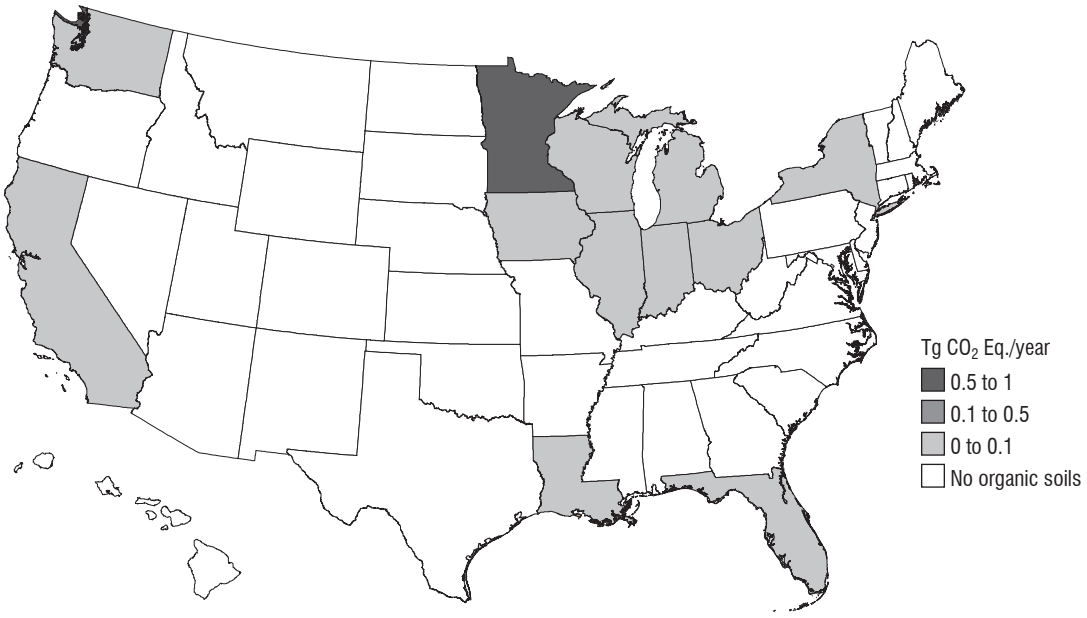
Total Net Annual CO_2 Flux for Mineral Soils Under Agricultural Management within States, 2009, *Land Converted to Grassland*



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-12

Total Net Annual CO_2 Flux for Organic Soils Under Agricultural Management within States, 2009, *Land Converted to Grassland*



Note: Values greater than zero represent emissions.

8. Waste

Waste management and treatment activities are sources of greenhouse gas emissions (see Figure 8-1). Landfills accounted for approximately 17 percent of total U.S. anthropogenic methane (CH_4) emissions in 2009, the third largest contribution of any CH_4 source in the United States. Additionally, wastewater treatment and composting of organic waste accounted for approximately 4 percent and less than 1 percent of U.S. CH_4 emissions, respectively. Nitrous oxide (N_2O) emissions from the discharge of wastewater treatment effluents into aquatic environments were estimated, as were N_2O emissions from the treatment process itself. N_2O emissions from composting were also estimated. Together, these waste activities account for less than 3 percent of total U.S. N_2O emissions. Nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) are emitted by waste activities, and are addressed separately at the end of this chapter. A summary of greenhouse gas emissions from the Waste chapter is presented in Table 8-1 and Table 8-2.

CO_2, N_2O, and CH_4 emissions from the incineration of waste are accounted for in the Energy sector rather than in the Waste sector because almost all incineration of municipal solid waste (MSW) in the United States occurs at waste-to-energy facilities where useful energy is recovered. Similarly, the Energy sector also includes an estimate of emissions from burning waste tires because virtually all of the combustion occurs in industrial and utility boilers that recover energy. The incineration of waste in the United States in 2009 resulted in 12.7 Tg CO_2 Eq. emissions, nearly half of which is attributable to the combustion of plastics. For more details on emissions from the incineration of waste, see Section 3.3.

Figure 8-1: 2009 Waste Chapter Greenhouse Gas Sources

[BEGIN BOX]

Box 8-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report, and this chapter, are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC).[197] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[198] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this Inventory do not preclude alternative examinations,[199] but rather this Inventory presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself, and this chapter, follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

[END BOX]

Overall, in 2009, waste activities generated emissions of 150.5 Tg CO_2 Eq., or just over 2 percent of total U.S. greenhouse gas emissions.

Table 8-1. Emissions from Waste (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH_4	**171.2**	**138.1**	**138.4**	**137.8**	**137.4**	**142.1**	**143.6**
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5

[197] See http://www.ipcc-nggip.iges.or.jp/public/index.html.

[198] See http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php.

[199] For example, see http://www.epa.gov/aboutepa/oswer.html.

Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
N_2O	**4.0**	**5.9**	**6.5**	**6.6**	**6.7**	**6.8**	**6.9**
Domestic Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Total	**175.2**	**143.9**	**144.9**	**144.4**	**144.1**	**149.0**	**150.5**

Note: Totals may not sum due to independent rounding.

Table 8-2. Emissions from Waste (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH_4	**8,152**	**6,576**	**6,591**	**6,563**	**6,541**	**6,769**	**6,840**
Landfills	7,018	5,317	5,358	5,321	5,299	5,520	5,593
Wastewater Treatment	1,118	1,199	1,159	1,167	1,163	1,168	1,167
Composting	15	60	75	75	79	80	79
N_2O	**13**	**19**	**21**	**21**	**22**	**22**	**22**
Domestic Wastewater Treatment	12	14	15	16	16	16	16
Composting	1	4	6	6	6	6	6

Note: Totals may not sum due to independent rounding.

8.1. Landfills (IPCC Source Category 6A1)

In 2009, landfill CH_4 emissions were approximately 117.5 Tg CO_2 Eq. (5,593 Gg of CH_4), representing the third largest source of CH_4 emissions in the United States, behind natural gas systems and enteric fermentation. Emissions from municipal solid waste (MSW) landfills, which received about 64.5 percent of the total solid waste generated in the United States, accounted for about 94 percent of total landfill emissions, while industrial landfills accounted for the remainder. Approximately 1,800 operational landfills exist in the United States, with the largest landfills receiving most of the waste and generating the majority of the CH_4 (*BioCycle* 2006, adjusted to include missing data from five states).

After being placed in a landfill, waste (such as paper, food scraps, and yard trimmings) is initially decomposed by aerobic bacteria. After the oxygen has been depleted, the remaining waste is available for consumption by anaerobic bacteria, which break down organic matter into substances such as cellulose, amino acids, and sugars. These substances are further broken down through fermentation into gases and short-chain organic compounds that form the substrates for the growth of methanogenic bacteria. These CH_4-producing anaerobic bacteria convert the fermentation products into stabilized organic materials and biogas consisting of approximately 50 percent carbon dioxide (CO_2) and 50 percent CH_4, by volume. Significant CH_4 production typically begins one or two years after waste disposal in a landfill and continues for 10 to 60 years or longer.

Methane emissions from landfills are a function of several factors, including: (1) the total amount of waste in MSW landfills, which is related to total waste landfilled annually; (2) the characteristics of landfills receiving waste (i.e., composition of waste-in-place, size, climate); (3) the amount of CH_4 that is recovered and either flared or used for energy purposes; and (4) the amount of CH_4 oxidized in landfills instead of being released into the atmosphere. From 1990 to 2009, net CH_4 emissions from landfills decreased by approximately 20 percent (see Table 8-3 and Table 8-4). This net CH_4 emissions decrease can be attributed to many factors, including changes in waste composition, an increase in the amount of landfill gas collected and combusted, a higher frequency of composting, and increased rates of recovery for degradeable materials (e.g, paper and paperboard).

The estimated annual quantity of waste placed in MSW landfills increased from about 209 Tg in 1990 to 297 Tg in 2009, an increase of 42 percent (see Annex 3.14). Despite increased waste disposal, the amount of decomposable materials (i.e., paper and paperboard, food scraps, and yard trimmings) discarded in MSW landfills have decreased by approximately 21 percent from 1990 to 2008 (EPA, 2009b). In addition, the amount of landfill gas collected and combusted has increased. In 1990, for example, approximately 970 Gg of CH_4 were recovered and combusted (i.e., used for energy or flared) from landfills, while in 2009, 7,208 Gg CH_4 was combusted, which represents a 3 percent increase in the quantity of CH_4 recovered and combusted from 2008 levels. In 2009, an estimated 49 new landfill gas-to-energy (LFGTE) projects and 32 new flares began operation.

Over the past 9 years, however, the net CH_4 emissions have fluctuated from year to year, but a slowly increasing trend has been observed. While the amount of landfill gas collected and combusted continues to increase every year, the rate of increase in collection and combustion no longer exceeds the rate of additional CH_4 generation from the amount of organic MSW landfilled as the U.S. population grows.

Over the next several years, the total amount of municipal solid waste generated is expected to increase as the U.S. population continues to grow. The percentage of waste landfilled, however, may decline due to increased recycling and composting practices. In addition, the quantity of CH_4 that is recovered and either flared or used for energy purposes is expected to continue to increase as a result of 1996 federal regulations that require large municipal solid waste landfills to collect and combust landfill gas (see 40 CFR Part 60, Subpart Cc 2005 and 40 CFR Part 60, Subpart WWW 2005), voluntary programs that encourage CH_4 recovery and use such as EPA's Landfill Methane Outreach Program (LMOP), and federal and state incentives that promote renewable energy (e.g., tax credits, low interest loans, and Renewable Portfolio Standards).

Table 8-3. CH_4 Emissions from Landfills (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
MSW Landfills	172.6	206.9	241.2	248.1	254.2	260.3	266.3
Industrial Landfills	11.5	14.3	15.2	15.3	15.4	15.5	15.6
Recovered							
Gas-to-Energy	(13.6)	(49.4)	(56.5)	(59.0)	(63.7)	(67.0)	(72.0)
Flared	(6.7)	(47.8)	(74.9)	(80.2)	(82.3)	(80.0)	(79.4)
Oxidized[a]	(16.4)	(12.4)	(12.5)	(12.4)	(12.4)	(12.9)	(13.1)
Total	**147.4**	**111.7**	**112.5**	**111.7**	**111.3**	**115.9**	**117.5**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.
[a] Includes oxidation at both municipal and industrial landfills.

Table 8-4. CH_4 Emissions from Landfills (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
MSW Landfills	8,219	9,854	11,486	11,813	12,107	12,395	12,679
Industrial Landfills	549	682	724	727	732	738	744
Recovered							
Gas-to-Energy	(649)	(2,352)	(2,691)	(2,807)	(3,033)	(3,189)	(3,429)
Flared	(321)	(2,276)	(3,566)	(3,820)	(3,918)	(3,810)	(3,779)
Oxidized[a]	(780)	(591)	(596)	(592)	(589)	(614)	(622)
Total	**7,018**	**5,317**	**5,358**	**5,321**	**5,299**	**5,520**	**5,593**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.
[a] Includes oxidation at municipal and industrial landfills.

Methodology

A detailed description of the methodology used to estimate CH_4 emissions from landfills can be found in Annex 3.14.

CH_4 emissions from landfills were estimated as the CH_4 produced from municipal solid waste landfills, plus the CH_4 produced by industrial landfills, minus the CH_4 recovered and combusted, minus the CH_4 oxidized before being released into the atmosphere:

$$CH_{4,\text{Solid Waste}} = [CH_{4,MSW} + CH_{4,Ind} - R] - Ox$$

where,

$CH_{4,\text{Solid Waste}}$ = CH_4 emissions from solid waste
$CH_{4,MSW}$ = CH_4 generation from municipal solid waste landfills,
$CH_{4,Ind}$ = CH_4 generation from industrial landfills,
R = CH_4 recovered and combusted, and
Ox = CH_4 oxidized from MSW and industrial landfills before release to the atmosphere.

The methodology for estimating CH_4 emissions from municipal solid waste landfills is based on the first order decay model described by the Intergovernmental Panel on Climate Change (IPCC 2006). Values for the CH_4 generation

potential (L_0) and rate constant (k) were obtained from an analysis of CH_4 recovery rates for a database of 52 landfills and from published studies of other landfills (RTI 2004; EPA 1998; SWANA 1998; Peer, Thorneloe, and Epperson 1993). The rate constant was found to increase with average annual rainfall; consequently, values of k were developed for 3 ranges of rainfall. The annual quantity of waste placed in landfills was apportioned to the 3 ranges of rainfall based on the percent of the U.S. population in each of the 3 ranges, and historical census data were used to account for the shift in population to more arid areas over time. For further information, see Annex 3.14.

National landfill waste generation and disposal data for 2007, 2008, and 2009 were extrapolated based on *BioCycle* data and the U.S. Census population from 2009. Data for 1989 through 2006 were obtained from *BioCycle* (2008). Because *BioCycle* does not account for waste generated in U.S. territories, waste generation for the territories was estimated using population data obtained from the U.S. Census Bureau (2010) and national per capita solid waste generation from *BioCycle* (2008). Estimates of the annual quantity of waste landfilled for 1960 through 1988 were obtained from EPA's *Anthropogenic Methane Emissions in the United States, Estimates for 1990: Report to Congress* (EPA 1993) and an extensive landfill survey by the EPA's Office of Solid Waste in 1986 (EPA 1988). Although waste placed in landfills in the 1940s and 1950s contributes very little to current CH_4 generation, estimates for those years were included in the first order decay model for completeness in accounting for CH_4 generation rates and are based on the population in those years and the per capita rate for land disposal for the 1960s. For calculations in this inventory, wastes landfilled prior to 1980 were broken into two groups: wastes disposed in landfills (Methane Conversion Factor, MCF, of 1) and those disposed in dumps (MCF of 0.6). Please see Annex 3.14 for more details.

The estimated landfill gas recovered per year was based on updated data collected from vendors of flaring equipment, a database of landfill gas-to-energy (LFGTE) projects compiled by LMOP (EPA 2009a), and a database maintained by the Energy Information Administration (EIA) for the voluntary reporting of greenhouse gases (EIA 2007). As the EIA database only included data through 2006; 2007 to 2009 recovery for projects included in the EIA database were assumed to be the same as in 2006. The three databases were carefully compared to identify landfills that were in two or all three of the databases to avoid double counting reductions. Based on the information provided by the EIA and flare vendor databases, the CH_4 combusted by flares in operation from 1990 to 2009 was estimated. This quantity likely underestimates flaring because these databases do not have information on all flares in operation. Additionally, the EIA and LMOP databases provided data on landfill gas flow and energy generation for landfills with LFGTE projects. If a landfill in the EIA database was also in the LMOP and/or the flare vendor database, the emissions avoided were based on the EIA data because landfill owners or operators reported the amount recovered based on measurements of gas flow and concentration, and the reporting accounted for changes over time. If both flare data and LMOP recovery data were available for any of the remaining landfills (i.e., not in the EIA database), then the emissions recovery was based on the LMOP data, which provides reported landfill-specific data on gas flow for direct use projects and project capacity (i.e., megawatts) for electricity projects. The flare data, on the other hand, only provided a range of landfill gas flow for a given flare size. Given that each LFGTE project is likely to also have a flare, double counting reductions from flares and LFGTE projects in the LMOP database was avoided by subtracting emission reductions associated with LFGTE projects for which a flare had not been identified from the emission reductions associated with flares. A further explanation of the improvements made to estimate the landfill gas recovered for the current Inventory can be found in Annex 3.14.

A destruction efficiency of 99 percent was applied to CH_4 recovered to estimate CH_4 emissions avoided. The value for efficiency was selected based on the range of efficiencies (98 to 100 percent) recommended for flares in EPA's AP-42 Compilation of Air Pollutant Emission Factors, Chapter 2.4 (EPA 1998), efficiencies used to establish new source performance standards (NSPS) for landfills, and in recommendations for closed flares used in LMOP.

Emissions from industrial landfills were estimated from activity data for industrial production (ERG 2010), waste disposal factors, and the first order decay model. As over 99 percent of the organic waste placed in industrial landfills originated from the food processing (meat, vegetables, fruits) and pulp and paper industries, estimates of industrial landfill emissions focused on these two sectors (EPA 1993). The amount of CH_4 oxidized by the landfill cover at both municipal and industrial landfills was assumed to be ten percent of the CH_4 generated that is not recovered (IPCC 2006, Mancinelli and McKay 1985, Czepiel et al. 1996). To calculate net CH_4 emissions, both CH_4 recovered and CH_4 oxidized were subtracted from CH_4 generated at municipal and industrial landfills.

Uncertainty and Time-Series Consistency

Several types of uncertainty are associated with the estimates of CH_4 emissions from landfills. The primary

uncertainty concerns the characterization of landfills. Information is not available on two fundamental factors affecting CH_4 production: the amount and composition of waste placed in every landfill for each year of its operation. The approach used here assumes that the CH_4 generation potential and the rate of decay that produces CH_4, as determined from several studies of CH_4 recovery at landfills, are representative of U.S. landfills.

Additionally, the approach used to estimate the contribution of industrial wastes to total CH_4 generation introduces uncertainty. Aside from uncertainty in estimating CH_4 generation potential, uncertainty exists in the estimates of oxidation by cover soils. There is also uncertainty in the estimates of CH_4 that is recovered by flaring and energy projects. The IPCC default value of 10 percent for uncertainty in recovery estimates was used in the uncertainty analysis when metering was in place (for about 64 percent of the CH_4 estimated to be recovered). For flaring without metered recovery data (approximately 34 percent of the CH_4 estimated to be recovered), a much higher uncertainty of approximately 50 percent was used (e.g., when recovery was estimated as 50 percent of the flare's design capacity).

N_2O emissions from the application of sewage sludge on landfills are not explicitly modeled as part of greenhouse gas emissions from landfills. N_2O emissions from sewage sludge applied to landfills would be relatively small because the microbial environment in landfills is not very conducive to the nitrification and denitrification processes that result in N_2O emissions. Furthermore, the 2006 IPCC Guidelines (IPCC 2006) did not include a methodology for estimating N_2O emissions from solid waste disposal sites "because they are not significant." Therefore, any uncertainty or bias caused by not including N_2O emissions from landfills is expected to be minimal.

The results of the IPCC Good Practice Guidance Tier 2 quantitative uncertainty analysis are summarized in Table 8-5. Landfill CH_4 emissions in 2009 were estimated to be between 61.1 and 164.5 Tg CO_2 Eq., which indicates a range of 48 percent below to 40 percent above the 2009 emission estimate of 117.5 Tg CO_2 Eq.

Table 8-5. Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Landfills (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Landfills	**CH_4**	**117.5**	**61.1**	**164.5**	**-48%**	**+40%**
MSW	CH_4	103.4	61.0	167.5	-41%	+62%
Industrial	CH_4	14.1	10.2	17.1	-28%	+21%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. A primary focus of the QA/QC checks was to ensure that CH_4 recovery estimates were not double-counted. Both manual and electronic checks were made to ensure that emission avoidance from each landfill was calculated in only one of the three databases. The primary calculation spreadsheet is tailored from the IPCC waste model and has been verified previously using the original, peer-reviewed IPCC waste model. All model input values were verified by secondary QA/QC review.

Recalculations Discussion

In developing the current Inventory, a separate Monte Carlo analysis was conducted for MSW and industrial landfills to better characterize the greater amount of uncertainty surrounding industrial waste data. Additional steps were also taken to better characterize the food waste decay rate and the methodology for the flare correction factor. A weighted component-specific decay rate for food waste of 0.156 yr^{-1} was used in the current Inventory as recommended by ICF International (2009). This replaced the previous Inventory's default food waste decay rate of 0.185 yr^{-1} and resulted in a decrease of landfill emissions of less than 1 percent. The majority of changes in CH_4 emissions from landfills over the time series resulted from improvements made to the flare correction factor to better associate flares in the flare vendor database with a landfill and/or Landfill Gas to Energy (LFGTE) project in the

EIA and LMOP databases.

The flare correction factor for the 1990 through 2008 Inventory report consisted of approximately 512 cases where flares were not directly associated with a landfill and/or LFGTE project in the EIA and/or LMOP databases. For these projects, CH_4 avoided would be overestimated as both the CH_4 avoided from flaring and the LFGTE project would be counted. To abstain from overestimating emissions avoided from flaring, the CH_4 avoided from flares with no identified landfill or LFGTE project were determined and the flaring estimate from the flare vendor database was reduced by this quantity (referred to as a flare correction factor) on a state-by-state basis.

If comprehensive data on flares were available, the majority of LFGTE projects in the EIA and LMOP databases would have an identified flare because it is assumed that most LFGTE projects have flares. However, given that the flare vendor data only covers approximately 50 to 75 percent of the flare population, an associated flare was not identified for all LFGTE projects. These LFGTE projects likely have flares; however, flares were unable to be identified due to one of two reasons: (1) inadequate identifier information provided by the flare vendor; or (2) a lack of the flare in the flare vendor database.

Additional effort was undertaken to improve the methodology behind the flare correction factor for the current Inventory to reduce the overall number of flares that were not matched (512) to landfills and/or LFGTE projects in the EIA and LMOP databases. Each flare in the flare vendor database not associated with a LFGTE project in the EIA or LMOP databases was investigated to determine if it could be matched to either a landfill in the EIA database or a LFGTE project in the LMOP database. For some unmatched flares, the location information was missing or incorrectly transferred to the flare vendor database. In other instances, the landfill names were slightly different between what the flare vendor provided and the actual landfill name as listed in the EIA and/or LMOP databases.

It was found that a large majority of the unidentified flares are associated with landfills in LMOP that are currently flaring, but are also considering LFGTE. These landfill projects considering a LFGTE project are labeled as candidate, potential, or construction in the LMOP database. The flare vendor database was improved to match flares with operational, shutdown as well as candidate, potential, and construction LFGTE projects, thereby reducing the total number of unidentified flares in the flare vendor database, all of which are used in the flare correction factor. The results of this effort significantly decreased the number of flares used in the flare correction factor from 512 to 27, impacted emission estimates for the entire time series, and resulted in an average annual decrease of 8.2 Tg CO_2 Eq. (6.5 percent) in CH_4 emissions from the Landfills source category for the period 1990 through 2008.

Planned Improvements

Beginning in 2010, all MSW landfills that accepted waste on or after January 1, 1980 and generate CH_4 in amounts equivalent to 25,000 metric tons or more of carbon dioxide equivalent (CO_2 Eq.) will be required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program (GHGRP). This consists of the landfill, landfill gas collection systems, and landfill gas destruction devices, including flares. In addition to reporting greenhouse gas information to EPA, landfill-specific characteristics such as annual waste disposal quantity, waste composition data, surface area, and cover type must also be reported. The data collected from the GHGRP will be used in future inventories to revise the parameters used in the CH_4 generation calculations, including degradeable organic carbon (DOC), the flare correction factor, the methane correction factor (MCF), fraction of DOC dissimilated (DOC_F), the destruction efficiency of flares, the oxidation factor (Ox), and the rate constant (k). The addition of this higher tier data will improve the emission calculations to provide a more accurate representation of gresnhouse gas emissions from MSW landfills.

[Begin Text Box]

Box 8-1: Biogenic Wastes in Landfills

Regarding the depositing of wastes of biogenic origin in landfills, empirical evidence shows that some of these wastes degrade very slowly in landfills, and the C they contain is effectively sequestered in landfills over a period of time (Barlaz 1998, 2006). Estimates of C removals from landfilling of forest products, yard trimmings, and food scraps are further described in the Land Use, Land-Use Change, and Forestry chapter, based on methods presented in IPCC (2003) and IPCC (2006).

[End Box]

8.2. Wastewater Treatment (IPCC Source Category 6B)

Wastewater treatment processes can produce anthropogenic CH_4 and N_2O emissions. Wastewater from domestic[200] and industrial sources is treated to remove soluble organic matter, suspended solids, pathogenic organisms, and chemical contaminants. Treatment may either occur on site, most commonly through septic systems or package plants, or off site at centralized treatment systems. Centralized wastewater treatment systems may include a variety of processes, ranging from lagooning to advanced tertiary treatment technology for removing nutrients. In the United States, approximately 20 percent of domestic wastewater is treated in septic systems or other on-site systems, while the rest is collected and treated centrally (U.S. Census Bureau 2009).

Soluble organic matter is generally removed using biological processes in which microorganisms consume the organic matter for maintenance and growth. The resulting biomass (sludge) is removed from the effluent prior to discharge to the receiving stream. Microorganisms can biodegrade soluble organic material in wastewater under aerobic or anaerobic conditions, where the latter condition produces CH_4. During collection and treatment, wastewater may be accidentally or deliberately managed under anaerobic conditions. In addition, the sludge may be further biodegraded under aerobic or anaerobic conditions. The generation of N_2O may also result from the treatment of domestic wastewater during both nitrification and denitrification of the N present, usually in the form of urea, ammonia, and proteins. These compounds are converted to nitrate (NO_3) through the aerobic process of nitrification. Denitrification occurs under anoxic conditions (without free oxygen), and involves the biological conversion of nitrate into dinitrogen gas (N_2). N_2O can be an intermediate product of both processes, but is more often associated with denitrification.

The principal factor in determining the CH_4 generation potential of wastewater is the amount of degradable organic material in the wastewater. Common parameters used to measure the organic component of the wastewater are the Biochemical Oxygen Demand (BOD) and Chemical Oxygen Demand (COD). Under the same conditions, wastewater with higher COD (or BOD) concentrations will generally yield more CH_4 than wastewater with lower COD (or BOD) concentrations. BOD represents the amount of oxygen that would be required to completely consume the organic matter contained in the wastewater through aerobic decomposition processes, while COD measures the total material available for chemical oxidation (both biodegradable and non-biodegradable). Because BOD is an aerobic parameter, it is preferable to use COD to estimate CH_4 production. The principal factor in determining the N_2O generation potential of wastewater is the amount of N in the wastewater.

In 2009, CH_4 emissions from domestic wastewater treatment were 16.0 Tg CO_2 Eq. (760 Gg). Emissions gradually increased from 1990 through 1997, but have decreased since that time due to decreasing percentages of wastewater being treated in anaerobic systems, including reduced use of on-site septic systems and central anaerobic treatment systems. In 2009, CH_4 emissions from industrial wastewater treatment were estimated to be 8.5 Tg CO_2 Eq. (407 Gg). Industrial emission sources have increased across the time series through 1999 and then fluctuated up and down with production changes associated with the treatment of wastewater from the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries. Table 8-6 and Table 8-7 provide CH_4 and N_2O emission estimates from domestic and industrial wastewater treatment.

With respect to N_2O, the United States identifies two distinct sources for N_2O emissions from domestic wastewater: emissions from centralized wastewater treatment processes, and emissions from effluent from centralized treatment systems that has been discharged into aquatic environments. The 2009 emissions of N_2O from centralized wastewater treatment processes and from effluent were estimated to be 0.3 Tg CO_2 Eq. (1 Gg) and 4.7 Tg CO_2 Eq. (15.2 Gg), respectively. Total N_2O emissions from domestic wastewater were estimated to be 5.0 Tg CO_2 Eq. (16.2 Gg). N_2O emissions from wastewater treatment processes gradually increased across the time series as a result of increasing U.S. population and protein consumption.

Table 8-6. CH_4 and N_2O Emissions from Domestic and Industrial Wastewater Treatment (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009

[200] Throughout the inventory, emissions from domestic wastewater also include any commercial and industrial wastewater collected and co-treated with domestic wastewater.

CH_4	**23.5**	**25.2**	**24.3**	**24.5**	**24.4**	**24.5**	**24.5**
Domestic	16.4	16.8	16.2	16.0	15.9	15.8	16.0
Industrial*	7.1	8.4	8.2	8.5	8.5	8.6	8.5
N_2O	**3.7**	**4.5**	**4.8**	**4.8**	**4.9**	**5.0**	**5.0**
Domestic	3.7	4.5	4.8	4.8	4.9	5.0	5.0
Total	**27.2**	**29.6**	**29.1**	**29.3**	**29.3**	**29.5**	**29.5**

* Industrial activity includes the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries.
Note: Totals may not sum due to independent rounding.

Table 8-7. CH_4 and N_2O Emissions from Domestic and Industrial Wastewater Treatment (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
CH_4	**1,118**	**1,199**	**1,159**	**1,167**	**1,163**	**1,168**	**1,167**
Domestic	780	801	770	764	758	759	760
Industrial*	338	398	389	403	405	409	407
N_2O	**12**	**14**	**15**	**16**	**16**	**16**	**16**
Domestic	12	14	15	16	16	16	16

* Industrial activity includes the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries.
Note: Totals may not sum due to independent rounding.

Methodology

Domestic Wastewater CH_4 Emission Estimates

Domestic wastewater CH_4 emissions originate from both septic systems and from centralized treatment systems, such as publicly owned treatment works (POTWs). Within these centralized systems, CH_4 emissions can arise from aerobic systems that are not well managed or that are designed to have periods of anaerobic activity (e.g., constructed wetlands), anaerobic systems (anaerobic lagoons and facultative lagoons), and from anaerobic digesters when the captured biogas is not completely combusted. CH_4 emissions from septic systems were estimated by multiplying the total 5-day BOD (BOD_5) produced in the United States by the percent of wastewater treated in septic systems (20 percent), the maximum CH_4 producing capacity for domestic wastewater (0.60 kg CH_4/kg BOD), and the CH_4 correction factor (MCF) for septic systems (0.5). CH_4 emissions from POTWs were estimated by multiplying the total BOD_5 produced in the United States by the percent of wastewater treated centrally (80 percent), the relative percentage of wastewater treated by aerobic and anaerobic systems, the relative percentage of wastewater facilities with primary treatment, the percentage of BOD_5 treated after primary treatment (67.5 percent), the maximum CH_4-producing capacity of domestic wastewater (0.6), and the relative MCFs for aerobic (zero or 0.3) and anaerobic (0.8) systems with all aerobic systems assumed to be well-managed. CH_4 emissions from anaerobic digesters were estimated by multiplying the amount of biogas generated by wastewater sludge treated in anaerobic digesters by the proportion of CH_4 in digester biogas (0.65), the density of CH_4 (662 g CH_4/m^3 CH_4) , and the destruction efficiency associated with burning the biogas in an energy/thermal device (0.99). The methodological equations are:

Emissions from Septic Systems = A
= (% onsite) × (total BOD_5 produced) × (B_o) × (MCF-septic) × 1/10^6

Emissions from Centrally Treated Aerobic Systems = B
= [(% collected) × (total BOD_5 produced) × (% aerobic) × (% aerobic w/out primary) + (% collected) × (total BOD_5 produced) × (% aerobic) × (% aerobic w/primary) × (1-% BOD removed in prim. treat.)] × (% operations not well managed) × (B_o) × (MCF-aerobic_not_well_man) × 1/10^6

Emissions from Centrally Treated Anaerobic Systems = C
= [(% collected) × (total BOD_5 produced) × (% anaerobic) × (% anaerobic w/out primary) + (% collected) × (total BOD_5 produced) × (% anaerobic) × (% anaerobic w/primary) × (1-%BOD removed in prim. treat.)] × (B_o) × (MCF-anaerobic) × 1/10^6

Emissions from Anaerobic Digesters = D
= [(POTW_flow_AD) × (digester gas)/ (per capita flow)] × conversion to m^3 × (FRAC_CH_4) × (365.25) × (density of CH_4) × (1-DE) × 1/10^9

Total CH_4 Emissions (Gg) = A + B + C + D

Where:

% onsite	= Flow to septic systems / total flow
% collected	= Flow to POTWs / total flow
% aerobic	= Flow to aerobic systems / total flow to POTWs
% anaerobic	= Flow to anaerobic systems / total flow to POTWs
% aerobic w/out primary	= Percent of aerobic systems that do not employ primary treatment
% aerobic w/primary	= Percent of aerobic systems that employ primary treatment
% BOD removed in prim. treat.	= 32.5%
% operations not well managed	= Percent of aerobic systems that are not well managed and in which some anaerobic degradation occurs
% anaerobic w/out primary	= Percent of anaerobic systems that do not employ primary treatment
% anaerobic w/primary	= Percent of anaerobic systems that employ primary treatment
Total BOD_5 produced	= kg BOD/capita/day × U.S. population × 365.25 days/yr
B_o	= Maximum CH_4-producing capacity for domestic wastewater (0.60 kg CH_4/kg BOD)
MCF-septic	= CH_4 correction factor for septic systems (0.5)
1/10^6	= Conversion factor, kg to Gg
MCF-aerobic_not_well_man.	= CH_4 correction factor for aerobic systems that are not well managed (0.3)
MCF-anaerobic	= CH_4 correction factor for anaerobic systems (0.8)
DE	= CH_4 destruction efficiency from flaring or burning in engine (0.99 for enclosed flares)
POTW_flow_AD	= Wastewater influent flow to POTWs that have anaerobic digesters (gal)
digester gas	= Cubic feet of digester gas produced per person per day (1.0 ft^3/person/day) (Metcalf and Eddy 1991)
per capita flow	= Wastewater flow to POTW per person per day (100 gal/person/day)
conversion to m^3	= Conversion factor, ft^3 to m^3 (0.0283)
FRAC_CH_4	= Proportion CH_4 in biogas (0.65)
density of CH_4	= 662 (g CH_4/m^3 CH_4)
1/10^9	= Conversion factor, g to Gg

U.S. population data were taken from the U.S. Census Bureau International Database (U.S. Census 2010) and include the populations of the United States, American Samoa, Guam, Northern Mariana Islands, Puerto Rico, and the Virgin Islands. Table 8-8 presents U.S. population and total BOD_5 produced for 1990 through 2009, while Table 8-9 presents domestic wastewater CH_4 emissions for both septic and centralized systems in 2009. The proportions of domestic wastewater treated onsite versus at centralized treatment plants were based on data from the 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, 2007, and 2009 American Housing Surveys conducted by the U.S. Census Bureau (U.S. Census 2009), with data for intervening years obtained by linear interpolation. The percent of wastewater flow to aerobic and anaerobic systems, the percent of aerobic and anaerobic systems that do and do not employ primary treatment, and the wastewater flow to POTWs that have anaerobic digesters were obtained from the 1992, 1996, 2000, and 2004 Clean Watershed Needs Survey (EPA 1992, 1996, 2000, and 2004a). Data for intervening years were obtained by linear interpolation and the years 2004 through 2009 were forecasted from the rest of the time series. The BOD_5 production rate (0.09 kg/capita/day) and the percent BOD_5 removed by primary treatment for domestic wastewater were obtained from Metcalf and Eddy (1991 and 2003). The CH_4 emission factor (0.6 kg CH_4/kg BOD_5) and the MCFs were taken from IPCC (2006). The CH_4 destruction efficiency for methane recovered from sludge digestion operations, 99 percent, was selected based on the range of efficiencies (98 to 100 percent) recommended for flares in AP-42 Compilation of Air Pollutant Emission Factors, Chapter 2.4 (EPA 1998), efficiencies used to establish new source performance standards (NSPS) for landfills, and in recommendations for closed flares used by the Landfill Methane Outreach Program (LMOP). The cubic feet of digester gas produced per person per day (1.0 ft^3/person/day) and the proportion of CH_4 in biogas (0.65) come from

Metcalf and Eddy (1991). The wastewater flow to a POTW (100 gal/person/day) was taken from the Great Lakes-Upper Mississippi River Board of State and Provincial Public Health and Environmental Managers, "Recommended Standards for Wastewater Facilities (Ten-State Standards)" (2004).

Table 8-8. U.S. Population (Millions) and Domestic Wastewater BOD_5 Produced (Gg)

Year	Population	BOD_5
1990	254	8,333
2000	286	9,414
2005	300	9,864
2006	303	9,958
2007	306	10,057
2008	309	10,149
2009	311	10,236

Source: U.S. Census Bureau (2010); Metcalf & Eddy 1991 and 2003.

Table 8-9. Domestic Wastewater CH_4 Emissions from Septic and Centralized Systems (2009)

	CH_4 emissions (Tg CO_2 Eq.)	% of Domestic Wastewater CH_4
Septic Systems	13.2	82.5%
Centralized Systems	2.8	17.5%
Total	**16.0**	**100%**

Note: Totals may not sum due to independent rounding.

Industrial Wastewater CH_4 Emission Estimates

CH_4 emissions estimates from industrial wastewater were developed according to the methodology described in IPCC (2006). Industry categories that are likely to produce significant CH_4 emissions from wastewater treatment were identified. High volumes of wastewater generated and a high organic wastewater load were the main criteria. The top five industries that meet these criteria are pulp and paper manufacturing; meat and poultry processing; vegetables, fruits, and juices processing; starch-based ethanol production; and petroleum refining. Wastewater treatment emissions for these sectors for 2009 are displayed in Table 8-10 below. Table 8-11 contains production data for these industries.

Table 8-10. Industrial Wastewater CH_4 Emissions by Sector (2009)

	CH_4 emissions (Tg CO_2 Eq.)	% of Industrial Wastewater CH_4
Pulp & Paper	4.1	48%
Meat & Poultry	3.6	42%
Petroleum Refineries	0.6	7%
Fruit & Vegetables	0.1	1%
Ethanol Refineries	0.1	1%
Total	**8.5**	**100%**

Note: Totals may not sum due to independent rounding.

Table 8-11. U.S. Pulp and Paper, Meat, Poultry, Vegetables, Fruits and Juices, Ethanol, and Petroleum Refining Production (Tg)

Year	Pulp and Paper	Meat (Live Weight Killed)	Poultry (Live Weight Killed)	Vegetables, Fruits and Juices	Ethanol	Petroleum Refining
1990	128.9	27.3	14.6	38.7	2.7	702.4
2000	142.8	32.1	22.2	50.9	4.9	795.2
2005	131.4	31.4	25.1	42.9	11.7	818.6
2006	137.4	32.5	25.5	42.9	14.5	826.7
2007	135.9	33.4	26.0	44.7	19.4	827.6
2008	134.5	34.4	26.6	45.1	26.9	836.8

2009	137.0	33.8	25.2	47.0	31.7	822.4

CH_4 emissions from these categories were estimated by multiplying the annual product output by the average outflow, the organics loading (in COD) in the outflow, the percentage of organic loading assumed to degrade anaerobically, and the emission factor. Ratios of BOD:COD in various industrial wastewaters were obtained from EPA (1997a) and used to estimate COD loadings. The B_o value used for all industries is the IPCC default value of 0.25 kg CH_4/kg COD (IPCC 2006).

For each industry, the percent of plants in the industry that treat wastewater on site, the percent of plants that have a primary treatment step prior to biological treatment, and the percent of plants that treat wastewater anaerobically were defined. The percent of wastewater treated anaerobically onsite (TA) was estimated for both primary treatment and secondary treatment. For plants that have primary treatment in place, an estimate of COD that is removed prior to wastewater treatment in the anaerobic treatment units was incorporated.

The methodological equations are:

$$CH_4 \text{ (industrial wastewater)} = P \times W \times COD \times \%TA \times B_o \times MCF$$

$$\%TA_p = [\%Plants_o \times \%WW_{a,p} \times \%COD_p]$$

$$\%TA_s = [\%Plants_a \times \%WW_{a,s} \times \%COD_s] + [\%Plants_t \times \%WW_{a,t} \times \%COD_s]$$

Where:

CH_4 (industrial wastewater)	= Total CH_4 emissions from industrial wastewater (kg/year)
P	= Industry output (metric tons/year)
W	= Wastewater generated (m^3/metric ton of product)
COD	= Organics loading in wastewater (kg/m^3)
%TA	= Percent of wastewater treated anaerobically on site
$\%TA_p$	= Percent of wastewater treated anaerobically on site in primary treatment
$\%TA_s$	= Percent of wastewater treated anaerobically on site in secondary treatment
$\%Plants_o$	= Percent of plants with onsite treatment
$\%WW_{a,p}$	= Percent of wastewater treated anaerobically in primary treatment
$\%COD_p$	= Percent of COD entering primary treatment
$\%Plants_a$	= Percent of plants with anaerobic secondary treatment
$\%Plants_t$	= Percent of plants with other secondary treatment
$\%WW_{a,s}$	= Percent of wastewater treated anaerobically in anaerobic secondary treatment
$\%WW_{a,t}$	= percent of wastewater treated anaerobically in other secondary treatment
$\%COD_s$	= percent of COD entering secondary treatment
B_o	= Maximum CH_4 producing potential of industrial wastewater (default value of 0.25 kg CH_4/kg COD)
MCF	= CH_4 correction factor, indicating the extent to which the organic content (measured as COD) degrades anaerobically

As described below, the values presented in Table 8-12 were used in the emission calculations.

Table 8-12. Variables Used to Calculate Percent Wastewater Treated Anaerobically by Industry (%)

Variable	Industry						
	Pulp and Paper	**Meat Processing**	**Poultry Processing**	**Fruit/ Vegetable Processing**	**Ethanol Production – Wet Mill**	**Ethanol Production – Dry Mill**	**Petroleum Refining**
$\%TA_p$	0	0	0	0	0	0	0
$\%TA_s$	10.5	33	25	4.2	33.3	75	100
$\%Plants_o$	60	100	100	11	100	100	100
$\%Plants_a$	25	33	25	5.5	33.3	75	100
$\%Plants_t$	35	67	75	5.5	66.7	25	0
$\%WW_{a,p}$	0	0	0	0	0	0	0
$\%WW_{a,s}$	100	100	100	100	100	100	100
$\%WW_{a,t}$	0	0	0	0	0	0	0

$\%COD_p$	100	100	100	100	100	100	100
$\%COD_s$	42	100	100	77	100	100	100

Pulp and Paper. Wastewater treatment for the pulp and paper industry typically includes neutralization, screening, sedimentation, and flotation/hydrocycloning to remove solids (World Bank 1999, Nemerow and Dasgupta 1991). Secondary treatment (storage, settling, and biological treatment) mainly consists of lagooning. In determining the percent that degrades anaerobically, both primary and secondary treatment were considered. In the United States, primary treatment is focused on solids removal, equalization, neutralization, and color reduction (EPA 1993). The vast majority of pulp and paper mills with on-site treatment systems use mechanical clarifiers to remove suspended solids from the wastewater. About 10 percent of pulp and paper mills with treatment systems use settling ponds for primary treatment and these are more likely to be located at mills that do not perform secondary treatment (EPA 1993). However, because the vast majority of primary treatment operations at U.S. pulp and paper mills use mechanical clarifiers, and less than 10 percent of pulp and paper wastewater is managed in primary settling ponds that are not expected to have anaerobic conditions, negligible emissions are assumed to occur during primary treatment.

Approximately 42 percent of the BOD passes on to secondary treatment, which consists of activated sludge, aerated stabilization basins, or non-aerated stabilization basins. No anaerobic activity is assumed to occur in activated sludge systems or aerated stabilization basins (note: although IPCC recognizes that some CH_4 can be emitted from anaerobic pockets, they recommend an MCF of zero). However, about 25 percent of the wastewater treatment systems used in the United States are non-aerated stabilization basins. These basins are typically 10 to 25 feet deep. These systems are classified as anaerobic deep lagoons (MCF = 0.8).

A time series of CH_4 emissions for 1990 through 2001 was developed based on production figures reported in the Lockwood-Post Directory (Lockwood-Post 2002). Published data from the American Forest and Paper Association, data published by Paper Loop, and other published statistics were used to estimate production for 2002 through 2009 (Pulp and Paper 2005, 2006, and monthly reports from 2003 through 2008; Paper 360° 2007). The overall wastewater outflow was estimated to be 85 m^3/metric ton, and the average BOD concentrations in raw wastewater was estimated to be 0.4 gram BOD/liter (EPA 1997b, EPA 1993, World Bank 1999).

Meat and Poultry Processing. The meat and poultry processing industry makes extensive use of anaerobic lagoons in sequence with screening, fat traps and dissolved air flotation when treating wastewater on site. About 33 percent of meat processing operations (EPA 2002) and 25 percent of poultry processing operations (U.S. Poultry 2006) perform on-site treatment in anaerobic lagoons. The IPCC default B_o of 0.25 kg CH_4/kg COD and default MCF of 0.8 for anaerobic lagoons were used to estimate the CH_4 produced from these on-site treatment systems. Production data, in carcass weight and live weight killed for the meat and poultry industry, were obtained from the USDA Agricultural Statistics Database and the Agricultural Statistics Annual Reports (USDA 2010). Data collected by EPA's Office of Water provided estimates for wastewater flows into anaerobic lagoons: 5.3 and 12.5 m^3/metric ton for meat and poultry production (live weight killed), respectively (EPA 2002). The loadings are 2.8 and 1.5 g BOD/liter for meat and poultry, respectively.

Vegetables, Fruits, and Juices Processing. Treatment of wastewater from fruits, vegetables, and juices processing includes screening, coagulation/settling, and biological treatment (lagooning). The flows are frequently seasonal, and robust treatment systems are preferred for on-site treatment. Effluent is suitable for discharge to the sewer. This industry is likely to use lagoons intended for aerobic operation, but the large seasonal loadings may develop limited anaerobic zones. In addition, some anaerobic lagoons may also be used (Nemerow and Dasgupta 1991). Consequently, 4.2 percent of these wastewater organics are assumed to degrade anaerobically. The IPCC default B_o of 0.25 kg CH_4/kg COD and default MCF of 0.8 for anaerobic treatment were used to estimate the CH_4 produced from these on-site treatment systems. The USDA National Agricultural Statistics Service (USDA 2010) provided production data for potatoes, other vegetables, citrus fruit, non-citrus fruit, and grapes processed for wine. Outflow and BOD data, presented in Table 8-13, were obtained from EPA (1974) for potato, citrus fruit, and apple processing, and from EPA (1975) for all other sectors.

Table 8-13. Wastewater Flow (m^3/ton) and BOD Production (g/L) for U.S. Vegetables, Fruits, and Juices Production

Commodity	Wastewater Outflow (m^3/ton)	BOD (g/L)
Vegetables		
Potatoes	10.27	1.765
Other Vegetables	8.74	0.801

Fruit		
Apples	3.66	1.371
Citrus	10.11	0.317
Non-citrus	12.42	1.204
Grapes (for wine)	2.78	1.831

Ethanol Production. Ethanol, or ethyl alcohol, is produced primarily for use as a fuel component, but is also used in industrial applications and in the manufacture of beverage alcohol. Ethanol can be produced from the fermentation of sugar-based feedstocks (e.g., molasses and beets), starch- or grain-based feedstocks (e.g., corn, sorghum, and beverage waste), and cellulosic biomass feedstocks (e.g., agricultural wastes, wood, and bagasse). Ethanol can also be produced synthetically from ethylene or hydrogen and carbon monoxide. However, synthetic ethanol comprises only about 2 percent of ethanol production, and although the Department of Energy predicts cellulosic ethanol to greatly increase in the coming years, currently it is only in an experimental stage in the United States. According to the Renewable Fuels Association, 82 percent of ethanol production facilities use corn as the sole feedstock and 7 percent of facilities use a combination of corn and another starch-based feedstock. The fermentation of corn is the principal ethanol production process in the United States and is expected to increase through 2012, and potentially more; therefore, emissions associated with wastewater treatment at starch-based ethanol production facilities were estimated (ERG 2006).

Ethanol is produced from corn (or other starch-based feedstocks) primarily by two methods: wet milling and dry milling. Historically, the majority of ethanol was produced by the wet milling process, but now the majority is produced by the dry milling process. The wastewater generated at ethanol production facilities is handled in a variety of ways. Dry milling facilities often combine the resulting evaporator condensate with other process wastewaters, such as equipment wash water, scrubber water, and boiler blowdown and anaerobically treat this wastewater using various types of digesters. Wet milling facilities often treat their steepwater condensate in anaerobic systems followed by aerobic polishing systems. Wet milling facilities may treat the stillage (or processed stillage) from the ethanol fermentation/distillation process separately or together with steepwater and/or wash water. CH_4 generated in anaerobic digesters is commonly collected and either flared or used as fuel in the ethanol production process (ERG 2006).

Available information was compiled from the industry on wastewater generation rates, which ranged from 1.25 gallons per gallon ethanol produced (for dry milling) to 10 gallons per gallon ethanol produced (for wet milling) (Ruocco 2006a,b; Merrick 1998; Donovan 1996; and NRBP 2001). COD concentrations were also found to be about 3 g/L (Ruocco 2006a; Merrick 1998; White and Johnson 2003). The amount of wastewater treated anaerobically was estimated, along with how much of the CH_4 is recovered through the use of biomethanators (ERG 2006). CH_4 emissions were then estimated as follows:

$$\text{Methane} = [\text{Production} \times \text{Flow} \times \text{COD} \times 3.785 \times ([\%\text{Plants}_o \times \%\text{WW}_{a,p} \times \%\text{COD}_p] + [\%\text{Plants}_a \times \%\text{WW}_{a,s} \times \%\text{COD}_s] + [\%\text{Plants}_t \times \%\text{WW}_{a,t} \times \%\text{COD}_s]) \times B_o \times \text{MCF} \times \%\text{ Not Recovered}] + [\text{Production} \times \text{Flow} \times 3.785 \times \text{COD} \times ([\%\text{Plants}_o \times \%\text{WW}_{a,p} \times \%\text{COD}_p] + [\%\text{Plants}_a \times \%\text{WW}_{a,s} \times \%\text{COD}_s] + [\%\text{Plants}_t \times \%\text{WW}_{a,t} \times \%\text{COD}_s]) \times B_o \times \text{MCF} \times (\%\text{ Recovered}) \times (1\text{-DE})] \text{ x } 1/10\text{^}9$$

Where:

Production	= gallons ethanol produced (wet milling or dry milling)
Flow	= gallons wastewater generated per gallon ethanol produced (1.25 dry milling, 10 wet milling)
COD	= COD concentration in influent (3 g/l)
3.785	= conversion, gallons to liters
$\%\text{Plants}_o$	= percent of plants with onsite treatment (100%)
$\%\text{WW}_{a,p}$	= percent of wastewater treated anaerobically in primary treatment (0%)
$\%\text{COD}_p$	= percent of COD entering primary treatment (100%)
$\%\text{Plants}_a$	= percent of plants with anaerobic secondary treatment (33.3% wet, 75% dry)
$\%\text{Plants}_t$	= percent of plants with other secondary treatment (66.7% wet, 25% dry)
$\%\text{WW}_{a,s}$	= percent of wastewater treated anaerobically in anaerobic secondary treatment (100%)
$\%\text{WW}_{a,t}$	= percent of wastewater treated anaerobically in other secondary treatment (0%)
$\%\text{COD}_s$	= percent of COD entering secondary treatment (100%)

B_o	= maximum methane producing capacity (0.25 g CH_4/g COD)
MCF	= methane conversion factor (0.8 for anaerobic systems)
% Recovered	= percent of wastewater treated in system with emission recovery
% Not Recovered	= 1 - percent of wastewater treated in system with emission recovery
DE	= destruction efficiency of recovery system (99%)
1/10^9	= conversion factor, g to Gg

A time series of CH_4 emissions for 1990 through 2009 was developed based on production data from the Renewable Fuels Association (RFA 2010).

Petroleum Refining. Petroleum refining wastewater treatment operations produce CH_4 emissions from anaerobic wastewater treatment. The wastewater inventory section includes CH_4 emissions from petroleum refining wastewater treated on site under intended or unintended anaerobic conditions. Most facilities use aerated biological systems, such as trickling filters or rotating biological contactors; these systems can also exhibit anaerobic conditions that can result in the production of CH_4. Oil/water separators are used as a primary treatment method; however, it is unlikely that any COD is removed in this step.

Available information from the industry was compiled. The wastewater generation rate, from CARB (2007) and Timm (1985), was determined to be 35 gallons per barrel of finished product. An average COD value in the wastewater was estimated at 0.45 kg/m^3 (Benyahia et al. 2006).

The equation used to calculate CH_4 generation at petroleum refining wastewater treatment systems is presented below:

$$\text{Methane} = \text{Flow} \times \text{COD} \times B_o \times \text{MCF}$$

Where:

Flow	= Annual flow treated through anaerobic treatment system (m^3/year)
COD	= COD loading in wastewater entering anaerobic treatment system (kg/m^3)
B_o	= maximum methane producing potential of industrial wastewater (default value of 0.25 kg CH_4 /kg COD)
MCF	= methane conversion factor (0.3)

A time series of CH_4 emissions for 1990 through 2009 was developed based on production data from the Energy Information Association (EIA 2010).

Domestic Wastewater N_2O Emission Estimates

N_2O emissions from domestic wastewater (wastewater treatment) were estimated using the IPCC (2006) methodology, including calculations that take into account N removal with sewage sludge, non-consumption and industrial wastewater N, and emissions from advanced centralized wastewater treatment plants:

- In the United States, a certain amount of N is removed with sewage sludge, which is applied to land, incinerated, or landfilled (N_{SLUDGE}). The N disposal into aquatic environments is reduced to account for the sewage sludge application.
- The IPCC methodology uses annual, per capita protein consumption (kg protein/[person-year]). For this inventory, the amount of protein available to be consumed is estimated based on per capita annual food availability data and its protein content, and then adjusts that data using a factor to account for the fraction of protein actually consumed.
- Small amounts of gaseous nitrogen oxides are formed as by-products in the conversion of nitrate to N gas in anoxic biological treatment systems. Approximately 7 grams N_2O is generated per capita per year if wastewater treatment includes intentional nitrification and denitrification (Scheehle and Doorn 2001). Analysis of the 2004 CWNS shows that plants with denitrification as one of their unit operations serve a population of 2.4 million people. Based on an emission factor of 7 grams per capita per year, approximately 21.2 metric tons of additional N_2O may have been emitted via denitrification in 2004. Similar analyses were completed for each year in the Inventory using data from CWNS on the amount of wastewater in centralized systems treated in denitrification units. Plants without intentional nitrification/denitrification are assumed to generate 3.2 grams N_2O per capita

per year.

N_2O emissions from domestic wastewater were estimated using the following methodology:

$$N_2O_{TOTAL} = N_2O_{PLANT} + N_2O_{EFFLUENT}$$

$$N_2O_{PLANT} = N_2O_{NIT/DENIT} + N_2O_{WOUT\ NIT/DENIT}$$

$$N_2O_{NIT/DENIT} = [(US_{POPND}) \times EF_2 \times F_{IND\text{-}COM}] \times 1/10\text{^}9$$

$$N_2O_{WOUT\ NIT/DENIT} = \{[(US_{POP} \times WWTP) - US_{POPND}] \times F_{IND\text{-}COM} \times EF_1\} \times 1/10\text{^}9$$

$$N_2O_{EFFLUENT} = \{[((US_{POP} - (0.9 \times US_{POPND})) \times Protein \times F_{NPR} \times F_{NON\text{-}CON} \times F_{IND\text{-}COM}) - N_{SLUDGE}] \times EF_3 \times 44/28\} \times 1/10\text{^}6$$

where,

N_2O_{TOTAL}	= Annual emissions of N_2O (Gg)
N_2O_{PLANT}	= N_2O emissions from centralized wastewater treatment plants (Gg)
$N_2O_{NIT/DENIT}$	= N_2O emissions from centralized wastewater treatment plants with nitrification/denitrification (Gg)
$N_2O_{WOUT\ NIT/DENIT}$	= N_2O emissions from centralized wastewater treatment plants without nitrification/denitrification (Gg)
$N_2O_{EFFLUENT}$	= N_2O emissions from wastewater effluent discharged to aquatic environments (Gg)
US_{POP}	= U.S. population
US_{POPND}	= U.S. population that is served by biological denitrification (from CWNS)
WWTP	= Fraction of population using WWTP (as opposed to septic systems)
EF_1	= Emission factor (3.2 g N_2O/person-year) – plant with no intentional denitrification
EF_2	= Emission factor (7 g N_2O/person-year) – plant with intentional denitrification
Protein	= Annual per capita protein consumption (kg/person/year)
F_{NPR}	= Fraction of N in protein, default = 0.16 (kg N/kg protein)
$F_{NON\text{-}CON}$	= Factor for non-consumed protein added to wastewater (1.4)
$F_{IND\text{-}COM}$	=Factor for industrial and commercial co-discharged protein into the sewer system (1.25)
N_{SLUDGE}	= N removed with sludge, kg N/yr
EF_3	= Emission factor (0.005 kg N_2O -N/kg sewage-N produced) – from effluent
0.9	= Amount of nitrogen removed by denitrification systems
44/28	= Molecular weight ratio of N_2O to N_2

U.S. population data were taken from the U.S. Census Bureau International Database (U.S. Census 2010) and include the populations of the United States, American Samoa, Guam, Northern Mariana Islands, Puerto Rico, and the Virgin Islands. The fraction of the U.S. population using wastewater treatment plants is based on data from the 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, 2007, and 2009 American Housing Survey (U.S. Census 2009). Data for intervening years were obtained by linear interpolation. The emission factor (EF_1) used to estimate emissions from wastewater treatment was taken from IPCC (2006). Data on annual per capita protein intake were provided by U.S. Department of Agriculture Economic Research Service (USDA 2009). Protein consumption data for 2005 through 2009 were extrapolated from data for 1990 through 2004. Table 8-14 presents the data for U.S. population and average protein intake. An emission factor to estimate emissions from effluent (EF_3) has not been specifically estimated for the United States, thus the default IPCC value (0.005 kg N_2O-N/kg sewage-N produced) was applied. The fraction of N in protein (0.16 kg N/kg protein) was also obtained from IPCC (2006). The factor for non-consumed protein and the factor for industrial and commercial co-discharged protein were obtained from IPCC (2006). Sludge generation was obtained from EPA (1999) for 1988, 1996, and 1998 and from Beecher et al. (2007) for 2004. Intervening years were interpolated, and estimates for 2005 through 2009 were forecasted from the rest of the time series. An estimate for the N removed as sludge (N_{SLUDGE}) was obtained by determining the amount of sludge disposed by incineration, by land application (agriculture or other), through surface disposal, in landfills, or through ocean dumping. In 2009, 271 Gg N was removed with sludge.

Table 8-14. U.S. Population (Millions), Available Protein (kg/person-year), and Protein Consumed (kg/person-year)

Year	Population	Available Protein	Protein Consumed
1990	254	38.7	29.6

2000	286	41.3	31.6
2005	300	41.7	32.1
2006	303	41.9	32.1
2007	306	42.1	32.2
2008	309	42.2	32.4
2009	311	42.4	32.5

Source: U.S. Census Bureau 2010, USDA 2009.

Uncertainty and Time-Series Consistency

The overall uncertainty associated with both the 2009 CH_4 and N_2O emission estimates from wastewater treatment and discharge was calculated using the IPCC Good Practice Guidance Tier 2 methodology (2000). Uncertainty associated with the parameters used to estimate CH_4 emissions include that of numerous input variables used to model emissions from domestic wastewater, and wastewater from pulp and paper manufacture, meat and poultry processing, fruits and vegetable processing, ethanol production, and petroleum refining. Uncertainty associated with the parameters used to estimate N_2O emissions include that of sewage sludge disposal, total U.S. population, average protein consumed per person, fraction of N in protein, non-consumption nitrogen factor, emission factors per capita and per mass of sewage-N, and for the percentage of total population using centralized wastewater treatment plants.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 8-15. CH_4 emissions from wastewater treatment were estimated to be between 15.3 and 35.9 Tg CO_2 Eq. at the 95 percent confidence level (or in 19 out of 20 Monte Carlo Stochastic Simulations). This indicates a range of approximately 37 percent below to 47 percent above the 2009 emissions estimate of 24.5 Tg CO_2 Eq. N_2O emissions from wastewater treatment were estimated to be between 1.2 and 9.7 Tg CO_2 Eq., which indicates a range of approximately 76 percent below to 93 percent above the actual 2009 emissions estimate of 5.0 Tg CO_2 Eq.

Table 8-15. Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Wastewater Treatment (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Wastewater Treatment	**CH_4**	**24.5**	**15.3**	**35.9**	**-37%**	**+47%**
Domestic	CH_4	16.0	7.6	26.6	-52%	+66%
Industrial	CH_4	8.5	5.1	13.1	-41%	+54%
Wastewater Treatment	**N_2O**	**5.0**	**1.2**	**9.7**	**-76%**	**+93%**

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed on activity data, documentation, and emission calculations. This effort included a Tier 1 analysis, including the following checks:

- Checked for transcription errors in data input;
- Ensured references were specified for all activity data used in the calculations;
- Checked a sample of each emission calculation used for the source category;
- Checked that parameter and emission units were correctly recorded and that appropriate conversion factors were used;
- Checked for temporal consistency in time series input data for each portion of the source category;
- Confirmed that estimates were calculated and reported for all portions of the source category and for all years;
- Investigated data gaps that affected emissions estimates trends; and

- Compared estimates to previous estimates to identify significant changes.

All transcription errors identified were corrected. The QA/QC analysis did not reveal any systemic inaccuracies or incorrect input values.

Planned Improvements Discussion

The methodology to estimate CH_4 emissions from domestic wastewater treatment currently utilizes estimates for the percentage of centrally treated wastewater that is treated by aerobic systems and anaerobic systems. These data come from the 1992, 1996, 2000, and 2004 CWNS. The question of whether activity data for wastewater treatment systems are sufficient across the timeseries to further differentiate aerobic systems with the potential to generate small amounts of CH_4 (aerobic lagoons) versus other types of aerobic systems, and to differentiate between anaerobic systems to allow for the use of different MCFs for different types of anaerobic treatment systems, continues to be explored. Recently available CWNS data for 2008 also is being evaluated for incorporation into the inventory. Due to significant changes in format, this dataset was unable to be included in the domestic wastewater calculations for the current Inventory. However, EPA continues to evaluate ways to incorporate the updated data into future years of the Inventory.

Currently, it is assumed that all aerobic systems are well managed and produce no CH_4 and that all anaerobic systems have an MCF of 0.8. Efforts to obtain better data reflecting emissions from various types of municipal treatment systems are currently being pursued.

A review of other industrial wastewater treatment sources for those industries believed to discharge significant loads of BOD and COD has been ongoing. Food processing industries have the highest potential for CH_4 generation due to the waste characteristics generated, and the greater likelihood to treat the wastes anaerobically. However, in all cases there is dated information available on U.S. treatment operations for these industries. A review of the organic chemicals industry was conducted in April 2010, during which only 1987 data was readily identified. It was concluded that current industry-level treatment system information is very difficult to obtain, as is time series data. Based on the 1987 data, emissions from this source are small and are not a likely industry category for significant CH_4 emissions. Therefore, this industry has not been included in the Inventory and there are no near future plans to do so. Similarly, the seafood processing industry was reviewed to estimate its potential to generate CH_4. Due to minimal anaerobic wastewater treatment operations at processing facilities, this industry was not selected for inclusion in the Inventory. Other industries will be reviewed as necessary for inclusion in future years of the Inventory.

Available data will be reviewed regarding anaerobic treatment at petroleum refineries. If necessary, the %TA for this industry will be revised accordingly. Currently, all petroleum plants are assumed to have anaerobic treatment.

With respect to estimating N_2O emissions, the default emission factor for indirect N_2O from wastewater effluent and direct N_2O from centralized wastewater treatment facilities has a high uncertainty. Current research is being conducted by the Water Environment Research Foundation (WERF) to measure N_2O emissions from municipal treatment systems. Such data will be reviewed as they are available to determine if a country-specific N_2O emission factor can or should be developed, or if alternate emission factors should be used. EPA expects WERF to publish a final N_2O generation report by the end of 2011. In addition, WERF recently conducted a study of greenhouse gas emissions from septic systems located in California. This study concluded that the emission rate for methane and nitrous oxide were 10.7 and 0.20 g/capita-d, respectively. EPA is currently reviewing the results of this study to determine if the systems evaluated are representative of U.S. operations and if a country-specific factor for septic systems can be introduced into the inventory. The effect would be to lower current estimates of CH_4 emissions by about half, and to include N_2O emission estimates where previously none were calculated. In addition, more investigation of new study results will be used to evaluate the method used to calculate N_2O emissions associated with effluent and whether septic systems are appropriately included in the calculation.

In addition, the estimate of N entering municipal treatment systems is under review. The factor that accounts for non-sewage N in wastewater (bath, laundry, kitchen, industrial components) also has a high uncertainty. Obtaining data on the changes in average influent N concentrations to centralized treatment systems over the time series would improve the estimate of total N entering the system, which would reduce or eliminate the need for other factors for non-consumed protein or industrial flow. The dataset previously provided by the National Association of Clean Water Agencies (NACWA) was reviewed to determine if it was representative of the larger population of centralized treatment plants for potential inclusion into the inventory. However, this limited dataset was not

representative of the number of systems by state or the service populations served in the United States, and therefore could not be incorporated into the inventory methodology. Additional data sources will continue to be researched with the goal of improving the uncertainty of the estimate of N entering municipal treatment systems.

8.3. Composting (IPCC Source Category 6D)

Composting of organic waste, such as food waste, garden (yard) and park waste, and sludge, is common in the United States. Advantages of composting include reduced volume in the waste material, stabilization of the waste, and destruction of pathogens in the waste material. The end products of composting, depending on its quality, can be recycled as fertilizer and soil amendment, or be disposed in a landfill.

Composting is an aerobic process and a large fraction of the degradable organic carbon in the waste material is converted into carbon dioxide (CO_2). Methane (CH_4) is formed in anaerobic sections of the compost, but it is oxidized to a large extent in the aerobic sections of the compost. Anaerobic sections are created in composting piles when there is excessive moisture or inadequate aeration (or mixing) of the compost pile. The estimated CH_4 released into the atmosphere ranges from less than 1 percent to a few percent of the initial C content in the material (IPCC 2006). Composting can also produce nitrous oxide (N_2O) emissions. The range of the estimated emissions varies from less than 0.5 percent to 5 percent of the initial nitrogen content of the material (IPCC 2006).

From 1990 to 2009, the amount of material composted in the United States has increased from 3,810 Gg to 19,857 Gg, an increase of approximately 421 percent. From 2000 to 2009, the amount of material composted in the United States has increased by approximately 33 percent. Emissions of CH_4 and N_2O from composting have increased by the same percentage (see Table 8-16 and Table 8-17). In 2009, CH_4 emissions from composting were 1.7 Tg CO_2 Eq. (79 Gg), and N_2O emissions from composting were 1.8 Tg CO_2 Eq. (6 Gg). The wastes that are composted include primarily yard trimmings (grass, leaves, and tree and brush trimmings) and food scraps from residences and commercial establishments (such as grocery stores, restaurants, and school and factory cafeterias). The composting waste quantities reported here do not include backyard composting. The growth in composting is attributable primarily to two factors: (1) steady growth in population and residential housing, and (2) state and local governments started enacting legislation that discouraged the disposal of yard trimmings in landfills. In 1992, 11 states and the District of Columbia had legislation in effect that banned or discouraged disposal of yard trimmings in landfills. In 2005, 21 states and the District of Columbia, representing about 50 percent of the nation's population, had enacted such legislation (EPA 2008).

Table 8-16. CH_4 and N_2O Emissions from Composting (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
CH_4	0.3	1.3	1.6	1.6	1.7	1.7	1.7
N_2O	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Total	**0.7**	**2.7**	**3.3**	**3.3**	**3.5**	**3.5**	**3.5**

Table 8-17. CH_4 and N_2O Emissions from Composting (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
CH_4	15	60	75	75	79	80	79
N_2O	1	4	6	6	6	6	6

Methodology

CH_4 and N_2O emissions from composting depend on factors such as the type of waste composted, the amount and type of supporting material (such as wood chips and peat) used, temperature, moisture content and aeration during the process.

The emissions shown in Table 8-16 and Table 8-17 were estimated using the IPCC default (Tier 1) methodology (IPCC 2006), which is the product of an emission factor and the mass of organic waste composted (note: no CH_4 recovery is expected to occur at composting operations):

$$E_i = M \times EF_i$$

where,

E_i = CH_4 or N_2O emissions from composting, Gg CH_4 or N_2O,
M = mass of organic waste composted in Gg,
EF_i = emission factor for composting, 4 g CH_4/kg of waste treated (wet basis) and 0.3 g N_2O/kg of waste treated (wet basis), and
i = designates either CH_4 or N_2O.

Estimates of the quantity of waste composted (M) are presented in Table 8-18. Estimates of the quantity composted for 1990 and 1995 were taken from the *Characterization of Municipal Solid Waste in the United States: 1996 Update* (Franklin Associates 1997); estimates of the quantity composted for 2000, 2005, 2006, 2007, and 2008 were taken from EPA's *Municipal Solid Waste In The United States: 2008 Facts and Figures* (EPA 2009); estimates of the quantity composted for 2009 were calculated using the 2008 quantity composted.

Table 8-18: U.S. Waste Composted (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Waste Composted	3,810	14,923	18,643	18,852	19,695	20,049	19,857

Source: Franklin Associates 1997 and EPA 2009.

Uncertainty and Time-Series Consistency

The estimated uncertainty from the 2006 IPCC Guidelines is ±50 percent for the Tier 1 methodology. Emissions from composting in 2009 were estimated to be between 1.8 and 5.3 Tg CO_2 Eq., which indicates a range of 50 percent below to 50 percent above the actual 2009 emission estimate of 3.5 Tg CO_2 Eq. (see Table 8-19).

Table 8-19 : Tier 1 Quantitative Uncertainty Estimates for Emissions from Composting (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO2 Eq.)	Uncertainty Range Relative to Emission Estimate (Tg CO2 Eq.)		Uncertainty Range Relative to Emission Estimate (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Composting	CH_4, N_2O	3.5	1.8	5.3	-50%	+50%

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

For future Inventories, additional efforts will be made to improve the estimates of CH_4 and N_2O emissions from composting. For example, a literature search may be conducted to determine if emission factors specific to various composting systems and composted materials are available.

8.4. Waste Sources of Indirect Greenhouse Gases

In addition to the main greenhouse gases addressed above, waste generating and handling processes are also sources of indirect greenhouse gas emissions. Total emissions of NO_x, CO, and NMVOCs from waste sources for the years 1990 through 2009 are provided in Table 8-20.

Table 8-20: Emissions of NO_x, CO, and NMVOC from Waste (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
NO_x	**+**	**2**	**2**	**2**	**2**	**2**	**2**
Landfills	+	2	2	2	2	2	2
Wastewater Treatment	+	+	+	+	+	+	+
Miscellaneous[a]	+	+	+	+	+	+	0
CO	**1**	**8**	**7**	**7**	**7**	**7**	**7**
Landfills	1	7	6	6	6	6	6
Wastewater Treatment	+	1	+	+	+	+	+
Miscellaneous[a]	+	+	+	+	+	+	+
NMVOCs	**673**	**119**	**114**	**113**	**111**	**109**	**76**
Wastewater Treatment	57	51	49	49	48	47	33
Miscellaneous[a]	557	46	43	43	42	41	29
Landfills	58	22	22	21	21	21	14

[a] Miscellaneous includes TSDFs (Treatment, Storage, and Disposal Facilities under the Resource Conservation and Recovery Act [42 U.S.C. § 6924, SWDA § 3004]) and other waste categories.

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.5 Gg.

Methodology

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emission estimates of these gases were provided by sector, using a "top down" estimating procedure—emissions were calculated either for individual sources or for many sources combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual source categories from various agencies. Depending on the source category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Uncertainty and Time-Series Consistency

No quantitative estimates of uncertainty were calculated for this source category. Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009.

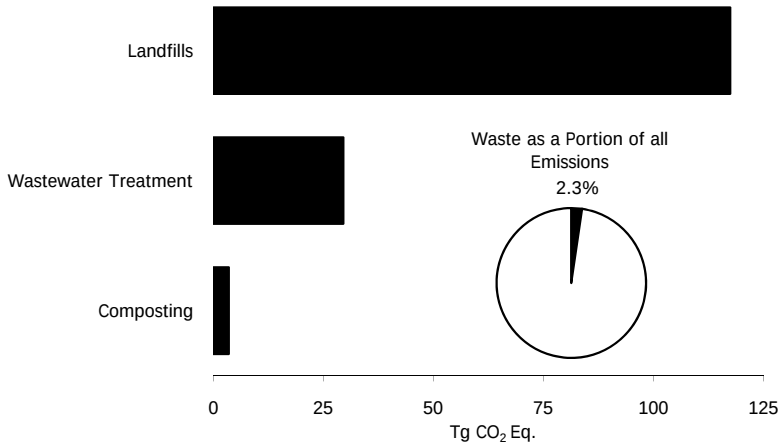


Figure 8-1: 2009 Waste Chapter Greenhouse Gas Sources

9. Other

The United States does not report any greenhouse gas emissions under the Intergovernmental Panel on Climate Change (IPCC) “Other” sector.

10. Recalculations and Improvements

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, "Both methodological changes and refinements over time are an essential part of improving inventory quality. It is *good practice* to change or refine methods" when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors."

The results of all methodological changes and historical data updates are presented in this section; detailed descriptions of each recalculation are contained within each source's description found in this report, if applicable. Table 10-1 summarizes the quantitative effect of these changes on U.S. greenhouse gas emissions and Table 10-2 summarizes the quantitative effect on net CO_2 flux to the atmosphere, both relative to the previously published U.S. Inventory (i.e., the 1990 through 2008 report). These tables present the magnitude of these changes in units of teragrams of carbon dioxide equivalent (Tg CO_2 Eq.).

The Recalculations Discussion section of each source presents the details of each recalculation. In general, when methodological changes have been implemented, the entire time series (i.e., 1990 through 2008) has been recalculated to reflect the change, per IPCC (2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies.

The following emission sources, which are listed in descending order of absolute average annual change in emissions between 1990 and 2008, underwent some of the most important methodological and historical data changes. A brief summary of the recalculations and/or improvements undertaken is provided for each emission source.

- *Natural Gas Systems (CH_4).* For the current Inventory, methodologies for gas well cleanups and condensate storage tanks were revised, and new data sources for centrifugal compressors with wet seals, unconventional gas well completions, and unconventional gas well workovers were used, relative to the previous Inventory. The net effect of these changes was an increase in total CH_4 emissions from natural gas systems of between 46.5 and 119.7 percent each year between 1990 and 2008, resulting in an overall annual average increase of 79.3 Tg CO_2 Eq. (66.4 percent). The natural gas production segment accounted for the largest increases, largely due to the methodological changes to gas well cleanups and the addition of unconventional gas well completions and workovers.

- *Landfills (CH_4)* Changes in CH_4 emissions from Landfills relative to the previous Inventory resulted from improvements made to better associate flares with the correct landfills or Landfill Gas to Energy projects across the nation. In addition, steps were also taken to further characterize the food waste decay rate. A weighted component-specific decay rate for food waste of 0.156 yr^{-1} was used in the current Inventory, replacing the previous Inventory's default food waste decay rate of 0.185 yr^{-1} These revisions impacted emission estimates for the entire time series and resulted in an average annual decrease of 8.3 Tg CO_2 Eq. (6.5 percent) in CH_4 emissions from Landfills for the period 1990 through 2008.

- *Manure Management (CH_4).* Changes in CH_4 emissions from Manure Management relative to the previous Inventory resulted from several updates. Volatile solid production rates for all animal types were updated based on data from the USDA and EPA's Cattle Enteric Fermentation Model. In addition, USDA data on swine were re-categorized, which changed the typical animal mass for two categories. These changes impacted emission estimates for the entire time series and resulted in an average annual increase of 3.5 Tg CO_2 Eq. (9.4 percent) in CH_4 emissions from Manure Management across the entire time series relative to the previous Inventory.

- *Agricultural Soil Management (N_2O).* Changes in N_2O emissions from Agricultural Soil Management relative to the previous Inventory resulted from methodological changes for estimating grassland areas and livestock manure nitrogen. These recalculations have opposing effects on emissions; grassland area was reduced, resulting in lower emissions, and livestock manure nitrogen increased, resulting in higher emissions. These changes affected the entire time series, resulting in an average annual reduction in N_2O emissions of 3.2 Tg CO_2 Eq. (1.5 percent) for the period 1990 through 2008 relative to the previous Inventory.

- *Iron and Steel Production & Metallurgical Coke Production (CO_2).* A calculation error in the previous Inventory regarding coal tar production and coke breeze production estimates was corrected for the current Inventory, resulting in an average annual decrease in CO_2 emissions from Iron and Steel Production & Metallurgical Coke Production of 2.2 Tg CO_2 Eq. (2.7 percent) for the period 1990 through 2008.
- *Non-Energy Uses of Fossil Fuels (CO_2).* Updates to the EIA Manufacturer's Energy Consumption Survey (MECS) for 2006 resulted in changes to CO_2 emissions from Non-Energy Uses of Fossil Fuels for 2003 through 2008 relative to the previous Inventory. Adjustments were made to the entire MECS time series to remove scrap tire consumption for use as a fuel, which is associated with the Waste Incineration chapter. In addition, emissions from synthetic rubber were revised across the entire time series. These changes impacted emission estimates from 1990 through 2008 resulting in an average annual decrease in CO_2 emissions of 1.4 Tg CO_2 Eq. (1.0 percent) across the entire time series.
- *Petroleum Systems (CH_4).* Well completion venting, well drilling, and offshore platform activity factors were updated relative to the previous Inventory from existing data sources from 1990 onward, and the emission factor for venting from fixed roof storage tanks in the crude oil production segment was increased to reflect the occurrence of gas venting through storage tanks. These changes affected the entire time series from Petroleum Systems, resulting in an average annual increase in CH_4 emissions of 1.3 Tg CO_2 Eq. (4.3 percent) for the period 1990 through 2008 relative to the previous report.
- *Nitric Acid Production (N_2O).* Changes in N_2O emission from Nitric Acid Production relative to the previous Inventory resulted from updated information on abatement technologies in use at production facilities and revised production data from the U.S. Census Bureau. These changes resulted in an average annual decrease in N_2O emissions of 1.3 Tg CO_2 Eq. (6.7 percent) across the entire time series relative to the previous report.
- *Electrical Transmission and Distribution (SF_6).* SF_6 emission estimates for the period 1990 through 2008 were updated relative to the previous Inventory based on (1) new data from EPA's SF_6 Emission Reduction Partnership; (2) revisions to interpolated and extrapolated non-reported Partner data; and (3) a correction made to 2004 transmission mile data for a large Partnership utility that had been interpreted incorrectly from the UDI database in previous years. In addition, the method for estimating potential emissions from the sector was updated for the current Inventory to assume that all SF_6 purchased by equipment manufacturers is either emitted or sent to utilities. These changes affected the entire time series, resulting in an average annual increase of 1.2 Tg CO_2 Eq. (6.6 percent) for the period 1990 through 2008 relative to the previous report.
- *Forestland Remaining Forestland (C Sink).* Changes to the estimated carbon stored in Forestland Remaining Forestland stemmed from recent additions to the Forest Inventory and Analysis Database (FIADB). Newer annual inventory data for most states including Oklahoma, California, Oregon, and Washington were added. Some older periodic inventories for some southern states were also updated. These changes resulted in an average annual increase in carbon stored in forestland of 6.8 Tg CO_2 Eq. (2.4 percent) for the period 1990 through 2008 relative to the previous inventory report.

Table 10-1: Revisions to U.S. Greenhouse Gas Emissions (Tg CO2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008
CO_2	**(1.1)**	**(2.2)**	**5.3**	**3.9**	**(0.2)**	**0.2**
Fossil Fuel Combustion	2.7	1.5	(0.1)	0.3	(0.3)	(6.8)
Electricity Generation	+	+	+	NC	+	(2.6)
Transportation	0.2	+	1.3	1.4	0.2	4.7
Industrial	1.0	(1.1)	(2.5)	(2.5)	(0.2)	(16.4)
Residential	(0.8)	(0.5)	(0.5)	(0.5)	0.7	5.5
Commercial	2.3	3.2	2.3	2.6	2.0	4.7
U.S. Territories	NC	NC	(0.7)	(0.7)	(3.0)	(2.7)
Non-Energy Use of Fuels	(1.0)	(1.2)	6.9	4.2	1.9	6.8
Iron and Steel Production & Metallurgical Coke Production	(3.0)	(2.2)	(1.8)	(1.8)	(1.8)	(3.0)
Natural Gas Systems	0.3	0.5	0.4	1.2	0.2	2.9
Cement Production	NC	(0.8)	(0.7)	(0.8)	(0.7)	(0.6)
Incineration of Waste	(0.1)	(0.2)	(0.2)	(0.2)	(0.6)	(1.0)

Ammonia Production and Urea Consumption	NC	NC	NC	NC	0.1	0.2
Lime Production	NC	NC	NC	NC	NC	NC
Cropland Remaining Cropland	NC	NC	NC	NC	(0.1)	1.0
Limestone and Dolomite Use	NC	NC	NC	NC	NC	(0.3)
Soda Ash Production and Consumption	NC	NC	NC	NC	NC	NC
Aluminum Production	NC	NC	NC	NC	NC	NC
Petrochemical Production	NC	NC	NC	NC	NC	NC
Carbon Dioxide Consumption	NC	NC	NC	+	NC	NC
Titanium Dioxide Production	NC	NC	NC	NC	NC	NC
Ferroalloy Production	NC	NC	NC	NC	NC	NC
Wetlands Remaining Wetlands	NC	NC	NC	NC	NC	0.1
Phosphoric Acid Production	NC	NC	NC	NC	NC	+
Zinc Production	(0.3)	(0.1)	0.6	0.6	0.7	0.8
Lead Production	0.2	0.3	0.3	0.3	0.3	0.3
Petroleum Systems	+	+	+	+	+	+
Silicon Carbide Production and Consumption	NC	NC	NC	NC	NC	NC
Land Use, Land-Use Change, and Forestry (Sink)[a]	*47.9*	*87.7*	*(106.1)*	*(105.2)*	*(105.5)*	*(100.1)*
Biomass - Wood[a]	*NC*	*NC*	*NC*	*(4.0)*	*(4.1)*	*(0.1)*
International Bunker Fuels[a]	+	+	*(0.8)*	*(0.7)*	*0.6*	*(1.5)*
Biomass - Ethanol[a]	*0.1*	*0.2*	*0.4*	*0.5*	*0.7*	*1.4*
CH_4	**61.5**	**73.9**	**78.3**	**103.9**	**95.4**	**109.1**
Natural Gas Systems	60.3	78.6	86.8	114.6	105.7	115.4
Enteric Fermentation	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Landfills	(1.9)	(9.0)	(13.1)	(15.3)	(15.2)	(10.4)
Coal Mining	NC	NC	NC	+	(0.2)	(0.5)
Manure Management	2.4	3.8	4.3	4.4	4.9	4.4
Petroleum Systems	1.5	1.3	1.1	1.1	1.2	1.1
Wastewater Treatment	+	+	+	+	+	0.2
Forest Land Remaining Forest Land	+	+	+	+	+	+
Rice Cultivation	NC	NC	NC	NC	NC	NC
Stationary Combustion	+	+	+	+	+	(0.2)
Abandoned Underground Coal Mines	NC	NC	+	(0.1)	(0.1)	+
Mobile Combustion	+	+	+	+	+	+
Composting	NC	NC	NC	NC	NC	+
Petrochemical Production	NC	NC	NC	NC	NC	NC
Iron and Steel Production & Metallurgical Coke Production	NC	NC	NC	NC	NC	NC
Field Burning of Agricultural Residues	(0.5)	(0.6)	(0.7)	(0.7)	(0.7)	(0.7)
Ferroalloy Production	NC	NC	NC	NC	NC	NC
Silicon Carbide Production and Consumption	NC	NC	NC	NC	NC	NC
Incineration of Waste	NC	NC	NC	NC	+	+
International Bunker Fuels[a]	+	+	+	+	+	+
N_2O	**(7.1)**	**(4.5)**	**(5.4)**	**(3.1)**	**(2.6)**	**(7.4)**
Agricultural Soil Management	(5.7)	(3.3)	(4.5)	(2.3)	(1.6)	(5.1)
Mobile Combustion	+	+	+	+	+	+
Manure Management	0.1	0.4	0.6	0.7	0.8	0.8
Nitric Acid Production	(1.2)	(1.3)	(1.1)	(1.1)	(1.3)	(2.6)
Stationary Combustion	+	+	+	(0.1)	(0.1)	+
Forest Land Remaining Forest Land	+	+	+	+	+	+
Wastewater Treatment	+	+	+	+	+	+
N2O from Product Uses	NC	NC	NC	NC	NC	NC
Adipic Acid Production	+	+	NC	NC	NC	NC
Composting	NC	NC	NC	NC	NC	+
Settlements Remaining Settlements	NC	NC	NC	NC	+	(0.1)
Incineration of Waste	NC	NC	NC	NC	+	+

Field Burning of Agricultural Residues	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Wetlands Remaining Wetlands	NC	NC	NC	NC	NC	+
International Bunker Fuels[a]	+	+	+	+	+	+
HFCs	**NC**	**+**	**1.0**	**1.6**	**2.1**	**2.5**
Substitution of Ozone Depleting Substances	NC	+	1.0	1.6	2.1	2.5
HCFC-22 Production	NC	NC	NC	NC	NC	NC
Semiconductor Manufacture	NC	NC	NC	NC	+	+
PFCs	**NC**	**NC**	**NC**	**NC**	**+**	**+**
Semiconductor Manufacture	NC	NC	NC	NC	+	+
Aluminum Production	NC	NC	NC	NC	NC	NC
SF_6	**1.8**	**1.0**	**1.2**	**0.9**	**0.5**	**+**
Electrical Transmission and Distribution	1.8	1.0	1.2	0.9	0.5	0.3
Magnesium Production and Processing	NC	NC	+	+	+	(0.1)
Semiconductor Manufacture	NC	NC	NC	NC	+	(0.2)
Net Change in Total Emissions[b]	**55.0**	**68.2**	**80.3**	**107.1**	**95.3**	**104.4**
Percent Change	**0.9%**	**1.0%**	**1.1%**	**1.5%**	**1.3%**	**1.5%**

+ Absolute value does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.
Parentheses indicate negative values
NC (No Change)
[a] Not included in emissions total.
[b] Excludes net CO_2 flux from Land Use, Land-Use Change, and Forestry, and emissions from International Bunker Fuels.
Note: Totals may not sum due to independent rounding.

Table 10-2: Revisions to Net Flux of CO_2 to the Atmosphere from Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Component: Net CO_2 Flux From Land Use, Land-Use Change, and Forestry	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**
Forest Land Remaining Forest Land	48.8	89.4	(105.0)	(105.0)	(105.0)	(99.1)
Cropland Remaining Cropland	NC	NC	NC	NC	NC	NC
Land Converted to Cropland	NC	NC	NC	NC	NC	NC
Grassland Remaining Grassland	(0.1)	+	0.1	0.1	0.2	0.2
Land Converted to Grassland	+	+	0.2	0.3	0.3	0.4
Settlements Remaining Settlements	NC	NC	NC	NC	NC	NC
Other	(0.7)	(1.9)	(1.4)	(0.6)	(1.1)	(1.7)
Net Change in Total Flux	**47.9**	**87.7**	**(106.1)**	**(105.2)**	**(105.5)**	**(100.1)**
Percent Change	**5.3%**	**13.2%**	**(11.2%)**	**(11.0%)**	**(11.0%)**	**(10.6%)**

NC (No Change)
Note: Numbers in parentheses indicate a decrease in estimated net flux of CO_2 to the atmosphere, or an increase in net sequestration.
Note: Totals may not sum due to independent rounding.
+ Absolute value does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

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Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic[1] sources and sinks of greenhouse gases is essential for addressing climate change. This inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change.

In 1992, the United States signed and ratified the UNFCCC. As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[2]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[3] The United States views this report as an opportunity to fulfill these commitments.

This chapter summarizes the latest information on U.S. anthropogenic greenhouse gas emission trends from 1990 through 2010. To ensure that the U.S. emissions inventory is comparable to those of other UNFCCC Parties, the estimates presented here were calculated using methodologies consistent with those recommended in the Revised 1996 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), and the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003). Additionally, the U.S. emission inventory has continued to incorporate new methodologies and data from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The structure of this report is consistent with the UNFCCC guidelines for inventory reporting.[4] For most source categories, the IPCC methodologies were expanded, resulting in a more comprehensive and detailed estimate of emissions.

[BEGIN BOX]

Box ES- 1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[5] Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[6] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that

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[1] The term "anthropogenic," in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[2] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>.

[3] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

[4] See < http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

[5] See < http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[6] See < http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>.

these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases (GHG) from large GHG emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground for sequestration or other reasons. Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. For calendar year 2010, the first year in which data were reported, facilities in 29 categories provided in 40 CFR part 98 were required to report their 2010 emissions by the September 30, 2011 reporting deadline.[7] The GHGRP dataset and the data presented in this inventory report are complementary and, as indicated in the respective planned improvements sections in this report's chapters, EPA is analyzing how to use facility-level GHGRP data to improve the national estimates presented in this inventory.

[END BOX]

ES.1. Background Information

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in their national greenhouse gas emission inventories.[8] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas emission inventories.

There are also several gases that do not have a direct global warming effect but indirectly affect terrestrial and/or solar radiation absorption by influencing the formation or destruction of greenhouse gases, including tropospheric and stratospheric ozone. These gases include carbon monoxide (CO), oxides of nitrogen (NO_x), and non-CH_4 volatile organic compounds (NMVOCs). Aerosols, which are extremely small particles or liquid droplets, such as those produced by sulfur dioxide (SO_2) or elemental carbon emissions, can also affect the absorptive characteristics of the atmosphere.

Although the direct greenhouse gases CO_2, CH_4, and N_2O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2010, concentrations of these greenhouse gases have increased globally by 39, 158, and 19 percent, respectively (IPCC 2007 and NOAA/ESLR 2009).

Beginning in the 1950s, the use of CFCs and other stratospheric ozone depleting substances (ODS) increased by nearly 10 percent per year until the mid-1980s, when international concern about ozone depletion led to the entry into force of the Montreal Protocol. Since then, the production of ODS is being phased out. In recent years, use of ODS substitutes such as HFCs and PFCs has grown as they begin to be phased in as replacements for CFCs and

[7] See <http://www.epa.gov/climatechange/emissions/ghgrulemaking.html> and <http://ghgdata.epa.gov/ghgp/main.do>.

[8] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in the annexes of the Inventory report for informational purposes.

HCFCs. Accordingly, atmospheric concentrations of these substitutes have been growing (IPCC 2007).

Global Warming Potentials

Gases in the atmosphere can contribute to the greenhouse effect both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the earth (e.g., affect cloud formation or albedo).[9] The IPCC developed the Global Warming Potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas.

The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO_2, and therefore GWP-weighted emissions are measured in teragrams (or million metric tons) of CO_2 equivalent (Tg CO_2 Eq.).[10,11] All gases in this Executive Summary are presented in units of Tg CO_2 Eq.

The UNFCCC reporting guidelines for national inventories were updated in 2006,[12] but continue to require the use of GWPs from the IPCC Second Assessment Report (SAR) (IPCC 1996). This requirement ensures that current estimates of aggregate greenhouse gas emissions for 1990 to 2010 are consistent with estimates developed prior to the publication of the IPCC Third Assessment Report (TAR) (IPCC 2001) and the IPCC Fourth Assessment Report (AR4) (IPCC 2007). Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. All estimates are provided throughout the report in both CO_2 equivalents and unweighted units. A comparison of emission values using the SAR GWPs versus the TAR and AR4 GWPs can be found in Chapter 1 and, in more detail, in Annex 6.1 of this report. The GWP values used in this report are listed below in Table ES-1.

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report

Gas	GWP
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

Source: IPCC (1996)
* The CH_4 GWP includes the direct effects and those indirect effects due

[9] Albedo is a measure of the Earth's reflectivity, and is defined as the fraction of the total solar radiation incident on a body that is reflected by it.

[10] Carbon comprises 12/44^{ths} of carbon dioxide by weight.

[11] One teragram is equal to 10^{12} grams or one million metric tons.

[12] See <http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Global warming potentials are not provided for CO, NO_x, NMVOCs, SO_2, and aerosols because there is no agreed-upon method to estimate the contribution of gases that are short-lived in the atmosphere, spatially variable, or have only indirect effects on radiative forcing (IPCC 1996).

ES.2. Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2010, total U.S. greenhouse gas emissions were 6,821.8 Tg or million metric tons CO_2 Eq. Total U.S. emissions have increased by 10.5 percent from 1990 to 2010, and emissions increased from 2009 to 2010 by 3.2 percent (213.5 Tg CO_2 Eq.). The increase from 2009 to 2010 was primarily due to an increase in economic output resulting in an increase in energy consumption across all sectors, and much warmer summer conditions resulting in an increase in electricity demand for air conditioning that was generated primarily by combusting coal and natural gas. Since 1990, U.S. emissions have increased at an average annual rate of 0.5 percent.

Figure ES-1 through Figure ES-3 illustrate the overall trends in total U.S. emissions by gas, annual changes, and absolute change since 1990. Table ES-2 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2010.

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg or million metric tons CO_2 Eq.)

Gas/Source	1990	2005	2006	2007	2008	2009	2010
CO_2	**5,100.5**	**6,107.6**	**6,019.0**	**6,118.6**	**5,924.3**	**5,500.5**	**5,706.4**
Fossil Fuel Combustion	4,738.3	5,746.5	5,653.0	5,757.8	5,571.5	5,206.2	5,387.8
Electricity Generation	1,820.8	2,402.1	2,346.4	2,412.8	2,360.9	2,146.4	2,258.4
Transportation	1,485.9	1,896.6	1,878.1	1,893.9	1,789.8	1,727.9	1,745.5
Industrial	846.4	816.4	848.1	844.4	806.5	726.6	777.8
Residential	338.3	357.9	321.5	341.6	349.3	339.0	340.2
Commercial	219.0	223.5	208.6	218.9	225.1	224.6	224.2
U.S. Territories	27.9	50.0	50.3	46.1	39.8	41.7	41.6
Non-Energy Use of Fuels	119.6	144.1	143.8	134.9	138.6	123.7	125.1
Iron and Steel Production & Metallurgical Coke Production	99.6	66.0	68.9	71.1	66.1	42.1	54.3
Natural Gas Systems	37.6	29.9	30.8	31.0	32.8	32.2	32.3
Cement Production	33.3	45.2	45.8	44.5	40.5	29.0	30.5
Lime Production	11.5	14.4	15.1	14.6	14.3	11.2	13.2
Incineration of Waste	8.0	12.5	12.5	12.7	11.9	11.7	12.1
Limestone and Dolomite Use	5.1	6.8	8.0	7.7	6.3	7.6	10.0
Ammonia Production	13.0	9.2	8.8	9.1	7.9	7.9	8.7
Cropland Remaining Cropland	7.1	7.9	7.9	8.2	8.6	7.2	8.0
Urea Consumption for Non-Agricultural Purposes	3.8	3.7	3.5	4.9	4.1	3.4	4.4
Soda Ash Production and Consumption	4.1	4.2	4.2	4.1	4.1	3.6	3.7
Petrochemical Production	3.3	4.2	3.8	3.9	3.4	2.7	3.3

Aluminum Production	6.8	4.1	3.8	4.3	4.5	3.0	3.0
Carbon Dioxide Consumption	1.4	1.3	1.7	1.9	1.8	1.8	2.2
Titanium Dioxide Production	1.2	1.8	1.8	1.9	1.8	1.6	1.9
Ferroalloy Production	2.2	1.4	1.5	1.6	1.6	1.5	1.7
Zinc Production	0.6	1.0	1.0	1.0	1.2	0.9	1.2
Phosphoric Acid Production	1.5	1.4	1.2	1.2	1.2	1.0	1.0
Wetlands Remaining Wetlands	1.0	1.1	0.9	1.0	1.0	1.1	1.0
Lead Production	0.5	0.6	0.6	0.6	0.5	0.5	0.5
Petroleum Systems	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.1	0.2
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(881.8)*	*(1,085.9)*	*(1,110.4)*	*(1,108.2)*	*(1,087.5)*	*(1,062.6)*	*(1,074.7)*
Wood Biomass and Ethanol Consumption[b]	*218.6*	*228.6*	*233.7*	*241.1*	*252.1*	*244.1*	*266.1*
International Bunker Fuels[c]	*111.8*	*109.8*	*128.4*	*127.6*	*133.7*	*122.3*	*127.8*
CH_4	**668.3**	**625.8**	**664.6**	**656.2**	**667.9**	**672.2**	**666.5**
Natural Gas Systems	189.6	190.5	217.7	205.3	212.7	220.9	215.4
Enteric Fermentation	133.8	139.0	141.4	143.8	143.4	142.6	141.3
Landfills	147.7	112.7	111.7	111.7	113.1	111.2	107.8
Coal Mining	84.1	56.8	58.1	57.8	66.9	70.1	72.6
Manure Management	31.7	47.9	48.4	52.7	51.8	50.7	52.0
Petroleum Systems	35.2	29.2	29.2	29.8	30.0	30.7	31.0
Wastewater Treatment	15.9	16.5	16.7	16.6	16.6	16.5	16.3
Rice Cultivation	7.1	6.8	5.9	6.2	7.2	7.3	8.6
Stationary Combustion	7.5	6.6	6.2	6.5	6.6	6.3	6.3
Abandoned Underground Coal Mines	6.0	5.5	5.5	5.3	5.3	5.1	5.0
Forest Land Remaining Forest Land	2.5	8.1	17.9	14.6	8.8	5.8	4.8
Mobile Combustion	4.7	2.5	2.4	2.2	2.1	2.0	1.9
Composting	0.3	1.6	1.6	1.7	1.7	1.6	1.6
Petrochemical Production	0.9	1.1	1.0	1.0	0.9	0.8	0.9
Iron and Steel Production & Metallurgical Coke Production	1.0	0.7	0.7	0.7	0.6	0.4	0.5
Field Burning of Agricultural Residues	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	0.2	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*	*0.2*
N_2O	**316.2**	**331.9**	**336.8**	**334.9**	**317.1**	**304.0**	**306.2**
Agricultural Soil Management	200.0	213.1	211.1	211.1	212.9	207.3	207.8
Stationary Combustion	12.3	20.6	20.8	21.2	21.1	20.7	22.6
Mobile Combustion	43.9	37.0	33.7	29.0	25.2	22.5	20.6
Manure Management	14.8	17.6	18.4	18.5	18.3	18.2	18.3
Nitric Acid Production	17.6	16.4	16.1	19.2	16.4	14.5	16.7
Wastewater Treatment	3.5	4.7	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Forest Land Remaining Forest Land	2.1	7.0	15.0	12.2	7.5	5.1	4.3
Adipic Acid Production	15.8	7.4	8.9	10.7	2.6	2.8	2.8
Composting	0.4	1.7	1.8	1.8	1.9	1.8	1.7
Settlements Remaining Settlements	1.0	1.5	1.5	1.6	1.5	1.4	1.4
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*	*1.2*
HFCs	**36.9**	**115.0**	**116.0**	**120.0**	**117.5**	**112.1**	**123.0**
Substitution of Ozone Depleting	0.3	99.0	101.9	102.7	103.6	106.3	114.6

Substances							
HCFC-22 Production	36.4	15.8	13.8	17.0	13.6	5.4	8.1
Semiconductor Manufacture	0.2	0.2	0.3	0.3	0.3	0.3	0.3
PFCs	**20.6**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**	**5.6**
Semiconductor Manufacture	2.2	3.2	3.5	3.7	4.0	4.0	4.1
Aluminum Production	18.4	3.0	2.5	3.8	2.7	1.6	1.6
SF_6	**32.6**	**17.8**	**16.8**	**15.6**	**15.0**	**13.9**	**14.0**
Electrical Transmission and Distribution	26.7	13.9	13.0	12.2	12.2	11.8	11.8
Magnesium Production and Processing	5.4	2.9	2.9	2.6	1.9	1.1	1.3
Semiconductor Manufacture	0.5	1.0	1.0	0.8	0.9	1.0	0.9
Total	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Net Emission (Sources and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Parentheses indicate negative values or sequestration. The net CO_2 flux total includes both emissions and sequestration, and constitutes a net sink in the United States. Sinks are only included in net emissions total.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2010. The primary greenhouse gas emitted by human activities in the United States was CO_2, representing approximately 83.6 percent of total greenhouse gas emissions. The largest source of CO_2, and of overall greenhouse gas emissions, was fossil fuel combustion. CH_4 emissions, which have decreased by 0.3 percent since 1990, resulted primarily from natural gas systems, enteric fermentation associated with domestic livestock, and decomposition of wastes in landfills. Agricultural soil management, mobile source fuel combustion and stationary fuel combustion were the major sources of N_2O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate HFC emissions. PFC emissions resulted from semiconductor manufacturing and as a by-product of primary aluminum production, while electrical transmission and distribution systems accounted for most SF_6 emissions.

Figure ES-4: 2010 Greenhouse Gas Emissions by Gas (percentages based on Tg CO_2 Eq.)

Overall, from 1990 to 2010, total emissions of CO_2 increased by 605.9 Tg CO_2 Eq. (11.9 percent), while total emissions of CH_4 and N_2O decreased by 1.7 Tg CO_2 Eq. (0.3 percent), and 10.0 Tg CO_2 Eq. (3.2 percent), respectively. During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 52.5 Tg CO_2 Eq. (58.2 percent). From 1990 to 2010, HFCs increased by 86.1 Tg CO_2 Eq. (233.1 percent), PFCs decreased by 15.0 Tg CO_2 Eq. (72.7 percent), and SF_6 decreased by 18.6 Tg CO_2 Eq. (57.0 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon sequestration in forests, trees in urban areas, agricultural soils, and landfilled yard trimmings and food scraps, which, in aggregate, offset 15.8 percent of total emissions in 2010. The following sections describe each gas's contribution to total U.S. greenhouse gas emissions in more detail.

Carbon Dioxide Emissions

The global carbon cycle is made up of large carbon flows and reservoirs. Billions of tons of carbon in the form of CO_2 are absorbed by oceans and living biomass (i.e., sinks) and are emitted to the atmosphere annually through natural processes (i.e., sources). When in equilibrium, carbon fluxes among these various reservoirs are roughly balanced. Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO_2 have risen about 39 percent (IPCC 2007 and NOAA/ESLR 2009), principally due to the combustion of fossil fuels. Within the

United States, fossil fuel combustion accounted for 94.4 percent of CO_2 emissions in 2010. Globally, approximately 30,313 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[13] Changes in land use and forestry practices can also emit CO_2 (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO_2 (e.g., through net additions to forest biomass). In addition to fossil-fuel combustion, several other sources emit significant quantities of CO_2. These sources include, but are not limited to non-energy use of fuels, iron and steel production and cement production (Figure ES-5).

Figure ES-5: 2010 Sources of CO_2 Emissions

As the largest source of U.S. greenhouse gas emissions, CO_2 from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2010. Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 0.7 percent from 1990 to 2010. The fundamental factors influencing this trend include (1) a generally growing domestic economy over the last 21 years, and (2) an overall growth in emissions from electricity generation and transportation activities. Between 1990 and 2010, CO_2 emissions from fossil fuel combustion increased from 4,738.3 Tg CO_2 Eq. to 5,387.8 Tg CO_2 Eq.—a 13.7 percent total increase over the twenty-one-year period. From 2009 to 2010, these emissions increased by 181.6 Tg CO_2 Eq. (3.5 percent).

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. In the short term, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants. In the long term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Figure ES-6: 2010 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure ES-7: 2010 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

The five major fuel consuming sectors contributing to CO_2 emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. CO_2 emissions are produced by the electricity generation sector as they consume fossil fuel to provide electricity to one of the other four sectors, or "end-use" sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector on the basis of each sector's share of aggregate electricity consumption. This method of distributing emissions assumes that each end-use sector consumes electricity that is generated from the national average mix of fuels according to their carbon intensity. Emissions from electricity generation are also addressed separately after the end-use sectors have been discussed.

Note that emissions from U.S. territories are calculated separately due to a lack of specific consumption data for the individual end-use sectors.

[13] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010a).

Figure ES-6, Figure ES-7, and Table ES-3 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table ES-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (Tg or million metric tons CO_2 Eq.)

End-Use Sector	1990	2005	2006	2007	2008	2009	2010
Transportation	**1,489.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.5**	**1,732.4**	**1,750.0**
Combustion	1,485.9	1,896.6	1,878.1	1,893.9	1,789.8	1,727.9	1,745.5
Electricity	3.0	4.7	4.5	5.1	4.7	4.5	4.5
Industrial	**1,533.1**	**1,553.3**	**1,560.2**	**1,559.8**	**1,503.8**	**1,328.6**	**1,415.4**
Combustion	846.4	816.4	848.1	844.4	806.5	726.6	777.8
Electricity	686.8	737.0	712.0	715.4	697.3	602.0	637.6
Residential	**931.4**	**1,214.7**	**1,152.4**	**1,205.2**	**1,192.2**	**1,125.5**	**1,183.7**
Combustion	338.3	357.9	321.5	341.6	349.3	339.0	340.2
Electricity	593.0	856.7	830.8	863.5	842.9	786.5	843.5
Commercial	**757.0**	**1,027.2**	**1,007.6**	**1,047.7**	**1,041.1**	**978.0**	**997.1**
Combustion	219.0	223.5	208.6	218.9	225.1	224.6	224.2
Electricity	538.0	803.7	799.0	828.8	816.0	753.5	772.9
U.S. Territories[a]	**27.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**	**41.6**
Total	**4,738.3**	**5,746.5**	**5,653.0**	**5,757.8**	**5,571.5**	**5,206.2**	**5,387.8**
Electricity Generation	**1,820.8**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,146.4**	**2,258.4**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.
[a] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report.

Transportation End-Use Sector. Transportation activities (excluding international bunker fuels) accounted for 32 percent of CO_2 emissions from fossil fuel combustion in 2010.[14] Virtually all of the energy consumed in this end-use sector came from petroleum products. Nearly 65 percent of the emissions resulted from gasoline consumption for personal vehicle use. The remaining emissions came from other transportation activities, including the combustion of diesel fuel in heavy-duty vehicles and jet fuel in aircraft. From 1990 to 2010, transportation emissions rose by 18 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 34 percent from 1990 to 2010, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

Industrial End-Use Sector. Industrial CO_2 emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 26 percent of CO_2 from fossil fuel combustion in 2010. Approximately 55 percent of these emissions resulted from direct fossil fuel combustion to produce steam and/or heat for industrial processes. The remaining emissions resulted from consuming electricity for motors, electric furnaces, ovens, lighting, and other applications. In contrast to the other end-use sectors, emissions from industry have steadily declined since 1990. This decline is due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements.

Residential and Commercial End-Use Sectors. The residential and commercial end-use sectors accounted for 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion in 2010. Both sectors relied heavily on electricity for meeting energy demands, with 71 and 78 percent, respectively, of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were due to the consumption of natural gas and petroleum for heating and cooking. Emissions from these end-use sectors have increased 29 percent since 1990, due to increasing electricity consumption for lighting, heating, air conditioning, and operating appliances.

[14] If emissions from international bunker fuels are included, the transportation end-use sector accounted for 34.0 percent of U.S. emissions from fossil fuel combustion in 2010.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 36 percent of U.S. energy from fossil fuels and emitted 42 percent of the CO_2 from fossil fuel combustion in 2010. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated with low CO_2 emitting energy technologies, particularly non-fossil options such as nuclear, hydroelectric, or geothermal energy. However, electricity generators rely on coal for over half of their total energy requirements and accounted for 94 percent of all coal consumed for energy in the United States in 2010. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions.

Other significant CO_2 trends included the following:

- CO_2 emissions from non-energy use of fossil fuels have increased 5.5 Tg CO_2 Eq. (4.6 percent) from 1990 through 2010. Emissions from non-energy uses of fossil fuels were 125.1 Tg CO_2 Eq. in 2010, which constituted 2.2 percent of total national CO_2 emissions, approximately the same proportion as in 1990.
- CO_2 emissions from iron and steel production and metallurgical coke production increased by 12.2 Tg CO_2 Eq. (28.9 percent) from 2009 to 2010, upsetting a trend of decreasing emissions. Despite this, from 1990 through 2010 emissions declined by 45.5 percent (45.3 Tg CO_2 Eq.). This decline is due to the restructuring of the industry, technological improvements, and increased scrap utilization.
- In 2010, CO_2 emissions from cement production increased by 1.5 Tg CO_2 Eq. (5.1 percent) from 2009. After decreasing in 1991 by two percent from 1990 levels, cement production emissions grew every year through 2006; emissions decreased in the three years prior to 2010. Overall, from 1990 to 2010, emissions from cement production have decreased by 8.3 percent, a decrease of 2.8 Tg CO_2 Eq.
- Net CO_2 uptake from Land Use, Land-Use Change, and Forestry increased by 192.8 Tg CO_2 Eq. (21.9 percent) from 1990 through 2010. This increase was primarily due to an increase in the rate of net carbon accumulation in forest carbon stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Methane Emissions

Methane (CH_4) is more than 20 times as effective as CO_2 at trapping heat in the atmosphere (IPCC 1996). Over the last two hundred and fifty years, the concentration of CH_4 in the atmosphere increased by 158 percent (IPCC 2007). Anthropogenic sources of CH_4 include natural gas and petroleum systems, agricultural activities, landfills, coal mining, wastewater treatment, stationary and mobile combustion, and certain industrial processes (see Figure ES-8).

Figure ES-8: 2010 Sources of CH_4 Emissions

Some significant trends in U.S. emissions of CH_4 include the following:

- Natural gas systems were the largest anthropogenic source category of CH_4 emissions in the United States in 2010 with 215.4 Tg CO_2 Eq. of CH_4 emitted into the atmosphere. Those emissions have increased by 25.8 Tg CO_2 Eq. (13.6 percent) since 1990.
- Enteric fermentation is the second largest anthropogenic source of CH_4 emissions in the United States. In 2010, enteric fermentation CH_4 emissions were 141.3 Tg CO_2 Eq. (21.2 percent of total CH_4 emissions), which represents an increase of 7.5 Tg CO_2 Eq. (5.6 percent) since 1990.
- Landfills are the third largest anthropogenic source of CH_4 emissions in the United States, accounting for 16.2 percent of total CH_4 emissions (107.8 Tg CO_2 Eq.) in 2010. From 1990 to 2010, CH_4 emissions from landfills decreased by 39.8 Tg CO_2 Eq. (27.0 percent), with small increases occurring in some interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas

collected and combusted,[15] which has more than offset the additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

- In 2010, CH_4 emissions from coal mining were 72.6 Tg CO_2 Eq., a 2.5 Tg CO_2 Eq. (3.5 percent) increase over 2009 emission levels. The overall decline of 11.5 Tg CO_2 Eq. (13.6 percent) from 1990 results from the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- Methane emissions from manure management increased by 64.0 percent since 1990, from 31.7 Tg CO_2 Eq. in 1990 to 52.0 Tg CO_2 Eq. in 2010. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions. The increase in liquid systems is the combined result of a shift to larger facilities, and to facilities in the West and Southwest, all of which tend to use liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site.

Nitrous Oxide Emissions

N_2O is produced by biological processes that occur in soil and water and by a variety of anthropogenic activities in the agricultural, energy-related, industrial, and waste management fields. While total N_2O emissions are much lower than CO_2 emissions, N_2O is approximately 300 times more powerful than CO_2 at trapping heat in the atmosphere (IPCC 1996). Since 1750, the global atmospheric concentration of N_2O has risen by approximately 19 percent (IPCC 2007). The main anthropogenic activities producing N_2O in the United States are agricultural soil management, fuel combustion in motor vehicles, stationary fuel combustion, manure management and nitric acid production (see Figure ES-9).

Figure ES-9: 2010 Sources of N_2O Emissions

Some significant trends in U.S. emissions of N_2O include the following:

- In 2010, N_2O emissions from mobile combustion were 20.6 Tg CO_2 Eq. (approximately 6.7 percent of U.S. N_2O emissions). From 1990 to 2010, N_2O emissions from mobile combustion decreased by 53.1 percent. However, from 1990 to 1998 emissions increased by 25.6 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to an overall decline in N_2O from this source.
- N_2O emissions from adipic acid production were 2.8 Tg CO_2 Eq. in 2010, and have decreased significantly in recent years due to the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 82.2 percent since 1990 and by 84.0 percent since a peak in 1995.
- N_2O emissions from stationary combustion increased 10.3 Tg CO_2 Eq. (84.4 percent) from 1990 through 2010. N_2O emissions from this source increased primarily as a result of an increase in the number of coal fluidized bed boilers in the electric power sector.
- Agricultural soils accounted for approximately 67.9 percent of N_2O emissions in the United States in 2010. Estimated emissions from this source in 2010 were 207.8 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2010, although overall emissions were 3.9 percent higher in 2010 than in 1990.

HFC, PFC, and SF_6 Emissions

HFCs and PFCs are families of synthetic chemicals that are used as alternatives to ODS, which are being phased out under the Montreal Protocol and Clean Air Act Amendments of 1990. HFCs and PFCs do not deplete the

[15] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

stratospheric ozone layer, and are therefore acceptable alternatives under the Montreal Protocol.

These compounds, however, along with SF_6, are potent greenhouse gases. In addition to having high global warming potentials, SF_6 and PFCs have extremely long atmospheric lifetimes, resulting in their essentially irreversible accumulation in the atmosphere once emitted. Sulfur hexafluoride is the most potent greenhouse gas the IPCC has evaluated (IPCC 1996).

Other emissive sources of these gases include electrical transmission and distribution systems, HCFC-22 production, semiconductor manufacturing, aluminum production, and magnesium production and processing (see Figure ES-10).

Figure ES-10: 2010 Sources of HFCs, PFCs, and SF_6 Emissions

Some significant trends in U.S. HFC, PFC, and SF_6 emissions include the following:

- Emissions resulting from the substitution of ozone depleting substances (ODS) (e.g., CFCs) have been consistently increasing, from small amounts in 1990 to 114.6 Tg CO_2 Eq. in 2010. Emissions from ODS substitutes are both the largest and the fastest growing source of HFC, PFC, and SF_6 emissions. These emissions have been increasing as phase-out of ODS required under the Montreal Protocol came into effect, especially after 1994, when full market penetration was made for the first generation of new technologies featuring ODS substitutes.
- HFC emissions from the production of HCFC-22 decreased by 77.8 percent (28.3 Tg CO_2 Eq.) from 1990 through 2010, due to a steady decline in the emission rate of HFC-23 (i.e., the amount of HFC-23 emitted per kilogram of HCFC-22 manufactured) and the use of thermal oxidation at some plants to reduce HFC-23 emissions.
- SF_6 emissions from electric power transmission and distribution systems decreased by 55.7 percent (14.9 Tg CO_2 Eq.) from 1990 to 2010, primarily because of higher purchase prices for SF_6 and efforts by industry to reduce emissions.
- PFC emissions from aluminum production decreased by 91.5 percent (16.9 Tg CO_2 Eq.) from 1990 to 2010, due to both industry emission reduction efforts and declines in domestic aluminum production.

ES.3. Overview of Sector Emissions and Trends

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2003 UNFCCC Guidelines on Reporting and Review (UNFCCC 2003), Figure ES-11 and Table ES-4 aggregate emissions and sinks by these chapters. Emissions of all gases can be summed from each source category from IPCC guidance. Over the twenty-one-year period of 1990 to 2010, total emissions in the Energy and Agriculture sectors grew by 645.8 Tg CO_2 Eq. (12.2 percent), and 40.6 Tg CO_2 Eq. (10.5 percent), respectively. Emissions slightly decreased in the Industrial Processes sector by 10.5 Tg CO_2 Eq. (3.4 percent) , while emissions from the Waste and Solvent and Other Product Use sectors decreased by 35.2 Tg CO_2 Eq. (21.0 percent) and less than 0.1 Tg CO_2 Eq. (0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry (LULUCF) sector (magnitude of emissions plus CO_2 flux from all LULUCF source categories) increased by 187.0 Tg CO_2 Eq. (21.5 percent).

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg or million metric tons CO_2 Eq.)

Chapter/IPCC Sector	1990		2005	2006	2007	2008	2009	2010
Energy	5,287.7		6,282.4	6,214.4	6,294.3	6,125.4	5,752.7	5,933.5
Industrial Processes	313.9		330.1	335.5	347.3	319.1	268.2	303.4

Solvent and Other Product Use	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Agriculture	387.8	424.6	425.4	432.6	433.8	426.4	428.4
Land-Use Change and Forestry	13.8	25.6	43.2	37.6	27.4	20.6	19.6
Waste	167.7	137.2	136.5	136.7	138.2	136.0	132.5
Total Emissions	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land-Use Change and Forestry (Sinks)	(881.8)	(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Emissions and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

* The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total.
Note: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Energy

The Energy chapter contains emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions. Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2010. In 2010, approximately 85 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 15 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure ES-12). Energy-related activities are also responsible for CH_4 and N_2O emissions (50 percent and 14 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 87.0 percent of total U.S. greenhouse gas emissions in 2010.

Figure ES-12: 2010 U.S. Energy Consumption by Energy Source

Industrial Processes

The Industrial Processes chapter contains by-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production. Additionally, emissions from industrial processes release HFCs, PFCs, and SF_6. Overall, emission sources in the Industrial Process chapter account for 4.4 percent of U.S. greenhouse gas emissions in 2010.

Solvent and Other Product Use

The Solvent and Other Product Use chapter contains greenhouse gas emissions that are produced as a by-product of various solvent and other product uses. In the United States, emissions from N_2O from product uses, the only source of greenhouse gas emissions from this sector, accounted for about 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a carbon equivalent basis in 2010.

Agriculture

The Agricultural chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO_2 fluxes, which are addressed in the Land Use, Land-Use Change, and Forestry Chapter). Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented 21.2 percent and 7.8 percent of total CH_4 emissions from

anthropogenic activities, respectively, in 2010. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions in 2010, accounting for 67.9 percent. In 2010, emission sources accounted for in the Agricultural chapters were responsible for 6.3 percent of total U.S. greenhouse gas emissions.

Land Use, Land-Use Change, and Forestry

The Land Use, Land-Use Change, and Forestry chapter contains emissions of CH_4 and N_2O, and emissions and removals of CO_2 from forest management, other land-use activities, and land-use change. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps resulted in a net uptake (sequestration) of C in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 86 percent of total 2010 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2010. The net forest sequestration is a result of net forest growth and increasing forest area, as well as a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth in these areas. In agricultural soils, mineral and organic soils sequester approximately 5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to permanent pastures and hay production, a reduction in summer fallow areas in semi-arid areas, an increase in the adoption of conservation tillage practices, and an increase in the amounts of organic fertilizers (i.e., manure and sewage sludge) applied to agriculture lands. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2010 resulted in a net C sequestration of 1,074.7 Tg CO_2 Eq. (Table ES-5). This represents an offset of 18.8 percent of total U.S. CO_2 emissions, or 15.8 percent of total greenhouse gas emissions in 2010. Between 1990 and 2010, total land use, land-use change, and forestry net C flux resulted in a 21.9 percent increase in CO_2 sequestration, primarily due to an increase in the rate of net C accumulation in forest C stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual C accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of annual C accumulation increased in urban trees.

Table ES-5: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Sink Category	1990	2005	2006	2007	2008	2009	2010
Forest Land Remaining Forest Land	(701.4)	(940.9)	(963.5)	(959.2)	(938.3)	(910.6)	(921.8)
Cropland Remaining Cropland	(29.4)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)	(15.6)
Land Converted to Cropland	2.2	5.9	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)	(8.3)
Land Converted to Grassland	(19.8)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)	(23.6)
Settlements Remaining Settlements	(57.1)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)	(98.0)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(11.6)	(11.0)	(10.9)	(10.9)	(12.7)	(13.3)
Total	**(881.8)**	**(1,085.9)**	**(1,110.4)**	**(1,108.2)**	**(1,087.5)**	**(1,062.6)**	**(1,074.7)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table ES-6. Liming of agricultural soils and urea fertilization in 2010 resulted in CO_2 emissions of 3.9 Tg CO_2 Eq. (3,906 Gg) and 4.1 Tg CO_2 Eq. (4,143 Gg), respectively. Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO_2 emissions of 1.0 Tg CO_2 Eq. (983 Gg), and N_2O emissions of less than 0.05 Tg CO_2 Eq. The application of synthetic fertilizers to forest soils in 2010 resulted in direct N_2O emissions of 0.4 Tg CO_2 Eq. (1 Gg). Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils in 2010 accounted for 1.4 Tg CO_2 Eq. (5 Gg). This represents an increase of 43 percent since 1990. Forest fires in 2010 resulted in CH_4 emissions of 4.8 Tg CO_2 Eq. (231 Gg), and in N_2O emissions of 4.0 Tg CO_2 Eq. (14 Gg).

Table ES-6: Emissions from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Source Category	1990	2005	2006	2007	2008	2009	2010
CO_2	**8.1**	**8.9**	**8.8**	**9.2**	**9.6**	**8.3**	**9.0**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.2	4.5	5.0	3.7	3.9
Cropland Remaining Cropland: Urea Fertilization	2.4	3.5	3.7	3.8	3.6	3.6	4.1
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.1	0.9	1.0	1.0	1.1	1.0
CH_4	**2.5**	**8.1**	**17.9**	**14.6**	**8.8**	**5.8**	**4.8**
Forest Land Remaining Forest Land: Forest Fires	2.5	8.1	17.9	14.6	8.8	5.8	4.8
N_2O	**3.1**	**8.5**	**16.5**	**13.8**	**9.0**	**6.5**	**5.7**
Forest Land Remaining Forest Land: Forest Fires	2.1	6.6	14.6	11.9	7.2	4.7	4.0
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.5	1.5	1.6	1.5	1.4	1.4
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**13.8**	**25.6**	**43.2**	**37.6**	**27.4**	**20.6**	**19.6**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Waste

The Waste chapter contains emissions from waste management activities (except incineration of waste, which is addressed in the Energy chapter). Landfills were the largest source of anthropogenic greenhouse gas emissions in the Waste chapter, accounting for 81.4 percent of this chapter's emissions, and 16.2 percent of total U.S. CH_4 emissions.[16] Additionally, wastewater treatment accounts for 16.1 percent of Waste emissions, 2.5 percent of U.S. CH_4 emissions, and 1.6 percent of U.S. N_2O emissions. Emissions of CH_4 and N_2O from composting are also accounted for in this chapter; generating emissions of 1.6 Tg CO_2 Eq. and 1.7 Tg CO_2 Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 1.9 percent of total U.S. greenhouse gas emissions in 2010.

ES.4. Other Information

Emissions by Economic Sector

Throughout the Inventory of U.S. Greenhouse Gas Emissions and Sinks report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes; Solvent Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following economic sectors: Residential, Commercial, Industry, Transportation, Electricity Generation, Agriculture, and U.S. Territories.

Table ES-7 summarizes emissions from each of these sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2010.

Figure ES-13: Emissions Allocated to Economic Sectors

[16] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land-Use, Land-Use Change, and Forestry chapter of the Inventory report.

Table ES-7: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg or million metric tons CO_2 Eq.)

Implied Sectors	1990	2005	2006	2007	2008	2009	2010
Electric Power Industry	1,866.2	2,448.8	2,393.0	2,459.1	2,405.8	2,191.4	2,306.5
Transportation	1,545.2	2,017.5	1,994.5	2,002.4	1,889.8	1,819.3	1,834.0
Industry	1,564.8	1,438.1	1,499.8	1,489.6	1,448.5	1,317.2	1,394.2
Agriculture	431.9	496.0	516.7	517.6	505.8	492.8	494.8
Commercial	388.0	374.3	359.9	372.2	381.8	382.0	381.7
Residential	345.4	371.3	336.1	358.4	368.4	360.0	365.2
U.S. Territories	33.7	58.2	59.3	53.5	48.4	45.5	45.5
Total Emissions	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land Use, Land-Use Change, and Forestry (Sinks)	(881.8)	(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Sources and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

Note: Totals may not sum due to independent rounding. Emissions include CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.
See Table 2-12 for more detailed data.

Using this categorization, emissions from electricity generation accounted for the largest portion (34 percent) of U.S. greenhouse gas emissions in 2010. Transportation activities, in aggregate, accounted for the second largest portion (27 percent), while emissions from industry accounted for the third largest portion (20 percent) of U.S. greenhouse gas emissions in 2010. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and energy efficiency improvements. The remaining 19 percent of U.S. greenhouse gas emissions were contributed by, in order of importance, the agriculture, commercial, and residential sectors, plus emissions from U.S. territories. Activities related to agriculture accounted for 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation. The commercial and residential sectors accounted for 6 and 5 percent, respectively, of emissions and U.S. territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO_2 emissions from fossil fuel combustion.

CO_2 was also emitted and sequestered by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Electricity is ultimately consumed in the economic sectors described above. Table ES-8 presents greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). To distribute electricity emissions among end-use sectors, emissions from the source categories assigned to electricity generation were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity.[17] These source categories include CO_2 from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO_2 and N_2O from incineration of waste, CH_4 and N_2O from stationary sources, and SF_6 from electrical transmission and distribution systems.

When emissions from electricity are distributed among these sectors, industrial activities account for the largest share of U.S. greenhouse gas emissions (30 percent) in 2010. Transportation is the second largest contributor to total U.S. emissions (27 percent). The residential and commercial sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2010. Emissions from these sectors increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption (e.g., lighting, appliances, etc.). In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels. Figure ES-14 shows the trend in these emissions by sector from 1990 to 2010.

Table ES-8: U.S Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed

[17] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

(Tg or million metric tons CO_2 Eq.)

Implied Sectors	1990	2005	2006	2007	2008	2009	2010
Industry	2,237.7	2,159.9	2,198.5	2,185.9	2,131.5	1,905.8	2,019.0
Transportation	1,548.3	2,022.3	1,999.1	2,007.6	1,894.6	1,823.9	1,838.6
Residential	953.2	1,244.6	1,183.4	1,238.5	1,227.3	1,162.9	1,226.6
Commercial	939.4	1,193.6	1,174.8	1,216.9	1,213.3	1,151.3	1,171.0
Agriculture	462.9	525.5	544.2	550.5	533.3	518.9	521.1
U.S. Territories	33.7	58.2	59.3	53.5	48.4	45.5	45.5
Total Emissions	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land Use, Land-Use Change, and Forestry (Sinks)	(881.8)	(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Sources and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

See Table 2-14 for more detailed data.

Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

[BEGIN BOX]

Box ES- 2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and nonutilities combined—was the largest source of U.S. greenhouse gas emissions in 2010; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-9 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.5 percent since 1990. This rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Figure ES-15).

Table ES-9: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	1990	2005	2006	2007	2008	2009	2010	Growth Rate[a]
GDP[b]	100	157	161	165	164	158	163	2.5%
Electricity Consumption[c]	100	134	135	137	136	131	137	1.6%
Fossil Fuel Consumption[c]	100	119	117	119	116	109	113	0.6%
Energy Consumption[c]	100	119	118	121	119	113	117	0.8%
Population[d]	100	118	120	121	122	123	123	1.1%
Greenhouse Gas Emissions[e]	100	117	116	117	114	107	110	0.5%

[a] Average annual growth rate
[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)
[c] Energy content-weighted values (EIA 2010b)
[d] U.S. Census Bureau (2010)
[e] GWP-weighted values

Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product
Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

Indirect Greenhouse Gases (CO, NO_x, NMVOCs, and SO_2)

The reporting requirements of the UNFCCC[18] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2010, EPA 2009),[19] which are regulated under the Clean Air Act. Table ES-10 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table ES-10: Emissions of NO_x, CO, NMVOCs, and SO_2 (Gg)

Gas/Activity	1990	2005	2006	2007	2008	2009	2010
NO_x	**21,705**	**15,899**	**15,039**	**14,380**	**13,545**	**11,467**	**11,467**
Mobile Fossil Fuel Combustion	10,862	9,012	8,488	7,965	7,441	6,206	6,206
Stationary Fossil Fuel Combustion	10,023	5,858	5,545	5,432	5,148	4,159	4,159
Industrial Processes	591	569	553	537	520	568	568
Oil and Gas Activities	139	321	319	318	318	393	393
Incineration of Waste	82	129	121	114	106	128	128
Agricultural Burning	8	6	7	8	8	8	8
Solvent Use	1	3	4	4	4	3	3
Waste	+	2	2	2	2	2	2
CO	**129,976**	**70,791**	**67,227**	**63,613**	**59,993**	**51,431**	**51,431**
Mobile Fossil Fuel Combustion	119,360	62,692	58,972	55,253	51,533	43,355	43,355
Stationary Fossil Fuel Combustion	5,000	4,649	4,695	4,744	4,792	4,543	4,543
Industrial Processes	4,125	1,555	1,597	1,640	1,682	1,549	1,549
Incineration of Waste	978	1,403	1,412	1,421	1,430	1,403	1,403
Agricultural Burning	268	184	233	237	270	247	247
Oil and Gas Activities	302	318	319	320	322	345	345
Waste	1	7	7	7	7	7	7
Solvent Use	5	2	2	2	2	2	2
NMVOCs	**20,930**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**	**9,313**
Mobile Fossil Fuel Combustion	10,932	6,330	6,037	5,742	5,447	4,151	4,151
Solvent Use	5,216	3,851	3,846	3,839	3,834	2,583	2,583
Industrial Processes	2,422	1,997	1,933	1,869	1,804	1,322	1,322
Stationary Fossil Fuel Combustion	912	716	918	1,120	1,321	424	424
Oil and Gas Activities	554	510	510	509	509	599	599
Incineration of Waste	222	241	238	234	230	159	159
Waste	673	114	113	111	109	76	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**	**8,599**
Stationary Fossil Fuel Combustion	18,407	11,541	10,612	10,172	8,891	7,167	7,167
Industrial Processes	1,307	831	818	807	795	798	798
Mobile Fossil Fuel Combustion	793	889	750	611	472	455	455
Oil and Gas Activities	390	181	182	184	187	154	154

[18] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

[19] NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2008).

Incineration of Waste	38	24	24	24	23	24	24
Waste	+	1	1	1	1	1	1
Solvent Use	+	+	+	+	+	+	+
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.5 Gg.

Key Categories

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) defines a key category as a "[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both."[20] By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends of individual source and sink categories. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses.

Figure ES-16 presents 2010 emission estimates for the key categories as defined by a level analysis (i.e., the contribution of each source or sink category to the total inventory level). The UNFCCC reporting guidelines request that key category analyses be reported at an appropriate level of disaggregation, which may lead to source and sink category names which differ from those used elsewhere in the inventory report. For more information regarding key categories, see section 1.5 and Annex 1.

Figure ES-16: 2010 Key Categories

Quality Assurance and Quality Control (QA/QC)

The United States seeks to continually improve the quality, transparency, and credibility of the Inventory of U.S. Greenhouse Gas Emissions and Sinks. To assist in these efforts, the United States implemented a systematic approach to QA/QC. While QA/QC has always been an integral part of the U.S. national system for inventory development, the procedures followed for the current inventory have been formalized in accordance with the QA/QC plan and the UNFCCC reporting guidelines.

Uncertainty Analysis of Emission Estimates

While the current U.S. emissions inventory provides a solid foundation for the development of a more detailed and comprehensive national inventory, there are uncertainties associated with the emission estimates. Some of the current estimates, such as those for CO_2 emissions from energy-related activities and cement processing, are considered to have low uncertainties. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty associated with the estimates presented. Acquiring a better understanding of the uncertainty associated with inventory estimates is an important step in helping to prioritize future work and improve the overall quality of the Inventory. Recognizing the benefit of conducting an uncertainty analysis, the UNFCCC reporting guidelines follow the recommendations of the IPCC Good Practice Guidance (IPCC 2000) and require that countries provide single estimates of uncertainty for source and sink categories.

Currently, a qualitative discussion of uncertainty is presented for all source and sink categories. Within the

[20] See Chapter 7 "Methodological Choice and Recalculation" in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

discussion of each emission source, specific factors affecting the uncertainty surrounding the estimates are discussed. Most sources also contain a quantitative uncertainty assessment, in accordance with UNFCCC reporting guidelines.

[BEGIN BOX]

Box ES- 3: Recalculations of Inventory Estimates

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, “Both methodological changes and refinements over time are an essential part of improving inventory quality. It is good practice to change or refine methods” when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors.” In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data.

In each Inventory report, the results of all methodology changes and historical data updates are presented in the "Recalculations and Improvements" chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. In general, when methodological changes have been implemented, the entire time series (in the case of the most recent inventory report, 1990 through 2010) has been recalculated to reflect the change, per the 2006 IPCC Guidelines (IPCC 2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies. References for the data are provided for additional information.

[END BOX]

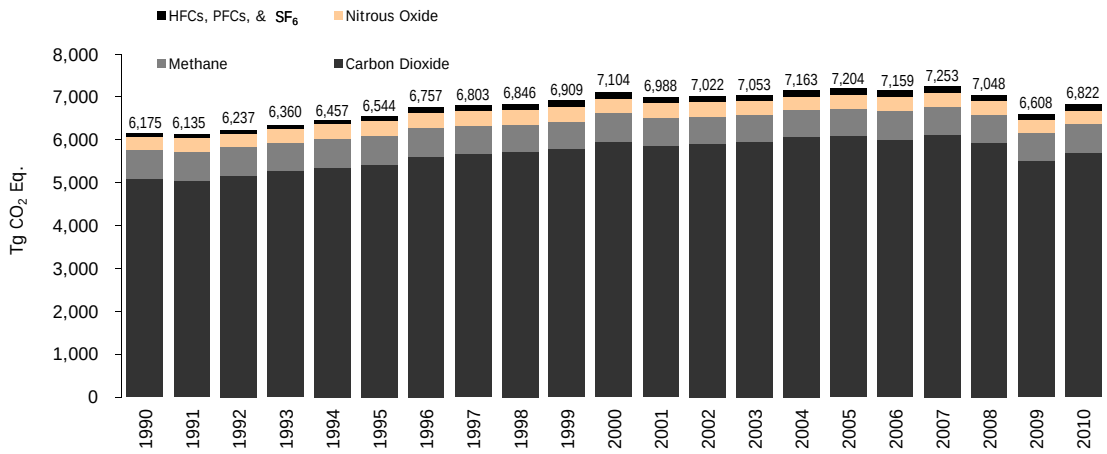


Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

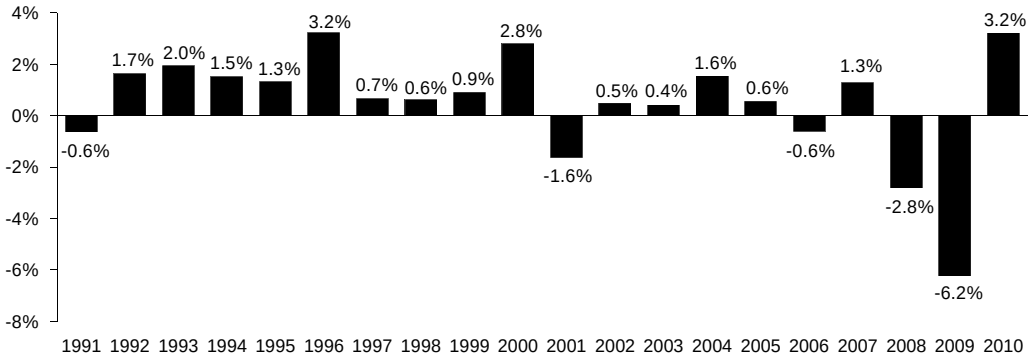


Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

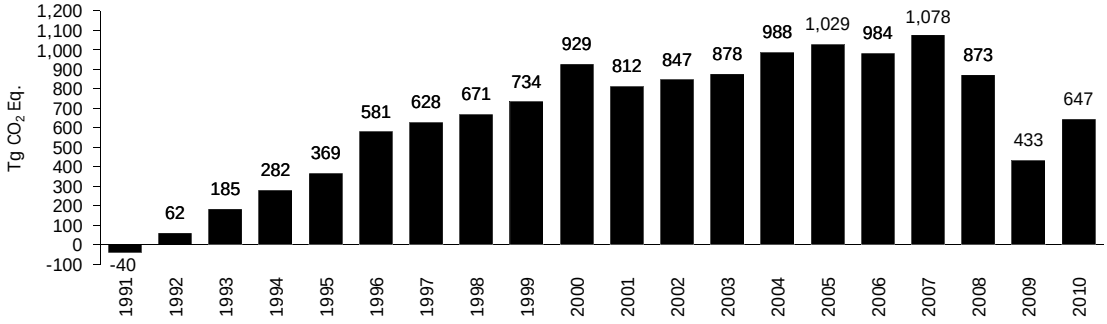


Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

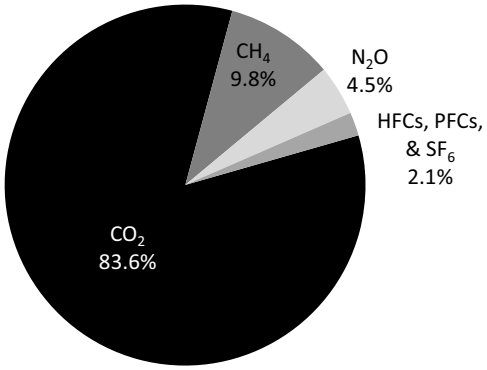


Figure ES-4: 2010 Greenhouse Gas Emissions by Gas (percents based on Tg CO_2 Eq.)

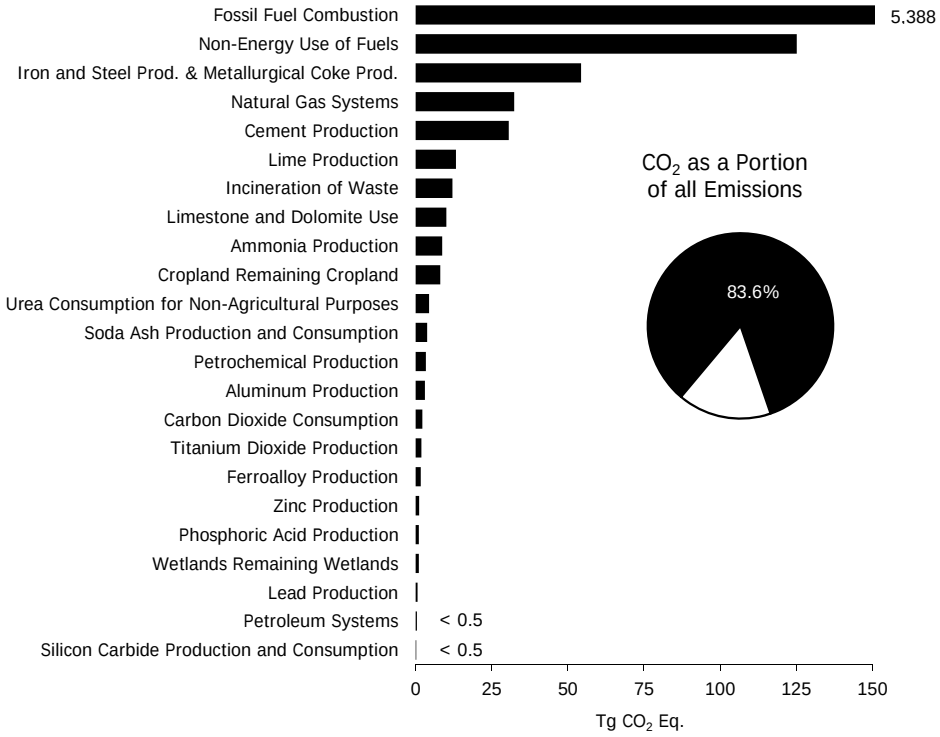


Figure ES-5: 2010 Sources of CO_2 Emissions

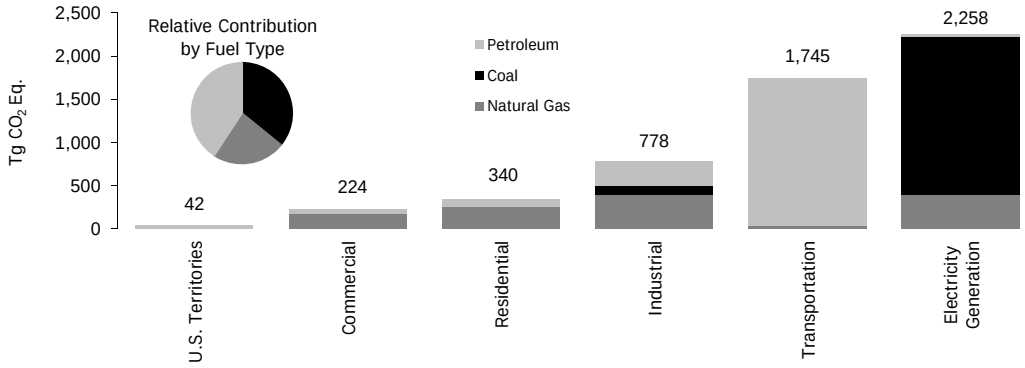


Figure ES-6: 2010 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

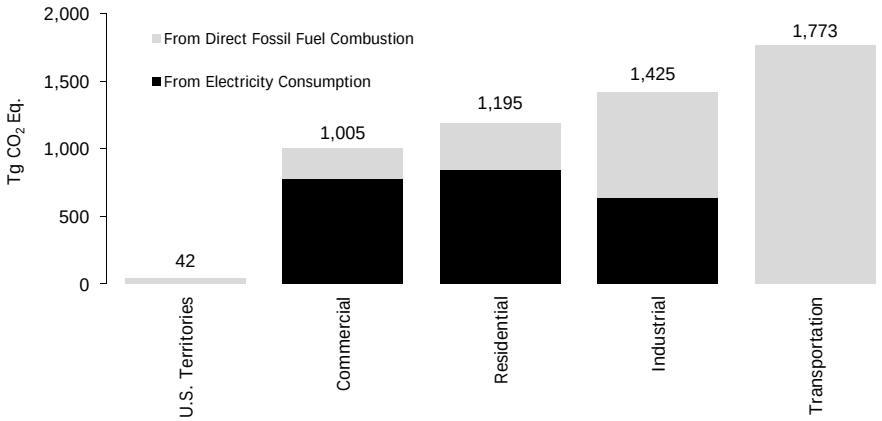


Figure ES-7: 2010 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

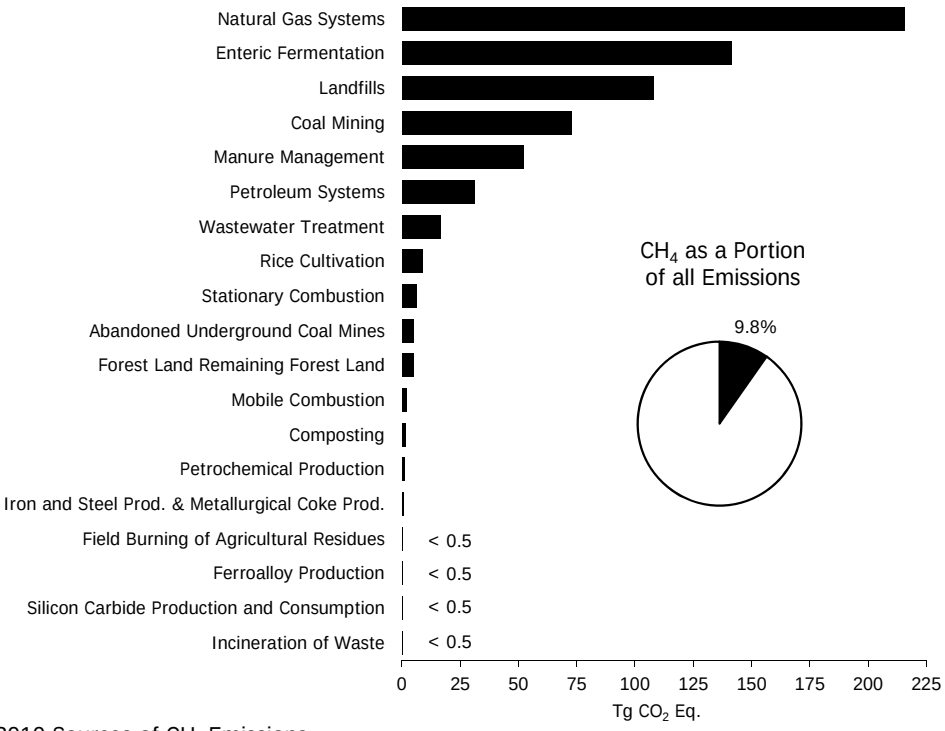


Figure ES-8: 2010 Sources of CH_4 Emissions

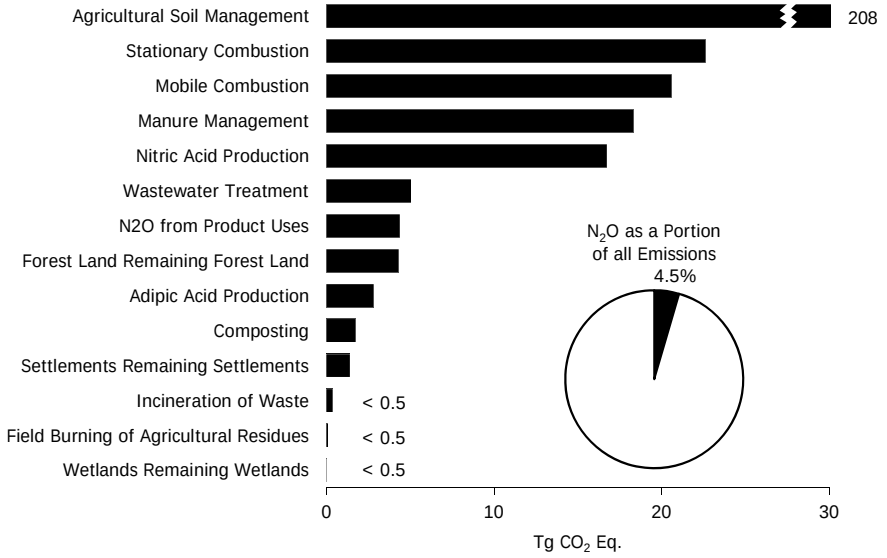


Figure ES-9: 2010 Sources of N_2O Emissions

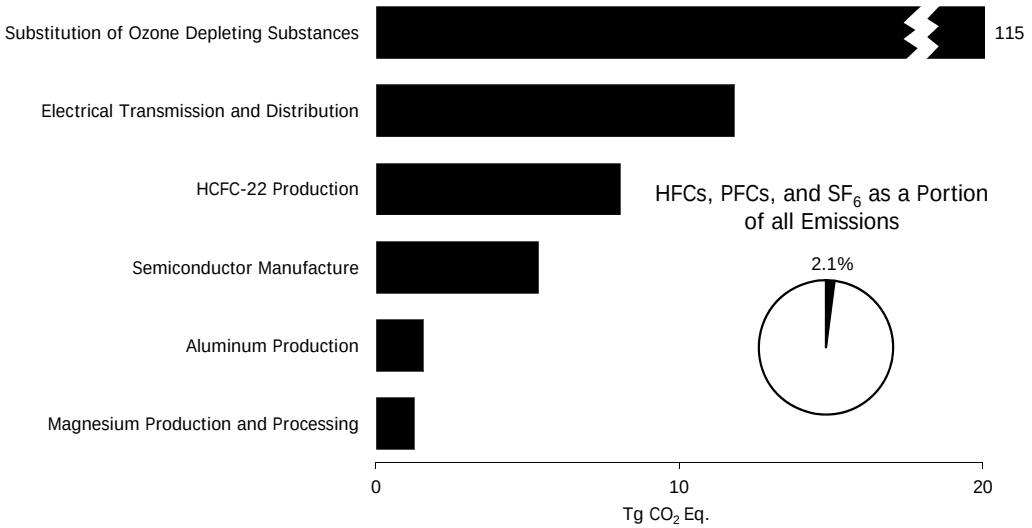
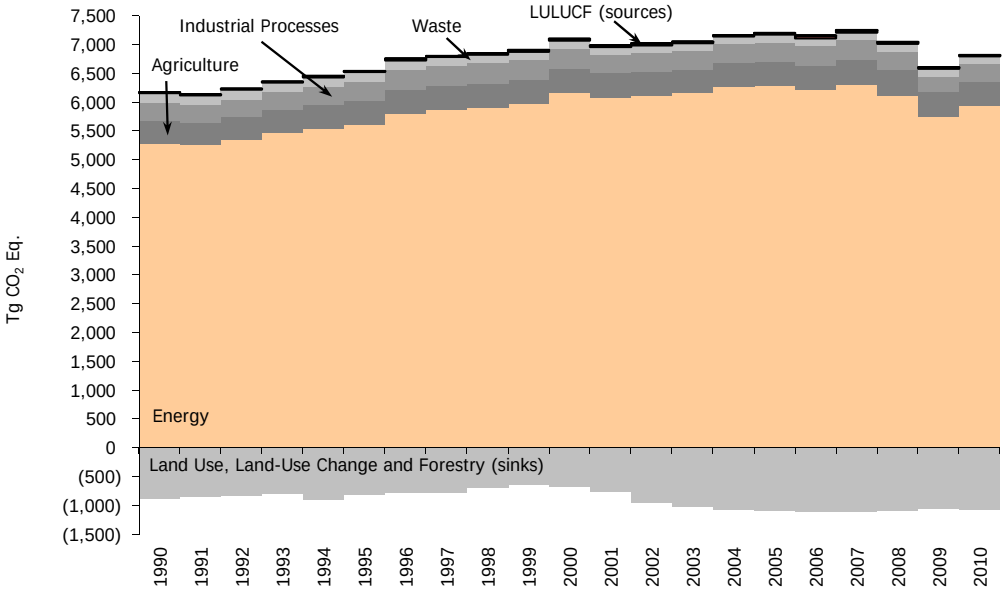


Figure ES-10: 2010 Sources of HFCs, PFCs, and SF_6 Emissions



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sectors

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

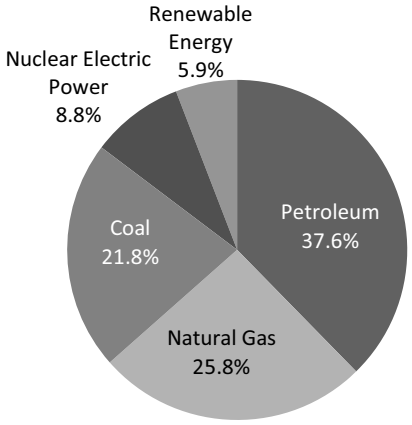


Figure ES-12: 2010 U.S. Energy Consumption by Energy Source

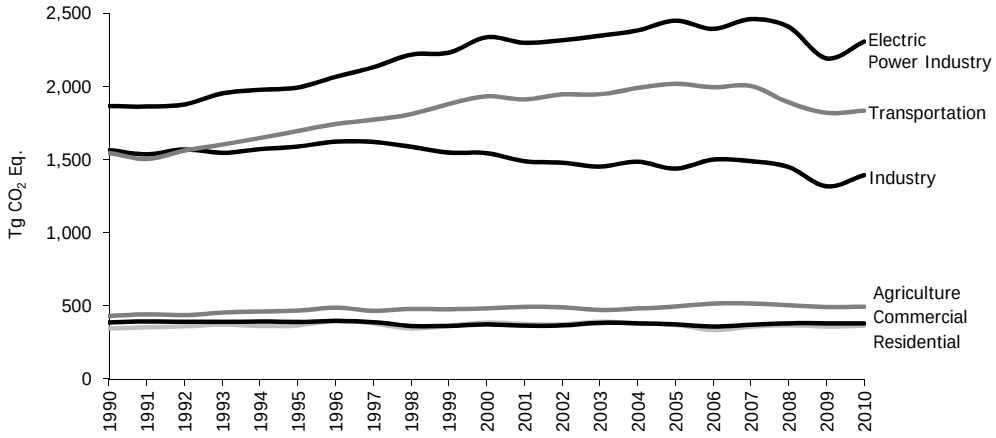


Figure ES-13: Emissions Allocated to Economic Sectors
Note: Does not include U.S. Territories.

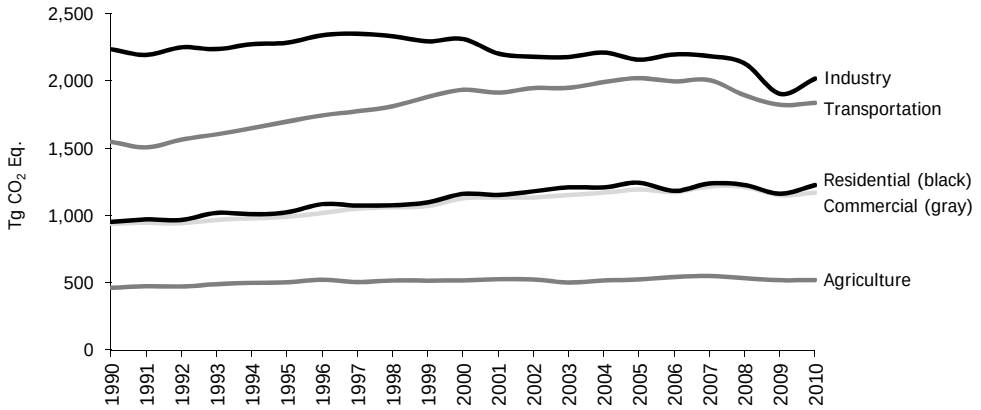


Figure ES-14: Emissions with Electricity Distributed to Economic Sectors
Note: Does not include U.S. Territories.

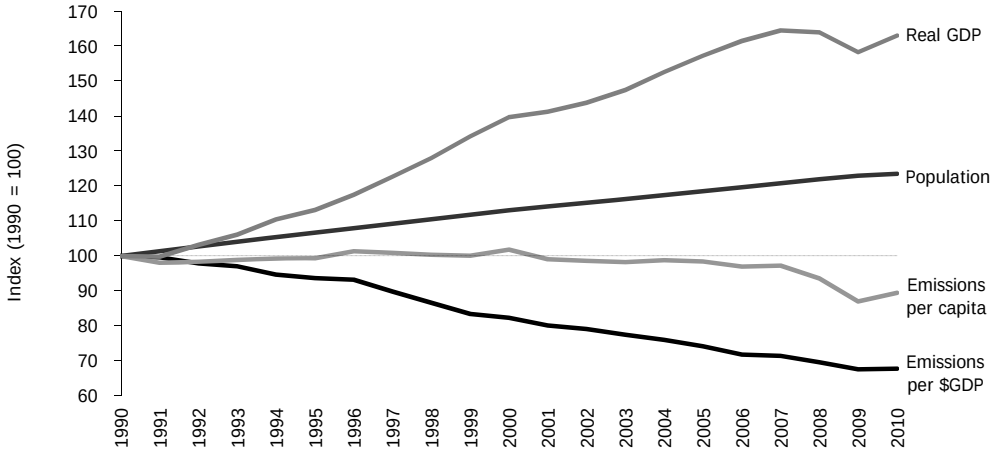


Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

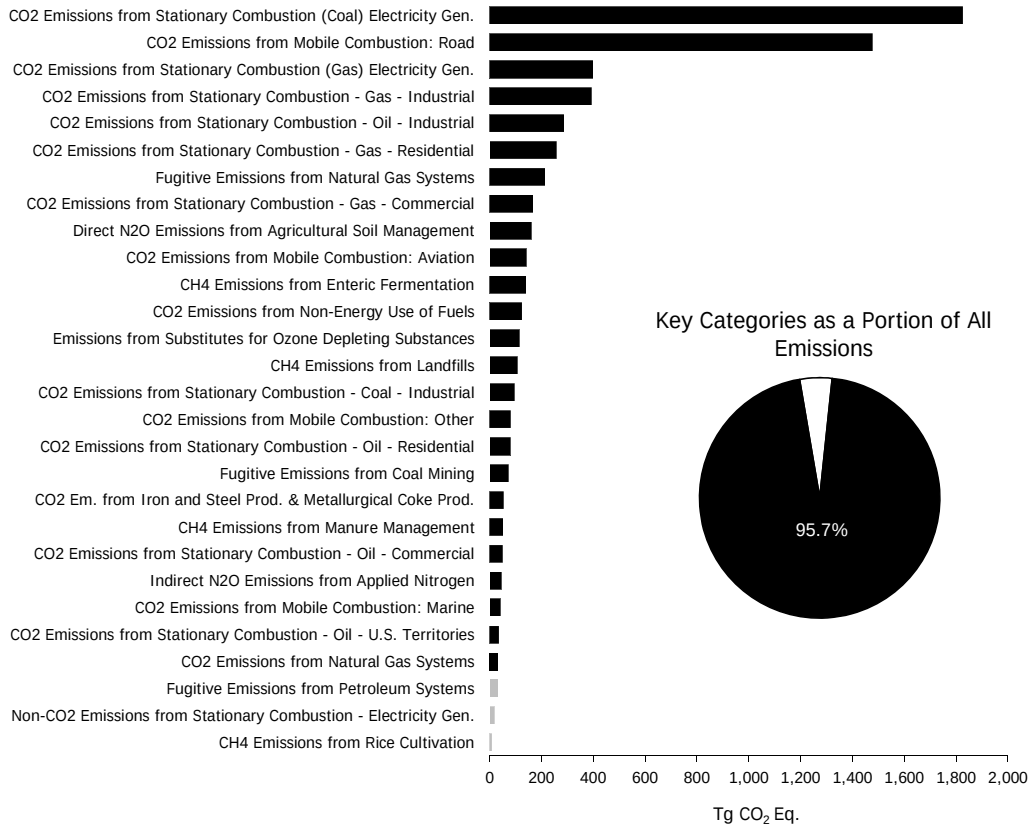


Figure ES-16: 2010 Key Categories

Notes: For a complete discussion of the key category analysis, see Annex 1.
Black bars indicate a Tier 1 level assessment key category.
Gray bars indicate a Tier 2 level assessment key category.

Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal

August 25, 2011

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Investment Research

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Written in collaboration with:

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Sustainable Energy Fellow
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Senior Vice President
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Executive Summary

— **Research conclusion and key messages—natural gas offers greenhouse gas advantages over coal**: Natural gas has been widely discussed as a less carbon-intensive alternative to coal as a power sector fuel. In April 2011, the U.S. Environmental Protection Agency released revised methodologies for estimating fugitive methane emissions from natural gas systems. These revisions mostly affected the production component of the natural gas value chain (namely, gas well cleanups), causing a very substantial increase in the methane emissions estimate from U.S. natural gas systems.[1][2] This large increase in the upstream component of the natural gas value chain caused some to question the GHG advantage of gas versus coal over the entire life-cycle from source to use. As a result of this renewed attention, while it remains unambiguous that natural gas has a lower carbon content per unit of energy than coal does, several recent bottom-up studies have questioned whether natural gas retains its greenhouse gas advantage when the entire life cycles of both fuels are considered.[3]

Particular scrutiny has focused on shale formations, which are the United States' fastest growing marginal supply source of natural gas. Several recent bottom-up life-cycle studies have found the production of a unit of shale gas to be more GHG-intensive than that of conventional natural gas.[4] Consequently, if the upstream emissions associated with shale gas production are not mitigated, a growing share of shale gas would increase the average life-cycle greenhouse gas footprint of the total U.S. natural gas supply.

Applying the latest emission factors from the EPA's 2011 upward revisions, our top-down life-cycle analysis

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[1] *EPA, Inventory of U.S. Greenhouse Gas Emissions And Sinks:1990 – 2009, U.S. EPA, EPA 430-R-11-005, http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf, cited in Mark Fulton, et al., "Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal," 14 March 2011, available at http://www.dbcca.com/dbcca/EN/_media/Comparing_Life_Cycle_Greenhouse_Gas.pdf.*

[2] *Note: For example, the EPA's estimates of methane emissions from U.S. natural gas systems in the base year of 2008 increased 120 percent between the 2010 and 2011 versions of their Inventory of U.S. Greenhouse Gas Emissions and Sinks.*

[3] *The two approaches for an LCA study are bottom-up and top-down. A bottom-up study analyzes the emissions from an individual representative or prototype process or facility and calculates the emissions of that specific part of the value chain. It then combines each step of the value chain to compute the total lifecycle emissions from source to use. A top-down study, in contrast, looks at the total national emissions for a particular use or sector and depicts the national average life-cycle emissions for each discrete part of source to use for that sector to arrive at an aggregate estimate. Each approach has benefits and limitations. The bottom-up approach provides insights into the emissions for a particular process or fuel source, but also depicts only that specific process or source. The top-down approach represents the emissions across an entire sector but does not focus on specific processes or technologies. Some of the data sources for a top-down analysis may be built up from bottom-up sources, but the top-down analysis still yields a more general result.*

[4] *Robert W. Howarth, et al., "Methane and the greenhouse-gas footprint of natural gas from shale formations,"* Climatic Change *(2011); Timothy J. Skone, National Energy Technology Laboratory (NETL), "Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States," presentation (Ithaca, NY: 12 May 2011; revised 23 May 2011); Mohan Jiang, et al., "Life cycle greenhouse gas emissions of Marcellus Shale gas,"* Environmental Research Letters *6 (3), 5 August 2011.*

(LCA)[5] finds that the EPA's new methodology increases the life-cycle emissions estimate of natural gas-fired electricity for the baseline year of 2008 by about 11 percent compared with its 2010 methodology. But even with these adjustments, we conclude that **on average, U.S. natural gas-fired electricity generation still emitted 47 percent less GHGs than coal from source to use using the IPCC's 100-year global warming potential for methane of 25**. This figure is consistent with the findings of all but one of the recent life-cycle analyses that we reviewed.

While our LCA finds that the EPA's updated estimates of methane emissions from natural gas systems do not undercut the greenhouse gas advantage of natural gas over coal, methane is nevertheless of concern as a GHG, and requires further attention. In its recent report on improving the safety of hydraulic fracturing, the U.S. Secretary of Energy's Advisory Board's Subcommittee on Shale Gas Production recommended that immediate efforts be launched to gather improved methane emissions data from shale gas operations.[6] In the meantime, methane emissions during the production, processing, transport, storage, and distribution of all forms of natural gas can be mitigated immediately using a range of existing technologies and best practices, many of which have payback times of three years or less.[7] Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle GHG footprint of natural gas. Although the adoption of these practices has been largely voluntary to date, the EPA proposed new air quality rules in July 2011 that would require the industry to mitigate many of the methane emissions associated with natural gas development, and in particular with shale gas development.[8]

Our research methodology: This paper seeks to assess the current state of knowledge about the average greenhouse gas footprints of average coal and natural gas-fired electricity in the system today, how the growing share of natural gas production from shale formations could change this greenhouse gas footprint at the margin, and what the findings imply for policymakers, investors and the environment. In the first part of the paper, we examine recent bottom-up life-cycle analyses to provide context for our top-down analysis. These bottom-up analyses' estimation of the life-cycle GHG footprint of shale gas provides information about the potential marginal GHG impact of shale's rising share in the U.S. natural gas supply, as well as which emissions streams can be targeted for the greatest GHG mitigation. In the second part of the paper, we conduct our own top-down life-cycle analysis of GHGs from natural-gas and coal-fired electricity in 2008 using the EPA's revised 2011 estimates as well as other publically available government data. We make three key adjustments to the data sets in order to calculate a more accurate and meaningful national level inventory: we include: 1) emissions associated with net natural gas and coal imports; 2) natural gas produced as a byproduct of petroleum production, and 3) the share of natural gas that passes through distribution pipelines before reaching power plants. This top-down analysis examines the implications of the EPA's revised (2011) estimates for the current and future average greenhouse gas footprint of U.S. natural gas-fired electricity and its comparison with coal-fired electricity.

GWP and power plant efficiency matter: Global warming potentials (GWPs) are used to convert the volumes of greenhouse gases with different heat-trapping properties into units of carbon dioxide-equivalent (CO_2e) for the purpose of examining the relative climate forcing impacts of different volumes of gas over discrete time periods. The Intergovernmental Panel on Climate Change's (IPCC) most recent assessment, published in 2007, estimates methane's GWP to be 25 times greater than that of carbon dioxide over a 100-year timeframe and 72 times greater than that of carbon dioxide over a 20-year timeframe.[9] Unless

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[5] *"Life-cycle analysis" (LCA) is a generic term, and the methodology and scope of analysis can vary significantly across studies. Our analysis assesses GHGs during the production, processing, transport, and use of natural gas and coal to generate electricity. Some studies include not only the direct and indirect emissions from the plant or factory that provides or makes a certain product, but also the emissions associated with the inputs used to manufacture and create the production facilities themselves. This study does not address the manufacturing, construction, or decommissioning of the equipment used in energy production. As with any study, the certainty of conclusions drawn from an LCA can only be as strong as the underlying data.*

[6] *U.S. Department of Energy, Secretary of Energy Advisory Board, Shale Gas Production Subcommittee, 90-Day Report, 18 August 2011, http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf.*

[7] *Numerous technologies and best practices to capture methane that would otherwise be vented during natural gas production, processing, transport, or distribution have been detailed by the U.S. EPA's voluntary Natural Gas STAR Program. Many of these have payback periods under 3 years. U.S. Environmental Protection Agency, Natural Gas STAR Program, "Recommended Technologies and Practices," available at http://www.epa.gov/gasstar/tools/recommended.html, viewed 29 July 2011.*

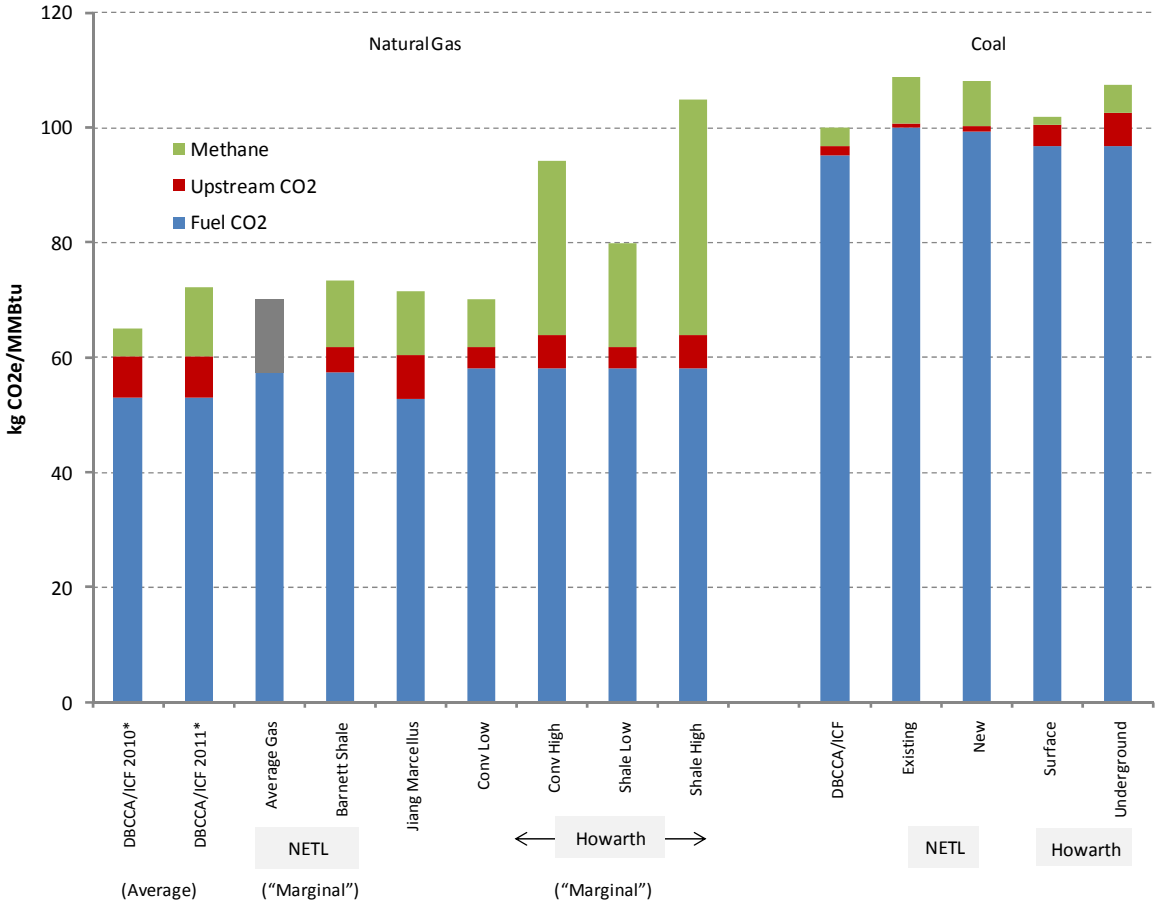
[8] *EPA, "Oil and Natural Gas Air Pollution Standards," http://epa.gov/airquality/oilandgas/, viewed 18 August 2011.*

[9] *Piers Forster et al., 2007: Changes in Atmospheric Constituents and in Radiative Forcing. In: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., D.*

otherwise specified, our analysis uses the 100-year GWP of 25 but we also calculate life-cycle emissions using a range of methane GWPs that have been proposed—including 72 and 105—in Appendix B of this report in order to show the sensitivities of the outputs to GWP. The choice of GWP does impact the relative GHG footprint between coal and gas. However, the life-cycle GHG footprint of gas is lower than coal under all GWPs tested, with the smallest difference calculated using a GWP of 105, where the GHG emissions in kilograms CO_2 per megawatt-hour of electricity generated (kg CO_2e/MWh) are 27 percent less than those of coal-fired generation.

In addition, assumed power plant efficiencies also have a measurable impact on the life-cycle comparison between natural gas and coal-fired electricity generation. Unless otherwise specified, our analysis uses average U.S. heat rates for coal and natural gas plants for the existing capital stock: 11,044 Btu/kWh (31% efficiency) for coal and 8,044 Btu/kWh (41% efficiency) for natural gas plants. We also calculate life-cycle emissions using heat rate estimates for new U.S. natural gas and coal plants in Appendix A (Exhibit A-11).

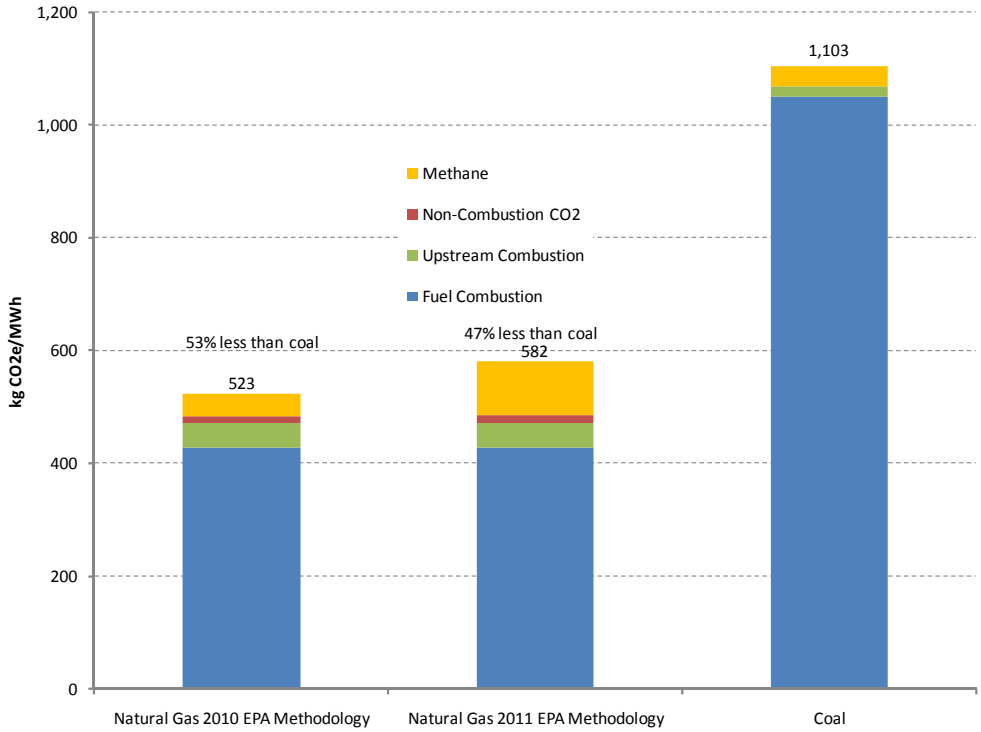
ES-1. Comparison of Recent Life-Cycle Assessments



Source: DBCCA Analysis 2011; NETL 2011; Jiang 2011; Howarth 2011. Note: NETL Average Gas study includes bar shaded grey due to inability to segregate upstream CO2 and methane values, which were both accounted for in the study. See page 10 for more information. *2011 EPA methodology compared to 2010.

Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M.Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA., p. 212.

ES-2. Average U.S. Life-Cycle GHG Emissions from Coal and Gas Electricity Generation, 2008 Comparing EPA 2010 Methodology with EPA 2011 Methodology



Source: DBCCA Analysis 2011. See pages 19 and 20 for more details.

Introduction and Key Exhibits

— **Our methodology:** Our top-down analysis addresses the emissions of three GHGs emitted during the production, processing, storage, transmission, distribution, and use of natural gas and coal in power plants:

1. Carbon dioxide (CO_2);
2. Methane (CH_4) and;
3. Nitrous oxide (N_2O)

Carbon dioxide is a product of fossil fuel combustion and is also released during some stages of gas processing. Methane, the primary component of natural gas (roughly 98 percent of pipeline-quality gas), is a potent GHG.[10] It is released at many points during the life-cycle of natural gas production and use and also during coal mining, and it is an important component of the life-cycle emissions of both fuels, but especially of natural gas. Methane emissions can be categorized as "fugitive" or "vented" emissions. Fugitive emissions include unintentional "leaks" from poorly sealed valves, flanges, meters, and other equipment.[11] Venting is the intentional release of methane as part of the operating procedure for a particular process. For example, when a compressor or a pipeline is taken out of service for repair, the compressed gas in the equipment may be released. There are a variety of venting operations associated with natural gas production that account for the majority of methane emissions in the natural gas sector. Because the amount of fugitive and vented methane is highly dependent on the practices and technologies that are used, the amount of methane emitted can vary significantly by facility and/or the stripping and "clean up" process employed. Although small amounts of methane and nitrous oxide are also emitted during fossil fuel combustion, carbon dioxide is by far the largest greenhouse gas product. In this paper, because the amounts of methane and nitrous oxide are such a small fraction of the total combustion-related emissions, we include them together with CO_2 on tables and figures under the heading "combustion."[12]

— **Reader roadmap:** In the section that follows, we start with a review of recent LCA studies. These studies have attempted to measure the life-cycle GHG footprint of shale gas and are valuable from our perspective in framing the marginal impact of shale gas on the GHG intensity of average natural gas-fired electricity. We then build up to a full comparison of the life-cycle emissions between natural gas and coal-fired electricity generation at a national level based on different assumptions and data adjustments in order to assess the impact that the EPA 2011 methodology change on GHG inventory has on the LCA comparison between average U.S. natural gas- and coal-fired electricity generation. We use emissions data for 2008 as a comparable baseline to show the impact of the 2010 and 2011 changes in EPA methane methodology to the life-cycle GHG emissions comparison between coal and natural gas in that year. (Note the Global Warming Potential used throughout this analysis is 25 unless otherwise noted – see Appendix B.) This overview provides a roadmap to follow the logic of our analytic approach.

- **Step 1:** In Exhibit 2, page 10 we compare the most recent bottom-up studies of the LCA of gas from hydraulically fractured shale formations versus coal as a starting point;

- **Step 2:** In Exhibit 4, page 13 we list the baseline EPA data for 2008 on the upstream natural gas emissions expressed as million metric tons of CO_2 equivalent ($MMTCO_2e$);

---

[10] *Methane remains in the atmosphere for ~9-15 years, compared to 100+ years for CO_2; Methane, however, is much more effective at trapping heat in the atmosphere than CO_2, particularly over 20 year time periods (Please see Appendix B at the end of this report).*

[11] *Of critical importance, such leaks can be fairly easily mitigated from a technical perspective at reasonable cost, which means that there is scope for improvement.*

[12] *The EPA Greenhouse Gas Reporting Rule gives CH_4 and N_2O emission factors for the combustion of different fossil fuels. For CH_4, emission factors of 0.001 kg/MMBtu of natural gas and 0.011 kg/MMBtu of coal were used. For N2O, emission factors of 0.0001 kg/MMBtu of natural gas and 0.0016 kg/MMBtu of coal were used. The emission factors are in table C-2, page 38 of Subpart C of the rule. (Please see:* http://www.epa.gov/climatechange/emissions/downloads09/GHG-MRR-FinalRule.pdf)
These were then adjusted using GWPs for CH_4 and N_2O to obtain emissions factors in kg CO_2e/MMBtu. Unless otherwise noted in the paper, 100-year GWP values from the IPCC's Fourth Assessment Report (2007) were used: 25 for CH_4 and 298 for N_2O. Using these values, the total GHGs emitted during the combustion of natural gas are 53.07 kg CO_2e/MMBtu (99.90% CO_2, 0.05% CH_4, 0.06% N_2O) and the total GHGs emitted during the combustion of coal are 95.13 kg CO_2e/MMBtu (99.21% CO_2, 0.29% CH_4, 0.50% N_2O).

- **Step 3:** In Exhibit 5, page 14, we adjust these baseline estimates to account for additional factors such as natural gas imports, methane emissions from other parts of the industry and other types of emissions associated with natural gas production;

- **Step 4:** In Exhibit 6, page 15, we combine our adjusted upstream and downstream natural gas emissions to derive a normalized life-cycle emissions expressed as kg/MMBTU (volume of greenhouse gases per unit of energy value delivered to the power plant) and compare with coal on an equivalent carbon-dioxide equivalent basis for the electricity sector using 2008 data and the EPA's 2011 methane emissions methodology;

- **Step 5:** In Exhibit 7, page 15, we rerun Step 3 above for 2008 emissions but using the EPA 2010 methane emission methodology from the EPA in order to show the impact of the revisions pre-combustion in kg CO_2e/MMBtu;

- **Step 6:** In Exhibit 8, page 15, we use EPA's 2011 methane emissions methodology to calculate emissions for 2009, the most recent year data available;

- **Step 7:** In Exhibit 10, page 17, we adjust upstream emissions from coal into standard volume units of MMTCO_2e in order to assess the emissions associated with the production and transportation from the mine to the power plant using 2008 data for an apples-to-apples comparison with gas;

- **Step 8:** In Exhibit 11, page 17, we then normalize these upstream coal emission factors into kg CO_2e/MMBtu (emission volume per unit of energy delivered);

- **Step 9:** In Exhibit 12, page 19, we compare the life-cycle emissions of natural gas and coal delivered to the power plant in kg CO_2e/MMMBtu using 2008 data but adjusted for both 2010 and 2011 EPA methane emission factor methodologies for natural-gas to show the impact of EPA's revisions;

- **Step 10:** In Exhibit 13, page 20, we show the LCA in terms of emissions per megawatt-hour of electricity generated from gas and coal using the national average power plant efficiencies for 2008. The life-cycle emissions for gas are 11 percent higher using the updated methodology. The Exhibit shows a six percentage point change with gas producing 47 percent lower emissions than coal using EPA's 2011 methane methodology compared to producing 53 percent lower emissions using EPA 2010 methane methodology based on a 100-year GWP value for methane of 25.

- **Sensitivity Analysis Using Alternative GWPs:** In Appendix B, we show the sensitivities of our LCA to different GWPs.

Overview of Natural Gas Systems and Emission Sources

Between its 2010 and 2011 editions of the Inventory, the EPA significantly revised its methodology for estimating GHG emissions from natural gas systems, resulting in an estimate of methane emissions from Natural Gas Systems in 2008 that was 120 percent higher than its previous estimate. Up until 2010, the Inventory had relied extensively upon emission and activity factors developed in a study by the EPA and the Gas Research Institute in 1996. For the 2011 Inventory, the EPA modified its treatment of two emissions sources that had not been widely used at the time of the 1996 study, but have since become common: gas well completions and workovers with hydraulic fracturing. It also significantly modified the estimation methodology for emissions from gas well cleanups, condensate storage tanks, and centrifugal compressors.

The bulk of the EPA's recent upward revisions of natural gas emissions estimates are related to the production part of the gas value chain. The largest component of the increase is due to revised estimates of methane released from liquids unloading: In some natural gas wells, downhole gas pressure is used to blow reservoir liquids that have accumulated at the bottom of the well to the surface.[13] The revisions also include an increase in the share of gas that is produced from hydraulically fractured shale gas wells and a change in the assumption as to how much of the flow-back emissions are flared. Previously, the EPA assumed that 100 percent of these emissions were flared or captured for sale. The new estimate assumes that approximately one third are flared and another third are captured through "reduced emission completions." Both of these are based on estimated counts of equipment and facility and associated emission factors.

These revisions have caused some to question whether replacing coal with natural gas would actually reduce GHGs, when emissions over the entire life cycles of both fuels are taken into account. Addressing these questions requires an understanding of:

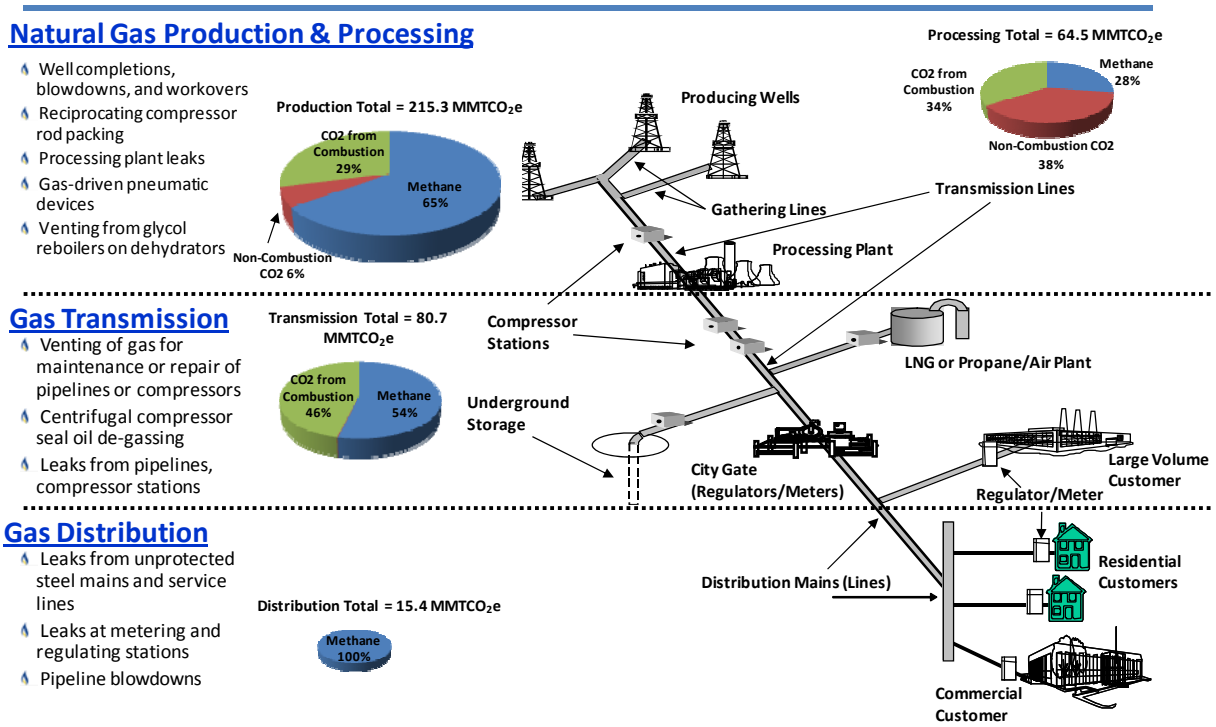
1) The best available data on emissions throughout the life cycles of natural gas and coal;
2) The specific sources and magnitudes of GHG emissions streams for natural gas produced from shale versus conventional formations; and
3) How an increase in the contribution of shale gas to the U.S. natural gas supply might impact the overall life-cycle GHG footprint of natural gas-fired electricity in the future as the marginal skews the average.

Up until the past few years, most of the U.S. natural gas supply came from the Gulf of Mexico and from western and southwestern states. More recently, mid-continental shale plays have been a growing source of supply. Natural gas is produced along with oil in most oil wells (as "associated gas") and also in gas wells that do not produce oil (as "non-associated gas").

Exhibit 1 illustrates the primary sources of GHG emissions during natural gas production, processing, transmission and distribution. The equipment for drilling both oil and gas wells is powered primarily by large diesel engines and also includes a variety of diesel-fueled mobile equipment. Raw natural gas is vented at various points during production and processing prior to compression and transport by pipeline. In some cases, the gas may be flared rather than vented to maintain safety and to relieve over-pressuring within different parts of the gas extraction and delivery system. Flaring produces CO_2, a less potent GHG than methane.

[13] *The technique of blowing out liquids is most frequently used in vertical wells containing "wet" or liquids-rich gas. It is being replaced by many producers with "plunger lifts" that remove liquids with much less gas release. In many shale wells, a technique is used where liquids are allowed to collect in a side section of the well and removed with a pump. EPA, Natural GAS Star, "Lessons Learned: Installing Plunger Lift Systems in Gas Wells," October 2006, available at http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf.*

Exhibit 1. Natural Gas Industry Processes and Methane Emission Sources



Sources: American Gas Association; EPA Natural Gas STAR Program, DBCCA analysis, 2011.

The recent focus of new natural gas development has been shale gas, which currently represents about 14 percent of U.S. domestic production but is expected to reach 45 percent or more by 2035.[14] Most gas-bearing shale formations lie 8,000 to 12,000 feet below the surface and are tapped by drilling down from the surface and then horizontally through the target formation, with lateral drills extending anywhere from 3,000 to 10,000 feet. After drilling is complete, operators hydraulically fracture the shale, pumping fluids at high pressure into the well to stimulate the production of the gas trapped in the target rock formation. Horizontal drilling and pumping water for hydraulic fracturing release additional engine emissions compared to conventional production techniques. In addition, when the produced water "flows back" out of the well, raw gas from the producing formation can be released into the atmosphere at the wellhead.[15]

In both associated and non-associated gas production, water and hydrocarbon liquids are separated from the gas stream after it is produced at the wellhead. The gas separation process may involve some fuel combustion and can also involve some venting and/or flaring. Shale plays in particular are geologically heterogeneous, and the energy requirements to extract gas can vary widely. Moreover, the methane content of raw gas varies widely among different gas formations. Although some gas is pure enough to be used as-is, most gas is first transported by pipeline from the wellhead to a gas processing plant. Gas processing plants remove additional hydrocarbon liquids such as ethane and butane as well as gaseous impurities from the raw gas, including CO_2, in order for the gas to be pipeline-quality and ready to be compressed and transported. This "formation" CO_2 is vented at the gas processing plant and represents another source of GHG emissions along with the combustion emissions from the plant's processing equipment.

From the gas processing plant, natural gas is transported, generally over long distances by interstate pipeline to the "city gate" hub and then to the power plant. The vast majority of the compressors that pressurize the pipeline to move

[14] *EIA Annual Energy Outlook 2011. DOE/EIA-0383ER(2011). Energy Information Administration, U.S. Department of Energy.* http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf

[15] *The GHG comparison between conventional and shale wells is important given the rapidly evolving industrial landscape with a share shift toward shale wells. For its part, the International Energy Agency (IEA) in a June 2011 Special Report: "Are We Entering a Global Age of Gas?" concluded that the LCA emissions of natural gas from shale wells is between 3.5 and 12 percent more than from conventional gas. IEA, June 2011, page 64.*

the gas are fueled by natural gas, although a small share is powered by electricity.[16] Compressors emit CO_2 emissions during fuel combustion and are also a source of fugitive and vented methane emissions through leaks in compressor seals, valves, and connections and through venting that occurs during operations and maintenance. Compressor stations constitute the primary source of vented methane emissions in natural gas transmission. Actual leakage from the pipelines themselves is very small.

Some power plants receive gas directly from transmission pipelines, while others have gas delivered through smaller distribution pipelines operated by local gas distribution companies (LDCs). Distribution lines do not typically require gas compression; however, some relatively small methane emissions do occur due to leakage from older distribution lines and valves, connections, and metering equipment.

Review of Recent Bottom-Up Life-Cycle Analyses: The Marginal Impact on Emissions

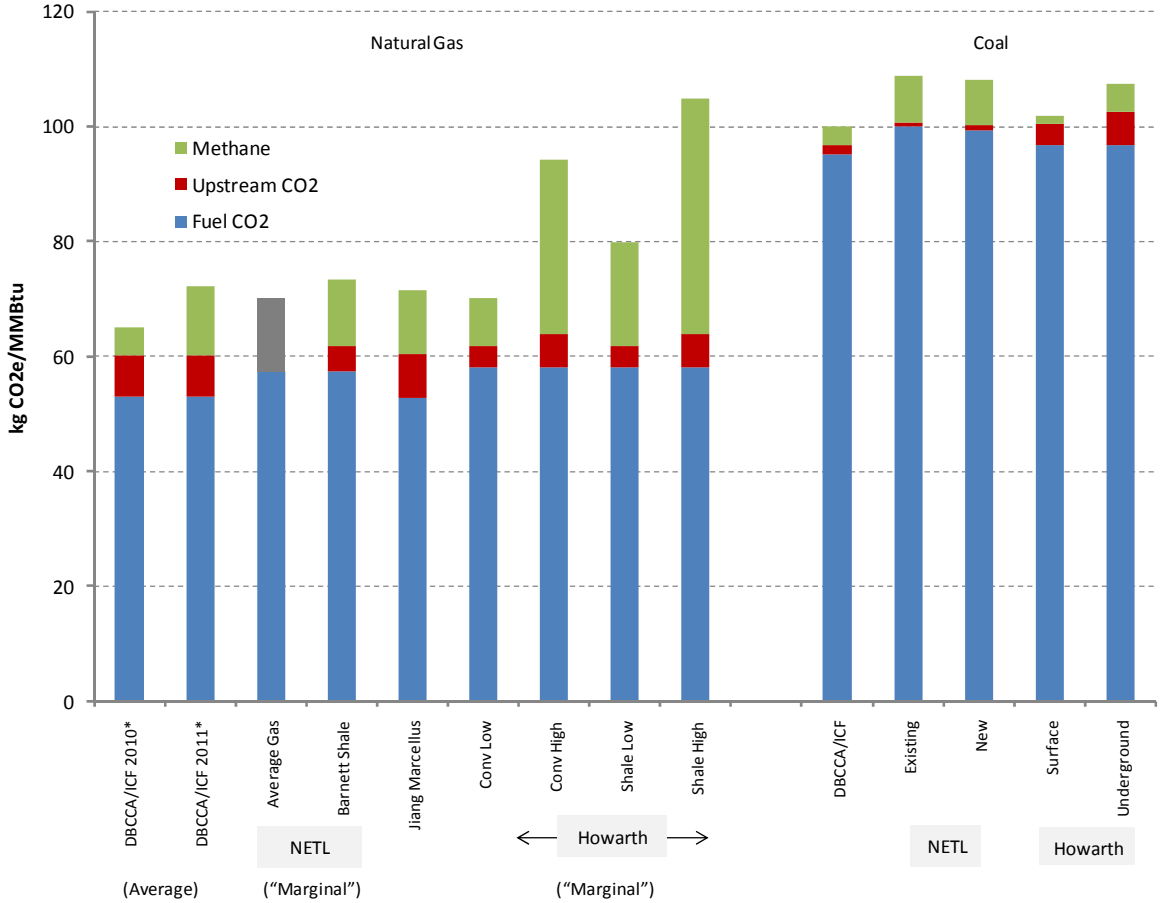
The assessment of how much more methane is released from shale gas production than from conventional production is a key factor in the discussion of possible changes in the life-cycle emissions of natural gas. As the shale gas component of U.S. production increases, a higher marginal greenhouse gas footprint from shale gas would raise the average greenhouse gas footprint of the U.S. natural gas supply overall. On the other hand, changing production technology and regulation could reduce emissions from both shale and other natural gas wells. The life-cycle GHG comparison between shale and conventional natural gas therefore has important implications for stakeholders who are considering policies and investment on the basis of how carbon-intensive natural gas is today and how carbon-intensive it is likely to be in the future.

A number of recent bottom-up life-cycle analyses attempt to quantify the GHG comparison between conventional and shale gas. Exhibit 2 shows the results of several of these analyses and how they compare to our top down analysis, which follows later.[17] Bottom-up figures are taken from studies by Skone, et al. (NETL), Jiang et al. (Jiang), and Howarth, et al. (Howarth). Because these and other life-cycle studies each make different assumptions as to the global warming potential of methane and the product whose greenhouse gas footprint is being measured—some use units of natural gas produced, others use units of natural gas delivered, and still other use units of electricity generated—we have normalized these figures using a GWP of 25. Any remaining variability in the GHG estimates are the result of differences in underlying emissions factors used. Despite differences in methodology and coverage, all of the recent studies except Howarth et al. estimate that life-cycle emissions from natural gas-fired generation are significantly less than those from coal-fired generation on a per MMBtu basis. As can be seen in Exhibit 2, our GHG estimate for average U.S. gas based on EPA's 2011 data (72.3 kg/MMBtu) is very similar to the National Energy Technology Laboratory's (NETL) bottom-up estimate for Barnett Shale gas (73.5 kg/MMBtu).

[16] *ORNL, Transportation Energy Data Book, Oak Ridge National Laboratory, U.S. Department of Energy, June 2010, http://cta.ornl.gov/data/index.shtml*

[17] *The results of the top-down life-cycle analysis conducted in the present study are displayed for reference. Bottom-up figures are taken from studies by Skone, et al. 2011 (NETL), Jiang et al. 2011 (Jiang), and Howarth, et al. 2011 (Howarth). All studies are normalized using a 100-year GWP for methane of 25, and given in kg CO_2e per MMBtu of fuel rather than kg CO_2e per MWh of electricity generated. Most studies use MMBtu of fuel produced as their metric; the present study uses MMBtu of fuel consumed, an explanation of which is given on p. 22. .*

Exhibit 2. Comparison of Recent Bottom-Up Life-Cycle Assessments.



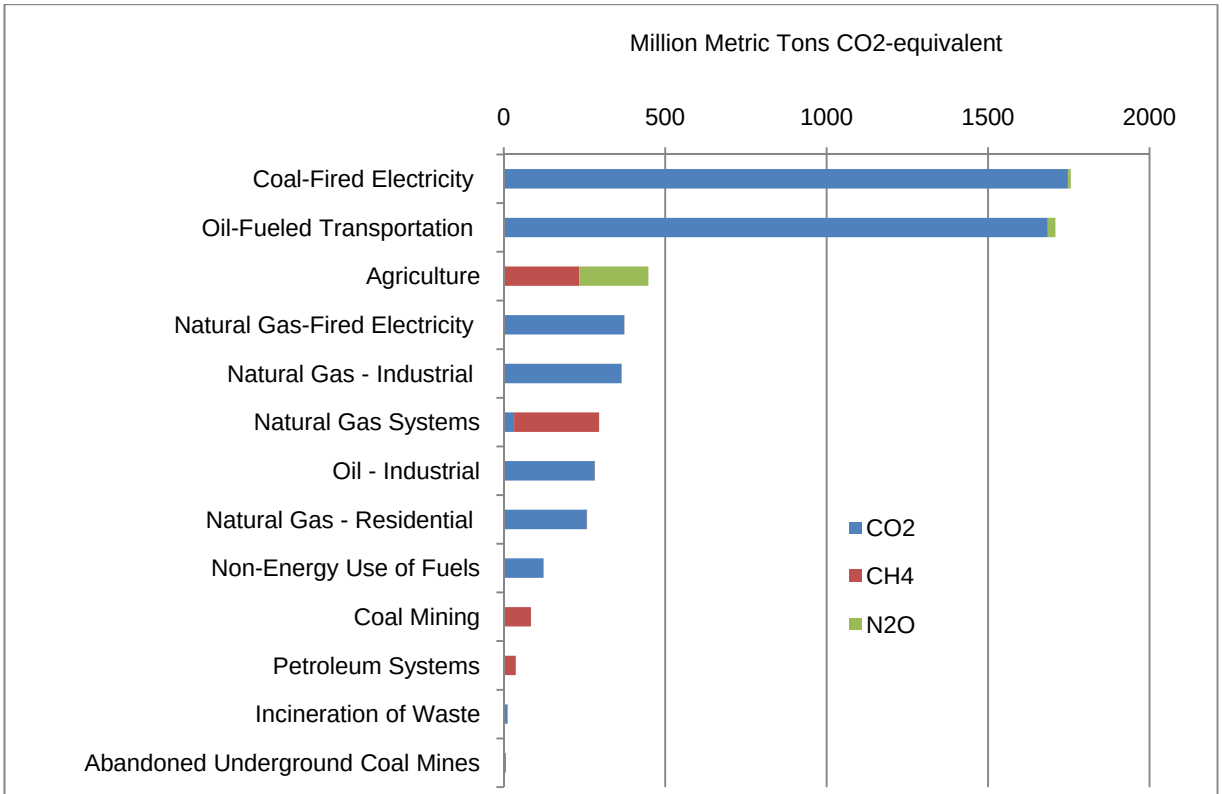
Source: DBCCA Analysis, 2011. Note: NETL Average Gas study includes bar shaded grey due to inability to segregate upstream CO2 and methane values, which were both accounted for in the study. *2011 EPA methodology compared to 2010.

Many of these studies draw upon data from the U.S. Environmental Protection Agency's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (hereafter "Inventory" or "Greenhouse Gas Inventory). The Inventory, published annually, is the official U.S. report on GHG emissions to the UN IPCC and the source for much of the analysis of U.S. emissions.[18] The inventory is developed from a variety of public and private data sources on the many different kinds of GHG emission sources in different sectors. It uses a combination of "bottom-up" analysis, utilizing counts and characteristics of individual facilities, and "top-down" analysis, such as national data on fuel combustion from the Energy Information Administration (EIA) to calculate CO_2 emissions from combustion, to build an estimate for total U.S. GHG annual emissions across a range of sectors.

Greenhouse gas emissions from natural gas and coal production, processing, transport, and distribution are estimated in the Inventory's "Natural Gas Systems" and "Coal Mining." In the EPA's 2011 edition of the Inventory, Natural Gas Systems were estimated to be the largest source of non-combustion, energy-related GHG emissions in the U.S., at 296 million metric tons of CO_2 equivalent (MMT CO_2e) in 2009. Coal mining came in third, with an estimated 85 MMT CO_2e of emissions. Fossil fuel combustion accounted for the vast majority of GHG emissions from the U.S. energy sector, with an estimated 1,747.6 MMT CO_2e coming from coal-fired electricity generation alone, while natural gas-fired electricity generation accounted for an additional 373.1 MMT CO_2e (Exhibit 3).[19]

[18] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* (April 2011), available at http://epa.gov/climatechange/emissions/usinventoryreport.html.
[19] All figures given in CO_2-equivalent here and elsewhere assume a global warming potential of 25 for methane unless otherwise noted. The EPA's Inventory uses a GWP of 21 for reporting purposes, so these numbers were converted to make them consistent with the GWP used for

Exhibit 3. U.S. Greenhouse Gas Emissions by Source Category, 2009.



These are the highest-emitting energy and agriculture sector source categories for 2009. Source: EPA 2011. Data were adjusted to use most recent IPCC GWPs for CH4 and N2O (25 and 298, respectively).

We draw two main conclusions from our survey of recent bottom-up life-cycle assessments. First, **the natural gas industry's practices are evolving rapidly, and better data are essential to ensuring that life-cycle greenhouse gas assessments remain up-to-date and reflect current industry behavior**. All of the bottom-up life-cycle assessments we surveyed identified significant uncertainty around certain segments of the natural gas life cycle stemming from data inadequacy. Among the sources of uncertainty identified were: formation-specific production rates, flaring rates during extraction and processing, construction emissions, transport distance, penetration and effectiveness of green completions and workovers, and formation-specific gas compositions.

Second, because shale gas appears to have a GHG footprint some 8 to 11 percent higher than conventional gas on a life-cycle basis per mmBtu based on these bottom up studies that we reviewed, **increased production of shale gas would tend to increase the average life-cycle GHG footprint from U.S. natural gas production if methane emissions from the upstream portion of the natural gas life are unmitigated**. This fact underlines **the importance of implementing the many existing control technologies and practices that can significantly reduce the overall greenhouse gas footprint of the natural gas industry**. Many companies are already reducing vented and flared methane emissions voluntarily through the EPA's voluntary Natural Gas STAR program. For example, the Inventory estimates that the completion emissions of methane from two thirds of shale gas production are already being mitigated through flaring or reduced emission completion.[20] If this is correct, then bottom-up life-cycle GHG estimates that do not account for reduced emissions completions are likely too high.

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the main analysis in this paper. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* (April 2011), available at http://epa.gov/climatechange/emissions/usinventoryreport.html.

[20] *Ibid.*

Stronger regulations limiting methane and other air pollutant emissions from oil and natural gas operations are also likely to lead to lower overall GHG emissions. Some states already require the adoption of certain methane controls: Wyoming and Colorado, for example, already require "no-flare" or "green" completions and workovers, which are reported to capture 70 to 90 percent of methane vented during completions and workovers following hydraulic fracturing. Because this methane can then be sold, users of green completions have reported payback times of less than one year.[21] Moreover, the EPA released proposed regulations for the gas production sector on July 28, 2011 that are expected to require mitigation of completion emissions from all wells.[22] This regulation is currently in the comment period and is set to be implemented by court order in 1Q12. If these regulations are adopted, there will be little or no difference between the emissions of hydraulically fractured and conventional gas wells.

Top-Down Life-Cycle Analysis of U.S. Natural Gas and Coal: Impact on the Average

The remainder of this paper develops a top-down life-cycle greenhouse gas analysis of natural gas and coal for the purpose of determining the impact of recent EPA revisions to methane emissions estimation methodologies on the current comparison between U.S. natural gas and coal-fired electricity.

Natural Gas

This analysis for natural gas includes each of the industry steps described in Exhibit 1 above. (See Appendix A for a detailed methodology.) The source of information for methane emissions and non-combustion CO_2 is the EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009* (April 2011 release), which includes updated estimates for methane emissions from natural gas production that are approximately twice the level indicated in the previous 2010 edition.[23] This LCA uses the data from both 2010 and 2011 EPA inventory reports to illustrate the effect that the EPA's latest increase in estimated methane emissions has on the overall LCA for gas (as discussed below), which we estimate to be about an 11 percent increase in the life-cycle emissions.

The U.S. Energy Information Administration (EIA) is the primary source for the data on natural gas consumption and associated CO_2 emissions in the various segments of the gas industry (fuel for gas compressors and gas processing plants).[24] In addition to the natural gas, petroleum is used for drill rigs, trucks and other mobile equipment, such as pumps for hydraulic fracturing. This analysis uses information from the Economic Census to estimate non-natural gas energy consumption and associated CO_2 emissions in the production sector.[25]

Sources of methane emissions are many and vary widely. Apart from EIA there are very few sources of aggregated data in the public domain. As noted earlier, the EPA recently increased its estimates significantly for several processes in natural gas production, and better data availability on methane leakage and venting will be critical going forward given the rapidly evolving gas production landscape. On this score, disclosures and reporting of upstream emissions have historically been voluntary. And while there is evidence that large volumes of GHGs are being captured by industry, the actual penetration rates of these voluntary programs is unknown[26].

For example, the EPA Natural Gas STAR program, a voluntary methane mitigation program, reports that its members reduced methane emissions from natural gas systems by 904 billion cubic feet between 2003 and 2009—equivalent to 365 $MMTCO_2e$.[27] This program has identified and documented many methane mitigation measures that could be applied more widely across both industries and are included in the EPA's Inventory of US Greenhouse Gas Emissions

[21] EPA, Natural Gas STAR Program, "Reduced Emissions Completions: Lessons Learned," available at http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf, viewed 2 August 2011.
[22] *EPA, "Oil and Natural Gas Air Pollution Standards," http://epa.gov/airquality/oilandgas/, viewed 18 August 2011.*
[23] *The new EPA data have raised questions on two ends, with some believing the estimates are too high and others believing they are too low. Some comments submitted to the EPA from gas producers about the Draft Inventory question the validity of these revisions, believing them too high. While on the other hand, there are environmental advocacy groups that question whether EPA's "activity factors" used in its methodology accurately represent the preponderance of shale wells being drilled in the Gulf Coast and North East regions, thereby raising the question of whether the emission factors are indeed high enough.*
[24] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*
[25] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*
[26] *Reported 2009 Natural Gas STAR voluntary emission reductions were the equivalent of ~$344 million in revenue (assuming $4/mmBtu gas) and the avoidance of 34.8 mn tonnes CO_2e; http://www.epa.gov/gasstar/accomplishments/index.html#content*
[27] *EPA Natural Gas STAR Program Accomplishments, page 2; http://www.epa.gov/gasstar/accomplishments/index.html*

and Sinks report.[28] Additionally, many mitigation activities are not reported to these programs. It is also possible that the EPA is missing or has underestimated some sources of upstream emissions for both natural gas and coal. Nevertheless, we expect that better information will be available in the spring of 2012 when reporting of data on upstream methane emissions through EPA's GHG Reporting Program commences.

In our LCA, the emission factors for the combustion of natural gas, coal and petroleum includes the CO_2 from complete combustion of the fuel plus the small amounts of nitrous oxide (N_2O) and unburned methane that result from the combustion. The emission factors for fuel combustion are taken from subpart C of the EPA Greenhouse Gas Reporting Program.[29] The N_2O and methane emissions from combustion are less than 1% of the CO_2 emissions. The total emission factors for combustion are:

- Natural gas – 53.07 kg CO_2 e/MMBtu
- Diesel fuel – 74.21 kg CO_2 e/MMBtu
- Coal – 95.11 kg CO_2 e/MMBtu

Exhibit 4 summarizes the data on total upstream GHG emissions calculated for the natural gas sector for the year 2008 using the April 2011 EPA inventory for methane adjusted for a methane GWP of 25 and the EIA data on fuel consumption. According to this inventory, U.S. production, processing, and transport of natural gas emitted 387.0 million tons of CO_2 equivalent ($MMTCO_2e$) in 2008.

Exhibit 4. Baseline U.S. Upstream Gas Emission Data for 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	146.3	11.3	47.2	204.8
Processing	18.7	21.4	19.4	59.5
Transmission	51.5	0.1	35.4	87.1
Distribution	35.6			35.6
Total	252.1	32.8	102.1	387.0

In this analysis, we adjust several factors to more accurately and robustly capture the life-cycle emissions associated with the use of natural gas on a national basis.

First, the emissions estimates account for natural gas production in the United States; however, because 13 percent of natural gas consumed in the U.S. was imported in 2008, we increase the production and processing emissions estimates to account for emissions from gas imports. Of that 13 percent in 2008, 11.7 percent was imported by pipeline from North America, mostly from Canada. The analysis assumes that other North American production operations are similar to those in the United States, so the emissions are increased linearly to account for these imports. In addition, 1.3 percent of the gas supply arrived via liquefied natural gas (LNG) imports. The LNG life cycle includes additional emissions associated with liquefaction, transportation, and regasification from source to use. The LNG portion is escalated by 76 percent to account for these emissions, based on a bottom-up LNG LCA prepared by NETL.[30] These are the most significant modifications made in our analysis, increasing the overall LCA for natural gas by 39 $MMTCO_2e$, or about 10 percent, primarily due to the adjustment for pipeline imports.

A second adjustment relates to methane emissions from distribution lines at local gas distribution companies. Since only 52 percent of the gas used for power generation is delivered by local distribution lines, the methane emissions associated with distribution have been discounted by that amount.[31] This reduces the total emissions by 18 $MMtCO_2e$, or 4 percent.

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[28] *EPA,* Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, April 2011, available at* *http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf, p. 152.*

[29] *EPA, Greenhouse Gas Reporting Program, Subpart C, U.S. Environmental Protection Agency, http://www.epa.gov/climatechange/emissions/ghgrulemaking.html*

[30] *Skone, T.J., 2010. Life Cycle Greenhouse Gas Analysis of Power Generation Options, National Energy Technology Laboratory, U.S. Department of Energy*

[31] *EIA, EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition", Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP1&CFID=5251631&CFTOKEN=51c7f7f0104e329d-3FD56B17-237D-DA68-24412047FB2CE3CB*

A final adjustment is for methane emissions from production of associated gas—gas produced from oil wells. We did this in order to accurately adjust the impact of associated gas in our net import correction. Most oil wells produce some natural gas, and some of this gas is collected and becomes part of the gas supply. The EPA inventory of U.S. GHG emissions estimates that methane emissions from petroleum systems are approximately 30 $MMTCO_2e$ per year.[32] Since some domestic natural gas is co-produced with petroleum, these emissions could be considered for inclusion in the LCA of emissions from the natural gas sector.

The associated natural gas produced and the methane emitted during petroleum production, processing, and transport are a byproduct of petroleum production. Methane emissions would occur even if no natural gas were captured and delivered for end-use consumption. In fact, the emissions might actually be higher in that case since there would be no economic incentive to capture the gas. By this assessment it would not be appropriate to count the methane emissions from petroleum production, since they are independent of the production of gas.

On the other hand, associated gas produced from oil wells represents a significant segment of U.S. gross withdrawals of natural gas, and if there are methane emissions associated with that production, it seems appropriate to include them in the LCA, even if the production is incidental to oil production. In that case, we have to evaluate how much of the methane emissions to allocate to gas production versus petroleum production. This calculation is shown in Appendix A and results in an additional 5 $MMTCO_2e$ of emissions being added, or a 1.4 percent increase.

Exhibit 5 shows our adjusted total emissions for 2008, which come to 423.8 $MMTCO_2e$ compared to the 387.0 baseline. The production segment is the largest contributor to GHG emissions from the natural gas supply chain, accounting for 57 percent of total emissions. Of the different gases, methane accounts for 59 percent of total GHG emissions using a GWP of 25.

Exhibit 5. Adjusted Total Upstream GHG Emissions from Natural Gas, 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	173.7	12.9	62.2	248.7
Processing	21.3	24.4	22.2	67.9
Transmission	51.5	0.1	37.2	88.8
Distribution	18.3	0.0	0.0	18.3
Total	264.9	37.4	121.5	423.8

To compare emissions from coal and natural gas on an apples-to-apples basis, the emissions are normalized to the amount of GHG per million Btu (MMBtu) of *natural gas delivered to consumers* using EIA data for gas deliveries[33]. Some LCAs normalize to GHG per unit of natural gas *produced*, which includes associated gas that is reinjected into the producing formation as well as natural gas liquids that are removed during gas processing and gas lost through fugitives and venting, in addition to gas actually delivered to consumers such as power plants. Using delivered rather than produced natural gas results in a slightly higher overall figure for life-cycle emissions but depicts more accurately the energy that is actually available to power plants. The total normalized upstream emissions are 19.2 kg CO_2e/MMBtu of natural gas delivered. (See Exhibit 6.) As discussed earlier, the emissions for combustion of the natural gas at the power plant are 53.1 kg CO_2e/MMBtu, so the total life-cycle GHG emissions at the point of use are 72.3 kg/MMBtu. Of this, the upstream emissions are 30 percent, 60 percent of which are from methane.

[32] *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2009, EPA 340-R-11-005, April 2011 page, 27*
[33] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*

Exhibit 6. Normalized Life-Cycle GHG Emissions for Natural Gas for 2008, using EPA 2011 Methane Emissions Methodolgy (kg CO_2e/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	7.9	0.6	2.8	11.3
Processing	1.0	1.1	1.0	3.1
Transmission	2.3	0.0	1.7	4.0
Distribution	0.8	0.0	0.0	0.8
Total Upstream	12.0	1.7	5.5	19.2
Fuel Combustion	0	0	53.1	53.1
Total	12.0	1.7	58.6	72.3

Doing the same calculation with the lower methane emissions estimated in the prior year's EPA inventory yields a value of 12.0 kg CO_2e/MMBtu for the upstream emissions. (See Exhibit 7) Including the end-use gas consumption, total life-cycle emissions are 65.1 kg CO_2/MMBtu, with the upstream portion accounting for 20 percent. In this case, methane makes up only about 40 percent of the upstream gas GHG footprint.

Exhibit 7. Normalized Life-Cycle GHG Emissions for Natural Gas for 2008, using EPA 2010 Methane Emissions Methodology (kg CO_2e/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	1.2	0.4	2.8	4.4
Processing	0.8	1.1	1.0	2.9
Transmission	2.1	0.0	1.7	3.8
Distribution	0.8	0.0	0.0	0.8
Upstream Total	4.9	1.6	5.5	12.0
Fuel Combustion	0	0	53.1	53.1
Total	4.9	1.6	58.6	65.1

Finally, Exhibit 8 applies the most recent EPA data to calculate the life-cycle emissions for 2009 using the 2011 methane emissions methodology. This is the most recent year for which data are available. The 2009 emissions are quite similar to the emissions calculated for 2008 using the same methodology (73.1 vs 72.1 expressed as kg CO2e/MMBtu).

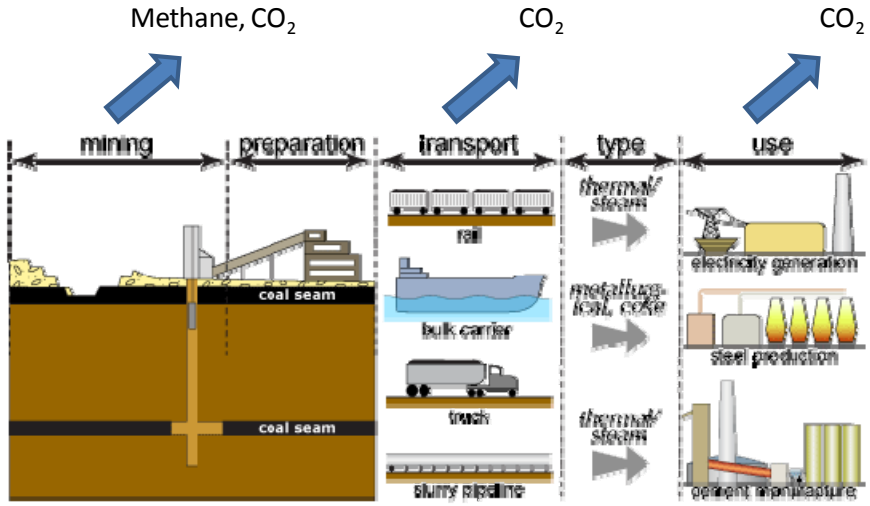
Exhibit 8. Normalized Life-Cycle GHG Emissions for Natural Gas for 2009, using EPA 2011 Methane Emissions Methodology (kg CO_2e/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	8.4	0.6	3.0	12.0
Processing	1.1	1.1	1.0	3.2
Transmission	2.4	0.0	1.6	4.0
Distribution	0.8	0.0	0.0	0.8
Upstream Total	12.8	1.7	5.6	20.1
Fuel Combustion	0.0	0.0	53.1	53.1
Total	12.8	1.7	58.7	73.1

Coal

The production and distribution of coal is simpler to analyze than that of natural gas because there are fewer steps in production and processing (Exhibit 9). Coal is produced in the U.S. from underground mines (40 percent) and surface mines (60 percent). In underground mines, most of the mining equipment is driven by electricity. In surface mines, the equipment runs on diesel fuel or electricity. This analysis estimates the direct and indirect emissions of the mining processes from Economic Census data[34]. (For detailed calculations of the coal LCA, see Appendix A.)

Exhibit 9. Coal Industry Segments and Emission Sources



Source: University of Wyoming

Coal formations contain methane, which is released when the coal is mined. The methane content varies among different coal formations but is generally higher for underground mines than for surface mines. Underground mines use ventilation to remove the methane, which is a safety hazard, and in some cases the methane can be recovered for use or flared to reduce GHG emissions. The U.S. GHG Inventory estimates the methane emissions from coal mining. Coal mines that are no longer active (i.e., are "abandoned") release methane as well: 7.0 $MMTCO_2e$ in 2008 (at 25 GWP). This would add an additional 0.4 kg CO_2e/MMBtu to the coal LCA but is not included here since we do not have similar data on methane emissions from abandoned gas wells.

Data on coal transportation by mode are available from the Economic Census[35]. More than 90 percent of coal is transported by train, with the remainder transported by barge, truck, or various combinations of these modes. This analysis derives the energy consumption per ton-mile from several sources to calculate CO_2 emissions. (See Appendix A.)

The United States is a net exporter of coal by 4 percent, so the production data are adjusted downward by that amount. Table 6 shows the adjusted upstream GHG emissions for coal, totaling 117.8 $MMTCO_2e$.

[34] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*

[35] *Ibid.*

Exhibit 10. Adjusted Total Upstream GHG Emissions from Coal for 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	79.9	0.0	14.0	93.9
Transportation	0.0	0.0	23.9	23.9
Total	79.9	0.0	37.9	117.8

As with the natural gas LCA, this analysis "normalizes" total emissions by the energy delivered to coal consumers (more than 90% power of whom are power generators), or 1,147 million short tons of coal in 2008. This yields a normalized upstream emission factor of 4.8 kg CO_2e/MMBtu consumed. (See Exhibit 11.) This value is about 25 percent of the upstream emissions from natural gas. The emission factor for combustion of coal is 95.1 kg/MMBtu, bringing the total end-use life-cycle emissions to 99.9 kg CO_2/MMBtu. In this case, although methane comprises 63 percent of the upstream emissions, the upstream component is only 5 percent of the total, with CO_2 emissions from the combustion of the coal itself being the dominant factor in the total life-cycle emissions.

Exhibit 11. Normalized Life-Cycle GHG Emissions from Coal for 2008 (kg CO_2e/MMBtu)

	Methane	CO_2 and N_2O from Combustion	**Total**
Production	3.3	0.6	3.9
Transportation	0.0	1.0	1.0
Total Upstream	3.3	1.5	4.8
Coal Combustion	0.0	95.1	95.1
End Use Total	3.3	96.6	99.9

Electricity Generation

Finally, life-cycle GHG emissions per MMBtu of fuel delivered to power plants are normalized to GHG emissions per MWh of electricity generated to account for the difference in coal and natural gas power plant efficiencies. In 2008, essentially all coal-fired electricity in the United States was generated by steam-turbine power plants, which combust fuel to boil water and use the resulting steam to drive a turbine.[36] Many coal plants are run almost all the time at full capacity to provide baseload power. Technology has improved over the past several decades and new plants have improved combustion efficiencies, but many active plants in the U.S. fleet were built before 1970 and are less efficient.

By contrast, natural gas is used in a range of power plant technologies, each of which fills a different role in the electricity dispatch. In 2008, only 12 percent of natural gas-fired electricity was generated by steam-turbine plants, most of which were built before 1980 and are relatively inefficient. An additional 9 percent was generated by simple-cycle gas turbines, relatively inefficient plants that are used to provide peaking power during limited periods. Since 2000, a large portion of new natural gas capacity additions have been combined-cycle units, which use waste heat from gas turbines to run steam turbines.

Combined-cycle plants have superior heat rates and may be used to provide baseload or intermediate power, depending on the particular grid and the price of gas. In 2008, 79 percent of gas-fired electricity was generated by combined-cycle plants. Two coal plants in the U.S. currently gasify coal to generate electricity in a combined-cycle configuration, but such plants, called Integrated Gasification Combined Cycle (IGCC) plants, have very low market penetration today.

[36] *All 2008 generation data from Energy Information Administration (EIA), Form EIA-923, 2008.*

The heat rate (the amount of fuel in Btus needed to generate a kilowatt-hour of electricity) of the electric generator is one of the most significant variables in estimating the GHG emissions per MWh of electricity.[37] Unless otherwise specified, this analysis uses heat rates representing the average efficiency of existing power plants in the U.S. fleet:

- **Average efficiency of existing capital stock:** National average values are based on EIA data for total gas or coal consumption for generation and total generation by each fuel. The heat rates are 8,044 Btu/kWh (41 percent efficiency) for gas generation and 11,044Btu/kWh (31 percent efficiency) for coal generation.

A sensitivity analysis comparing life-cycle emissions results using average heat rates and heat rates representative of new natural gas and coal plants is shown in Appendix A (Exhibit A-12).

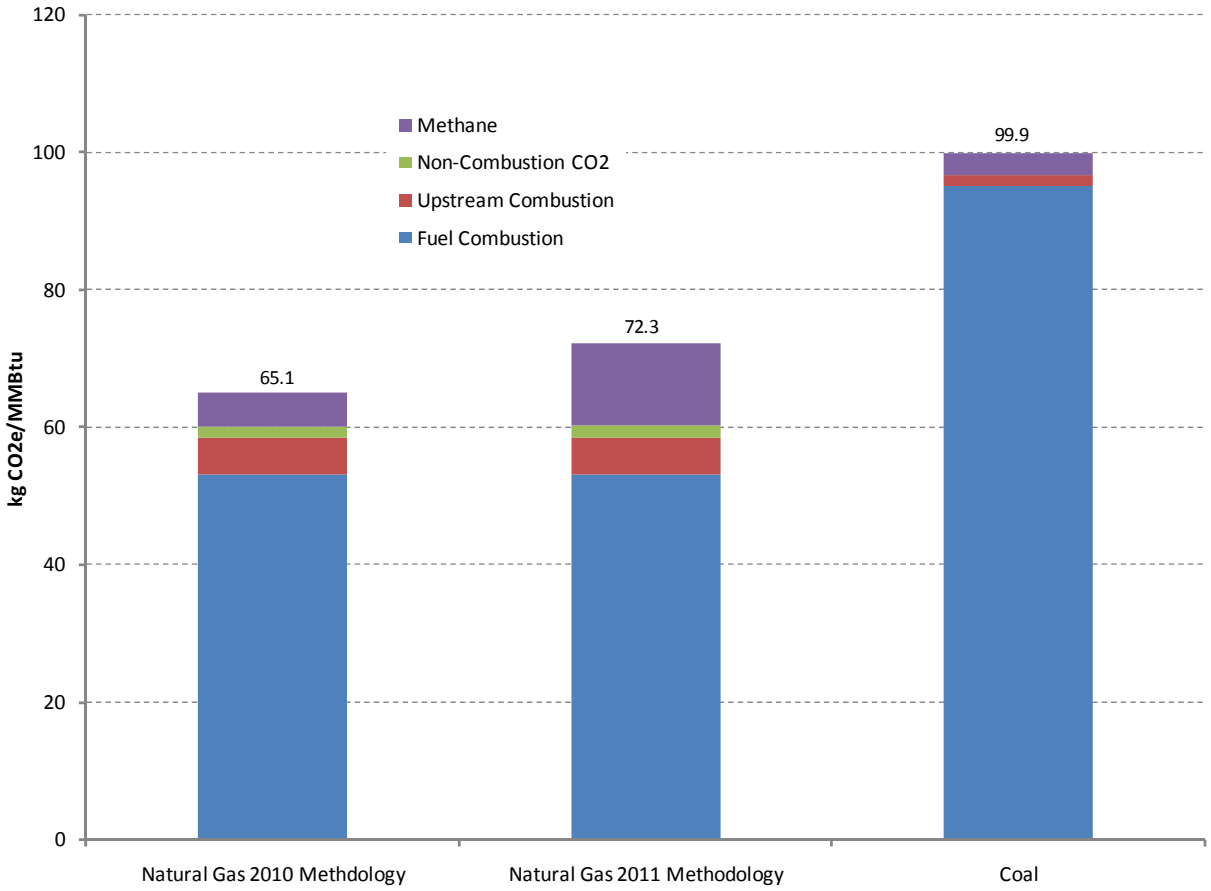
- **Efficiency of new plants:** In its *Annual Energy Outlook 2010*[38], EIA provides a value for a new plant in 2009, and for future plants that accounts for future cost reductions from learning and production efficiencies ("nth" plant). The values used here are the average of the two values for a gas combined-cycle plant (6,998 Btu/kWh, 49 percent efficiency) and a new supercritical coal plant (8,970 Btu/kWh, 38 percent efficiency).

Summary of Results and Sensitivity Analysis for Top=Down Analysis

Exhibit 12 compares the calculated LCA emissions (by GHG) for gas delivered to power plants for (a) natural gas using the EPA 2010 methodology, (b) natural gas using the EPA 2011 methodology, and (c) coal. In all cases, the emissions are dominated by CO_2 from final combustion of the fuel at the power plant. The upstream emissions are larger for gas, and the power plant combustion emissions are higher for coal. The LCA for coal is dominated by the CO_2 from the coal combustion itself. The upstream component is larger for natural gas, and methane is a larger component of the emissions. Using the increased methane emission estimate for gas from the 2011 methodology results in the LCA for natural gas being 11 percent higher than with the 2010 estimate. The gas life-cycle value using the 2011 methodology is 28 percent lower than the coal value.

[37] The power industry uses efficiency and heat rate to express power plant efficiency. Heat rate in Btu/kWh = 3413/efficiency. A lower heat rate signifies a higher efficiency.
[38] *EIA, Assumptions to the Annual Energy Outlook 2010 – Table 8-2,* DOE/EIA-0554(2010), *Energy Information Administration, U.S. Department of Energy.* http://www.eia.gov/oiaf/aeo/assumption/pdf/electricity_tbls.pdf

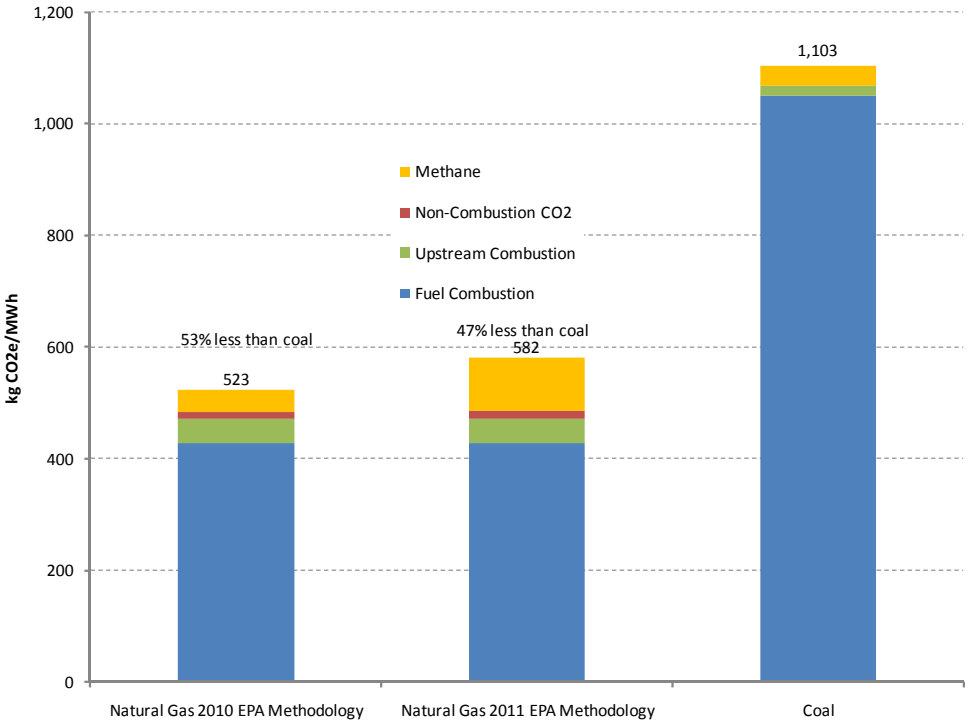
Exhibit 12: Life-Cycle Emissions as Delivered to Power Plants, 2008 (kg CO_2e/MMBtu)



Source: DBCCA Analysis 2011

Exhibit 13 shows the LCA in terms of GHG emissions per megawatt-hour of electricity generated from gas and coal, using the national average power plant efficiencies. The gas value using the 2011 EPA methane emissions estimates is 582 kg CO_2e/MWh—or 11 percent higher than the 523 kg CO_2e/MWh calculated using data for 2010 methodology. The value for coal is 1,103 kg CO_2e/MWh. Because coal plants are on average less efficient than gas plants, the difference between gas and coal is greater than the fuel-only comparison at the burner tip prior to combustion and conversion to electricity. **Natural gas-fired electricity, using the 2011 methodology, has 47 percent lower life-cycle GHG emissions per unit of electricity than coal-fired electricity.**

Exhibit 13: Electric Generating LCA, by Greenhouse Gas, 2008 (kg CO_2e/MWh)



Source: DBCCA Analysis 2011

Conclusions

Our top-down LCA of natural gas and coal-based generation using publicly available data shows that the EPA's recent revision of methane emissions increases the life-cycle GHG emissions for natural gas-fired electricity by about 11 percent from estimates based on the earlier values. Our conclusion is that, on average, natural gas-fired power generation emits significantly fewer GHGs compared to coal-fired power generation. Life-cycle emissions for natural gas generation using new EPA estimates are 47 lower than for coal-based generation when using a GWP of 25. The impact of different GWPs to our LCA can be found in Appendix B.

Nevertheless, methane, despite its shorter lifetime than carbon dioxide, is of concern as a GHG. Compared to coal-fired generation, methane emissions, including a large venting component, comprise a much larger share of natural-gas generation's GHGs. And while measurement of upstream emissions and public disclosure of those emissions still has room for improvement, methane emissions during the production, processing, transport, storage, and distribution of natural gas can be mitigated now at moderately low cost using existing technologies and best practices. Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle GHG footprint of natural gas.

Appendix A
Detailed Methodology and Calculations

Natural Gas

The natural gas LCA addresses emissions from extraction through electricity generation for 2008. The primary data sources are the EPA *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009* and EIA data on natural gas consumption[39]. Exhibit A-1 shows the basic information on total emissions by industry segment for 2008. The methane emissions are from the EPA Inventory and adjusted from a GWP of 21 to a GWP of 25. The non-combustion CO_2 emissions are from the same source and include CO_2 from combustion of flared gas and the formation CO_2 vented from gas processing plants. The CO_2 from combustion is primarily from the EIA data on gas consumption in the gas industry. The gas consumed in the production segment is the "lease gas" reported by EIA, which is gas consumed in the producing areas. EIA also reports "vented and flared gas," which is assumed here to be all flared but is already included in the EPA category of non-combustion emissions. The "processing" category includes the "plant gas" reported by EIA, and "transmission" includes the pipeline and distribution fuel reported by EIA. The total upstream emissions from these sources are 387.0 $MMTCO_2e$ based on a 100 year GWP of 25.

Detailed data collection and verification, as well as LCA harmonization to common metrics and system boundaries are critical for improving the rigor of LCA analysis. The National Renewable Energy Laboratory's Joint Institute for Strategic Energy Analysis, www.jisea.org, will be conducting such an evaluation in the coming months, which may improve upon the historical data sets used by EPA.

Exhibit A-1: Basic U.S. Upstream Gas Emission Data for 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	146.3	11.3	47.2	204.8
Processing	18.7	21.4	19.4	59.5
Transmission	51.5	0.1	35.4	87.1
Distribution	35.6			35.6
Total	252.1	32.8	102.1	387.0

There are several additions to this basic information. First, there are some electric driven compressors on the pipeline network. This electricity consumption of 2,936.6 million kWh is from the ORNL *Transportation Data Book*[40]. (That estimate is based on a fixed share of 1.5 percent of the natural gas consumption.) The emission factor for electricity throughout the analysis is 603 kg CO_2/MWh, calculated from EIA data on total generation and CO_2 emissions. This electricity consumption adds 1.8 $MMTCO_2e$ to the pipeline emissions. There is also diesel fuel, gasoline and other petroleum fuel used in gas drilling and production that is not separately reported by EIA. This information is collected by the Economic Census[41]**Error! Bookmark not defined.** but only by NAICS code and only every 10 years (the latest reporting year is 2007). The four relevant NAICS codes are: 211111 (crude petroleum and natural gas extraction); 211112 (natural gas liquid extraction); 213111 (drilling oil and gas wells); and 213112 (support activities for oil and gas operations).

Three of these codes (excepting NGL extraction) combine data for oil and gas operation. The gas portion is calculated based on the gas share of U.S. producing oil and gas wells (55.4 percent) or active drilling rigs (83.2 percent). Also, the Census lists expenditures only by fuel type. The actual consumption is estimated from the expenditures based on average price for each fuel. The consumption is then converted to CO_2 emissions using the emission factors from the EPA GHG Reporting Program. These emissions are then escalated from 2007 to 2008 based on EIA data for production (3.9 percent increase). The calculations are summarized in Exhibit A-2. Total emissions for this segment are 7.2 $MMTCO_2e$.

[39] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*
[40] *ORNL, Transportation Energy Data Book, Oak Ridge National Laboratory, U.S. Department of Energy, June 2010, http://cta.ornl.gov/data/index.shtml*
[41] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*

Exhibit A-2: Gas Industry Upstream Non-Gas Emissions

Energy Consumption (MMBtu)						
NAICS		Distillate	Gasoline	Other	Residual Oil	Undistributed
211111	Extraction	29,055,998	10,031,608	--	6,539,144	8,502,932
211112	NGL Extraction	288,585	352,861	66,627	--	168,613
213111	Drilling	10,014,334	3,808,638	551,713	3,967,479	5,446,747
213112	Support	20,671,552	13,157,404	893,604	7,166,105	4,389,137

CO_2 Emission Factors		Distillate	Gasoline	Other	Residual Oil	Other
		73.96	70.22	62.98	75.1	62.98

CO_2 Emissions ($MMTCO_2e$)						
211111	Extraction	2.1	0.7	0	0.5	0.5
211112	NGL Extraction	0	0	0	0	0
213111	Drilling	0.7	0.3	0	0.3	0.3
213112	Support	1.5	0.9	0.1	0.5	0.3

Gas Share of Emissions ($MMTCO_2e$)						
21111	Extraction	1.8	0.6	0	0.4	0.4
211112	NGL Extraction	0	0	0	0	0
213111	Drilling	0.4	0.1	0	0.2	0.2
213112	Support	1.3	0.8	0	0.4	0.2

Source: EPA, ORNL, Census Bureau, DBCCA Analysis 2011

Another adjustment is for methane emissions from “associated” gas produced from oil wells. Most oil wells produce gas, much of which is captured and delivered to consumers. The EPA *Inventory of U.S. GHG Emissions* estimates methane emissions from petroleum systems to be approximately 30 $MMTCO_2e$ per year.

Since some domestic natural gas is co-produced with petroleum, one could consider all of these emissions be included in the life-cycle analysis of emissions from the natural gas sector. However, the natural gas produced and the methane emissions are a byproduct of petroleum production. Methane emissions would occur even if no natural gas were captured and delivered for end-use consumption. In fact, the emissions might actually be higher in that case since there would be no economic incentive to capture the gas. One could also therefore maintain that it is not appropriate to count the methane emissions from petroleum production toward gas use, since they are independent of the production of gas and are related to petroleum consumption.

On the other hand, associated gas produced from oil wells is a significant segment of U.S. gross withdrawals of natural gas, and if there are methane emissions associated with that production, it seems appropriate to include them in the life-cycle analysis, even if the production is incidental to oil production. In that case, we have to evaluate how much of the methane emissions to allocate to gas production versus petroleum production.

The EPA inventory separates the methane emissions from petroleum systems at the wellhead oil separator. Methane emitted on the oil side downstream from the separator is allocated to the petroleum side, and methane emitted on the natural gas side is allocated to the natural gas side. The part that must be allocated here is the upstream production emissions, of which the largest components are miscellaneous venting and fugitives and venting from gas-powered pneumatic devices. The approach in this analysis is to simply allocate these emissions based on the energy value of oil versus gas produced from these wells.

According to the EIA, the gross production of natural gas from petroleum wells in 2008 was 5.7 trillion cubic feet (Tcf)[42]. However, much of this gas (3.3 Tcf) was not gathered for sale but was reinjected into the producing formation. Some of the gas is reinjected to push more oil out of the formation. Most of the reinjection (3.0 Tcf) is from Alaska production where there is no pipeline to bring the gas to market. It is reinjected as a means of storage until the time when a pipeline may be built to the lower 48 states. In any case, the associated gas actually produced for potential sale is 2.5 Tcf. On an energy basis, this is 20 percent energy value of the net associated gas plus the 1.8 billion barrels of U.S. oil production in 2008.

Of the methane emission sources in petroleum production, we include pneumatic device venting, combustion and process upsets, miscellaneous venting and fugitives, and wellhead fugitives. Tank venting is not included because it is purely related to oil production. Total methane emissions for these sources in 2008 were 25.6 $MMTCO_2e$, according to the EPA inventory. Taking 20 percent of this total gives 5.0 $MMTCO_2e$ of additional methane emissions to allocate to the natural gas LCA, increasing the unadjusted emission baseline by 1.4 percent.

With these additions (electricity, non-gas fuel, and methane from petroleum systems), total upstream gas production emissions are 402.0 $MMTCO_2e$.

The total emissions are then adjusted for imports. The calculations above include emissions for U.S. production, but a net 13 percent of natural gas was imported in 2008. Of this, 11.7 percent was imported by pipeline from Mexico and Canada (mostly the latter). This analysis assumes that production processes are similar throughout North America, so the production emissions are escalated by 11.7 percent to account for the pipeline imports. The remaining 1.3 percent of imports were LNG imports. LNG has a higher LCA than conventional gas due to gasification, liquefaction, and transportation processes. The LCA for LNG is estimated at 176 percent of conventional gas based on the LCA performed by NETL[30] The production emissions for the LNG component are increased by this amount. The adjustment for imports is the largest adjustment, increasing the emissions by about 39 $MMTCO_2e$, or 10 percent.

The other adjustment in this analysis is related to fugitive methane emissions from gas distribution lines at local gas distribution companies (LDCs). Methane emissions from local distribution lines are 35.6 $MMTCO_2e$ (at 25 GWP), but many power plants receive gas deliveries directly from interstate pipelines rather than via local distribution lines. Relatively few power plants actually purchase gas from LDCs, but some receive gas deliveries from the LDCs. The EIA-176 survey[43] provides data on deliveries by LDCs to electric generators; however, these reported deliveries total 6.5 Tcf, which is almost equal to total gas consumption for electricity generation. This is because intrastate pipeline deliveries in California, Texas, and Florida are included in the EIA-176 survey. Excluding these three states, 59 percent of gas to electric generators is delivered by LDCs. Based on this, only 59 percent of the distribution company methane emissions are included in the adjusted values. This adjustment decreases the emissions by about 17 $MMTCO_2e$, or 4 percent. Exhibit A-3 shows the adjusted final upstream GHG emissions for natural gas: 423.8 $MMTCO_2e$. Methane emissions account for more than half of the total.

Exhibit A-3: Adjusted Total Upstream GHG Emissions from Natural Gas for 2008, using EPA 2011 Methodology for Methane ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	173.7	12.9	62.2	248.7
Processing	21.3	24.4	22.2	67.9
Transmission	51.5	0.1	37.2	88.8
Distribution	18.3	0.0	0.0	18.3
Total	264.9	37.4	121.5	423.8

These total emissions are then normalized to kg CO_2e/MMBtu of delivered natural gas based on the EIA data on natural gas delivered to consumers: 21.4 trillion cubic feet (Tcf). The total normalized upstream emissions are 19.2 kg CO_2e/MMBtu. (See Exhibit A-4.) The emissions for combustion of the gas at the point of use are 53.07 kg

[42] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*
[43] *EIA, EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition", Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP1&CFID=5251631&CFTOKEN=51c7f7f0104e329d-3FD56B17-237D-DA68-24412047FB2CE3CB*

CO_2e/MMBtu (including N_2O and unburned methane), so the total life-cycle GHG emissions at the point of use are 70.4 kg CO_2e/MMBtu. Of this, the upstream emissions are 24 percent and methane is slightly over half of the upstream component.

Exhibit A-4: Normalized Life-cycle GHG Emissions for Natural Gas for 2008, using 2011 EPA Methodology for Methane (kg CO_2/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	7.9	0.6	2.8	11.3
Processing	1.0	1.1	1.0	3.1
Transmission	2.3	0.0	1.7	4.0
Distribution	0.8	0.0	0.0	0.8
Total Upstream	12.0	1.7	5.5	19.2
Fuel Combustion	0	0	53.1	53.1
Total	12.0	1.7	58.6	72.3

The same methodology is applied using EPA's 2010 estimate of methane emissions, to show the effect of the updated, increased 2011 methane emission estimate. Exhibits A-5 and A-6 show the total and normalized emissions for this case. The normalized upstream emissions with the old data are 12.0 kg CO_2e/MMBtu. Including the end-use gas combustion; total life-cycle emissions including end-use combustion are 65.1 kg CO_2/MMBtu, with the upstream portion accounting for 20 percent. In this case, methane makes up only about 40 percent of the upstream gas GHG footprint.

Exhibit A-5: Adjusted Total Upstream GHG Emissions from Natural Gas, 2008, using 2010 EPA Methodology for Methane (MMTCO_2e)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	25.9	9.7	62.2	97.8
Processing	17.7	24.4	22.2	64.2
Transmission	46.9	0.1	37.2	84.2
Distribution	18.3	0.0	0.0	18.3
Total	108.8	34.2	121.5	264.6

Exhibit A-6: Normalized Life-cycle GHG Emissions for Natural Gas for 2008, using 2010 EPA Methodology for Methane (kg CO_2/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	1.2	0.4	2.8	4.4
Processing	0.8	1.1	1.0	2.9
Transmission	2.1	0.0	1.7	3.8
Distribution	0.8	0.0	0.0	0.8
Upstream Total	4.9	1.6	5.5	12.0
Fuel Combustion	0	0	53.1	53.1
Total	4.9	1.6	58.6	65.1

Coal LCA

The upstream energy consumption for coal production is calculated using the 2007 Economic Census[44] data on fuel and electricity consumption in the same way as the non-gas fuel for gas production. In this case, there is a separate NAICS code for coal production, so no adjustments are necessary. The same CO_2 emission factors and the emission factor for electricity use are used as for the data on gas production. (See Exhibit A-7.) The values are adjusted from 2007 to 2008 based on the production in each year—a 2.2 percent increase. The total CO_2 emissions from energy consumption for coal production are 14.0 $MMTCO_2e$. Methane emissions from coal mines of 67.1 $MMTCO_2e$ (79.9 at 25 GWP) are taken from the EPA GHG inventory. Methane from abandoned coal mines is not included.

Exhibit A-7: Upstream GHG Calculation for Coal

	Coal	Distillate	Natural Gas	Gasoline	Residual Oil	Other	Electricity (MWh)
MMBtu	3,607,020	52,597,178	2,487,920	4,846,529	25,739,212	2,039,820	11,444,477
kg CO2/MMBtu	94.38	73.96	53.02	70.22	75.10	62.98	603.01
MMTCO2e	0.34	3.89	0.13	0.34	1.93	0.13	6.90

The estimate of transportation emissions is based on the Commodity Flow Summary[45] developed by the U.S. Department of Transportation and Census Bureau, which provides information on ton-miles of coal transported by different modes. Rail is the primary mode of transportation, with rail-only accounting for 91 percent of the ton-miles and rail and other modes (truck and barge) accounting for the remainder. This analysis applies a ton-mile fuel consumption factor[46, 47, 48] to calculate fuel consumption and converts the fuel consumption to CO_2 using the same EPA emission factors used for other sectors. (See Exhibit A-8.) For mixed mode, rail or barge are assumed to account for 75 percent of the ton-miles and truck for 50 percent. Most coal is delivered via dedicated equipment—e.g., a coal unit train travels only to and from the mine to the power plant. Thus, the fuel consumed in returning empty to the mine must be included. This analysis assumes 100-percent empty return as part of the energy consumption, with the empty fuel consumption being one-third of the loaded consumption based on the weight of the empty vehicle. The total consumption calculated is 23.9 $MMTCO_2$.

Exhibit A-8: GHG Calculation for Coal Transportation

Mode	Ton-Miles (million)	Fuel Consumption (ton-mi/gal)	GHG Emissions (MMTCO2)	Round-Trip Emissions (MMTCO2)
Truck	14,002	110.00	1.28	1.67
Rail	773,290	480.00	16.26	21.13
Water	6,548	730.00	0.09	0.12
Truck and rail	785	388.00	0.02	0.03
Truck and water	7,257	575.00	0.13	0.17
Rail and water	26,994	605.00	0.45	0.59
Other multiple modes	4,353	480.00	0.09	0.12
Other and unknown modes	2,567	480.00	0.05	0.07
Total	835,796	-	18.38	23.89

In the case of coal, the U.S. is a net exporter of about 4 percent of its production, so the total production emissions are adjusted downward by this amount to calculate the emissions attributable to coal consumed in the U.S. Exhibit A-9 shows the final adjusted upstream emissions: 117.8 $MMTCO_2e$.

[44] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*
[45] *U.S. Department of Transportation, Research and Innovative Technology Administration, Bureau of Transportation Statistics and U.S. Census Bureau, 2007 Commodity Flow Survey.*
[46] *Federal Railroad Administration, "Comparative Evaluation of Rail and Truck Fuel Efficiency on Competitive Corridors", November 19, 2009.*
[47] *Army Corps of Engineers, "Waterborne Commerce Statistics Center", http://www.ndc.iwr.usace.army.mil//data/data1.htm*
[48] *American Railroad Association*

Exhibit A-9: Adjusted Total Upstream GHG Emissions from Coal, 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	79.9	0.0	14.0	93.9
Transportation	0.0	0.0	23.9	23.9
Total	79.9	0.0	37.9	117.8

These values are then normalized by the total 2008 consumption of coal in the U.S. of 1,147 million tons of coal, assuming an average heating value of 10,250 Btu/lb.[49] This yields a normalized upstream emission factor of 4.3 kg CO_2/MMBtu consumed. (See Exhibit A-10.) The value is about 25 percent of the upstream emissions from natural gas. The emission factor for combustion of coal is 95.1 kg CO_2e/MMBtu, bringing the total end use life-cycle emissions to 99.9 kg CO_2/MMBtu. In this case, although methane is still 63 percent of the upstream emissions, the upstream component is only 4 percent of the total, with the CO_2 emissions from the coal itself being the dominant factor.

Exhibit A-10: Normalized Upstream GHG Emissions for Coal for 2008 (kg CO_2/MMBtu)

	Methane	CO_2 and N_2O from Combustion	**Total**
Production	3.3	0.6	3.9
Transportation	0.0	1.0	1.0
Total Upstream	3.3	1.5	4.8
Coal Combustion	0.0	95.1	95.1
End Use Total	3.3	96.6	99.9

Electricity Generation
The efficiency[50] of the electric generator is one of the most significant variables in estimating the GHG emissions per MWh of electricity. This analysis looks at two values:

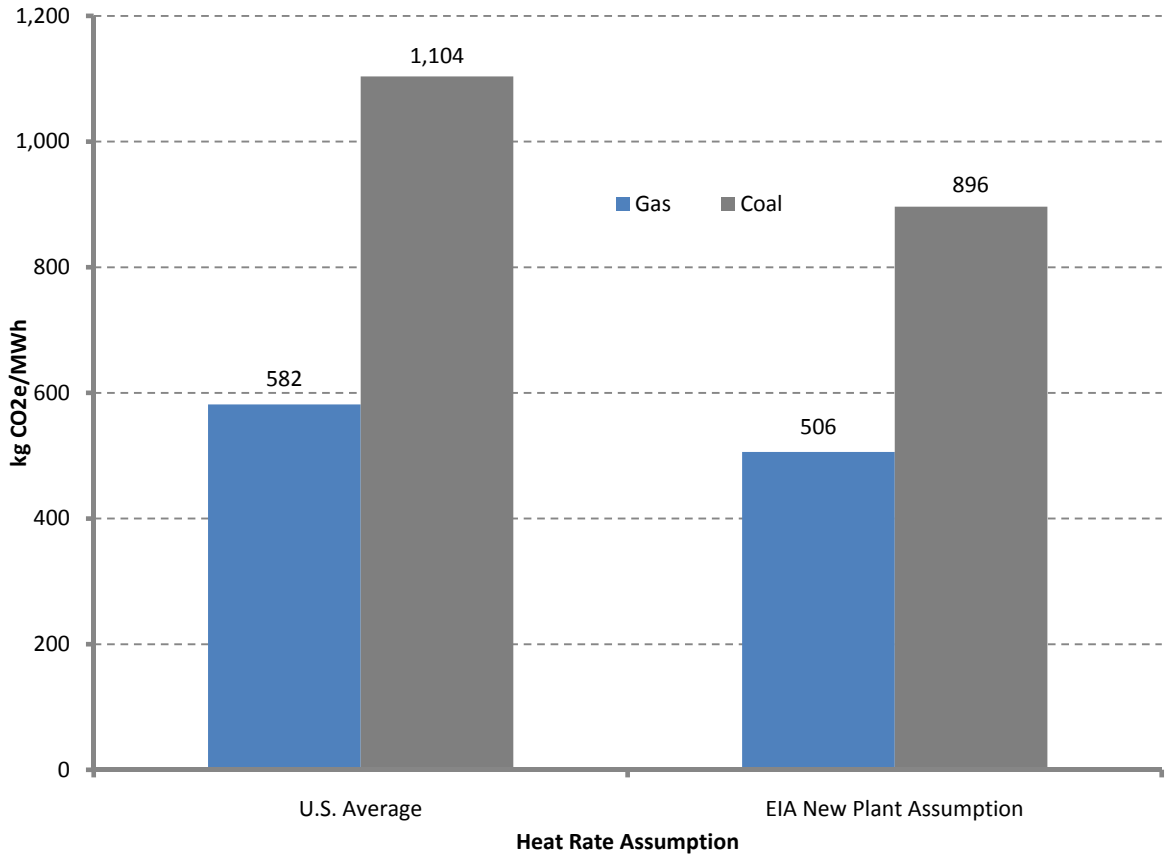
- **National average efficiency values** based on EIA data[51, 52, 53, 54] for total gas or coal consumption for generation and total generation by each fuel. (See Exhibit A-11.)
- **Efficiency[55] for new power plants** assumed by the EIA in its *Annual Energy Outlook 2010*[38]. EIA provides a value for a new plant in 2009 and for subsequent plants ("nth plant") of each type for which the cost may be lower due to learning and production improvement. The values used here are the average of the values for a gas combined-cycle plant (6,998 Btu/kWh, 49 percent efficiency) and a new supercritical coal plant (8,970 Btu/kWh, 38 percent efficiency). (See Exhibit A-12.)

Exhibit A-11: Calculation of Average Power Plant Efficiencies

	Energy Consumption (Quads)	Generation (Billion kWh)	Heat Rate (Btu / kWh)	Efficiency
Gas	7	883.00	8,044.00	0.42
Coal	22	1,986.00	11,044.00	0.31

[49] *EIA, Annual Coal Data, Energy Information Administration, U.S. Department of Energy, http://www.eia.gov/totalenergy/data/annual/pdf/sec7_5.pdf*
[50] *The power industry uses efficiency and heat rate to express power plant efficiency. Heat rate is Btu/kWh = 3413/efficiency. A lower heat rate signifies a higher efficiency.*
[51] *EIA, Electric Power Monthly, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/cneaf/electricity/epm/table2_4_a.html*
[52] *EIA, Electric Power Monthly, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/aer/txt/ptb0802a.html*
[53] *EIA, Annual Energy Review, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/cneaf/electricity/epm/table2_1_a.html*
[54] *EIA, Quarterly Coal Report, U.S. Department of Energy, http://www.eia.gov/cneaf/coal/quarterly/html/t32p01p1.pdf*

Exhibit A-12: Effect of Power Plant Heat Rate on Life-Cycle Emissions



Source: DBCCA analysis, 2011.

Appendix B
Effect of Global Warming Potential (GWP)

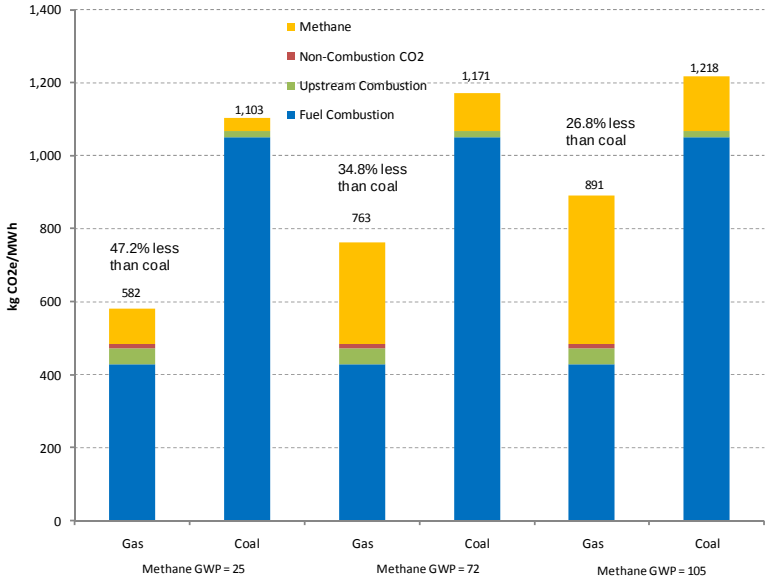
Methane is a potent GHG and its effect varies depending on the lifetime over which it is evaluated. The IPCC uses a 100 year lifetime for its analysis and a 100 year GWP of 25 for methane. Others believe that short-lived GHGs should be evaluated on a 20 year lifetime.

In its recently completed study on natural gas, MIT explains the reasons that a 100 GWP is commonly used:

> *"Because the various GHGs have different lives in the atmosphere (e.g., on the scale of a decade for methane, but centuries for CO_2), the calculation of GWPs depends on the integration period. Early studies calculated this index for 20-, 100- and 500-year integration periods. The IPCC decided to use the 100-year measure, and it is a procedure followed by the U.S. and other countries over several decades. An outlier in this domain is the Cornell study which recommends the application of the 20-year value in inter-fuel comparison. A 20-year GWP would emphasize the near-term impact of methane but ignore serious longer-term risks of climate change from GHGs that will remain in the atmosphere for hundreds to thousands of years, and the 500-year value would miss important effects over the current century. Methane is a more powerful GHG than CO_2, and its combination of potency and short life yields the 100-year GWP used in this study."* [56]

In addition, scientific work continues on the appropriate GWPs for different GHGs. Although the IPCC 20-year GWP for methane is 72, new work by Shindell et al[57] proposes a 20-year GWP of 105 for methane. Exhibit B-1 above shows the effect of different methane GWPs on the LCA using the EPA 2011 methodology. Since methane is a much larger component of the LCA for natural gas, the GWP has a much larger effect on gas than coal. Going from the 100 year GWP to the 20-year GWP of 72 increases life-cycle emissions for natural gas by 31 percent and for coal by only 6 percent. At the GWP of 72, the power plant emissions for natural gas are 35 percent lower than those for coal. At the 105 GWP, the emissions for the gas-fired plant are 27 percent lower than those for coal.

Exhibit B-1: Effect of Methane GWP on Life-Cycle Emissions



Source: DBCCA Analysis 2011

[56] *The Future of Natural Gas, Moniz, Ernest J.; Jacoby, Henry D.; Meggs, Anthony J.M. (Study co-chairs), MIT Energy Initiative, 2011.*
[57] *Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. Science 326:716–718*

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LETTER

Methane and the greenhouse-gas footprint of natural gas from shale formations

A letter

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Abstract We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

Keywords Methane · Greenhouse gases · Global warming · Natural gas · Shale gas · Unconventional gas · Fugitive emissions · Lifecycle analysis · LCA · Bridge fuel · Transitional fuel · Global warming potential · GWP

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Many view natural gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing greenhouse gas (GHG) emissions compared to oil or coal over coming decades (Pacala and Socolow 2004). Development of "unconventional" gas dispersed in shale is part of this vision, as the potential resource may be large, and in many regions conventional reserves are becoming depleted (Wood et al. 2011). Domestic production in the U.S. was predominantly from conventional reservoirs through the 1990s, but by 2009 U.S. unconventional production exceeded that of conventional gas. The Department of Energy predicts that by 2035 total domestic production will grow by 20%, with unconventional gas providing 75% of the total (EIA 2010a). The greatest growth is predicted for shale gas, increasing from 16% of total production in 2009 to an expected 45% in 2035.

Although natural gas is promoted as a bridge fuel over the coming few decades, in part because of its presumed benefit for global warming compared to other fossil fuels, very little is known about the GHG footprint of unconventional gas. Here, we define the GHG footprint as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion. The GHG footprint of shale gas has received little study or scrutiny, although many have voiced concern. The National Research Council (2009) noted emissions from shale-gas extraction may be greater than from conventional gas. The Council of Scientific Society Presidents (2010) wrote to President Obama, warning that some potential energy bridges such as shale gas have received insufficient analysis and may aggravate rather than mitigate global warming. And in late 2010, the U.S. Environmental Protection Agency issued a report concluding that fugitive emissions of methane from unconventional gas may be far greater than for conventional gas (EPA 2010).

Fugitive emissions of methane are of particular concern. Methane is the major component of natural gas and a powerful greenhouse gas. As such, small leakages are important. Recent modeling indicates methane has an even greater global warming potential than previously believed, when the indirect effects of methane on atmospheric aerosols are considered (Shindell et al. 2009). The global methane budget is poorly constrained, with multiple sources and sinks all having large uncertainties. The radiocarbon content of atmospheric methane suggests fossil fuels may be a far larger source of atmospheric methane than generally thought (Lassey et al. 2007).

The GHG footprint of shale gas consists of the direct emissions of CO_2 from end-use consumption, indirect emissions of CO_2 from fossil fuels used to extract, develop, and transport the gas, and methane fugitive emissions and venting. Despite the high level of industrial activity involved in developing shale gas, the indirect emissions of CO_2 are relatively small compared to those from the direct combustion of the fuel: 1 to 1.5 g C MJ^{-1} (Santoro et al. 2011) vs 15 g C MJ^{-1} for direct emissions (Hayhoe et al. 2002). Indirect emissions from shale gas are estimated to be only 0.04 to 0.45 g C MJ^{-1} greater than those for conventional gas (Wood et al. 2011). Thus, for both conventional and shale gas, the GHG footprint is dominated by the direct CO_2 emissions and fugitive methane emissions. Here we present estimates for methane emissions as contributors to the GHG footprint of shale gas compared to conventional gas.

Our analysis uses the most recently available data, relying particularly on a technical background document on GHG emissions from the oil and gas industry (EPA 2010) and materials discussed in that report, and a report on natural gas losses on federal lands from the General Accountability Office (GAO 2010). The

EPA (2010) report is the first update on emission factors by the agency since 1996 (Harrison et al. 1996). The earlier report served as the basis for the national GHG inventory for the past decade. However, that study was not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed facilities of companies that voluntarily participated (Kirchgessner et al. 1997). The new EPA (2010) report notes that the 1996 "study was conducted at a time when methane emissions were not a significant concern in the discussion about GHG emissions" and that emission factors from the 1996 report "are outdated and potentially understated for some emissions sources." Indeed, emission factors presented in EPA (2010) are much higher, by orders of magnitude for some sources.

1 Fugitive methane emissions during well completion

Shale gas is extracted by high-volume hydraulic fracturing. Large volumes of water are forced under pressure into the shale to fracture and re-fracture the rock to boost gas flow. A significant amount of this water returns to the surface as flow-back within the first few days to weeks after injection and is accompanied by large quantities of methane (EPA 2010). The amount of methane is far more than could be dissolved in the flow-back fluids, reflecting a mixture of fracture-return fluids and methane gas. We have compiled data from 2 shale gas formations and 3 tight-sand gas formations in the U.S. Between 0.6% and 3.2% of the life-time production of gas from wells is emitted as methane during the flow-back period (Table 1). We include tight-sand formations since flow-back emissions and the patterns of gas production over time are similar to those for shale (EPA 2010). Note that the rate of methane emitted during flow-back (column B in Table 1) correlates well to the initial production rate for the well following completion (column C in Table 1). Although the data are limited, the variation across the basins seems reasonable: the highest methane emissions during flow-back were in the Haynesville, where initial pressures and initial production were very high, and the lowest emissions were in the Uinta, where the flow-back period was the shortest and initial production following well completion was low. However, we note that the data used in Table 1 are not well documented, with many values based on PowerPoint slides from EPA-sponsored workshops. For this paper, we therefore choose to represent gas losses from flow-back fluids as the mean value from Table 1: 1.6%.

More methane is emitted during "drill-out," the stage in developing unconventional gas in which the plugs set to separate fracturing stages are drilled out to release gas for production. EPA (2007) estimates drill-out emissions at 142×10^3 to 425×10^3 m^3 per well. Using the mean drill-out emissions estimate of 280×10^3 m^3 (EPA 2007) and the mean life-time gas production for the 5 formations in Table 1 (85×10^6 m^3), we estimate that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. If we instead use the average life-time production for a larger set of data on 12 formations (Wood et al. 2011), 45×10^6 m^3, we estimate a percentage emission of 0.62%. More effort is needed to determine drill-out emissions on individual formation. Meanwhile, in this paper we use the conservative estimate of 0.33% for drill-out emissions.

Combining losses associated with flow-back fluids (1.6%) and drill out (0.33%), we estimate that 1.9% of the total production of gas from an unconventional shale-gas

Table 1 Methane emissions during the flow-back period following hydraulic fracturing, initial gas production rates following well completion, life-time gas production of wells, and the methane emitted during flow-back expressed as a percentage of the life-time production for five unconventional wells in the United States

	(A) Methane emitted during flow-back (10^3 m^3)[a]	(B) Methane emitted per day during flow-back (10^3 m^3 day^{-1})[b]	(C) Initial gas production at well completion (10^3 m^3 day^{-1})[c]	(D) Life-time production of well (10^6 m^3)[d]	(E) Methane emitted during flow-back as % of life-time production[e]
Haynesville (Louisiana, shale)	6,800	680	640	210	3.2
Barnett (Texas, shale)	370	41	37	35	1.1
Piceance (Colorado, tight sand)	710	79	57	55	1.3
Uinta (Utah, tight sand)	255	51	42	40	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Flow-back is the return of hydraulic fracturing fluids to the surface immediately after fracturing and before well completion. For these wells, the flow-back period ranged from 5 to 12 days

[a] Haynesville: average from Eckhardt et al. (2009); Piceance: EPA (2007); Barnett: EPA (2004); Uinta: Samuels (2010); Denver-Julesburg: Bracken (2008)

[b] Calculated by dividing the total methane emitted during flow-back (column A) by the duration of flow-back. Flow-back durations were 9 days for Barnett (EPA 2004), 8 days for Piceance (EPA 2007), 5 days for Uinta (Samuels 2010), and 12 days for Denver-Julesburg (Bracken 2008); median value of 10 days for flow-back was assumed for Haynesville

[c] Haynesville: http://shale.typepad.com/haynesvilleshale/2009/07/chesapeake-energy-haynesville-shale-decline-curve.html1/7/2011 and http://oilshalegas.com/haynesvilleshalestocks.html; Barnett: http://oilshalegas.com/barnettshale.html; Piceance: Kruuskraa (2004) and Henke (2010); Uinta: http://www.epmag.com/archives/newsComments/6242.htm; Denver-Julesburg: http://www.businesswire.com/news/home/20100924005169/en/Synergy-Resources-Corporation-Reports-Initial-Production-Rates

[d] Based on averages for these basins. Haynesville: http://shale.typepad.com/haynesvilleshale/decline-curve/); Barnett: http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm and Wood et al. (2011); Piceance: Kruuskraa (2004); Uinta: http://www.epmag.com/archives/newsComments/6242.htm

[e] Calculated by dividing column (A) by column (D)

Table 2 Fugitive methane emissions associated with development of natural gas from conventional wells and from shale formations (expressed as the percentage of methane produced over the lifecycle of a well)

	Conventional gas	Shale gas
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total emissions	1.7 to 6.0%	3.6 to 7.9%

See text for derivation of estimates and supporting information

well is emitted as methane during well completion (Table 2). Again, this estimate is uncertain but conservative.

Emissions are far lower for conventional natural gas wells during completion, since conventional wells have no flow-back and no drill out. An average of 1.04×10^3 m^3 of methane is released per well completed for conventional gas (EPA 2010), corresponding to 1.32×10^3 m^3 natural gas (assuming 78.8% methane content of the gas). In 2007, 19,819 conventional wells were completed in the US (EPA 2010), so we estimate a total national emission of 26×10^6 m^3 natural gas. The total national production of onshore conventional gas in 2007 was 384×10^9 m^3 (EIA 2010b). Therefore, we estimate the average fugitive emissions at well completion for conventional gas as 0.01% of the life-time production of a well (Table 2), three orders of magnitude less than for shale gas.

2 Routine venting and equipment leaks

After completion, some fugitive emissions continue at the well site over its lifetime. A typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery apparatus. Many of these potentially leak, and many pressure relief valves are designed to purposefully vent gas. Emissions from pneumatic pumps and dehydrators are a major part of the leakage (GAO 2010). Once a well is completed and connected to a pipeline, the same technologies are used for both conventional and shale gas; we assume that these post-completion fugitive emissions are the same for shale and conventional gas. GAO (2010) concluded that 0.3% to 1.9% of the life-time production of a well is lost due to routine venting and equipment leaks (Table 2). Previous studies have estimated routine well-site fugitive emissions as approximately 0.5% or less (Hayhoe et al. 2002; Armendariz 2009) and 0.95% (Shires et al. 2009). Note that none of these estimates include accidents or emergency vents. Data on emissions during emergencies are not available and have never, as far as we can determine, been used in any estimate of emissions from natural gas production. Thus, our estimate of 0.3% to 1.9% leakage is conservative. As we discuss below, the 0.3% reflects use of best available technology.

Additional venting occurs during "liquid unloading." Conventional wells frequently require multiple liquid-unloading events as they mature to mitigate water intrusion as reservoir pressure drops. Though not as common, some unconventional wells may also require unloading. Empirical data from 4 gas basins indicate that 0.02

to 0.26% of total life-time production of a well is vented as methane during liquid unloading (GAO 2010). Since not all wells require unloading, we set the range at 0 to 0.26% (Table 2).

3 Processing losses

Some natural gas, whether conventional or from shale, is of sufficient quality to be "pipeline ready" without further processing. Other gas contains sufficient amounts of heavy hydrocarbons and impurities such as sulfur gases to require removal through processing before the gas is piped. Note that the quality of gas can vary even within a formation. For example, gas from the Marcellus shale in northeastern Pennsylvania needs little or no processing, while gas from southwestern Pennsylvania must be processed (NYDEC 2009). Some methane is emitted during this processing. The default EPA facility-level fugitive emission factor for gas processing indicates a loss of 0.19% of production (Shires et al. 2009). We therefore give a range of 0% (i.e. no processing, for wells that produce "pipeline ready" gas) to 0.19% of gas produced as our estimate of processing losses (Table 2). Actual measurements of processing plant emissions in Canada showed fourfold greater leakage than standard emission factors of the sort used by Shires et al. (2009) would indicate (Chambers 2004), so again, our estimates are very conservative.

4 Transport, storage, and distribution losses

Further fugitive emissions occur during transport, storage, and distribution of natural gas. Direct measurements of leakage from transmission are limited, but two studies give similar leakage rates in both the U.S. (as part of the 1996 EPA emission factor study; mean value of 0.53%; Harrison et al. 1996; Kirchgessner et al. 1997) and in Russia (0.7% mean estimate, with a range of 0.4% to 1.6%; Lelieveld et al. 2005). Direct estimates of distribution losses are even more limited, but the 1996 EPA study estimates losses at 0.35% of production (Harrison et al. 1996; Kirchgessner et al. 1997). Lelieveld et al. (2005) used the 1996 emission factors for natural gas storage and distribution together with their transmission estimates to suggest an overall average loss rate of 1.4% (range of 1.0% to 2.5%). We use this 1.4% leakage as the likely lower limit (Table 2). As noted above, the EPA 1996 emission estimates are based on limited data, and Revkin and Krauss (2009) reported "government scientists and industry officials caution that the real figure is almost certainly higher." Furthermore, the IPCC (2007) cautions that these "bottom-up" approaches for methane inventories often underestimate fluxes.

Another way to estimate pipeline leakage is to examine "lost and unaccounted for gas," e.g. the difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers. At the global scale, this method has estimated pipeline leakage at 2.5% to 10% (Crutzen 1987; Cicerone and Oremland 1988; Hayhoe et al. 2002), although the higher value reflects poorly maintained pipelines in Russia during the Soviet collapse, and leakages in Russia are now far less (Lelieveld et al. 2005; Reshetnikov et al. 2000). Kirchgessner et al. (1997) argue against this approach, stating it is "subject to numerous errors including gas theft, variations in

temperature and pressure, billing cycle differences, and meter inaccuracies." With the exception of theft, however, errors should be randomly distributed and should not bias the leakage estimate high or low. Few recent data on lost and unaccounted gas are publicly available, but statewide data for Texas averaged 2.3% in 2000 and 4.9% in 2007 (Percival 2010). In 2007, the State of Texas passed new legislation to regulate lost and unaccounted for gas; the legislation originally proposed a 5% hard cap which was dropped in the face of industry opposition (Liu 2008; Percival 2010). We take the mean of the 2000 and 2007 Texas data for missing and unaccounted gas (3.6%) as the upper limit of downstream losses (Table 2), assuming that the higher value for 2007 and lower value for 2000 may potentially reflect random variation in billing cycle differences. We believe this is a conservative upper limit, particularly given the industry resistance to a 5% hard cap.

Our conservative estimate of 1.4% to 3.6% leakage of gas during transmission, storage, and distribution is remarkably similar to the 2.5% "best estimate" used by Hayhoe et al. (2002). They considered the possible range as 0.2% and 10%.

5 Contribution of methane emissions to the GHG footprints of shale gas and conventional gas

Summing all estimated losses, we calculate that during the life cycle of an average shale-gas well, 3.6 to 7.9% of the total production of the well is emitted to the atmosphere as methane (Table 2). This is at least 30% more and perhaps more than twice as great as the life-cycle methane emissions we estimate for conventional gas, 1.7% to 6%. Methane is a far more potent GHG than is CO_2, but methane also has a tenfold shorter residence time in the atmosphere, so its effect on global warming attenuates more rapidly (IPCC 2007). Consequently, to compare the global warming potential of methane and CO_2 requires a specific time horizon. We follow Lelieveld et al. (2005) and present analyses for both 20-year and 100-year time horizons. Though the 100-year horizon is commonly used, we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades (IPCC 2007). We use recently modeled values for the global warming potential of methane compared to CO_2: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al. 2009). These are somewhat higher than those presented in the 4th assessment report of the IPCC (2007), but better account for the interaction of methane with aerosols. Note that carbon-trading markets use a lower global-warming potential yet of only 21 on the 100-year horizon, but this is based on the 2nd IPCC (1995) assessment, which is clearly out of date on this topic. See Electronic Supplemental Materials for the methodology for calculating the effect of methane on GHG in terms of CO_2 equivalents.

Methane dominates the GHG footprint for shale gas on the 20-year time horizon, contributing 1.4- to 3-times more than does direct CO_2 emission (Fig. 1a). At this time scale, the GHG footprint for shale gas is 22% to 43% greater than that for conventional gas. When viewed at a time 100 years after the emissions, methane emissions still contribute significantly to the GHG footprints, but the effect is diminished by the relatively short residence time of methane in the atmosphere. On this time frame, the GHG footprint for shale gas is 14% to 19% greater than that for conventional gas (Fig. 1b).

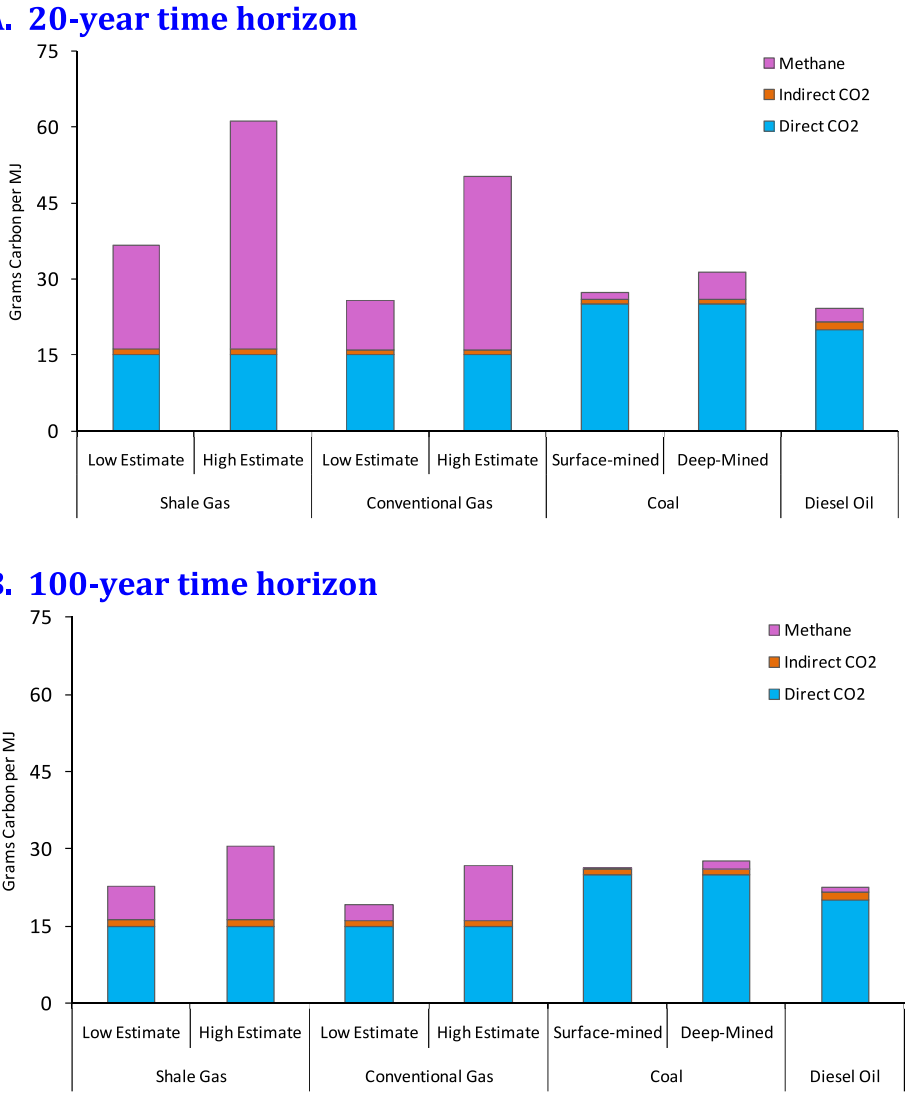

Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** is for a 100-year time horizon. Estimates include direct emissions of CO_2 during combustion (*blue bars*), indirect emissions of CO_2 necessary to develop and use the energy source (*red bars*), and fugitive emissions of methane, converted to equivalent value of CO_2 as described in the text (*pink bars*). Emissions are normalized to the quantity of energy released at the time of combustion. The conversion of methane to CO_2 equivalents is based on global warming potentials from Shindell et al. (2009) that include both direct and indirect influences of methane on aerosols. Mean values from Shindell et al. (2009) are used here. Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure

6 Shale gas versus other fossil fuels

Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion (Fig. 1a; see Electronic Supplemental Materials for derivation of the estimates for diesel oil and coal). Over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions (Fig. 1b). For the 20 year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5-times greater. At the 100-year time scale, the footprint for shale gas is similar to or 35% greater than for oil.

We know of no other estimates for the GHG footprint of shale gas in the peer-reviewed literature. However, we can compare our estimates for conventional gas with three previous peer-reviewed studies on the GHG emissions of conventional natural gas and coal: Hayhoe et al. (2002), Lelieveld et al. (2005), and Jamarillo et al. (2007). All concluded that GHG emissions for conventional gas are less than for coal, when considering the contribution of methane over 100 years. In contrast, our analysis indicates that conventional gas has little or no advantage over coal even over the 100-year time period (Fig. 1b). Our estimates for conventional-gas methane emissions are in the range of those in Hayhoe et al. (2002) but are higher than those in Lelieveld et al. (2005) and Jamarillo et al. (2007) who used 1996 EPA emission factors now known to be too low (EPA 2010). To evaluate the effect of methane, all three of these studies also used global warming potentials now believed to be too low (Shindell et al. 2009). Still, Hayhoe et al. (2002) concluded that under many of the scenarios evaluated, a switch from coal to conventional natural gas could aggravate global warming on time scales of up to several decades. Even with the lower global warming potential value, Lelieveld et al. (2005) concluded that natural gas has a greater GHG footprint than oil if methane emissions exceeded 3.1% and worse than coal if the emissions exceeded 5.6% on the 20-year time scale. They used a methane global warming potential value for methane from IPCC (1995) that is only 57% of the new value from Shindell et al. (2009), suggesting that in fact methane emissions of only 2% to 3% make the GHG footprint of conventional gas worse than oil and coal. Our estimates for fugitive shale-gas emissions are 3.6 to 7.9%.

Our analysis does not consider the efficiency of final use. If fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation (see Electronic Supplemental Materials). However, this does not greatly affect our overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity (Table in Electronic Supplemental Materials). Further, shale-gas is promoted for other uses, including as a heating and transportation fuel, where there is little evidence that efficiencies are superior to diesel oil.

7 Can methane emissions be reduced?

The EPA estimates that 'green' technologies can reduce gas-industry methane emissions by 40% (GAO 2010). For instance, liquid-unloading emissions can be greatly

reduced with plunger lifts (EPA 2006; GAO 2010); industry reports a 99% venting reduction in the San Juan basin with the use of smart-automated plunger lifts (GAO 2010). Use of flash-tank separators or vapor recovery units can reduce dehydrator emissions by 90% (Fernandez et al. 2005). Note, however, that our lower range of estimates for 3 out of the 5 sources as shown in Table 2 already reflect the use of best technology: 0.3% lower-end estimate for routine venting and leaks at well sites (GAO 2010), 0% lower-end estimate for emissions during liquid unloading, and 0% during processing.

Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies, or REC (EPA 2010). However, REC technologies require that pipelines to the well are in place prior to completion, which is not always possible in emerging development areas. In any event, these technologies are currently not in wide use (EPA 2010).

If emissions during transmission, storage, and distribution are at the high end of our estimate (3.6%; Table 2), these could probably be reduced through use of better storage tanks and compressors and through improved monitoring for leaks. Industry has shown little interest in making the investments needed to reduce these emission sources, however (Percival 2010).

Better regulation can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

8 Conclusions and implications

The GHG footprint of shale gas is significantly larger than that from conventional gas, due to methane emissions with flow-back fluids and from drill out of wells during well completion. Routine production and downstream methane emissions are also large, but are the same for conventional and shale gas. Our estimates for these routine and downstream methane emission sources are within the range of those reported by most other peer-reviewed publications inventories (Hayhoe et al. 2002; Lelieveld et al. 2005). Despite this broad agreement, the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas.

The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. We do not intend that our study be used to justify the continued use of either oil or coal, but rather to demonstrate that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

Finally, we note that carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change.

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Life cycle greenhouse gas emissions of Marcellus shale gas

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Abstract
This study estimates the life cycle greenhouse gas (GHG) emissions from the production of Marcellus shale natural gas and compares its emissions with national average US natural gas emissions produced in the year 2008, prior to any significant Marcellus shale development. We estimate that the development and completion of a typical Marcellus shale well results in roughly 5500 t of carbon dioxide equivalent emissions or about 1.8 g CO_2e/MJ of gas produced, assuming conservative estimates of the production lifetime of a typical well. This represents an 11% increase in GHG emissions relative to average domestic gas (excluding combustion) and a 3% increase relative to the life cycle emissions when combustion is included. The life cycle GHG emissions of Marcellus shale natural gas are estimated to be 63–75 g CO_2e/MJ of gas produced with an average of 68 g CO_2e/MJ of gas produced. Marcellus shale natural gas GHG emissions are comparable to those of imported liquefied natural gas. Natural gas from the Marcellus shale has generally lower life cycle GHG emissions than coal for production of electricity in the absence of any effective carbon capture and storage processes, by 20–50% depending upon plant efficiencies and natural gas emissions variability. There is significant uncertainty in our Marcellus shale GHG emission estimates due to eventual production volumes and variability in flaring, construction and transportation.

Keywords: life cycle assessment, greenhouse gases, Marcellus shale, natural gas

S Online supplementary data available from stacks.iop.org/ERL/6/034014/mmedia

1. Introduction

Marcellus shale is a rapidly developing new source of US domestic natural gas. The Appalachian Basin Marcellus shale extends from southern New York through the western portion of Pennsylvania and into the eastern half of Ohio and northern West Virginia (Kargbo *et al* 2010). The estimated basin area is between 140 000 and 250 000 km^2 (Kargbo *et al* 2010), and has a depth ranging from 1200 to 2600 m (US DOE 2009). The shale seam's net thickness ranges from 15 to 60 m (US DOE 2009) and is generally thicker from west to east (Hill *et al* 2004). Figure 1 shows the location of the Marcellus and other shale gas formations in the continental United States.

Shale gas has become an important component of the current US natural gas production mix. In 2009, shale gas was 16% of the 21 trillion cubic feet (Tcf) or 600 million cubic meters (Mm^3) total dry gas produced (US EIA 2011a, 2011b). In 2035, the EIA expects the share to increase to 47% (12 Tcf or 340 Mm^3) of total gas production. The prospect of rapid shale gas development has resulted in interest in expanding

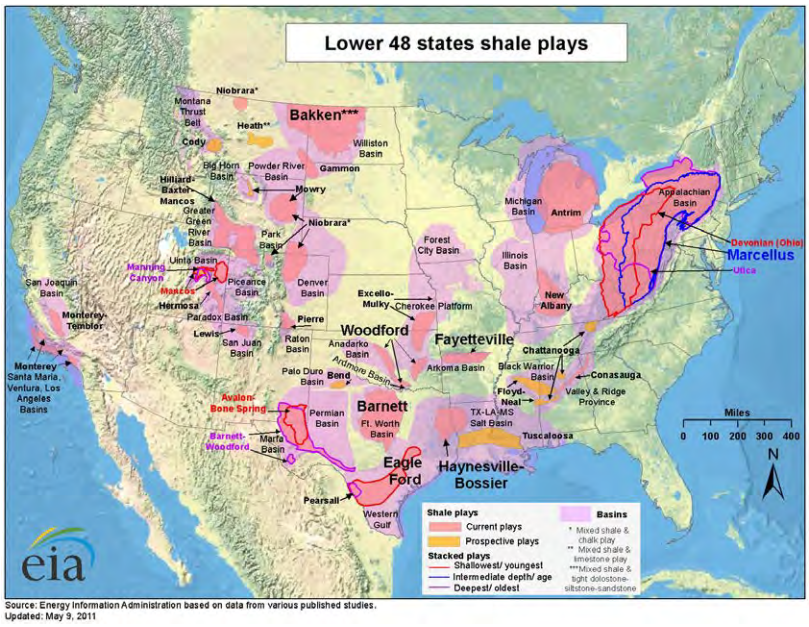

Figure 1. Shale gas plays and basins in the 48 states (source: US Energy Information Administration 2011a, available at http://www.eia.gov/oil_gas/rpd/shale_gas.jpg).

natural gas use including increased natural gas fired electricity generation, use as an alternative transportation fuel, and even exporting as liquefied natural gas. To date most shale gas activity has been in the Barnett shale in Texas. However, the immense potential of the Marcellus shale has stimulated increased attention. The shale play has an estimated gas-in-place of 1500 Tcf or 42 000 Mm^3, of which 262–500 Tcf or 7400–14 000 Mm^3 are thought to be recoverable (Hill *et al* 2004, US DOE 2009).

Advancements in horizontal drilling and hydraulic fracturing, demonstrated successfully in the Barnett shale and first applied in the Marcellus shale in 2004, have enabled the recovery of economical levels of Marcellus shale gas. After vertical drilling reaches the depth of the shale, the shale formation is penetrated horizontally with lateral lengths extending thousands of feet to ensure maximum contact with the gas-bearing seam. Hydraulic fracturing is then used to increase permeability that in turn increases the gas flow.

In this study, life cycle greenhouse gas (GHG) emissions associated with the Marcellus shale gas production are estimated. The difference between GHG emissions of natural gas production from unconventional Marcellus gas wells and average domestic wells is considered to help determine the environmental impacts of the development of shale gas resources. The results of this analysis are compared with life cycle GHG emissions of average domestic natural gas pre-Marcellus and imported liquefied natural gas. In addition domestic coal and Marcellus shale for electricity generation are compared. Other environmental issues may also be of concern in the Marcellus shale development, including disruption of natural habitats, the use of water and creation of wastewater as well as the impacts of truck transport in rural areas. However these environmental issues are outside the scope of our analysis and are not addressed in this paper.

In estimating GHG emissions, we include GHG emissions of carbon dioxide, methane and nitrous oxide. We converted the GHG emissions to carbon dioxide equivalents according to the global warming potential (GWP) factors reported by IPCC. We use the 100-year GWP factor, in which methane has a global warming potential (GWP) 25 times higher than carbon dioxide (IPCC 2007).

2. Marcellus shale gas analysis boundaries and functional unit

The boundary of our analysis and the major process steps included in our estimates are shown in figure 2. Final life cycle emission estimates are reported in grams of carbon dioxide equivalent emissions per megajoule of natural gas (g CO_2e/MJ) produced. Each of the individual processes in the natural gas life cycle has an associated upstream supply chain and is included in this study to provide a full assessment of GHG emissions associated with Marcellus shale gas. The sources of GHG emissions considered in the LCA include: emissions from the production and transportation of material involved in the well development activities (such as trucking water); emissions from fuel consumption for powering the drilling and fracturing equipment; methane leaks and fuel combustion emissions associated with gas production, processing, transmission, distribution, and natural gas combustion.

The life cycle of Marcellus shale natural gas begins with a 'preproduction phase' that includes the well site investigation, preparation of the well pad including grading and construction of the well pad and access roads, drilling, hydraulic fracturing, and well completion (Soeder and Kappel 2009). After this preproduction phase is completed, the well becomes operational and starts producing natural gas. This natural gas can require additional processing to remove water, CO_2 and/or

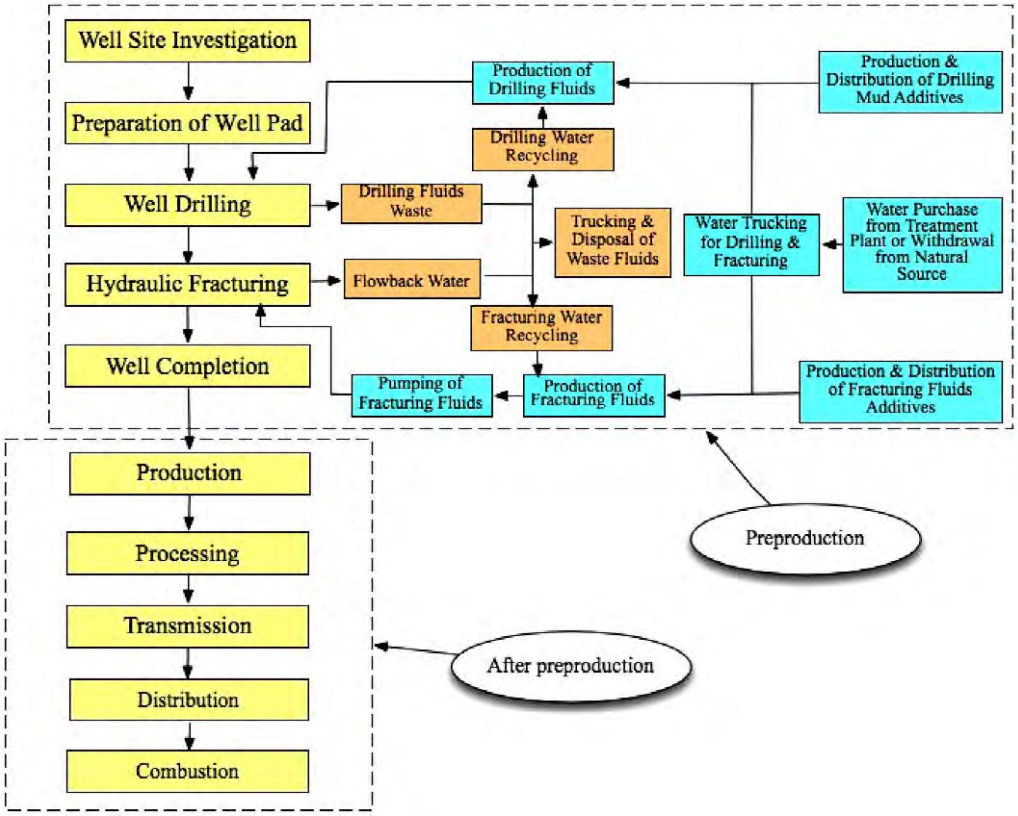

Figure 2. Analysis boundaries and gas production processes.

natural gas liquids before it enters the natural gas transmission and distribution system, which delivers it to final end users. For this work we assume that the GHG emissions for production, transmission, distribution and combustion of Marcellus shale natural gas are similar to average domestic gas sources as estimated by Jaramillo *et al* (2007) and further developed and updated by Venkatesh *et al* (2011).

Finally, natural gas has many current and potential uses including electricity generation, chemical feedstock, and as a transportation fuel. Modeling these uses allows comparisons of different primary energy sources. Here we model its use for power generation since it is the largest single use of natural gas in the US (US EIA 2011a, 2011b).

As previously mentioned, this study integrates GHG emissions from the life cycle of water associated with Marcellus shale gas production. Large amounts of water are consumed in the drilling and hydraulic fracturing processes (preproduction phase). Hydraulic fracturing uses fluid pressure to fracture the surrounding shale. The fracturing fluid consists of water mixed with a number of additives necessary to successfully fracture the shale seam. The source of the water varies and can be surface or ground water, purchased from a local public water supplier, or reused fracturing water. In this study we assume 45% of the water is reused on site and the original sources are surface water (50%) and purchased from a local water treatment plant (50%). Regardless of the water source used to produce the hydraulic fracturing fluid, trucks transport the water for impoundment at the well pad. In addition, flowback water (hydraulic fracturing fluid that returns to the surface) and produced water must be trucked to the final disposal site. This water is assumed to be disposed of via deep well injection. A detailed description of the method and data sources used to estimate the GHG emissions associated with all these stages is presented in section 3.

Marcellus shale gas production is in its infancy. Thus, industry practice is evolving and even single well longevity is unknown. Assumptions related to production rates and ultimate recovery have considerable uncertainty. Below, we include a sensitivity analysis for a wide range of inputs parameters.

This study does not consider any GHG emissions outside of the Marcellus shale gas preproduction and production processes. Natural processes or development actions such as hydraulic fracturing might lead to emissions of the shale gas external to a well, particularly in the case of poorly installed well casings (Osborn *et al* 2011). Any such external leaks are not included in this study.

3. Methods for calculating life cycle greenhouse gas emissions

Our study used a hybrid combination of process activity emission estimates and economic input–output life cycle assessment estimates to estimate the preproduction GHG emission estimates (Hendrickson *et al* 2006, CMU GDI 2010). Emissions from production, processing and transport were adapted from the literature. We include emissions estimates based on different data sources and reasonable

Table 1. Greenhouse gas estimation approaches and data sources.

Process	Estimation approaches	Data sources
Preparation of Well Pad:		
Vegetation clearing	Estimated area cleared multiplied by vegetative carbon storage to obtain carbon loss due to land use change	NY DEC (2009), Tilman *et al* (2006)
Well pad construction	Detailed cost estimate and EIO-LCA model	RSMeans (2005), CMU GDI (2010)
Well drilling:		
Drilling energy consumption	(1) Energy required and emission factor, and (2) cost estimate and EIO-LCA model	Harper (2008), Sheehan *et al* (2000), CMU GDI (2010)
Drilling mud production	(1) Cost estimate and EIO-LCA and (2) emission factors multiplied by quantity.	Shaker (2005), PRé Consultants (2007), CMU GDI (2010)
Drilling water consumption	Trucking emissions plus water treatment emissions multiplied by quantity	Wang and Santini (2009), URS Corporation (2010), PA DEP (2010), Stokes and Horvath (2006)
Hydraulic fracturing:		
Pumping	Pumping energy multiplied by emission factor	URS Corporation (2010), Kargbo *et al* (2010), Currie and Stelle (2010), Sheehan *et al* (2000)
Additives production	Additive quantities cost and EIO-LCA model	URS Corporation (2010), CMU GDI (2010)
Water consumption	Trucking emissions	Wang and Santini (2009), URS Corporation (2010), Stokes and Horvath (2006), PA DEP (2010)
Well completion:	If flaring, gas flow emission factor multiplied by flaring time	NY DEC (2009), PA DEP (2010)
Wastewater disposal:		
Deep well injection	Deep well injection costs and EIO-LCA model	US ACE (2006), CMU GDI (2010)
Production, processing, transmission and storage, and combustion	Assumed comparable to national average	Venkatesh *et al* (2011)

ranges of process parameters. Table 1 summarizes estimation approaches used in this study, while calculation details appear in the supplementary information (available at stacks.iop.org/ERL/6/034014/mmedia).

In section 3.1, we report point estimates of GHG emissions for a base case. In section 5, we report range estimates and consider the sensitivity of point estimates to particular assumptions. Table 2 summarizes important parameter assumptions and possible ranges. Uniform or triangular distributions are assigned to these parameters based on whether we had two (uniform) or three (triangular) data points. When more data was available, parameters of probability distributions that best fit the data were estimated. A Monte Carlo analysis was performed using these distributions, to estimate the emissions from the various activities considered in our life cycle model.

3.1. Emissions from Marcellus shale gas preproduction

Horizontal wells are drilled on a multi-well pad to achieve higher cost-effectiveness. It is reported that a Marcellus well pad might have as few as one well per pad and as many as 16, but more typically 6–8 (ICF International 2009, NY DEC 2009, Currie and Stelle 2010). As a base case scenario, we chose to analyze the typical pad with six wells, each producing 2.7 Bcf (3.0×10^9 MJ), representing an average of 0.3 MMcf per day of gas for 25 years. Other production estimates are higher. EQT (2011), for example, provides a production estimate of 7.3 Bcf (8.1×10^9 MJ) and Range Resources at 4.4 Bcf (4.9×10^9 MJ) (Ventura 2009). Within the LCA framework the impacts are distributed across the total volume of gas produced during the lifetime of the well. Thus, the choice of using the low end ultimate recovery as the base case should be considered conservative. With Marcellus shale gas production currently in its infancy, the average production characteristics have significant uncertainty, so we perform an

Table 2. Parameter assumptions and ranges. (Note: sources for base case and range values are in table 1 and discussed in the supplementary material (available at stacks.iop.org/ERL/6/034014/mmedia).)

Parameter	Base case	Range
Area of access road (acres)	1.43	0.1–2.75
Wells per pad (number)	6	1–16
Area of well pad (acres)	5	2–6
Vertical drilling depth (ft)	8500	7000–10 000
Horizontal drilling length (ft)	4000	2000–6000
Fracturing water (MMgal/well)	4	2–6
Flowback fraction (%)	37.5	35–40
Recycling fraction (%)	45	30–60
Trucking distance between well site and water source (miles)	5	0–10
Trucking distance between well site and deep well injection facility (miles)	80	3–280
Well completion time with collection system in place (h)	18	12–24
Well completion time without collection system in place (days)	9.5	4–15
Fraction of flaring (%)	76	51–100
Initial 30 day gas flow rate (MMscf/day)	4.1	0.7–10
Average well production rate (MMscf/day)	0.3	0.3–10
Well lifetime (years)	25	5–25

extensive sensitivity analysis over a range of flow rates and well lifetimes, as discussed below.

The EIO-LCA (CMU GDI 2010) model was used to estimate GHG emissions from the construction of the access road and the multi-well pad. These costs were estimated using the utility price cost estimation method (RSMeans 2005). The size of an average Marcellus well pad is reported as being between 2 and 6 acres and typically between 4 and 5 acres (16 000 and 20 000 m^2) during drilling and fracturing phase (NY DEC 2009, Columbia University 2009). The costs of constructing this pad are estimated to be \$3.0–\$3.3 million per well pad in 2002 dollars (see the supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for detail). Using these costs as input, GHG emissions associated with well pad construction are estimated with the EIO-LCA (CMU GDI 2010) model.

Greenhouse gas emissions associated with drilling operations were calculated by two methods; (1) using the drilling energy intensity (table 1) and the life cycle diesel engine emissions factor of 635 g CO_2e per hp–hr output (Sheehan *et al* 2000), and (2) using drilling cost data and the EIO-LCA model (CMU GDI 2010). The EIA estimated the average drilling cost for natural gas wells in 2002 to be \$176 per foot (including the cost for drilling and equipping the wells and for surface producing facilities) (US EIA 2008). Emissions associated with the production of the drilling mud components were based on data from the SimaPro life cycle tool and the EIO-LCA economic model (PRé Consultants 2007, CMU GDI 2010).

Hydraulic fracturing associated GHG emissions result from the operation of the diesel compressor used to move and compress the fracturing fluid to high pressure, the emissions associated with the production of the hydraulic fracturing fluid, and from fugitive methane emissions as flowback water is captured. The last category of emissions is discussed separately below. Energy and emissions associated with the hydraulic fracturing process were modeled by using vendor specific diesel data along with the emission factor described above. The emissions of hydraulic fracturing fluid production are estimated with EIO-LCA model, based on the price of additives and fracturing fluid composition (see supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for detail).

There may be significant GHG emissions as a result of flaring and venting activities that occur during well casing and gathering equipment installation. The natural gas associated with the hydraulic fracturing flowback water is flared and vented. Flaring is used for testing the well gas flow prior to the construction of the gas gathering system which transport the gas to the sales line. Well completion emissions depend on the flaring/venting time, gas flow rate during well completion, the ratio of flaring to venting, and flaring efficiency. Uncertainty/variability analysis was conducted to investigate the effect of flaring/venting time, gas flow rate during fracturing water flowback, and flaring per cent on the well completion emissions. For those well completions with the collection facilities in place, gas is flared for between 12 and 24 h, due to necessary flowback operations. In wells where the appropriate gas gathering system as a tie to the gas sales line is not available for the gas during fracturing water flowback, the flaring or venting can occur for between 4 and 15 days as shown in table 2 (NY DEC 2009). In our model, we assumed the gas release rate during well completion equals the initial 30 day gas production rate for the base case and considered a scenario with both venting and flaring (see supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for details).

3.2. Emissions from Marcellus shale gas production to combustion

GHG emissions for production, processing, transmission, distribution and combustion of Marcellus shale natural gas are assumed to be similar to the US average domestic gas system that have been estimated previously (Jaramillo *et al* 2007). Jaramillo *et al* (2007) estimates were updated to include the uncertainty and variability in life cycle estimates and recalculated with recent and/or more detailed information by Venkatesh *et al* (2011). The GHG emissions from these life cycle stages consist of vented methane (gas release during operation), fugitive methane (unintentional leaks) and CO_2 emissions from the processing plants and from fuel consumption. Methane leakage rates throughout the natural gas system (excluding the preproduction processes previously discussed) are a major concern and our analysis has an implied fugitive emissions rate of 2%, consistent with the EPA natural gas industry study (US EPA 1996, 2010).

Venkatesh *et al* (2011) estimated the mean emission factors used in this study: 9.7 g CO_2e/MJ of natural gas in production; 4.3 g CO_2e MJ for processing; 1.4 g CO_2e/MJ for transmission and storage; 0.8 g CO_2e/MJ for distribution; and 50 g CO_2e/MJ for combustion.

3.3. Emissions associated with the life cycle of water used for drilling and hydraulic fracturing

Water resource management is a critical component of the production of Marcellus shale natural gas. Chesapeake Energy (2010) indicates that 100 000 gallons of water are used for drilling mud preparation. Two to six million gallons of water per well are required for the hydraulic fracturing process (Staaf and Masur 2009). About 85% of the drilling mud is reused (URS Corporation 2010). The flowback and recycling rates are used to estimate the total volume of water required. About 60–65% of this hydrofracturing fluid is recovered (URS Corporation 2010). For the flowback water, a recycle rate from 30 to 60% can be achieved (Agbaji *et al* 2009). The rest of the flowback water is temporarily stored in the impoundment and transported off site for disposal. Base case assumptions for these parameters are shown in table 2.

Emissions associated with drilling water use and hydraulic fracturing water use result from water taken from surface water resources or a local public water system; truck transport to the well pad, and then from the pad to disposal via deep well injection. It is assumed that no GHG emissions are related

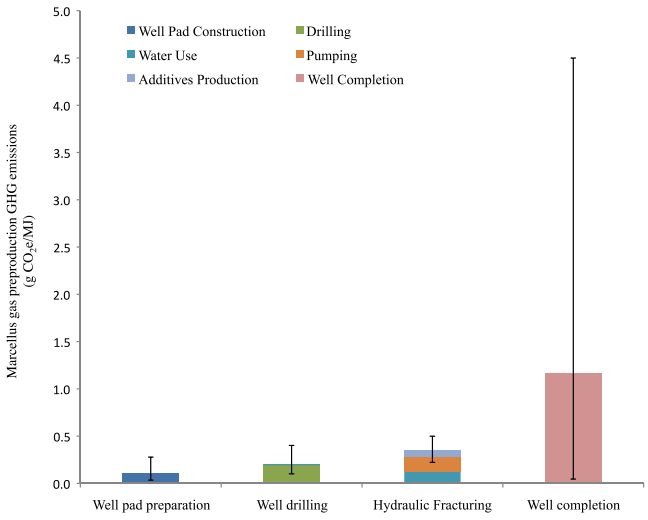

Figure 3. GHG emissions from different stages of Marcellus shale gas preproduction.

with producing water if it comes from surface water resources. For the water purchased from a local public water system, the emission factor for water treatment is used, which is estimated to be 3.4 g CO_2e/gallon of water generated according to Stokes and Horvath (2006). The energy intensity for transportation of liquids via truck is assumed to be 1028 Btu/ton mile for both forward and back-haul trips, as given in the GREET model (Wang and Santini 2009). In this study we assume that separate round trips are needed to transport the freshwater to the pad and to remove wastewater to the disposal site. This is to say that trucks bring in the freshwater from the source and return to the source empty; trucks also collect the wastewater from the well site and return to the well site empty. The life cycle emission factor (wells to wheels) for diesel as a transportation fuel is 93 g CO_2e/MJ (Wang and Santini 2009).

To estimate transport emissions associated with water taken from surface streams and water purchased from the local public water system, we used spatial analysis (ArcGIS) to estimate the distance from the surface water source to the well pad using well operational data and geographical information from Pennsylvania Department of Environmental Protection (2010). We depicted the overall distribution pattern of Marcellus wells under drilling and production in PA and NY in June 2010 by GIS. The distance from the well site to the surface water source is assumed to be 5 miles or 8 km in the base case of the model and the same transportation distance is also assumed for the water purchased from local public water system. We assumed an equal probability for sourcing water between surface water and the local public water system.

The trucking distance between well site and deep well injection facility was also estimated by GIS (PA DEP 2010). The average value of 80 miles or 130 km as determined by GIS was used in the base case.

4. Results for the base case

A total of 5500 t CO_2e is emitted during 'preproduction' per well. This is equivalent to 1.8 g CO_2e/MJ of natural gas produced over the lifetime of the well. Figure 3 depicts the GHG emissions by preproduction stage and by source. As can be seen, the completion stage has the largest GHG emissions, which result from flaring and/or venting. The error bars represent the limits of the 90% confidence interval of the emissions from each stage based on the uncertainty analysis.

A recent EPA report addressing emissions from the natural gas industry reported that 177 t of CH_4 is released during the completion of an unconventional gas well (US EPA 2010). This estimate is consistent with the analysis here and falls within the range estimated by our study, 26–1000 t of CH_4 released per completion and a mean value of 400 t of CH_4 released per completion. In our model, this methane released during the well completion is either flared with a combustion efficiency of 98% or vented without recovery.

Adding the preproduction emissions estimate to the downstream emission estimated by Venkatesh *et al* (2011) results in an overall GHG emissions factor of 68 g CO_2e/MJ of gas produced (figure 4). The life cycle emissions are dominated by combustion that accounts for 74% of the total emissions.

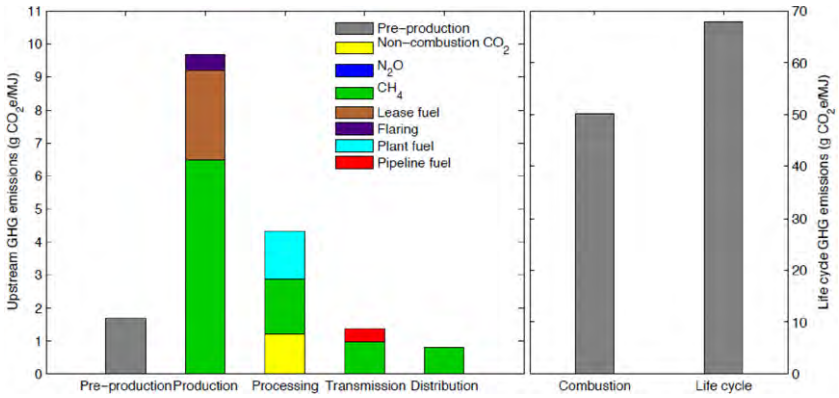

Figure 4. GHG emissions through the life cycle of Marcellus shale gas. (Preproduction through distribution emissions are on left scale; combustion and total life cycle emissions are on right scale. No carbon capture is included after combustion.)

Table 3. Uncertainty analysis on Marcellus gas preproduction.

Life cycle stage	Mean (g CO_2e/MJ)	Standard deviation (g CO_2e/MJ)	COV	90% CI-L (%)	90% CI-U (%)
Well pad preparation	0.13	0.1	0.72	58	131
Drilling	0.21	0.1	0.50	51	95
Hydraulic fracturing	0.35	0.1	0.24	37	42
Completion	1.15	1.8	1.53	96	287
Total	1.84	1.8	0.96	67	179

Table 4. Sensitivity of emissions from wells with different production rates and lifetimes. (Source: author calculations.)

Average gas flow (MMscf/day)	Lifetime (years)	Emissions from preproduction (g CO_2e/MJ)	Preproduction % contribution to life cycle emissions of Marcellus shale gas (%)	Total life cycle emissions (g CO_2e/MJ)
10	25	0.1	0.1	65.3
10	10	0.1	0.2	65.3
10	5	0.3	0.4	65.5
3	25	0.2	0.3	65.4
3	10	0.5	0.7	65.7
3	5	0.9	1.4	66.1
1	25	0.6	0.8	65.8
1	10	1.4	2.1	66.6
1	5	2.8	4.1	68.0
0.3	25	1.8	2.7	67.0
0.3	10	5	6.6	69.8
0.3	5	9.2	12.4	74.4

5. Sensitivity and uncertainty

Our results are subject to considerable uncertainty, particularly for the production rates and well lifetime. Table 3 summarizes the uncertainty analysis on the emission estimates for preproduction based on the distribution of parameters used.

Table 4 addresses model sensitivity to different estimates of ultimate gas recovery from wells, investigating the impact of different production rates and lifetimes. At high production rates and long well lifetimes the preproduction GHG emissions are normalized over higher volumes of natural gas than when using low flow rates and short well lifetimes. Comparing the case of 10 MMscf/day with a 25-year well lifetime to 0.3 MMscf/day with a 5-year well lifetime, table 4 shows that the emissions go from 0.1 to 9.2 g CO_2e/MJ. The overall life cycle emissions change from 65 to 74 g CO_2e/MJ. However, the preproduction emissions are less than 15% of the total life cycle emissions in all cases.

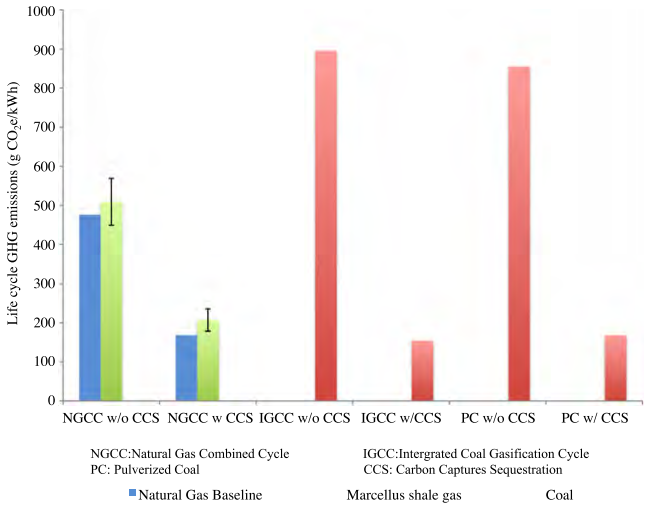

Figure 5. Comparison of life cycle GHG emissions from current domestic natural gas, Marcellus shale gas and coal for use in electricity production.

6. Comparison with coal for power generation

Marcellus shale gas emissions can be compared to alternative energy sources and processes when using a common metric such as electricity generated. Currently coal power plants are used to generate base load. Natural gas power plants, especially inefficient ones, are used to provide regulation services to balance supply and demand at times when base load power plants are insufficient or there is high-frequency variability in load or from renewable resources. Natural gas combined cycle (NGCC) plants could be used to generate base load thus competing directly with coal to provide this service. For this reason our comparison includes the emissions associated with using Marcellus shale gas in a NGCC power plant (efficiency of 50%) and the emissions from using coal in pulverized coal (PC) plants (efficiency of 39%) and integrated gasification combined cycle (IGCC) plants (efficiency of 38%). The results of these comparisons can be seen in figure 5. For this comparison point values are used for the life cycle GHG emissions of coal-based electricity. The error bars found in figure 5 represent the low and high emissions values for Marcellus shale gas, based on the assumptions of well production rate and well lifetime. The high-emission scenario assumes a 5-year well with 0.3 MMscf/day production rate

while the low-emission scenario, assumes a 25-year well with 10 MMscf/day production rate. Also shown in figure 5 are the life cycle emissions of electricity generated in power plants with carbon capture and sequestration (CCS) capabilities (efficiency of 43% for NGCC with CCS; efficiency of 30% for PC with CCS; efficiency of 33% for ICGG with CCS).

In general, natural gas provides lower greenhouse emission for all cases studied whether the gas is derived from Marcellus shale or the average 2008 domestic natural gas system. When advanced technologies are used with CSS then the emissions are similar and coal provides slightly less emissions. This implies that the upstream emissions for natural gas life cycle are higher than the upstream emissions from coal, once efficiencies of power generation are taken into account (Jaramillo *et al* 2007).

The comparison of natural gas and coal for electricity allows us to investigate the impact of three additional model uncertainty components including the choice of leakage rate, GWP values, and re-refracking of a Marcellus gas well. This study assumes a 2% production phase leakage rate based on the volume of gas produced (US EPA 2010, Venkatesh *et al* 2011). Assuming the average efficiency of 43% for natural gas fired electricity generation and 32% for coal fired plants the fugitive emissions rate would need to be 14% (resulting in a life cycle emission factor for Marcellus gas of 125 g CO_2e/MJ) before the overall life cycle emissions including those of electricity generation would be greater than coal. This is an exorbitantly high leakage rate and to put it into perspective, using 2009 dry natural gas production estimates and the average wellhead price, we calculate that the economic losses a would total around $11 billion. If we convert our data to the 20-year GWP the break-even point is reduced to 7% because of the higher impacts attributed to methane. Finally, we modeled a single hydraulic fracturing event occurring during well preproduction (figure 3). Above we calculated that the break-even emission factor that would make coal and natural electricity generation the same is 125 g CO_2e/MJ of natural gas. With the current emissions estimate for Marcellus gas of 68 g CO_2e/MJ, and a hydraulic fracturing event (and its associated flaring and venting emissions) contributing 1.5 g CO_2e/MJ to this estimate, more than 25 fracturing events would need to occur in a single well before the decision between coal and natural gas would change.

7. Comparison with liquefied natural gas as a future source

In 2005 EIA suggested that domestic natural gas production and Canadian imports would decline as natural gas consumption increased. EIA predicted that liquefied natural gas (LNG) imports would grow to offset the deficits in North American production (US EIA 2011a, 2011b). As a result of the development of unconventional natural gas reserves, EIA has changed their projections. The Annual Energy Outlook 2011 reference case (US EIA 2011a, 2011b) predicts that increases in shale gas production, including Marcellus, will more than offset the decline in conventional natural gas and decreasing imports from Canada and will allow for increases in natural gas consumption. Since shale gas is projected to be the largest component of the unconventional sources of future natural gas production, it seem appropriate to compare its emissions to those of the gas that would be used if shale gas were not produced. Venkatesh *et al* (2011) estimated the life cycle GHG from LNG imported to the US to have a mean of 70 g CO_2e/MJ, These results are based on emissions due to production and liquefaction in the countries of origin, shipping the gas to the US by ocean tanker, regasification in the US and its transmission, distribution and subsequent combustion. On average, the emissions of Marcellus shale gas were about 3% lower than LNG. As with the overall Marcellus gas results, there is considerable uncertainty to the comparisons. However, we conclude that as these unconventional sources of natural gas supplant LNG imports, overall emissions will not rise.

8. Conclusion

The GHG emission estimates shown here for Marcellus gas are similar to current domestic gas. Other shale gas plays could generate different results considering regional environmental variability and reservoir heterogeneity. Green completion and capturing the gas for market that would otherwise be flared or vented, could reduce the emissions associated with completion and thus would significantly reduce the largest source of emissions specific to Marcellus gas preproduction. These preproduction emissions, however, are not substantial contributors to the life cycle estimates, which are dominated by the combustion emissions of the gas. For comparison purposes, Marcellus shale gas adds only 3% more emissions to the average conventional gas, which is likely within the uncertainty bounds of the study. Marcellus shale gas has lower GHG emissions relative to coal when used to generate electricity.

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NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States

Timothy J. Skone, P.E.

Office of Strategic Energy Analysis and Planning

May 12, 2011

Presented at: Cornell University Lecture Series

U.S. DEPARTMENT OF ENERGY

Overview

1. Who is NETL?
2. What is the role of natural gas in the United States?
3. Who uses natural gas in the U.S.?
4. Where does natural gas come from?
5. What is the life cycle GHG footprint of domestic natural gas extraction and delivery to large end-users?
6. How does natural gas power generation compare to coal-fired power generation on a life cycle GHG basis?
7. What are the opportunities for reducing GHG emissions?

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Who is NETL?

National Energy Technology Laboratory

MISSION

Advancing energy options to fuel our economy, strengthen our security, and improve our environment

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Pennsylvania

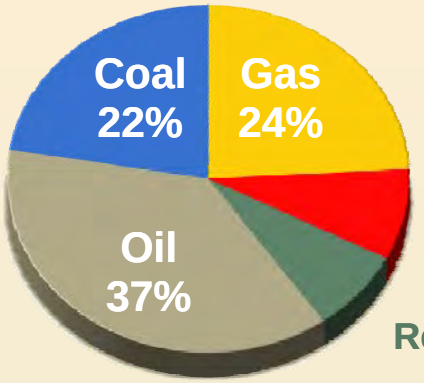
West Virginia

Question #2:

What is the role of natural gas in the United States?

Energy Demand 2008

100 QBtu / Year
84% Fossil Energy



Nuclear
8%

Renewables
8%

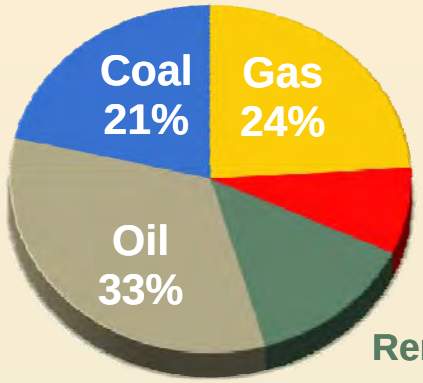
5,838 mmt CO_2

+ 14%

United States

Energy Demand 2035

114 QBtu / Year
78% Fossil Energy

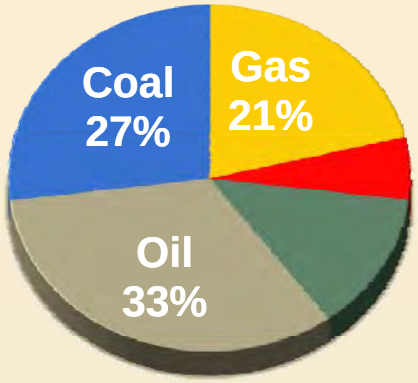


Nuclear
8%

Renewables
14%

6,311 mmt CO_2

487 QBtu / Year
81% Fossil Energy



Nuclear
6%

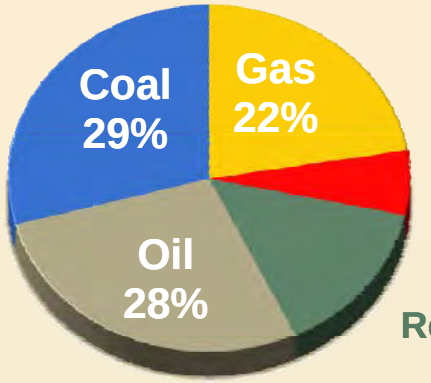
Renewables*
13%

29,259 mmt CO_2

+ 47%

World

716 QBtu / Year
79% Fossil Energy



Nuclear
8%

Renewables*
15%

42,589 mmt CO_2

Sources: U.S. data from EIA, Annual Energy Outlook 2011; World data from IEA, World Energy Outlook 2010, Current Policies Scenario

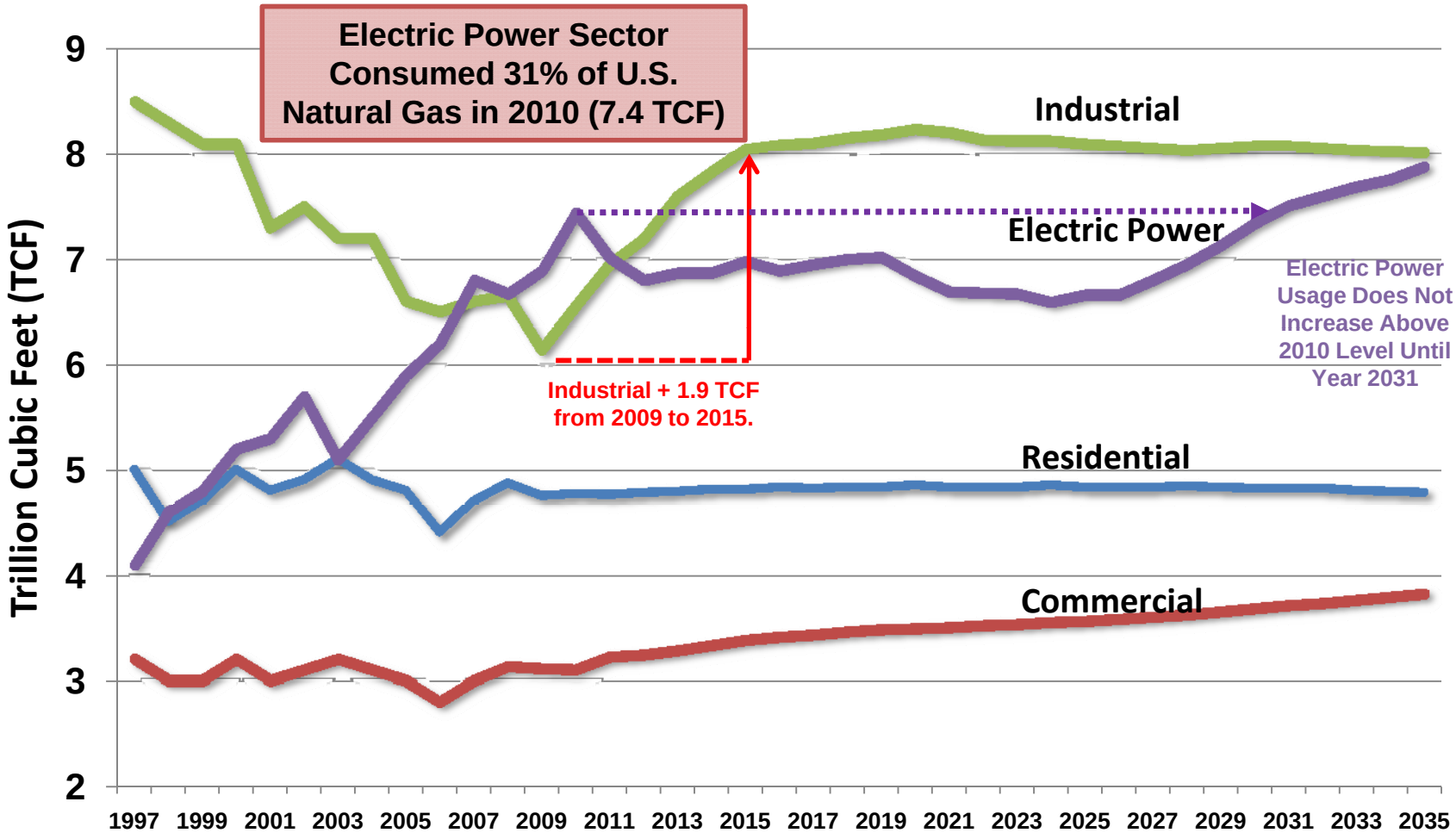
* Primarily traditional biomass, wood, and waste.

Question #3:

Who uses natural gas in the United States?

Domestic Natural Gas Consumption

Sectoral Trends and Projections: 2010 Total Consumption = 23.8 TCF



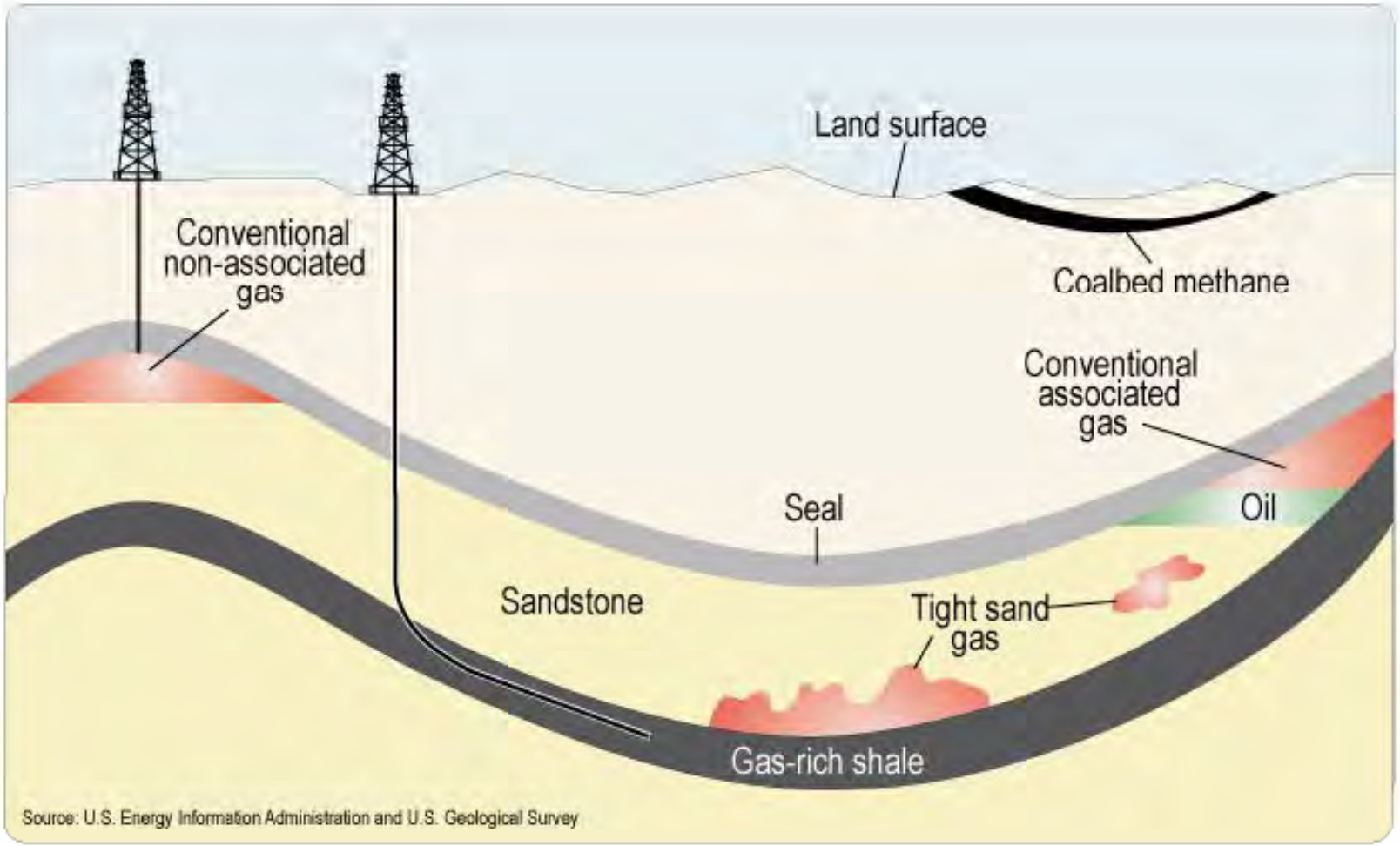
+1.9 TCF Resurgence in Industrial Use of Natural Gas by 2015 Exceeds the Net Incremental Supply; No Increase in Natural Gas Use for Electric Power Sector Until 2031

Source: EIA Annual Energy Review 2009 and Annual Energy Outlook 2011

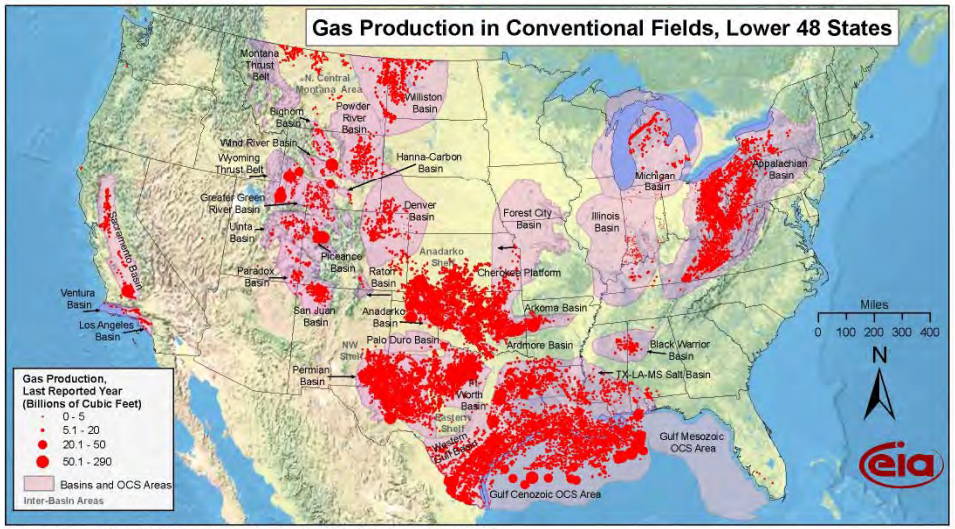
Question #4:

Where does natural gas come from?

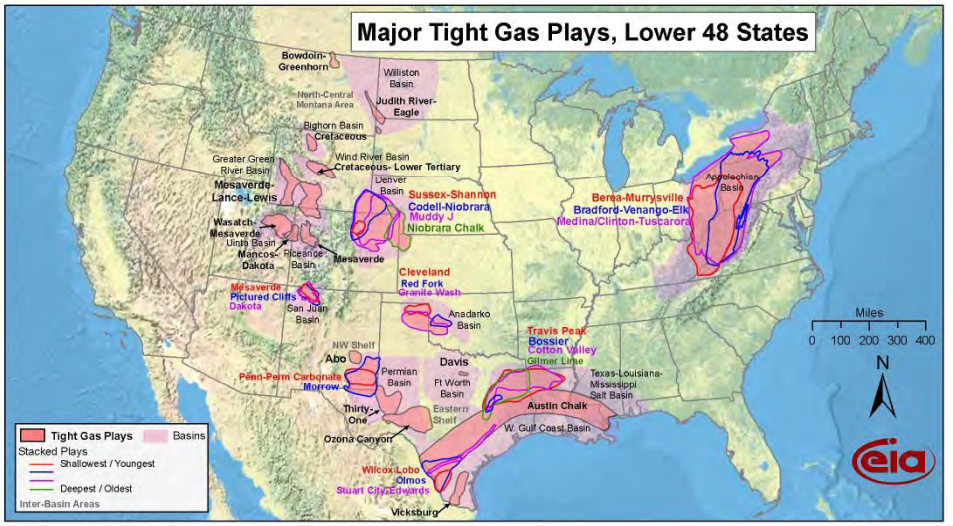
Schematic Geology of Onshore Natural Gas Resources



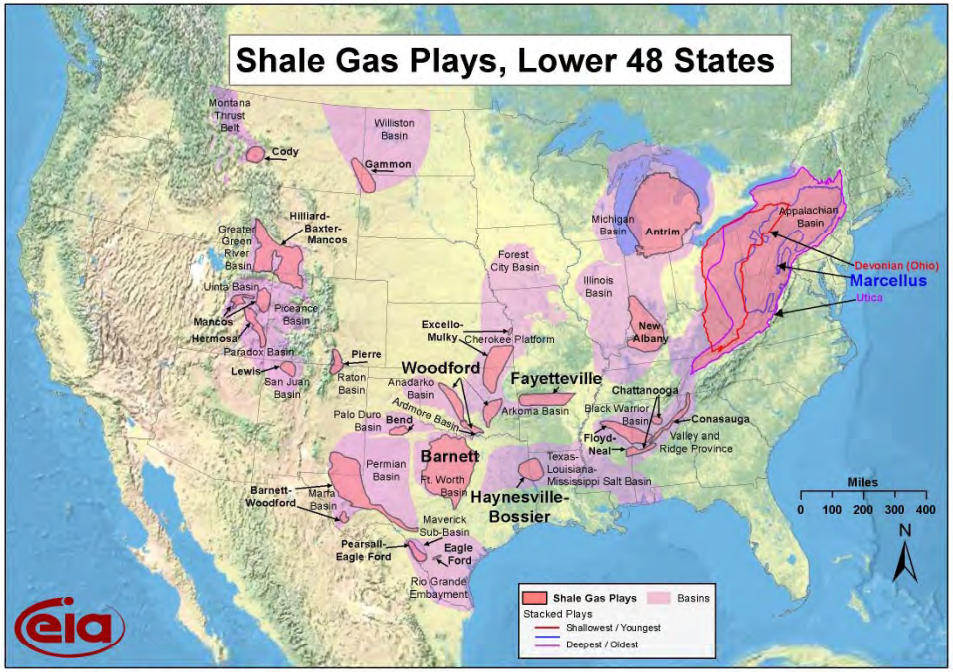
Source: EIA, Today in Energy, February 14, 2011; Modified USGS Figure from Fact Sheet 0113-01; www.eia.doe.gov/todayinenergy/detail.cfm?id=110 Last Accessed May 5, 2011.



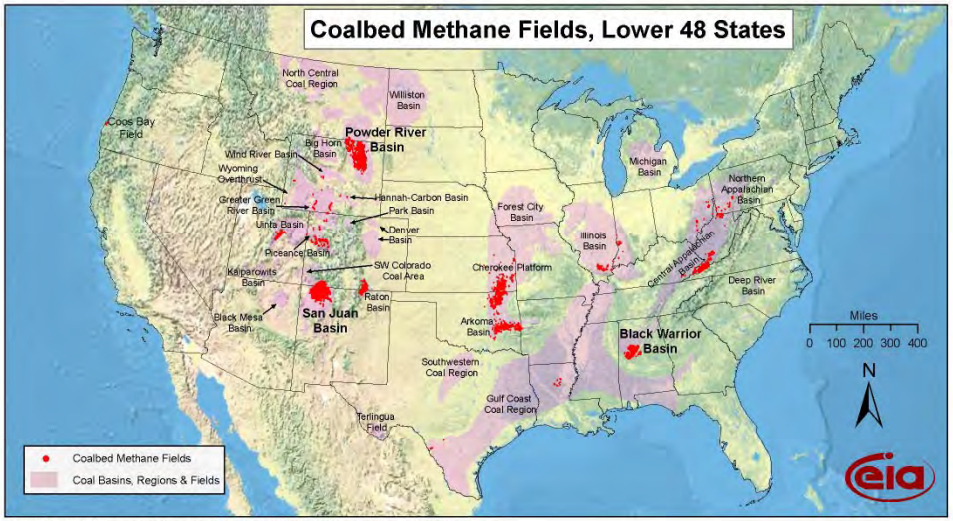
Source: Energy Information Administration based on data from HPDI, IN Geological Survey, USGS
Updated: April 8, 2009



Source: Energy Information Administration based on data from various published studies
Updated: June 6, 2010



Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010



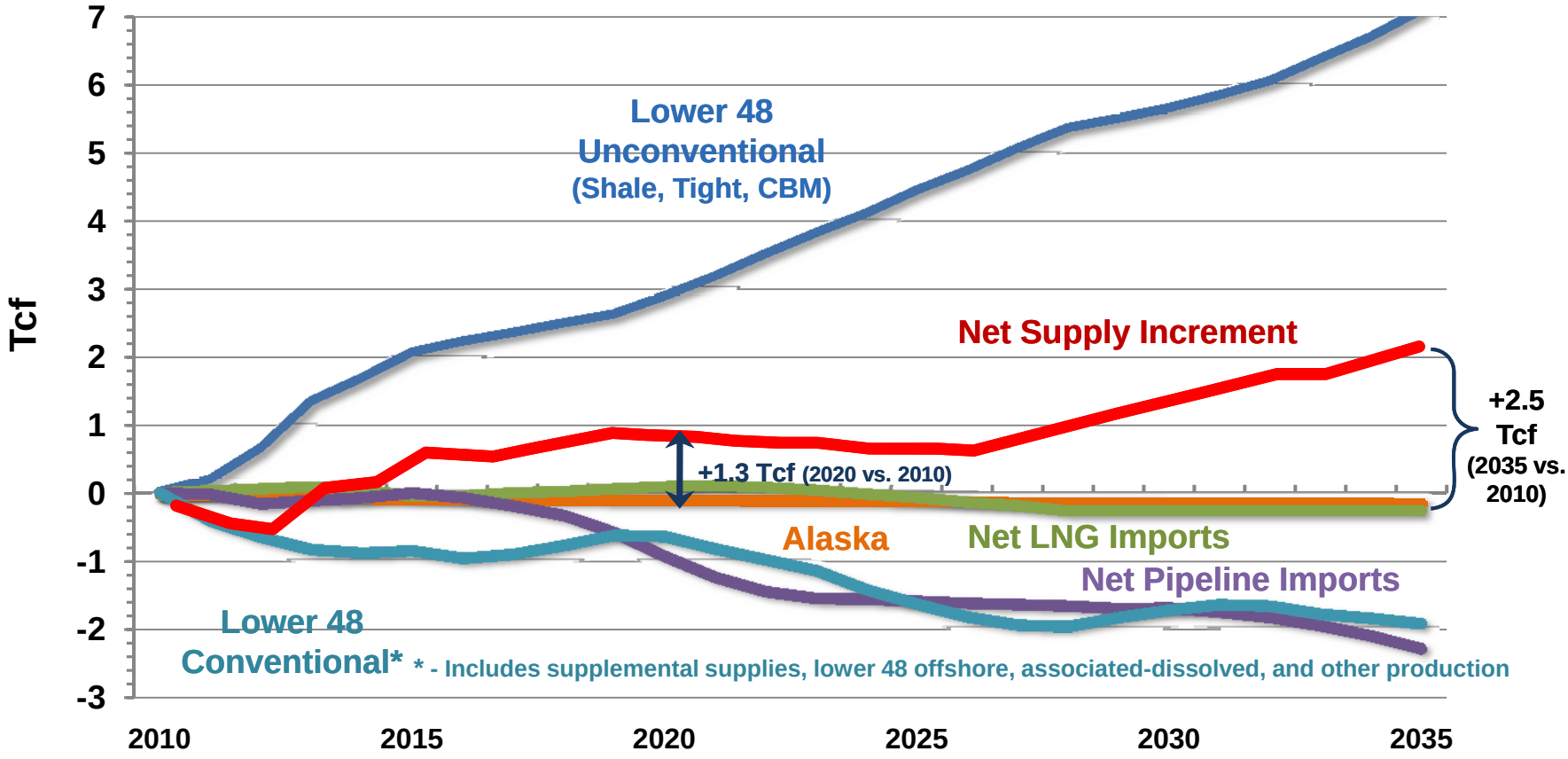
Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

EIA Natural Gas Maps

Source: EIA, Natural Gas Maps, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm Last Accessed May 5, 2011.

Sources of Incremental Natural Gas Supply

(Indexed to 2010)



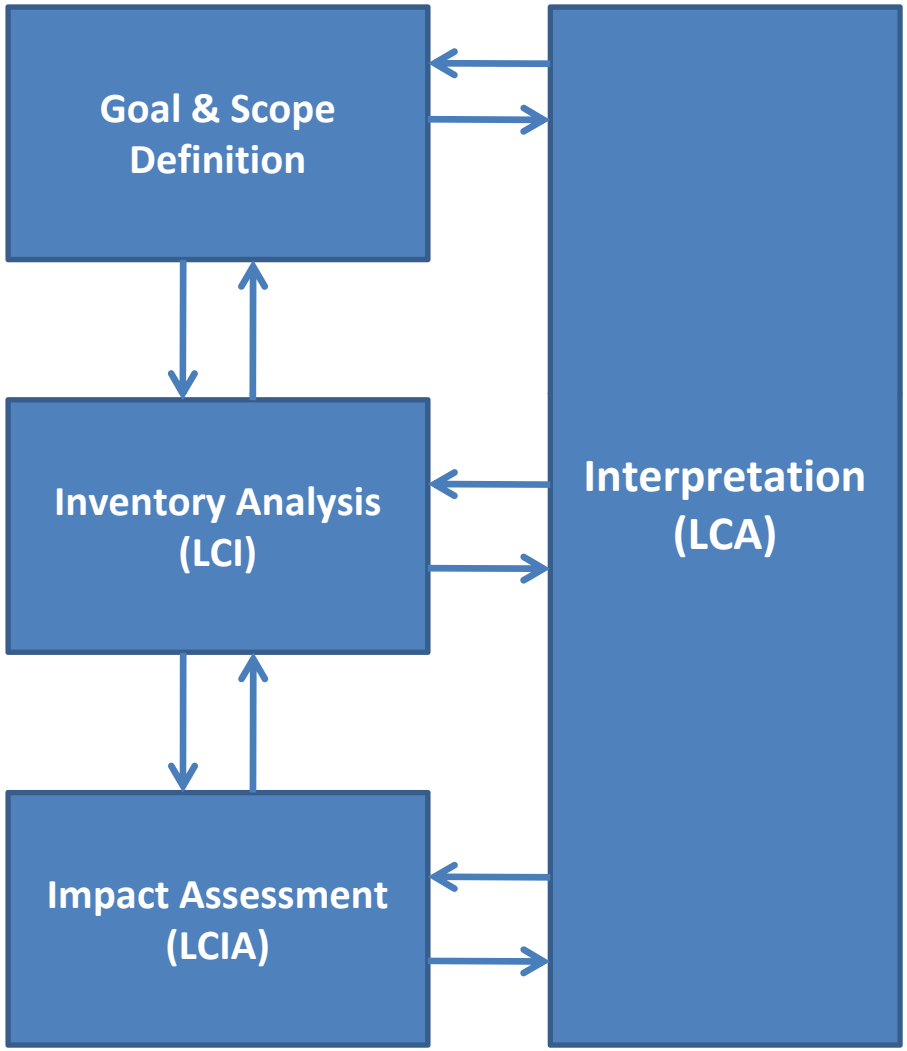
Unconventional Production Growth Offset by Declines in Conventional Production and Net Pipeline Imports; 1.3 Tcf Increment by 2020 Does Not Support Significant Coal Generation Displacement

Source: EIA, Annual Energy Outlook 2011

Question #5:

What is the life cycle GHG footprint of domestic natural gas extraction and delivery to large end-users?

Overview: Life Cycle Assessment Approach



Source: ISO 14040:2006, Figure 1 – Stages of an LCA (reproduced)

The Type of LCA Conducted Depends on Answers to these Questions:

1. What Do You Want to Know?
2. How Will You Use the Results?

International Organization for Standardization (ISO) for LCA

- ISO 14040:2006 Environmental Management – Life Cycle Assessment – Principles and Framework
- ISO 14044 Environmental Management – Life Cycle Assessment – Requirements and Guidelines
- ISO/TR 14047:2003 Environmental Management – Life Cycle Impact Assessment – Examples of Applications of ISO 14042
- ISO/TS 14048:2002 Environmental Management – Life Cycle Assessment – Data Documentation Format

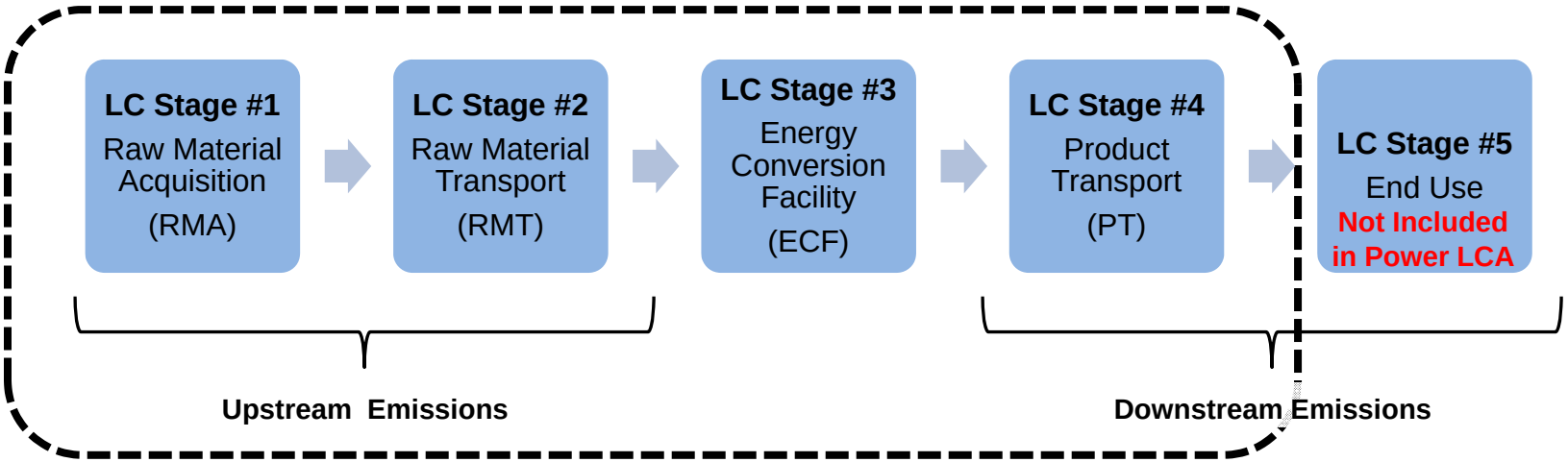
Overview: Life Cycle Assessment Approach

The Type of LCA Conducted Depends on Answers to these Questions :

1. **What Do You Want to Know?**
   - **The GHG footprint of natural gas, lower 48 domestic average, extraction, processing, and delivery to a large end-user (e.g., power plant)**
   - **The comparison of natural gas used in a baseload power generation plant to baseload coal-fired power generation on a lbs CO_2e/MWh basis**
2. **How Will You Use the Results?**
   - **Inform research and development activities to reduce the GHG footprint of both energy feedstock extraction and power production in existing and future operations**

NETL Life Cycle Analysis Approach

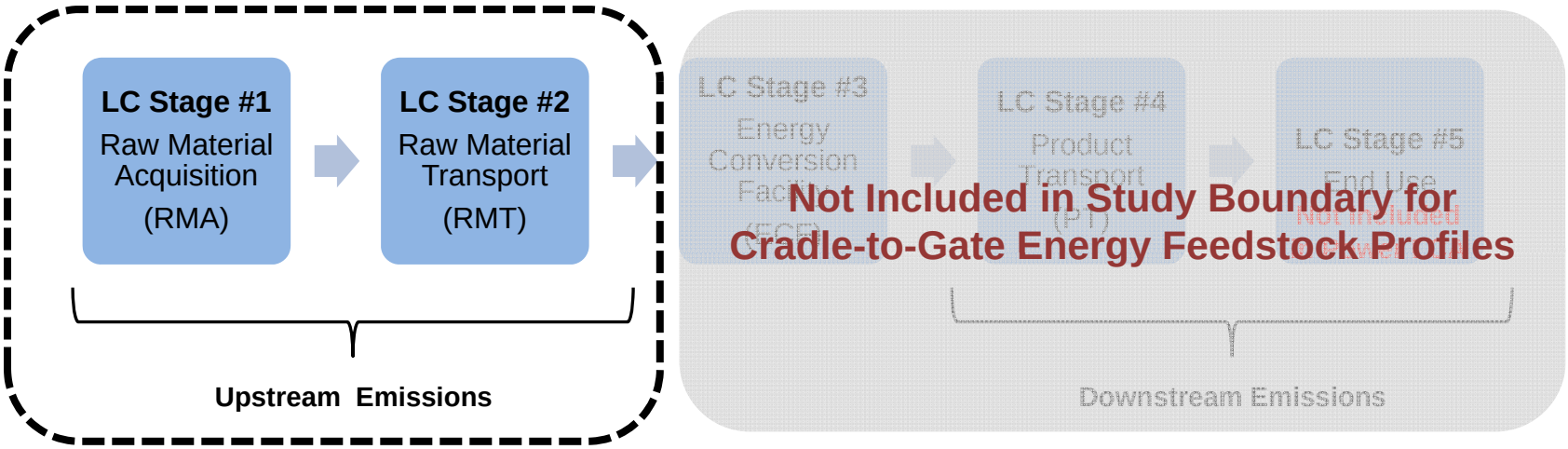
- **Compilation and evaluation of the inputs, outputs, and the potential environmental impacts of a product or service throughout its life cycle, from raw material acquisition to the final disposal**



- **The ability to compare different technologies depends on the functional unit (denominator); for power LCA studies:**
  - 1 MWh of electricity delivered to the end user

NETL Life Cycle Analysis Approach for Natural Gas Extraction and Delivery Study

- **The study boundary for "domestic natural gas extraction and delivery to large end-users" is represented by Life Cycle (LC) Stages #1 and #2 only.**



- **Functional unit (denominator) for energy feedstock profiles is:**
  - 1 MMBtu of feedstock delivered to end user
    (MMBtu = million British thermal units)

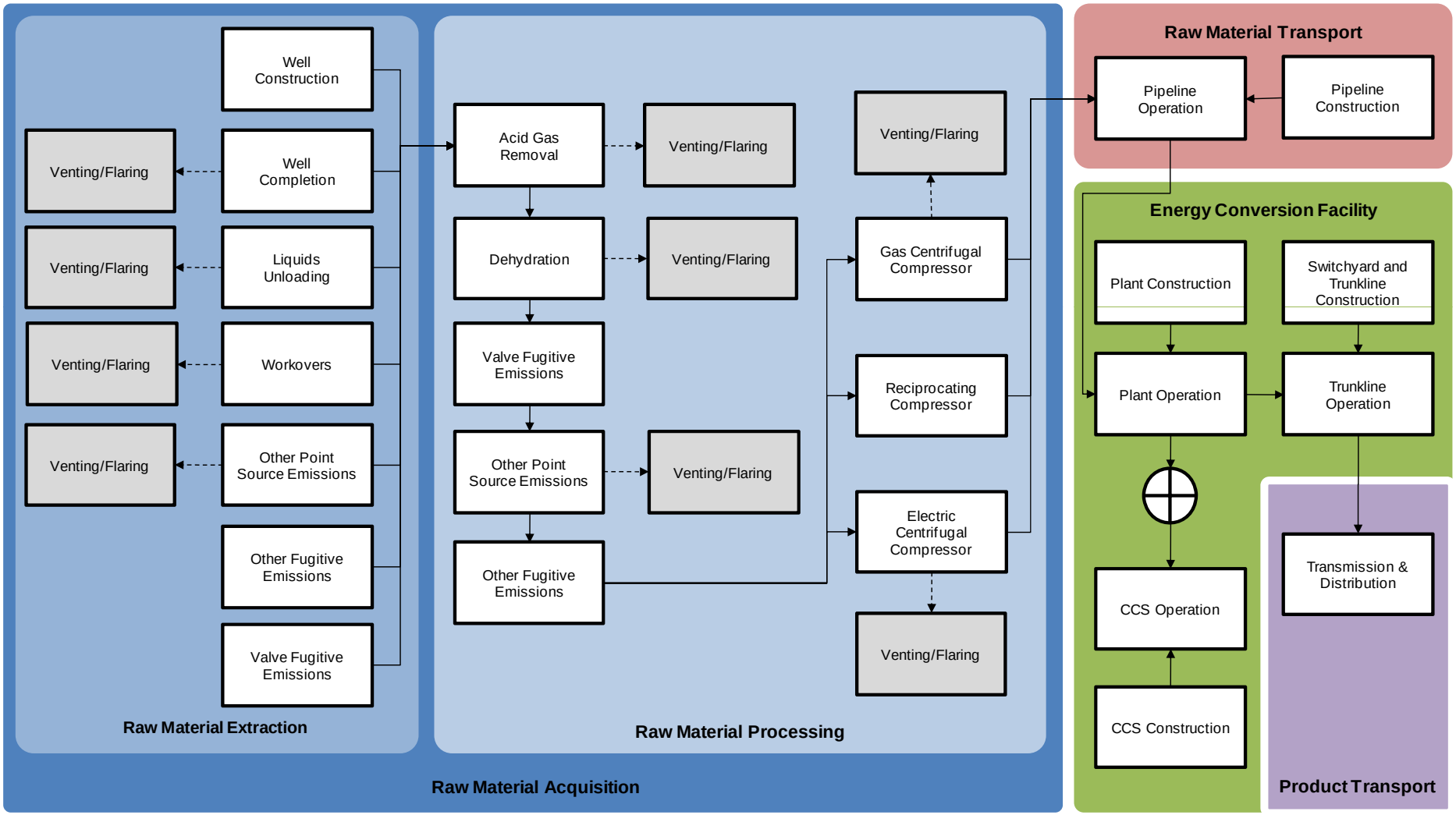
NETL Life Cycle Study Metrics

- **Greenhouse Gases**
  - CO_2, CH_4, N_2O, SF_6
- **Criteria Air Pollutants**
  - NO_X, SO_X, CO, PM10, Pb
- **Air Emissions Species of Interest**
  - Hg, NH_3, radionuclides
- **Solid Waste**
- **Raw Materials**
  - Energy Return on Investment
- **Water Use**
  - Withdrawn water, consumption, water returned to source
  - Water Quality
- **Land Use**
  - Acres transformed, greenhouse gases

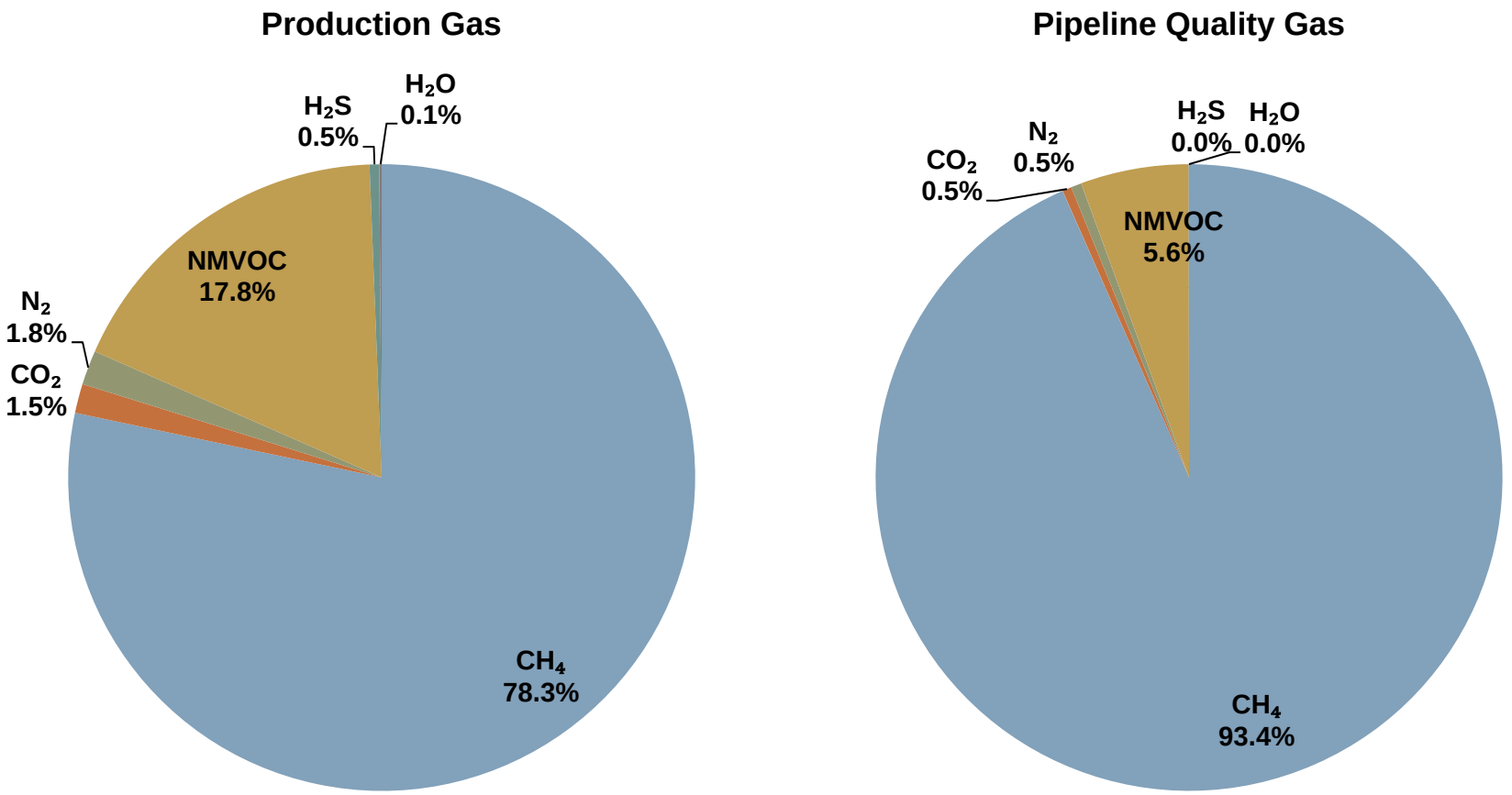
Converted to Global Warming Potential using IPCC 2007 100-year CO_2 equivalents

CO_2 = 1
CH_4 = 25
N_2O = 298
SF_6 = 22,800

NETL Life Cycle Model for Natural Gas



Natural Gas Composition by Mass



Carbon content (75%) and energy content (1,027 btu/cf) of pipeline quality gas is very similar to raw production gas (within 99% of both values)

Natural Gas Extraction Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Source							
Contribution to 2009 Natural Gas Mix	Percent	23%	7%	13%	32%	16%	9%
Estimated Ultimate Recovery (EUR), Production Gas	BCF/well	8.6	4.4	67.7	1.2	3.0	0.2
Production Rate (30-yr average)	MCF/day	782	399	6,179	110	274	20
Natural Gas Extraction Well							
Flaring Rate at Extraction Well Location	Percent	51%	51%	51%	15%	15%	51%
Well Completion, Production Gas (prior to flaring)	MCF/completion	47	47	47	4,657	11,643	63
Well Workover, Production Gas (prior to flaring)	MCF/workover	3.1	3.1	3.1	4,657	11,643	63
Well Workover, Number per Well Lifetime	Workovers/well	1.1	1.1	1.1	3.5	3.5	3.5
Liquids Unloading, Production Gas (prior to flaring)	MCF/episode	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading, Number per Well Lifetime	Episodes/well	930	n/a	930	n/a	n/a	n/a
Pneumatic Device Emissions, Fugitive	lb CH_4/MCF	0.05	0.05	0.01	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/MCF	0.003	0.003	0.002	0.003	0.003	0.003
Other Sources of Emissions, Fugitive	lb CH_4/MCF	0.043	0.043	0.010	0.043	0.043	0.043

Natural Gas Processing Plant Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Acid Gas Removal (AGR) and CO_2 Removal Unit							
Flaring Rate for AGR and CO_2 Removal Unit	Percent	100%					
Methane Absorbed into Amine Solution	lb CH_4/MCF	0.04					
Carbon Dioxide Absorbed into Amine Solution	lb CO_2/MCF	0.56					
Hydrogen Sulfide Absorbed into Amine Solution	lb H_2S/MCF	0.21					
NMVOC Absorbed into Amine Solution	lb NMVOC/MCF	6.59					
Glycol Dehydrator Unit							
Flaring Rate for Dehydrator Unit	Percent	100%					
Water Removed by Dehydrator Unit	lb H_2O/MCF	0.045					
Methane Emission Rate for Glycol Pump & Flash Separator	lb CH_4/MCF	0.0003					
Pneumatic Devices & Other Sources of Emissions							
Flaring Rate for Other Sources of Emissions	Percent	100%					
Pneumatic Device Emissions, Fugitive	lb CH_4/MCF	0.05					
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/MCF	0.02					
Other Sources of Emissions, Fugitive	lb CH_4/MCF	0.03					

Natural Gas Processing Plant Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Compression at Gas Plant							
Compressor, Gas-powered Combustion, Reciprocating	Percent	100%	100%		100%	75%	100%
Compressor, Gas-powered Turbine, Centrifugal	Percent			100%			
Compressor, Electrical, Centrifugal	Percent					25%	

Natural Gas Transmission Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Emissions on Transmission Infrastructure							
Pipeline Transport Distance (national average)	Miles	450					
Transmission Pipeline Infrastructure, Fugitive	lb CH_4/MCF-Mile	0.0003					
Transmission Pipeline Infrastructure, Fugitive (per 450 miles)	lb CH_4/MCF	0.15					
Natural Gas Compression on Transmission Infrastructure							
Distance Between Compressor Stations	Miles	75					
Compression, Gas-powered Reciprocating	Percent	29%					
Compression, Gas-powered Centrifugal	Percent	64%					
Compression, Electrical Centrifugal	Percent	7%					

Uncertainty Analysis Modeling Parameters

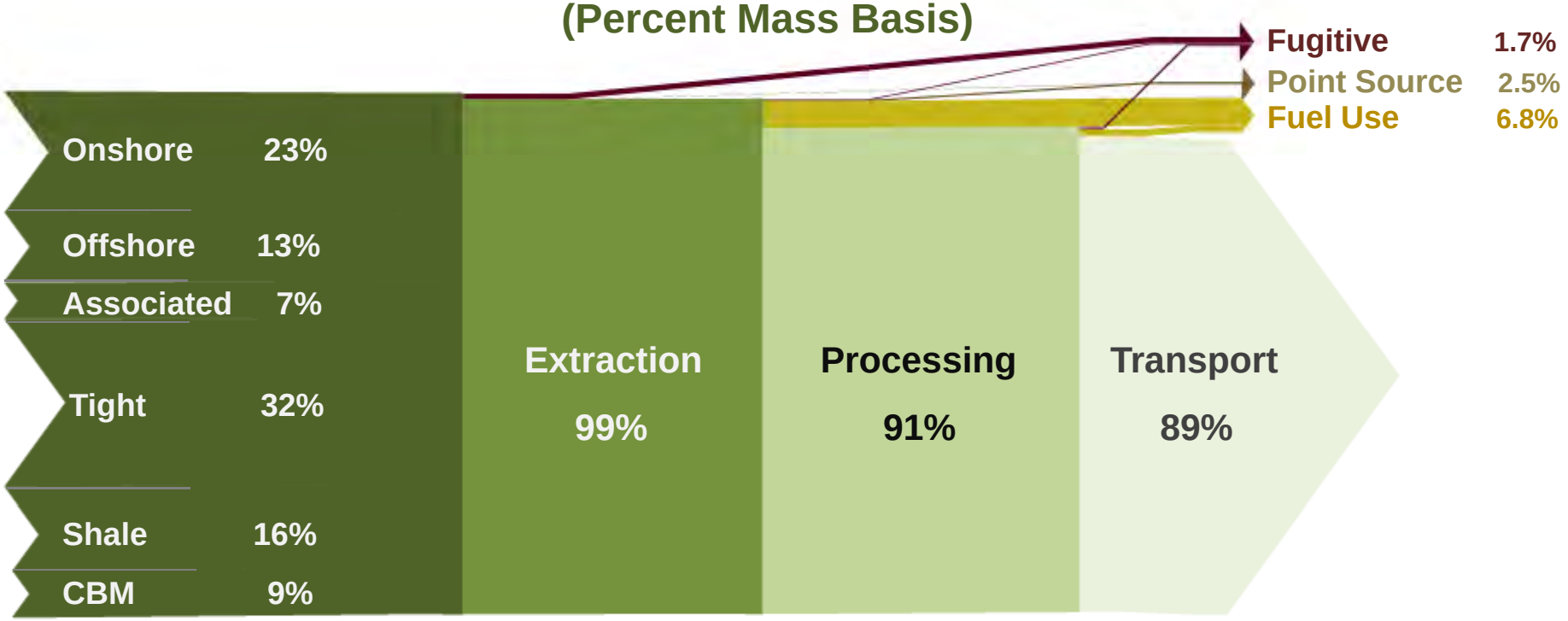
Parameter	Units	Scenario	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Production Rate	MCF/day	Low	403 (-49%)	254 (-36%)	3,140 (-49%)	77 (-30%)	192 (-30%)	14 (-30%)
		Nominal	**782**	**399**	**6,179**	**110**	**274**	**20**
		High	1,545 (+97%)	783 (+96%)	12,284 (+99%)	142 (+30%)	356 (+30%)	26 (+30%)
Flaring Rate at Well	%	Low	41% (-20%)	41% (-20%)	41% (-20%)	12% (-20%)	12% (-20%)	41% (-20%)
		Nominal	**51%**	**51%**	**51%**	**15%**	**15%**	**51%**
		High	61% (+20%)	61% (+20%)	61% (+20%)	18% (+20%)	18% (+20%)	61% (+20%)
Pipeline Distance	miles	Low	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)
		Nominal	**450**	**450**	**450**	**450**	**450**	**450**
		High	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)

Error bars reported are based on setting each of the three parameters above to the values that generate the lowest and highest result.

Note: "Production Rate" and "Flaring Rate at Well" have an inverse relationship on the effect of the study result. For example to generate the lower bound on the uncertainty range both "Production Rate" and "Flaring Rate Well" were set to "High" and "Pipeline Distance" was set to "Low".

Accounting for Natural Gas from Extraction thru Delivery to a Large End-User

(Percent Mass Basis)

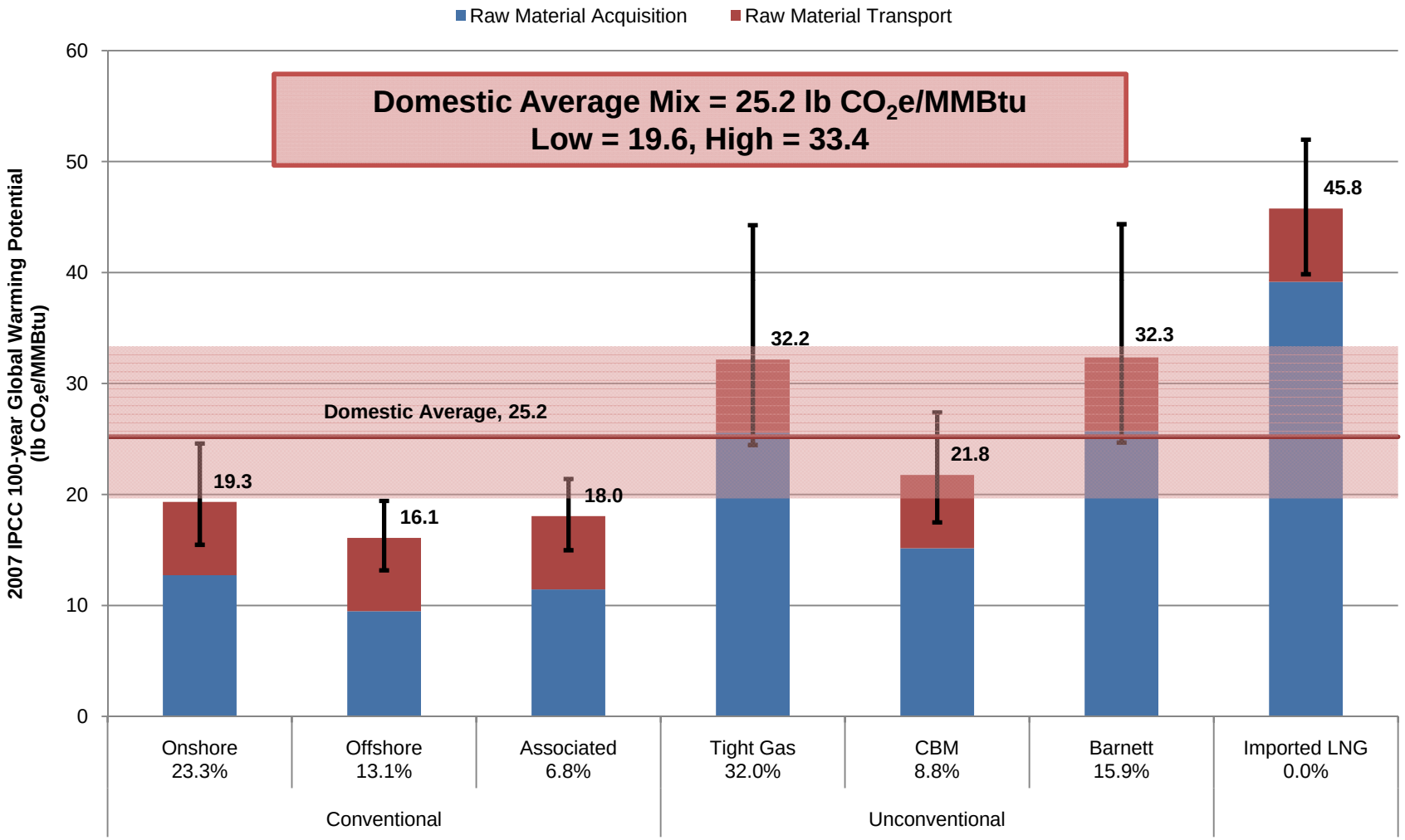


Natural Gas Resource Table	Raw Material Acquisition		Raw Material Transport	Cradle-to-Gate Total:
	Extraction	Processing		
Extracted from Ground	100%	N/A	N/A	100%
Fugitive Losses	1.1%	0.2%	0.4%	1.7%
Point Source Losses (Vented or Flared)	0.1%	2.4%	0.0%	2.5%
Fuel Use	0.0%	5.3%	1.6%	6.8%
Delivered to End User	N/A	N/A	89.0%	89.0%

11% of Natural Gas Extracted from the Earth is Consumed for Fuel Use, Flared, or Emitted to the Atmosphere (point source or fugitive)

Of this, 62% is Used to Power Equipment

Life Cycle GHG Results for Average Natural Gas Extraction and Delivery to a Large End-User

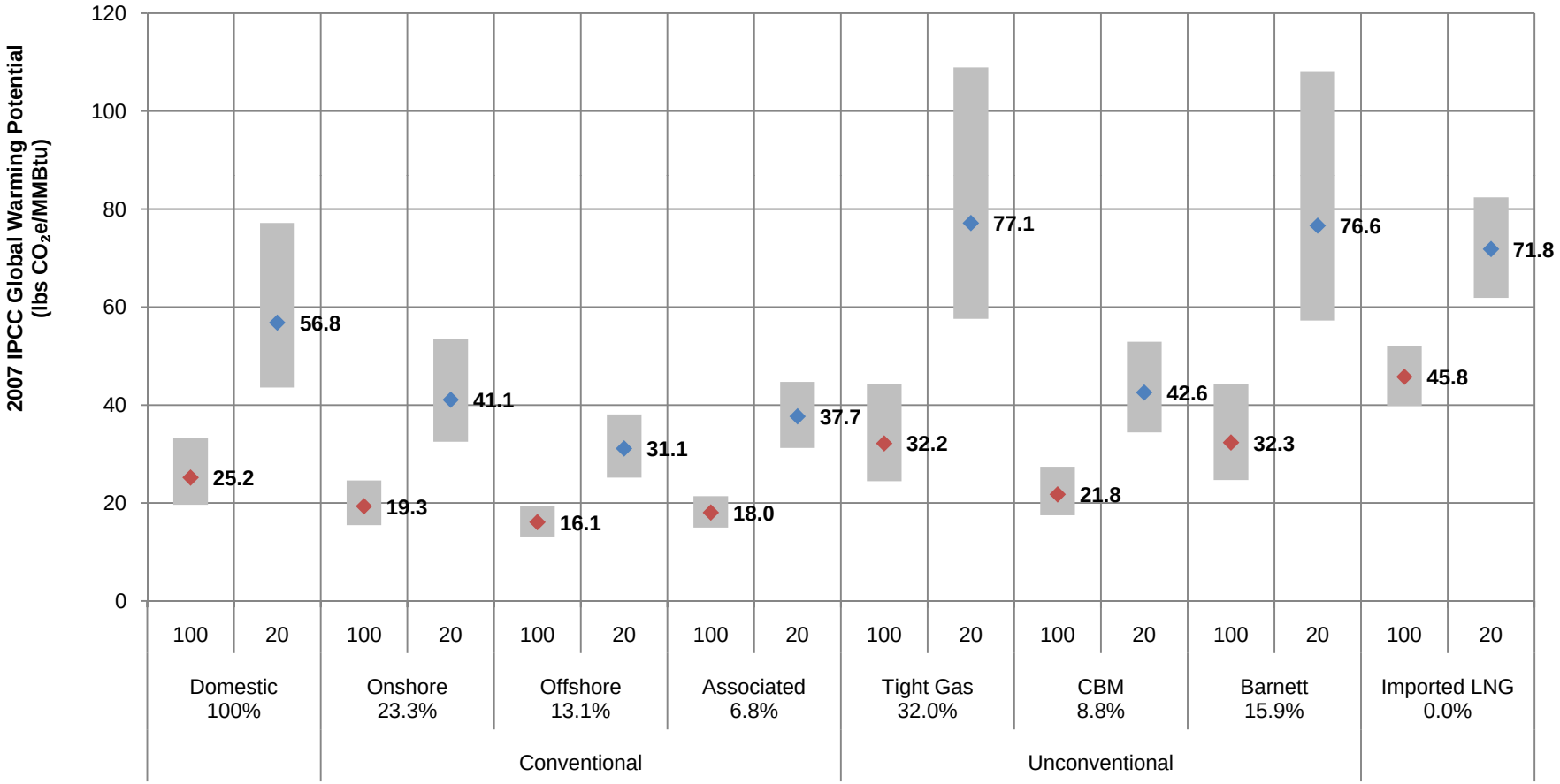


Life Cycle GHG Results for Average Natural Gas Extraction and Delivery to a Large End-User

Comparison of 2007 IPCC GWP Time Horizons:

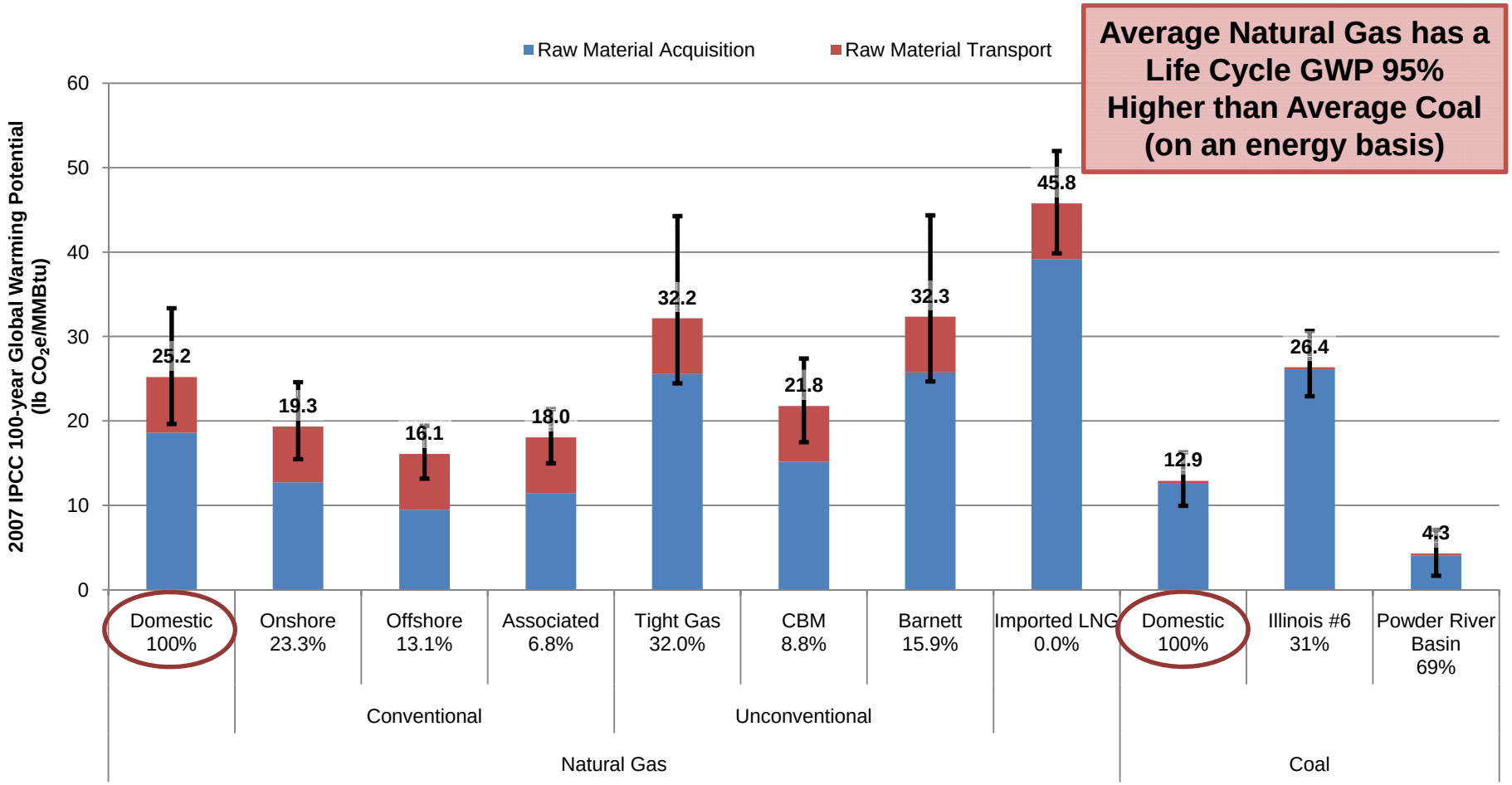
100-year Time Horizon: CO_2 = 1, CH_4 = 25, N_2O = 298

20-year Time Horizon: CO_2 = 1, CH_4 = 72, N_2O = 289



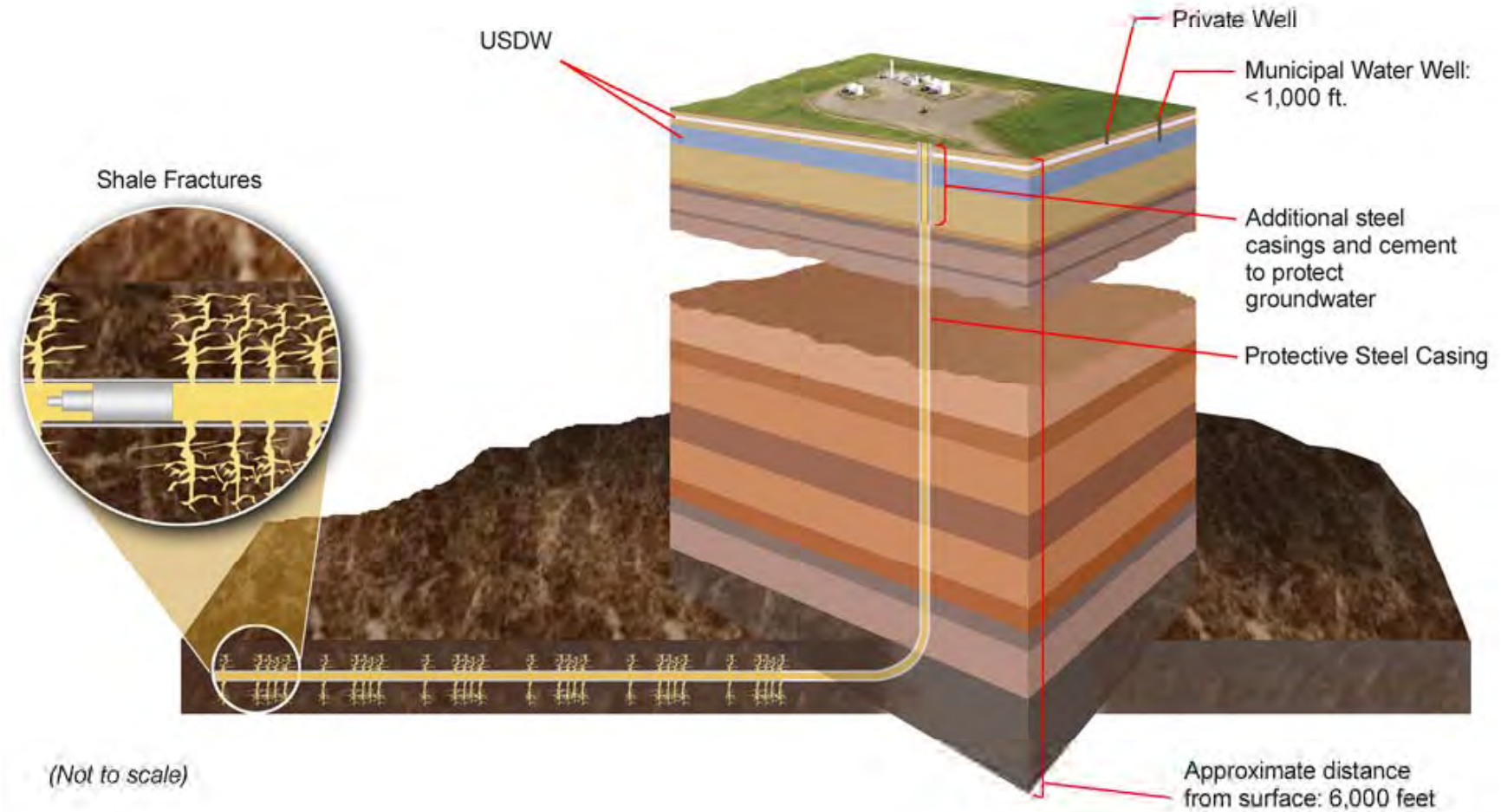
Life Cycle GHG Results for "Average" Natural Gas Extraction and Delivery to a Large End-User

Comparison of Natural Gas and Coal Energy Feedstock GHG Profiles



Average Natural Gas has a Life Cycle GWP 95% Higher than Average Coal (on an energy basis)

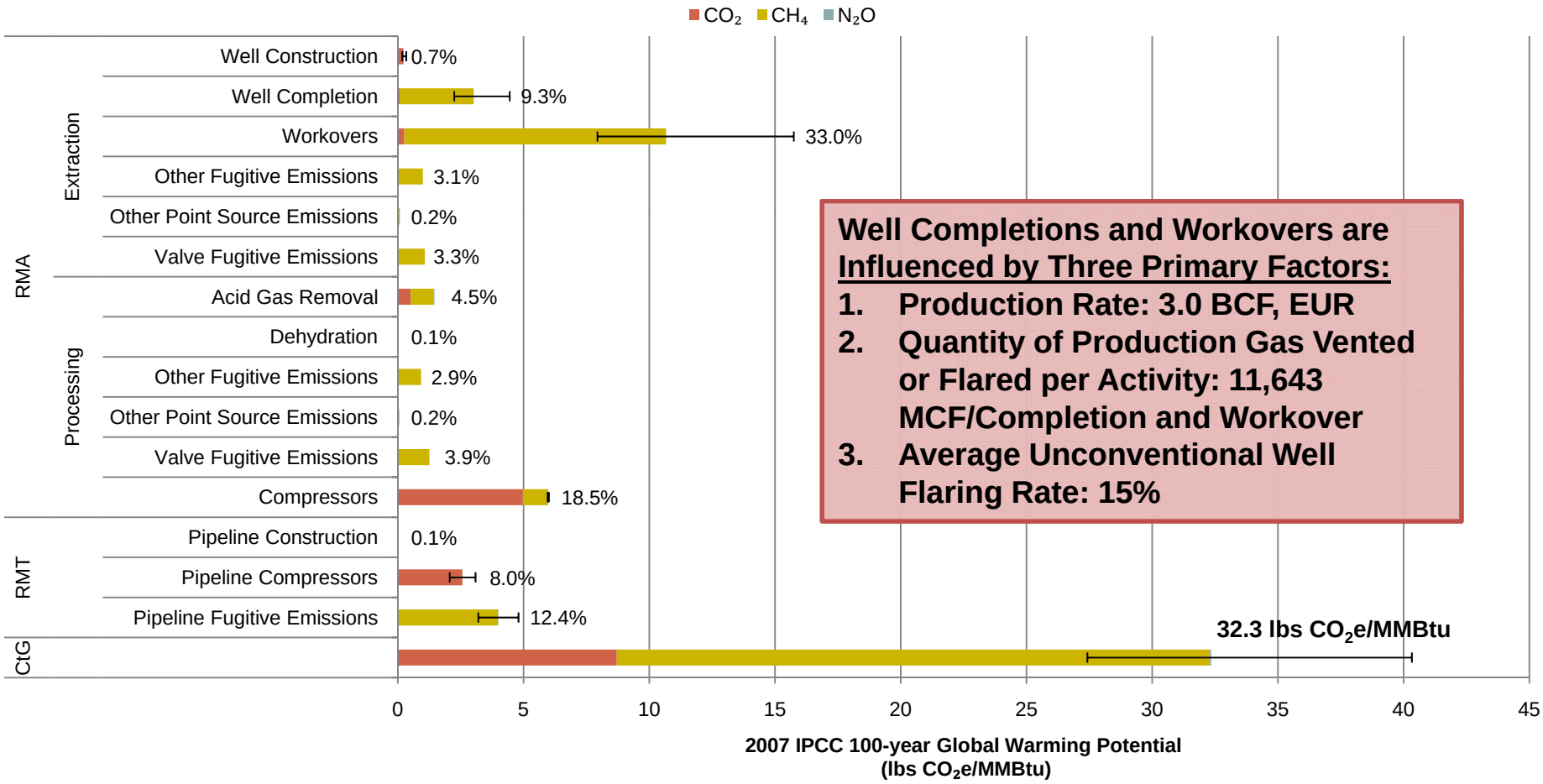
A Deeper Look at Unconventional Natural Gas Extraction via Horizontal Well, Hydraulic Fracturing (*the Barnett Shale Model*)



Source: NETL, *Shale Gas: Applying Technology to Solve America's Energy Challenge*, January 2011

NETL Upstream Natural Gas Profile:
Barnett Shale: Horizontal Well, Hydraulic Fracturing

GWP Result: IPCC 2007, 100-yr (lb CO_2e/MMBtu)

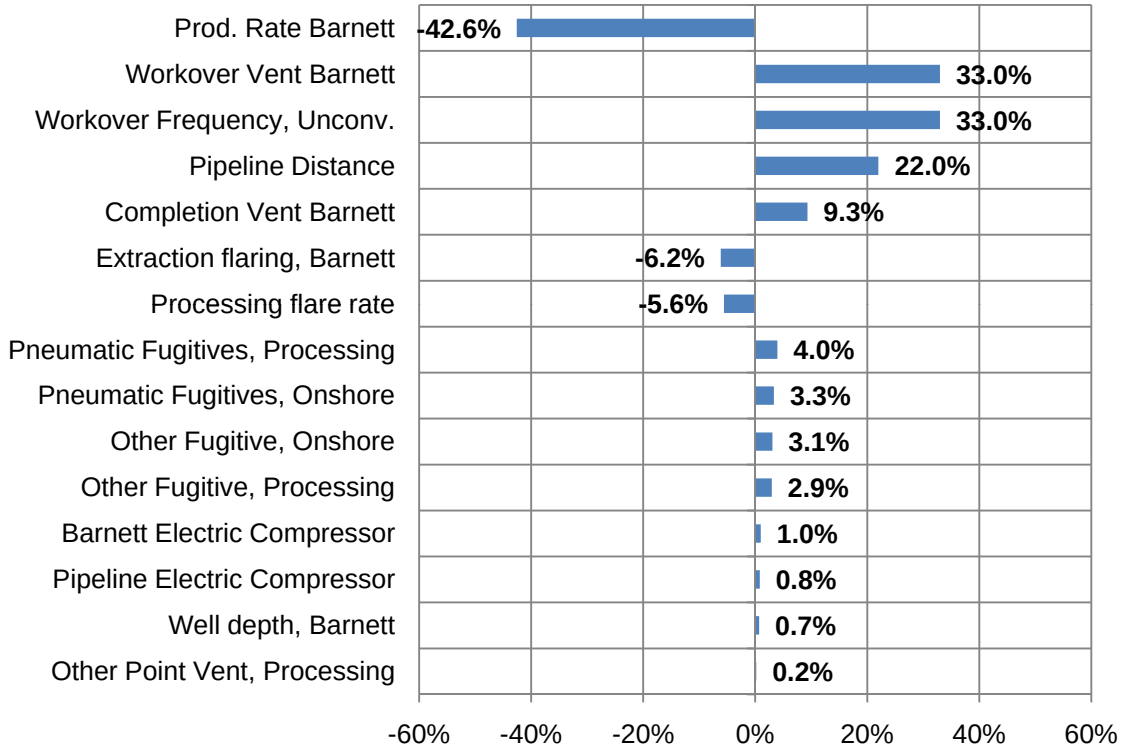


Well Completions and Workovers are Influenced by Three Primary Factors:

1. **Production Rate: 3.0 BCF, EUR**
2. **Quantity of Production Gas Vented or Flared per Activity: 11,643 MCF/Completion and Workover**
3. **Average Unconventional Well Flaring Rate: 15%**

NETL Upstream Natural Gas Profile:
Barnett Shale: Horizontal Well, Hydraulic Fracturing

Sensitivity Analysis



Default Value	Units
11,508	lb/day
489,023	lb/episode
0.118	episodes/yr
450	miles
489,023	lb/episode
15.0	%
100	%
0.001480	lb fugitives/lb processed gas
0.001210	lb fugitives/lb extracted gas
0.001119	lb fugitives/lb extracted gas
0.001089	lb fugitives/lb processed gas
25	%
7	%
13,000	feet
0.0003940	lb fugitives/lb processed gas

"0%" = 32.3 lb CO_2e/MMBtu Delivered; IPCC 2007, 100-yr Time Horizon

Example: A 1% increase in production rate from 11,508 lb/day to 11,623 lb/day results in a 0.426% decrease in cradle-to-gate GWP, from 32.3 to 32.2 lbs CO_2e/MMBtu

Question #6:

How does natural gas power generation compare to coal-fired power generation on a life cycle GHG basis?

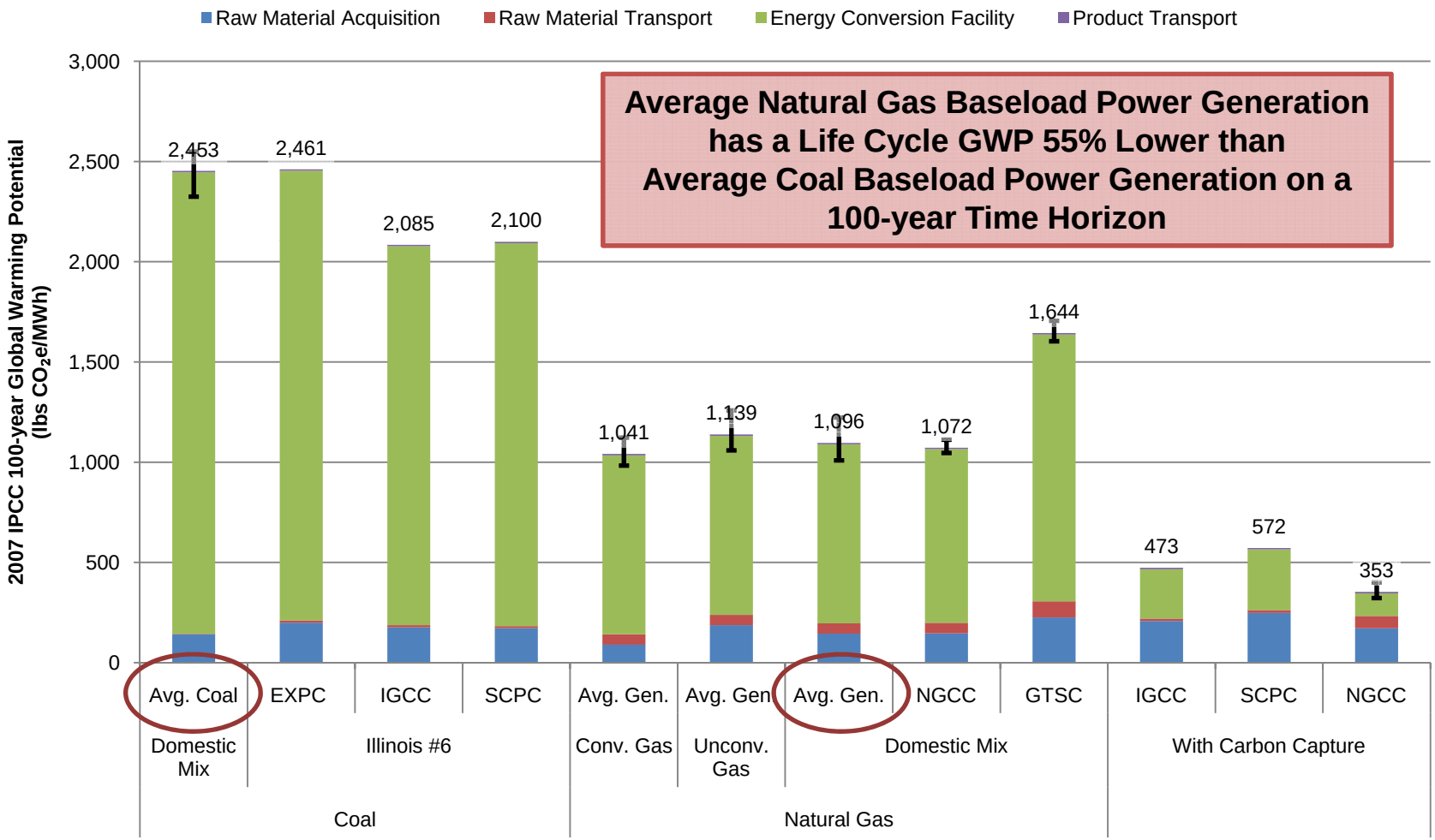
Power Technology Modeling Properties

Plant Type	Plant Type Abbreviation	Fuel Type	Capacity (MW)	Capacity Factor	Net Plant HHV Efficiency
2009 Average Coal Fired Power Plant[a]	Avg. Coal	Domestic Average	Not Calculated	Not Calculated	33.0%
Existing Pulverized Coal Plant	EXPC	Illinois No. 6	434	85%	35.0%
Integrated Gasification Combined Cycle Plant	IGCC	Illinois No. 6	622	80%	39.0%
Super Critical Pulverized Coal Plant	SCPC	Illinois No. 6	550	85%	36.8%
2009 Average Baseload (> 40 MW) Natural Gas Plant[a]	Avg. Gen.	Domestic Average	Not Calculated	Not Calculated	47.1%
Natural Gas Combined Cycle Plant	NGCC	Domestic Average	555	85%	50.2%
Gas Turbine Simple Cycle	GTSC	Domestic Average	360	85%	32.6%
Integrated Gasification Combined Cycle Plant with 90% Carbon Capture	IGCC/CCS	Illinois No. 6	543	80%	32.6%
Super Critical Pulverized Coal Plant with 90% Carbon Capture	SCPC/CCS	Illinois No. 6	550	85%	26.2%
Natural Gas Combined Cycle Plant with 90% Carbon Capture	NGCC/CCS	Domestic Average	474	85%	42.8%

[a] **Net plant higher heating value (HHV) efficiency reported is based on the weighted mean of the 2007 fleet as reported by U.S. EPA, eGrid (2010).**

Comparison of Power Generation Technology Life Cycle GHG Footprints

Raw Material Acquisition thru Delivery to End Customer (lb CO_2e/MWh)



Note: EXPC, IGCC, SCPC, and NGCC (combustion) results, with and without CCS, are based on scenario specific modeling parameters; not industry average data.

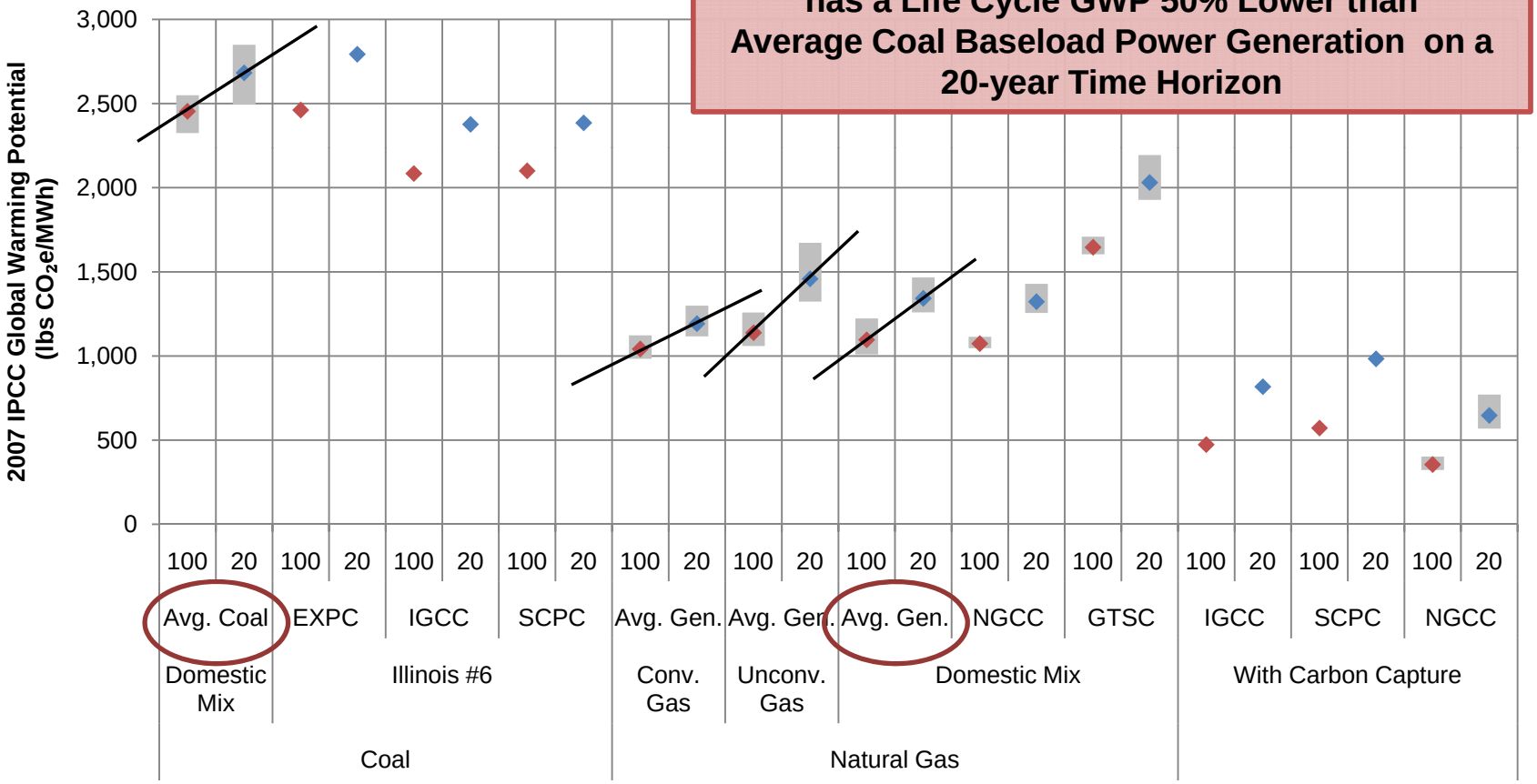
Comparison of Power Generation Technology Life Cycle GHG Footprints (lbs CO_2e/MWh)

Comparison of 2007 IPCC GWP Time Horizons:

100-year Time Horizon: CO_2 = 1, CH_4 = 25, N_2O = 298

20-year Time Horizon: CO_2 = 1, CH_4 = 72, N_2O = 289

Average Natural Gas Baseload Power Generation has a Life Cycle GWP 50% Lower than Average Coal Baseload Power Generation on a 20-year Time Horizon



Note: EXPC, IGCC, SCPC, and NGCC (combustion) results, with and without CCS, are based on scenario specific modeling parameters; not industry average data.

Study Data Limitations

- **Data Uncertainty**
  - Episodic emission factors
  - Formation-specific production rates
  - Flaring rates (extraction and processing)
  - Natural gas pipeline transport distance

- **Data Availability**
  - Formation-specific gas compositions (including CH_4, H_2S, NMVOC, and water)
  - Effectiveness of green completions and workovers
  - Fugitive emissions from around wellheads (between the well casing and the ground)
  - GHG emissions from the production of fracing fluid
  - Direct and indirect GHG emissions from land use from access roads and well pads
  - Gas exploration
  - Treatment of fracing fluid
  - Split between venting and fugitive emissions from pipeline transport

Question #7:

What are the opportunities for reducing GHG emissions?

Technology Opportunities

- **Opportunities for Reducing the GHG Footprint of Natural Gas Extraction and Delivery**
  - Reduce emissions from unconventional gas well completions and workovers
    - Better data is needed to properly characterize this opportunity based on basin type, drilling method, and production rate
  - Improve compressor fuel efficiency
  - Reduce pipeline fugitive emissions thru technology and best management practices (collaborative initiatives)

- **Opportunities for Reducing the GHG Footprint of Natural Gas and Coal-fired Power Generation**
  - Capture the CO_2 at the power plant and sequester it in a saline aquifer or oil bearing reservoir (CO_2-EOR)
  - Improve existing power plant efficiency
  - Invest in advanced power research, development, and demonstration

All Opportunities Need to Be Evaluated on a Sustainable Energy Basis: Environmental Performance, Economic Performance, and Social Performance (e.g., energy reliability and security)

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Recent NETL Life Cycle Assessment Reports

Available at http://www.netl.doe.gov/energy-analyses/:

- Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant
- Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant
- Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant
- Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant
- Life Cycle Analysis: Power Studies Compilation Report

Analysis complete, report in draft form:

- Life Cycle GHG Analysis of Natural Gas Extraction and Delivery
- Life Cycle Assessment of Wind Power with GTSC Backup
- Life Cycle Assessment of Nuclear Power

Other related Life Cycle Analysis publications available on NETL web-site:

- Life Cycle Analysis: Power Studies Compilation Report (Pres., LCA X Conference)
- An Assessment of Gate-to-Gate Environmental Life Cycle Performance of Water-Alternating-Gas CO_2-Enhanced Oil Recovery in the Permian Basin (Report)
- A Comparative Assessment of CO_2 Sequestration through Enhanced Oil Recovery and Saline Aquifer Sequestration (Presentation, LCA X Conference)

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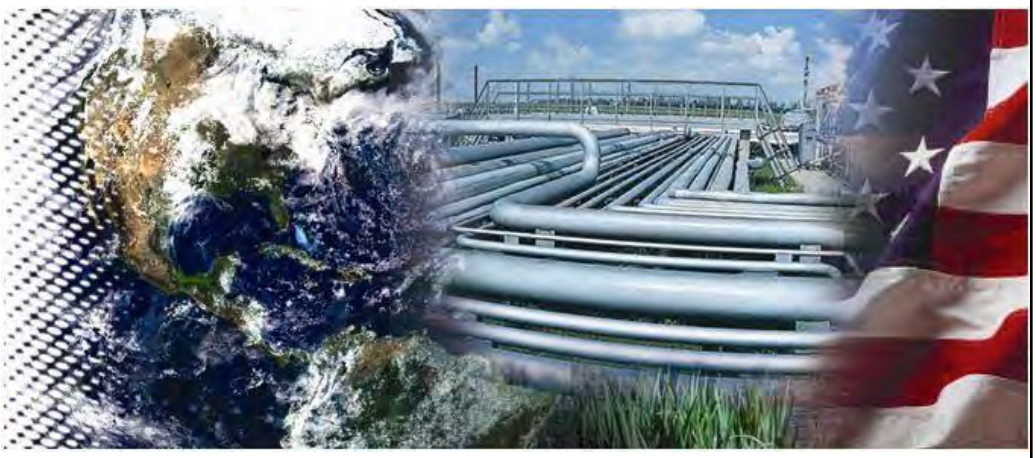

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October 24, 2011

DOE/NETL-2011/1522

U.S. DEPARTMENT OF ENERGY

Disclaimer

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Final Report

October 24, 2011

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Acronyms and Abbreviations

AGR	Acid gas removal
API	American Petroleum Institute
bbl	Barrel
Bcf	Billion cubic feet
BOE	Barrel of oil equivalent
Btu	British thermal unit
CBM	Coal bed methane
CCS	Carbon capture and sequestration
cf	Cubic feet
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DOE	Department of Energy
eGRID	Emissions & Generation Resource Integrated Database
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EUR	Estimated ultimate recovery
EXPC	Existing pulverized coal
g	Gram
gal	Gallon
Gg	Gigagram
GHG	Greenhouse gas
GTSC	Gas turbine simple cycle
GWP	Global warming potential
H_2S	Hydrogen sulfide
hp-hr	Horsepower-hour
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
km	Kilometer
kWh	Kilowatt-hour
lb, lbs	Pound, pounds
LCA	Life cycle assessment, analysis
LNG	Liquefied natural gas
m	Meter
m^3	Meters cubed
Mbbl	Thousand barrels
Mcf	Thousand cubic feet
MJ	Megajoule
MMbbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
MW	Megawatt
MWh	Megawatt-hour
N_2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural gas combined cycle
NMVOC	Non-methane volatile organic compound
NREL	National Renewable Energy Laboratory
PRB	Powder River Basin
psig	Pounds per square inch gauge
PT	Product transport
RMA	Raw material acquisition
RMT	Raw material transport
SCPC	Super critical pulverized coal
T&D	Transmission and distribution
Tcf	Trillion cubic feet
ton	Short ton (2,000 lb)
tonne	Metric ton (1,000 kg)
UP	Unit process

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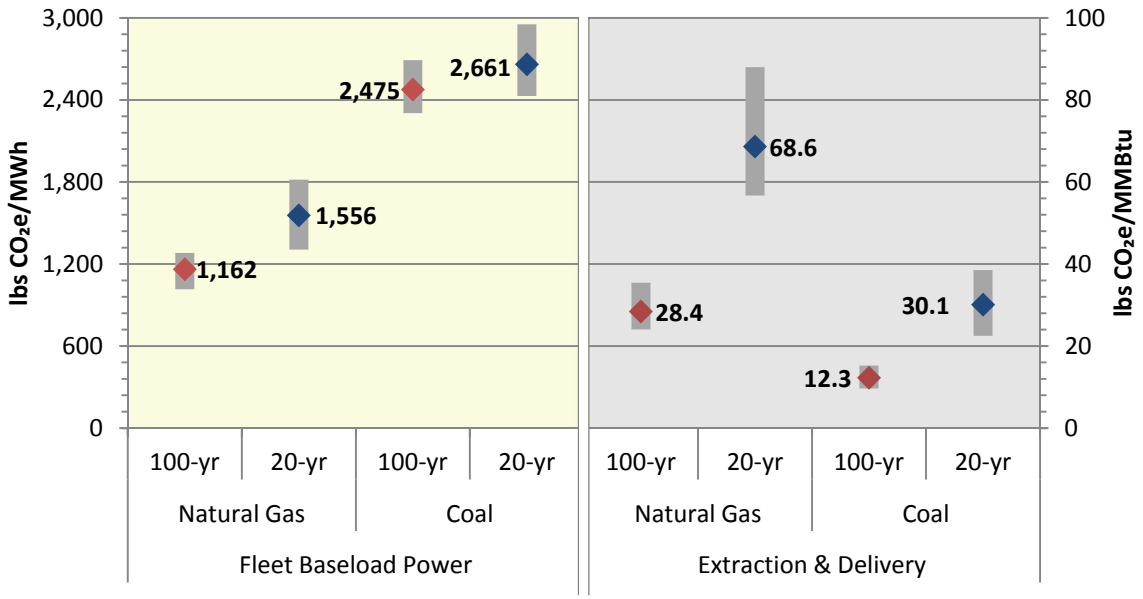
Executive Summary

Natural gas-fired baseload power production has life cycle greenhouse gas emissions 42 to 53 percent lower than those for coal-fired baseload electricity, after accounting for a wide range of variability and compared across different assumptions of climate impact timing. The lower emissions for natural gas are primarily due to differences in the current fleets' average efficiency – 53 percent for natural gas versus 35 percent for coal, and a higher carbon content per unit of energy for coal than natural gas. Even using unconventional natural gas, from tight sands, shale and coal beds, and compared with a 20-year global warming potential (GWP), natural gas-fired electricity has 39 percent lower greenhouse gas emissions than coal per delivered megawatt-hour (MWh) using current technology.

In a life cycle analysis (LCA), comparisons must be based on providing an equivalent service or function, which in this study is the delivery of 1 MWh of electricity to an end user. This life cycle greenhouse gas inventory also developed upstream (from extraction to delivery to a power plant) emissions for delivered energy feedstocks, including six different domestic sources of natural gas, of which three are unconventional gas, and two types of coal, and then combines them both into domestic mixes. These are important characterizations for the LCA community, and can be used as inputs into a variety of processes. However, these upstream, or cradle-to-gate, results are not appropriate to compare when making energy policy decisions, since the two uncombusted fuels do not provide an equivalent function. These results highlight the importance of specifying an end-use basis—not necessarily power production—when comparing different fuels.

Figure ES-1: Natural Gas and Coal GHG Emissions Comparison

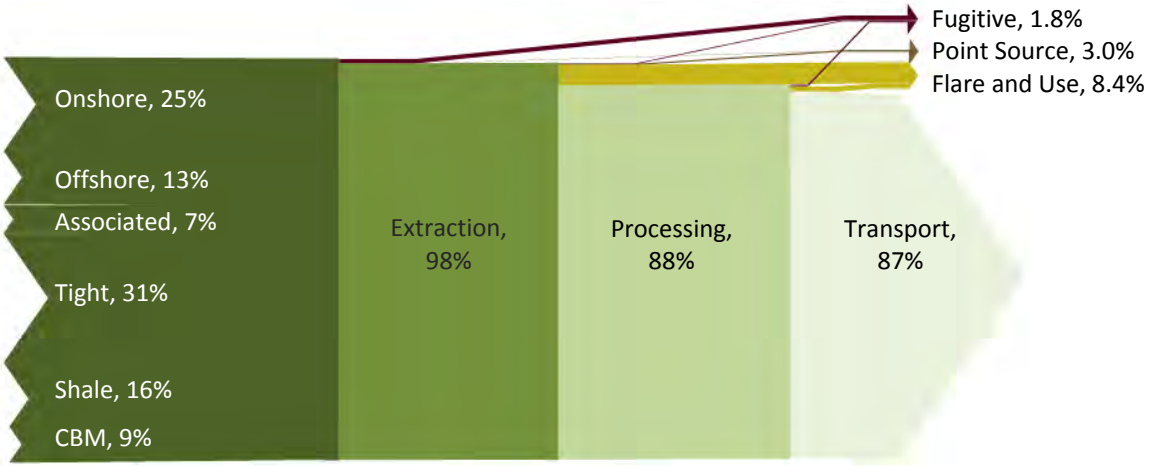


Despite the conclusion that natural gas has lower greenhouse gases than coal on a delivered power basis, the extraction and delivery of the gas has a large climate impact —32 percent of U.S. methane emissions and 3 percent of U.S. greenhouse gases (EPA, 2011b). As **Figure ES-2** shows, there are significant emissions and use of natural gas—13 percent at the city or plant gate—even without considering final distribution to small end-users. The vast majority of the reduction in extracted

natural gas —64 percent cradle-to-gate—are not emitted to the atmosphere, but can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations. Increasing compressor efficiency would lower both the rate of use and the CO_2 emissions associated with the combustion of the gas for energy. Note that this figure accounts for the total mass of natural gas extracted from the earth, including water, acid gases, and other non-methane content.

But, with methane making up 75 to 95 percent of the natural gas flow, there are many opportunities for reducing the climate impact associated with direct venting to the atmosphere. A further 24 percent of the natural gas losses can be characterized as point source, and have the potential to be flared—essentially a conversion of GWP-potent methane to carbon dioxide.

Figure ES-2: Cradle-to-Gate Reduction in Delivered Natural Gas for 2009



The conclusions drawn from this analysis are robust to a wide array of assumptions. However, as with any inventory, they are dependent on the underlying data, and there are many opportunities to enhance the information currently being collected. This analysis shows that the results are both sensitive to and impacted by the uncertainty of a few key parameters: use and emission of natural gas along the pipeline transmission network; the rate of natural gas emitted during unconventional gas extraction processes such as well completion and workovers; and the lifetime production of wells, which determine the denominator over which lifetime emissions are placed.

Table ES-1: Average and Marginal Upstream Greenhouse Gas Emissions (lbs CO_2e/MMBtu)

Source		Average	Marginal	Percent Change
Conventional	Onshore	34.2	20.1	-41.2%
	Offshore	14.3	14.1	-1.4%
	Associated	18.5	18.4	-0.8%
Unconventional	Tight	32.4	32.4	0.0%
	Shale	32.5	32.5	0.0%
	Coal Bed Methane	19.1	19.3	1.4%
Liquefied Natural Gas		42.8	42.5	-0.6%

This analysis inventoried both average and marginal production rates for each natural gas type, with results shown in **Table ES-1**. The average represents natural gas produced from all wells, including older and low productivity stripper wells. The marginal production rate represents natural gas from

newer, higher productivity wells. The largest difference was for onshore conventional natural gas, which had a 41 percent reduction in upstream greenhouse gas emissions from 20.1 to 34.2 lbs CO_2e/MMBtu when going from marginal to average production rates. This change has little impact on emissions from power production.

This inventory and analysis are for greenhouse gases only, and there are many other factors that must be considered when comparing energy options. A full inventory of conventional and toxic air emissions, water use and quality, and land use is currently under development, and will allow comparison of these fuels across multiple environmental categories. Further, all options need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security. There are many opportunities for decreasing the greenhouse gas emissions from natural gas and coal extraction, delivery and power production, including reducing fugitive methane emissions at wells and mines, and implementing advanced combustion technologies and carbon capture and storage.

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1 Introduction

Natural gas is seen as a cleaner burning and flexible alternative to other fossil fuels, and is used in residential, commercial, industrial, and transportation applications in addition to an expanding role in power production. However, the primary component of natural gas by mass is methane, which is also a powerful greenhouse gas—8 to 72 times as potent as carbon dioxide (Forster et al., 2007). Losses of this methane to the atmosphere during the extraction, transmission, and delivery of natural gas to end users made up 32 percent of U.S. 2009 total methane emissions, and 3 percent of all greenhouse gases (EPA, 2011b). The rate of loss, and the associated emissions, varies with the source of natural gas—both the geographic location of the formation, as well as the technology used to extract the gas.

This report expands upon previous life cycle assessments (LCA) performed by the National Energy Technology Laboratory (NETL) of natural gas power generation technologies by describing in detail the greenhouse gas emissions due to extracting, processing and transporting various sources of natural gas to large end users, and the combustion of that natural gas to produce electricity. Emissions inventories are created for the 2009 average natural gas production, but also for natural gas produced from the next highly-productive well for each source of natural gas. This context allows analysis of what the emissions are, and also what they could be in the future.

This analysis also includes an expanded system which compares the life cycle greenhouse gases (GHGs) from baseload natural gas-fired power plants with the GHGs generated by coal-fired plants, including extraction and transportation of the respective fuels. This comparison provides perspective on the scale of fuel extraction and delivery emissions relative to subsequent emissions from power generation and electricity transmission.

Beyond presenting the inventory, the goal of this report is to provide a clear presentation of NETL's natural gas model, including documentation of key assumptions, data sources, and model sensitivities. Further, areas of large uncertainty in the inventory are highlighted, along with areas for potential improvement for both data collection and greenhouse gas reductions.

This greenhouse gas inventory and analysis are part of a larger comprehensive life cycle assessment being performed on the same natural gas system. That assessment effort includes new sources of shale gas and expands the inventory beyond greenhouse gases to include criteria and hazardous air pollutants, water use and quality, direct and indirect land use and greenhouse gases from land use change.

2 Inventory Method, Assumptions, and Data

This ISO 14040-compliant inventory and analysis applies the LCA framework to determine the greenhouse gas burdens of natural gas extraction, transport and use in the U.S. The boundaries, basis of comparison, model structure, and data used by this analysis are discussed below. Further detail is available in the Appendix to this document.

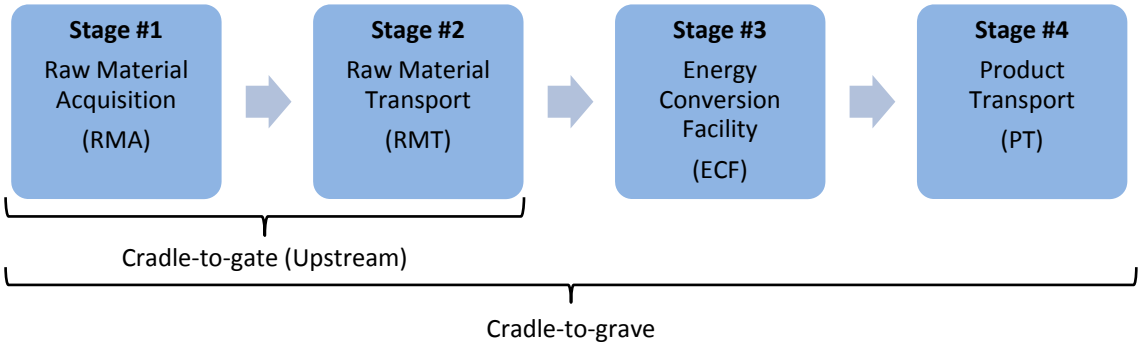
2.1 Boundaries

The first piece of this analysis is a cradle-to-gate greenhouse gas inventory that focuses on raw material acquisition and transport; as such, it is also referred to as an upstream inventory, upstream being a relative term (relative, in this case, to the power plant). As shown in **Figure 2-1**, and in more detail in **Figure 2-2**, the boundary of Stage #1 includes all construction and operation activities necessary to extract fuel from the earth, and ends when fuel is extracted, prepared, and ready for final transport to the power plant. Stage #2 includes all construction and operation activities necessary to

move fuel from the extraction and processing point to the power plant, and ends at the power plant gate. The boundary of the upstream inventory of natural gas does not include the distribution system of natural gas to small end users, but rather is representative of delivery to a large end user such as a power plant or even a city gate.

The second piece of this analysis is a cradle-to-grave context to compare the greenhouse gas emissions of natural gas extraction and transport with those of electricity production and transmission. Neither piece of analysis includes the use of the produced product, but rather ends when the product is delivered. Coal-fired power systems are used as a further point of comparison.

Figure 2-1: Life Cycle Stages and Boundary Definitions



2.2 Basis of Comparison (Functional Unit)

To establish a basis for comparison, the LCA method requires specification of a functional unit, the goal of which is to define an equivalent service provided by the systems of interest. Within the cradle-to-gate boundary of this analysis, the functional unit is 1 MMBtu of fuel delivered to the gate of an energy conversion facility or other large end user. When the boundaries of the analysis are expanded to include power production, the functional unit is the delivery of 1 MWh of electricity to the consumer. In both contexts, the period over which the service is provided is 30 years.

2.2.1 Global Warming Potential

Greenhouse gases in this inventory are reported on a common mass basis of carbon dioxide equivalents (CO_2e) using the global warming potentials (GWP) of each gas from the 2007 Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (Forster, et al., 2007). The default GWP used is the 100-year time frame, but in some cases, results for the 20-year time frame are presented as well. Selected results comparing all three time frames are included in the Appendix. **Table 2-1** shows the GWPs used for the greenhouse gases inventoried in this study.

Table 2-1: IPCC Global Warming Potentials (Forster, et al., 2007)

GHG	20-year	100-year (Default)	500-year
CO_2	1	1	1
CH_4	72	25	7.6
N_2O	289	298	153
SF_6	16,300	22,800	32,600

2.3 Representativeness of Inventory Results

This inventory uses data gathered from a variety of sources, each of which represents a particular temporal period, geographic location, and state of technology. Since the results of this study are the combination of each of those sources, this section discusses what the results of this study represent in each of those categories.

2.3.1 Temporal

The natural gas upstream inventory results best represent the year 2009, because of the use of the 2009 EIA natural gas production data to create the mix of natural gas sources in the domestic average result and well production rates for each source of natural gas. The year-over-year change to that mix of natural gas sources is small, and the results could represent a period from 2004 to 2012.

This study does not attempt to forecast technological advances or market shifts that might significantly change production rates or emissions of less mature formations.

The inventory results through the conversion of fuel to electricity represent the year 2010 for NETL system study-based technologies and the year 2007 for the fleet average values for coal and natural gas, since this is the vintage of the latest eGRID data release (EPA, 2010). Again, there would be little year-over-year change to the information, and so this LCA could reasonably represent a longer time period, from 2004 to 2015.

Some information included in this inventory pre-dates the temporal period stated above, but was determined to be the latest or highest quality available data.

The time frame of this study is 30 years, but that does not accurately represent a well drilled 30 years from now and operating 60 years into the future. An assumption is made about resource availability based on current estimated ultimate recovery values, and forecasts from the Energy Information Administration (EIA).

2.3.2 Geographic

The results of this inventory are representative of the lower 48 United States. Natural gas from Alaska is neither explicitly included nor excluded, nor are imports and exports. In some situations, source data may not break out information about geographic location, and so is implicitly included in this inventory. However, the error associated with this type of inclusion—or exclusion—is small.

2.3.3 Technological

The natural gas upstream inventory results include two distinct technological representations. The first is a baseline result which represents average 2009 natural gas production, including production from older, less productive wells. Production data from that year is used to create an average domestic mix of natural gas sources, and the production rate of each source well is generally based on 2009 well count and production data. The second set of results is representative of a new marginal unit of natural gas produced in 2009; these results use a variety of methods to create production rates for wells which would create the next unit of natural gas.

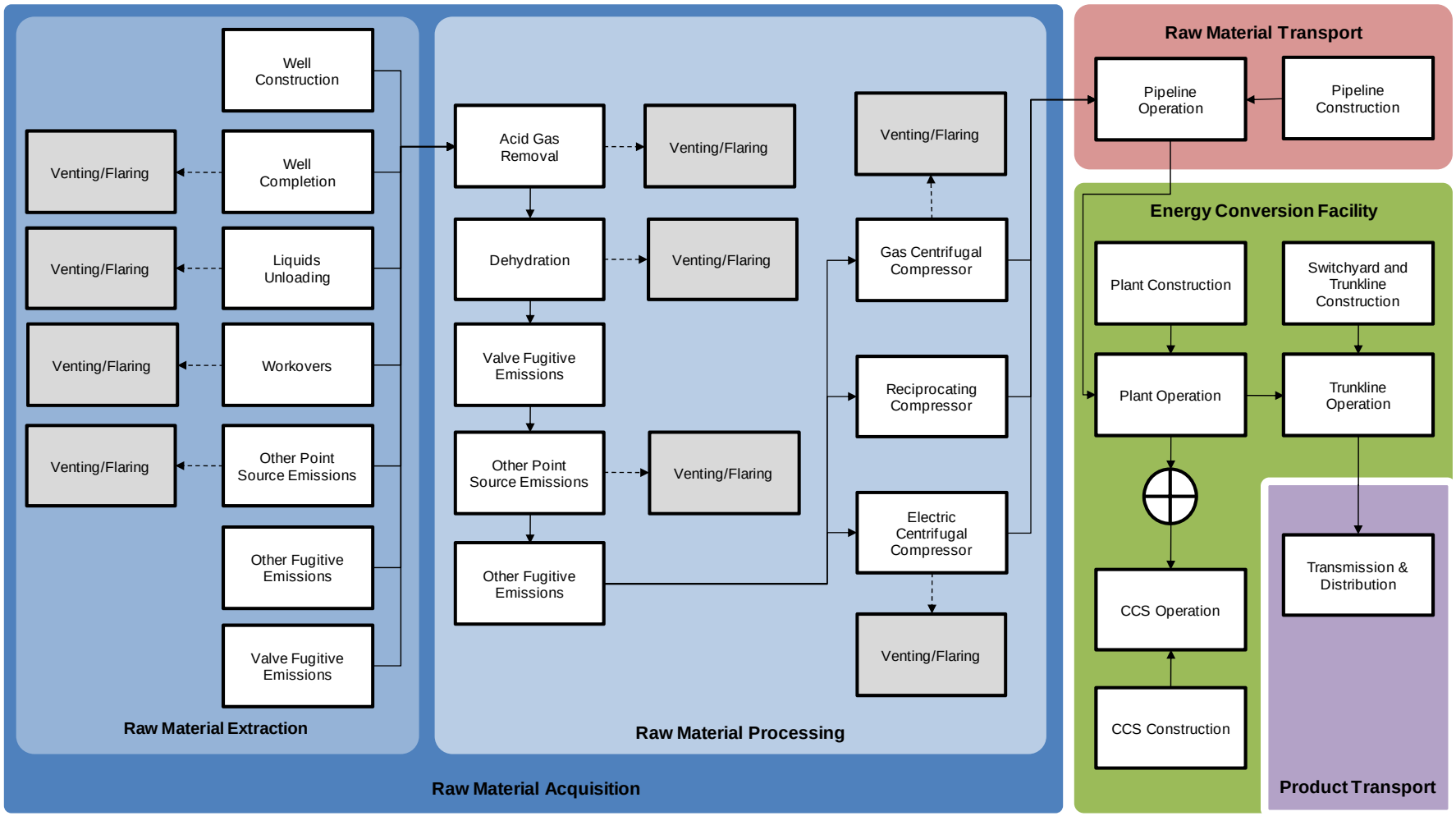
The results of this inventory are representative of currently installed technology as of 2011. This installed base is different from current technology because it includes much older equipment that is still operating.

2.4 Model Structure

All results for this inventory were calculated by NETL's LCA model for natural gas power systems. This model is an interconnected network of operation and construction blocks. Each block in the model, referred to as a unit process, accounts for the key inputs and outputs of an activity. The inputs of a unit process include the purchased fuels, resources from nature (fossil feedstocks, biomass, or water), and man-made raw materials. The outputs of a unit process include air emissions, water effluents, solid waste, and product(s). The role of an LCA model is to converge on the values for all intermediate flows within the interconnected network of unit processes and then scale the flows of all unit processes to a common basis, or functional unit.

The network of unit processes used for the modeling of natural gas power is shown in **Figure 2-2**. Note that only the RMA and RMT portions of the model are necessary to determine the upstream environmental burdens of natural gas; a broader scope—from raw material acquisition through delivery of electricity—is necessary to determine the cradle-to-grave environmental burdens of natural gas power. For simplicity, the following figure shows the extraction and delivery for a generic natural gas scenario; NETL's actual model uses six parallel modules to arrive at the life cycle results for a mix of six types of natural gas. This figure also shows a breakdown of the RMA stage into extraction and processing sub-stages.

Figure 2-2: Natural Gas LCA Modeling Structure



2.5 Data

The primary unit processes of this model are based on data compiled by NETL. Secondary unit processes, such as production of construction materials besides steel, are based on third party data. A full description of data sources is available in the Appendix.

Where data for the inventory is available, high and low values are collected, along with a nominal value. When results are presented, three cases are shown: a nominal case, a high case and a low case. The high and low results (error bars on the results) are a deterministic representation of the variability on the data and not indicative of an underlying distribution or likelihood.

2.5.1 Sources of Natural Gas

This inventory and analysis includes results for natural gas domestically extracted from six sources in the lower 48 states:

1. Conventional onshore
2. Associated
3. Conventional offshore
4. Tight sands
5. Shale formations (Barnett)
6. Coal bed methane

This is not a comprehensive list of natural gas extracted or consumed in the United States. Natural gas extracted in Alaska, 2 percent of domestically extracted natural gas, is included as conventional onshore production. The Haynesville shale play makes up a large portion of unconventional shale production, but it is assumed here that the Barnett play is representative of all shale production. Imported natural gas (18 percent of 2009 total consumption, 88 percent of which is imported via pipeline from Canada) is not included. About 12 percent of imports in 2009 were brought in as liquefied natural gas (LNG) from a variety of countries of origin. While this inventory includes a profile for LNG from offshore extraction in Trinidad and Tobago, this natural gas is not included in the domestic production mix.

Table 2-2 shows the makeup of the domestic production mix in the United States in 2009 and the mix of conventional and unconventional extraction. Note that in 2009 unconventional natural gas sources make up 56 percent of production and the majority of consumption in the Unites States (EIA, 2011a).

Table 2-2: Mix of U.S. Natural Gas Sources (EIA, 2011a)

Source	Conventional			Unconventional		
	Onshore	Associated	Offshore	Tight	Shale	CBM
Domestic Mix	25%	13%	7%	31%	16%	9%
Type Mix	44%			56%		
	56%	15%	29%	56%	28%	15%

The characteristics of these six sources of natural gas are summarized next, including a description of the extraction technologies.

2.5.1.1 Onshore

Conventional onshore natural gas is recovered by vertical drilling techniques. Once a conventional onshore natural gas well has been discovered, the natural gas reservoir does not require significant preparation or stimulation for natural gas recovery. Compressors are used to move natural gas

through all process equipment and pressurize it for pipeline transport. Approximately 25 percent (5.2 TCF) of U.S. natural gas production is from conventional onshore gas wells (EIA, 2011a).

An intermittent procedure called liquids unloading is performed at mature onshore conventional natural gas wells to remove water and other liquids from the wellbore; if these liquids are not removed, the flow of natural gas is impeded. Another intermittent activity is a well workover, which is necessary to repair damage to the wellbore and replace downhole equipment, if necessary.

Natural gas is lost through intentional venting, which may be necessary for safety reasons, during well completion when natural gas recovery equipment or gathering lines have not yet been installed, or when key process equipment is offline for maintenance. When feasible, vented natural gas can be recovered and flared, which reduces the global warming potential of the vented natural gas by converting methane to carbon dioxide. Losses of natural gas also result from fugitive emissions due to the opening and closing of valves, and processes where it is not feasible to use vapor recovery equipment.

2.5.1.2 Offshore

Conventional offshore natural gas is recovered by vertical drilling techniques, similar to onshore. Once a conventional offshore natural gas well has been discovered, the natural gas reservoir does not require significant preparation or stimulation for natural gas recovery. A natural gas reservoir must be large in order to justify the capital outlay for the completion of the well and construction of an offshore drilling platform, so production rates tend to be very high. Approximately 13 percent (2.7 TCF) of the United States natural gas supply in 2009 was from the conventional extraction from offshore natural gas wells (EIA, 2011a).

2.5.1.3 Associated

Associated natural gas is co-extracted with crude oil. The extraction of onshore associated natural gas is similar to the extraction methods for conventional onshore natural gas (discussed above). Similar to conventional onshore and offshore natural gas wells, associated natural gas extraction includes losses due to well completion, workovers, and fugitive emissions. Since the natural gas is co-produced with petroleum, the use of oil/gas separators is necessary to recover natural gas from the mixed product stream. Another difference between associated natural gas and other conventional natural gas sources is that liquid unloading is not necessary for associated natural gas wells because the flow of petroleum prevents the accumulation of liquids in the well. Approximately 7 percent (1.4 TCF) of U.S. natural gas production is from conventional onshore oil wells (EIA, 2011a). The majority of these wells are in Texas and Louisiana (EIA, 2010).

2.5.1.4 Tight Gas

The largest single source of domestically produced natural gas, and the largest share of unconventional natural gas, is tight gas. From naturalgas.org, tight gas is defined as follows:

> …trapped in unusually impermeable, hard rock, or in a sandstone or limestone formation that is unusually impermeable and non-porous (tight sand). In a conventional natural gas deposit, once drilled, the gas can usually be extracted quite readily, and easily. A great deal more effort has to be put into extracting gas from a tight formation. Several techniques exist that allow natural gas to be extracted, including fracturing and acidizing. However, these techniques are also very costly. Like all unconventional natural gas, the economic incentive must be there to incite

companies to extract this costly gas instead of more easily obtainable, conventional natural gas (NGSA, 2010).

Approximately 31 percent (6.6 TCF) of natural gas produced domestically is from tight deposits. This analysis assumes tight gas wells are vertically drilled and hydraulically fractured.

2.5.1.5 Shale

Natural gas is also dispersed throughout shale formations, such as the Barnett Shale region in northern Texas. Shale gas cannot be recovered using conventional extraction technologies, but is recovered through the use of horizontal drilling and hydraulic fracturing (hydrofracking). Horizontal drilling creates a wellbore that runs the length of a shale formation, and hydrofracking uses high pressure fluid (a mixture of water, surfactants, and proppants) for breaking apart the shale formation and facilitating the flow of natural gas. Hydrofracking is performed during the original completion of a shale gas well, but due to the steeply declining production curves of shale gas wells, hydrofracking is also performed during the workover of shale gas wells. Unlike conventional natural gas wells, shale gas wells do not require liquid unloading because wellbore liquids are reduced during workover operations. Natural gas from shale formations accounts for approximately 16 percent (3.3 TCF) of the U.S. natural gas production (EIA, 2011a).

2.5.1.6 Coal Bed Methane

Natural gas can be recovered from coal seams through the use of shallow horizontal drilling. The development of a well for coal bed methane requires horizontal drilling followed by a depressurization period during which naturally-occurring water is discharged from the coal seam. Coal bed methane (CBM) wells do not require liquid unloading and the emissions from CBM workovers are similar to those for shale gas wells. The production of natural gas from CBM wells accounts for approximately 9 percent (1.8 TCF) of the U.S. natural gas production (EIA, 2011a).

2.5.2 Natural Gas Composition

Relevant to all phases of the life cycle, the composition of natural gas varies considerably depending on source, and even within a source. For simplicity, a single assumption regarding natural gas composition is used, although that composition is modified as the natural gas is prepared for the pipeline (EPA, 2011a). **Table 2-3** shows the composition on a mass basis of production and pipeline quality natural gas. The pipeline quality natural gas has had water and acid gases (CO_2 and H_2S) removed, and non-methane VOCs either flared or separated for sale. The pipeline quality natural gas has higher methane content per unit mass. The energy content does not change significantly.

Table 2-3: Natural Gas Composition on a Mass Basis

Component	Production	Pipeline Quality
CH_4 (Methane)	78.3%	92.8%
NMVOC (Non-methane VOCs)	17.8%	5.54%
N_2 (Nitrogen)	1.77%	0.55%
CO_2 (Carbon dioxide)	1.51%	0.47%
H_2S (Hydrogen Sulfide)	0.50%	0.01%
H_2O (Water)	0.12%	0.01%

2.5.3 Data for Natural Gas Extraction

This analysis models the extraction of natural gas by characterizing key construction and operation activities at the natural gas wellhead. A summary of each unit process of NETL's model of natural gas extraction is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculations for these unit processes.

2.5.3.1 Well Construction

Data for the construction and installation of natural gas wellheads are based on the energy requirements and linear drill speed of diesel-powered drilling rigs, the depths of wells, and the casing materials required for a wellbore. Construction and installation are one-time activities that are apportioned to each unit of natural gas operations by dividing all construction and installation emissions by the lifetime in years and production in million cubic feet of a typical well.

2.5.3.2 Well Completion

The data for well completion describe the emission of natural gas that occurs during the development of a well, before natural gas recovery and other equipment have been installed at the wellhead. Well completion is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from an event that occurs one time in the life of a well.

The methane emissions from the completion of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 36.65 Mcf/completion and unconventional wells produce 9,175 Mcf/completion (EPA, 2011a).

Within the unconventional well category, NETL adjusted EPA's completion emission factors to account for the different reservoir pressures of unconventional wells. NETL used EPA's emission factor of 9,175 Mcf of methane per completion for Barnett Shale gas wells. NETL adjusted this emission factor downward for tight gas in order to account for the lower reservoir pressures of tight gas wells. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor. The production rate of tight gas wells is 40 percent of that for Barnett Shale wells (with EURs of 1.2 BCF for tight gas vs. 3.0 BCF for Barnett Shale), and thus NETL assumes that the completion emission factor for tight gas wells is 3,670 Mcf of methane per completion (40 percent × 9,175 = 3,670).

CBM wells also involve unconventional extraction technologies, but have lower reservoir pressures than shale gas or tight gas wells. The corresponding emission factor of CBM wells is 49.57 Mcf of methane per completion, which is the well completion factor that EPA reports for low pressure wells (EPA, 2011a).

The analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. For instance, when factoring for the density of natural gas, a conventional completion emission of 36.65 Mcf is equivalent to 1,540 lbs. CH_4/completion.

2.5.3.3 Liquid Unloading

The data for liquids unloading describe the emission of natural gas that occurs when water and other condensates are removed from a well. These liquids impede the flow of natural gas from the well, and thus producers must occasionally remove the liquids from the wellbore. Liquid unloading is necessary for conventional gas wells—it is not necessary for unconventional wells or associated gas

wells. Liquid unloading is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from the occasional maintenance of a well.

The methane emissions from liquids unloading are based on the total unloading emissions from conventional wells in 2007, the number of active conventional wells in 2007, and the average frequency of liquids unloading (EPA, 2011a). The resulting emission factor for liquids unloading is 776 lb CH_4/episode.

2.5.3.4 Workovers

Well workovers are necessary for cleaning wells and, in the case of shale and tight gas wells, use hydraulic fracturing to re-stimulate natural gas formations. The workover of a well is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from the occasional maintenance of a well. As stated in EPA's technical support document of the petroleum and natural gas industry (EPA, 2011a), conventional wells produce 2.454 Mcf of methane per workover. EPA assumes that the emissions from unconventional well workovers are equal to the emission factors for unconventional well completion (EPA, 2011a). Thus, for unconventional wells, this analysis uses the same emission factors for well completion (discussed above) and well workovers.

Unlike well completions, well workovers occur more than one time during the life of a well. For conventional wells, there were approximately 389,000 wells and 14,600 workovers in 2007 (EPA, 2011a), which translates to 0.037 workovers per well-year. Similarly, for unconventional wells, there were approximately 35,400 wells and 4,180 workovers in 2007 (EPA, 2011a), which translates to 0.118 workovers per well-year.

2.5.3.5 Other Point Source Emissions

Routine emissions from natural gas extraction include gas that is released from wellhead and gathering equipment. These emissions are referred to as "other point source emissions." This analysis assumes that a portion of these emissions are flared, while the balance is vented to the atmosphere. For conventional wells, 51 percent of other point source emissions are flared, while for unconventional wells, a 15 percent flaring rate is used (EPA, 2011a).

Data for the other point source emissions from natural gas extraction are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for onshore and offshore wells. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas production rate in 2006. The emission factors for other point source emissions from natural gas extraction are shown in **Table 2-4**.

2.5.3.6 Other Fugitive Emissions

Routine emissions from natural gas extraction include fugitive emissions from equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other fugitive emissions," and cannot be captured for flaring. Data for other fugitive emissions from natural gas extraction are based on EPA data for onshore and offshore natural gas wells (EPA, 2011a). EPA's data is based on 2006 production (EPA, 2011a) and shows the annual methane emissions for specific extraction activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas production rate in 2006. The emission factors for other fugitive emissions from natural gas extraction are included in **Table 2-4**.

2.5.3.7 Valve Fugitive Emissions

The extraction of natural gas uses pneumatic devices for the opening and closing of valves and other control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas extraction site, and thus the pneumatic operation of valves results in the emission of fugitive gas.

Data for the fugitive emissions from valves (and other pneumatically-operated devices) are based on EPA data for onshore and offshore gas wells (EPA, 2011a). EPA's data are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific extraction activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas production rate. The emission factors for fugitive valve emissions from natural gas extraction are included in **Table 2-4**.

Table 2-4: Other Point Source and Fugitive Emissions from Natural Gas Extraction

NG Extraction Emission Source	Onshore Extraction	Offshore Extraction	Units
Other Point Source Emissions	7.49E-05	3.90E-05	lb CH_4/lb NG extracted
Other Fugitive Emissions	1.02E-03	2.41E-04	lb CH_4/lb NG extracted
Valve Fugitive Emissions (including pneumatic devices)	2.63E-03	1.95E-06	lb CH_4/lb NG extracted

2.5.3.8 Venting and Flaring

Venting and flaring are necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Venting and flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring at a natural gas well include carbon dioxide, methane, and nitrous oxide. The mass composition of unprocessed natural gas (referred to as "production natural gas") is 78.3 percent CH_4, 1.51 percent CO_2, 1.77 percent nitrogen, and 17.8 percent non-methane hydrocarbons (NMVOCs) (EPA, 2011a). This composition is used to model flaring at the natural gas processing plant. Flaring has a 98 percent destruction efficiency (98 percent of carbon in the flared gas is converted to CO_2), the methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2, and N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

2.5.4 Data for Natural Gas Processing

This analysis models the processing of natural gas by developing an inventory of key gas processing operations, including acid gas removal, dehydration, and sweetening. Standard engineering calculations were applied to determine the energy and material balances for the operation of key natural gas equipment. A summary of NETL's natural gas processing data is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculations for NETL's natural gas processing data.

2.5.4.1 Acid Gas Removal

Raw natural gas contains hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas. Amine-based processes are the predominant technologies for acid gas removal (AGR). The energy consumed by an amine reboiler accounts for the majority of energy consumed by the AGR process. Reboiler energy consumption is a function of the amine flow rate, which, in turn, is related to the amount of H_2S removed from natural gas. The H_2S content of raw natural gas is highly variable, with concentrations ranging from one part per million on a mass basis to 16 percent by mass in extreme cases. An H_2S concentration of 0.5 percent by mass of raw natural gas (Foss, 2004) is modeled in this analysis.

In addition to absorbing H_2S, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 0.000971 lb of methane per lb of natural gas sweetened (API, 2009).

Raw natural gas contains naturally-occurring CO_2 that contributes to the acidity of natural gas. A mass balance around the AGR unit, which balances the mass of gas input with the mass of gas venting and natural gas product, shows that 0.013 lb of naturally-occurring CO_2 is vented per lb of processed natural gas.

Non-methane volatile organic compounds (NMVOCs) are a co-product of AGR. A mass balance shows that 84 percent of the vented gas from the AGR process is NMVOC. They are separated and sold as a high value product on the market. Co-product allocation based on the energy content of the natural gas stream exiting the AGR unit and the NMVOC stream was used to apportion life cycle emissions and other burdens between the natural gas and NMVOC products.

2.5.4.2 Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel. The methane emissions from dehydration operations include combustion and venting emissions. This analysis estimates the fuel requirements and venting losses of dehydration in order to determine total methane emissions from dehydration.

NETL's data for natural gas dehydration accounts for the reboiler used by the dehydration process, the flow rate of glycol solvent, and the methane vented from the regeneration of glycol solvent. All of these activities depend on the concentrations of gas and water that enter and exit the dehydration process. The typical water content for untreated natural gas is 49 lbs. per million cubic feet (MMcf). In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs./MMcf of natural gas (EPA, 2006). The flow rate of glycol solution is three gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gallon (EPA, 2006).

2.5.4.3 Valve Fugitive Emissions

The processing of natural gas uses pneumatic devices for the opening and closing of valves and other process control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery

equipment on all valves and other control devices at a natural gas processing plant, and thus the pneumatic operation of valves results in the emission of fugitive gas.

Data for the fugitive emissions from pneumatic devices are based on EPA data for gas processing plants (EPA, 2011a). EPA's data is based on 2006 production (EPA, 2011a) and shows the annual methane emissions for specific processing activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for valve fugitive emissions from natural gas processing is included in **Table 2-5**.

2.5.4.4 Other Point Source Emissions

Routine emissions from natural gas processing include gas that is released from processing equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other point source emissions." This analysis assumes that 100 percent of other point source emissions from natural gas processing are captured and flared.

Data for the other point source emissions from natural gas processing are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific gas processing activities. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for other point source emissions from natural gas processing is included in **Table 2-5**.

2.5.4.5 Other Fugitive Emissions

Routine emissions from natural gas processing include fugitive emissions from processing equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other fugitive emissions." and cannot be captured for flaring.

Data for the other fugitive emissions from natural gas processing are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific gas processing activities. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for other fugitive emissions from natural gas processing is included in **Table 2-5**.

Table 2-5: Other Point Source and Fugitive Emissions from Natural Gas Processing

NG Processing Emission Source	Value	Units
Other Point Source Emissions	3.68E-04	lb CH_4/lb NG processed
Other Fugitive Emissions	8.25E-04	lb CH_4/lb NG processed
Valve Fugitive Emissions (including pneumatic devices)	6.33E-06	lb CH_4/lb NG processed

2.5.4.6 Venting and Flaring

The venting and flaring process for natural gas processing is similar to that of natural gas extraction, described in **Section 2.5.3.8**, except all of the other point source emissions at the natural gas processing plant are flared. The combustion products of flaring at a natural gas processing plant include carbon dioxide, methane, and nitrous oxide. The mass composition of pipeline quality natural gas is 92.8 percent CH_4, 0.47 percent CO_2, 0.55 percent nitrogen, and 5.5 percent NMVOCs; this composition is used to model flaring at the natural gas processing plant. Flaring has a 98 percent destruction efficiency (98 percent of carbon in the flared gas is converted to CO_2); the methane

emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2; and N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

2.5.4.7 Natural Gas Compression

Compressors are used to increase the natural gas pressure for pipeline distribution. This analysis assumes that the inlet pressure to compressors at the natural gas extraction and processing site is 50 psig and the outlet pressure is 800 psig. Three types of compressors are used at natural gas processing plants: gas-powered reciprocating compressors, gas-powered centrifugal compressors, and electrically-powered centrifugal compressors.

Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Burklin & Heaney, 2006).

Gas-powered centrifugal compressors are commonly used at offshore natural gas extraction sites. The amount of natural gas required for gas powered centrifugal compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures).

If the natural gas extraction site is near a source of electricity, it has traditionally been financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a populated area. An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine.

Centrifugal compressors (both gas-powered and electrically-powered) lose natural gas through a process called wet seal degassing, which involves the regeneration of lubricating oil that is circulated between the compressor shaft and housing. This analysis uses an EPA study that sampled venting emissions from 15 offshore platforms (Bylin et al., 2010) and implies a wet seal degassing emission factor of 0.0069 lb of natural gas/lb of processed natural gas.

2.5.5 Data for Natural Gas Transport

This analysis models the transport of natural gas by characterizing key construction and operation activities for pipeline transport. A summary of NETL's natural gas transport data is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculation methods for NETL's natural gas transport data.

2.5.5.1 Natural Gas Transport Construction

The construction of a natural gas pipeline is based on the linear density, material requirements, and length for pipeline construction. A typical natural gas transmission pipeline is 32 inches in diameter and is constructed of carbon steel. Construction is a one-time activity that is apportioned to each unit of natural gas transport by dividing all construction burdens by the book life in years and throughput in million cubic feet of the pipeline.

2.5.5.2 Natural Gas Transport Operations

Data for the operation of a natural gas pipeline are based on national inventory data for methane emissions from natural gas transmission (EPA, 2011b) and a national pipeline compressor survey compiled by EIA (Gaul, 2011). Air emissions from pipeline operations are calculated by applying AP-42 emission factors to the portion of pipeline natural gas that is combusted for compressor power. Seven percent of U.S. natural gas pipeline compressors rely on electric power, and thus the emission profile of the U.S. electricity grid is used to model the emissions associated with electric compressor operations. Finally, the estimated transport capacity of U.S. national gas pipelines (in ton-miles) is applied to the other pipeline variables in order to correlate pipeline emissions with pipeline distance.

2.5.6 Data for Other Energy Sources

The overall goal of this analysis is to understand the greenhouse gas burdens of natural gas extraction and transport. However, the modeling of the conversion of natural gas energy to electricity and electricity transmission is necessary in order to understand how significant extraction and transport are in the cradle-to-grave life cycle context. Additionally, including a comparison both to the upstream greenhouse gases from coal extraction and transport, and the conversion of coal to electricity allows comparison of the fuels on a common basis.

Coal was chosen as a comparable fossil energy source to natural gas that will be used for power production. Because a mix of natural gas sources is developed to represent a domestic production average, a similar method was followed for developing an average domestic coal extraction and transport profile. Two sources of coal are used in the mix, and a wide range of uncertainty is applied to sensitive parameters to ensure the domestic average is captured. The two coal sources are:

- Illinois No. 6 Underground-mined Bituminous
- Powder River Basin Surface-mined Sub-bituminous

Table 2-6 shows the properties used for each type of coal, as well as the proportion of U.S. supply used to create the average profile. The methane content is indicative of what is emitted to the atmosphere during the mining process, not the methane contained in the coal in the formation or after mining.

Table 2-6: Coal Properties

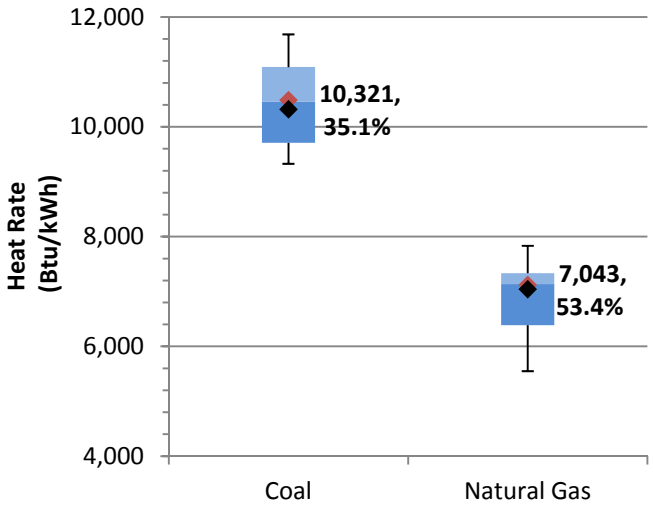
Coal Type	U.S. Supply Share (% by energy)	Energy Content (Btu/lb)	Carbon Content (% by mass)	Methane Emissions (cf CH_4/ton)
Sub-bituminous	69%	8,564	50.1%	8 – 98 (51)
Bituminous	31%	11,666	63.8%	360 – 500 (422)
Average		9,526	54.3%	

Additional information for the Illinois No. 6 profile can be found in the appendix and in the NETL document, *Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant (NETL, 2010e).* Additional information for the Powder River Basin coal extraction and transport profile can be found in the appendix to this document.

2.5.7 Data for Energy Conversion Facilities

The simplest way to compare the full life cycle of coal and natural gas is to produce electricity, although there are alternative uses for both feedstocks. To compare inputs of coal and natural gas on a common basis, production of baseload electricity was chosen. Seven different power plant options are used – three for natural gas and four for coal. Three of the options include carbon capture technology and sequestration infrastructure. Two of the options are U.S. fleet averages based on eGRID data, while the remainder are NETL baseline models. For the U.S. fleet average power plants, **Figure 2-3** shows the distribution of heat rates and associated efficiencies from eGRID. To arrive at the samples shown below, plants smaller than 200MW, with capacity factors lower than 60 percent, and with primary feedstock percentages below 85 percent were cut. The boxes are the first and third quartiles, and the whiskers the 5th and 95th percentiles. The division in the boxes is the median value. The black diamond is the mean, and the orange diamond is the production-weighted mean.

Figure 2-3: Fleet Baseload Heat Rates for Coal and Natural Gas (EPA, 2010)



2.5.7.1 Natural Gas Combined Cycle (NGCC)

The NGCC power plant is based a 555-MW thermoelectric generation facility with two parallel, advanced F-Class gas fired combustion turbines. Each combustion turbine is followed by a heat recovery steam generator that produces steam that is fed to a single steam turbine. The NGCC plant consumes natural gas at a rate of 75,900 kg/hr and has an 85 percent capacity factor. Other details on the fuel consumption, water withdrawal and discharge, and emissions to are detailed in NETL's bituminous baseline (NETL, 2010a). The carbon capture scenario for NGCC is configured a Fluor Econamine carbon dioxide capture system that recovers 90 percent of the CO_2 in the flue gas

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant (NETL, 2010d).*

2.5.7.2 Gas Turbine Simple Cycle (GTSC)

The GTSC plant uses two parallel, advanced F-Class natural gas-fired combustion turbines/generators. The performance of the GTSC plant was adapted from NETL baseline of NGCC power by considering only the streams that enter and exit the combustion turbines/generators and not

accounting for any process streams related to the heat recovery systems used by combined cycles. The net output of the GTSC plant is 360 MW and it has an 85 percent capacity factor.

2.5.7.3 U.S. 2007 Average Baseload Natural Gas

The average baseload natural gas plant was developed using data from eGRID on plant efficiency (EPA, 2010). The most recent eGRID data is representative of 2007 electricity production. The average heat rate was calculated for plants with a capacity factor over 60 percent and a capacity greater than 200MW to represent those plants performing a baseload role. The average efficiency (weighted by production, so the efficiency of larger, more productive plants had more weight) was 53.4 percent. This heat rate is applied to the energy content of natural gas (which ranges from 990 and 1,030 Btu/cf) in order to determine the feed rate of natural gas per average U.S. natural gas power. Similarly, the carbon content of natural gas (which ranges from 72 percent to 80 percent) is factored by the feed rate of natural gas, 99 percent oxidation efficiency, and a molar ratio of 44/12 to determine the CO_2 emissions per unit of electricity generation.

2.5.7.4 Integrated Gasification Combined Cycle (IGCC)

The plant modeled is a 640 MW IGCC thermoelectric generation facility located in southwestern Mississippi utilizing an oxygen-blown gasifier equipped with a radiant cooler followed by a water quench. A slurry of Illinois No. 6 coal and water is fed to two parallel, pressurized, entrained flow gasifier trains. The cooled syngas from the gasifiers is cleaned before being fed to two advanced F-Class combustion turbine/generators. The exhaust gas from each combustion turbine is fed to an individual heat recovery steam generator where steam is generated. All of the net steam generated is fed to a single conventional steam turbine generator. A syngas expander generates additional power.

This facility has a capacity factor of 80 percent. For the carbon capture case, the plant is a 556 MW facility with a two-stage Selexol solvent process to capture both sulfur compounds and CO_2 emissions. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant (NETL, 2010c).*

2.5.7.5 Supercritical Pulverized Coal (SCPC)

This plant is a 550 MW facility located at a greenfield site in southeast Illinois utilizing a single-train supercritical steam generator. Illinois No. 6 pulverized coal is conveyed to the steam generator by air from the primary air fans. The steam generator supplies steam to a conventional steam turbine generator. Air emission control systems for the plant include a wet limestone scrubber that removes sulfur dioxide, a combination of low-nitrogen oxides burners and overfire air, and a selective catalytic reduction unit that removes nitrogen oxides, a pulse jet fabric filter that removes particulates, and mercury reductions via co-benefit capture.

The carbon capture case is a 546 MW plant configured with 90 percent CCS utilizing an additional sulfur polishing step to reduce sulfur content and a Fluor Econamine FG Plus process. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant (NETL, 2010e).*

2.5.7.6 Existing Pulverized Coal (EXPC)

This case is an existing pulverized coal power plant that fires coal at full load without capturing carbon dioxide from the flue gas. This case is based on a 434 MW plant with a subcritical boiler that fires Illinois No. 6 coal, has been in commercial operation for more than 30 years, and is located in southern Illinois. The net efficiency of this power plant is 35 percent.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant (NETL, 2010b).*

2.5.7.7 U.S. 2007 Average Baseload Coal

Using a similar method to the fleet average natural gas baseload plant, a mean and weighted average efficiency of 35.1 percent were pulled from eGRID. Using the coal characteristics detailed in **Table 2-6**, a feed rate and emissions rate were created.

For each option, the transmission and distribution (T&D) of electricity incurs a 7 percent loss, resulting in the production of additional electricity and extraction of necessary fuel to overcome this loss. All upstream life cycle stages scale according to this loss factor.

Construction is included in the four NETL developed models. It accounts for less than 1 percent of overall greenhouse gas impact, and so was excluded from the total for the fleet average plants.

The performance characteristics of the power plants modeled in this analysis are summarized in **Table 2-7**. Note that for the average natural gas and coal power plants, low, nominal and high values are indicated.

Table 2-7: Power Plant Performance Characteristics

Property		Natural Gas			Coal					
		NGCC	GTSC	Avg. NG	IGCC	IGCC (w/ CCS)	SCPC	SCPC (w/ CCS)	EXPC	Avg. Coal
Performance										
Net Output	MW	555	360	> 200	640	556	550	546	434	> 200
Heat Rate[1]	Btu/kWh L			7,334						11,090
	Btu/kWh N	6,798	11,323	7,043	8,756	10,458	8,687	12,002	9,749	10,321
	Btu/kWh H			6,387						9,708
Efficiency	% L			46.5%						30.8%
	% N	50.2%	30.1%	48.4%	39.0%	32.6%	39.3%	28.4%	35.0%	33.1%
	% H			53.4%						35.1%
Capacity Fac.	%	85%	85%	> 60%	80%	80%	85%	85%	85%	> 60%
Feedstocks										
Natural Gas	cf/MWh	6,619	11,025	6,858	-	-	-	-	-	-
Ill. No. 6 Coal	lb/MWh	-	-	-	730	876	745	1,036	734	649
PRB Coal	lb/MWh	-	-	-	-	-	-	-	-	355
Air Emissions										
CO_2	lb/MWh	804	1,100	817	1,723	206	1,768	244	2,075	1,999
CO_2 Capture	%	n/a	n/a	n/a	n/a	90%	n/a	90%	n/a	n/a

[1] L, N, H indicated Low, Nominal (default), and High values, respectively.

2.5.8 Summary of Key Model Parameters

The following table summarizes the key parameters that affect the life cycle results for the extraction of natural gas. This includes the amounts of methane emissions from routine activities, frequency and emission rates from non-routine operations, depths of different well types, flaring rates of vented gas, production rates, and domestic supply shares.

Table 2-8: Key Parameters for Six Types of Natural Gas Sources

Property (Units)	Onshore	Associated	Offshore	Tight Sands	Shale	CBM
Natural Gas Source						
Production Rate (Mcf/day) (Range)	66 (46 - 86)	121 (85 - 157)	2,800 (1,960 - 3,641)	110 (77 - 143)	274 (192 - 356)	105 (73 - 136)
Natural Gas Extraction Well						
Flaring Rate (%)	51% (41 - 61%)			15% (12 - 18%)		
Well Completion (Mcf/episode)	47			4,657	11,643	63
Well Workover (Mcf/episode)	3.1			4,657	11,643	63
Well Workover Frequency (Episode/well/yr)	1.1			3.5		
Liquids Unloading (Mcf/episode)	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading Frequency (Episodes/well)	930	n/a	930	n/a	n/a	n/a
Valve Emissions, Fugitive (lb CH_4/Mcf)	0.11		0.0001	0.11		
Other Sources, Point Source (lb CH_4/Mcf)	0.003		0.002	0.003		
Other Sources, Fugitive (lb CH_4/Mcf)	0.043		0.01	0.043		
Acid Gas Removal (AGR) and CO_2 Removal Unit						
Flaring Rate (%)	100%					
CH_4 Absorbed (lb CH_4/Mcf)	0.04					
CO_2 Absorbed (lb CO_2/Mcf)	0.56					
H_2S Absorbed (lb H_2S/Mcf)	0.21					
NMVOC Absorbed (lb NMVOC/Mcf)	6.59					
Glycol Dehydrator Unit						
Flaring Rate (%)	100%					
Water Removed (lb H_2O/Mcf)	0.045					
CH_4 Emission Rate (lb CH_4/Mcf)	0.0003					
Valves & Other Sources of Emissions						
Flaring Rate (%)	100%					
Valve Emissions, Fugitive (lb CH_4/Mcf)	0.0003					
Other Sources, Point Source (lb CH_4/Mcf)	0.02					
Other Sources, Fugitive (lb CH_4/Mcf)	0.03					
Natural Gas Compression at Gas Plant						
Compressor, Gas-powered Reciprocating (%)	100%	100%		100%	75%	100%
Compressor, Gas-powered Centrifugal (%)			100%			
Compressor, Electrical, Centrifugal (%)					25%	
Natural Gas Emissions on Transmission Infrastructure						
Pipeline Transport Distance (mi.)	604 (483 - 725)					
Pipeline Emissions, Fugitive (lb CH_4/Mcf-mi.)	0.0003					
Natural Gas Compression on Transmission Infrastructure						
Distance Between Compressors (mi.)	75					
Compressor, Gas-powered Reciprocating (%)	78%					
Compressor, Gas-powered Centrifugal (%)	19%					
Compressor, Electrical, Centrifugal (%)	3%					

3 Inventory Results

This section includes upstream results for the average production case, marginal upstream results, and results after conversion to electricity.

3.1 Average Upstream Inventory Results

This analysis defines upstream activities as the raw material acquisition and transport activities that are necessary for the delivery of fuel to a power plant. The results of this analysis include the upstream GHG emissions for natural gas. For the natural gas supply chain, upstream includes well operations and natural gas processing activities, as well as the pipeline transport of natural gas from the extraction site to a power plant.

Figure 3-1: Upstream Cradle-to-gate Natural Gas GHG Emissions by Source

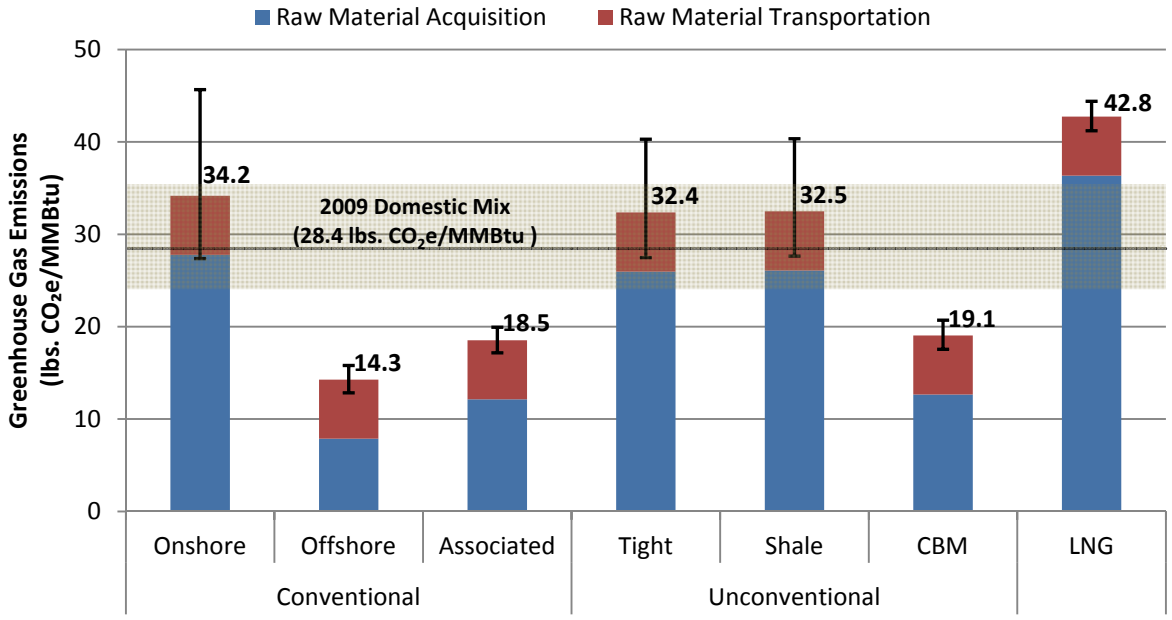


Figure 3-1 shows the comparative upstream greenhouse gases of the six sources of domestic gas, imported liquefied natural gas, and the 2009 mix of all of those sources, broken out by life cycle stage. These results are based on IPCC 100-year GWP. The domestic average of 28.4 lbs. CO_2e/MMBtu and its associated uncertainty are shown overlaying the results for the other types of gas. This average is calculated using the percentages shown in **Table 2-2**. It is worth noting here that the RMT result is the same for all types of natural gas. It is assumed in this study that natural gas is a commodity that is indistinguishable once put on the transport network, so the distance traveled is the same for all types of natural gas. The distance parameter is adjustable, so if a natural gas type with a short distance to markets were evaluated, the RMT value would be smaller.

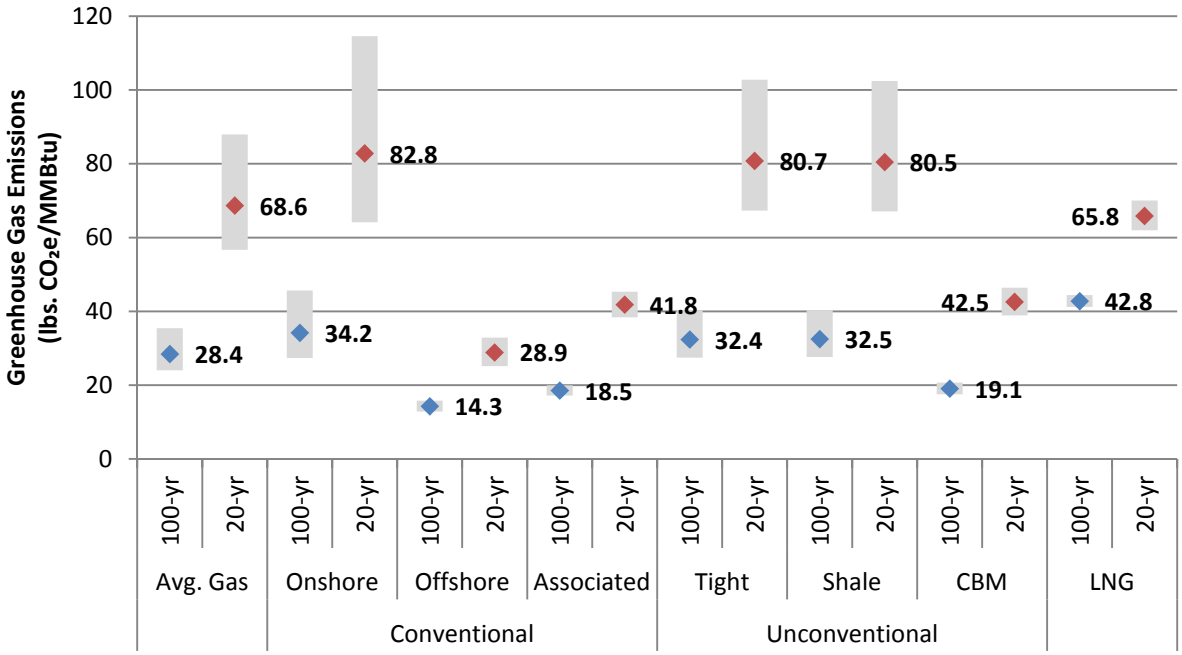
Offshore sourced natural gas has the lowest greenhouse gases of any source. This is due to the very high production rate of offshore wells and an increased emphasis on controlling methane emissions for safety and risk-mitigation reasons.

Imported gas has a significantly higher greenhouse gases than even domestic unconventional extraction. It is fundamentally an offshore extraction process, which has the lowest GHGs of all the

sources. The additional impact is due to the refrigeration, ocean transport and liquefaction processes. Uncertainty is highest for the unconventional sources due to high episodic emissions (well completions, workovers, etc.) and a wide range of observed production rates to allocate those emissions.

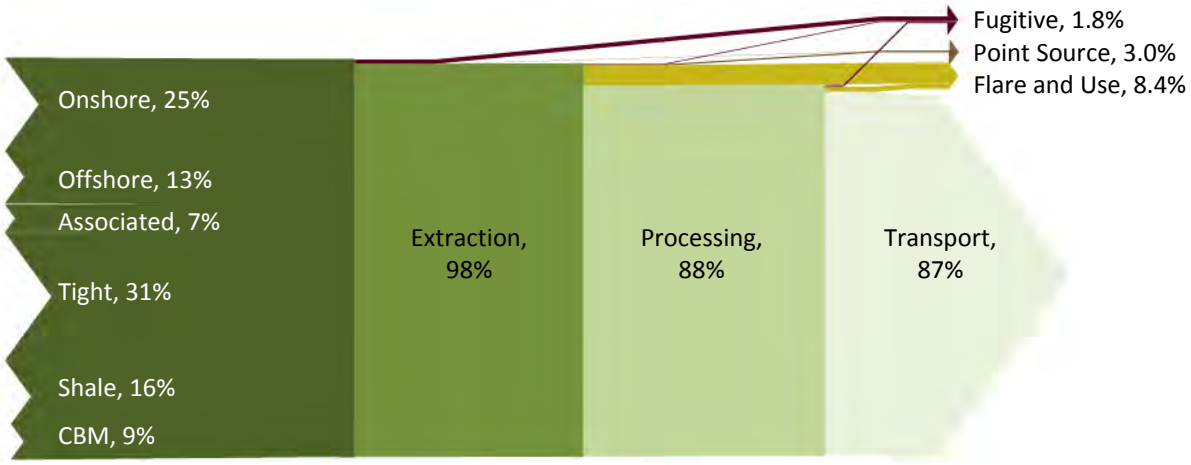
The key sources of GHG emissions in the natural gas supply chain are the combustion of fossil fuels and the venting of methane from natural gas processing and compression equipment.

Figure 3-2: Upstream Cradle-to-gate Natural Gas GHG Emissions by Source and GWP



The results in **Figure 3-2** compare the basic results from **Figure 3-1** across two sets of global warming potentials (detailed in **Table 2-1**). Converting the inventory of greenhouse gases to 20-year GWP, where methane's factor increases from 25 to 72, magnifies the difference between conventional and unconventional sources of natural gas, and the importance of methane losses to the cradle-to-gate GHG results.

Figure 3-3: Cradle-to-Gate Reduction in Extracted Natural Gas



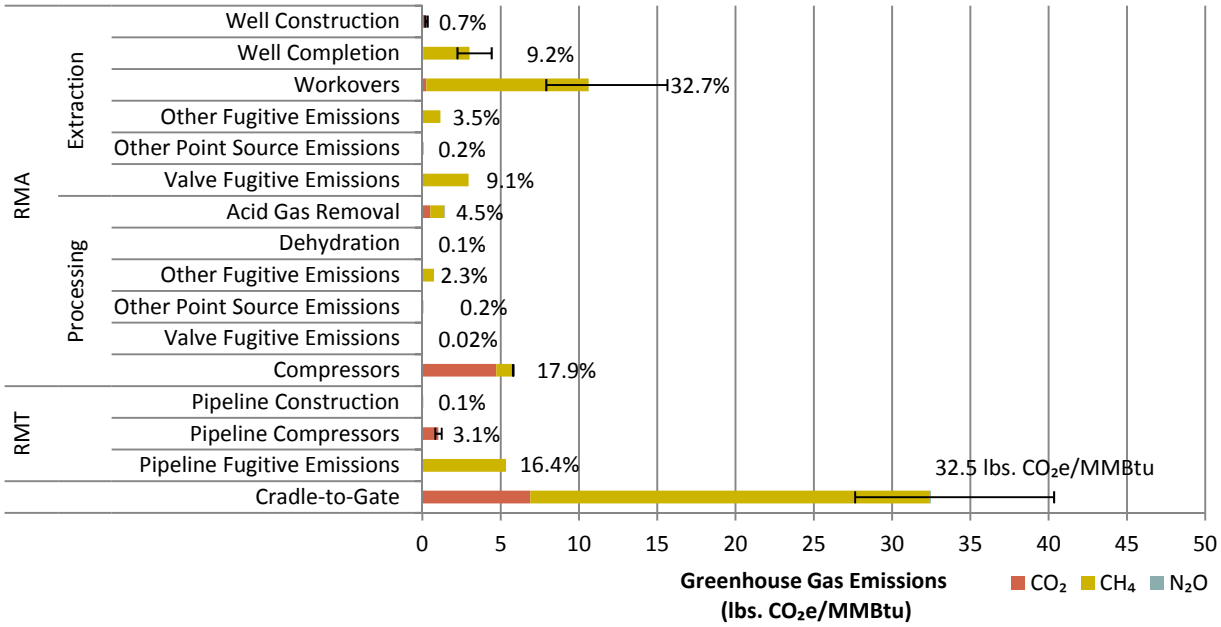
The Sankey diagram shown in **Figure 3-3** shows the reduction in natural gas (not solely methane) from extraction to delivery at the plant gate. This information is also not weighted by global warming potential. **Table 3-1** shows the same information in table form. Of the natural gas extracted from the ground, only 87 percent is delivered to the plant or city gate; 13 percent is either used internally for power, released at a point source and then flared – if applicable, or lost as a fugitive emission. It is important to recognize that not all of this gas is emitted to the atmosphere. In fact, 64 percent of the reduction in natural gas is used to power various processing equipment, most significantly compressors providing motive force for the natural gas. Further, 23 percent are point source emissions, generally concentrated enough to be flared; this, importantly from a climate change perspective, converts the methane to carbon dioxide. Only 13 percent of emissions are considered fugitive: spatially separated emissions difficult to capture or control.

Table 3-1: Natural Gas Losses from Extraction and Transportation

Process	Raw Material Acquisition		Transport	Total
	Extraction	Processing		
Extracted from Ground	100.0%			100.0%
Fugitive Losses	1.2%	0.1%	0.5%	1.8%
Point Source Losses (Vented or Flared)	0.8%	2.2%	0.0%	3.0%
Flare and Fuel Use	0.0%	7.6%	0.8%	8.4%
Delivered to End User				86.9%

By expanding the underlying data in NETL's model, a better understanding of the key contributions to natural gas emissions can be achieved. **Figure 3-4** shows the GHG contribution of specific extraction and transport activities for the Barnett Shale profile. This figure further shows the contribution of methane (CH_4), nitrous oxide (N_2O) and carbon dioxide (CO_2) to the total greenhouse gases. Similar data exists for each source of natural gas, as well as for the domestic average.

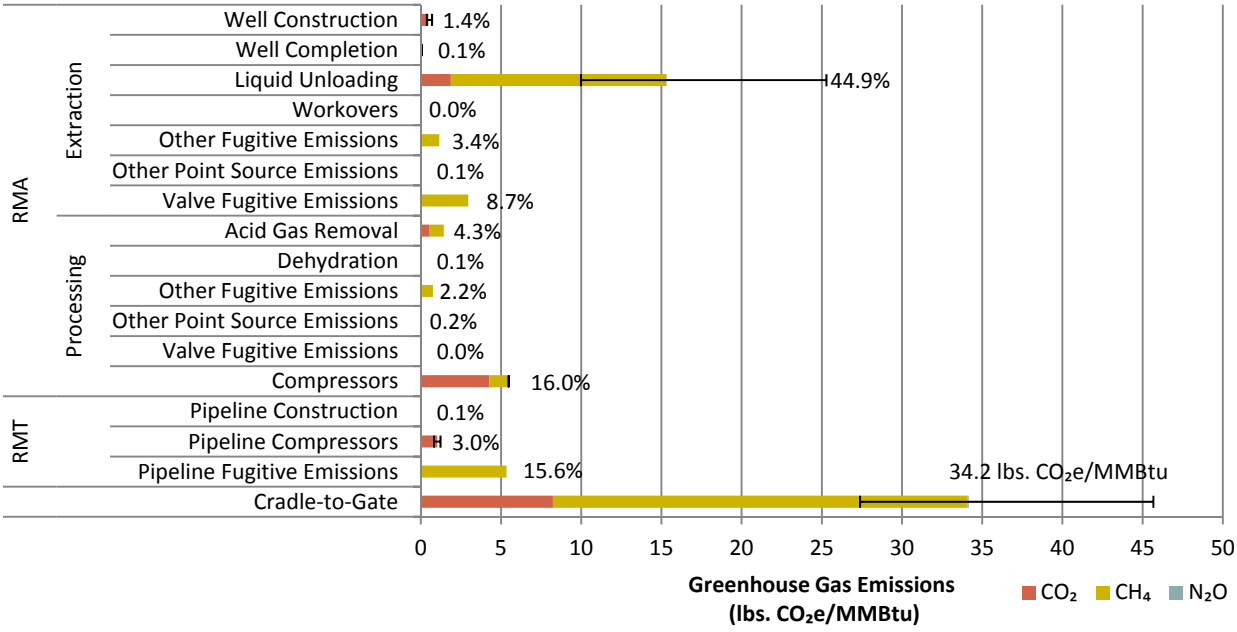
Figure 3-4: Expanded Greenhouse Gas Results for Barnett Shale Gas



This figure shows clearly how important methane is to the total greenhouse gas emissions. In most energy systems, carbon dioxide is the primary concern, but for natural gas extraction, processing and transport, the methane drives the result, and most of the uncertainty. With this unconventional gas, the importance (and associated uncertainty) associated with episodic emissions such as well completion and workover can be seen as well. Well construction, on the other hand, contributes less than 1 percent to the total. Moreover, from the compressors at the last stage of the processing step along with the compressor operations and fugitive emissions on the pipeline, the importance of transport can be seen from these results.

Figure 3-5 shows similar cradle-to-gate results for the natural gas extracted from conventional onshore wells. As with the shale profile, the major contributors are the fuel use and fugitive emissions from the transport, and episodic emissions like liquid unloading. Liquid unloading along contributes 45 percent to the total emissions, and the majority of the uncertainty as well. The uncertainty indicated here is due to a wide range in production rate, not the emission factor for liquids unloading. As discussed in the modeling method, production rate is used to apportion episodic emissions.

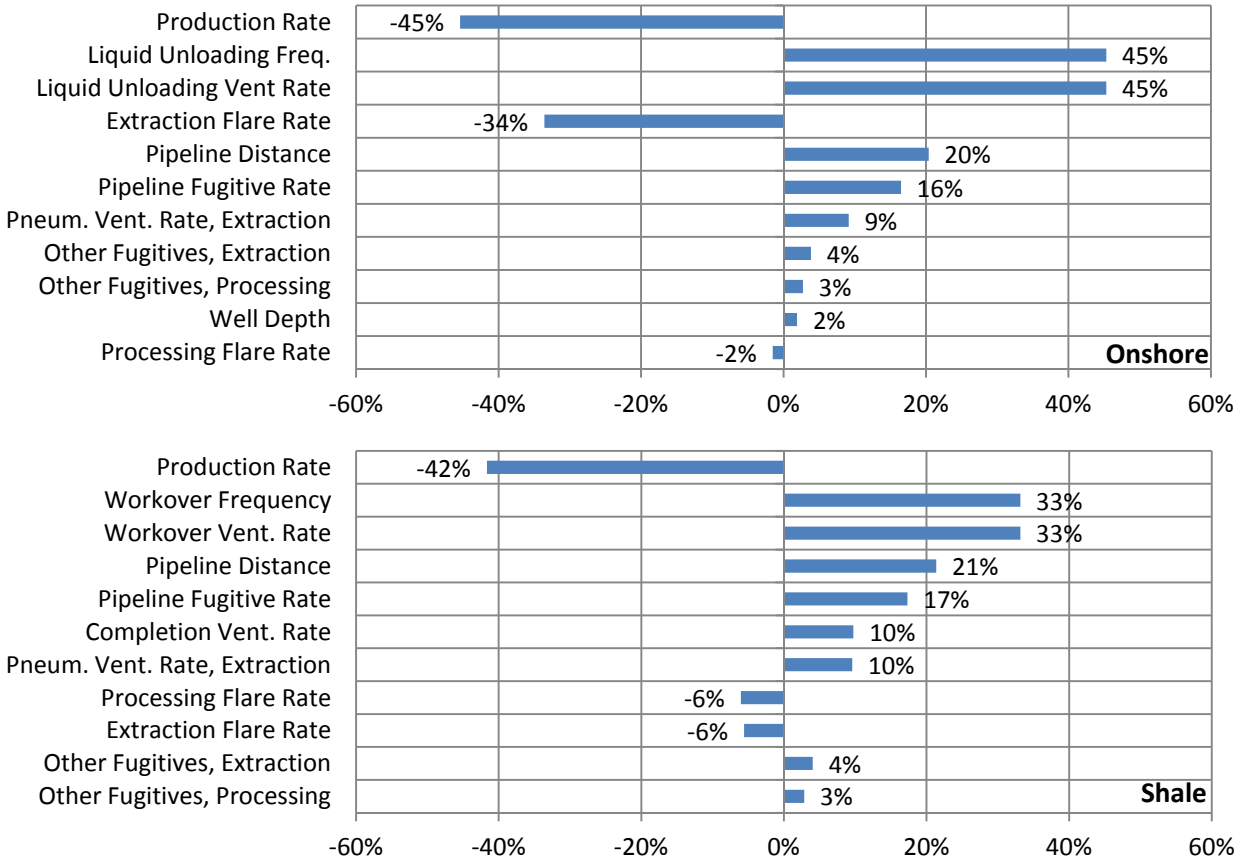
Figure 3-5: Expanded Greenhouse Gas Results for Onshore Natural Gas



This analysis uses a parameterized modeling approach that allows the alteration and subsequent analysis of key variables. Doing so allows the identification of variables that have the greatest effect on results. Sensitivity results are shown in **Figure 3-6**. Parameters were adjusted and displayed regardless of whether uncertainty information was collected for that parameter. Percentages above are relative to a unit change in parameter value; all parameters are changed by the same percentage, allowing comparison of the magnitude of change to the result across all parameters. Positive results indicate that an increase in the parameter leads to an increase in the result. A negative value indicates an inverse relationship; an increase in the parameter would lead to a decrease in the overall result.

For example, a 5 percent increase in shale Production Rate would result in a 2.1 percent (5 percent of 42 percent) decrease in cradle-to-gate GHGs, from 32.5 to 31.8 lbs. CO_2e/MMBtu. A corresponding 5 percent increase in onshore Production rate results in a 2.3 percent decrease to 33.4 lbs. CO_2e/MMBtu. Thus, onshore is more sensitive to changes in production rate than shale gas.

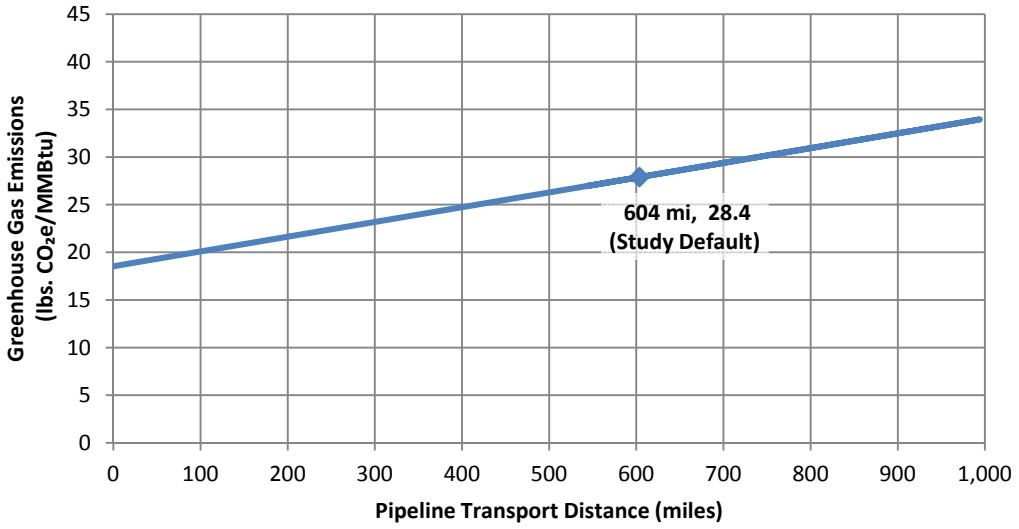
Figure 3-6: Sensitivity of Onshore and Shale GHGs to Changes in Parameters



The results in **Figure 3-6** show that both the onshore and shale profiles are sensitive to changes in pipeline distance, which is currently set to 604 miles for all profiles. As more unconventional sources like Marcellus shale which is close to major demand centers (New York, Boston, Toronto) come on the market, the average distance natural gas has to travel will go down, decreasing the overall impact.

The pipeline transport of natural gas is inherently energy intensive because compressors are required to continuously alter the physical state of the natural gas in order to maintain adequate pipeline pressure. Further, the majority of compressors on the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline. **Figure 3-7** shows the sensitivity of natural gas losses to pipeline distance. The study default for domestic sources of natural gas is 604 miles, which was determined by solving for the distance at which the per-mile emissions were equivalent to the U.S. annual natural gas transmission methane emissions in 2009. See **Appendix A** for full discussion on determining a default distance.

Figure 3-7: Sensitivity of GHGs Results to Pipeline Distance



3.2 Results for Marginal Production

Marginal production is defined here as the next unit of natural gas produced not included in the average, presumably from a new, highly productive well for each type of natural gas. Since older, less productive wells are ignored as part of these results, the production rate per well is much higher, episodic emissions are spread across more produced gas, and the corresponding GHG inventory is lower. **Table 3-2** shows the production rate assumptions used for both the average and marginal cases.

Table 3-2: Production Rate Assumptions for Average and Marginal Cases

Source	Well Count	Dry Production (Tcf)	Production Rate (Mcf/day)					
			Average			Marginal		
			N	L (-30%)	H (+30%)	N	L (-30%)	H (+30%)
Onshore	216,129	5.2	66	46	86	593	297	1,186
Offshore	2,641	2.7	2,801	1,961	3,641	6,179	3,090	12,358
Associated	31,712	1.4	121	85	157	399	200	798
Tight Sands	162,656	6.6	111	78	144	110	77	143
Shale	32,797	3.3	274	192	356	274	192	356
CBM	47,165	1.8	105	73	136	105	73	136

Results are shown below in **Table 3-3**. The marginal and average production rates for the unconventional sources (tight, shale and CBM) were identical, and so there is no change shown below. There was a significant change in the production rate for all the mature conventional sources. Large numbers of the wells from each of these sources are nearing the end of the useful life, and have dramatically lower production rates, bringing the average far below what would be expected of a new well of each type.

Table 3-3: Average and Marginal Upstream Greenhouse Gas Emissions (lbs CO_2e/MMBtu)

Source		Average	Marginal	Percent Change
Conventional	Onshore	34.2	20.1	-41.2%
	Offshore	14.3	14.1	-1.4%
	Associated	18.5	18.4	-0.8%
Unconventional	Tight	32.4	32.4	0.0%
	Shale	32.5	32.5	0.0%
	Coal Bed Methane	19.1	19.3	1.4%
Liquefied Natural Gas		42.8	42.5	-0.6%

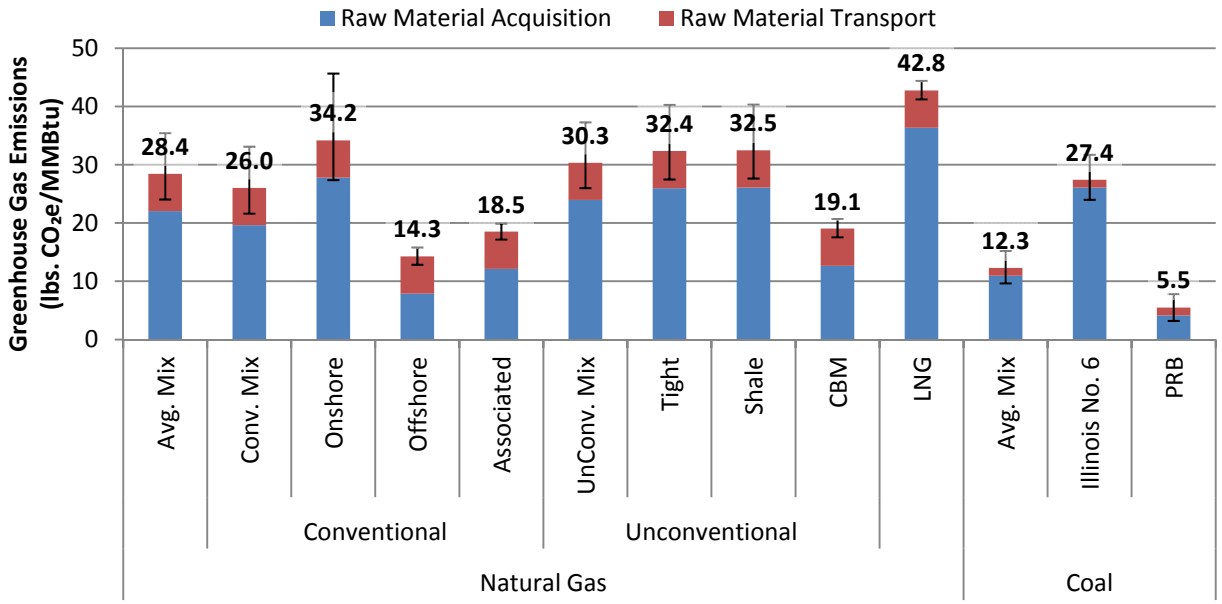
Interestingly, although the production rates for both associated gas and offshore gas change significantly, there is little change to the upstream value: a drop of 0.8 percent and 1.4 percent respectively. This has to do with the characteristics of these types of wells; the flow of natural gas in offshore wells is so strong that there is no need to periodically perform liquids unloading, and for associated wells, the petroleum co-product is constantly removing any liquid in the well. This means the only episodic emission (one which would need to be allocated by lifetime production of the well) is the construction or completion of the well, which is small in both cases, as a percentage of overall emissions.

That leaves onshore conventional production as the only source which shows a significant difference (a drop of 41.2 percent) between the average and marginal production. There are over 200,000 active onshore conventional wells, over 80 percent of which have daily production below the average rate of 138 Mcf/day (EIA, 2010). Yet, when this marginal natural gas is run through electricity generation, there is only a 7 percent drop in greenhouse gas emissions.

3.3 Comparison to Other Fossil Energy Sources

Additional insight can be gained by comparing the life cycle of natural gas power to those of coal. The upstream GHG emissions for various fuels are shown in **Figure 3-8**.

Figure 3-8: Comparison of Upstream GHG Emissions for Various Feedstocks

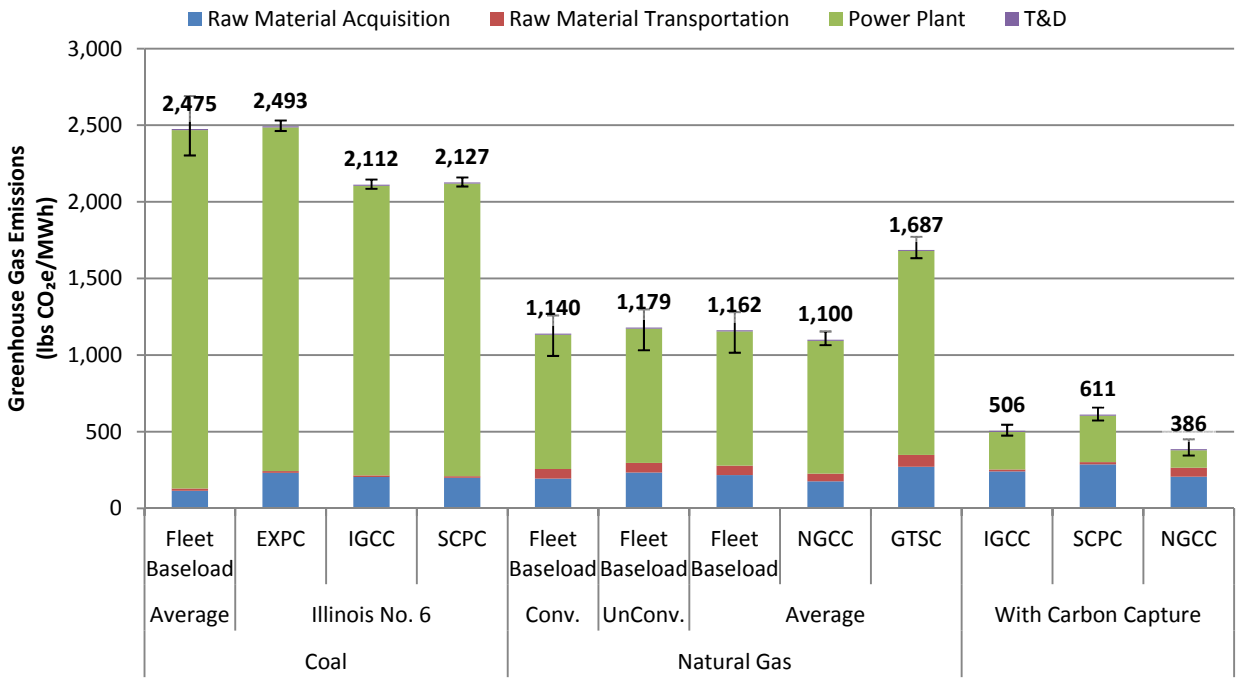


Compared on an upstream energy basis, natural gas has higher GHG emissions than coal. Comparing the domestic mixes from **Figure 3-8**, natural gas is nominally 116 percent more greenhouse gas intense than coal. Gassier bituminous coal such as Illinois No. 6 is more comparable, but only makes up 31 percent of domestic consumption on an energy basis.

3.4 Role of Energy Conversion

The per unit energy upstream emissions comparisons shown above are somewhat misleading in that a unit of coal and natural gas often provide different services. If they do provide the same service, they often do so with different efficiencies—it is more difficult to get useful energy out of coal than it is out of natural gas. To provide a common basis of comparison, different types of natural gas and coal are run through various power plants and converted to electricity. Note that there are alternative uses of both fuels, and as such, different bases on which they could be compared. However, in the United States, the vast majority of coal is used for power production, and so provides the most relevant comparison. **Figure 3-9** compares results for natural gas and coal power on the basis of 1 MWh of electricity delivered to the consumer. In addition to the NETL baseline fossil plants with and without carbon capture and sequestration, these results include a simple cycle gas turbine (GTSC) and representations of fleet average baseload coal and natural gas plants, as described in **Section 2.5.7**.

Figure 3-9: Life Cycle GHG Emissions for Electricity Production



In contrast to the upstream results, which showed a significantly higher GHGs for natural gas than coal, these results show that natural gas power, on a 100-year GWP basis, has a much lower impact than coal power without capture, even when using unconventional natural gas. Even when using less efficient simple cycle turbines, which provide peaking power to the grid, there are far fewer greenhouse gases emitted than for coal-fired power. Because of different the different roles played by these plants, the fairest comparison is the domestic mix of coal run through an average baseload coal power plant with the domestic mix of natural gas run through the average baseload natural gas plant. In that case, the coal-fired plant has emissions of 2,475 lbs. CO_2e/MWh, more than double the emissions of the natural –gas fired plant at 1,162 lbs. CO_2e/MWh.

Figure 3-10 shows the same results but applying and comparing 100- and 20-year IPCC global warming potentials to the inventoried greenhouse gases.

Figure 3-10: Comparison of Power Production GHG Emissions on 100- and 20-year GWPs

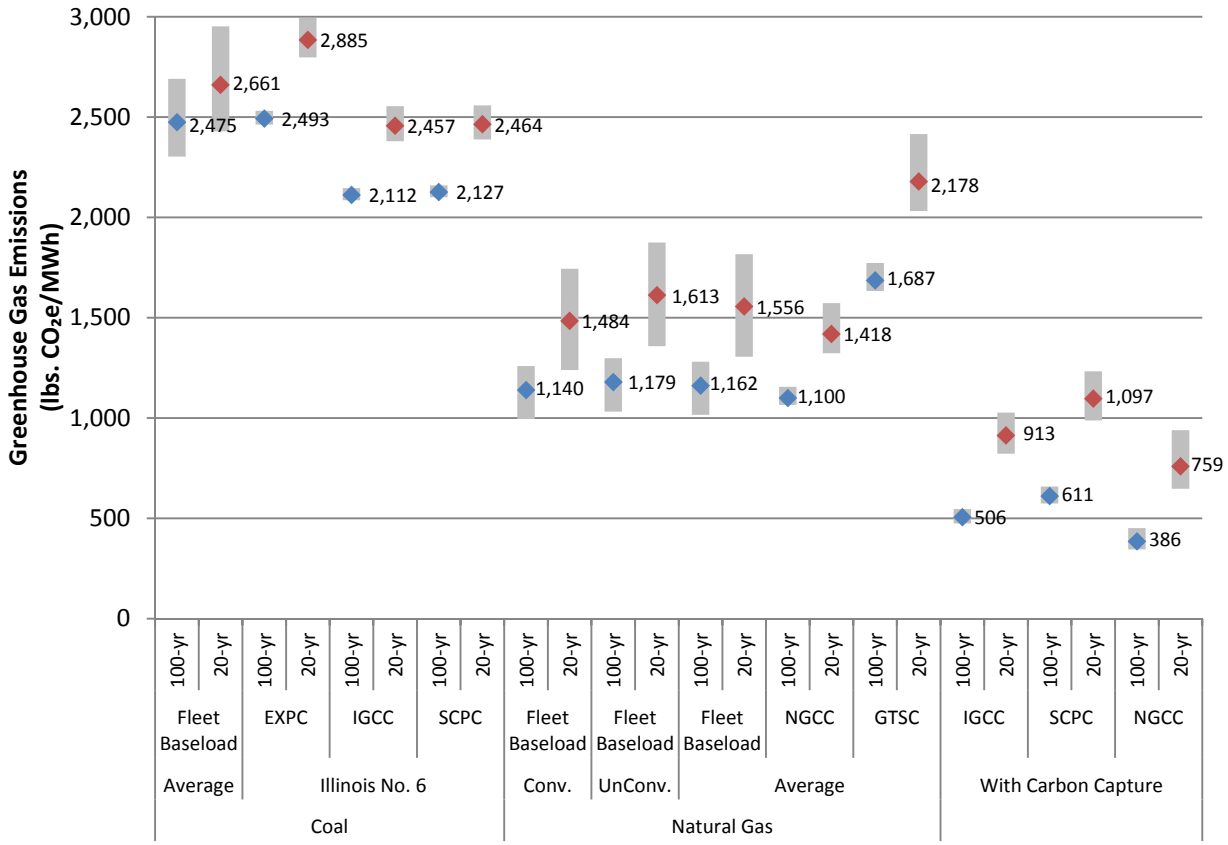


Figure 3-10 shows that even when using a GWP of 72 for CH_4 to increase the relative impact of upstream methane from natural gas, gas-fired power still has lower GHGs than coal-fired power. This conclusion holds across a range of fuel sources (conventional vs. unconventional for natural gas, bituminous vs. average for coal) and a range of power plants (GTSC, NGCC, average for natural gas, and IGCC, SCPC, EXPC, and average for coal). The one situation where this conclusion changed is the use of unconventional natural gas in an NGCC unit with carbon capture compared to an IGCC unit with carbon capture. The high end of the range overlaps the nominal value for IGCC in this situation.

4 Discussion

The following section contains a comparison of the results of this analysis to other natural gas LCAs, a discussion on data limitations, recommendations for improvement and final conclusions.

4.1 Comparison to Other Natural Gas LCAs

Authors at universities and other government labs have conducted research on the natural gas life cycle. The methods and conclusions of three such papers are summarized below.

Life Cycle Assessment of a Natural Gas Combined Cycle Power Generation System (Spath & Mann, 2000)

This NREL study is somewhat dated, having been published in 2000, but using data from the 1990s. It is a high quality study, which makes solid assumptions and tests those assumptions with documented sensitivity analysis. It uses national, annual, top-down information to develop the upstream emissions for natural gas extraction and transportation. Because of this, there are no data specific to unconventional extraction. This study includes not only greenhouse gases but select criteria air emissions and an energy balance. A qualitative impact assessment is performed as well.

Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation (Jaramillo, Griffin, & Matthews, 2007)

This widely cited paper is the most recent publicly available, peer-reviewed study that directly compares life cycle greenhouse gas emissions of power generated from natural gas and coal. Due to concerns regarding gas price volatility at the time the paper was being written, it also includes a comparison of LNG and synthetic natural gas (SNG) from coal. Rather than attempting to represent the next megawatt-hour generated by using best available technology, it looks at average current megawatt-hours generated, so plant efficiencies tend to be lower and emission factors higher. It mixes technologies (NGCC vs. GTSC) and roles (baseload vs. peaking). Like the NREL study, the upstream emissions for both natural gas and coal are top-down numbers. These values are somewhat dated, and represent a homogeneous gas supply rather than breaking out unconventional extraction.

Development of a Top Down Screening Model Using 2011 EPA Greenhouse Gas Inventory

Although this study uses emission factors from the EPA that went into building the 2011 U.S. Greenhouse Gas Inventory, it did not use the annual emissions estimates to generate a top-down value. Rather, some of the EPA emission factors were applied against specific activities, combined with other data sources and standard engineering calculations in a comprehensive hybrid bottom-up approach.

For comparison purposes, NETL performed a top-down analysis of 2009 domestic natural gas production using EPA's 2011 GHG inventory. This top-down approach was not a comprehensive LCA, but was a screening method that resulted in an aggregated, national-level estimate of GHG emissions. The top-down approach gave a GHG result of 36.6 lbs. CO_2e/MMBtu of delivered natural gas to a large end user, with +30 percent and -19 percent uncertainty. NETL's comprehensive LCA model of natural gas gives a GHG result of 28.4 lbs. CO_2e/MMBtu of delivered natural gas, which is 24 percent lower than the top-down value derived from EPA's national inventory. The nominal top-down number from EPA's inventory is within NETL's uncertainty range, but NETL and EPA use many of the same emission factors for natural gas production, and thus an explanation of the 24 percent difference is necessary.

An overarching reason for the difference between EPA's national inventory and NETL's natural gas life cycle analysis model is that EPA's inventory is based on the emissions reported for an entire industry sector over one year, while NETL's model accounts for the operating characteristic of six types of natural gas extraction technologies over a 30-year period and then mixes the six types according to the 2009 U.S. natural gas supply profile. Three specific examples of this fundamental difference between modeling approaches are as follows:

1. A difference in method between activity-based scaling to the national level vs. well-specific production rates that scale results to each of six extraction types.
2. Differences in episodic emission factors for tight gas and the contribution of tight gas to the national inventory.
3. Time series discrepancies inherent in EPA's episodic emission factors.

Clarification on these differences is provided below.

For each type of natural gas well, NETL apportions episodic emission factors based on the production rate of a single well. These apportioned emissions are then compiled according to the relative contribution of each well type to the domestic mix to arrive at the domestic average emissions. EPA's national GHG inventory, on the other hand, does not use well production rates, but uses well activity counts for conventional and unconventional wells to scale up the episodic emission factors to a national level. It is possible that the production rates of the wells that were sampled during the development of EPA's episodic emission factors do not align with the average well production rates applied by NETL. Or the activity counts used by EPA do not align with the contribution of the six natural gas types to the national mix as modeled by NETL.

When modeling tight gas, NETL made adjustments to EPA's emission factors for well completions and workovers. A close look at EPA's documentation (EPA, 2011a) indicates that its unconventional completion and workover emission factors are representative of high-pressure, tight gas wells in the San Juan and Piceance Basins that were completed using a horizontal hydraulic fracturing method and have a high, for tight gas basins, EUR of approximately 2 to 4 BCF. NETL's survey of tight gas production in the U.S. determined that an EUR of 1.2 BCF is more representative of average U.S. tight gas production. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor for tight gas well completion and workovers. NETL uses an emission factor of 3,670 Mcf CH_4 per episode for the completion and workover of tight gas wells. It is worth noting that EPA does not distinguish between tight sands and shale gas in the annual inventory, a general category of unconventional natural gas is characterized by low and high pressure formations. NETL applied EPA's unconventional completion and workover emission factor for low pressure formations (49.57 Mcf CH_4) reported in Subpart W Technical Support Document (EPA, 2011a) to the coal bed methane well profile and the corresponding high pressure well emission factor to shale gas based on the correlation of representative EUR of 3 BCF for Barnett Shale and the San Juan and Piceance Basin EUR's representing a range of 2 to 4 BCF. While the EPA Subpart W Technical Support Document detailed the results for unconventional well completions and workovers for low pressure formations, the annual inventory (EPA, 2011a) discusses unconventional well activity as a single category assumed to be completed by hydraulic fracture, for the purposes of the inventory, and applies the high pressure formation emission factor of 9,175 Mcf CH_4 for all unconventional well completions and workovers in the annual activity count.

The differences between the top-down and comprehensive approaches is further influenced by whether or not EPA explicitly accounts for tight gas production or simply includes tight gas within its conventional onshore natural gas activity factors. Tight gas represents 31 percent of the 2009 U.S. domestic natural gas supply, and thus the results for NETL's domestic mix are sensitive to changes in the tight gas results (the extent of this sensitivity is demonstrated by the tornado chart for the domestic natural gas mix). It is not clear if EPA includes tight gas within its conventional or unconventional category. If EPA accounts for tight gas in its conventional category, then liquids unloading would be incorrectly assigned to tight gas production, which would result in an overstated result. Alternatively, if EPA accounts for tight gas in its unconventional category, then a well completion and workover emission factor based on high production tight gas formations using horizontal hydraulic fracture was applied, which would result in an overstated result. This difference is only relevant in the comparative context between the two modeling approaches (screening versus comprehensive life cycle analysis). With respect to the purpose of the EPA national inventory approach, the effects are minimized based on the granularity of the overall analysis and the comparison of results at the national sector level. As described above, NETL adjusted the episodic emission factors for tight gas and coal bed methane based on well completion method and production profile.

EPA's documentation of unconventional emission factors are provided in its Subpart W document, which is the basis for its national inventory results (EPA, 2011a). EPA's 2009 GHG inventory is representative of 2009 natural gas production; however, a close look at EPA's Subpart W document reveals that the episodic emission factors are based on relatively small samples of natural gas wells from 2006 and 2007. It is common for LCAs to use data from a broad range of years. However, the behavior of the natural gas industry was especially volatile between 2007 and 2009. The imposition of emission factors that are representative of 2006 and 2007 upon other natural gas data that are representative of anomalous activity in 2009 creates a time-series lag that introduces uncertainty to the emission factor.

Figure 4-1: Natural Gas Well Development vs. Natural Gas Production (EIA, 2011b, 2011c)

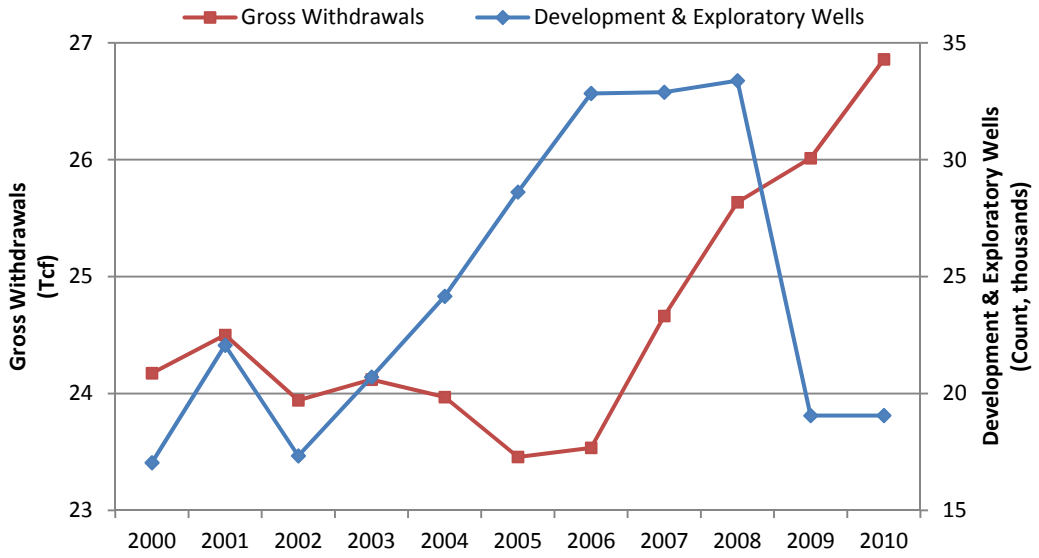


Figure 4-1 shows how increases in natural gas withdrawals lag between five and six years behind the increase in natural gas well drilling activity. Using a numerator with 2006 to 2007 data for well

activity, and 2009 data for withdrawals for the numerator could cause an undefined level of uncertainty in the emission factor. The modeling approaches used by EPA and NETL (as described in the first item above) react differently to this time-series lag. It is possible that NETL's model diminishes these effects because it amortizes the emissions over a 30-year operating period. **Table 4-1** shows the differences among key parameters of the NETL and EPA models.

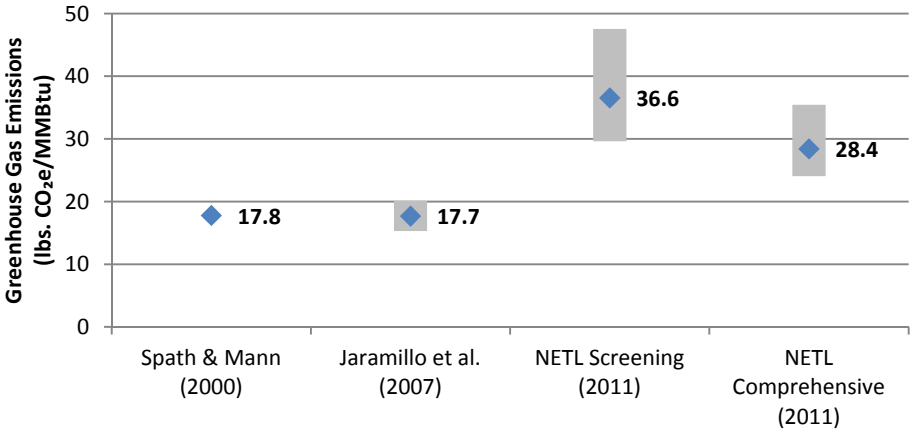
Table 4-1: Parameter Comparison between NETL and EPA Natural Gas Modeling

Property[1]	Units	NETL						EPA	
		Onshore	Assoc.	Offshore	Tight Sands[2]	Barnett Shale	CBM[3]	Conv.	Unconv.
Contribution to 2009 Mix	Percent	25%	7%	13%	31%	16%	9%	n/a	n/a
Production Rate (30-yr average)	Mcf/day	66	121	2,800	110	274	105	n/a	n/a
Active Wells (2007)	Count	n/a	n/a	n/a	n/a	n/a	n/a	431,035	41,790
Flaring Rate at Well	Percent	51%	51%	51%	15%	15%	51%	51%	15%
Completion Emissions	Mcf CH_4/episode	36.7	36.7	36.7	3,670	9,175	49.6	36.7	9,175
Workover Emissions	Mcf CH_4/episode	2.5	2.5	2.5	3,670	9,175	49.6	2.5	9,175
Workover Frequency	Episodes/year	0.04	0.04	0.04	0.12	0.12	0.12	0.04	0.12
Liquids Unloading Emissions	Mcf CH_4/episode	18.5	n/a	18.5	n/a	n/a	n/a	18.5	n/a
Liquids Unloading Frequency	Episodes/year	31	n/a	31	n/a	n/a	n/a	31	31

Figure 4-2 shows comparative greenhouse gas emissions from the three studies reviewed above. Results from each study were converted to a common basis of 100-year Global Warming Potential in pounds CO_2e per MMBtu gas delivered. The NREL study did not have an explicit range of values, so the central estimate is shown. For Jaramillo et al., the central estimate is the average of the high and low values.

[1] All emission rates are prior to flaring.
[2] The tight sands emission factor for well completions and workovers was calculated by NETL by reducing EPA's completion and workover factor (3,670 Mcf CH_4) for unconventional wells. The emission rates for completions and workovers are associated with the production rates and reservoir pressures of a well.
[3] The CBM emission factor for well completions and workovers (49.57 Mcf CH_4) is from EPA's documentation of low pressure wells. While CBM wells are an unconventional source of natural gas, they have a low reservoir pressure and thus have lower emission rates from completions and workovers.

Figure 4-2: Comparison of Natural Gas Upstream GHGs from Other Studies



4.2 Data Limitations

A key objective of an LCA is to normalize all data to a common basis (the functional unit). Like all LCAs, this analysis is limited by data uncertainty and data limitations. Key instances of data uncertainty and limitation are summarized below.

4.2.1 Data Uncertainty

Episodic emissions, natural gas production rates, flaring rates, and pipeline distance are four areas of data uncertainty in this analysis and represented within the study results.

Episodic emission factors include the non-routine release of natural gas during well completion, workovers, and liquid unloading. The results of this analysis are sensitive to these episodic emissions. The data for episodic emissions from natural gas wells is limited to a relatively small sample of wells and includes data going back as far as 1996 (EPA, 2011a). These emission factors are not necessarily applicable to all natural gas wells. For instance, it is likely that some unconventional wells have been completed using best practices and thus have low completion emissions, while some conventional wells have been completed with poor practices and thus have high completion emissions. However, there is no basis for claiming that a more recent, larger sampling of natural gas wells would increase or decrease these emission factors.

This analysis uses the production rate for each type of natural gas well for apportioning episodic emissions to a unit of natural gas production. The production rates of unconventional natural gas wells (Barnett Shale, tight gas, and CBM wells) are based on estimated ultimate recovery (EUR) data that are specific to each formation and have specific geographical constraints (Lyle, 2011). Representativeness of unconventional production rate data provides a reasonable confidence range of +/-30 percent. Production data for conventional wells is more variable, exhibiting a 200 percent increase from the low to high production rates. This variability is due to the broad range in age, reservoir, and technology characteristics for conventional wells, making it difficult to define a "typical" conventional natural gas well.

Flaring rate is the portion of vented natural gas that is combusted; the unflared portion is released directly to the atmosphere. Conventional wells flare 51 percent of vented gas, while unconventional wells flare 15 percent of vented natural gas (EPA, 2011a). The natural gas processing plant is modeled at a 100 percent flaring rate. While technology is available to capture and flare virtually all of the vented natural gas from extraction and processing, economics and other practical concerns

often prevent the implementation of such technologies. To account for uncertainty, this analysis varied the default values for flaring rates by +/-20 percent. It is likely that there are natural gas wells that fall outside of this range; however, based on professional judgment, we expect this range to account for average natural gas production.

The transmission of natural gas by pipeline involves the combustion of a portion of the natural gas in compressors as well as fugitive losses of natural gas. The total natural gas combustion and fugitive emissions is a function of pipeline distance, which was estimated at an average distance of 604 miles. This distance is based on the characteristics of the entire transmission network and delivery rate for natural gas in the U.S. It is possible that some natural gas sources are located significantly closer to their final markets than other sources of natural gas. To account for this uncertainty, this analysis varies the average pipeline distance by +/- 20 percent, which is an uncertainty range based on professional judgment.

4.2.2 Data Availability

Most data required for this analysis were readily available. However, there are several instances for which more detailed data would enhance the functionality of the LCA model and allow further discernment among natural gas types.

- Formation-specific gas compositions (CH_4, H_2S, NMVOC, and water) for each natural gas type would allow the assignment of specific venting emissions for natural gas extraction and processing. It would also allow the calculation of the specific heat load required for natural gas processing equipment (acid gas removal and dehydration).
- The effectiveness of green completions and workovers would allow further scrutiny of the episodic emissions at wells and, possibly, further data granularity among the three unconventional well types (Barnett Shale, tight gas, and CBM wells).
- No data are available for the fugitive emissions from around wellheads (between the well casing and the ground). This is a possible emission source that could present a significant opportunity for reductions in natural gas losses at a specific wellhead or site, but is not expected to be a significant contribution from an average natural gas perspective.
- Data for water sourcing and production of other fluids used for hydraulic fracturing would expand the boundaries of this analysis further and provide more details on the activities that contribute most to the environmental burdens of unconventional natural gas production and delivery.
- Direct and indirect GHG emissions from land use from access roads and well pads would expand the scope of this analysis further and provide more details on the activities that contribute most to the environmental burdens of unconventional natural gas production and delivery.
- Data for the energy requirements of natural gas exploration would allow further comparisons between conventional and unconventional natural gas. Historically, conventional natural gas fields have been difficult to find, but relatively easy to develop once they are located (NGSA, 2010). In contrast, unconventional gas fields are easy to find, but require significant preparation before natural gas is recovered.

- The energy requirements for the treatment of flowback water from the hydraulic fracturing of unconventional wells would represent an environmental burden that could allow further differentiation among natural gas extraction types.
- The current EPA GHG inventory data for natural gas pipeline emissions includes methane emissions in one category. A split between venting and fugitive emissions from pipeline transport would facilitate recommendations for reducing pipeline losses. Vented emissions may present opportunities for recovery, while fugitive emissions may not represent feasible opportunities for recovery.

4.3 Recommendations for Improvement

Creating a greenhouse gas inventory from a life cycle perspective gives not only a more complete picture of the impact of the process in question, but also allows for identification for the areas of largest impact, and those with the greatest opportunity for improvement. Since this inventory is presented on two different bases, opportunities were identified in both the extraction and delivery of natural gas as well as the production of electricity from natural gas and coal.

4.3.1 Reducing the GHG Emissions of Natural Gas Extraction and Delivery

Unconventional gas sources (shale, tight sands, coal bed methane, etc.) now make up the majority of natural gas extraction. As such, the emissions released during well completion and periodic well workovers are a major contributor to the overall greenhouse gas footprint, and a large opportunity for reduction. However, due to the relatively recent development of unconventional resources, better data is needed to characterize this opportunity based on basin type, drilling method, and production in order to better identify the potential for reductions.

Transportation of processed natural gas to the point at which it is consumed – in this inventory, large end users such as power plants – makes up a large portion of the overall upstream impact. There are two components to this impact: the first is the use of energy to compress the natural gas – the initial compression to put the natural gas on the pipeline, and then periodic compression as the motive force to push the natural gas along the transmission system. The second component is fugitive emissions from joints in the pipeline and other equipment. Improving compressor efficiency not only increases the amount of sellable product, but reduces the greenhouse gases emitted delivering that product. Pipeline fugitive emissions could be reduced with both technology and best management practices.

4.3.2 Reducing the GHG Emissions of Natural Gas and Coal-fired Electricity

Although efforts to reduce methane emissions from natural gas and coal extraction and transportation are important and should be continued, most GHG emissions from their extraction, transportation and use comes in the form of post-combustion carbon dioxide. Three high-level opportunities for reducing these emissions include:

- Capture the CO_2 at the power plant and sequester it in a saline aquifer or oil bearing reservoir
- Improve existing power plant efficiency
- Invest in advanced power research, development, and demonstration

Further, all opportunities need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security.

4.4 Conclusions

This greenhouse gas (GHG) analysis inventories six different sources of natural gas, including three types of unconventional gas, combines them into a domestic mix, and then compares the inventory on both a delivered feedstock and delivered electricity basis to a similar domestic mix of coal. The results show that average coal, across a wide range of variability, and compared across different assumptions of climate impact timing, has lower greenhouse gas emissions than domestically produced natural gas when compared as a delivered energy feedstock—over 50 percent less than natural gas per unit of energy.

However, the conclusion that coal is the cleaner fuel flips once the fuels are converted to electricity in power plants with different efficiencies—53 percent for natural gas versus 35 percent for coal. Natural gas-fired electricity has a 42 percent to 53 percent lower climate impact than coal-fired electricity. Even when fired on 100 percent unconventional natural gas, from tight sands, shale and coal beds, and compared on a 20-year GWP, natural gas-fired electricity has 39 percent lower greenhouse gases than coal. This shifting conclusion based on a change in the basis of comparison highlights the importance of specifying an end-use basis—not necessarily power production—when comparing different fuels.

Despite the conclusion that natural gas has lower greenhouse gases than coal on a delivered power basis, the extraction and delivery of the gas has a large climate impact —32 percent of U.S. methane emissions and 3 percent of U.S. greenhouse gases. There are significant emissions and use of natural gas—13 percent at the city or plant gate—even without considering final distribution to small end-users. The vast majority of the reduction in extracted natural gas —70 percent cradle-to-gate—are not emitted to the atmosphere, but can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations. Increasing compressor efficiency would lower both the rate of use and the CO_2 emissions associated with the combustion of the gas for energy.

But, with methane making up 75 to 95 percent of the natural gas flow, there are many opportunities for reducing the climate impact associated with direct venting to the atmosphere. A further 17 percent of the natural gas losses can be characterized as point source, and have the potential to be flared—essentially a conversion of GWP-potent methane to carbon dioxide.

The conclusions drawn from this inventory and the associated analysis are robust to a wide array of assumptions. However, as with any inventory, they are dependent on the underlying data, and there are many opportunities to enhance the information currently being collected. This analysis shows that the results are both sensitive to and impacted by the uncertainty of a few parameters: use and emission of natural gas along the pipeline transmission network; the rate of natural gas emitted during unconventional gas extraction processes such as well completion and workovers; and the lifetime production of wells, which determine the denominator over which lifetime emissions are placed.

This inventory and analysis are for greenhouse gases only, and there are many other factors that must be considered when comparing energy options. A full inventory of conventional and toxic air emissions, water use and quality, and land use is currently under development, and will allow comparison of these fuels across multiple environmental categories. Further, all opportunities need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security.

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Appendix A:
Data and Calculations for Greenhouse Gas Inventory

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The energy and material flows tracked by NETL's life cycle analysis (LCA) method in support of this study are used to quantify emissions of greenhouse gases (CO_2, CH_4, and N_2O, SF_6) that would result from natural gas extraction and transport, and from coal extraction and transport. The methods for calculating these flows for the raw material acquisition (RMA) and raw material transport (RMT) of natural gas and coal are provided below.

Some common engineering conversions used in this study are:

- 1 tonne = 1,000 kg
- 1 kg = 2.205 lb
- 1 m^3 = 35.3 cf
- Natural Gas Density: 1 cf of natural gas = 0.042 lb natural gas
- Natural Gas Energy Content: 1,027 Btu/cf natural gas
- The molar ratio of CO_2 to carbon is 44/12

A.1 Raw Material Acquisition: Natural Gas

In this analysis, the boundary of the RMA for natural gas begins with the extraction of natural gas from nature and ends with processed natural gas ready for pipeline delivery. Key activities in the RMA of natural gas are as follows:

- Well construction and installation
- Natural gas sweetening (acid gas removal)
- Natural gas dehydration
- Natural gas venting and flaring
- Natural gas compression
- Well decommissioning

The data sources and assumptions for calculating the greenhouse gas (GHG) emissions from each RMA activity are provided below. In most cases, the methane emissions are calculated by using standard engineering calculations around key gas field equipment, followed by the application of the Environmental Protection Agency (EPA) AP-42 emission factors as necessary.

Well Construction and Installation

NETL's LCA model of natural gas extraction includes the construction and installation activities for natural gas wells. Construction is defined as the cradle-to-gate burdens of key materials that embody key equipment and structures. Installation is defined as the activity of preparing a site, erecting buildings or other structures, and putting equipment in place.

The construction of natural gas wells requires a well casing that provides strength to the well bore and prevents contamination of the geological formations that surround the gas reservoir. In the case of offshore extraction, a large platform is also required. A well is lined with a carbon steel casing that is held in place with concrete. A typical casing has an inner diameter of 8.6 inches, is 0.75 inches thick, and weighs 24 pounds per foot (NaturalGas.org, 2004). The weight of concrete used by the well walls is assumed to be equal to the weight of the steel casing. The total length of a natural gas well is variable, based on the natural gas extraction profile under consideration. The well lengths considered in this study are as follows: conventional onshore: 1,990 m; conventional offshore: 2,660 m; conventional onshore associated: 1,500 m; shale gas: 3,980 m; coal bed methane: 3,980 m; and tight gas: 2,525 m. The total weight of materials for the construction of a well bore is estimated by factoring the total well length by the linear weight of carbon steel and concrete.

The installation of natural gas wells includes the drilling of the well, followed by the installation of the well casing. Horizontal drilling is used for unconventional natural gas reserves where hydrocarbons are dispersed throughout a matrix of shale or coal. An advanced drilling rig has a drilling speed of 17.8 meters per hour, which translates to the drilling of a 7,000 foot well in approximately 10 days (NaturalGas.org, 2004). A typical diesel engine used for oil and gas exploration has a power of 700 horsepower and a heat rate of 7,000 Btu/hp-hr (EPA, 1995). The methane emissions from well installation is the product of the following three variables: heat rate of drilling engine (7,000 Btu/hp-hr), methane emission factor (EPA, 1995) for diesel combustion in stationary industrial engines (6.35E-05 lb/hp-hr), and the total drilling time (in hours).

The daily production rate of a natural gas well is an important factor in apportioning one-time construction activities or intermittent operations to a unit of natural gas production. Typical production rates vary considerably based on well type. Production rates also vary based on well specific factors, such as the age of the natural gas well. For instance, the average daily production rate for new, horizontal shale gas wells in the Barnett Shale region is as high as 2.5 million standard cubic feet (MMcf) per day, but declines at a rapid rate (Hayden & Pursell, 2005). The observed production rates in the Barnett Shale region decline 55 percent during the first year, 25 percent during the second year, 15 percent during the third year, and 10 percent each following year (Hayden & Pursell, 2005). The production rates for each type of natural gas well are shown in **Table A-12**. These production rates include the average production of natural gas wells in 2009 (the basis year of this analysis), as marginal production rates. Marginal production rates exclude poorly performing, mature wells that will likely be removed from service within a couple of years.

The construction and material requirements are apportioned to one kilogram of natural gas product by dividing them by the lifetime production of the well. The natural gas wells considered in this study are presumed to produce natural gas at the rates discussed above, with a lifetime of 30 years. Thus, construction and material requirements, and associated GHG emissions, are apportioned over the lifetime production rate specific to each type of natural gas well, based on average well production rates.

Natural Gas Sweetening (Acid Gas Removal)

Raw natural gas contains varying levels of hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas and causes fouling when combusted in equipment. The removal of H_2S from natural gas is known as sweetening. Amine-based processes are the predominant technologies for the sweetening of natural gas.

The H_2S content of raw natural gas is highly variable, with concentrations ranging from one part per million on a mass basis to 16 percent by mass in extreme cases. An H_2S concentration of 0.5 percent by mass is modeled in this analysis. This H_2S concentration is based on raw gas composition data compiled by the Gas Processors Association (Foss, 2004).

The energy consumed by the amine reboiler accounts for the majority of energy consumed by the sweetening process. Reboiler energy consumption is a function of the amine flow rate, which, in turn, is related to the amount of H_2S removed from natural gas. Approximately 0.30 moles of H_2S are removed per 1 mole of circulated amine solution (Polasek, 2006), the reboiler duty is approximately 1,000 Btu per gallon of amine (Arnold, 1999), and the reboiler has a thermal efficiency of 92 percent. The molar mass of amine solution is assumed to be 83 g/mole, which is estimated by averaging the molar mass of monoethanolamine (61 g/mole) and diethanolamine (105 g/mole). The density of the

amine is assumed to be 8 lb/gal (3.62 kg/gal). The calculation of energy input per kilogram of natural gas product is shown in **Equation 1**.

$$\frac{0.005\ kg\ H_2S}{kg\ NG\ product} * \frac{1\ kg\ mol\ H_2S}{34\ kg\ H_2S} * \frac{1\ kg\ mol\ amine}{0.30 kg\ mol\ H_2S} * \frac{83\ kg\ amine}{kg\ mol\ amine} * \frac{1\ gal\ amine}{3.62\ kg\ amine} * \frac{1{,}000\ Btu\ reboiler\ duty}{gal\ amine} * \frac{1\ Btu\ energy\ input}{0.92\ Btu\ reboiler\ duty} = \frac{12.2\ Btu}{kg\ NG\ product} = \frac{26.9\ Btu}{lb\ NG\ product} \quad \textbf{(Equation 1)}$$

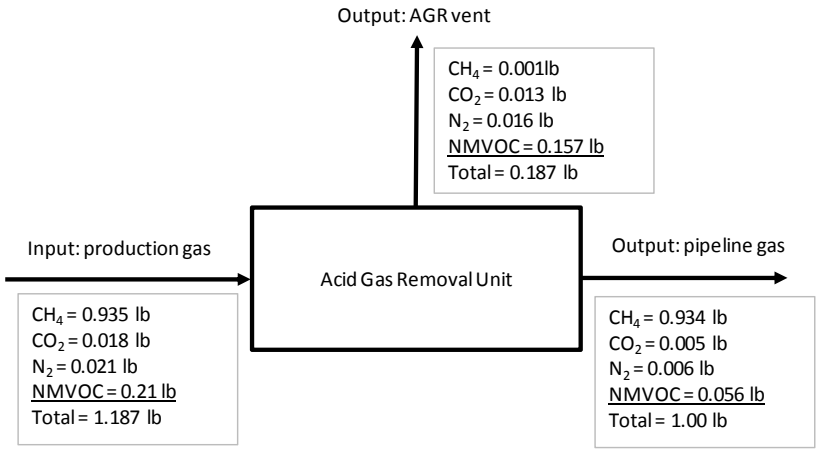
The amine reboiler combusts natural gas to generate heat for amine regeneration. This analysis applies EPA emission factors for industrial boilers (EPA, 1995) to the energy consumption rate discussed in the above paragraph in order to estimate the combustion emissions from amine reboilers.

The sweetening of natural gas is also a source of vented methane emissions. In addition to absorbing H_2S, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 0.000971 lb of methane per lb per natural gas sweetened (API, 2009). The calculation of methane released by amine reboiler venting is shown in **Equation 2**.

$$\frac{0.0185\ tonne\ CH_4}{10^6\ cf\ NG} * \frac{1{,}000\ kg}{tonne} * \frac{2.205\ lb}{kg} * \frac{1 cf}{0.042\ lb} = \frac{9.71 \times 10^{-4}\ lb\ CH_4}{lb\ NG} \quad \textbf{(Equation 2)}$$

Raw natural gas contains naturally-occurring CO_2 that contributes to the acidity of natural gas. Most of this CO_2 is absorbed by the amine solution during the sweetening of natural gas and is ultimately released to the atmosphere when the amine is regenerated. This analysis calculates the mass of naturally-occurring CO_2 emissions from the acid gas recovery (AGR) unit by balancing the composition of production gas (natural gas that has been extracted but has not undergone significant processing) and pipeline-quality gas. Production gas contains 1.52 mass percent CO_2 and pipeline-quality natural gas contains 0.47 mass percent CO_2. A mass balance around the AGR unit, which balances the mass of gas input with the mass of gas venting and gas product, shows that 0.013 lb of naturally-occurring CO_2 is vented per lb of processed natural gas. The key constraints of this mass balance are the different compositions of input gas (production gas) and output gas (pipeline-quality gas) and the methane venting rate from amine regeneration. The mass balance around the AGR unit is illustrated by **Figure A-1.**

Figure A-1: Mass Balance for Acid Gas Removal



As shown by the mass balance around the AGR unit, the majority (84 percent by mass) of the AGR vent stream is NMVOC. At this concentration, NMVOCs are a high-value energy product. Thus, from an LCA perspective, NMVOCs are a valuable co-product of the AGR process. Co-product allocation is used to apportion life cycle emissions and other burdens between the natural gas and NMVOC products.

In this analysis, the relative energy contents of the natural gas and NMVOC outputs from the AGR process are used as the basis for co-product allocation. The heating value of pipeline-quality natural gas is 24,452 Btu/lb (which is calculated from the default study value of 1,027 Btu/cf). The heating value of NMVOCs is 21,025 Btu/lb, which is calculated from the composition of the vent stream from the AGR unit and the heating values of each NMVOC component (The Engineering Toolbox, 2011); the calculation of the heating value of NMVOC is shown in **Table A-1**. As shown by the mass balance (**Figure A-1**), 0.157 lbs of NMVOC are produced for every lb of natural gas produced. When these mass flows are converted to an energy basis using the above heating values, 88.1 percent of the product leaving the AGR process is natural gas and 11.9 percent is NMVOCs. Thus, the natural gas model allocates 88.1 percent of the energy requirements and environmental emissions of acid gas removal to the natural gas product.

Table A-1: Heating Value of NMVOC Co-Product from AGR Process

NMVOC Component	Percent Mass	Heating Value (Btu/lb)
CH_4	0%	23,811
Ethane	44.1%	20,525
Propane	26.7%	21,564
Iso-Butane	5.9%	21,640
n-Butane	10.4%	21,640
iso-Pentane	3.0%	20,908
n-Pentane	3.9%	20,908
Hexanes	3.0%	20,526
Heptanes Plus	2.9%	21,000
Other (N_2 and CO_2)	0%	0
Composite Heating Value		21,025

The following table shows the energy consumption and GHG emissions for acid gas removal. These energy and emission factors do not account for the co-product allocation between natural gas and NMVOCs. The co-product allocation between natural gas and NMVOC is performed within the modeling software (GaBi).

For **Table A-2**, the energy used for acid gas removal is based on a 0.005 kg H_2S per of raw natural gas, a molar loading of 0.30 mol H2S per mole of amine solution, and a reboiler duty of 1,000 Btu/gal of regenerated amine, and a reboiler efficiency of 92 percent. The CH_4 venting factor assumes that the reboiler vent is not flared.

Table A-2: Acid Gas Removal (Sweetening)

Flow Name	Value	Units	Reference
Air Emission Factors			
CO_2	2.86	lb CO_2/lb NG fuel	API 2009
N_2O	1.52E-05	lb N_2O/lb NG fuel	API 2009
CH_4 (combustion)	5.48E-05	lb CH_4/lb NG fuel	API 2009
Energy Inputs and Outputs			
Reboiler energy	26.9	Btu/lb NG product	calculated
Reboiler fuel	2.26E-04	lb NG fuel/lb NG product	calculated
Air Emissions			
CO_2 (combustion)	6.47E-04	lb CO_2/lb NG product	calculated
CO_2 (vented)	0.013	lb CO_2/lb NG product	calculated
N_2O	3.54E-06	lb N_2O/lb NG product	calculated
CH_4 (combustion)	1.27E-05	lb CH_4/lb NG product	calculated
CH_4 (vented)	9.71E-04	lb CH_4/lb NG product	API 2009
NMVOC (vented)	0.157	lb NMVOC/lb NG product	calculated

Natural Gas Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel. The methane emissions from dehydration operations include combustion and venting emissions. This analysis estimates the fuel requirements and venting losses of dehydration in order to determine total methane emissions from dehydration.

The fuel requirements of dehydration are a function of the reboiler duty. Due to the heat integration of the absorber and stripper streams, the reboiler, which is heated by natural gas combustion, is the only equipment in the dehydration system that consumes fuel. The reboiler duty (the heat requirements for the reboiler) is a function of the flow rate of glycol solution, which, in turn, is a function of the difference in water content between raw and dehydrated natural gas. The typical water content for untreated natural gas is 49 lbs/MMcf. In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs/MMcf of natural gas (EPA, 2006). The flow rate of glycol solution is 3 gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gal (EPA, 2006). By factoring the change in water content, the glycol flow rate, and boiler heat requirements, the energy requirements for dehydration are 152,000 Btu/MMcf of dehydrated natural gas (as shown by **Equation 3** and **Equation 4** below). Assuming that the reboiler is fueled by natural gas, this translates to 1.48E-04 lb of natural gas combusted per lb of dehydrated natural gas (as shown by the equations below). The emission factor for the combustion of natural gas in boiler equipment produces 2.3 lb CH_4/million cf natural gas (API, 2009). After converting to common units, the above fuel consumption rate and methane emission factor translate to 8.09E-09 lb CH_4/lb NG treated.

$$\frac{3.00\ gal\ glycol}{lb\ water} * \frac{1{,}124\ Btu}{gal\ glycol} * \frac{(49-4)\ lb\ water}{MMCF\ NG} = \frac{152{,}000\ Btu}{MMcf\ NG} \qquad \textbf{(Equation 3)}$$

$$\frac{152{,}000\ Btu}{MMcf\ NG} * \frac{MMcf\ NG}{10^6 cf\ NG} * \frac{1\ cf\ NG}{1027\ Btu} = \frac{1.48\times10^{-4}\ lb\ NG\ fuel}{lb\ NG\ product} \quad \textbf{(Equation 4)}$$

In addition to absorbing water, the glycol solution also absorbs methane from the natural gas stream. This methane is lost to evaporation during the regeneration of glycol in the stripper column. Flash separators are used to capture most of methane emissions from glycol strippers; nonetheless, small amounts of methane are vented from dehydrators. The emission of methane from glycol dehydration is based on emission factors developed by the Gas Research Institute (API, 2009). Based on this emission factor, 8.06E-06 lb of methane is released for every pound of natural gas that is dehydrated.

For **Table A-3**, the energy used for dehydration is based on 3 gallons of glycol per pound of water removed, a reboiler duty of 1,124 Btu per gallon of glycol regenerated, and 45 pounds of water removed per MMcf of natural gas produced. The methane venting factor assumes that no flash separator is used to control venting emissions.

Table A-3: Natural Gas Dehydration

Flow Name	Value	Units	Reference
Air Emission Factors			
CO_2	2.86	lb CO_2/lb NG fuel	API 2009
N_2O	1.52E-05	lb N_2O/lb NG fuel	API 2009
CH_4 (combustion)	5.48E-05	lb CH_4/lb NG fuel	API 2009
Energy Inputs and Outputs			
Reboiler energy	1.52E-01	Btu/cf NG product	API 2009
Reboiler fuel	1.48E-04	lb NG fuel/lb NG product	calculated
Air Emissions			
CO_2	4.24E-04	lb CO_2/lb NG product	calculated
N_2O	2.26E-09	lb N_2O/lb NG product	calculated
CH_4 (combustion)	8.10E-09	lb CH_4/lb NG product	calculated
CH_4 (venting)	8.06E-06	lb CH_4/lb NG product	API 2009

Natural Gas Venting and Flaring

Venting and flaring are necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Venting and flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well, or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring include carbon dioxide, methane, and nitrous oxide. The flaring emission factors published by the American Petroleum Institute (API, 2009) are based on the following recommendations by the Intergovernmental Panel on Climate Change (IPCC):

- If measured data are not available, assume flaring has a 98 percent destruction efficiency. Destruction efficiency is a measure of how much carbon in the flared gas is converted to CO_2 (API, 2009).
- The CO_2 emissions from flaring are the product the destruction efficiency, carbon content of the flared gas, the molar ratio of CO_2 to carbon (44/12). Methane is 75 percent carbon by mass, and the other hydrocarbons in natural gas are approximately 81 percent carbon by mass

(Foss, 2004); the composite carbon content of natural gas is calculated by factoring these carbon compositions with the natural gas composition.

- Methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2 (API, 2009).
- N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

The mass composition of unprocessed natural gas (referred to as "production natural gas") is 78.8 percent CH_4, 1.5 percent CO_2, 1.78 percent nitrogen, and 17.9 percent non-methane hydrocarbons (NMVOCs) (EPA, 2011a). The mass composition of pipeline quality natural gas is 93.4 percent CH_4, 0.47 percent CO_2, 0.55 percent nitrogen, and 5.6 percent NMVOCs. The composition of production natural gas to model flaring during natural gas extraction, and the composition of pipeline quality natural gas is used to model flaring at the natural gas processing plant. The above method for estimating flaring emissions was applied to these gas compositions to develop flaring emission factors for production and pipeline natural gas. The following table summarizes the mass composition and flaring emissions for these two gas compositions.

Table A-4: Natural Gas Flaring

Emission	Production NG	Pipeline NG	Units	Reference
Natural Gas Composition				
CH_4	78.8%	93.4%	% mass	(EPA, 2011a)
CO_2	1.52%	0.47%	% mass	(EPA, 2011a)
Nitrogen	1.78%	0.55%	% mass	(EPA, 2011a)
NMVOC	17.90%	5.57%	% mass	(EPA, 2011a)
Flaring Emissions				
CO_2	2.67	2.69	lb CO_2/lb flared NG	API, 2009
N_2O	8.95E-05	2.79E-05	lb N_2O/lb flared NG	API, 2009
CH_4	1.53E-02	1.81E-02	lb CH_4/lb flared NG	API, 2009

The venting rate of natural gas is necessary to apply the above emission factors to a unit of natural gas production. Venting rates are highly variable and depend more on the production practices and condition of equipment at an extraction site that the type of natural gas reservoir. Thus, venting rates have been parameterized in the model to allow uncertainty analysis.

Recent data indicate that only 51 percent of vented natural gas from conventional natural gas extraction operations is flared and the remaining 49 percent is released to the atmosphere (EPA, 2011a). The flaring rate is even lower for unconventional wells, which flare 15 percent of vented natural gas (EPA, 2011a). The flaring rate at natural gas processing plants is assumed to be 100 percent.

Venting from Well Completion

The methane emissions from the completion of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 36.65 Mcf/completion and unconventional wells produce 9,175 Mcf/completion (EPA, 2011a). Barnett Shale and tight gas wells are high pressure wells, and thus have higher completion venting than coal bed methane and conventional wells (EPA, 2011a).

When modeling tight gas, adjustments were made to EPA's emission factors for well completions and workovers. EPA's documentation (EPA, 2011a) indicates that its unconventional completion

and workover emissions are representative of high-pressure, tight gas wells in the San Juan and Piceance basins, which are horizontal wells that were completed using hydraulic fracturing and have an estimated ultimate recovery of 3 Bcf. A survey of tight gas production in the U.S. determined that an estimated ultimate recovery of 1.2 Bcf is more representative of U.S. tight gas production. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor for tight gas well completion and workovers. An emission factor of 3,670 Mcf CH_4 per episode for the completion and workover of tight gas wells is used.

Tight gas emissions are not the only emission factor adjusted for the model. While coal bed methane (CBM) wells are an unconventional source of natural gas, they have a low reservoir pressure and thus have relatively low emission rates from completions and workovers. The CBM emission factor used for the completion and workover of CBM wells is 49.57 Mcf CH_4 (EPA, 2011a). This is much lower than the completion and workover emission factor that EPA recommends for unconventional wells (9,175 Mcf CH_4).

The analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. Using a natural gas density of 0.042 lb/cf (API, 2009) the methane emissions from conventional well completions are 1,538 lb/completion (698 kg/completion). For unconventional wells the venting rates are 386,000 lb/completion (175,000 kg/completion) for Barnett Shale, 2,090 lb/completion (946 kg/completion) for coal bed methane, and 154,000 lb/completion (70,064 kg/completion) for tight gas (EPA, 2011a).

Venting from Well Workovers

The methane emissions from the workover of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 2.454 Mcf/workover and unconventional wells produce 9,175 Mcf/workover. (Note that the workover emission factor for unconventional wells is the same as the completion emission factor for unconventional wells.) This analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. Using a natural gas density of 0.042 lb/cf (API, 2009) and the conversion factor of 2.205 lb/kg, the methane emissions from well workovers are 103 lb/workover (46.7 kg/workover) for conventional wells. The workover venting rates for unconventional wells are assumed to be equal to their completion venting rates (EPA, 2011a).

Unlike well completions, well workovers occur more than one time during the life of a well. The frequency of well workovers was calculated using EPA's accounting of the total number of natural gas wells in the U.S. and the total number of workovers performed per year (all data representative of 2007). For conventional wells, there were approximately 389,000 wells and 14,600 workovers in 2007 (EPA, 2011a), which translates to 0.037 workovers per well-year. Similarly, for unconventional wells, there were approximately 35,400 wells and 4,180 workovers in 2007 (EPA, 2011a), which translates to 0.118 workovers per well-year.

Venting from Liquid Unloading

Liquid unloading is necessary for conventional gas wells. It is not necessary for unconventional wells or associated gas wells.

The methane emissions from the unloading of liquid from conventional wells are based on emission factors developed by EPA. In 2007, conventional wells produced 223 Bcf/year (EPA, 2011a), which is 4.25 million metric tons per year using a natural gas density of 0.042 lb/cf. There were

approximately 389,000 unconventional wells in 2007. When the annual emissions are divided by the total number of wells, the resulting emission factor is 10.9 metric tons per well-year.

Liquid unloading is a routine operation for conventional gas wells. The frequency of liquid unloading was calculated using EPA's assessment of two producers and the unloading activities for their wells (EPA, 2011a). From this sampling, EPA calculated that there are 31 liquid unloading episodes per well-year (EPA, 2011a).

When the emission factor for liquid unloading is divided by the average number of unloading episodes, the resulting methane emission factor is 776 lb/episode (352 kg/episode).

Venting from Wet Seal Degassing

The emission factor for wet seal degassing accounts for the natural gas lost during the regeneration of wet seal oil, which is used for centrifugal compressors. This analysis uses an EPA study that sampled venting emissions from 15 offshore platforms (Bylin et al., 2010). According to EPA's sampling of these platforms, the emissions from wet seal oil degassing are 33.7 million m^3 of methane annually. These platforms produce 4.88 billion m^3 of natural gas annually. When the emission rate for this category is divided by the production rate, the resulting emission factor is 0.00690 m^3 of vented gas per m^3 of produced gas. Assuming the emissions have the same density as the produced gas, this emission factor is 0.00690 lb of natural gas/lb produced natural gas.

Fugitive Emissions from Pneumatic Devices

The extraction and processing of natural gas uses pneumatic devices for the opening and closing of valves and other process control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas extraction or processing site. Thus, this analysis assumes that the operation of pneumatic systems result in the emission of fugitive natural gas emissions.

Data for the fugitive emissions from pneumatic devices are based on EPA data for offshore wells, onshore wells, and gas processing plants (EPA, 2011a). EPA’s data is based on 2006 production (EPA, 2011a) and shows the methane emissions for specific wellhead and processing activities. This analysis translated EPA’s data to a basis of lb methane per lb of natural gas production by dividing the methane emission rate by the natural gas production rate. For example, the annual emissions from pneumatic devices used for offshore production are 7 MMcf of methane; when divided by the annual offshore production rate of 3,584,190 MMcf, this translates to an emission factor of 1.95E-06 lb of methane per lb of natural gas produced (this calculation assumes that the volumetric densities of methane and natural gas are the same). The fugitive emissions from pneumatic devices used by offshore wells, onshore wells, and natural gas processing plants are shown in the following table.

Table A-5: Fugitive Emissions from Pneumatic Devices

Location	MMcf/yr (EPA, 2011a)		Emission Factor
	CH_4 emission	NG Production	lb CH_4/lb NG
Onshore	52,421	19,950,828	2.63E-03
Offshore	7.0	3,584,190	1.95E-06
Processing	93	14,682,188	6.33E-06

Other Point Source and Fugitive Emissions

The emissions described above account for natural gas emissions from specific processes, including the episodic releases of natural gas during well completion, workovers, and liquid unloading, as well as routine releases from wet seal degassing, AGR, and dehydration. Natural gas is also released by other extraction and processing equipment. To account for these other emissions, NETL's model includes two additional emission categories: other point source emissions and other fugitive emissions. Other point source emissions account for natural gas emissions that are not accounted for elsewhere in model and can be recovered for flaring. Other fugitive emissions include emissions that are not accounted for elsewhere in the model and cannot be recovered for flaring.

EPA's Background Technical Support Document - Petroleum and Natural Gas Industry (EPA, 2011a) was used for quantifying the other point source and fugitive emissions from natural gas extraction and processing. A three-step process was used to filter EPA's venting and flaring data so that it is consistent with the boundary assumptions of this analysis:

1. Emissions that are accounted for by NETL's existing natural gas unit processes were not included in the categories for other point source and fugitive emissions. For example, EPA provides emission rates for well construction, well completion, dehydration, and pneumatic devices. The emissions from these activities are accounted for elsewhere in NETL's model and thus, to avoid double counting, are not included in the emission factors for other point and fugitive emissions.
2. Emissions that fall within NETL's boundary definitions for natural gas processing were moved from the natural gas extraction category to the natural gas processing category.
3. The EPA data (EPA, 2011a) does not discern between point source and fugitive emissions, so emissions were assigned to the point source or fugitive emission categories based on another EPA reference that provides more details on point source and fugitive emissions (Bylin, et al., 2010).

Other Point Source and Fugitive Emissions from Onshore Extraction

The data for other point source and fugitive emissions from onshore extraction are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from construction, dehydration, compressors, well completion, and pneumatic devices; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Additionally, emissions from Kimray pumps, condensate tanks, and compressor blowdowns are re-categorized as natural gas *processing* emissions in NETL's model, and are thus not included in the emission factors for natural gas *extraction*. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from onshore gas extraction are 7.49E-05 lb CH_4/lb NG extracted and 1.02E-03 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-6**.

Table A-6: Other Point Source and Fugitive Emissions from Onshore NG Extraction

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Normal Fugitives				
Gas Wells	2,751	Construction		
Heaters	1,463		1,463	
Separators	4,718			4,718
Dehydrators	1,297	Dehydrator		
Meters/Piping	4,556			4,556
Small Reciprocating Compressor	2,926	Reciprocating Compressor		
Large Reciprocating Compressor	664	Reciprocating Compressor		
Large Reciprocating Stations	45	Reciprocating Compressor		
Pipeline Leaks	8,087			8,087
Vented and Combusted				
Completion Flaring	0	Well Completion V&F		
Well Drilling	96	Well Completion		
Coal Bed Methane	3,467	Well Completion		
Pneumatic Device Vents	52,421	Pneumatic Devices		
Chemical Injection Pumps	2,814			2,814
Kimray Pumps	11,572	In NG processing boundary		
Dehydrator Vents	3,608	Dehydrator V&F		
Condensate Tanks without Control Devices	1,225	In NG processing boundary		
Condensate Tanks with Control Devices	245	In NG processing boundary		
Gas Engines, Compressor Exhaust Vented	11,680	Gas Compressor		
Well Workovers				
Well Workovers, Gas Wells	47	Well Workovers		
Well Workovers, Well Clean Ups (Low Pressure Gas Wells)	9,008	Well Workovers		
Blowdowns				
Blowdowns, Vessel	31		31	
Blowdowns, Pipeline	129			129
Blowdowns, Compressors	113	In NG processing boundary		
Blowdowns, Compressor Starts	253	In NG processing boundary		
Upsets				
Pressure Relief Valves	29			29
Mishaps	70			70
Total Emissions	123,315		1,494	20,403
Total NG Extracted	19,950,828			
Emission Rate (lb CH_4/lb NG extracted)			**7.49E-05**	**1.02E-03**

Other Venting and Fugitive Emissions from Offshore Extraction

The data for other point source and fugitive emissions from offshore extraction are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from drilling rigs, flares, centrifugal seals, glycol dehydrators, gas engines and turbines, and pneumatic pumps; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from offshore gas extraction are 3.90E-05 lb CH_4/lb NG extracted and 2.41E-04 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-7.**

Table A-7: Other Point Source and Fugitive Emissions from Offshore NG Extraction

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Amine gas sweetening unit	0.2	AGR and CO_2 removal		
Boiler/heater/burner	0.8		0.80	
Diesel or gasoline engine	0.01		0.01	
Drilling Rig	3	Construction		
Flare	24	Venting and Flaring		
Centrifugal Seals	358	Centrifugal Compressor		
Connectors	0.8			0.80
Flanges	2.4			2.38
Open Ended Line	0.1			0.10
Other	44			44.0
Pump Fugitive	0.5			0.50
Valves	19			19.00
Glycol Dehydrator	25	Dehydrator		
Loading Operation	0.1			0.10
Separator	796			796
Mud Degassing	8.0		8.00	
Natural Gas Engines	191	Reciprocating compressor		
Natural Gas Turbines	3.0	Centrifugal compressor		
Pneumatic Pumps	7.0	Pneumatic Devices		
Pressure Level Controls	2.0			2.00
Storage Tanks	7.0		7.00	
Variable Exhaust Nozzle Exhaust Gas	124		124	
Total Emissions	1616		140	865
Total Processed NG	3,584,190			
Emission Rate (lb CH_4/lb NG extracted)			**3.90E-05**	**2.41E-04**

Other Venting and Fugitive Emissions from Natural Gas Processing

The data for other point source and fugitive emissions from natural gas processing are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from reciprocating compressors, centrifugal compressors, AGR units, dehydrators, and pneumatic devices; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from natural gas processing are 3.68E-04 lb CH_4/lb NG extracted and 8.25E-04 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-8**.

Table A-8: Other Point Source and Fugitive Emissions from NG Processing

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Normal Fugitives				
Plants	1,634		3,104	
Recip Compressors	17,351	Reciprocating Compressor		
Centrifugal Compressors	5,837	Centrifugal Compressor		
Vented and Combusted (Normal Operations)				
Compressor Exhaust, Gas Engines	6,913	Reciprocating Compressor		
Compressor Exhaust, Gas Turbines	195	Centrifugal Compressor		
AGR Vents	643	AGR and CO_2 removal		
Kimray Pumps (Glycol Pump for Dehydrator)	177			11,749
Dehydrator Vents	1,088	Dehydrator venting & flaring		
Pneumatic Devices	93	Pneumatic Device		
Routine Maintenance				
Blowdowns/Venting	2,299		2,299	366
Total Emissions	36,230		5,403	12,115
Total Production	14,682,188			
Emissions Rate (lb CH_4/lb NG processed)			**3.68E-04**	**8.25E-04**

Natural Gas Compression

Compressors are used to increase the gas pressure for pipeline distribution. This analysis assumes that the inlet pressure to compressors at the natural gas extraction and processing site is 50 psig and the outlet pressure is 800 psig. The inlet pressure depends on the pressure of the natural gas reservoir and pressure drop during gas processing and thus introduces uncertainty to the model. The outlet pressure of 800 psig is a standard pressure for pipeline transport of natural gas.

The energy required for compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMcf of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb/cf and converting to kilograms gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas. This energy rate represents the required *output* of the compressor shaft; the *input* fuel requirements for compression vary according to compression technology. The two types of compressors used for natural gas operations are reciprocating compressors and centrifugal compressors. These two compressor types are discussed below.

Reciprocating compressors account for an estimated 75 percent of wellhead compression in the Barnett Shale gas play, and are estimated to accounted for all wellhead compression at conventional onshore, conventional onshore associated, and coal bed methane wells. Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Houston Advanced Research Center, 2006). The average energy intensity of a gas-powered turbine is 8.74 Btu/hp-hr (Houston Advanced Research Center, 2006). Using a natural gas heating value of 1,027 Btu/cf (API, 2009), a natural gas density of 0.042 lb/cf (API, 2009), and converting to kilograms translates to 217 kg of natural gas per MWh of centrifugal, gas-powered turbine output. This fuel factor represents the mass of natural gas that is

combusted per compressor energy output. The carbon dioxide emissions from a gas-powered, 4-stroke reciprocating compressor are 110 lb/MMBtu of fuel input. Similarly, the methane emissions from the same type of reciprocating compressor are 1.25 lb/MMBtu of fuel input (EPA, 1995); these methane emissions result from leaks in compressor rod packing systems and are based on measurements conducted by the EPA on a sample of 22 compressors (EPA, 1995).

The emissions for the operation of wellhead compressors are shown in **Table A-9** below.

Table A-9: Gas-Powered Reciprocating Compressor Operations

Air Emission Factors			
CO_2	110 lb/MMBtu fuel	0.047 kg/MJ fuel	EPA 1995
CH_4	1.25 lb/MMBtu fuel	5.37E-04 kg/MJ fuel	EPA 1995
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb	1.63E-04 MWh/kg	GE 2005
Heat rate	478 lb NG/MWh	217 kg NG/MWh	HARC 2006
Fuel input	3.54E-02 lb NG/lb NG	3.54E-02 kg NG/kg NG	calculated
Air Emissions			
CO_2	0.095 lb/lb NG	0.095 kg/kg NG	calculated
CH_4	1.08E-03 lb/lb NG	1.08E-03 kg/kg NG	calculated

Gas powered centrifugal compressors are commonly used at offshore natural gas extraction sites. The amount of natural gas required for gas powered centrifugal compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage centrifugal compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMcf of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb/cf and converting to kilograms gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas.

Table A-10: Gas-Powered Centrifugal Compressor Operations

Air Emission Factors			
CO_2	110 lb/MMBtu fuel	0.047 kg/MJ fuel	EPA 1995
CH_4	8.60E-03 lb/MMBtu fuel	3.70E-06 kg/MJ fuel	EPA 1995
N_2O	3.00E-03 lb/MMBtu fuel	1.29E-06 kg/MJ fuel	EPA 1995
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb	1.63E-04 MWh/kg	GE 2005
Heat rate	443 lb NG/MWh	201 kg NG/MWh	API 2009
Fuel input	3.28E-02 lb NG/lb NG	3.28E-02 kg NG/kg NG	calculated
Air Emissions			
CO_2	0.088 lb/lb NG	0.088 kg/kg NG	calculated
CH_4	6.89E-06 lb/lb NG	6.89E-06 kg/kg NG	calculated
N_2O	2.40E-06 lb/lb NG	2.40E-06 kg/kg NG	calculated

Electrically-powered centrifugal compressors account for an estimated 25 percent of wellhead compression in the Barnett Shale gas play, but were not found to be utilized in substantial numbers outside of the Barnett Shale. If the natural gas extraction site is near a source of electricity, it has traditionally been financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a city.

An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine. The average power range of electrically-driven compressor in the U.S. natural gas transmission network is greater than 500 horsepower. This analysis assumes that compressors of this size have an efficiency of 95 percent (DOE, 1996). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output. The upstream emissions associated with the generation of electricity are modeled with the fuel mix of the Electric Reliability Council of Texas (ERCOT) grid, which is representative of electricity generation in Texas (the location of Barnett Shale). The air emissions from electricity generation are based on the 2005 fuel mix for the ERCOT region (Texas) and are modeled by NETL's LCA model for power generation. Electric compressors have negligible methane emissions because they do not require a fuel line for the combustion of product natural gas and incomplete combustion of natural gas is not an issue (EPA, 2011c). Electric compressors are also recommended by EPA's Natural Gas STAR program as a strategy for reducing system emissions of methane (EPA, 2011c).

Table A-11: Electrically-Powered Centrifugal Compressor Operations

Air Emissions from Electricity Generation			
CO_2	1,784 lb/MWh	809 kg/MWh	calculated
N_2O	2.29E-02 lb/MWh	1.04E-02 kg/MWh	calculated
CH_4	2.36 lb/MWh	1.07 kg/MWh	calculated
SF_6	2.23E-09 lb/MWh	1.01E-09 kg/MWh	calculated
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb NG	1.63E-04 MWh/kg	GE 2005
Heat rate	1.053 MWh/MWh	1.053 MWh/MWh	API 2009
Electricity input	7.80E-05 MWh/lb NG	1.72E-04 MWh/kg NG	calculated
Air Emissions			
CO_2	0.139 lb/lb NG	0.139 kg/kg NG	calculated
N_2O	1.78E-06 lb/lb NG	1.78E-06 kg/kg NG	calculated
CH_4	1.84E-04 lb/lb NG	1.84E-04 kg/kg NG	calculated
SF_6	1.73E-13 lb/lb NG	1.73E-13 kg/kg NG	calculated

Well Decommissioning

This analysis assumes that the de-installation of a natural gas well incurs ten percent of the energy requirements and emissions as the original installation of the well.

Compilation of Natural Gas Processes

All energy and emissions data for the extraction of natural gas are described above. The compilation of these data into a model for natural gas extraction involves the connection of all unit processes into an interdependent network.

To model the extraction of natural gas from different sources (onshore, offshore, unconventional, etc.) it is necessary to tune each unit process within this network with a set of source-specific parameters. The assumptions used to adjust the unit processes into profiles of specific natural gas types are shown in **Table A-12**.

Table A-12: Natural Gas Modeling Parameters

Property	Units	Onshore	Associated	Offshore	Tight Sands	Barnett Shale	Coal Bed Methane
Natural Gas Source							
Contribution to 2009 Natural Gas Mix	Percent	23%	7%	13%	32%	16%	9%
2009 Production Rate	Mcf/day	65.6	121	2,795	110	273	104
Marginal Production Rate	Mcf/day	592	398	6,165	110	273	76.2
Natural Gas Extraction Well							
Flaring Rate at Extraction Well Location	Percent	51%	51%	51%	15%	15%	51%
Well Completion, Production Gas (prior to flaring)	Mcf/completion	47	47	47	4,657	11,643	63
Well Workover, Production Gas (prior to flaring)	Mcf/workover	3.1	3.1	3.1	4,657	11,643	63
Well Workover, Number per Well Lifetime	Workovers/well	1.1	1.1	1.1	3.5	3.5	3.5
Liquids Unloading, Production Gas (prior to flaring)	Mcf/episode	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading, Number per Well Lifetime	Episodes/well	930	n/a	930	n/a	n/a	n/a
Pneumatic Device Emissions, Fugitive	lb CH_4/Mcf	0.05	0.05	0.01	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/Mcf	0.003	0.003	0.002	0.003	0.003	0.003
Other Sources of Emissions, Fugitive	lb CH_4/Mcf	0.043	0.043	0.01	0.043	0.043	0.043
Natural Gas Processing Plant							
AGR and CO_2 Removal Unit							
Flaring Rate for AGR and CO_2 Removal Unit	Percent	100%	100%	100%	100%	100%	100%
Methane Absorbed into Amine Solution	lb CH_4/Mcf	0.04	0.04	0.04	0.04	0.04	0.04
Carbon Dioxide Absorbed into Amine Solution	lb CO_2/Mcf	0.56	0.56	0.56	0.56	0.56	0.56
Hydrogen Sulfide Absorbed into Amine Solution	lb H_2S/Mcf	0.21	0.21	0.21	0.21	0.21	0.21
NMVOC Absorbed into Amine Solution	lb NMVOC/Mcf	6.59	6.59	6.59	6.59	6.59	6.59
Glycol Dehydrator Unit							
Flaring Rate for Dehydrator Unit	Percent	100%	100%	100%	100%	100%	100%
Water Removed by Dehydrator Unit	lb H_2O/Mcf	0.045	0.045	0.045	0.045	0.045	0.045
Methane Emission Rate for Glycol Pump & Flash Separator	lb CH_4/Mcf	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Pneumatic Devices and Other Sources of Emissions							
Flaring Rate for Other Sources of Emissions	Percent	100%	100%	100%	100%	100%	100%
Pneumatic Device Emissions, Fugitive	lb CH_4/Mcf	0.05	0.05	0.05	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/Mcf	0.02	0.02	0.02	0.02	0.02	0.02
Other Sources of Emissions, Fugitive	lb CH_4/Mcf	0.03	0.03	0.03	0.03	0.03	0.03
Natural Gas Compression at Gas Plant							
Compressor, Gas-powered Combustion, Reciprocating	Percent	100%	100%		100%	75%	100%
Compressor, Gas-powered Turbine, Centrifugal	Percent			100%			
Compressor, Electrical, Centrifugal	Percent					25%	

Production Rates for Conventional Onshore Natural Gas Wells

The purpose of this discussion is to describe the data sources and calculations used to determine the typical production rate of conventional onshore natural gas wells. The population of conventional onshore wells is a lot more diverse that other types of natural gas wells, and thus it is necessary to distinguish between the large population of wells with low production rates and the relatively small population of wells with high production rates.

The Energy Information Administration (EIA) collects production data for oil and gas wells in the U.S. and organizes it according to production rates. The EIA data for total U.S. production is shown in **Table A-13**. The data in **Table A-13** are copied directly from EIA (EIA, 2010b) and show 22 production rate brackets. The lowest bracket includes wells that produce less than one barrel of oil equivalent (BOE) per day, and the highest bracket represents wells that produce more than 12,800 BOE per day. The EIA data have separate groups for oil wells and gas wells; from these data, we know that in 2009 the U.S. had 363,459 oil wells and 461,388 gas wells. These data also show the co-production of oil at gas wells as well as the average per well production rate within each production rate bracket.

The goal of this discussion is to focus on conventional onshore gas extraction. The data in **Table A-13** includes offshore production, and to develop a more accurate representation of onshore gas production, it is necessary to remove offshore data from the total U.S. profile. The EIA also has data for offshore production, as shown by **Table A-14**. By subtracting the offshore data from the total U.S. well profile, production data exclusive to onshore wells can be determined, as shown in **Table A-15**.

Table A-13: U.S. Total 2009 Distribution of Wells by Production Rate Bracket (EIA, 2010b)

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (MMbbl)	% of Oil Prod.	Oil Rate per Well (bbl/Day)	Annual Gas Prod. (Bcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (Bcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (MMbbl)	Oil Rate per Well (bbl/Day)
0-1	127,734	35.1	15.4	0.9	0.4	4.8	0.1	91,005	19.7	73.4	0.3	2.4	0.7	0.0
1-2	45,649	12.6	21.8	1.3	1.4	9.5	0.6	45,034	9.8	131.1	0.5	8.3	1.3	0.1
2-4	47,803	13.2	45.3	2.8	2.7	22.3	1.3	60,930	13.2	358.3	1.5	16.6	3.6	0.2
4-6	27,625	7.6	43.6	2.7	4.4	29.4	3.0	43,009	9.3	428.4	1.8	28.0	4.4	0.3
6-8	21,816	6.0	48.3	2.9	6.2	36.7	4.7	32,564	7.1	457.8	1.9	39.4	4.5	0.4
8-10	15,482	4.3	42.9	2.6	7.7	40.0	7.2	24,829	5.4	451.1	1.9	50.8	4.3	0.5
10-12	12,642	3.5	43.8	2.7	9.7	33.5	7.4	18,967	4.1	420.5	1.8	62.1	4.1	0.6
12-15	11,801	3.2	50.3	3.1	11.9	37.3	8.8	21,718	4.7	591.1	2.5	76.2	5.7	0.7
15-20	13,895	3.8	75.1	4.6	15.2	60.8	12.3	23,974	5.2	841.3	3.5	98.5	7.7	0.9
20-25	8,157	2.2	56.6	3.4	19.6	46.2	16.1	16,539	3.6	744.2	3.1	126.5	7.5	1.3
25-30	6,276	1.7	52.3	3.2	23.7	46.5	21.1	11,638	2.5	644.9	2.7	156.7	5.1	1.2
30-40	7,207	2.0	75.3	4.6	30.0	69.0	27.5	16,083	3.5	1,122.3	4.7	197.4	9.5	1.7
40-50	3,684	1.0	49.0	3.0	39.1	42.1	33.5	9,959	2.2	895.6	3.7	255.6	7.1	2.0
50-100	7,934	2.2	159.7	9.7	59.4	171.4	63.7	22,546	4.9	3,156.6	13.2	402.7	22.4	2.9
100-200	3,070	0.8	119.1	7.3	118.3	115.9	115.1	13,444	2.9	3,520.4	14.7	782.4	30.8	6.8
200-400	1,469	0.4	109.9	6.7	233.9	122.3	260.3	5,528	1.2	2,572.2	10.7	1,545.1	22.3	13.4
400-800	663	0.2	92.3	5.6	447.9	128.5	623.6	2,038	0.4	1,708.3	7.1	3,007.9	22.2	39.0
800-1,600	264	0.1	77.8	4.7	900.8	114.4	1,325.0	816	0.2	1,342.4	5.6	6,039.3	25.0	112.6
1,600-3,200	145	0.0	86.8	5.3	1,770.4	121.8	2,485.6	460	0.1	1,633.2	6.8	11,907.5	35.8	261.0
3,200-6,400	66	0.0	88.1	5.4	3,950.0	92.9	4,167.6	247	0.1	1,913.3	8.0	22,917.6	46.1	552.0
6,400-12,800	47	0.0	112.4	6.8	7,428.9	132.1	8,729.2	51	0.0	725.3	3.0	46,468.5	9.9	635.0
> 12,800	30	0.0	176.5	10.7	18,162.2	136.8	14,083.1	9	0.0	227.5	0.9	84,081.9	3.3	1,204.3
Total	**363,459**	**100.0**	**1,642.3**	**100.0**	**12.9**	**1,614.4**	**12.7**	**461,388**	**100.0**	**23,959.1**	**100.0**	**148.5**	**283.2**	**1.8**

Table A-14: Federal Gulf 2009 Distribution of Wells by Production Rate Bracket (EIA, 2010a)

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (Mbbl)	% of Oil Prod.	Oil Rate per Well (bbl/Day)	Annual Gas Prod. (MMcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (MMcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (Mbbl)	Oil Rate per Well (bbl/Day)
0-1	46	1.5	3.1	0.0	0.3	4.8	0.4	116	4.4	52.2	0.0	1.9	0.7	0.0
1-2	23	0.8	6.5	0.0	1.2	10.2	1.9	55	2.1	112.1	0.0	8.2	1.7	0.1
2-4	40	1.3	30.4	0.0	2.5	43.0	3.5	70	2.7	278.2	0.0	15.8	4.2	0.2
4-6	37	1.2	41.6	0.0	4.0	71.0	6.8	74	2.8	538.6	0.0	27.4	8.1	0.4
6-8	43	1.4	66.9	0.0	5.4	108.4	8.8	51	1.9	499.7	0.0	37.8	8.2	0.6
8-10	46	1.5	101.6	0.0	7.0	169.0	11.7	43	1.6	609.0	0.0	50.0	6.4	0.5
10-12	32	1.1	89.2	0.0	9.2	111.5	11.5	35	1.3	547.3	0.0	56.6	14.5	1.5
12-15	65	2.2	229.0	0.0	11.3	267.8	13.2	51	1.9	1,041.6	0.1	69.9	28.1	1.9
15-20	99	3.3	448.9	0.1	14.1	676.8	21.2	89	3.4	2,557.3	0.1	93.8	43.2	1.6
20-25	101	3.4	625.5	0.1	18.6	792.3	23.5	84	3.2	3,023.3	0.2	121.1	56.3	2.3
25-30	111	3.7	856.6	0.2	23.1	937.8	25.3	77	2.9	3,140.6	0.2	146.8	59.5	2.8
30-40	216	7.2	2,107.2	0.4	28.5	2,821.7	38.2	126	4.8	7,456.0	0.4	191.8	109.5	2.8
40-50	189	6.3	2,403.6	0.4	37.1	2,952.2	45.6	108	4.1	7,788.0	0.4	240.3	175.6	5.4
50-100	638	21.3	13,471.4	2.5	60.5	16,722.2	75.1	351	13.3	42,876.5	2.3	394.8	718.7	6.6
100-200	506	16.9	21,060.9	3.9	118.8	23,817.1	134.4	388	14.7	99,838.2	5.3	815.0	1,272.4	10.4
200-400	303	10.1	23,902.4	4.4	234.2	27,232.1	266.9	357	13.5	171,637.2	9.1	1,587.1	2,113.7	19.5
400-800	157	5.2	24,319.8	4.5	465.6	28,928.2	553.8	281	10.6	267,687.1	14.2	3,139.7	3,352.2	39.3
800-1,600	124	4.1	37,018.6	6.8	911.9	51,361.6	1,265.2	155	5.9	297,842.7	15.8	6,179.4	5,209.8	108.1
1,600-3,200	86	2.9	53,804.6	9.9	1,901.4	73,151.5	2,585.1	72	2.7	281,825.9	15.0	12,283.7	5,179.9	225.8
3,200-6,400	58	1.9	79,016.7	14.5	4,001.7	81,878.3	4,146.6	34	1.3	259,606.8	13.8	24,584.0	4,941.2	467.9
6,400-12,800	45	1.5	107,626.0	19.8	7,472.5	126,500.1	8,782.9	16	0.6	234,073.5	12.4	53,797.6	909.8	209.1
> 12,800	30	1.0	176,482.4	32.5	18,162.2	136,845.3	14,083.1	8	0.3	200,795.6	10.7	85,773.4	2,324.5	992.9
Total	**2,995**	**100.0**	**543,712.9**	**100.0**	**541.3**	**575,403.0**	**572.8**	**2,641**	**100.0**	**1,883,827.2**	**100.0**	**2,396.7**	**26,538.1**	**33.8**

Table A-15: U.S. 2009 Distribution of Onshore Gas Wells (EIA, 2010a, 2010b)

Prod. Rate Bracket (BOE/day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (Bcf)	% of Gas Prod.	Gas Rate per Well (Mcf/day)	Annual Oil Prod. (MMbbl)	Oil Rate per Well (bbl/day)	Gas Energy Equivalent (MMBtu/day)	Oil Energy Equivalent (MMBtu/day)	% of Energy from Gas	Adjusted Gas Rate per Well, (Mcf/Day)[1]
0-1	90,889	19.8%	73.4	0.3%	2.2	0.7	0.0	2.3	0.1	94.9%	2.3
1-2	44,979	9.8%	131.0	0.6%	8.0	1.3	0.1	8.2	0.5	94.7%	8.4
2-4	60,860	13.3%	358.0	1.6%	16.1	3.6	0.2	16.6	0.9	94.6%	17.0
4-6	42,935	9.4%	427.9	1.9%	27.3	4.4	0.3	28.0	1.6	94.5%	29.0
6-8	32,513	7.1%	457.3	2.1%	38.5	4.5	0.4	39.6	2.2	94.7%	41.0
8-10	24,786	5.4%	450.5	2.0%	49.8	4.3	0.5	51.1	2.8	94.9%	52.0
10-12	18,932	4.1%	420.0	1.9%	60.8	4.1	0.6	62.4	3.4	94.8%	64.0
12-15	21,667	4.7%	590.1	2.7%	74.6	5.7	0.7	76.6	4.2	94.9%	79.0
15-20	23,885	5.2%	838.7	3.8%	96.2	7.7	0.9	98.8	5.1	95.1%	101.0
20-25	16,455	3.6%	741.2	3.4%	123.0	7.4	1.2	127.0	7.0	94.6%	130.0
25-30	11,561	2.5%	641.8	2.9%	152.0	5.0	1.2	156.0	7.0	95.8%	159.0
30-40	15,957	3.5%	1,114.8	5.1%	191.0	9.4	1.6	197.0	9.0	95.5%	201.0
40-50	9,851	2.1%	887.8	4.0%	247.0	6.9	1.9	254.0	11.0	95.8%	258.0
50-100	22,195	4.8%	3,113.7	14.1%	384.0	21.7	2.7	395.0	16.0	96.2%	399.0
100-200	13,056	2.8%	3,420.6	15.5%	718.0	29.5	6.2	737.0	36.0	95.4%	753.0
200-400	5,171	1.1%	2,400.6	10.9%	1,272.0	20.2	10.7	1,306.0	62.0	95.5%	1,332.0
400-800	1,757	0.4%	1,440.6	6.5%	2,246.0	18.9	29.4	2,307.0	170.0	93.1%	2,412.0
800-1,600	661	0.1%	1,044.6	4.7%	4,330.0	19.8	82.0	4,446.0	476.0	90.3%	4,793.0
1,600-3,200	388	0.1%	1,351.4	6.1%	9,542.0	30.6	216.0	9,800.0	1,254.0	88.7%	10,763.0
3,200-6,400	213	0.0%	1,653.7	7.5%	21,271.0	41.2	529.0	21,845.0	3,071.0	87.7%	24,261.0
6,400-12,800	35	0.0%	491.2	2.2%	38,452.0	9.0	704.0	39,490.0	4,082.0	90.6%	42,427.0
> 12,800	1	0.0%	26.7	0.1%	73,163.0	1.0	2,673.0	75,138.0	15,501.0	82.9%	88,256.0
Total	**458,747**	**100.0%**	**22,075.4**	**100.0%**	**132.0**	**256.8**	**1.5**	**135.0**	**8.9**	**93.8%**	**140.0**

[1] Adjusted by energy-based co-product allocation

Co-product Allocation of Oil

The EIA data also shows that gas wells produce a small share of oil. On an energy basis, oil comprises approximately 3.8 to 17 percent of gas well production, depending on the production rate bracket. Using energy-based, co-product allocation, it is necessary to scale the production rates of the gas wells so they are representative of 100 percent gas production.

For example, a gas well that has daily production rates of 718 Mcf of natural gas and 6.2 barrels of oil has a total daily production of 773 MMBtu of energy. This energy equivalency is calculated using heating values of 1,027 Btu/cf for natural gas and 5.8 MMBtu/bbl for oil. If expressed solely on and energy-equivalent basis of natural gas, 773 MMBtu of energy is equal to 753 Mcf of natural gas. Thus, in this instance, accounting for the co-production of oil increases the nominal production rate of the gas well from 718 Mcf/day to 752 Mcf/day. Note that this nominal rate of 752 Mcf/day does not represent the actual gas produced by the well, but is an LCA accounting method that uses the relative energies of produced oil and natural gas to scale the gas production rate so it is representative of a well that produces only natural gas.

Selection of Representative Production Brackets

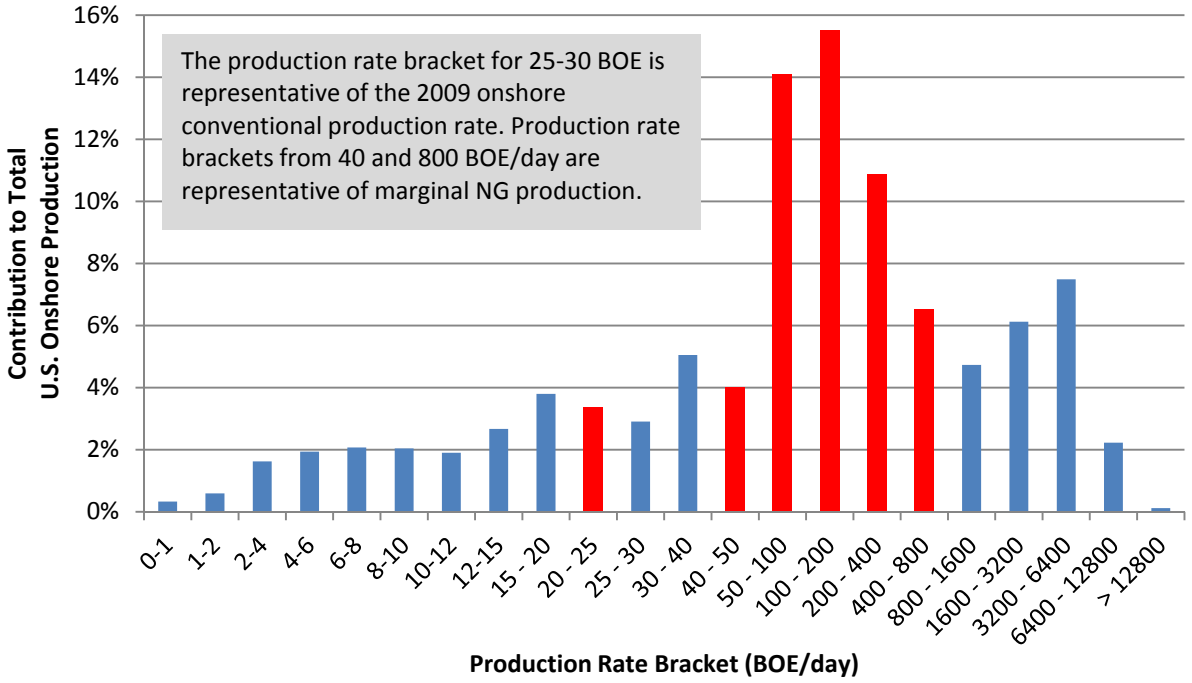
The production rates of onshore conventional natural gas wells vary widely and are a function of reservoir properties, extraction technology, and age. As shown by the EIA data, the production rates of onshore gas wells range from less than 1 BOE/day to more than 12,800 BOE/day. There are not enough data to determine the split between conventional and unconventional wells within each production rate bracket; however, the total production of each bracket and the production rates of unconventional wells can be used to determine the most likely production rates for onshore conventional natural gas. The distribution of gas wells by total gas produced is shown in **Figure A-2**

The production categories in **Table A-15** include a large population of wells in the lowest production rate bracket; 19.8 percent of U.S. onshore natural gas wells produce less than one BOE per day. Similarly, the production rate bracket for 1 - 2 BOE/day includes 9.8 percent of natural gas wells, the production rate bracket for 2 - 4 BOE/day includes 13.3 percent of natural gas wells, and the production rate bracket for 4 - 6 BOE/day includes 9.4 percent of natural gas wells. While these four production rate brackets account for 52 percent of the total count of natural gas wells, they account for only 4.5 percent of total natural gas production.

The average production rate for conventional onshore natural gas wells in 2009 was 66 Mcf per day. This production rate was calculated by dividing the amount of onshore conventional natural gas that was produced in 2009 by the total number of onshore conventional natural gas wells in 2009.

The marginal production rate for conventional onshore natural gas was calculated by selecting the most productive region of the production rate brackets. The production rate brackets that include 40 to 800 BOE/day represent 51 percent of total onshore natural gas production. The average production rate of this range of wells is 592 Mcf/day.

Figure A-2: Distribution of Onshore Natural Gas Wells



A.2 Raw Material Acquisition: Coal

Raw material extraction for coal incorporates extraction profiles for coal derived from the PRB, where sub-bituminous, low-rank coal extracted from thick coal seams (up to approximately 180 feet) via surface mines located in Montana and Wyoming, and coal derived from the Illinois No. 6 coal seam, where bituminous coal is extracted from approximately 2 to 15 foot seams via underground longwall and continuous mining. Each modeling approach is described below.

Powder River Basin Coal

The PRB coal-producing region consists of counties in two states – Big Horn, Custer, Powder River, Rosebud, and Treasure in Montana, and Campbell, Converse, Crook, Johnson, Natrona, Niobrara, Sheridan, and Weston in Wyoming (EIA, 2009). PRB coal is advantageous in comparison to bituminous coals in that it has lower ash and sulfur content. However, PRB coal also has a lower heating value than higher rank coals (Clyde Bergemann, 2005). In 2007, there were 17 surface mines extracting PRB coal, which produced over 479 million short tons (EIA, 2009).

PRB coal is modeled using modern mining methods in practice at the following mines: Peabody Energy's North Antelope-Rochelle mine (97.5 million short tons produced in 2008), Arch Coal, Inc.'s Black Thunder Mine (88.5 million short tons produced in 2008), Rio Tinto Energy America's Jacobs Ranch (42.1 million short tons produced in 2008), and Cordero Rojo Operation (40.0 million short tons produced in 2008). These four mines were the largest surface mines in the United States in 2008 according to the National Mining Association's 2008 Coal Producer Survey (National Mining Association, 2009).

Equipment and Mine Site

Much of the equipment utilized for surface coal mining in the PRB is very large. GHG emissions that result from the production of construction materials required for coal extraction were quantified for the following equipment, within the model: track loader (10 pieces at 26,373 kg each); rotary drill (3 pieces at 113,400 kg each); walking dragline (3 pieces at 7,146,468 kg each); electric mining shovel (10 pieces at 1,256,728 kg each); mining truck (11 pieces at 278,690 kg each); coal crusher (1 piece at 115,212 kg); conveyor (1 piece at 1,064,000 kg); and loading silo (6 pieces at 10,909,569 kg each).

Coal seams are located relatively close to the ground surface in the PRB such that large-scale surface mining is common. The coal seam ranges in thickness from 42 to 184 feet thick (EPA, 2004a). Before overburden drilling and cast blasting can be carried out, topsoil and unconsolidated overburden must be removed from the consolidated overburden that is to be blasted. These operations use both truck and shovel operations and bulldozing to move these materials to a nearby stockpile location so that they can be used in post-mining site reclamation. Estimates are made for topsoil/overburden operations based on requirements reported in the Energy and Environmental Profile of the U.S. Mining Industry (DOE, 2002) for a hypothetical western surface coal mine.

Overburden Blasting and Removal

Blast holes are drilled into overburden for subsequent ammonium nitrate and fuel oil packing and detonation using large rotary drills. Drills use electricity to drill 220-270 millimeter diameter holes through sandstone, siltstone, mudstone and carbonaceous shale that make up the overburden. Typically this overburden contains water, which controls particulate emission associated with drilling activities. For the purposes of this assessment it is assumed that drilling operations produce no direct emissions. Electricity requirements for drilling are taken from the U.S. DOE report Mining Industry for the Future: Energy and Environmental Profile of the U.S. Mining Industry (DOE, 2002).

Cast blasting is a blasting technique that was developed relatively recently, and has found broad application in large surface mines. Cast blasting comminutes (breaks into fragments/particles) overburden, and also moves an estimated 25-35 percent (modeled at 30 percent) of the blasted overburden to the target fill location (Mining Technology, 2007). The model assumes that blasting uses ammonium nitrate and fuel oil explosives with a powder factor[1] of 300 g per m^3 of overburden blasted (SME, 1990), and GHG emissions associated with explosive production and the blasting process are included in the model, based on EPA's AP-42 report (EPA, 1995).

Overburden removal is achieved primarily through dragline operations, with the remainder moved using large electric shovels. Dragline excavation systems are among the largest on-land machines, and utilize a large bucket suspended from a boom, where the bucket is scraped along the ground to fill the bucket. The bucket is then emptied at a nearby fill location. Electricity requirements for dragline operation combined with other on site operations, were estimated based on electricity usage at the North Antelope Rochelle Mine, to be approximately 971 kWh per 1000 tons of coal (Peabody, 2006). During this time dragline operation accounted for approximately 50% of the overburden energy.

[1] Powder factor refers to the mass of explosive needed to blast a given mass of material.

Coal Recovery

Following overburden removal, coal is extracted using truck and shovel-type operations. Because of the large scale of operations, large electric mining shovels (Bucyrus 495 High Performance Series) are assumed to be employed, with a bucket capacity of 120 tons, alongside 320-400 ton capacity mining trucks (Bucyrus International Inc., 2008).

The amount of coal that could be moved by a single shovel per year was determined by using data for the Black Thunder and Cordero Rojo coal mines (Mining Technology, 2007). A coal hauling distance of two miles is assumed, with a round-trip distance of four miles, based on evaluation of satellite imagery of mining operations. The extracted coal is ground and crushed to the necessary size for transportation. It is assumed that the coal does not require cleaning before leaving the mine site. The crushed coal is carried from the preparation facility to a loading silo by an overland conveyor belt. From the loading silo, the coal is loaded into railcars for transportation.

Coal Bed Methane Emissions

During coal acquisition, methane is released during both the coal extraction and post-mining coal preparation activities. While the PRB has relatively low specific methane content, the large thickness of the coal deposit (80 feet thick or more in many areas) has a large methane content per square foot of surface area. As a result the PRB has recently begun to be exploited on a large scale. Extraction of coal bed methane, prior to mining of the coal seam, results in a net reduction of the total amount of coal bed methane that is emitted to the atmosphere, since extracted methane is typically sold into the natural gas market, and eventually combusted.

For the purposes of this assessment, it is assumed that the coal seam in the area of active mining was previously drilled to extract methane. Based on recent data available from the EPA, coal bed methane emissions for surface mining, including the PRB, are expected to range from 8 to 98 standard cubic feet per ton (cf/ton) of produced coal, with a typical value of 51 cf/ton (EPA, 2011b).

Illinois No. 6 Coal

Illinois No. 6 coal is part of the Herrin Coal, and is a bituminous coal that is found in seams that typically range from about 2 to 15 feet in thickness, and is found in the southern and eastern regions of Illinois and surrounding areas. Illinois No. 6 coal is commonly extracted via underground mining techniques, including continuous mining and longwall mining. Illinois No. 6 coal seams may contain relatively high levels of mineral sediments or other materials, and therefore require coal cleaning (beneficiation) at the mine site. The following sections describe the unit processes modeled for Illinois No. 6 coal mining.

Equipment and Mine Site

Extraction of Illinois No. 6 coal requires several types of major equipment and mining components, in order to operate the coal mine. The following components were modeled for use during underground mining operations: site paving and concrete, conveyor belt, stacker/reclaimer, crusher, coal cleaning, silo, wastewater treatment, continuous miner, longwall mining systems (including shear head, roof supports, armored force conveyor, stage loader, and mobile belt tailpiece), and shuttle car systems with replacement. Overall, when considering materials requirements for the construction of these systems, the material inputs values shown in **Table A-16** were required for mine and mining system construction, on a per lb of coal output basis. GHG emissions associated

with the production of these materials were incorporated into the model and accounted for as construction related emissions.

Table A-16: Construction Materials Required for Illinois No. 6 Coal Mining

Construction Material	Amount	Units
Cold-Rolled Steel	1.47E-05	lb/lb coal produced
Hot-dip Galvanized Steel	1.52E-06	lb/lb coal produced
Rubber	4.45E-07	lb/lb coal produced
Steel Plate	1.80E-04	lb/lb coal produced
Concrete	6.06E-05	lb/lb coal produced
Rebar	1.41E-06	lb/lb coal produced
Polyvinylchloride Pipe	1.30E-07	lb/lb coal produced
Steel, Stainless, 316	6.77E-08	lb/lb coal produced
Stainless Steel Cold Roll 431	6.77E-08	lb/lb coal produced
Cast Iron	3.38E-07	lb/lb coal produced
Copper Mix	8.11E-09	lb/lb coal produced
Asphalt	1.11E-03	lb/lb coal produced

Coal Mine Operations

Operations of the coal mine were based on operation of the Galatia Mine, which is operated by the American Coal Company and located in Saline County, Illinois. Sources reviewed in support of coal mine operations include Galatia Mine production rates, electricity usage, particulate emissions, methane emissions, wastewater discharge permit monitoring reports, and communications with Galatia Mine staff. When data from the Galatia Mine were not available, surrogate data were taken from other underground mines, as relevant.

Electricity is the main source of energy for coal mine operations. Electricity use for this model was estimated based on previous estimates made by EPA for electricity use for underground mining and coal cleaning at the Galatia Mine (EPA, 2008). The life cycle profile for electricity use is based on eGRID2007. The Emissions and Generation Resource Integrated Database (eGRID) is a comprehensive inventory of environmental attributes for electric power systems (EPA, 2010).

Although no Galatia Mine data were found that estimated the diesel fuel used during mining operations, it was assumed that some diesel would be used to operate trucks for moving materials, workers, and other secondary on-site operations. Therefore, diesel use was estimated for the Galatia Mine from 2002 U.S. Census data for bituminous coal underground mining operations and associated cleaning operations (U.S. Census Bureau, 2004). Emissions of GHGs were based on emissions associated with the use of diesel. EPA Tier 4 diesel standards for non-road diesel engines were used, since these standards would go into effect within a couple years of commissioning of the mine for this study (EPA, 2004b).

Coal Bed Methane

During the acquisition of Illinois No. 6 coal, methane is released during both the underground coal extraction and the post-mining coal preparation activities. Illinois No. 6 coal seams are not nearly as thick as PRB coals, and as a result are less commonly utilized as a resource for coal bed methane extraction. Instead, methane capture may be applied during the coal extraction process. Based on recent data available from the EPA, coal bed methane emissions for underground mining, including mining within the Illinois No. 6 coal seam, are expected to range from 360 to 500 cf/ton of produced

coal, with a nominal value of 422 cf/ton (EPA, 2011b). It is assumed that no methane capture is applied for Illinois No. 6 coal.

A.3 Raw Material Transport: Natural Gas

The boundary of raw material transport begins with receipt of processed natural gas at the extraction site and ends with the delivery of natural gas to an energy conversion facility. Methane emissions from pipeline operations are a function of pipeline distance. This analysis uses a pipeline transport distance of 604 miles (971.4 km), which is the average distance for natural gas pipeline transmission in the U.S. The data sources and assumptions for calculating the greenhouse gas emissions from construction and operation of natural gas transmission pipelines are discussed below.

Pipeline Construction and Decommissioning

Carbon steel is the primary material used in the construction of natural gas pipelines. The mass of pipeline per unit length was determined using an online calculator (Steel Pipes & Tubes, 2009). The weight of valves and fittings were estimated at an additional 10 percent of the total pipeline weight. The pipeline was assumed to have a life of 30 years. The mass of pipeline construction per kilogram of natural gas was determined by dividing the total pipeline weight by the total natural gas flow through the pipeline for a 30-year period.

The decommissioning of a natural gas pipeline involves cleaning and capping activities. This analysis assumes that the decommissioning of a natural gas pipeline incurs 10 percent of the energy requirements and emissions as the original installation of the pipeline.

Pipeline Operations

The U.S. has an extensive natural gas pipeline network that connects natural gas supplies and markets. Compressor stations are necessary every 50 to 100 miles along the natural gas transmission pipelines in order to boost the pressure of the natural gas. Compressor stations consist of centrifugal and reciprocating compressors. Most natural gas compressors are powered by natural gas, but, when electricity is available, electrically-powered compressors are used.

A 2008 paper published by the Interstate Natural Gas Association of America provides data from its 2004 database, which shows that the U.S. pipeline transmission network has 5,400 reciprocating compressors and over 1,000 gas turbine compressors (Hedman, 2008). Further, based on written communication from El Paso Pipeline Group, approximately three percent of transmission compressors are electrically driven (El Paso Pipeline Group, 2011). El Paso Pipeline Group has the highest transmission capacity of all natural gas pipeline companies in the U.S., and it is thus assumed that the share of electrically-powered compressors in their fleet is representative of the entire natural gas transmission network. Based on written communication with El Paso Pipeline Group (El Paso Pipeline Group, 2011), the share of compressors on the U.S. natural gas pipeline transmission network is approximately 78 percent reciprocating compressors, 19 percent turbine-powered centrifugal compressors, and 3 percent electrically-powered compressors.

The use rate of natural gas for fuel in transmission compressors was calculated from the Federal Energy Regulatory Commission (FERC) Form 2 database, which is based on an annual survey of gas producers and pipeline companies (FERC, 2010). The 28 largest pipeline companies were pulled from the FERC Form 2 database. These 28 companies represent 81 percent of NG transmission in 2008. The FERC data for 81 percent of U.S. natural gas transmission is assumed to be a representative sample of the fuel use rate of the entire transmission network. This data shows that

0.96 percent of natural gas product is consumed as compressor fuel. This fuel use rate was converted to a basis of kg of natural gas consumed per kg of natural gas transported by multiplying it by the total natural gas delivered by the transmission network in 2008 (EIA, 2011) and dividing it by the annual tonne-km of pipeline transmission in the U.S. (Dennis, 2005). The total delivery of natural gas in 2008 was 21 Tcf, which is approximately 400 billion kg of natural gas. The annual transport rate for natural gas transmission was steady from 1995 through 2003, at approximately 380 billion tonne-km per year. More recent transportation data are not available, and thus this analysis assumes the same tonne-km rate for 2008 as shown from 1995 through 2003.

The air emissions from the combustion of natural gas by compressors are estimated by applying EPA emission factors to the natural gas consumption rate of the compressors (EPA, 1995). Specifically, the emission profile of gas-powered, centrifugal compressors is based on emission factors for gas turbines; the emission profile of gas-powered, reciprocating compressors is based on emission factors for 4-stroke, lean burn engines. For electrically-powered compressors, this analysis assumes that the indirect emissions are representative of the U.S. average fuel mix for electricity generation.

The average power of electrically-driven compressors for U.S. NG transmission is assumed to be the same as the average power of all compressors on the transmission network. An average compressor on the U.S. natural gas transmission network has a power rating of 14,055 horsepower (10.5 MW) and a throughput of 734 million cubic feet of natural gas per day (583,000 kg NG/hour) (EIA, 2007). Electrically-driven compressors have efficiencies of 95 percent (DOE, 1996; Hedman, 2008). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output.

In addition to air emissions from combustion processes, fugitive venting from pipeline equipment results in the methane emissions to air. The fugitive emission rate for natural gas pipeline operations is based on data published by the Bureau of Transportation Statistics (BTS) and EPA. The transport data for natural gas transmission is based on ton-mileage estimates by BTS, which calculates 253 billion ton-miles of natural gas transmission in 2003 (Dennis, 2005). The 2003 data are the most recent data point in the BTS reference, and thus EPA's inventory data for the years 2000 and 2005 were interpolated to arrive at a year 2003 value of 1,985 million kg of fugitive methane emissions per year (EPA, 2011b). Dividing the EPA emission by the transport requirements and converting to metric units gives 5.37E-06 kg/kg-km.

Calculation of Average Natural Gas Transmission Distance

The average pipeline distance for natural gas transport is determined by balancing national emission inventory (EPA, 2011b) and natural gas consumption data (EIA, 2011) with NETL's unit process emission factor for fugitive methane emissions from pipeline operations. **Equation 5** shows the national inventory and consumption data on the left-hand side and NETL's emission factor for fugitive methane on the right-hand side.

$$\frac{E_{methane}}{NG_{consumption}} = d * EF_{methane} \qquad \textbf{(Equation 5)}$$

Where,

$E_{methane}$ = Total pipeline fugitive methane emissions (default = 2,115E+06 kg CH_4/yr)
$NG_{consumption}$ = consumption of natural gas (default = 21.84 MMBtu/yr)
$EF_{methane}$ = Emission factor for fugitive methane (default =9.97E-05 kg CH_4/MMBtu-km)

The default value for total fugitive emissions of methane from pipeline transmission are based on the 2009 national inventory emissions for natural gas transmission and storage reported by EPA (EPA, 2011b). The value reported by EPA is 2,115 Gg CH_4/yr, which is equal to 2,115 million kg CH_4/yr.

The default value for annual natural gas consumption is based on annual EIA statistics for natural gas production and consumption (EIA, 2011). The volume of natural gas transported by pipeline is 21.26 Tcf/year. This value is the midpoint of the volume of processed natural gas injected to the pipeline transmission network and the volume of natural gas delivered to consumers. In 2009 the volume of natural gas injected to the natural gas transmission network by NG processing plants was 21.56 Tcf; this volume was calculated by subtracting the natural gas consumption at the extraction and processing sites (1.28 Tcf) from total annual consumption (22.84 Tcf) (EIA, 2011). In 2009 the volume of natural gas delivered to consumers was 20.97 Tcf (EIA, 2011). The average volume of natural gas transmission was converted to an energy basis using an energy density of 1,027 Btu/cf; 21.26 Tcf/year is equivalent to 21.84 E+09 MMBtu. Converting to an energy basis (using a density of 0.042 lbs/cf and energy content of 1,027 Btu/cf) gives 21.84 billion MMBtu.

For **Equation 5** it is necessary to convert the emission factor for fugitive emissions from pipeline operations (calculated above) to an energy basis so that it can be factored with the annual consumption data for natural gas. The emission factor used by the pipeline unit process is 5.37E-06 kg/kg-km. Converting to an energy basis (using the conversion factors of 0.042 lb/cf NG and 1,027 Btu/cf) results in an emission factor of 9.97E-05 kg CH_4/MMBtu-km.

The unknown *d* in **Equation 5** is the distance (km) that reconciles NETL's unit process with the national level data. Solving for *d* gives the following equation:

$$d = \frac{E_{methane}}{NG_{consumption} * EF_{methane}} \qquad \textbf{(Equation 6)}$$

Applying the default values to **Equation 6** gives a distance of 971 km (604 miles), as shown in **Equation 7**.

$$d = \frac{2{,}115\times10^{6} kg\ CH_4/yr}{(21.84\times10^{9} MMBtu/yr)(9.97\times10^{-5} kg CH_4/MMBtu\ km)} = 971\ km \qquad \textbf{(Equation 7)}$$

The pipeline transport of natural gas results in losses of natural gas product to two activities: (1) fugitive emissions and (2) natural gas used as fuel in pipeline compressors. Based on the data and assumptions of this unit process, the transmission of natural gas a distance of 971 km results in a 1.45 percent loss of natural gas product (1.0148 kg of natural gas are injected into the pipeline to deliver 1.0 kg of natural gas to the consumer). The annual data for natural gas production and consumption (EIA, 2011) show a 2.81 percent loss of natural gas for transmission and distribution (natural gas processing plants produce 21.56 Tcf of natural gas and 20.97 Tcf of natural gas are delivered to consumers). The 2.81 percentage loss factor includes pipeline *distribution* in addition to pipeline transmission, and thus it is expected for the transmission losses (1.45 percent) to be lower than the transmission and distribution loss (2.81 percent).

The default values for key variables for NETL's model of natural gas pipeline transmission are shown in the **Table A-17**.

Table A-17: Natural Gas Transport to Large End User

Natural Gas Emissions and Transmission Infrastructure	Units	Value
Pipeline Transport Distance (national average)	Miles	604
Distance Between Compressor Stations	Miles	75
Compression, Gas-powered, Reciprocating Engine	Percent	78%
Compression, Gas-powered, Centrifugal Engine	Percent	19%
Compression, Electrical, Centrifugal Engine	Percent	3%

A.4 Raw Material Transport: Coal

Train transport was modeled for the transport of both PRB and Illinois No. 6 coal from mining sites to energy conversion facilities. Mined coal is presumed to be transported by rail from PRB and Illinois No. 6 coal mine sources, in support of electricity production. Coal is assumed to be transported via unit train, where a unit train is defined as one locomotive pulling 100 railcars loaded with coal. The locomotive is powered by a 4,400 horsepower diesel engine (General Electric, 2008) and each car has a 100-ton coal capacity (NETL, 2007).

GHG emissions for train transport are evaluated based on typical diesel combustion emissions for a locomotive engine. Loss of coal during transport is assumed to be equal to the fugitive dust emissions; loss during loading at the mine is assumed to be included in the coal reject rate and no loss is assumed during unloading. It is assumed that the majority of the railway connecting the coal mine and the energy conversion facility is existing infrastructure. An assumed 25-mile rail spur was constructed between the energy conversion facility and the primary railway.

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Appendix B:
Inventory Results in Alternate Units

Table B-1: Upstream Greenhouse Gas Inventory Results for Natural Gas

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Avg. Gas	CO_2	5.93E+00	1.05E+00	6.98E+00	2.69E+00	4.76E-01	3.16E+00	2.55E+00	4.51E-04	3.00E-03	1.22E+01	2.16E+00	1.43E+01
	N_2O	1.85E-04	2.02E-05	2.05E-04	8.39E-05	9.17E-06	9.31E-05	7.95E-05	8.69E-06	8.82E-05	3.80E-04	4.15E-05	4.22E-04
	CH_4	6.42E-01	2.14E-01	8.56E-01	2.91E-01	9.69E-02	3.88E-01	2.76E-01	9.18E-02	3.68E-01	1.32E+00	4.39E-01	1.76E+00
	CO_2e (20-year)	52.2	16.4	68.6	23.7	7.5	31.1	22.4	7.1	29.5	107.2	33.8	141.0
	CO_2e (100-year)	22.0	6.4	28.4	10.0	2.9	12.9	9.5	2.7	12.2	45.3	13.1	58.4
	CO_2e (500-year)	10.8	2.7	13.5	4.9	1.2	6.1	4.7	1.2	5.8	22.3	5.5	27.8
Conv. Gas	CO_2	6.34E+00	1.05E+00	7.38E+00	2.87E+00	4.76E-01	3.35E+00	2.72E+00	4.51E-01	3.17E+00	1.30E+01	2.16E+00	1.52E+01
	N_2O	2.14E-04	2.02E-05	2.35E-04	9.72E-05	9.17E-06	1.06E-04	9.22E-05	8.69E-06	1.01E-04	4.40E-04	4.15E-05	4.82E-04
	CH_4	5.29E-01	2.14E-01	7.43E-01	2.40E-01	9.69E-02	3.37E-01	2.28E-01	9.18E-02	3.19E-01	1.09E+00	4.39E-01	1.53E+00
	CO_2e (20-year)	44.5	16.4	60.9	20.2	7.5	27.6	19.1	7.1	26.2	91.4	33.8	125.2
	CO_2e (100-year)	19.6	6.4	26.0	8.9	2.9	11.8	8.4	2.7	11.2	40.3	13.1	53.5
	CO_2e (500-year)	10.4	2.7	13.1	4.7	1.2	5.9	4.5	1.2	5.6	21.3	5.5	26.8
UnConv. Gas	CO_2	5.60E+00	1.05E+00	6.65E+00	2.54E+00	4.76E-01	3.02E+00	2.41E+00	4.51E-01	2.86E+00	1.15E+01	2.16E+00	1.37E+01
	N_2O	1.62E-04	2.02E-05	1.82E-04	7.33E-05	9.17E-06	8.25E-05	6.95E-05	8.69E-06	7.82E-05	3.32E-04	4.15E-05	3.74E-04
	CH_4	7.32E-01	2.14E-01	9.45E-01	3.32E-01	9.69E-02	4.29E-01	3.15E-01	9.18E-02	4.06E-01	1.50E+00	4.39E-01	1.94E+00
	CO_2e (20-year)	58.3	16.4	74.8	26.5	7.5	33.9	25.1	7.1	32.1	119.8	33.8	153.6
	CO_2e (100-year)	23.9	6.4	30.3	10.9	2.9	13.8	10.3	2.7	13.0	49.2	13.1	62.3
	CO_2e (500-year)	11.2	2.7	13.9	5.1	1.2	6.3	4.8	1.2	6.0	23.0	5.5	28.5
Onshore Gas	CO_2	7.18E+00	1.05E+00	8.23E+00	3.26E+00	4.76E-01	3.74E+00	3.09E+00	4.51E-01	3.54E+00	1.48E+01	2.16E+00	1.69E+01
	N_2O	2.13E-04	2.02E-05	2.33E-04	9.66E-05	9.17E-06	1.06E-04	9.16E-05	8.69E-06	1.00E-04	4.38E-04	4.15E-05	4.79E-04
	CH_4	8.21E-01	2.14E-01	1.03E+00	3.72E-01	9.69E-02	4.69E-01	3.53E-01	9.18E-02	4.45E-01	1.69E+00	4.39E-01	2.12E+00
	CO_2e (20-year)	66.3	16.4	82.8	30.1	7.5	37.5	28.5	7.1	35.6	136.3	33.8	170.0
	CO_2e (100-year)	27.8	6.4	34.2	12.6	2.9	15.5	11.9	2.7	14.7	57.0	13.1	70.2
	CO_2e (500-year)	13.5	2.7	16.1	6.1	1.2	7.3	5.8	1.2	6.9	27.6	5.5	33.1
Offshore Gas	CO_2	5.37E+00	1.05E+00	6.42E+00	2.44E+00	4.76E-01	2.91E+00	2.31E+00	4.51E-01	2.76E+00	1.10E+01	2.16E+00	1.32E+01
	N_2O	2.55E-04	2.02E-05	2.75E-04	1.15E-04	9.17E-06	1.25E-04	1.09E-04	8.69E-06	1.18E-04	5.23E-04	4.15E-05	5.64E-04
	CH_4	9.71E-02	2.14E-01	3.11E-01	4.40E-02	9.69E-02	1.41E-01	4.17E-02	9.18E-02	1.34E-01	1.99E-01	4.39E-01	6.38E-01
	CO_2e (20-year)	12.4	16.4	28.9	5.6	7.5	13.1	5.3	7.1	12.4	25.5	33.8	59.3
	CO_2e (100-year)	7.9	6.4	14.3	3.6	2.9	6.5	3.4	2.7	6.1	16.2	13.1	29.3
	CO_2e (500-year)	6.1	2.7	8.8	2.8	1.2	4.0	2.6	1.2	3.8	12.6	5.5	18.1
Assoc. Gas	CO_2	5.04E+00	1.05E+00	6.09E+00	2.29E+00	4.76E-01	2.76E+00	2.17E+00	4.51E-01	2.62E+00	1.04E+01	2.16E+00	1.25E+01
	N_2O	1.42E-04	2.02E-05	1.62E-04	6.42E-05	9.17E-06	7.34E-05	6.09E-05	8.69E-06	6.96E-05	2.91E-04	4.15E-05	3.32E-04
	CH_4	2.82E-01	2.14E-01	4.96E-01	1.28E-01	9.69E-02	2.25E-01	1.21E-01	9.18E-02	2.13E-01	5.80E-01	4.39E-01	1.02E+00
	CO_2e (20-year)	25.4	16.4	41.8	11.5	7.5	19.0	10.9	7.1	18.0	52.2	33.8	85.9
	CO_2e (100-year)	12.1	6.4	18.5	5.5	2.9	8.4	5.2	2.7	8.0	24.9	13.1	38.1
	CO_2e (500-year)	7.2	2.7	9.9	3.3	1.2	4.5	3.1	1.2	4.2	14.8	5.5	20.3

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Tight Gas	CO_2	5.53E+00	1.05E+00	6.57E+00	2.51E+00	4.76E-01	2.98E+00	2.38E+00	4.51E-01	2.83E+00	1.13E+01	2.16E+00	1.35E+01
	N_2O	1.57E-04	2.02E-05	1.78E-04	7.14E-05	9.17E-06	8.06E-05	6.77E-05	8.69E-06	7.64E-05	3.23E-04	4.15E-05	3.65E-04
	CH_4	8.16E-01	2.14E-01	1.03E+00	3.70E-01	9.69E-02	4.67E-01	3.51E-01	9.18E-02	4.43E-01	1.68E+00	4.39E-01	2.11E+00
	CO_2e (20-year)	64.3	16.4	80.7	29.2	7.5	36.6	27.6	7.1	34.7	132.1	33.8	165.8
	CO_2e (100-year)	26.0	6.4	32.4	11.8	2.9	14.7	11.2	2.7	13.9	53.3	13.1	66.5
	CO_2e (500-year)	11.7	2.7	14.4	5.3	1.2	6.5	5.1	1.2	6.2	24.1	5.5	29.6
CBM Gas	CO_2	5.45E+00	1.05E+00	6.50E+00	2.47E+00	4.76E-01	2.95E+00	2.34E+00	4.51E-01	2.79E+00	1.12E+01	2.16E+00	1.33E+01
	N_2O	1.55E-04	2.02E-05	1.75E-04	7.03E-05	9.17E-06	7.95E-05	6.67E-05	8.69E-06	7.53E-05	3.18E-04	4.15E-05	3.60E-04
	CH_4	2.86E-01	2.14E-01	5.00E-01	1.30E-01	9.69E-02	2.27E-01	1.23E-01	9.18E-02	2.15E-01	5.88E-01	4.39E-01	1.03E+00
	CO_2e (20-year)	26.1	16.4	42.5	11.8	7.5	19.3	11.2	7.1	18.3	53.6	33.8	87.4
	CO_2e (100-year)	12.7	6.4	19.1	5.7	2.9	8.6	5.4	2.7	8.2	26.0	13.1	39.1
	CO_2e (500-year)	7.7	2.7	10.3	3.5	1.2	4.7	3.3	1.2	4.4	15.7	5.5	21.2
Shale Gas	CO_2	5.84E+00	1.05E+00	6.89E+00	2.65E+00	4.76E-01	3.13E+00	2.51E+00	4.51E-01	2.96E+00	1.20E+01	2.16E+00	1.42E+01
	N_2O	1.74E-04	2.02E-05	1.94E-04	7.89E-05	9.17E-06	8.81E-05	7.48E-05	8.69E-06	8.35E-05	3.57E-04	4.15E-05	3.99E-04
	CH_4	8.07E-01	2.14E-01	1.02E+00	3.66E-01	9.69E-02	4.63E-01	3.47E-01	9.18E-02	4.39E-01	1.66E+00	4.39E-01	2.10E+00
	CO_2e (20-year)	64.0	16.4	80.5	29.0	7.5	36.5	27.5	7.1	34.6	131.5	33.8	165.3
	CO_2e (100-year)	26.1	6.4	32.5	11.8	2.9	14.7	11.2	2.7	14.0	53.6	13.1	66.7
	CO_2e (500-year)	12.0	2.7	14.7	5.5	1.2	6.7	5.2	1.2	6.3	24.7	5.5	30.2
LNG Gas	CO_2	2.93E+01	1.05E+00	3.04E+01	1.33E+01	4.76E-01	1.38E+01	1.26E+01	4.51E-01	1.31E+01	6.02E+01	2.16E+00	6.24E+01
	N_2O	3.42E-04	2.02E-05	3.62E-04	1.55E-04	9.17E-06	1.64E-04	1.47E-04	8.69E-06	1.56E-04	7.02E-04	4.15E-05	7.44E-04
	CH_4	2.78E-01	2.14E-01	4.91E-01	1.26E-01	9.69E-02	2.23E-01	1.19E-01	9.18E-02	2.11E-01	5.70E-01	4.39E-01	1.01E+00
	CO_2e (20-year)	49.4	16.4	65.8	22.4	7.5	29.9	21.2	7.1	28.3	101.5	33.8	135.2
	CO_2e (100-year)	36.4	6.4	42.8	16.5	2.9	19.4	15.6	2.7	18.4	74.7	13.1	87.8
	CO_2e (500-year)	31.5	2.7	34.2	14.3	1.2	15.5	13.5	1.2	14.7	64.7	5.5	70.1

Table B-2: Upstream Greenhouse Gas Inventory Results for Marginal Natural Gas

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marg. Onshore Gas	CO_2	5.11E+00	1.05E+00	6.16E+00	2.32E+00	4.76E-01	2.79E+00	2.20E+00	4.51E-01	2.65E+00	1.05E+01	2.16E+00	1.26E+01
	N_2O	1.44E-04	2.02E-05	1.64E-04	6.53E-05	9.17E-06	7.44E-05	6.19E-05	8.69E-06	7.06E-05	2.96E-04	4.15E-05	3.37E-04
	CH_4	3.41E-01	2.14E-01	5.55E-01	1.55E-01	9.69E-02	2.52E-01	1.47E-01	9.18E-02	2.38E-01	7.01E-01	4.39E-01	1.14E+00
	CO_2e (20-year)	29.7	16.4	46.1	13.5	7.5	20.9	12.8	7.1	19.8	61.0	33.8	94.8
	CO_2e (100-year)	13.7	6.4	20.1	6.2	2.9	9.1	5.9	2.7	8.6	28.1	13.1	41.2
	CO_2e (500-year)	7.7	2.7	10.4	3.5	1.2	4.7	3.3	1.2	4.5	15.9	5.5	21.4
Marg. Offshore Gas	CO_2	5.34E+00	1.05E+00	6.39E+00	2.42E+00	4.76E-01	2.90E+00	2.30E+00	4.51E-01	2.75E+00	1.10E+01	2.16E+00	1.31E+01
	N_2O	2.54E-04	2.02E-05	2.74E-04	1.15E-04	9.17E-06	1.24E-04	1.09E-04	8.69E-06	1.18E-04	5.21E-04	4.15E-05	5.62E-04
	CH_4	9.01E-02	2.14E-01	3.04E-01	4.09E-02	9.69E-02	1.38E-01	3.87E-02	9.18E-02	1.31E-01	1.85E-01	4.39E-01	6.24E-01
	CO_2e (20-year)	11.9	16.4	28.3	5.4	7.5	12.9	5.1	7.1	12.2	24.4	33.8	58.2
	CO_2e (100-year)	7.7	6.4	14.1	3.5	2.9	6.4	3.3	2.7	6.0	15.8	13.1	28.9
	CO_2e (500-year)	6.1	2.7	8.7	2.8	1.2	4.0	2.6	1.2	3.8	12.5	5.5	18.0

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marg. Assoc. Gas	CO_2	4.91E+00	1.05E+00	5.96E+00	2.23E+00	4.76E-01	2.70E+00	2.11E+00	4.51E-01	2.56E+00	1.01E+01	2.16E+00	1.22E+01
	N_2O	1.37E-04	2.02E-05	1.57E-04	6.22E-05	9.17E-06	7.14E-05	5.90E-05	8.69E-06	6.77E-05	2.82E-04	4.15E-05	3.23E-04
	CH_4	2.82E-01	2.14E-01	4.95E-01	1.28E-01	9.69E-02	2.25E-01	1.21E-01	9.18E-02	2.13E-01	5.78E-01	4.39E-01	1.02E+00
	CO_2e (20-year)	25.2	16.4	41.7	11.4	7.5	18.9	10.8	7.1	17.9	51.8	33.8	85.6
	CO_2e (100-year)	12.0	6.4	18.4	5.4	2.9	8.3	5.2	2.7	7.9	24.6	13.1	37.8
	CO_2e (500-year)	7.1	2.7	9.7	3.2	1.2	4.4	3.0	1.2	4.2	14.5	5.5	20.0
Marg. Tight Gas	CO_2	5.53E+00	1.05E+00	6.57E+00	2.51E+00	4.76E-01	2.98E+00	2.38E+00	4.51E-01	2.83E+00	1.13E+01	2.16E+00	1.35E+01
	N_2O	1.57E-04	2.02E-05	1.78E-04	7.14E-05	9.17E-06	8.06E-05	6.77E-05	8.69E-06	7.64E-05	3.23E-04	4.15E-05	3.65E-04
	CH_4	8.16E-01	2.14E-01	1.03E+00	3.70E-01	9.69E-02	4.67E-01	3.51E-01	9.18E-02	4.43E-01	1.68E+00	4.39E-01	2.11E+00
	SF_6	6.49E-09	2.50E-09	8.99E-09	2.94E-09	1.13E-09	4.08E-09	2.79E-09	1.07E-09	3.86E-09	1.33E-08	5.13E-09	1.85E-08
	CO_2e (20-year)	64.3	16.4	80.7	29.2	7.5	36.6	27.6	7.1	34.7	132.1	33.8	165.8
	CO_2e (100-year)	26.0	6.4	32.4	11.8	2.9	14.7	11.2	2.7	13.9	53.3	13.1	66.5
	CO_2e (500-year)	11.7	2.7	14.4	5.3	1.2	6.5	5.1	1.2	6.2	24.1	5.5	29.6
Marg. Shale Gas	CO_2	5.84E+00	1.05E+00	6.89E+00	2.65E+00	4.76E-01	3.13E+00	2.51E+00	4.51E-01	2.96E+00	1.20E+01	2.16E+00	1.42E+01
	N_2O	1.74E-04	2.02E-05	1.94E-04	7.89E-05	9.17E-06	8.81E-05	7.48E-05	8.69E-06	8.35E-05	3.57E-04	4.15E-05	3.99E-04
	CH_4	8.07E-01	2.14E-01	1.02E+00	3.66E-01	9.69E-02	4.63E-01	3.47E-01	9.18E-02	4.39E-01	1.66E+00	4.39E-01	2.10E+00
	CO_2e (20-year)	64.0	16.4	80.5	29.0	7.5	36.5	27.5	7.1	34.6	131.5	33.8	165.3
	CO_2e (100-year)	26.1	6.4	32.5	11.8	2.9	14.7	11.2	2.7	14.0	53.6	13.1	66.7
	CO_2e (500-year)	12.0	2.7	14.7	5.5	1.2	6.7	5.2	1.2	6.3	24.7	5.5	30.2
Marg. CBM Gas	CO_2	5.67E+00	1.05E+00	6.72E+00	2.57E+00	4.76E-01	3.05E+00	2.44E+00	4.51E-01	2.89E+00	1.16E+01	2.16E+00	1.38E+01
	N_2O	1.62E-04	2.02E-05	1.83E-04	7.36E-05	9.17E-06	8.28E-05	6.98E-05	8.69E-06	7.85E-05	3.33E-04	4.15E-05	3.75E-04
	CH_4	2.88E-01	2.14E-01	5.02E-01	1.31E-01	9.69E-02	2.28E-01	1.24E-01	9.18E-02	2.16E-01	5.92E-01	4.39E-01	1.03E+00
	CO_2e (20-year)	26.5	16.4	42.9	12.0	7.5	19.5	11.4	7.1	18.4	54.4	33.8	88.1
	CO_2e (100-year)	12.9	6.4	19.3	5.9	2.9	8.8	5.6	2.7	8.3	26.6	13.1	39.7
	CO_2e (500-year)	7.9	2.7	10.6	3.6	1.2	4.8	3.4	1.2	4.5	16.2	5.5	21.7
Marg. LNG Gas	CO_2	2.93E+01	1.05E+00	3.03E+01	1.33E+01	4.76E-01	1.38E+01	1.26E+01	4.51E-01	1.30E+01	6.01E+01	2.16E+00	6.23E+01
	N_2O	3.41E-04	2.02E-05	3.61E-04	1.54E-04	9.17E-06	1.64E-04	1.46E-04	8.69E-06	1.55E-04	7.00E-04	4.15E-05	7.41E-04
	CH_4	2.70E-01	2.14E-01	4.83E-01	1.22E-01	9.69E-02	2.19E-01	1.16E-01	9.18E-02	2.08E-01	5.54E-01	4.39E-01	9.92E-01
	CO_2e (20-year)	48.8	16.4	65.2	22.1	7.5	29.6	21.0	7.1	28.0	100.2	33.8	133.9
	CO_2e (100-year)	36.1	6.4	42.5	16.4	2.9	19.3	15.5	2.7	18.3	74.2	13.1	87.3
	CO_2e (500-year)	31.4	2.7	34.1	14.2	1.2	15.4	13.5	1.2	14.6	64.5	5.5	69.9

Table B-3: Upstream Greenhouse Gas Inventory Results for Coal

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Avg. Coal	CO_2	1.32E+00	1.33E+00	2.64E+00	5.97E-01	6.02E-01	1.20E+00	5.66E-01	5.71E-01	1.14E+00
	N_2O	5.29E-04	3.21E-05	5.61E-04	2.40E-04	1.46E-05	2.54E-04	2.27E-04	1.38E-05	2.41E-04
	CH_4	3.78E-01	7.23E-04	3.79E-01	1.72E-01	3.28E-04	1.72E-01	1.63E-01	3.11E-04	1.63E-01
	CO_2e (20-year)	28.7	1.4	30.1	13.0	0.6	13.7	12.3	0.6	12.9
	CO_2e (100-year)	10.9	1.4	12.3	5.0	0.6	5.6	4.7	0.6	5.3
	CO_2e (500-year)	4.3	1.3	5.6	1.9	0.6	2.5	1.8	0.6	2.4
Illinois No. 6 Coal	CO_2	2.53E+00	1.33E+00	3.86E+00	1.15E+00	6.02E-01	1.75E+00	1.09E+00	5.71E-01	1.66E+00
	N_2O	3.97E-05	3.21E-05	7.18E-05	1.80E-05	1.46E-05	3.26E-05	1.71E-05	1.38E-05	3.09E-05
	CH_4	9.40E-01	7.23E-04	9.41E-01	4.27E-01	3.28E-04	4.27E-01	4.04E-01	3.11E-04	4.05E-01
	SF_6	4.98E-07	5.47E-12	4.98E-07	2.26E-07	2.48E-12	2.26E-07	2.14E-07	2.35E-12	2.14E-07
	CO_2e (20-year)	70.3	1.4	71.7	31.9	0.6	32.5	30.2	0.6	30.8
	CO_2e (100-year)	26.1	1.4	27.4	11.8	0.6	12.4	11.2	0.6	11.8
	CO_2e (500-year)	9.7	1.3	11.0	4.4	0.6	5.0	4.2	0.6	4.7
PRB Coal	CO_2	7.73E-01	1.33E+00	2.10E+00	3.51E-01	6.02E-01	9.53E-01	3.32E-01	5.71E-01	9.03E-01
	N_2O	7.48E-04	3.21E-05	7.80E-04	3.39E-04	1.46E-05	3.54E-04	3.22E-04	1.38E-05	3.35E-04
	CH_4	1.26E-01	7.23E-04	1.26E-01	5.70E-02	3.28E-04	5.74E-02	5.41E-02	3.11E-04	5.44E-02
	CO_2e (20-year)	10.0	1.4	11.4	4.6	0.6	5.2	4.3	0.6	4.9
	CO_2e (100-year)	4.1	1.4	5.5	1.9	0.6	2.5	1.8	0.6	2.4
	CO_2e (500-year)	1.8	1.3	3.2	0.8	0.6	1.4	0.8	0.6	1.4

Table B-4: Upstream Greenhouse Gas Inventory Results for Natural Gas-fired Power Generation

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (Avg. Gas)	CO_2	5.81E+01	1.01E+01	8.75E+02	0.00E+00	9.43E+02	2.63E+01	4.60E+00	3.97E+02	0.00E+00	4.28E+02	7.31E+00	1.28E+00	1.10E+02	0.00E+00	1.19E+02
	N_2O	1.81E-03	1.96E-04	2.45E-03	0.00E+00	4.45E-03	8.22E-04	8.88E-05	1.11E-03	0.00E+00	2.02E-03	2.28E-04	2.47E-05	3.08E-04	0.00E+00	5.61E-04
	CH_4	6.31E+00	2.09E+00	2.44E-02	0.00E+00	8.42E+00	2.86E+00	9.46E-01	1.11E-02	0.00E+00	3.82E+00	7.95E-01	2.63E-01	3.07E-03	0.00E+00	1.06E+00
	SF_6	4.80E-07	4.38E-12	0.00E+00	3.16E-04	3.16E-04	2.18E-07	1.99E-12	0.00E+00	1.43E-04	1.44E-04	6.04E-08	5.51E-13	0.00E+00	3.98E-05	3.99E-05
	CO_2e (20-year)	513.0	160.4	877.0	5.2	1,555.6	232.7	72.8	397.8	2.3	705.6	64.6	20.2	110.5	0.6	196.0
	CO_2e (100-year)	216.4	62.4	875.9	7.2	1,161.8	98.2	28.3	397.3	3.3	527.0	27.3	7.9	110.4	0.9	146.4
	CO_2e (500-year)	106.3	26.0	875.1	10.3	1,017.7	48.2	11.8	396.9	4.7	461.6	13.4	3.3	110.3	1.3	128.2
Fleet Baseload (Conv. Gas)	CO_2	6.22E+01	1.01E+01	8.75E+02	0.00E+00	9.47E+02	2.82E+01	4.60E+00	3.97E+02	0.00E+00	4.30E+02	7.84E+00	1.28E+00	1.10E+02	0.00E+00	1.19E+02
	N_2O	2.10E-03	1.96E-04	2.45E-03	0.00E+00	4.75E-03	9.55E-04	8.88E-05	1.11E-03	0.00E+00	2.15E-03	2.65E-04	2.47E-05	3.08E-04	0.00E+00	5.98E-04
	CH_4	5.26E+00	2.09E+00	2.44E-02	0.00E+00	7.37E+00	2.38E+00	9.46E-01	1.11E-02	0.00E+00	3.34E+00	6.62E-01	2.63E-01	3.07E-03	0.00E+00	9.28E-01
	SF_6	5.26E-08	4.38E-12	0.00E+00	3.16E-04	3.16E-04	2.39E-08	1.99E-12	0.00E+00	1.43E-04	1.43E-04	6.63E-09	5.51E-13	0.00E+00	3.98E-05	3.98E-05
	CO_2e (20-year)	441.3	160.4	877.0	5.2	1,483.9	200.2	72.8	397.8	2.3	673.1	55.6	20.2	110.5	0.6	187.0
	CO_2e (100-year)	194.3	62.4	875.9	7.2	1,139.7	88.1	28.3	397.3	3.3	517.0	24.5	7.9	110.4	0.9	143.6
	CO_2e (500-year)	102.5	26.0	875.1	10.3	1,013.9	46.5	11.8	396.9	4.7	459.9	12.9	3.3	110.3	1.3	127.8

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (UnConv. Gas)	CO_2	5.47E+01	1.01E+01	8.75E+02	0.00E+00	9.39E+02	2.48E+01	4.60E+00	3.97E+02	0.00E+00	4.26E+02	6.90E+00	1.28E+00	1.10E+02	0.00E+00	1.18E+02
	N_2O	1.58E-03	1.96E-04	2.45E-03	0.00E+00	4.22E-03	7.17E-04	8.88E-05	1.11E-03	0.00E+00	1.91E-03	1.99E-04	2.47E-05	3.08E-04	0.00E+00	5.32E-04
	CH_4	7.15E+00	2.09E+00	2.44E-02	0.00E+00	9.26E+00	3.24E+00	9.46E-01	1.11E-02	0.00E+00	4.20E+00	9.01E-01	2.63E-01	3.07E-03	0.00E+00	1.17E+00
	SF_6	8.20E-07	4.38E-12	0.00E+00	3.16E-04	3.17E-04	3.72E-07	1.99E-12	0.00E+00	1.43E-04	1.44E-04	1.03E-07	5.51E-13	0.00E+00	3.98E-05	3.99E-05
	CO_2e (20-year)	570.1	160.4	877.0	5.2	1,612.7	258.6	72.8	397.8	2.3	731.5	71.8	20.2	110.5	0.6	203.2
	CO_2e (100-year)	234.0	62.4	875.9	7.2	1,179.5	106.1	28.3	397.3	3.3	535.0	29.5	7.9	110.4	0.9	148.6
	CO_2e (500-year)	109.4	26.0	875.1	10.3	1,020.8	49.6	11.8	396.9	4.7	463.0	13.8	3.3	110.3	1.3	128.6
Fleet Baseload (Marg. Onshore Gas)	CO_2	4.99E+01	1.01E+01	8.75E+02	0.00E+00	9.35E+02	2.26E+01	4.60E+00	3.97E+02	0.00E+00	4.24E+02	6.29E+00	1.28E+00	1.10E+02	0.00E+00	1.18E+02
	N_2O	1.41E-03	1.96E-04	2.45E-03	0.00E+00	4.05E-03	6.38E-04	8.88E-05	1.11E-03	0.00E+00	1.84E-03	1.77E-04	2.47E-05	3.08E-04	0.00E+00	5.10E-04
	CH_4	3.33E+00	2.09E+00	2.44E-02	0.00E+00	5.44E+00	1.51E+00	9.46E-01	1.11E-02	0.00E+00	2.47E+00	4.20E-01	2.63E-01	3.07E-03	0.00E+00	6.86E-01
	SF_6	9.27E-09	4.38E-12	0.00E+00	3.16E-04	3.16E-04	4.20E-09	1.99E-12	0.00E+00	1.43E-04	1.43E-04	1.17E-09	5.51E-13	0.00E+00	3.98E-05	3.98E-05
	CO_2e (20-year)	290.4	160.4	877.0	5.2	1,332.9	131.7	72.8	397.8	2.3	604.6	36.6	20.2	110.5	0.6	167.9
	CO_2e (100-year)	133.7	62.4	875.9	7.2	1,079.1	60.6	28.3	397.3	3.3	489.5	16.8	7.9	110.4	0.9	136.0
	CO_2e (500-year)	75.5	26.0	875.1	10.3	986.9	34.2	11.8	396.9	4.7	447.6	9.5	3.3	110.3	1.3	124.3
GTSC (Avg. Gas)	CO_2	7.26E+01	1.27E+01	1.33E+03	0.00E+00	1.42E+03	3.29E+01	5.75E+00	6.04E+02	0.00E+00	6.42E+02	9.15E+00	1.60E+00	1.68E+02	0.00E+00	1.78E+02
	N_2O	2.27E-03	2.45E-04	2.86E-05	0.00E+00	2.54E-03	1.03E-03	1.11E-04	1.30E-05	0.00E+00	1.15E-03	2.86E-04	3.08E-05	3.61E-06	0.00E+00	3.20E-04
	CH_4	7.90E+00	2.61E+00	2.64E-03	0.00E+00	1.05E+01	3.58E+00	1.18E+00	1.20E-03	0.00E+00	4.77E+00	9.95E-01	3.29E-01	3.32E-04	0.00E+00	1.32E+00
	SF_6	6.00E-07	5.48E-12	4.34E-08	3.16E-04	3.17E-04	2.72E-07	2.48E-12	1.97E-08	1.43E-04	1.44E-04	7.56E-08	6.90E-13	5.47E-09	3.98E-05	3.99E-05
	CO_2e (20-year)	641.8	200.7	1,330.7	5.2	2,178.4	291.1	91.0	603.6	2.3	988.1	80.9	25.3	167.7	0.6	274.5
	CO_2e (100-year)	270.7	78.0	1,330.6	7.2	1,686.6	122.8	35.4	603.6	3.3	765.0	34.1	9.8	167.7	0.9	212.5
	CO_2e (500-year)	133.0	32.6	1,330.6	10.3	1,506.4	60.3	14.8	603.5	4.7	683.3	16.8	4.1	167.6	1.3	189.8
NGCC (Avg. Gas)	CO_2	4.71E+01	8.23E+00	8.66E+02	0.00E+00	9.22E+02	2.14E+01	3.73E+00	3.93E+02	0.00E+00	4.18E+02	5.94E+00	1.04E+00	1.09E+02	0.00E+00	1.16E+02
	N_2O	1.47E-03	1.59E-04	3.33E-05	0.00E+00	1.66E-03	6.67E-04	7.21E-05	1.51E-05	0.00E+00	7.55E-04	1.85E-04	2.00E-05	4.20E-06	0.00E+00	2.10E-04
	CH_4	5.12E+00	1.69E+00	1.31E-03	0.00E+00	6.82E+00	2.32E+00	7.68E-01	5.94E-04	0.00E+00	3.09E+00	6.46E-01	2.13E-01	1.65E-04	0.00E+00	8.59E-01
	SF_6	3.89E-07	3.55E-12	7.55E-07	3.16E-04	3.17E-04	1.77E-07	1.61E-12	3.42E-07	1.43E-04	1.44E-04	4.91E-08	4.48E-13	9.51E-08	3.98E-05	4.00E-05
	CO_2e (20-year)	416.5	130.2	866.5	5.2	1,418.5	188.9	59.1	393.1	2.3	643.4	52.5	16.4	109.2	0.6	178.7
	CO_2e (100-year)	175.7	50.6	866.5	7.2	1,100.0	79.7	23.0	393.0	3.3	499.0	22.1	6.4	109.2	0.9	138.6
	CO_2e (500-year)	86.3	21.1	866.5	10.3	984.2	39.2	9.6	393.0	4.7	446.4	10.9	2.7	109.2	1.3	124.0
NGCC/ccs (Avg. Gas)	CO_2	5.52E+01	9.65E+00	1.13E+02	0.00E+00	1.78E+02	2.51E+01	4.38E+00	5.13E+01	0.00E+00	8.07E+01	6.96E+00	1.22E+00	1.42E+01	0.00E+00	2.24E+01
	N_2O	1.72E-03	1.86E-04	5.18E-05	0.00E+00	1.96E-03	7.82E-04	8.45E-05	2.35E-05	0.00E+00	8.90E-04	2.17E-04	2.35E-05	6.53E-06	0.00E+00	2.47E-04
	CH_4	6.01E+00	1.99E+00	1.71E-03	0.00E+00	7.99E+00	2.72E+00	9.01E-01	7.78E-04	0.00E+00	3.63E+00	7.57E-01	2.50E-01	2.16E-04	0.00E+00	1.01E+00
	SF_6	4.57E-07	4.16E-12	8.81E-07	3.16E-04	3.17E-04	2.07E-07	1.89E-12	4.00E-07	1.43E-04	1.44E-04	5.75E-08	5.25E-13	1.11E-07	3.98E-05	4.00E-05
	CO_2e (20-year)	488.2	152.7	113.2	5.2	759.2	221.5	69.2	51.3	2.3	344.4	61.5	19.2	14.3	0.6	95.7
	CO_2e (100-year)	205.9	59.3	113.1	7.2	385.6	93.4	26.9	51.3	3.3	174.9	25.9	7.5	14.3	0.9	48.6
	CO_2e (500-year)	101.2	24.8	113.1	10.3	249.3	45.9	11.2	51.3	4.7	113.1	12.7	3.1	14.2	1.3	31.4

Table B-5: Upstream Greenhouse Gas Inventory Results for Coal-fired Power Generation

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (Avg. Coal)	CO_2	1.38E+01	1.39E+01	2.33E+03	0.00E+00	2.35E+03	6.26E+00	6.31E+00	1.06E+03	0.00E+00	1.07E+03	1.74E+00	1.75E+00	2.93E+02	0.00E+00	2.97E+02
	N_2O	5.54E-03	3.36E-04	3.99E-02	0.00E+00	4.58E-02	2.51E-03	1.53E-04	1.81E-02	0.00E+00	2.08E-02	6.98E-04	4.24E-05	5.03E-03	0.00E+00	5.77E-03
	CH_4	3.96E+00	7.57E-03	2.67E-02	0.00E+00	4.00E+00	1.80E+00	3.43E-03	1.21E-02	0.00E+00	1.81E+00	4.99E-01	9.54E-04	3.37E-03	0.00E+00	5.04E-01
	SF_6	1.77E-06	5.73E-11	0.00E+00	3.16E-04	3.18E-04	8.03E-07	2.60E-11	0.00E+00	1.43E-04	1.44E-04	2.23E-07	7.22E-12	0.00E+00	3.98E-05	4.00E-05
	CO_2e (20-year)	300.8	14.5	2,340.1	5.2	2,660.6	136.4	6.6	1,061.5	2.3	1,206.8	37.9	1.8	294.9	0.6	335.2
	CO_2e (100-year)	114.6	14.2	2,339.2	7.2	2,475.2	52.0	6.4	1,061.1	3.3	1,122.7	14.4	1.8	294.7	0.9	311.9
	CO_2e (500-year)	44.8	14.0	2,333.0	10.3	2,402.1	20.3	6.4	1,058.2	4.7	1,089.6	5.6	1.8	294.0	1.3	302.7
EXPC (Illinois No. 6 Coal)	CO_2	2.24E+01	1.18E+01	2.23E+03	0.00E+00	2.27E+03	1.02E+01	5.34E+00	1.01E+03	0.00E+00	1.03E+03	2.83E+00	1.48E+00	2.81E+02	0.00E+00	2.85E+02
	N_2O	3.52E-04	2.85E-04	3.77E-02	0.00E+00	3.83E-02	1.60E-04	1.29E-04	1.71E-02	0.00E+00	1.74E-02	4.44E-05	3.59E-05	4.75E-03	0.00E+00	4.83E-03
	CH_4	8.35E+00	6.42E-03	2.51E-02	0.00E+00	8.38E+00	3.79E+00	2.91E-03	1.14E-02	0.00E+00	3.80E+00	1.05E+00	8.08E-04	3.17E-03	0.00E+00	1.06E+00
	SF_6	4.42E-06	4.85E-11	6.11E-07	3.16E-04	3.21E-04	2.00E-06	2.20E-11	2.77E-07	1.43E-04	1.46E-04	5.57E-07	6.11E-12	7.70E-08	3.98E-05	4.04E-05
	CO_2e (20-year)	623.7	12.3	2,243.5	5.2	2,884.7	282.9	5.6	1,017.6	2.3	1,308.5	78.6	1.6	282.7	0.6	363.5
	CO_2e (100-year)	231.4	12.0	2,242.7	7.2	2,493.3	104.9	5.5	1,017.3	3.3	1,130.9	29.2	1.5	282.6	0.9	314.1
	CO_2e (500-year)	86.1	11.9	2,236.8	10.3	2,345.0	39.0	5.4	1,014.6	4.7	1,063.7	10.8	1.5	281.8	1.3	295.5
IGCC (Illinois No. 6 Coal)	CO_2	1.98E+01	1.04E+01	1.89E+03	0.00E+00	1.92E+03	8.98E+00	4.72E+00	8.57E+02	0.00E+00	8.71E+02	2.49E+00	1.31E+00	2.38E+02	0.00E+00	2.42E+02
	N_2O	3.11E-04	2.52E-04	4.67E-05	0.00E+00	6.09E-04	1.41E-04	1.14E-04	2.12E-05	0.00E+00	2.76E-04	3.92E-05	3.17E-05	5.89E-06	0.00E+00	7.68E-05
	CH_4	7.37E+00	5.66E-03	9.58E-03	0.00E+00	7.38E+00	3.34E+00	2.57E-03	4.35E-03	0.00E+00	3.35E+00	9.28E-01	7.13E-04	1.21E-03	0.00E+00	9.30E-01
	SF_6	3.90E-06	4.28E-11	7.69E-07	3.16E-04	3.21E-04	1.77E-06	1.94E-11	3.49E-07	1.43E-04	1.45E-04	4.91E-07	5.40E-12	9.69E-08	3.98E-05	4.04E-05
	CO_2e (20-year)	550.4	10.9	1,890.8	5.2	2,457.2	249.7	4.9	857.7	2.3	1,114.6	69.3	1.4	238.2	0.6	309.6
	CO_2e (100-year)	204.2	10.6	1,890.4	7.2	2,112.4	92.6	4.8	857.5	3.3	958.2	25.7	1.3	238.2	0.9	266.2
	CO_2e (500-year)	76.0	10.5	1,890.2	10.3	1,987.0	34.5	4.8	857.4	4.7	901.3	9.6	1.3	238.2	1.3	250.4
IGCC/ccs (Illinois No. 6 Coal)	CO_2	2.33E+01	1.22E+01	2.46E+02	0.00E+00	2.81E+02	1.06E+01	5.55E+00	1.11E+02	0.00E+00	1.28E+02	2.94E+00	1.54E+00	3.10E+01	0.00E+00	3.54E+01
	N_2O	3.66E-04	2.96E-04	9.13E-05	0.00E+00	7.54E-04	1.66E-04	1.34E-04	4.14E-05	0.00E+00	3.42E-04	4.61E-05	3.73E-05	1.15E-05	0.00E+00	9.50E-05
	CH_4	8.67E+00	6.67E-03	1.15E-02	0.00E+00	8.69E+00	3.93E+00	3.02E-03	5.20E-03	0.00E+00	3.94E+00	1.09E+00	8.40E-04	1.45E-03	0.00E+00	1.10E+00
	SF_6	4.59E-06	5.04E-11	8.72E-07	3.16E-04	3.21E-04	2.08E-06	2.29E-11	3.96E-07	1.43E-04	1.46E-04	5.78E-07	6.35E-12	1.10E-07	3.98E-05	4.05E-05
	CO_2e (20-year)	648.1	12.8	246.6	5.2	912.7	294.0	5.8	111.9	2.3	414.0	81.7	1.6	31.1	0.6	115.0
	CO_2e (100-year)	240.4	12.5	246.1	7.2	506.2	109.0	5.7	111.6	3.3	229.6	30.3	1.6	31.0	0.9	63.8
	CO_2e (500-year)	89.5	12.3	245.9	10.3	358.0	40.6	5.6	111.5	4.7	162.4	11.3	1.6	31.0	1.3	45.1

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
SCPC (Illinois No. 6 Coal)	CO_2	1.94E+01	1.02E+01	1.91E+03	0.00E+00	1.94E+03	8.78E+00	4.61E+00	8.66E+02	0.00E+00	8.79E+02	2.44E+00	1.28E+00	2.41E+02	0.00E+00	2.44E+02
	N_2O	3.04E-04	2.46E-04	6.99E-05	0.00E+00	6.20E-04	1.38E-04	1.12E-04	3.17E-05	0.00E+00	2.81E-04	3.83E-05	3.10E-05	8.81E-06	0.00E+00	7.81E-05
	CH_4	7.20E+00	5.53E-03	8.98E-03	0.00E+00	7.22E+00	3.27E+00	2.51E-03	4.07E-03	0.00E+00	3.27E+00	9.07E-01	6.97E-04	1.13E-03	0.00E+00	9.09E-01
	SF_6	3.81E-06	4.19E-11	8.26E-07	3.16E-04	3.21E-04	1.73E-06	1.90E-11	3.74E-07	1.43E-04	1.45E-04	4.80E-07	5.27E-12	1.04E-07	3.98E-05	4.04E-05
	CO_2e (20-year)	538.0	10.6	1,910.1	5.2	2,463.9	244.0	4.8	866.4	2.3	1,117.6	67.8	1.3	240.7	0.6	310.5
	CO_2e (100-year)	199.6	10.4	1,909.7	7.2	2,126.9	90.5	4.7	866.2	3.3	964.7	25.1	1.3	240.6	0.9	268.0
	CO_2e (500-year)	74.3	10.2	1,909.5	10.3	2,004.3	33.7	4.6	866.2	4.7	909.2	9.4	1.3	240.6	1.3	252.5
SCPC/ccs (Illinois No. 6 Coal)	CO_2	2.78E+01	1.46E+01	3.02E+02	0.00E+00	3.45E+02	1.26E+01	6.63E+00	1.37E+02	0.00E+00	1.56E+02	3.51E+00	1.84E+00	3.81E+01	0.00E+00	4.34E+01
	N_2O	4.37E-04	3.53E-04	1.07E-04	0.00E+00	8.97E-04	1.98E-04	1.60E-04	4.85E-05	0.00E+00	4.07E-04	5.50E-05	4.45E-05	1.35E-05	0.00E+00	1.13E-04
	CH_4	1.04E+01	7.95E-03	9.79E-03	0.00E+00	1.04E+01	4.69E+00	3.61E-03	4.44E-03	0.00E+00	4.70E+00	1.30E+00	1.00E-03	1.23E-03	0.00E+00	1.31E+00
	SF_6	5.48E-06	6.02E-11	8.34E-07	3.16E-04	3.22E-04	2.48E-06	2.73E-11	3.78E-07	1.43E-04	1.46E-04	6.90E-07	7.58E-12	1.05E-07	3.98E-05	4.06E-05
	CO_2e (20-year)	773.3	15.3	302.8	5.2	1,096.5	350.7	6.9	137.4	2.3	497.4	97.4	1.9	38.2	0.6	138.2
	CO_2e (100-year)	286.8	14.9	302.4	7.2	611.3	130.1	6.8	137.2	3.3	277.3	36.1	1.9	38.1	0.9	77.0
	CO_2e (500-year)	106.7	14.7	302.2	10.3	434.0	48.4	6.7	137.1	4.7	196.8	13.4	1.9	38.1	1.3	54.7

API
American Petroleum Institute

anga
America's Natural Gas Alliance

Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production

Summary and Analysis of API and ANGA Survey Responses

Terri Shires and Miriam Lev-On
URS Corporation and The LEVON Group

FINAL REPORT
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Executive Summary

This document presents the results from a collaborative effort among members of the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) to gather data on key natural gas production activities and equipment emission sources - including unconventional natural gas production - that are essential to developing estimates of methane emissions from upstream natural gas production.

API and ANGA members undertook this effort as part of an overall priority to develop new and better data about natural gas production and make this information available to the public. This information acquired added importance in 2011, when the EPA released an inventory of U.S. greenhouse gases (GHG) emissions that substantially increased estimates of methane emissions from Petroleum and Natural Gas Systems. Public comments submitted by both trade associations reflected a number of concerns – most notably that EPA's estimates were based on a small set of data submitted by a limited number of companies in a different context (i.e., data not developed for the purpose of estimating nationwide emissions).

The API/ANGA data set (also referred to as ANGA/API) provides data on 91,000 wells distributed over a broad geographic area and operated by over 20 companies. This represents nearly one-fifth (18.8%) of the estimated number of total wells used in EPA's 2010 emissions inventory.[1] The ANGA/API data set is also more than 10 times larger than the set of wells in one of EPA's key data sources taken from an older Natural Gas Star sample that was never intended for developing nationwide emissions estimates. ***Although more and better data efforts will still be needed, API/ANGA members believe this current collaborative effort is the most comprehensive data set compiled for natural gas operations.***

As Table ES-1 demonstrates, survey results in two source categories – liquids unloading and unconventional gas well re-fracture rates - substantially lower EPA's estimated emissions from natural gas production and shift Natural Gas Systems from the largest contributor of methane emissions to the second largest (behind Enteric Fermentation, which is a consequence of bovine digestion).[2] The right-hand column of this table shows the impact of ANGA/API data on the estimated emissions for each source category. Gas well liquids unloading and the rate at which unconventional gas wells are re-fractured are key contributors to the overall GHG emissions estimated by EPA in the national emissions inventory. For example, methane emissions from liquids unloading and unconventional well re-fracturing accounted for 59% of EPA's estimate for overall natural gas production sector methane emissions. Overall, API/ANGA activity data for these two source categories indicate that EPA estimates of potential emissions from the production sector of "Natural Gas Systems" would be 50% lower if EPA were to use ANGA/API's larger and more recent survey results.

[1] EPA's 2010 national inventory indicates a total of 484,795 gas wells (EPA, 2012).

[2] Table ES-2 of the 2010 national inventory (EPA, 2012).

TABLE ES-1. EMISSION COMPARISON BETWEEN EPA AND INDUSTRY DATA

Source Category	EPA		API/ANGA		Impact on Source Category Emissions
	Metric tons of CH4	% of EPA Emissions Total	Metric tons of CH4	% of Revised Emissions Total	API & ANGA - EPA / EPA % Difference
Gas Wells Liquids Unloading	4,501,465 *	51%	637,766	14%	-86%
Unconventional Well Re-fracture Rates	712,605 *	8%	197,311	4%	-72%
Other Production Sector Emissions**	3,585,600	41%	3,585,600	81%	
Total Production Sector Emissions	8,799,670		4,420,677		-50%

* EPA's estimates are adjusted to industry standard conditions of 60 degrees F and 14.7 psia for comparison to the ANGA/API emission estimates.

**The "Other Production Sector Emissions" are comprised of over 30 different source categories detailed in Table A-129 in the Annex of the EPA's 2012 national inventory. The "Other Production Sector Emissions" are the same values for this comparison between the EPA national inventory and the API/ANGA survey to focus the comparison on quantified differences in emission estimates for gas well liquids unloading and unconventional well re-fracture rates.

As mentioned above, the differences between EPA and ANGA/API estimates hinge on the following key differences in activity data and thus considerably impact overall emissions from Natural Gas Systems:

- ***Liquids unloading and venting.*** API/ANGA data showed lower average vent times as well as a lower percentage of wells with plunger lifts and wells venting to the atmosphere than EPA assumed. This is particularly significant because liquids unloading accounted for 51% of EPA's total "Natural Gas Systems" methane emissions in the 2010 inventory. Applying emission factors based on ANGA/API data reduces the calculated emissions for this source by 86% (from 4,501,465 metric tons of CH_4 to 637,766 metric tons of CH_4 when compared on an equivalent basis) from EPA's 2010 national GHG inventory.
- ***Re-fracture rates for unconventional wells***. API/ANGA members collected data on re-fracture rates for unconventional wells in two phases. The first phase collected data for all well types (conventional and unconventional), while the second phase targeted unconventional gas wells. Both phases of the survey data show significantly lower rates of well re-fracturing than the 10% assumption used by EPA. As discussed in detail in this report, the re-fracture rate varied from 0.7% to 2.3%. The second phase of the survey gathered data from only unconventional well activity and using the re-fracture rate data from this second phase of the ANGA/API survey reduces the national emission estimate

for this source category by 72%, - from 712,605 metric tons of CH_4 to 197,311 metric tons of CH_4 when compared on an equivalent basis.

This report also discusses an important related concern that the government lacks a single coordinated and cohesive estimate of well completions and well counts. Although the 2010 national GHG inventory appears to under-represent the number of well completions according to the numbers reported through both the API/ANGA data and IHS CERA, differences in national well data reporting systems make it difficult to accurately investigate well completion differences with any certainty. The EPA inventory, which uses data from HPDI, and the Energy Information Administration (in addition to privately sourced data) all report different well counts that do not consistently distinguish between conventional and unconventional wells. Without a consistent measure for the quantity and type of wells, it is difficult to be confident of the accuracy of the number of wells that are completed annually, let alone the amount of emissions from them. Natural gas producers strongly believe that the effects of any possible under-representation of well completions will be offset by a more realistic emission factor for the rate of emissions per well.

This survey also collected data on centrifugal compressors and pneumatic controllers. While the sample sizes are too small to make strong conclusions, the results discussed in the body of the report indicate that further research is necessary to accurately account for the different types of equipment in this area (e.g., wet vs. dry seal centrifugal compressors and "high bleed," "low bleed," and "intermittent bleed" pneumatic controllers).

As government and industry move forward in addressing emissions from unconventional gas operations, three key points are worth noting:

- ***In addition to the voluntary measures undertaken by industry, more data will become available in the future.*** Emission reporting requirements under Subpart W of the national Greenhouse Gas Reporting Program (GHGRP) went into effect January 1, 2011 with the first reporting due in the fall of 2012. As implementation of the GHGRP progresses from year to year, the natural gas industry will report more complete and more accurate data. If EPA makes use of the data submitted and transparently communicates their analyses, ANGA/API members believe this will increase public confidence in the emissions estimated for key emission source categories of the Natural Gas Systems sector.
- ***Industry has a continuous commitment to improvement.*** It is clear that companies are not waiting for regulatory mandates or incentives to upgrade equipment, or to alter practices like venting and flaring in favor of capturing methane where practical. Instead, operators are seizing opportunities to reduce the potential environmental impacts of their operations. Industry is therefore confident that additional, systematic collection of production sector activity data will not only help target areas for future reductions but also demonstrate significant voluntary progress toward continually 'greener' operations.
- ***Members of industry participating in this survey are committed to providing information about the new and fast-changing area of unconventional oil and gas operations. API and ANGA members look forward to working with the EPA to revise current assessment methodologies as well as promote the accurate and defensible uses of existing data sources.***

1. Overview

The accuracy of GHG emission estimates from unconventional natural gas production has become a matter of increasing public debate due in part to limited data, variability in the complex calculation methodologies, and assumptions used to approximate emissions where measurements in large part are sparse to date. Virtually all operators have comprehensive methane mitigation strategies; however, beyond the requirements of the Environmental Protection Agency's (EPA) Mandatory Reporting Rule or incentives of programs like the EPA's Natural Gas Star program, data is often not gathered in a unified way that facilitates comparison among companies.

In an attempt to provide additional data and identify uncertainty in existing data sets, the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) began a joint study on methane (CH_4) emissions from unconventional gas operations in July 2011. The first part of this section offers context to the decision to conduct this survey, while the second offers a brief introduction to the survey itself.

1.1 Context

Shale gas will undoubtedly play a key role in America's energy future and therefore additional information must be collected to quantify the methane emissions from both conventional and unconventional natural gas production. Meaningful, publicly available data is a priority, especially in light of EPA's 2011 revision of its calculation methodology for Natural Gas Systems in the 2009 national inventory (EPA, 2011b). (EPA added two new sources for unconventional gas well completions and workovers, and also significantly revised its estimates for liquids unloading and made adjustments to other source categories.) These changes substantially increased EPA's estimated GHG emissions for the production sector of the Natural Gas Systems by 204%.

Industry was alarmed by the upward adjustment, especially since previous EPA estimates had been based on a 1996 report prepared by the EPA and GRI – and did not take into account the considerable improvements in equipment and industry practice that have occurred in the fifteen years between 1996 and 2011 (GRI, 1996).

An EPA technical note to the 2009 inventory attributed the changes to adjustments in calculation methods for existing sources, including gas well liquids unloading, condensate storage tanks, and centrifugal compressor seals. EPA also added two new sources not previously included in its inventories, namely unconventional gas well completions and workovers (re-completions) (EPA, 2011e).

Industry did not have an adequate opportunity to examine EPA's rationale for the new emissions factor prior to its initial release. Unlike changes in regulatory requirements, EPA is not required to initiate a formal comment process for changes in methodologies like emission factors and calculations methods in the national GHG inventory. As such, EPA is not compelled to incorporate or consider input provided by stakeholders and experts. Indeed, changes to methodologies are often made without the benefit of dialogue or expert review. Although EPA further acknowledged in the 2010 inventory (released in 2012), that their natural gas calculations needed work, their practice is to continue using the same numbers until adjusted estimates have

been made. It is important to note that EPA has indicated a willingness to engage and discuss this matter with some members of industry; however, no time frame has yet been determined for this discussion.

Under the best of circumstances, EPA had remarkably little information to draw on in determining their new emission factor. Input from industry on this topic was not directly solicited. Specific guidance also did not exist on the international level, nor was it available from other national regulators. A review of the Intergovernmental Panel on Climate Change (IPCC) and other inventories submitted to the United Nations Framework Convention on Climate Change (UNFCCC) indicate that the U.S. is currently the only country to date to differentiate between conventional and unconventional natural gas production. Regulators, academics, and environmentalists around the world therefore considered the new estimated emission factor as an unprecedented development in a controversial issue.

Widespread criticism of the figures revealed problematic methodology and less justification for the underlying numbers than originally anticipated. In a paper entitled *Mismeasuring Methane*, the well-respected energy consultancy IHS CERA succinctly detailed several concerns about the revisions – most notably that EPA's new estimate was based on only four (4) data points that natural gas well operators had submitted voluntarily under the Natural Gas Star Program, which highlights emissions reductions. Together, the four data points cover approximately 8,880 wells – or roughly 2% of those wells covered in the EPA's national greenhouse gas inventory. Those numbers, which were submitted in the context of showcasing achieved emissions reductions and not to estimate emissions, were then extrapolated to over 488,000 wells in the 2009 emissions inventory (IHS CERA, 2011).

With an emerging topic like shale energy development, however, the impact of EPA's revised estimates was enormous. Emission estimates from production using EPA's figures were used to question the overall environmental benefits of natural gas. They were cited widely by unconventional gas opponents - many of whom used the new figures selectively and without caveats like "estimated" to argue against further development of shale energy resources. For example, an article published by ProPublica cited the revised EPA emission factors as "new research" which "casts doubt" on whether natural gas contributes lower GHG emissions than other fossil fuels (Lustgarten, 2011). Many of these studies – e.g., the work of Howarth *et al.* were widely reported in the popular press (Zellers, 2011) with little attention to the quality of analysis behind their conclusions.

Notably, other authors using more robust and defensible scientific methodologies argued that - even with undoubtedly high emissions estimates - natural gas still possessed a lifecycle advantage when its comparative efficiency in electricity generation was taken into account. For example, a study by Argonne National Laboratory utilizing the same EPA data sources concluded that taking into account power plant efficiencies, electricity from natural gas shows significant life-cycle GHG benefits over coal power plants (Burnham, 2011). Unfortunately, the complex technical arguments in these studies generated considerably less media and public attention.

It is important to understand that the ongoing debate about the accuracy of EPA's adjusted emission factor as contained in the 2009 inventory did not keep these numbers from being used in a series of rules that have wide ranging ramifications on national natural gas policies both in the United States and globally. Many countries considering shale energy

development remain bound by the emissions reduction targets in the Kyoto Protocol and their regulatory discussions reflect greenhouse gas concerns. In addition to the very real risk that other countries could adopt the emission factor before the EPA can refine its calculations, the possibility of higher emissions (even if only on paper) might deter other nations from developing their own unconventional energy resources.

By the summer of 2011, it was clear to ANGA/API members (also referred to as API/ANGA members) that gathering additional data about actual emissions and points of uncertainty during unconventional gas production was essential to improve GHG life cycle analysis (LCA) of natural gas for the following reasons: 1) to focus the discussion of emissions from natural gas production around real data; 2) to promote future measurement and mitigation of emissions from natural gas production; and 3) to contribute to improving the emission estimation methods used by EPA for the natural gas sector in their annual national GHG inventory.

1.2 Introduction to the API/ANGA Survey

API and ANGA members uniformly believed that EPA's current GHG emissions estimates for the natural gas production sector were overstated due to erroneous activity data in several key areas - including liquids unloading, well re-fracturing, centrifugal compressors, and pneumatic controllers. Members therefore worked cooperatively to gather information through two data requests tailored to focus on these areas and reasonably accessible information about industry activities and practices. Specifically, information was requested on gas well types, gas well venting/flaring from completions, workovers, and liquids unloading, and the use of centrifugal compressor and pneumatic controllers.

The actual data requests sent to members can be found in Appendix A, and Appendix B provides more detailed data from the ANGA/API well survey information**.**

Survey results and summaries of observations, including comparisons to EPA's emission estimation methods, are provided in the following sections.

2. Well Data

This section examines well data gathered by API and ANGA members. Overall, ANGA/API's survey effort gathered activity data from over 20 companies covering nearly 91,000 wells and 19 of the 21 American Association of Petroleum Geologists (AAPG) basins[3] containing over 1% of the total well count in EPA's database of gas wells. Members believe that the API/ANGA survey represents the most comprehensive data set ever compiled for natural gas operations and, as such, provides a much more accurate picture of operations and emissions.

Information to characterize natural gas producing wells was collected by survey in two parts:

- The first part of the survey requested high-level information on the total number of operating gas wells, the number of gas well completions, and the number of gas well workovers with hydraulic fracturing. Data on over 91,000 wells was collected primarily for 2010, with some information provided for the first half of 2011.
- The second part of the survey requested more detailed well information about key activities. The well information collected through the two surveys is provided in Appendix B.

Section 2.1 looks at overall natural gas well counts, Section 2.2 examines completion data from ANGA/API members, and Section 2.3 briefly identifies several unresolved issues concerning well counts and classifications that could benefit from future analysis for examination. For the purposes of this report, unconventional wells are considered to be shale gas wells, coal bed wells, and tight sand wells which must be fractured to produce economically.

2.1 National Gas Well Counts

To provide context for the information collected by API and ANGA, comparisons were made to information about national gas wells from EPA and the U.S. Energy Information Administration (EIA). Unfortunately, the government lacks a single coordinated and cohesive set of estimates for gas wells.

Industry grew concerned when it became apparent that significant discrepancies existed among different sources of national gas well data. The EPA inventory, the EIA, and IHS all reported different well counts that do not consistently distinguish between key areas like conventional and unconventional wells. Furthermore, there does not appear to be a single technical description for classifying wells that is widely accepted. Without consistent measures and definitions for the quantity and type of wells, it is difficult to reach agreement on the number of unconventional wells completed annually - let alone their emissions.

[3] Basins are defined by the American Association of Petroleum Geologists (AAPG) AAPG–CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978.

Both the EIA data and the EPA data accompanying the national GHG inventory lack sufficient detail for well classifications to provide a basis for helpful comparison with the survey data reported here. Instead, national well data developed as part of mandatory emissions reporting is used for comparison because it has the most appropriate level of detail in well categories (EPA, 2011d).

In EPA's database gas well count (EPA, 2011d), 21 of the AAPG basins each have more than 1% of the total well count. The API/ANGA survey has wells from 19 of those 21 basins. In terms of wells represented by these basins, 92% of the total EPA database well count is accounted for by wells in those 21 basins, while 95% of the ANGA/API surveyed gas wells are accounted for by those 21 basins. These results are summarized in Table 1 and illustrated in Figure 1. This indicates that the API/ANGA survey results have good representation for the basins with the largest numbers of wells nationally.

TABLE 1. COMPARISON OF GAS WELL COUNT DATA BY AAPG BASIN: SUMMARY STATISTICS

	EPA Database Gas Well Count*	API/ANGA Survey Data	ANGA/API as a % of EPA
Total number of U.S. gas wells	355,082 gas wells	91,028 gas wells	26%
Number of significant AAPG basins**	21 basins	Data on wells in 19 of those 21 basins	90%
Number of wells in significant AAPG basins	325,338 wells	86,759 wells	27%
% of total wells in significant AAPG basins	92%	95%	

* EPA's database gas well count (EPA, 2011d) differs from the well count provided in EPA's 2010 national inventory, but provides more detail on the types of wells. Additional details are provided in Appendix B.

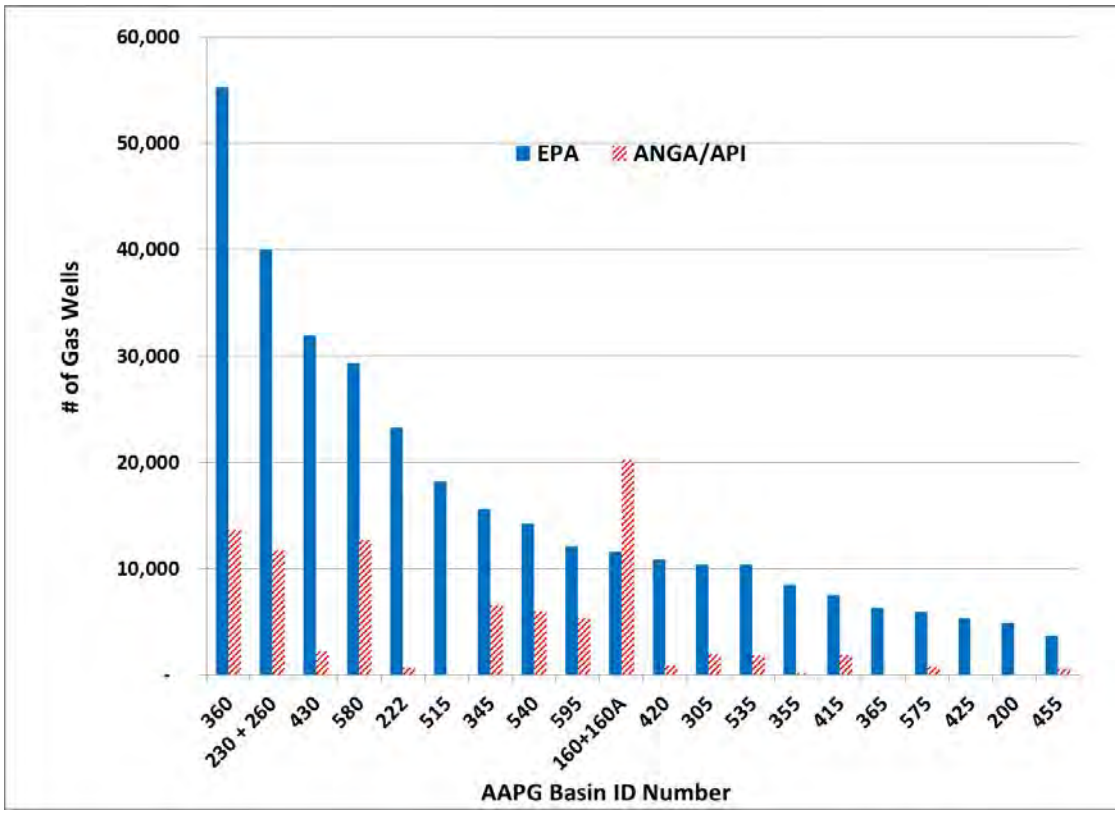
** Significant basins are defined as basins with more than 1% of the total national gas wells.

As shown in Figure 1, the API/ANGA survey results more heavily represent gas wells in specific AAPG basins when compared to EPA's basin-level well counts (EPA, 2011c). Unlike the EPA data, the ANGA/API data is more heavily influenced by AAPG 160 and 160A. AAPG basins 360, 230, and 580 are important for both data sets.

The smaller data set provided by EPA (2011d) may not include all of the Marcellus shale wells (particularly in Pennsylvania), and the well classification system used in this smaller data set could probably be made more rigorous. Although this comparison may not show a perfect distributional match for the basin by basin distribution of the API/ANGA survey data presented here, it does not change the fundamental conclusion of the ANGA/API survey since this data set does cover 90% of the basins and 27% of the national gas well count for the significant basins as reported by EPA (EPA, 2011d). The data discussed in this report provides substantial new information for understanding the emissions from Natural Gas Systems and offers a compelling justification for re-examining the current emission estimates for unconventional gas wells.

Appendix B contains more detail about the industry well data sample compared to the overall data maintained by the government. Unless otherwise noted, further statistical comparisons of well data throughout this paper are done with reference to the EPA data because it was the only one which effectively parsed the data by well type (EPA, 2011d).

FIGURE 1. COMPARISON OF EPA TO API/ANGA GAS WELL COUNT DATA BY AAPG BASIN



2.2 Gas Well Completions

Acknowledging the somewhat different time periods covered, the API/ANGA survey data represents 57.5% of the national data for tight gas well completions and 44.5% of shale gas well completions, but only 7.5% of the national conventional well completions and 1.5% of coal-bed methane well completions. About one-third of the surveyed well completions (2,205) could not be classified into the well types requested (i.e., tight, shale, or coal-bed methane). The survey results for well completions are provided in Table 2 and compared to national data provided to ANGA by IHS.[4]

EPA's 2010 inventory showed 4,169 gas well completions with hydraulic fracturing (EPA, 2012, Table A-122); however, EPA does not provide a breakout of completions by well type (shale gas, tight gas or coal-bed methane). In comparing the EPA 2010 count of gas well completions with hydraulic fracturing (4,169 completions) to both the survey results and data

[4] Data provided in e-mail from Mary Barcella (IHS) to Sara Banaszak (ANGA) on August 29,2011. Data were pulled from current IHS well database and represent calendar year 2009 (2010 data are not yet available).

provided by IHS, it seems that EPA's national GHG inventory underestimates the number of well completions. Even accounting for the difference in time periods (2010 for EPA compared to 2010/2011 data from the ANGA/API survey), the national inventory appears to under-represent the number of well completions.

TABLE 2. API/ANGA SURVEY – SUMMARY OF GAS WELL COMPLETIONS BY NEMS REGION AND WELL TYPE*
(FIRST SURVEY DATA REQUEST PHASE)

NEMS Region	Conventional Wells	Shale	Coal-bed Methane	Tight	Unspecified	Regional Total
API/ANGA Survey Data Gas Well Completions						
Northeast	2	291	3	67	126	489
Gulf Coast	81	588	-	763	374	1,806
Mid-Continent	22	734	-	375	270	1,401
Southwest	425	442	-	346	310	1,523
Rocky Mountain	10		30	977		1,017
Unspecified	-	-	-	-	1,125	1,125
Survey TOTAL	540	2,055	33	2,528	2,205	7,361
% of Survey Total	7.3%	27.9%	0.4%	34.3%	30.0%	
2010 IHS Gas Well Completions						IHS Total
2010 National Well Completions (from IHS)[1]	7,178	4,620	2,254	4,400		18,452
	38.9%	25.0%	12.2%	23.8%		
API/ANGA as % of IHS National Well Counts	7.5%	44.5%	1.5%	57.5%		

* ANGA/API survey data represents well counts current for calendar year 2010 or the first half of 2011.

** EPA's national GHG inventory does not designate gas wells by classifications of "shale", "coal bed methane" or "tight".

As shown in Table 3, the ANGA/API survey noted 7,361 gas well completions for 2010 and the first half of 2011. This is equivalent to approximately 40% of the gas well completions reported by IHS for 2010. Although EPA's 2010 national GHG inventory appears to under-represent the number of gas well completions according to the numbers reported through both the API/ANGA data and the IHS, differences in national well data reporting systems make it difficult to accurately investigate well completion differences with certainty. The EPA inventory, which uses data from HPDI, and the Energy Information Administration (in addition to privately sourced data) - all of which report different well counts that do not consistently distinguish between conventional and unconventional wells. Without a consistent measure for the quantity and type of wells, it is difficult to be confident of the accuracy of how many wells are completed annually, let alone to estimate their emissions. Industry strongly believes that the effects of any current under-representation of well completions will be offset by a more realistic emission factor for the rate of emissions per well.

TABLE 3. SUMMARY OF GAS WELL COMPLETIONS DATA (FIRST SURVEY DATA REQUEST PHASE)

	# Completions for Gas Wells without hydraulic fracturing	# Completions for Gas Wells with hydraulic fracturing	Total Completions
2010 National Well Completions (from EPA; EPA 2012)	702	4,169	4,871
% of National Total	14%	86%	
API/ANGA Survey Well Completions	540	6,821	7,361
% of National Total	7%	93%	
Well Completions from IHS	7,178	11,274	18,452
% of National Total	39%	61%	

Table 4 provides detailed data for well completions from the ANGA/API survey. From the survey, 94% of gas well completions in 2010 and the first half of 2011, were conducted on wells with hydraulic fracturing. About one-half of all gas well completions for this time period were for tight wells, and about one-half of all gas well completions were for vertical wells with hydraulic fracturing. Any differences in totals between Tables 2, 3 and 4 are because these tables were derived from the two different data requests sent to member companies as described previously in the introduction to Section 2.

TABLE 4. API/ANGA SURVEY – ADDITIONAL DETAILS ON GAS WELL COMPLETIONS (SECOND SURVEY DATA REQUEST PHASE)

	# Completions for Gas Wells with hydraulic fracturing (HF)				Gas Wells without hydraulic fracturing		Total Completions
	# Vertical wells completions	# Horizontal well completions	Total Wells with HF	% of Wells with HF	# Completions	% of Wells without HF	
TOTAL Conventional	315	57	372	69%	164	31%	536
TOTAL Shale	317	1,863	2,180	99%	30	1%	2,210
TOTAL Tight	2,054	368	2,422	96%	106	4%	2,528
TOTAL Coal Bed Methane	27	3	30	91%	3	9%	33
TOTAL OVERALL	**2,713**	**2,291**	**5,004**	**94%**	**303**	**6%**	**5,307**

The following points summarize survey information provided in Tables 2, 3 and 4. These tables represent a snapshot of well activity data during this time.

- Overall, the survey showed 94% of the 5,307 wells reported in the API/ANGA data set as completed in 2010 and the first half of 2011 used hydraulic fracturing.
- *536 conventional gas wells were completed in 2010 and the first half 2011.*
  - 59% were vertical wells with hydraulic fracturing,
  - 11% were horizontal wells with hydraulic fracturing, and
  - 31% were wells without hydraulic fracturing.
- *2,210 shale gas wells were completed in 2010 and the first half 2011.*
  - 14% were vertical wells with hydraulic fracturing,
  - 84% were horizontal wells with hydraulic fracturing, and
  - 1% were wells without hydraulic fracturing.
- *2,528 tight gas wells were completed in 2010 and the first half 2011.*
  - 81% were vertical wells with hydraulic fracturing,
  - 15% were horizontal wells with hydraulic fracturing, and
  - 4% were wells without hydraulic fracturing.
- *33 coal-bed methane wells were completed in 2010 and the first half 2011.*
  - 82% were vertical wells with hydraulic fracturing,
  - 9% were horizontal wells with hydraulic fracturing, and
  - 9% were wells without hydraulic fracturing.

2.3 Data Limitations Concerning Wells

In response to follow-up questions on well data, EPA indicated that they classified gas well formations into four types (conventional, tight, shale, and coal-bed) (EPA, 2011d). When developing the gas well classifications, EPA applied their judgment where data were not available in the database. ANGA and API are interested in using the well database compiled by IHS or a similar database, to more completely classify gas wells at some point in the future. The API/ANGA survey did not specifically define conventional wells for collecting the well data presented in this section, leaving the respondents to determine the classification of wells based on their knowledge of the well characteristics or state classifications. As such, this well classification may vary somewhat according to the respondent's classification of wells.

It should be noted that there is not a generally accepted definition for "gas wells." Producers might be producing from several zones in the same formation, and different states define "gas" or "oil" wells differently due to the historical structure of royalties and revenues. There is also no commonly used definition of "conventional" gas wells. Thus, different definitions of these terms may have produced inconsistency in the classification of wells between gas and oil, and conventional and unconventional for the surveyed results, as well as for the EPA and EIA national data. For the purposes of this report, unconventional wells are considered to be

shale gas wells, coal bed wells, and tight sand wells which must be fractured to produce economically.

3. Gas Well Liquids Unloading

Gas well clean ups also known as liquids unloading accounts for 51% of total CH_4 emissions from the natural gas production sector in EPA's national GHG inventory (EPA, 2012).[5] This was a considerable increase from the 6% of CH_4 emissions that liquids unloading represented in the 2008 inventory. The accuracy of assumptions regarding this activity was therefore a major concern to API/ANGA members.

As the name indicates, liquids unloading is a technique to remove water and other liquids from the wellbore so as to improve the flow of natural gas in conventional wells and unconventional wells.

In EPA's national inventory, emissions from gas well liquids unloading are based on the following assumptions:

- 41.3% of conventional wells require liquids unloading.
- 150,000 plunger lifts are in service, which equates to 42% of gas wells.
- The average gas well is blown down to the atmosphere 38.73 times per year.
- The average casing diameter is 5 inches.
- A gas well is vented to the atmosphere for 3 hours once the liquids are cleared from the well.

The ANGA/API survey gathered activity and emissions related information for gas well liquids unloading. Information was received covering eight conventional well data sets and 26 unconventional well data sets. The following information was requested:

- Geographic area represented by the information provided;
- Time period – data were annualized to 12 months if the information was provided for a partial year;
- Number of operated gas wells represented by the information provided;
- Number of gas wells with plunger lift installed;
- Number of gas wells with other artificial lift (beam pump; ESP; etc.);
- Total number of gas well vents;
- Number of wells with and without plunger lifts that vent to the atmosphere;
- Total count of gas well vents for time period with and without plunger lifts;
- Average venting time for wells with and without plunger lifts;
- Average daily production of venting gas wells (Mcf/day);
- Average depth of venting wells (feet);

[5] See EPA Table A-129, of Annex 3 of the 2010 inventory report.

- Average casing diameter of venting gas wells (inches);
- Average tubing diameter of venting gas wells with plunger lift (inches); and
- Average surface pressure - venting gas wells (psig).

Table 5 summarizes the results from the API/ANGA survey and compares the results to the assumptions EPA uses to estimate emissions for this source in the national GHG inventory.

The ANGA/API data differed from EPA's assumptions in several ways:

1) API/ANGA showed lower percentages of wells with plunger lifts;
2) API/ANGA data indicated lower percentages of wells venting to the atmosphere;
3) API/ANGA data showed lower average vent times than EPA's numbers; and
4) Casing diameters from the API/ANGA survey were comparable to EPA's assumption of 5 inches.

TABLE 5. ANGA/API SURVEY – SUMMARY OF LIQUIDS UNLOADING DATA

Parameter	API/ANGA Survey		EPA Assumptions
	Conventional Wells	Unconventional Wells	
Number of gas wells with plunger lifts	10%	45%	42%
Number of gas wells with other artificial lift (beam pump, ESP, etc.)	25%	7%	
Number of gas wells vented to the atmosphere for liquids unloading	11%	16%	41.3%
# vents per well (weighted average)	303.9 (all data)* 32.4 (w/o outliers) **	33.6	38.7
Average venting time per vent (weighted average)			3 hours
With plunger lifts	0.25 hours	0.77 hours	
Without plunger lifts	1.78 hours	1.48 hours	
Weighted Average casing diameter	4.64 inches	5.17 inches	5 inches
Weighted Average tubing diameter	2.27 inches	2.43 inches	
Average Emission factor, Mscf/well			
With plunger lifts	823 (all data)* 14.7 (w/o outliers)**	196	
Without plunger lifts	56.4	318	
Weighted average Methane emission factor, Mscf CH4/well	175*		1,316

* Includes all liquids unloading data from the ANGA/API survey

** Excluding two high data points

When examining Table 5, it is important to note the presence of several outliers. Two data responses for operations with conventional wells reported very high frequencies of vents to the atmosphere. These data sets represent 174 gas wells with plunger lifts (out of a total 788 gas wells with plunger lifts represented by the total data set) located in the Mid-Continent region. The wells represented by these data points have plunger lifts that vent to the atmosphere for each plunger cycle. The information was confirmed by the two data respondents and is an artifact of the plunger control for these wells which results in very short venting durations (between 4 and 5 minutes) for each plunger cycle. As a result, accounting for the high frequency of plunger lift cycles for these wells results in a high average vent frequency, but still produces a lower emission factor than the EPA assumptions.

Excluding these two data points, the API/ANGA survey data for the number of vents per well was comparable to EPA's assumed frequency. Moreover, even with the high frequency of vents from these wells, the emissions are much lower than EPA's estimates (see Table 6).

TABLE 6. ANGA/API SURVEY –LIQUIDS UNLOADING EMISSIONS COMPARISON

NEMS Region	API/ANGA Survey		EPA Inventory			API & ANGA - EPA EPA % Difference in Emissions
	Emission Factor, Mscf CH4/well	Estimated Emissions, tonnes CH_4	# wells	Emission Factor, Mscf CH_4/well	Estimated Emissions, tonnes CH_4 *	
Northeast	136	202,503	77,931	1,360	2,027,265	-90%
Mid Continent	392	235,813	31,427	703	422,893	-44%
Rocky Mountain	177	90,387	26,620	690	351,672	-74%
Southwest	36	7,913	11,444	865	189,407	-96%
Gulf Coast	169	101,150	31,331	2,519	1,510,259	-93%
West Coast	No data for this region		638	1,492	Excluded for consistent comparison	
TOTAL	175 (weighted average)	637,766	179,391		4,501,465	-86%

*EPA estimated emissions = # wells × EPA emission factor, converted to mass emissions based on 60 degrees F and 14.7 psia

These variances among operators in ANGA/API data demonstrate the challenge of applying national emissions estimates to conditions in which there can be considerable variation in wells and operating techniques, among and even within various regions. As member companies have noted in various comments to regulators, oil and natural gas production operations vary considerably according to factors such as local geology, hydrology, and state law.

EPA noted that wells equipped with plunger lifts have approximately 60% lower emissions from liquids unloading than wells without plunger lifts (EPA, 2011b). From the API/ANGA survey, an emission reduction of about 38% was observed for the unconventional

wells equipped with plunger lifts compared to those without plunger lifts. However, Table 5 indicates that for conventional gas wells, the average emission factor is higher for wells with plunger lifts compared to those without when the two high data points are included. Excluding the two high data points, the emission factor for conventional wells with plunger lifts is 74% lower than the emission factor for conventional wells without plunger lifts.

One reason for this discrepancy in the data may be that EPA has acknowledged that their current estimation method for liquids unloading does not account for activities used to reduce CH_4 emissions by many different artificial lift methods used in industry. According to Natural Gas Star Reports, the applicable emission reductions range from 4,700 to 18,250 Mscf/yr for plunger lift systems (EPA, 2006); however, since the emission reductions are reported separate from the emission estimate in the national inventory, they cannot be linked back to EPA emission source categories.

Emissions were calculated by applying Equation W-8 or W-9 from the EPA GHG reporting rule in 40 CFR 98 Subpart W, where Equation W-8 applies to gas wells without plunger lifts, and Equation W-9 applies to gas wells with plunger lifts. Appendix C summarizes the data collected and estimated emissions. The emission results are shown in Table 6 by NEMS region for comparison to EPA's emission estimates. The ANGA/API survey averaged the emission factors data within each NEMS region for conventional and unconventional wells combined. The emission results shown in Table 6 were determined by applying the API/ANGA emission factors and EPA emission factors, respectively, to the total number of wells requiring liquids unloading from the 2010 national GHG inventory.

As production companies continue to collect information for EPA's mandatory GHG reporting program, better information on liquids unloading frequency and emissions will be available. One area that would benefit from additional information is an investigation of regional differences, or plunger lift control practices, in view of the high frequency of vents observed for two data sets containing conventional gas wells with plunger lifts in the Mid-Continent region.

Key findings of the ANGA/API survey on liquids unloading are:

- ***For all of the NEMS regions, the API/ANGA survey data resulted in lower emission estimates than EPA estimated for the 2010 national GHG inventory when compared on a consistent basis.***
- ***Overall, the change in emission factors based on data collected from the ANGA/API survey reduces estimated emissions for this source by 86% from the emissions reported in EPA's 2010 national GHG inventory.***

4. Hydraulic Fracturing and Re-fracturing (Workovers)

A well workover refers to remedial operations on producing natural gas wells to try to increase production. Starting with the 2009 inventory, EPA split the estimation of emissions from producing gas wells into conventional (i.e., without hydraulic fracturing) and unconventional (i.e., with hydraulic fracturing). For workovers of wells without hydraulic fracturing, the 2009 and 2010 national inventories used emission factors of the same order of magnitude as the 2008 inventory (2,454 scf of CH_4/workover). In contrast, the unconventional (with hydraulic fracturing) well workover emission factor increased by a factor of three thousand (3,000).

EPA did acknowledge that the new emission factor for well workovers was based on limited information (EPA, 2011a). Moreover, several publications including *Mismeasuring Methane* by IHS CERA underscored the perils of extrapolating estimates using only four (4) data points representing approximately two percent (2%) of wells – particularly when the data was submitted in the context of the Natural Gas Star program, which was designed to highlight emissions reduction options (IHS CERA, 2011). Unfortunately, even if the EPA's workover factor is high, it must be used in estimated emissions calculations until it is officially changed.

EPA's new emission factor is 9.175 MMscf of natural gas per re-fracture (equivalent to 7.623 MMscf CH_4/re-fracture). Additionally, EPA used this new emission factor in conjunction with an assumed re-fracture rate of 10% for unconventional gas well workovers each year to arrive at their GHG emission estimate for this particular category.

4.1 API/ANGA Survey

The ANGA/API survey requested counts for gas well workovers or re-fractures in two separate phases of the survey, covering 91,028 total gas wells (Table 7 covering 2010 and first half of 2011 data) and 69,034 unconventional gas wells (Table 8, 2010 data only), respectively.

The first phase of the survey was part of the general well data request. Counts of workovers by well type (conventional, tight, shale, and coal bed methane) and by AAPG basin were requested. The frequency of workovers was calculated by dividing the reported workover rates by the reported total number of each type of gas well. These results are summarized in Table 7, which includes a comparison to national workover data from EPA's annual GHG inventory. The high number of workovers in the Rocky Mountain region is discussed further below.

Table 7 indicates that even for the high workover rates associated with unconventional tight gas wells, the workover rate is much less than EPA's assumed 10% of gas wells re-fractured each year. Based on this first phase of the survey,

- The overall workover rate involving hydraulic fracturing was 1.6%.
- However, many of these workovers were in a single area, AAPG-540, where workovers are known to be conducted more routinely than in the rest of the country (as described in more detail below Table 8). Excluding AAPG 540, the overall workover rate involving hydraulic fracturing was 0.7%

- For all unconventional wells in Table 7, the overall workover rate involving hydraulic fracturing was 2.2%. Excluding AAPG 540, the overall workover rate involving hydraulic fracturing was 0.9%.

TABLE 7. API/ANGA SURVEY – SUMMARY OF GAS WELL WORKOVERS WITH HYDRAULIC FRACTURING IN 2010 AND FIRST HALF OF 2011 BY NEMS REGION AND WELL TYPE (FIRST PHASE DATA SURVEY)

NEMS Region	Conventional Wells	Unconventional Wells			
		Shale	Coal-bed Methane	Tight	Unspecified
Northeast	-	-	-	-	-
Gulf Coast	-	5	-	38	73
Mid-Continent	8	1	-	73	33
Southwest	60	25	-	8	7
Rocky Mountain	4	-	25	901	-
West Coast	-	-	-	-	-
Unspecified	-	-	-	-	200
Survey TOTAL	72	31	25	1,020	313
		1,076			
% of national	0.3%	21.3%			
Overall Survey Total % of national	1,461 5.6%				

National Workover Counts (from EPA's 2010 national inventory)	Conventional Wells	Unconventional Wells
	21,088	5,044
	80.7%	19.3%
	26,132	

	Conventional Wells	Unconventional Wells			
		Shale	Coal-bed Methane	Tight	Unspecified
% Workover Rate with Hydraulic Fracturing (from ANGA/API Survey)	0.3%	0.3%	0.5%	3.0%	2.4%
Tight w/out AAPG 540				0.5%	
Unconventional Wells		2.2%			
W/out AAPG 540		0.9%			
All Wells	1.6%				
All Wells w/out AAPG 540	0.7%				

Also, the ANGA/API survey collected information on the number of workovers for vertical and horizontal unconventional gas wells. Nearly 99% of the unconventional gas well workovers were on vertical wells. Additionally, 18% of the gas well workovers from the API/ANGA survey were conducted on gas wells without hydraulic fracturing.

A second phase of the survey was conducted which targeted collecting gas well re-fracture information for 2010 to provide a better estimate than EPA's assumption that 10% of wells are re-fractured each year. This portion of the ANGA/API survey requested information just for "unconventional" gas wells (i.e., those located on shale, coal-bed methane, and tight formation reservoirs), where the formations require fracture stimulation to economically produce gas. A re-fracture or workover was defined for this second phase of the survey as a re-completion to a different zone in an existing well or a re-stimulation of the same zone in an existing well. These results are summarized in Table 8.

While there likely is significant overlap of unconventional well data reported in the first and second phases of the survey (which covered over 62,500 unconventional wells and 69,000 unconventional wells respectively), combined these data indicate an unconventional well re-fracture rate of 1.6% to 2.3% including AAPG 540 and 0.7% to 1.15% excluding AAPG 540.

AAPG Basin 540 (i.e. DJ Basin) which is part of the Rocky Mountain Region stands out in Tables 7 and 8. After four (4) to eight (8) years of normal production decline, the gas wells in this basin can be re-fractured in the same formation and returned to near original production. Success of the re-fracture program in the DJ Basin is uniquely related to the geology of the formation, fracture reorientation, fracture extension and the ability to increase fracture complexity. Also, most DJ Basin gas wells are vertical or directional, which facilitates the ability to execute re-fracture operations successfully and economically. These characteristics result in a high re-fracture or workover rate specific to this formation.

ANGA and API believe the high re-fracture rate observed in the DJ Basin is unique and not replicated in other parts of the country. There may be a few other formations in the world that have similar performance, but the successful re-fracture rate in the DJ Basin is not going to be applicable to every asset/formation and there is no evidence of the high re-fracture rate in any of the other 22 AAPGs covered in the API/ANGA survey. It is highly dependent on the type of rock, depositional systems, permeability, etc. For these reasons, re-fracture rates for tight gas wells and all gas wells with and without AAPG Basin 540 are summarized in Tables 7 and 8.

TABLE 8. API/ANGA SURVEY – SUMMARY OF 2010 GAS WELL WORKOVERS ON UNCONVENTIONAL WELLS BY AAPG BASIN AND NEMS REGION (SECOND PHASE SURVEY DATA)

NEMS Region	AAPG	Number of Unconventional Operating Gas Wells	Number of Hydraulic Fracture Workovers on Previously Fracture Stimulated Wells	% Wells re-fractured per year	Regional % Wells re-fractured per year
Northeast	160	1,976	0	0.00%	0%
	160A	760	0	0.00%	
Gulf Coast	200	2	0	0.00%	0.91%
	220	649	2	0.31%	
	222	629	3	0.48%	
	230	820	4	0.49%	
	250	13	0	0.00%	
	260	2,830	36	1.27%	
Mid-Continent	345	3,296	11	0.33%	0.95%
	350	213	3	1.41%	
	355	282	8	2.84%	
	360	7,870	89	1.13%	
	375	12	0	0.00%	
	385	1	0	0.00%	
	400	64	0	0.00%	
Southwest	415	1,834	0	0.00%	1.04%
	420	838	8	0.95%	
	430	1,548	36	2.33%	
	435	2	0	0.00%	
Rocky Mountain	515	1	0	0.00%	4.7%
	540	5,950	866	14.55%	
	580	8,197	8	0.10%	
	595	5,222	32	0.61%	
Not specified		26,025	487	1.87%	1.87%
Unconventional TOTAL (all wells)		**69,034**	**1,593**	**2.31%**	
Unconventional Median		790	3		
Rocky Mountain Region Unconventional Total		19,370	906	4.68%	
Unconventional TOTAL (Without AAPG 540)		63,084	727	1.15%	

4.2 WRAP Survey

Other information on re-fracture rates is available in a survey conducted by the Western Regional Air Partnership (WRAP). WRAP conducted a survey of production operators in the Rocky Mountain Region (Henderer, 2011) as part of the initiative to develop GHG reporting guidelines for a regional GHG cap and trade program.

Within each basin in this region, the top oil and gas producers were identified and invited to participate in the survey. The goal was to have operator participation that represented 80% of the production for the region. The spreadsheet survey requested information on the completions, workovers, and emissions associated with these activities. An emission factor and frequency of re-fracturing was developed for each basin as a weighted average of the operator responses.

The re-fracture rates from the WRAP survey are shown in Table 9 (Henderer, 2011).

TABLE 9. WRAP SURVEY – SUMMARY OF GAS WELL WORKOVERS BY AAPG BASIN FOR THE ROCKY MOUNTAIN REGION, 2006 DATA

AAPG Basin	# Wells represented by survey	# Wells Recompleted	% Recompleted
515	4,484	121	2.70%
530	731	5	0.68%
535	4,982	201	4.03%
540	8,247	636	7.71%
580	3,475	14	0.40%
595	4,733	275	5.81%
Total	26,652	1,252	
Weighted average			4.70%

AAPG Basin 540 results in the highest re-fracture rate for this data set, consistent with the ANGA/API survey as noted above. It is noteworthy that, while there are differences among individual AAPG Basin results, the weighted average re-fracture rate from the WRAP survey in 2006 is the same as the Rocky Mountain regional 4.7% re-fracture rate from the API/ANGA survey shown in Table 8.

4.3 Impact of Completions and Re-fracture Rate Assumptions

Table 10 compares the considerable reduction in the national GHG inventory that would result from applying a lower re-fracture rate.

EPA indicated that the national inventory assumes 10% of unconventional gas wells are re-fractured each year. Table 10 replaces this value with results from the ANGA/API survey. A re-fracture rate of 1.15% is applied to unconventional gas wells in the Mid-Continent and Southwest regions (No unconventional gas wells were assigned to the Northeast and Gulf Coast regions. The West Coast region is not shown since the API/ANGA survey did not include any responses for gas well operations in this region.) A re-fracture rate of 4.7% is applied to unconventional gas wells in the Rocky Mountain region.

With these adjustments to the re-fracture rate for unconventional gas wells, the national emission estimate is reduced by 72% for this emission source category, from 712,605 metric tons of CH_4 to 197,311 metric tons of CH_4 when compared on a consistent basis.

4.4 Completion and Re-fracture Emission Factor

In the 2009 GHG national inventory, EPA applies an emission factor of 2,454 scf CH_4/event for conventional gas well workovers, while the emission factor for unconventional gas well completions and workovers was increased to 7,623,000 scf CH_4/event (EPA, 2011b). Similarly, for the 2010 national GHG inventory, EPA maintained the emission factor of 2,454 scf CH_4/event for gas well workovers without hydraulic fracturing, but applied an average emission factor of 7,372,914 to gas well workovers with hydraulic fracturing (EPA, 2012). (EPA applies slightly different emission factors for each NEMS region based on differing gas compositions.)

The ANGA/API survey focused on activity data and did not collect data to revise the emission factor for unconventional gas well completions and workovers.

TABLE 10. API/ANGA SURVEY –GAS WELL WORKOVER EMISSIONS COMPARISON

NEMS Region	Well type	2010 EPA National Inventory # workover	Adjusted # workovers (based on API/ANGA survey)	2010 EPA National Inventory		Revised Emissions, tonnes CH_4 (based on ANGA/API survey)	API & ANGA - EPA EPA % Difference
				Emission Factor, scf CH_4/workover	Estimated Emissions, tonnes CH_4*		
Northeast	Wells without Hydraulic Fracturing	8,208	8,208	2,607	409	409	
	Wells with Hydraulic Fracturing	0	0	7,694,435	0	0	
Mid Continent	Wells without Hydraulic Fracturing	3,888	3,888	2,574	191	191	
	Wells with Hydraulic Fracturing	1,328	153	7,672,247	194,950	22,462**	-89%
Rocky Mountain	Wells without Hydraulic Fracturing	3,822	3,822	2,373	174	174	
	Wells with Hydraulic Fracturing	2,342	1,100	7,194,624	322,402	151,432**	-53%
Southwest	Wells without Hydraulic Fracturing	1,803	1,803	2,508	87	87	
	Wells with Hydraulic Fracturing	1,374	158	7,387,499	194,217	22,382**	-89%
Gulf Coast	Wells without Hydraulic Fracturing	3,300	3,300	2,755	174	174	
	Wells with Hydraulic Fracturing	0	0	8,127,942	0	0	
TOTAL					712,605	197,311	-72%

* EPA Estimated emissions = 2010 # Workovers x EPA 2010 Emission Factor, converted to mass emissions based on 60°F and 14.7 psia.

** Revised emissions = Adjusted # Workovers x Emission Factor, converted to mass emissions based on 60°F and 14.7 psia.

Emissions Data from WRAP Study

The WRAP study discussed in Section 4.2 also gathered data on emissions from completions. This information supports a revised emission factor but was reported by sources outside the ANGA/API data survey. The results are summarized in Table 11. The WRAP emission factor is 78% lower than EPA's emission factor (9.175 MMscf gas/event). The WRAP survey did not provide a methodology for determining emissions data.

TABLE 11. WRAP SURVEY – SUMMARY OF COMPLETION EMISSIONS FOR THE ROCKY MOUNTAIN REGION, 2006 DATA

AAPG Basin	Weighted average gas emissions from completion, Mcf gas/well	# completions represented
515	167	207
530	268	54
535	76	642
540	59	608
580	6,559	283
595	4,053	819
Total		2,613
Weighted average	2,032 Mcf/well	

4.5 Data Limitations for Completion and Re-fracture Emissions

Although the data sets are limited, it appears that EPA's assumed re-fracture rate of 10% is a significant overestimate. Information from the API/ANGA survey indicates that even including what appears to be unique activity in AAPG-540, the re-fracture rate is much less frequent, ranging from 1.6% to 2.3% based on two sets of survey information (Tables 7 and 8, respectively). The re-fracture rate for AAPG Basin 540 appears to be higher than other areas in the U.S. due to unique geologic characteristics in that region (4.7% based on a weighted average of data reported for that region). Without AAPG Basin 540, the national rate of re-fracturing is between 0.7% and 1.15% of all gas wells annually.

Additionally, limited information on the emissions from completions and workovers with hydraulic fracturing indicate that EPA's GHG emission factor for these activities is significantly overestimated. It is expected that better emissions data will develop as companies begin to collect information for EPA's mandatory GHG reporting program (EPA, 2011c).

5. Other Surveyed Information

EPA had indicated that activity data for centrifugal compressor wet seals and pneumatic devices used in the national inventory is lacking. Note that the need for better equipment data persists throughout the majority of the U.S. inventory and is not unique to the oil and natural gas industry. The ANGA/API survey requested the following information related to centrifugal compressors and pneumatic devices:

- The number of centrifugal compressors, reported separately for production/gathering versus processing;
- The number of centrifugal compressors with wet versus dry seals, reported separately for production/gathering versus processing;
- The number of pneumatic controllers, classified as "high-bleed," "low-bleed," and "intermittent," reported separately for well sites, gathering/compressor sites, and gas processing plants; and
- The corresponding number of well sites, gathering/compressor sites, and gas processing plants, associated with the pneumatic controller count.

5.1 Centrifugal Compressors

Processing Facilities

The API/ANGA survey collected the equivalent of 5% of the national centrifugal compressor count for gas processing operations (38 centrifugal compressors from the survey, compared to 811 from EPA's 2010 national GHG inventory). For the gas processing centrifugal compressors reported through the survey, 79% were dry seal compressors and 21% were wet seals. EPA's 2010 national inventory reported 20% of centrifugal compressors at gas processing plants were dry seal, and 80% were wet seal. EPA's emission factor for wet seals (51,370 scfd CH_4/compressor) is higher than the emission factor for dry seals (25,189 scfd CH_4/compressor).[6]

Based on the ANGA/API survey, EPA appears to be overestimating emissions from centrifugal compressors. If the small sample size from the API/ANGA survey is representative, non-combustion emissions from centrifugal compressors would be 173,887 metric tons of methane compared to 261,334 metric tons of methane from the 2010 national inventory (when applying industry standard conditions of 60 °F and 14.7 psia to convert volumetric emissions to mass emissions). Although based on very limited data, if the ANGA/API survey results reflect the population of wet seal versus dry seal centrifugal compressors, the emissions from this source would be reduced by 34% from EPA's emission estimate in the national inventory. Better data on the number of centrifugal compressors and seal types will be available from companies reporting to EPA under the mandatory GHG reporting program.

[6] EPA Table A-123, of Annex 3 of the 2010 inventory report.

Production and Gathering Facilities

Very few of the data sets reported through the API/ANGA survey indicate counts of centrifugal compressors associated with production/gathering operations - only 550 centrifugal compressors from 21 participating companies. EPA's 2010 GHG inventory did not include centrifugal compressors in production/gathering operations. On a well basis, the survey responses equate to 0.07 centrifugal compressors per gas well, with 81% dry seal centrifugal compressors and the remaining wet seal compressors. Information reported through EPA's mandatory GHG reporting program will provide additional information to account for GHG emissions from centrifugal compressors in production operations.

5.2 Pneumatic Controllers

Table 12 summarizes the survey responses for pneumatic controllers. For each type of location – gas well sites, gathering compressor sites, and gas processing plants – the count of the number of sites represented by the survey data is shown. Table 12 also shows the percent of each pneumatic controller type for each type of location.

TABLE 12. ANGA/API SURVEY –PNEUMATIC CONTROLLER COUNTS

	Gas Well Sites		Gathering/ Compressor Sites		Gas Processing Plants	
# wells, sites or plants	48,046 wells		1,988 sites		21 plants	
# controllers/well, site or plant	0.99 per well		8.6 per site		7.8 per plant	
# Low Bleed Controllers	12,850	27%	5,596	33%	117	71%
# High Bleed Controllers	11,188	24%	1,183	7%	47	29%
# Intermittent Controllers	23,501	49%	10,368	60%	0	0%

The survey requested that the responses designate pneumatic controllers as either "high bleed", "low bleed", or "intermittent" following the approach each company is using for Subpart W reporting. For example, Subpart W defines high-bleed pneumatic devices as automated, continuous bleed flow control devices powered by pressurized natural gas where part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of 6 standard cubic feet per hour (EPA, 2011c).

EPA does not currently track pneumatic controllers by controller type in the national inventory. This information will be collected under 40 CFR 98 Subpart W starting in September 2012. From the API/ANGA survey, intermittent bleed controllers are the more prevalent type at gas well sites and gathering/compressor sites, while gas plants predominately use low-bleed controllers. No intermittent controllers were reported for gas plants by the survey respondents.

Table 13 compares emission results based on applying the emission factors from the EPA's GHG reporting rule to emissions presented in the 2010 national GHG inventory, using the counts of pneumatic controller from the ANGA/API survey for production operations.

For production, the EPA national inventory combines pneumatic controller counts associated with large compressor stations with pneumatic controllers in production. An emission factor for each NEMS region is applied to the count of total controllers in each NEMS region. For this comparison, a weighted average emission factor of 359 scfd CH_4/device was applied to the count of pneumatic controllers located at well sites and gathering/compressor sites.

Under the EPA mandatory reporting rule (40 CFR 98 Subpart W), separate emission factors are applied to pneumatic controllers based on the controller type and whether the controller is located in the Eastern or Western region of the United States, as specified in the rule (EPA, 2011c). For this comparison, an average of the eastern and western emission factors is applied to each device type in computing the emission estimates resulting from the EPA GHG reporting rule.

TABLE 13. PNEUMATIC CONTROLLER EMISSION COMPARISON – PRODUCTION OPERATIONS

	API/ANGA Survey Count of Controllers			EPA GHG Reporting Rule (Subpart W)		2010 National GHG Inventory	
	Gas Well Sites	Gathering/ Compressor Sites	Total	Emission Factor,* scfh CH_4/device	Emissions, tonnes CH_4/yr	Emission Factor, scfd CH_4/device	Emissions, tonnes CH_4/yr
# Low Bleed Controllers	12,850	5,596	18,446	1.58	4,885	359	46,286
# High Bleed Controllers	11,188	1,183	12,371	42.35	87,814		31,042
# Intermittent Controllers	23,501	10,368	33,869	15.3	86,856		84,987
Total			64,686		179,556		162,315

* Emission factors shown are the average of the eastern and western emission factors from Table W-1A (EPA, 2011c).

Based on the types of pneumatic controllers reported in the ANGA/API survey, EPA's mandatory GHG reporting rule could increase CH_4 emissions 11% over the pneumatic controller portion of the 2010 national GHG inventory. To put this in context, in EPA's inventory report for 2010, emissions from pneumatic controllers accounted for approximately 13% of CH_4 emissions from the natural gas field production stage. Any increase from that initially reported data, however, will likely represent a worst case scenario. It is important to remember that pneumatic controllers operate only intermittently, so variability such as the frequency and duration of the activations will be important information to consider when defining an accurate and effective reporting regime for these sources.

EPA's mandatory GHG reporting rule does not require reporting emissions from pneumatic controllers at gas processing plants, so no emission factors are specified. The GHG national inventory applies an emission factor of 164,721 scfy CH_4 per gas plant for pneumatic controllers. For the national inventory, this results in 1,856 tonnes CH_4 emissions - a very small contribution to CH_4 emissions from onshore oil and gas operations.

6. Conclusions

API and ANGA members believe this to be the most comprehensive set of natural gas data to date and are pleased to share these results with both regulators and the public.

Based on the information gathered from member companies during this project, it appears that EPA has overstated several aspects of GHG emissions from unconventional natural gas production. As summarized in Table 14, the ANGA/API survey data results in significantly lower emission estimates for liquids unloading and unconventional gas well refracturing when compared to EPA's emission estimates in the national inventory. Using the combined emission estimates from the survey for these two key emission sources would indicate a 50% reduction in calculated natural gas production sector emissions compared to EPA's estimates. This reduction would shift Natural Gas Systems from the largest to the second largest producer of methane emissions (approximately 123.4 MMT CO_2e in lieu of 215.4 MMT CO_2e), behind Enteric Fermentation (which is a consequence of bovine digestion, at 141.3 MMT CO_2e).

TABLE 14. EMISSION COMPARISON BETWEEN EPA AND INDUSTRY DATA

Source Category	EPA National Inventory		API/ANGA Survey		Impact on Source Category Emissions
	Metric tons of CH4	% of EPA Production Total	Metric tons of CH4	% of Revised Production Total	API & ANGA - EPA / EPA % Difference in Emissions
Liquids Unloading	4,501,465 *	51%	637,766	14%	-86%
Unconventional Well Re-fracture Rates	712,605 *	8%	197,311	4%	-72%
Other Production Sector Emissions**	3,585,600	41%	3,585,600	81%	
Total Production Sector Emissions	8,799,670		4,420,677		-50%

* EPA's estimates are adjusted to industry standard conditions of 60 degrees F and 14.7 psia for comparison to the ANGA/API emission estimates.

**The "Other Production Sector Emissions" are comprised of over 30 different source categories detailed in Table A-129 in the Annex of the EPA's 2012 national inventory. The "Other Production Sector Emissions" are the same values for this comparison between the EPA national inventory and the API/ANGA survey to focus the comparison on quantified differences in emission estimates for gas well liquids unloading and unconventional well re-fracture rates.

This project was directed toward gathering more robust information on workovers, completions, liquids unloading, centrifugal compressors, and pneumatic controllers with the intent of supporting revisions to the activity factors used in EPA's national inventory and cited

by many media publications. Although limited information was collected on centrifugal compressors and pneumatic controllers, the survey results indicated potential additional differences, which are not included in the Table 14 comparison, when comparing total emissions from all sources to the national inventory. Additional future data collection efforts, including more detailed reporting under Subpart W of the GHGRP will likely resolve these differences and continue to inform the overall natural gas emissions data.

In the meantime, however, while API and ANGA recognize that the data collected for this report represents a sample of the universe of natural gas wells operating in the U.S., we believe that the conclusions drawn from the data analysis are relevant and representative of natural gas production as whole. In EPA's gas well count, 21 of the AAPG basins each have more that 1% of the total well count. The ANGA/API survey has wells from 19 of those 21 basins. In terms of wells represented by these basins, 92% of the total EPA well count is accounted for by wells in those 21 basins, while 95% of the API/ANGA surveyed gas wells are accounted for by those 21 basins. This indicates that the ANGA/API survey results have good representation for the basins with the largest numbers of wells nationally.

Industry also believes that the systematic approach in which the API/ANGA data were collected and vetted by natural gas experts is an improvement over the *ad hoc* way in which EPA collected some of their data. This study indicates that EPA should reconsider their inventory methodologies for unconventional natural gas production particularly in light of more comprehensive and emerging data from the industry. ANGA and API members look forward to working with the agency to continue to educate and evaluate the latest data as it develops about the new and fast-changing area of unconventional well operations.

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Appendix A. API/ANGA Survey Forms

The following provides the survey forms used to gather data presented in this report.

FIGURE A-1. SURVEY INSTRUCTIONS

The attached worksheets request data to support both the API/ANGA Natural Gas Life Cycle Analysis Project, as well as updates to EPA's National GHG Inventory. Portions of this information are consistent with data required for Subpart W, in which case data collected for Subpart W can be provided.

EPA's most recent national inventory significantly increased the emission estimates for gas well completions and workovers with hydraulic fracturing and gas well liquids unloading. These increases prompted public criticism of unconventional natural gas production.
While acknowledging their unconventional well workover activity factors were based on limited data, EPA has also indicated that activity data for centrifugal compressor wet seals and pneumatic devices used in the national inventory is lacking.

API and ANGA are requesting this information to develop more rigorous emission estimates for these important emission sources. This spreadsheet primarily focuses on activity factor information. A second data request will be developed later this year to collect information to support improved emission factors.

Company confidential information will be protected.

Please do not send information responsive to the data request to API or ANGA. Neither API nor ANGA will review member data sent in response to this request. Any submission to API or ANGA that appears to contain information responsive to EPA's data request will be returned to the sender unopened.

Please send the completed spreadsheets to:
Terri_Shires@URScorp.com
Questions may be directed to the same address, or by phone: 512-419-5466

Respondents are asked to complete as much information as possible. Some worksheets request data in varying levels of detail, with guidance on the minimum level of information needed. Some worksheets request data for more than one year or more than one production basin, if available. Gaps in the data are OK if the information is not available.

Additional instructions and guidance are provided on each worksheet.

Schedule:

Data indicated in blue font and shading is requested by August 15

Data indicated in green font is requested by September 16, if this level of information available. This more detailed information will help develop more rigorous emissions estimates for these sources.

FIGURE A-2. GAS WELL SURVEY DATA

Table 1. Producing Gas Wells - Activity Data

Please provide the following information for gas producing wells

		Conventional Wells	Unconventional Wells			Year	Geographic Area Represented	Comments
			Shale	Coal-bed Methane	Tight			
A	Total # of Operating Gas wells							Total of rows A(1) and A(2)
A(1)	# Wells w/out hydraulic fracturing (anytime in their history)							
A(2)	# Wells with hydraulic fracturing (any time in their history)							If counts are not available by vertical and horizontal, please complete this row
A(2)(a)	# Vertical wells with hydraulic fracturing (anytime in their history)							Please provide this level of detail, if available for wells with hydraulic fracturing
A(2)(b)	# Horizontal wells with hydraulic fracturing (anytime in their history)							
B	# Gas well Completions							Total of rows B(1), B(2) and B(3)
B(1)	# Completions for Vertical wells with hydraulic fracturing							
B(2)	# Completions for Horizontal wells with hydraulic fracturing							Please provide this level of detail, if available
B(3)	# Completions for wells without hydraulic fracturing							
C	# Gas well Workovers with hydraulic fracturing (refracs)							Total of rows C(1) and C(2)
C(1)	# Workovers for Vertical wells with hydraulic fracturing							
C(2)	# Workovers for Horizontal wells with hydraulic fracturing							Please provide this level of detail, if available
C(3)	# Workovers for wells without hydraulic fracturing							

Guidance:
2010 data is preferred, with U.S. geographic coverage as broad as possible.

Please duplicate the table to provide data for additional calendar years (if available) or additional geographic areas (if needed).

Note that some of this information overlaps with the data requested under the "Re-frac" worksheet.

Please provide information that you have available.

Blue rows are the minimum level of detail needed

Green rows provide more detailed information and have a longer response time

Geographic area:

Please indicate whether the information provided is for all of your operations in the U.S., or just a sub-part (single basin or multiple basins)

FIGURE A-3. GAS WELL WORKOVER SURVEY DATA

Table 2. Gas Well Workover Activity Data: Frequency of Re-fractures

	Year	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001
A	*Geographic area*										
B	*Number of Unconventional Operating Gas Wells*										
C	*Number of Fracture Stimulation Wells Completed each year (New Completions)*										
D	*Number of Fracture Stimulation Jobs conducted each year on Previously Fracture Stimulated Wells (i.e., # of Workovers or re-fracs)*										

Guidance

Please provide information that you have available.

Please provide data that are available for any or all of the years listed. Gaps in the data are OK.

Copy the table to provide data for additional geographic areas

A Geographic Area: Please indicate whether the information provided is for all of your operations in the U.S., or just a sub-part (single basin or multiple basins)

B Provide the number of Unconventional Operating Wells. This refers to wells located on shale, coal-bed Methane, and Tight Formations reservoirs. Unconventional reservoirs are reservoirs that require fracture stimulation to economically produce.

C Provide the number of new completions conducted in the year. This may be the same value provided in the "Well data" worksheet, Item B.

D Provide the number of re-fractures (workovers). A re-frac or workover is defined as a re-completion to a different zone in an existing well or re-stimulation of the same zone in an existing well. This may be the same value provided in the "Well data" worksheet, Item C. Hydraulic Fracture jobs conducted more than 30 days from the end of one stimulation job to the beginning of another stimulation job in the same well-bore is a new re-frac.

Notes

The EPA uses an assumption that 10% of wells are refractured each year to determine the number of re-frac's per year and then multiplies this by 9.175 MMSCF methane per re-frac to arrive at their inventory for this particular category.

For the year reported in Table 1, this table requests redundant information. The purpose of this table is to collect refracture information over a ten-year time period to provide a better estimate to EPA's assumption that 10% of wells are refractured each year.

FIGURE A-4. GAS WELL LIQUIDS UNLOADING SURVEY DATA

Table 3. Gas Well Venting for Liquids Unloading (Well Clean-ups)

A Please indicate if the information provided in Table 3 follows the Subpart W methodologies (yes or no)

		Conventional	Unconventional	Total	Comments
B	Geographic Area				
C	Time Period - Months				
D	Number of Operated Gas Wells Represented by the information provided				Unconventional wells are: Shale, coal-bed methane, and tight formation (sand, carbonate, etc.) that must be fracture stimulated to produce economic quantities of gas
E	Number of Gas Wells with Plunger Lift Installed				
F	Number of Gas Wells with Other Artificial Lift (Beam Pump; ESP; etc.)				
G	Number of Gas Wells Vented to the atmosphere for Liquids Unloading				EPA assumes that 41.3% of conventional gas wells (437,800) are vented for liquids unloading
H	Total number of Gas Well Vents for Time Period				EPA assumes that each venting well vents 38.7 times per year
I	Average Venting Time per Vent				EPA assumes that each venting event is 3 hours duration
J	*Number of Wells with Plunger Lifts that vent to the atmosphere*				This is a sub-category of data item #5. Please indicate here the number of wells that vent to the atmosphere
K	*Total Count of Gas Well Vents for Time Period - w/plunger*				
L	*Total Count of Gas Well Vents for Time Period - w-o/plunger*				
M	*Average Venting Time - w/plunger*				Hours per Vent - fractional hours if appropriate
N	*Average Venting Time - w-o/plunger*				Hours per Vent - fractional hours if appropriate
O	*Average Daily Production of Venting Gas Wells*				mcf/day
P	*Average Depth of Venting Wells*				feet
Q	*Average Casing Diameter of Venting Gas Wells*				inches
R	*Average Tubing Diameter of Venting Gas Wells w/plunger Lift*				inches
S	*Average Surface Pressure - Venting Gas Wells*				psig

Guidance:

This table represents data from a sampling of wells (as opposed to data for all of your wells).

If information is not available by conventional or unconventional wells, just provide data in the "total" column.

A If you do not have data based on Subpart W, please indicate this in data item A by typing yes or no in the shaded box

Copy the table to provide data for additional geographic areas

Please provide information that you have available.

Blue rows are the minimum level of detail needed

Green rows provide more detailed information

B Geographic Area: Please indicate whether the information provided is for all of your operations in the U.S., or just a sub-part (single basin or multiple basins).

C Time period: Indicate the number of months represented by the information provided. Ideally this is based on some portion of 2011 data collected for Subpart W reporting.

J This data line is a sub-category if data item E. From the difference between these two items, we are trying to determine the fraction of plunger equipped wells that do not vent.

K,L Please enter the number of liquids unloading events where gas is released to the atmosphere.

Notes:

Many companies have likely been tracking well venting for liquids unloading for several months due to Subpart W. API is soliciting information from members to correct/confirm EPA's assumptions regarding well un-loading. If you do not have the wells split out into Conventional and Unconventional categories then simply report the total counts and information in the Conventional categories.

FIGURE A-5. OTHER SURVEY DATA

Table 4. Other Activity Data

A

Centrifugal Compressors			
	Production/ gathering	Processing	
Year			2010 data is preferred, but available information from any recent year is OK
Number of Centrifugal Compressors			Include both engine/turbine driven and electric driven
Number with Dry Seals			
Number with Wet Seals			

B

Pneumatic Devices (Controllers)				
	Well Sites	Gathering/ Compressor Sites	Gas Processing Plants	
Year				2010 data is preferred, but available information from any recent year is OK
Number of Sites/Plants Covered				The total number of wells sites, gathering compressor sites, of gas processing plants represented by the inventory of devices below
Number of Low Bleed				EPA defines low bleed as <6 scfh
Number of High Bleed				EPA defines high bleed as >6 scfh
Number of Intermittent				

Guidance

For pneumatic devices: Do not include counts of devices operated on compressed air. Designate pneumatic devices between "high bleed", "low bleed", or "intermittent" following the approach your company is using for Subpart W reporting.

Appendix B. ANGA/API Well Survey Information

Responses from the API/ANGA survey covered more than 60,000 wells and provided data on:

- # of gas wells without hydraulic fracturing (anytime in their history)
- # of gas wells with hydraulic fracturing (any time in their history);
  - # of vertical gas wells with hydraulic fracturing (anytime in their history);
  - # of horizontal gas wells with hydraulic fracturing (anytime in their history);
- # of completions for vertical gas wells with hydraulic fracturing;
- # of completions for horizontal gas wells with hydraulic fracturing;
- # of completions for gas wells without hydraulic fracturing;
- # of workovers for vertical wells with hydraulic fracturing;
- # of workovers for horizontal wells with hydraulic fracturing; and
- # of workovers for wells without hydraulic fracturing.

Table B-1 summarizes the well data collected by the ANGA/API survey and presents its distribution by formation type and region. The regional distribution follows the National Energy Modeling System (NEMS) regions defined by the EIA. The data are compared to EPA's national well counts classified by type as provided in the August 2011 database file (EPA, 2011d).

TABLE B-1. API/ANGA SURVEY – SUMMARY OF GAS WELL COUNTS BY TYPE AND NEMS REGION*

NEMS Region	Conventional Wells	Shale	Coal-bed Methane	Tight	Unspecified
Northeast	12,144	3,541	9	3,874	2,563
Gulf Coast	2,870	1,990	-	7,968	1,521
Mid-Continent	9,081	2,333	-	3,747	5,579
Southwest	646	1,208	-	726	2,326
Rocky Mountain	3,707	366	5,458	18,053	11
West Coast	-	-	-	-	-
Unspecified					1,307
Survey TOTAL	28,448	9,438	5,467	34,368	13,307
% of EPA 2010 Well Counts (from database file)	14.2%	30.1%	11.5%	45.6%	
Overall Survey Total	91,028				
EPA Well Counts (2010, from database file)	200,921	31,381	47,371	75,409	
	56.6%	8.8%	13.3%	21.2%	
	355,082				
EPA National Inventory (2010)	484,795				
EIA National Well Count (2010)	487,627				

* ANGA/API survey data represents well counts current for calendar year 2010 or the first half of 2011.

As shown in Table B-1, data from the API/ANGA survey represent approximately 26% of the national gas wells reported by EPA's database (or 18.7% of the EIA well count data). This includes almost 46% of all tight gas wells and 30% of shale gas wells. This may indicate that the ANGA/API information has an uneven representation of unconventional gas wells, and in particular shale and tight gas wells, but it also appears that EPA's data may mis-categorize these types of wells. For example, the EPA/HPDI data set contains few wells from Pennsylvania and West Virginia while the API/ANGA survey includes 9,422 wells from that area (AAPG 160A).

Table B-2 summarizes additional details on the natural gas wells information collected through the second data collection effort by the ANGA/API survey which covered 60,710 wells.

TABLE B-2. ANGA/API SURVEY – ADDITIONAL DETAILS ON GAS WELL COUNTS*

	# Wells w/out hydraulic fracturing (anytime in their history)	# Wells with hydraulic fracturing (any time in their history)		
		Total	# Vertical wells	# Horizontal wells
TOTAL Conventional	1,498	16,678	14,844	1,834
TOTAL Coal Bed Methane	42	3,475	3,424	42
TOTAL Shale	1,931	9,084	2,012	7,072
TOTAL Tight	122	27,880	24,048	3,835
TOTAL OVERALL	**3,593**	**57,117**	**44,325**	**12,783**

* API/ANGA survey data represents well counts current for calendar year 2010 or the first half of 2011.

Additional information on natural gas wells with and without hydraulic fracturing was provided for approximately two-thirds (60,710 natural gas wells) of the total well data collected by the ANGA/API survey. For this subset of the well data, 94% of the gas wells have been hydraulically fractured at some point in their operating history, including almost 92% of the conventional wells. EPA's 2010 national inventory reported 50,434 gas wells with hydraulic fracturing. This is very similar to the number of unconventional gas wells that EPA reported in the 2009 national inventory. ***Based on the API/ANGA survey results, it appears that EPA has underestimated the number of gas wells with hydraulic fracturing.***

Of the ANGA/API survey responses for wells that have been hydraulically fractured, most (77.6%) are vertical wells. Vertical wells are predominately conventional gas wells, coal-bed methane and tight gas wells; while the majority of shale gas wells are horizontal. EPA does not currently distinguish between vertical and horizontal gas wells.

A Short Note About EPA and EIA's Well Counts

There is a discrepancy of over 132,000 natural gas wells between the EPA database information (EPA, 2011d) and the EIA national gas well counts (EIA, 2012), and a difference of almost 130,000 gas wells between the two EPA data sources (EPA, 2011d and EPA, 2012). This difference needs to be understood since ultimately both the IHS (EIA) and HPDI (EPA) data originate from the same state-level sources of information.

The EIA provides a gas well count of 487,627 for 2010 based on Form EIA-895A[7], the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals

[7] Form EIA-895, Annual Quantity And Value Of Natural Gas Production Report; http://www.eia.gov/survey/form/eia_895/form.pdf

Management Service) data, and World Oil Magazine (EIA, 2010). However, the EIA does not classify gas wells by conventional and unconventional, or by formation types, precluding more detailed comparison against the EIA data. For some parameters the classifications were based on qualitative descriptions of the formations' physical properties (e.g. permeability) rather than on actual measurements (i.e. permeability data in millidarcy readings).[8]

EPA provides a similar well count in the 2010 national inventory: 434,361 non-associated gas wells + 50,434 gas wells with hydraulic fracturing, resulting in a total of 484,795 gas wells (EPA, 2012). Further classification of gas wells or description on what constitutes a "non-associated" gas well versus a "gas well with hydraulic fracturing" is not provided in EPA's national inventory.

Small differences in the HPDI and IHS original data may arise from definitional differences as HPDI and IHS compile the raw data. In addition, each state may have a different interpretation of well definitions of gas versus oil wells that introduces differences among states for the wells reported. EPA had indicated in discussions with the API/ANGA group that their database well count information may not include all of the wells in the Marcellus basin. EIA indicates 44,500 gas wells in Pennsylvania in 2010. However, even in accounting for these wells, there is still a large difference (almost 88,000 wells) between EPA's total gas well number from their database source and EIA's well data.

Nevertheless, these discrepancies among the well counts need to be understood since these data all originate from the same state-level sources of information. Differences could arise, for example, from different interpretations of well definitions.

Since the EIA data is the *de facto* benchmark in the energy industry, the difference between the EIA and EPA well count data needs to be understood before any meaningful conclusions can be made from the EPA data.

Since EPA's well count from HPDI was much lower than the EIA, this report does not attempt to come up with a national gas well count but chose to use the 355,082 number from the EPA HPDI database because it was the only available database which parsed the wells into conventional and unconventional categories (EPA, 2011d).

[8] Information provided by Don Robinson of ICF (EPA's contractor).

Appendix C. Emission Estimates for Gas Well Liquids Unloading

Tables C-1 through C-4 summarize the liquids unloading emissions data collected through the API/ANGA survey and the resulting emission estimates. The emission factors reported in Table 4 are based on a regional weighted average of the conventional and unconventional gas wells, with and without plunger lifts. This provided a consistent comparison against the EPA emission factors which are reported only on a regional basis and do not differentiate between conventional and unconventional wells or wells with and without plunger lifts.

TABLE C-1. LIQUIDS UNLOADING FOR CONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS

NEMS Region	Northeast		Gulf Coast		Mid-Continent		Southwest
# venting gas wells	190	916	12	6	1	38	220
# gas well vents	4,335	39,668	144	60	1	2,444	880
Average casing diameter, inches	5	4.5	5.5	3.65	4.83	4	5.5
Average well depth, feet	3,375	3,448	10,000	19,334	7,033	4,269	8,000
Average surface pressure, psig (for venting wells)	85	50	Applied average 122	224	25.5	60.8	100
Average venting time, hours	1	2	1	2.5	.25	4.95	1
Average gas flow rate, Mscfd	2,861	7,388.5	300	664	58.43	84	100
Total emissions, scf gas/yr	11,503,329	51,547,287	1,961,463	1,322,380	1,548	3,769,194	7,879,520
Emissions per well, scfy gas/well	60,544	56,274	163,455	220,397	1,548	99,189	35,816

TABLE C-2. LIQUIDS UNLOADING FOR CONVENTIONAL GAS WELLS WITH PLUNGER LIFTS

NEMS Region	Northeast		Mid-Continent		
# venting gas wells	33	109	164	2	10
# gas well vents	1,272	4,217	489,912	23	7,300
Average tubing diameter, inches	2	2.375	1.995	2	2.375
Average well depth, feet	3,375	3,448	4,269	7,033	9,500
Average surface pressure, psig (for venting wells)	85	50	60.8	25.5	500
Average venting time, hours	1	0.3	0.067	0.75	0.08
Average gas flow rate, Mscfd	2,861	7,388.5	84	58.43	30
Total emissions, scf gas/yr	599,664	1,517,294	187,255,825	6,713	72,367,809
Emissions per well, scfy gas/well	18,172	13,920	1,141,804	3,357	7,236,781

TABLE C-3. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS

NEMS Region	Northeast	Gulf Coast					
# venting gas wells	337	6	14	8	27	11	15
# gas well vents	27,720	6	14	104	207	572	15
Average casing diameter, inches	4.5	5.5	5.5	5.5	4.5	5.5	10.75
Average well depth, feet	4,845	6,000	8,500	11,000	9,000	13,752	16,000
Average surface pressure, psig (for venting wells)	121.6	400	3,200	200	50	450	1,671
Average venting time, hours	1.3638	3	4	1	5.3	2	2
Average gas flow rate, Mscfd	26	200	13,000	25	130	353	8,500
Total emissions, scf gas/yr	122,362,610	177,839	5,887,104	2,560,844	722,663	39,633,526	17,501,885
Emissions per well, scfy gas/well	363,094	29,640	420,507	320,106	26,765	3,603,048	1,166,792

TABLE C-3. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS, CONTINUED

NEMS Region	Gulf Coast				Mid-Continent			
# venting gas wells	146	2	10	40	177	3	136	215
# gas well vents	146	12	120	40	400	7.2	391.2	2,580
Average casing diameter, inches	4.5	5.5	5.5	8.625	5.5	4.92	5.02	5.5
Average well depth, feet	8,500	11,647	11,000	12,500	3,911	10,293	7,888	11,000
Average surface pressure, psig (for venting wells)	15	25	94	661	80	90.04	98.75	200
Average venting time, hours	0.6875	1.5	4	1	2.5	1.58	1.925	0.5
Average gas flow rate, Mscfd	99	83	92	6,500	250	727	875	100
Total emissions, scf gas/yr	139,473	40,837	1,400,265	9,096,858	1,416,389	77,333	2,874,991	63,528,630
Emissions per well, scfy gas/well	955	20,418	140,027	227,421	8,002	25,778	21,140	295,482

TABLE C-3. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS, CONTINUED

NEMS Region	Southwest			Rocky Mountain		
# venting gas wells	228	6	3	113	2	28
# gas well vents	221	6	1	2,004	4	10,584
Average casing diameter, inches	9.625	5.5	5	4.038	4.7	4.5
Average well depth, feet	8,725	8,000	15,000	11,149	11,056	10,844
Average surface pressure, psig (for venting wells)	208	50	200	250	250	198
Average venting time, hours	1	0.5	6.67	1.616	0.75	3.18
Average gas flow rate, Mscfd	1,500	12	150	127	433	83
Total emissions, scf gas/yr	13,747,516	26,862	63,188	33,701,560	90,364	170,274,852
Emissions per well, scfy gas/well	60,296	4,477	21,063	298,244	45,182	6,081,245

TABLE C-4. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITH PLUNGER LIFTS

NEMS Region	Northeast			Gulf Coast				
# venting gas wells	308	103	5	3	2	22	59	5
# gas well vents	63,840	75,190	194	156	2	22	354	5
Average tubing diameter, inches	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Average well depth, feet	4,845	2,500	7,000	13,752	16,000	8,500	11,647	12,500
Average surface pressure, psig (for venting wells)	121.6	200	130	450	1,671	15	25	661
Average venting time, hours	0.2209	0.05	0.1	2	1	0.875	0.3	0.5
Average gas flow rate, Mscfd	26	15	628	353	8,500	99	83	6,500
Total emissions, scf gas/yr	78,496,300	78,461,940	368,444	2,036,862	288,681	7,401	215,123	86,220
Emissions per well, scfy gas/well	254,858	761,766	73,689	678,954	144,341	336	3,646	17,244

TABLE C-4. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITH PLUNGER LIFTS, CONTINUED

NEMS Region	Mid-Continent				Southwest
# venting gas wells	48	4	64	29	18
# gas well vents	155,742	9.6	170.4	348	25
Average tubing diameter, inches	2.375	3.88	4.11	2.4	1.995
Average well depth, feet	3,911	10,293	7,888	Applied average 9,521	8,725
Average surface pressure, psig (for venting wells)	80	90.04	98.75	74.69	208
Average venting time, hours	0.0833	2.99	2.6	0.5425	0.5
Average gas flow rate, Mscfd	250	727	875	Average applied 1,276.8	1500
Total emissions, scf gas/yr	101,698,021	124,984	906,144	529,679	66,812
Emissions per well, scfy gas/well	2,118,709	31,246	14,158	18,265	3,712

TABLE C-4. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITH PLUNGER LIFTS, CONTINUED

NEMS Region	Rocky Mountain				
# venting gas wells	247	23	296	19	793
# gas well vents	1,476	51.43	2,080	21,888	9,516
Average tubing diameter, inches	1.997	1.92	2.375	2.375	2.375
Average well depth, feet	11,149	11,164	11,056	10,844	7,400
Average surface pressure, psig (for venting wells)	250	290	250	198	150
Average venting time, hours	0.407	1.12	2.1	0.455	0.67
Average gas flow rate, Mscfd	127	454	433	83	46
Total emissions, scf gas/yr	6,070,440	238,833	12,027,460	98,082,094	22,045,130
Emissions per well, scfy gas/well	24,577	10,384	40,633	5,162,215	27,800

The calculated emissions shown in Tables C-1 through C-4 are based on applying Equation W-8 from 40 CFR 98 Subpart W to gas well liquid unloading without plunger lifts and Equation W-9 to gas well liquid unloading with plunger lifts. The equations and the terms are provided below.

98.233(f)(2) *Calculation Methodology 2.* Calculate the total emissions for well venting for liquids unloading using Equation W–8 of this section.

$$E_{s,n} = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_q \times \left(HR_{p,q} - 1.0\right)\times Z_{p,q}\right)\right] \quad \text{(Eq. W-8)}$$

Where:

$E_{s,n}$= Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of wells with well venting for liquids unloading for each sub-basin.

0.37×10^{-3}= {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

CD_p= Casing internal diameter for each well, p, in inches.

WD_p= Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.

SP_p= Shut-in pressure or surface pressure for wells with tubing production and no packers or casing pressure for each well, p, in pounds per square inch absolute (psia) or casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure of each well, p, in the sub-basin, in pounds per square inch absolute (psia).

V_p= Number of vents per year per well, p.

SFR_p= Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$= Hours that each well, p, was left open to the atmosphere during unloading, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

$Z_{p,q}$= If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

98.233(f)(3) *Calculation Methodology 3.* Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W–9 of this section.

$$E_{s,n} = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_q \times \left(HR_{p,q} - 0.5\right)\times Z_{p,q}\right)\right] \quad \text{(Eq. W-9)}$$

Where:

$E_{s,n}$= Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of wells with well venting for liquids unloading for each sub-basin.

0.37×10^{-3}= {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

TD_p= Tubing internal diameter for each well, p, in inches.

WD_p= Tubing depth to plunger bumper for each well, p, in feet.

SP_p= Flow-line pressure for each well, p, in pounds per square inch absolute (psia), using engineering estimate based on best available data.

V_p= Number of vents per year for each well, p.

SFR_p= Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$= Hours that each well, p, was left open to the atmosphere during each unloading, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

$Z_{p,q}$= If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.